



# Quarterly Report to Shareholders

For the nine months ended September 30, 2011



## Progress Announces Third Quarter Results

*North Montney continues to drive new era of growth*

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
<b>FINANCIAL HIGHLIGHTS</b>				
<b>Income Statement</b> (\$ thousands, except per share amounts)				
Petroleum and natural gas revenue	114,037	105,305	348,492	334,635
Cash flow <sup>1</sup>	51,563	45,094	169,503	143,112
Per share – diluted <sup>2</sup>	0.22	0.21	0.74	0.72
Cash dividends declared <sup>3</sup>	23,395	22,886	69,666	66,246
Per share	0.10	0.10	0.30	0.30
<b>Balance Sheet</b> (\$ thousands)				
Working capital deficiency (surplus)	(89,702)	58,929	(89,702)	58,929
Bank debt	-	218,133	-	218,133
Convertible debentures	353,100	247,355	353,100	247,355
Total debt	263,398	524,417	263,398	524,417
Capital expenditures	113,759	108,380	300,136	267,414
<b>OPERATIONAL HIGHLIGHTS</b>				
<b>Average Daily Production</b>				
Natural gas (mcf/d)	224,629	222,540	222,407	209,637
Crude oil (bbls/d)	2,037	1,872	2,064	1,900
Natural gas liquids (bbls/d)	3,462	3,373	3,539	3,496
Total daily production (boe/d)	42,937	42,335	42,671	40,335
<b>Average Realized Prices</b>				
Natural gas (\$/mcf)	3.73	3.78	3.83	4.29
Crude oil (\$/bbl)	89.99	69.79	90.85	72.66
Natural gas liquids (\$/bbl)	61.27	51.35	65.23	53.56
<b>Wells Drilled, Net</b>	12.0	20.2	36.5	48.6

(1) Represents cash flow from operating activities before changes in non-cash working capital.

(2) For the three months ended September 30, 2011 the Debentures are dilutive for earnings per share but anti-dilutive for cash flow per share. For the cash flow per share amount, the dilutive number of shares is 232,358,650.

(3) The dividends declared include dividends that grantees are entitled to on the vesting of the Share Unit Plan, the Long Term Incentive Plan and Performance Unit Incentive Plan.

Progress Energy Resources Corp. (“Progress” or the “Company”) announced results for the three months ended September 30, 2011 (the “Quarter”). The Quarter was highlighted by the closing of the transaction to create a strategic partnership with PETRONAS. Also in the Quarter, Progress released the results of an independent evaluation of the discovered-petroleum-initially-in-place (“DPIIP”) and Contingent Resources for 22 percent of the Company’s Montney land base (the “Evaluated Area”).

“We have set out to establish Progress as a premier investment in the natural gas business,” said Michael Culbert, President and Chief Executive Officer of Progress. “The study completed by our independent reserve evaluator affirms the scope and scale of our North Montney asset while our partnership with PETRONAS provides the capital required to continue to delineate our resource base and position us for long-term growth.”

## Highlights

- On August 2, 2011, closed the \$1.07 billion strategic partnership transaction with PETRONAS, with Progress receiving 25 percent of the total consideration (\$267.5 million) in cash and 75 percent (\$802.5 million) in the form of a capital carry;
- On September 12, 2011 announced the results of an independent evaluation of DPIIP and Contingent Resource for 139,150 net acres of Progress lands in the Town area of the Foothills of British Columbia, with DPIIP estimated at 27.3 trillion cubic feet (“Tcf”) and best estimate of Contingent Resource of 8.1 Tcf. The net present value, reflecting the recovery of capital costs using an eight percent discount rate, of the best estimate of Contingent Resources is \$8.6 billion;
- Drilled a total of 13 wells (11.8 net) in the Quarter of which 12 (10.8 net) were Montney horizontals. Six wells (5.3 net) of the drilled wells were brought on stream in the Quarter and the balance will be brought on stream before year end. The wells were primarily drilled in five of the Company’s Montney development pods at Town South, Town North, Gundy, Kobes, and Caribou;
- Entered into multi-year agreements with Spectra Energy Corp. to provide a total of 370 million cubic feet (“mmcf”) per day of gathering and processing services to support Progress’ Montney growth plans in northeast British Columbia;
- Produced 42,937 barrels of oil equivalent (“boe”) per day in the Quarter. Unplanned outages at major gas processing facilities and the shutting in of adjacent Montney wells during completion operations impacted production by approximately 1,000 boe per day in the Quarter;
- Generated cash flow of \$51.6 million in the Quarter or \$0.22 per share, diluted; and,
- As at September 30, 2011, Progress was undrawn on its \$650 million covenant-based credit facility and had a working capital surplus of \$90 million.

## North Montney Program Update

Progress has built the industry’s largest Montney land position at over 1,250 net sections, or approximately 825,000 net acres, spanning 560 kilometers from northwest Alberta to northeast British Columbia. The primary focus of the Company’s North Montney program remains in the Foothills of northeast British Columbia where Progress holds approximately 625,000 net acres of largely contiguous Montney rights. Progress continues to pursue the strategic plan set out in November 2010 of doubling its production base over the next five years by developing multiple 50 mmcf per day development pods. Approximately 75 percent of the Company’s capital spending in 2011 has been directed towards the Montney. Drilling plans will be focused on Progress’ development pods for the remainder of 2011, including 10 horizontals in the fourth quarter. Progress is currently producing more than 80 mmcf per day, net, from the North Montney area. Progress’ North Montney wells have the advantage of receiving a deep drilling royalty credit of approximately \$2 million per well and

additionally, produce approximately 20 barrels of high value natural gas liquids per million cubic feet of gas produced, which is in line with the Company's overall corporate average for natural gas liquids produced.

During the quarter, at the Town South development pod (100 percent working interest), Progress drilled two horizontal wells targeting the upper and lower Montney. Town South has reached its 50 mmcf per day production target and will now evolve to a maintenance phase which implies the annual drilling of approximately six horizontal wells per year to sustain volumes at 50 mmcf per day.

Also in the Quarter, at Gundy (100 percent working interest), Progress drilled four horizontal wells, one targeting the lower Montney and three the upper Montney. These wells were completed with an average rate of 5.3 mmcf per day. To accommodate the additional volumes, the Gundy processing facility, which is currently on stream at 25 mmcf per day, will be expanded to 50 mmcf per day during the fourth quarter of 2011.

At the Town North pod development (100 percent working interest), Progress drilled and completed one horizontal well targeting the upper Montney. Progress now has seven producing horizontals in Town North area, with both the upper and lower Montney being productive. Town North's first 25 mmcf per day processing facility was brought on stream early in the second quarter of 2011.

At Caribou (100 percent working interest), Progress drilled one horizontal well in the Quarter targeting the lower Montney which will be completed in the fourth quarter. A third well will be drilled in the fourth quarter. These wells will utilize existing infrastructure, with a new Montney facility expected to be constructed in 2013.

At the Kobes development pod (30 percent working interest), Progress completed two horizontal wells with initial production averaging 8.9 mmcf per day each from the two wells. As at quarter end, the Kobes pod was producing approximately 10 mmcf per day net to Progress. Progress operates the northern portion of the Kobes development, while the southern area is partner operated.

At Nig (50 percent working interest), approximately 25 kilometers east of Town, a horizontal well was drilled in the upper Montney and is currently being completed. The first horizontal in this area tested 4.6 mmcf per day and is expected to be on-stream within a month.

In the Bubbles/Jedney area (100 per cent working interest), Progress continued delineation work on its North Montney lands, drilling one vertical well in the Quarter. The well tested both the upper and lower Montney with initial test rates of 1.7 mmcf per day. The Company holds approximately 60,000 net acres of undeveloped land in the Bubbles/Jedney area, located 25 kilometers northeast of the Town area, with plans for a first horizontal well in 2012.

## **Deep Basin of Northwest Alberta**

Progress holds a material land position covering approximately 280,000 net acres in the Deep Basin of northwest Alberta. Given the large and contiguous nature of the land base, the Company is able to test play concepts, including liquids-rich gas plays and light oil plays, and with success can quickly establish a meaningful position at lower cost than industry competitors. Of note, Progress holds 140,000 net Montney acres in the Deep Basin where the pace of industry activity is increasing.

Progress focused its Deep Basin gas drilling program in the first quarter of 2011 to benefit from the Alberta Drilling Royalty Credit Program which ended on March 31, 2011. The Company maintains a large inventory of liquids-rich natural gas drilling locations but will focus its Deep Basin capital investment for the remainder of 2011 on its growing light oil opportunities.

Progress has identified more than 50 net light oil horizontal locations on its acreage position in the Deep Basin, where the Company has deeper natural gas production. In addition, the Company is evaluating another 20 net prospective sections, or approximately 13,000 net acres of land within the Deep Basin. The Dunvegan formation is a pervasive package of stacked marine and fluvial Cretaceous sands ranging in thickness from one meter units to over 25 meters of reservoir. Detailed in-house geologic mapping of over 100 kilometers has illustrated several

productive fairways across the Company's lands where it has previously drilled deeper gas tests. Progress has drilled and completed three horizontal Dunvegan wells since the fourth quarter of 2010, with first month average production of 300 boe per day for each well. A further three wells, at an all-in cost of \$4 million per well, are planned to be drilled in 2011 with plans for an increased drilling program in 2012.

### **PETRONAS Strategic Partnership**

During the Quarter, Progress closed the transaction to create a strategic partnership with the Malaysian national oil and gas company, PETRONAS, to develop a portion of Progress' Montney assets in the Foothills of northeast British Columbia. Progress sold a 50 percent working interest in its Altares, Lily, and Kahta properties (the "North Montney Joint Venture") to PETRONAS for CDN\$1.07 billion in cash and carried interest. As well, the partners will explore opportunities to develop liquefied natural gas ("LNG") export capacity in British Columbia ("the LNG Export Joint Venture"). Progress received 25 percent of the total consideration (CDN\$267.5 million) in cash at closing. The remaining \$802.5 million will be in the form of a capital carry whereby PETRONAS will fund 75 percent of Progress' 50 percent interest.

Three rigs will be operating on the North Montney Joint Venture properties in the fourth quarter. The LNG Export Joint Venture has selected an engineering firm to undertake the technical detailed feasibility as well as initiate the site selection process.

### **DPIIP Evaluation – Validating the Scope and Scale of the North Montney**

In the Quarter Progress announced the results of an independent evaluation of 217 net sections or 139,150 net acres of land in the Foothills of northeast British Columbia (the "Evaluated Area"). The Evaluated area includes the Company's three pod developments at Town South, Town North, and Gundy. The estimate of DPIIP for the Evaluated Area is 27.3 Tcf or approximately 126 billion cubic feet ("Bcf") per section on average. The best estimate of the Contingent Resource for the Evaluated Area is 8.1 Tcf, with a high case estimate of 10.2 Tcf and a low case of 5.4 Tcf. The net present value, reflecting the recovery of capital costs using an eight percent discount rate, of the best estimate of Contingent Resources is \$8.6 billion.

DPIIP is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. DPIIP is typically broken down into four components including production, reserves, contingent resource and discovered unrecoverable petroleum initially in place. Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. It is also appropriate to classify as Contingent Resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. The primary contingency which prevents the classification of the Contingent Resources as reserves is the current early stage of development. Additional drilling, completion, and testing data is generally required before

Progress can commit to their development. As additional drilling takes places, it is expected that the Contingent Resources will be booked as reserves. Estimates of DPIIP and Contingent Resources described herein are estimates only; the actual resources may be higher or lower than those calculated in the independent evaluation. There is no certainty that the resources described in the evaluation will be commercially produced.

### **Financial Strength**

In 2011, Progress has taken considerable steps to ensure that the Company can fund its capital program in the near and long term. During the first four months of 2011, the Company divested of non-core assets with associated production of approximately 800 boe per day for proceeds of approximately \$35 million. The successful closing of the PETRONAS strategic partnership provided \$267.5 million in cash, further strengthening the Company's balance sheet.

In the second quarter of 2011 the Company renegotiated its bank credit facility to be a covenant-based facility rather than a borrowing base facility. This facility is a 3-year extendible revolving secured facility in the amount of \$650 million from a syndicate of lenders with an initial maturity date of April 29, 2014. As at

September 30, 2011, the Company was undrawn on its \$650 million revolving credit facility and had a working capital surplus of \$90 million. During the Quarter, the 6.25 percent convertible debenture was settled in cash for \$75 million. As Progress continues to grow its production, reserves and cash flow with the objective of doubling the size of the Company in the next five years, this new facility and the strategic partnership with PETRONAS will provide increased flexibility to fund the Company's strategic plan.

Cash flow for the Quarter was \$51.6 million or \$0.22 per share, diluted. Capital investment was \$113.8 million. Debt-to-total capitalization as at September 30, 2011 was eight percent. Progress' average gas price in the Quarter was \$3.73 per thousand cubic feet ("mcf"). The Company's high heat content gas stream achieves a premium to AECO prices. Royalty rates averaged 12.3 percent in the Quarter which was lower than the same period in 2010 due to the higher proportion of Montney production which benefits from the British Columbia Deep Well Credit Program. Operating costs averaged \$5.56 per boe, or \$0.93 per mcf, in the Quarter reflecting the Company's continued focus on operational efficiencies and maximization of volumes through existing facilities.

In the first half of 2011, Progress entered into a series of hedges on a portion of its natural gas production, buying puts on 30,000 gigajoule ("GJ") per day at a net floor of \$3.43 per GJ. The Company now has 60,000 GJ per day or approximately 22 percent of its natural gas production hedged at a net floor of approximately \$3.41 per GJ or approximately \$3.90 per mcf, based on Progress' high heat content gas, for the period from May 1, 2011 to October 31, 2011. The Company also entered into a series of AECO basis swaps on 40,000 million British Thermal Units ("mmbtu") per day for 2011 at a net differential of US\$0.50 per mmbtu and on 40,000 mmbtu per day for 2012 at a net differential of US\$0.62 per mmbtu.

## **Investor Day**

Progress will be holding its 2<sup>nd</sup> Annual Investor Day from 8:30 a.m. to noon on Tuesday, November 1, 2011 at the Westin Hotel in Calgary, Alberta and on Wednesday, November 2, 2011 at the Royal York Hotel in Toronto. Institutional investors interested in attending either session are asked to contact Kurtis Barrett at [kbarrett@progressenergy.com](mailto:kbarrett@progressenergy.com) or at 403-539-1843 or Kim Lewis at [kewis@progressenergy.com](mailto:kewis@progressenergy.com) or at 403-539-1801.

## **Fourth Quarter Dividend and Dividend Reinvestment Program**

The Board of Directors of Progress today announced that the fourth quarter eligible dividend will be maintained at \$0.10 per share. The eligible dividend will be payable on January 16, 2012 to common shareholders of record as of December 31, 2011. The ex-dividend date is expected to be December 28, 2011. Based on the October 26, 2011 closing share price on the Toronto Stock Exchange of \$14.66, this represents an annualized yield of approximately 2.7 percent. The amount of future cash dividends, if any, is subject to the discretion of the Progress Board of Directors.

Progress has a dividend reinvestment plan (the "DRIP") that allows eligible shareholders of Progress to direct that their cash dividends be reinvested in additional common shares which, when issued from treasury, will be issued at 95 percent of the Average Market Price (as defined in the DRIP) on the applicable dividend payment date. A registered shareholder who wishes to enroll in the DRIP may do so by contacting Computershare Trust Company of Canada, the Plan Agent. Beneficial shareholders who wish to participate in the DRIP should contact the broker or other nominee through which their common shares are held to provide appropriate enrollment instructions and to ensure any deadlines or other requirements that such broker or nominee may impose or be subject to are met. U.S. residents may not participate in the DRIP program.

## Outlook

With a large number of wells completed and expected to come on stream during the fourth quarter, we are on track to exit 2011 at our previously announced guidance of approximately 50,000 boe per day. Achieving the exit rate will result in year-over-year production growth of approximately 15 percent.

As a result of incremental land acquisitions, infrastructure investments and the commencement of the North Montney Joint Venture activities, the 2011 capital program has been expanded to \$400 million.

The focus of our capital program for the remainder of the year will be the continued advancement of our highly economic Montney pod developments at Town South, Town North, Gundy, and Kobes. Additionally, activity on our North Montney Joint Venture lands in the Altares, Lily and Kahta will continue to increase as we enter this winter. We will continue to take advantage of the factors that make the North Montney attractive; the natural gas we produce is sweet and therefore does not require expensive sour gas processing; we attract a deep drilling royalty credit of approximately \$2 million per well; and, we produce approximately 20 barrels per million cubic feet of high-value natural gas liquids. Along with our experience in the area, continued improvement of drilling and completions technologies and strong initial production rates and recoveries, we are well positioned to deliver value for shareholders.

Along with the majority of other global commodities, North American natural gas prices weakened in the Quarter, as concerns about slowing economic growth weighed on markets. Comparatively, landed LNG prices in Japan rose approximately 20 percent in the Quarter to settle above USD\$17 per mmbtu. We remain optimistic about the long-term prospects for natural gas in North America. The partnership that we have established with PETRONAS, a global leader in LNG development and marketing, may provide Progress with the opportunity to gain direct exposure to Asian pricing, which would be unique amongst our peer group. The recent announcements, by the province of British Columbia, to grow a viable LNG industry is further evidence of momentum building for the large scale development of LNG facilities on the West Coast.

With a strong balance sheet, access to capital, a strong joint venture partner and large contiguous land positions in attractive plays, we are well positioned to execute on our strategic growth plan to reach 100,000 boe per day by the end of 2015.

## Consolidated Financial Statements and MD&A

Third Quarter 2011 Consolidated Financial Statements and Notes to the Consolidated Financial Statements and Management's Discussion and Analysis for Progress Energy Resources Corp. have been filed on SEDAR ([www.sedar.com](http://www.sedar.com)) under Progress Energy Resources Corp. and can also be accessed on the Company's website at [www.progressenergy.com](http://www.progressenergy.com).

Progress is a Calgary based, mid-size energy Company primarily focused on natural gas exploration, development and production in northwest Alberta and northeast British Columbia. Common shares of Progress are listed on the Toronto Stock Exchange under the symbol PRQ.

### For further information:

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## MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis ("MD&A") of financial results is dated October 27, 2011 and is to be read in conjunction with the accompanying unaudited interim consolidated financial statements and related notes for the period ended September 30, 2011 of Progress Energy Resources Corp. ("Progress" or the "Company") and the audited consolidated financial statements and related notes and MD&A for the year ended December 31, 2010. The interim consolidated financial statements have been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting". Previously the Company prepared its 2010 interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). The adoption of IFRS has not had an impact on the Company's operations, strategic decisions or cash flow from operations before changes in non-cash working capital. The reporting and the measurement currency is the Canadian dollar.

### Description of Business

Progress is a Calgary based, natural gas focused company. The principal undertaking of the Company is to explore for, develop and hold interests in petroleum and natural gas properties. Primary operating regions include the Deep Basin of northwest Alberta and the northeast British Columbia Foothills. The common shares of the Company trade on the Toronto Stock Exchange ("TSX") under the symbol PRQ. The 5.25 percent and 5.75 percent convertible unsecured subordinated debentures (the "Debentures") trade on the TSX under the symbols PRQ.DB.B and PRQ.DB.C, respectively. The 6.25 percent convertible unsecured subordinated debentures were repaid on maturity on September 30, 2011.

### JOINT ARRANGEMENT WITH PETRONAS

On August 2, 2011 Progress and the Malaysian national oil and gas company, PETRONAS, entered into a strategic partnership to develop Progress' Montney shale assets in the Altares, Lily, and Kahta areas in the Foothills of northeast British Columbia and to pursue the development of a liquefied natural gas ("LNG") export facility on the west coast of British Columbia (the "Joint Arrangement"). The Joint Arrangement resulted in the creation of the North Montney Upstream Joint Venture, owned 50 percent by Progress and 50 percent by PETRONAS, and the LNG Export Joint Venture, owned 20 percent by Progress and 80 percent by PETRONAS, as described below. A Support Agreement is in place that sets forth the conditions on which the North Montney Upstream Joint Venture and the LNG Export Joint Venture should be coordinated, developed and provide support to each other. A Subscription Agreement was also entered into whereby Progress may obtain financing from PETRONAS to fund future capital expenditures the terms of which are also described below.

#### North Montney Upstream Joint Venture

Under the arrangement, Progress sold 50 percent of its working interest in the Altares, Lily and Kahta areas to PETRONAS, approximately 75,000 net acres of undeveloped land representing approximately nine percent of Progress' total Montney land holdings. Progress received \$267.5 million in cash on the closing of the transaction resulting in a gain of approximately \$236.0 million which is reflected in the Company's net earnings for the three and nine months ended September 30, 2011. In addition, Progress will receive \$802.5 million over the next five years in the form of a capital carry whereby PETRONAS will pay 75 percent of Progress' share of future capital expenditures in the North Montney Upstream Joint Venture (the "Upstream Joint Venture") for a total consideration of \$1.07 billion. The \$802.5 million will be recognized as a reduction to capital spending in proportion to the capital spent. Under the terms of the Upstream Joint Venture, any amount of the \$802.5 million that remains outstanding at the end of five years, being August 2, 2016, will be paid to Progress in full. Such a payout, if any, would be recognized in earnings. Progress is the operator of the Upstream Joint Venture which is comprised of approximately 150,000 total net acres of land, including both Progress' and PETRONAS' ownership share.

## **LNG Export Joint Venture**

The LNG Export Joint Venture has launched a feasibility study to evaluate the potential of building and operating a new LNG export facility on the west coast of British Columbia. PETRONAS will be leading the development of the LNG export facility and PETRONAS and Progress will jointly market the LNG utilizing PETRONAS' well-established and extensive network of global customers. In accordance with the Support Agreement the production from the Upstream Joint Venture will be dedicated to the LNG Export Joint Venture. Until a positive investment decision is made, the production from the Upstream Joint Venture will be sold on a short term contract basis. If the investment decision has not been made within five years, the Upstream Joint Venture may freely market its production. The five years may be extended an additional two years if substantial progress has been achieved toward making a final investment decision.

## **Subscription Agreement**

Prior to making the final investment decision on the LNG export facility, PETRONAS has the option to participate in any security offering by Progress, public or private, of up to 10 percent of the offering. At the time of a successful LNG investment decision, Progress can require PETRONAS to purchase common shares from treasury on a private placement basis for the lesser of \$600 million or that number of common shares that would result in PETRONAS having an ownership interest of 10 percent of the issued and outstanding common shares of Progress. If Progress elects to require PETRONAS to purchase common shares that would result in them owning less than five percent of the issued and outstanding common shares, then PETRONAS will have the option to purchase common shares resulting in it having an ownership interest of 10 percent. If Progress elects to require PETRONAS to purchase common shares resulting in an ownership interest of between five and 10 percent, PETRONAS can elect to purchase common shares amounting to an additional five percent ownership interest. The proceeds will be placed in escrow and used to fund future capital expenditures of the Upstream Joint Venture. If PETRONAS holds an ownership of 10 percent or more of Progress, it also has the right to nominate one individual to be a director of Progress.

## **OPERATING SUMMARY**

In accordance with Canadian industry practice, production volumes, reserve volumes and revenues are reported on a Company interest basis (working interest plus royalty interest), before deduction of Crown and other royalties, unless otherwise indicated. The Company's results of operations are dependent on production volumes of natural gas, crude oil and natural gas liquids and the prices received for this production. Prices for these commodities have shown significant volatility during recent years and are determined by supply and demand factors, including weather, general economic conditions and changes in the Canadian/United States ("US") currency exchange rate.

In this MD&A, production and reserves information may be presented on a "barrel of oil equivalent" or "boe" basis with six thousand cubic feet ("mcf") of natural gas being equivalent to one barrel ("bbl") of crude oil or natural gas liquids. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

## Production

	Three Months Ended September 30		Nine Months Ended September 30		Change
	2011	2010	2011	2010	
<b>Average Daily Production</b>					
Natural gas ( <i>mcf/d</i> )	224,629	222,540	222,407	209,637	6%
Crude oil ( <i>bbls/d</i> )	2,037	1,872	2,064	1,900	9%
Natural gas liquids ( <i>bbls/d</i> )	3,462	3,373	3,539	3,496	1%
Total daily production ( <i>boe/d</i> )	42,937	42,335	42,671	40,335	6%
Sulphur sales ( <i>tons/d</i> )	56	81	66	93	(29%)

Progress' production for the three months ended September 30, 2011 (the "Quarter") averaged 42,937 boe per day consisting of 224,629 mcf per day of natural gas, 2,037 bbls per day of crude oil and 3,462 bbls per day of natural gas liquids. Production during the Quarter was slightly higher than the same period in 2010 of 42,335 boe per day. Unplanned outages at major gas processing facilities and the shutting in of adjacent Montney wells during completion operations impacted production for the Quarter by approximately 1,000 boe per day. The Company's production portfolio for the Quarter was weighted 87 percent to natural gas, five percent to crude oil and eight percent to natural gas liquids.

Natural gas production of 224,629 mcf per day for the Quarter was slightly higher than the same period in 2010 of 222,540 mcf per day. Crude oil and natural gas liquids ("NGL") production for the Quarter of 5,499 bbls per day was slightly higher than the same period in 2010 of 5,245 bbls per day.

Progress undertook an asset disposition program in early 2011 to further focus its asset base in the Deep Basin of northwest Alberta and the Foothills of northeast British Columbia. As a result, on March 31, 2011, the Company disposed of its Two Creek Alberta properties for approximately \$12.7 million (approximately 260 boe per day) and disposed of certain royalty interests in the Copton, Alberta area for approximately \$4.2 million (approximately 60 boe per day). In April 2011, the Company disposed of its Fort St. John Plains North properties for approximately \$12.7 million (approximately 380 boe per day) as well as certain properties in the Copton, Alberta area for approximately \$4.8 million (approximately 115 boe per day). As described above, Progress also disposed of 50 percent of its Montney working interest in Altares, Lily and Kahta areas during the Quarter. As the working interest was primarily undeveloped land, the transaction had no impact to production during the Quarter.

Year-to-date 2011 production was 42,671 boe per day consisting of 222,407 mcf per day of natural gas, 2,064 bbls per day of crude oil and 3,539 bbls per day of natural gas liquids. This production was six percent higher than the same period in 2010 of 40,335 boe per day due to the Company's acquisition of certain northeast British Columbia Foothills assets (the "Foothills Acquisition") on March 31, 2010 as well as the successful drilling results which more than offset the impact of the McMahon turnaround and dispositions in 2010 and 2011. The 15 day McMahon turnaround, which is scheduled every three years, reduced year-to-date production by approximately 1,400 boe per day. The Company's production portfolio for the nine months ended September 30, 2011 was weighted 87 percent to natural gas, five percent to crude oil and eight percent to natural gas liquids.

With a large number of wells completed and expected to come on stream during the fourth quarter, Progress is on track to exit 2011 at the previous announced guidance of approximately 50,000 boe per day.

## Production by Region

	Three Months Ended September 30		Nine Months Ended September 30		Change
	2011	2010	2011	2010	
<b>Average Daily Production (boe/d)</b>					
Foothills	29,394	23,535	27,921	20,452	37%
Fort St. John Plains	1,314	1,723	1,409	1,854	(24%)
Other	525	572	489	606	(19%)
<b>Total British Columbia</b>	<b>31,233</b>	<b>25,830</b>	<b>29,819</b>	<b>22,912</b>	<b>30%</b>
Deep Basin	11,524	15,887	12,567	15,987	(21%)
Central Alberta	-	53	-	878	(100%)
Other	180	565	285	558	(49%)
<b>Total Alberta</b>	<b>11,704</b>	<b>16,505</b>	<b>12,852</b>	<b>17,423</b>	<b>(26%)</b>
<b>Total daily production</b>	<b>42,937</b>	<b>42,335</b>	<b>42,671</b>	<b>40,335</b>	<b>6%</b>

Excludes sulphur production

## Pricing

### Natural Gas Markets

Progress' realized natural gas price for the Quarter was \$3.73 per mcf (\$3.22 per gigajoule ("gj")) compared to \$3.78 per mcf (\$3.28 per gj) for the same period in 2010. The AECO daily index averaged \$3.47 per gj in the Quarter (2010 - \$3.36 per gj), the AECO monthly index averaged of \$3.53 per gj (2010 - \$3.52 per gj) and the Station #2 daily index averaged \$3.10 per gj (2010 - \$3.16 per gj). Progress markets its natural gas at a mix of daily and monthly pricing.

For the nine months ended September 30, 2011 Progress' realized natural gas price was \$3.83 per mcf (\$3.32 per gj) compared to \$4.29 per mcf (\$3.74 per gj) for the same period in 2010. During the nine months ended September 30, 2011 the AECO daily index averaged \$3.57 per gj (2010 - \$3.91 per gj), the AECO monthly index averaged of \$3.55 per gj (2010 - \$4.09 per gj) and the Station #2 daily index averaged \$3.25 per gj (2010 - \$3.72 per gj).

In the Quarter Henry Hub prices averaged \$4.05 per mmbtu, but ended the Quarter at a low of \$3.67 per mmbtu, a steep 15 percent decline versus the second quarter of 2011. Excessive heat in the early part of July propelled gas prices to an eight percent week over week gain, their largest since November 2010. The effects of rapidly increasing US supply were felt into August, as large storage injections took place despite extreme heat. Supply was the focus of the market for the remainder of the Quarter, with no demand catalysts large enough to lift prices, which steadily fell in August and September. Tropical storm activity in the Gulf of Mexico did not disrupt offshore production in a meaningful way in the Quarter. With Gulf of Mexico production declining as a share of total US production, down 2.3 percent to 7.2 percent year over year, the effects of future storm activity on prices may be lessened. A turbulent global economic environment was bearish for natural gas demand, as forecasts for reduced GDP growth around the world implied reduced demand for commodities including natural gas.

Much like the second quarter of 2011, abnormal weather events were the key driver of natural gas prices in the Quarter. A La Nina weather pattern is forecasted for the 2011-12 winter, meaning below normal temperatures are probable for the majority of North America. Unseasonably cold weather would likely result in increased gas consumption from residential and electricity generation sources. In the long term, the recent announcements by the province of British Columbia to grow a viable LNG industry, as well as the National Energy Board's approval of the first Canadian LNG export license are encouraging steps towards accessing higher priced Asian markets.

## Oil Markets

Progress' realized prices for its liquids streams for the Quarter were \$89.99 per bbl (2010 - \$69.79 per bbl) for crude oil and \$61.27 per bbl (2010 - \$51.35 per bbl) for natural gas liquids. For the nine months ended September 30, 2011 Progress realized \$90.85 per bbl (2010 - \$72.66 per bbl) for crude oil and \$65.23 per bbl (2010 - \$53.56 per bbl) for natural gas liquids.

Crude oil prices fell dramatically in the Quarter, losing 16 percent from July to September, after enduring a 12 percent decline in the second quarter of 2011. Prices ended the Quarter at \$79.20 per bbl, falling below \$80 per bbl for the first time since October 2010. Demand from the BRIIC nations (Brazil, Russia, India, Indonesia, and China) and continued unrest in Libya provided support to prices in July, with oil hovering in the \$95-\$100 per bbl range. The US debt ceiling impasse and Eurozone contagion worries hit crude markets hard towards the end of July, culminating with oil trading at an eight month low in early August after S&P downgraded the US' credit rating. Tropical storm activity in the Gulf provided a brief respite for prices, with shipping lanes being disrupted and refineries shuttering due to flooding concerns, both reducing the short term availability of crude. Oil prices fell in mid-September as the US Federal Reserve announced it would not engage in a third round of quantitative easing, pessimism increased concerning European officials capacity to solve Greece's debt problems and global growth forecasts were cut. Economic data from China indicated that manufacturing output may be slowing, albeit remaining at high levels relative to developed nations. Cooling of the Chinese economy, the largest consumer of crude oil, contributed to further bearish sentiment.

Crude oil prices continue to face substantial uncertainty, with foreseeable risks to both the upside and downside. OPEC's spare capacity has been reduced as a result of the ongoing unrest in the Middle East and North Africa, which could make it difficult for OPEC to respond should further supply disruptions surface. Fears persist that the debt crisis in the Eurozone could trigger a credit crunch similar to 2008, which would further hamper the already struggling global economy and curtail crude oil demand.

## Commodity Prices

	Three Months Ended September 30		Nine Months Ended September 30		Change
	2011	2010	2011	2010	
<b>Average Benchmark Prices</b>					
Natural gas – AECO (daily) (\$/gj)	3.47	3.36	3.57	3.91	(9%)
Natural gas – AECO (monthly) (\$/gj)	3.53	3.52	3.55	4.09	(13%)
Natural gas – Station #2 (daily) (\$/gj)	3.10	3.16	3.25	3.72	(13%)
Crude oil – WTI (US\$/bbl)	89.76	76.20	95.48	77.65	23%
Crude oil – Edmonton par price (Cdn\$/bbl)	91.97	74.59	94.34	76.65	23%
Exchange rate (Cdn\$/US\$)	0.9802	1.0391	0.9780	1.0359	(6%)
<b>Average Realized Prices</b>					
Natural gas (\$/mcf)	3.73	3.78	3.83	4.29	(11%)
Crude oil (\$/bbl)	89.99	69.79	90.85	72.66	25%
Natural gas liquids (\$/bbl)	61.27	51.35	65.23	53.56	22%
Sulphur – net (\$/ton)	108.51	4.57	103.23	16.98	508%

## Price Risk Management

The Company, from time to time, may enter into financial contracts for the purpose of protecting its cash flow from the volatility of natural gas prices and Canadian to US foreign exchange rates. For the Quarter, the Company's risk management program had a net realized loss of \$1.3 million (2010 - \$5.7 million gain). For the nine months ended September 30, 2011 the Company's risk management program had a net realized gain of \$2.7 million (2010 - \$8.7 million gain).

At September 30, 2011 the fair value of the financial contracts was a liability of \$2.8 million (2010 - \$10.6 million asset). At September 30, 2011 the Company had the following financial contracts outstanding:

Contracts	Volume	Pricing Point	Strike Price \$/gj	Premium	Term
Bought Put Option	5,000 gj/d	AECO	\$3.610	\$0.3400	Feb 1/11 to Oct 31/11
Bought Put Option	5,000 gj/d	AECO	\$3.650	\$0.3350	Feb 1/11 to Oct 31/11
Bought Put Option	5,000 gj/d	AECO	\$3.830	\$0.3570	Feb 1/11 to Oct 31/11
Bought Put Option	10,000 gj/d	AECO	\$3.760	\$0.3400	May 1/11 to Dec 31/11
Bought Put Option	10,000 gj/d	AECO	\$3.785	\$0.3475	May 1/11 to Dec 31/11
Bought Put Option	10,000 gj/d	AECO	\$3.780	\$0.3500	May 1/11 to Dec 31/11

Contracts	Volume	Pricing Point	Strike Price \$/gj	Cost/Premium	Term
Swap – call spread	5,000 gj/d	AECO	\$3.60 - \$4.60	\$0.26	Feb 1/11 to Oct 31/11
Swap – call spread	5,000 gj/d	AECO	\$3.65 - \$4.65	\$0.26	Feb 1/11 to Oct 31/11
Swap – call spread	5,000 gj/d	AECO	\$3.81 - \$4.81	\$0.26	Feb 1/11 to Oct 31/11

Contracts	Volume	Pricing Point	Differential	Term
Swap – basis hedge	30,000 mmbtu/d	Nymex	(\$0.5000)	May 1/11 to Dec 31/11
Swap – basis hedge	10,000 mmbtu/d	Nymex	(\$0.4950)	May 1/11 to Dec 31/11
Swap – basis hedge	10,000 mmbtu/d	Nymex	(\$0.6300)	Jan 1/12 to Dec 31/12
Swap – basis hedge	10,000 mmbtu/d	Nymex	(\$0.6250)	Jan 1/12 to Dec 31/12
Swap – basis hedge	10,000 mmbtu/d	Nymex	(\$0.6175)	Jan 1/12 to Dec 31/12
Swap – basis hedge	10,000 mmbtu/d	Nymex	(\$0.6150)	Jan 1/12 to Dec 31/12

Contracts	Volume	Pricing Point	Strike Price \$/gj	Term
Sold Calls	10,000 gj/d	AECO	\$7.575	Jan 1/11 to Dec 31/11
Sold Calls	10,000 gj/d	AECO	\$7.500	Jan 1/11 to Dec 31/11

The change in the fair value of the financial contracts for the three and nine months ended September 30, 2011 was a loss of \$1.0 million and a loss of \$6.8 million, respectively (2010 - \$1.1 million gain and \$7.8 million gain) due primarily to the change in the Canadian to US exchange rate and the impact on the basis hedges.

## Revenue

For the Quarter petroleum and natural gas revenue increased eight percent to \$114.0 million compared to \$105.3 million for the same period in 2010 due to higher crude oil and NGL prices. Production revenue for the Quarter consisted of \$77.1 million from natural gas sales, \$16.9 million from crude oil sales, \$19.5 million from the sale of natural gas liquids and \$0.6 million from the sale of sulphur.

For the nine months ended September 30, 2011, revenues of \$348.5 million were higher than the same period in 2010 of \$334.6 million as a result of both higher production and higher crude oil and NGL prices.

<b>Petroleum and Natural Gas Revenue</b> (\$ thousands)	<b>Three Months Ended September 30</b>		<b>Nine Months Ended September 30</b>		<b>Change</b>
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>	
Natural gas sales	<b>77,099</b>	77,318	<b>232,396</b>	245,432	(5%)
Crude oil sales	<b>16,866</b>	12,020	<b>51,193</b>	37,680	36%
Natural gas liquids sales	<b>19,517</b>	15,933	<b>63,030</b>	51,118	23%
Sulphur sales (net)	<b>555</b>	34	<b>1,873</b>	405	362%
<b>Petroleum and natural gas revenue</b>	<b>114,037</b>	105,305	<b>348,492</b>	334,635	4%

<b>Petroleum and Natural Gas Revenue</b> (\$ thousands)	<b>Natural Gas</b>	<b>Crude Oil &amp; NGLs</b>	<b>Sulphur</b>	<b>Total</b>
Three months ended September 30, 2010	77,318	27,953	34	105,305
Price variance	(945)	8,949	532	8,536
Production variance	726	(519)	(11)	196
<b>Three months ended September 30, 2011</b>	<b>77,099</b>	<b>36,383</b>	<b>555</b>	<b>114,037</b>

<b>Petroleum and Natural Gas Revenue</b> (\$ thousands)	<b>Natural Gas</b>	<b>Crude Oil &amp; NGLs</b>	<b>Sulphur</b>	<b>Total</b>
Nine months ended September 30, 2010	245,432	88,798	405	334,635
Price variance	(27,986)	22,019	1,587	(4,380)
Production variance	14,950	3,406	(119)	18,237
<b>Nine months ended September 30, 2011</b>	<b>232,396</b>	<b>114,223</b>	<b>1,873</b>	<b>348,492</b>

### Royalties

For the Quarter, royalties decreased 12 percent to \$14.0 million from \$16.0 million for the same period in 2010 due to higher incentives received during the Quarter which are described below. Royalty expense consists of royalties paid to provincial governments, freehold landowners and overriding royalty owners. The Company's average royalty rate for the Quarter was 12.3 percent compared to 15.2 percent in 2010. The decrease in the royalty rate was primarily due to \$4.2 million of royalty credits received in the Quarter under British Columbia's deep royalty credit program described below.

For the nine months ended September 30, 2011 royalties decreased 19 percent to \$42.7 million compared to \$52.8 million for the same period in 2010. The Company's average royalty rate was 12.2 percent compared to 15.8 percent in 2010. The decrease was primarily due to \$11.9 million of royalty credits received for the nine months ended September 30, 2011 under British Columbia's deep royalty credit program.

Management anticipates based on current commodity prices and royalty regimes, the average royalty rate for 2011 will be approximately 12 percent of petroleum and natural gas revenue, a reduction from its previous guidance of 13 percent.

Progress' operations are in the provinces of British Columbia and Alberta, both of which have implemented incentives for the energy sector. The programs most applicable to Progress' operations are described below.

#### *British Columbia - Deep royalty credit program*

The current formula based deep royalty credit program includes horizontal wells drilled between 1,900 and 2,300 metres. The program has no expiration date. To date Progress has earned an average of \$2.1 million per well of deep royalty credits on each of its Montney horizontal wells. As at September 30, 2011, of the total credits earned to date of approximately \$90.6 million, \$11.9 million was offset against royalty expense for the year-to-date 2011 (\$3.4 million for the year ended 2010) with \$75.3 million remaining to be recognized as a future reduction to royalty expense. The two percent royalty relief program and the deep royalty credit program will co-exist but a company will only benefit from one program at a time. The deep royalty credit will apply first. If it is exhausted before the first 12 months of production, the two percent royalty will be in effect for the remainder of the first 12 months. If the deep royalty credit is not exhausted before the first 12 months, the two percent royalty program will not apply. The deep royalty credit is treated as a reduction to royalty expense.

#### *Alberta - Five percent royalty rate on first year of production*

The Alberta government has implemented a five percent royalty rate on the first year of production on new natural gas and conventional oil wells up to a maximum 500,000 mcf of natural gas or 50,000 bbls of crude oil. This results in a lower royalty expense for Progress on its new wells.

### **Operating Expenses**

Operating expenses during the Quarter decreased seven percent to \$22.0 million from \$23.6 million for the same period in 2010. On a boe basis, operating expenses for the Quarter decreased eight percent to \$5.56 from \$6.07 in the same period in 2010 primarily as a result of efficiencies realized, drilling operations being focused in low operating cost areas and the sale of high operating expense assets in 2010 and 2011.

For the nine months ended September 30, 2011 operating expenses decreased five percent to \$64.7 million compared to \$68.5 million for the same period in 2010. On a boe basis, year-to-date operating expenses decreased 11 percent to \$5.56 compared to \$6.22 for the same period in 2010 as a result of efficiencies realized, growth in low operating cost areas and dispositions of high operating expense assets.

Management anticipates operating expenses for 2011 to average \$5.50 per boe, which is at the lower end of the previous guidance.

### **Transportation Expenses**

Transportation expenses for the Quarter increased nine percent to \$13.7 million compared to \$12.6 million for the same period in 2010. The increase was the result of a higher proportion of the Company's production coming from British Columbia where the Company pays an all-in charge for regulated gathering, processing and transmission fees on much of its production thereby avoiding facility construction. This all-in charge is included in transportation expenses. On a boe basis, transportation expenses for the Quarter increased seven percent to \$3.48 compared to \$3.24 for the same period in 2010. For the nine months ended September 30, 2011 transportation expenses increased 11 percent to \$38.9 million compared to \$35.0 million for the same period in 2010 due to both higher production as well as a higher proportion of the production coming from British Columbia. On a boe basis, transportation expenses for the nine months ended September 30, 2011 increased five percent to \$3.34 compared to \$3.18 for the same period in 2010.

Management anticipates transportation expenses for 2011 to average \$3.25 to \$3.40 per boe which is consistent with guidance.

## Operating Netbacks

Although many wells produce both crude oil and natural gas, a well is categorized as a natural gas well or an oil well based upon the higher proportion of natural gas or crude oil production. The following table summarizes the operating netbacks for natural gas and oil properties for the three and nine months ended September 30, 2011 compared to the same periods in 2010:

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
<b>Natural Gas Properties (\$/mcf)</b>				
Sales price	4.40	4.25	4.60	4.78
Realized gain (loss) on financial instruments	(0.06)	0.26	0.04	0.14
Royalties	(0.54)	(0.60)	(0.54)	(0.71)
Operating expenses	(0.88)	(0.94)	(0.88)	(0.97)
Transportation expenses	(0.60)	(0.55)	(0.56)	(0.54)
Operating netback – natural gas properties	2.32	2.42	2.66	2.70
<b>Oil Properties (\$/bbl)</b>				
Sales Price	66.51	57.50	74.33	59.52
Royalties	(7.53)	(14.73)	(12.30)	(13.66)
Operating expenses	(9.67)	(15.02)	(10.91)	(13.04)
Transportation expenses	(1.77)	(2.00)	(2.26)	(1.87)
Operating netback – oil properties	47.54	25.75	48.86	30.95
<b>All Properties (\$/boe)</b>				
Sales Price <sup>1</sup>	28.87	27.04	29.92	30.39
Realized gain (loss) on financial instruments	(0.32)	1.47	0.23	0.79
Royalties	(3.56)	(4.12)	(3.67)	(4.80)
Operating expenses	(5.56)	(6.07)	(5.56)	(6.22)
Transportation expenses	(3.48)	(3.24)	(3.34)	(3.18)
Operating netback – all properties	15.95	15.08	17.58	16.98

<sup>1</sup> Includes sulphur net revenue (loss) with no associated production as no conversion exists for tons to boe.

## General and Administrative Expenses

For the Quarter, general and administrative expenses, net of overhead recoveries, (“G&A”) of \$3.8 million was slightly higher than the same period in 2010 of \$3.6 million. For the nine months ended September 30, 2011 G&A expenses of \$11.3 million were slightly higher than the same period in 2010 of \$11.0 million. On a boe basis, G&A for the Quarter of \$0.97 was four percent higher than the same period in 2010 of \$0.93 while year-to-date 2011 G&A was \$0.97 compared to \$1.00 for the same period in 2010.

The Company capitalized approximately \$0.6 million of G&A during the Quarter (2010 - \$0.6 million) and \$1.9 million for the nine months ended September 30, 2011 (2010 - \$1.5 million). These costs represent compensation related to geological and geophysical staff.

Management anticipates G&A expenses to average approximately \$1.00 per boe in 2011 which is consistent with guidance.

## Share Based Compensation Expenses

### *Stock Options, Restricted Units and Performance Units*

The Company has a stock based compensation plan (the “Plan”) comprised of a Stock Option Plan, as well as a Share Unit Plan which includes both Restricted Unit Awards and Performance Unit Awards. Unless otherwise approved by the shareholders, the Company may grant up to a maximum of 1,700,000 common shares pursuant to the Share Unit Plan. The Restricted Unit Awards are whole share awards that entitle the holder to that number of shares at the end of the vesting period. Performance Unit Awards are similar to the Restricted Unit Awards however, a performance factor is applied to the grant on the vesting date. Both the Restricted Unit Awards and Performance Unit Awards vest at the end of a three year period and include accumulated dividends paid over the three year period, however for new employees, their initial grant will vest 20 percent on the first anniversary date, 30 percent on the second anniversary and 50 percent on the third anniversary. Under the Stock Option Plan, unless otherwise approved by the shareholders, the Company may grant up to a maximum of 10,000,000 stock options. The stock options granted under the Stock Option Plan prior to 2011 vest one third in each of the second, third and fourth year anniversary dates from the date of grant. Stock options granted in 2011 vest one third in each of the first, second and third year anniversary dates from the date of grant. The options expire in five years from the date of grant.

On January 15, 2009 ProEx Energy Ltd. (“ProEx”) acquired Progress Energy Trust (the “Trust”) and changed its name to Progress Energy Resources Corp. (the “Arrangement”). As a result, grants that were outstanding from the Trust and ProEx, which included performance units and units granted under the Trust’s Long Term Incentive Component (“LTI”) as well as stock options of ProEx, will continue until their original vesting dates.

### *Long Term Incentive Component of the Trust*

Awards granted under the LTI component of the Trust’s compensation plan vest over three years with 40 percent vesting on the second anniversary of the date of grant and 60 percent vesting on the third anniversary of the date of grant. An additional 15 percent grant will be paid if the holder holds the common shares they receive on the second anniversary date for one additional year.

### *Performance Units of the Trust*

The performance units granted by the Trust vest at the end of a three year performance period at which time they will be converted to common shares, or the cash equivalent, and include the accumulated distributions of the Trust and accumulated dividends of the Company over the three year period. For new employees, their initial grant vest 20 percent on the first anniversary date, 30 percent on the second anniversary and 50 percent on the third anniversary. The actual number of common shares paid is dependent upon a performance factor that is determined based on the Company’s performance relative to its peers and ranges from 0.5 to 1.5 times the initial grant, except for performance units granted to the Trust’s executives effective July 2, 2008 which can range from 0 to 3 times. Payment may be in the form of cash or common shares, at the Company’s option. Management anticipates, at the end of the performance period, accumulated distributions and dividends will be paid in cash and common shares will be paid from treasury. Actual performance factors will not be determined until the end of the three year performance periods.

For the Quarter, share based compensation expenses of \$2.4 million were 14 percent lower than the same period in 2010 of \$2.8 million. On a boe basis, share based compensation expense for the Quarter was \$0.61 per boe compared to \$0.72 per boe for the same period in 2010. The decrease was due to the settlement on July 1, 2011 of the performance units granted in 2008 by the Trust. For the nine months ended September 30, 2011 share based compensation expenses decreased 21 percent to \$7.3 million (\$0.63 per boe) compared to \$9.3 million (\$0.84 per boe) for the same period in 2010 as a result of a decrease in the anticipated performance factor on the performance units granted in 2008 by the Trust from 1.5 times to 1.375 times that was recognized in the second quarter of 2011. Alternatively, for the same period in 2010, an adjustment was made to increase the anticipated performance factors on the performance units granted in 2007 and 2008 by the Trust from 1.0 times to 1.5 times.

As at September 30, 2011, there were 7,766,434 stock options outstanding. This includes 6,653,067 stock options that were granted under the Stock Option Plan and 1,113,367 stock options granted by ProEx prior to the Arrangement that will continue until their original expiry date or until they are exercised or forfeited.

The following tables summarize the activity for the nine months ended September 30, 2011 and the year ended December 31, 2010 for the stock options, Share Unit Plan, performance units of the Trust and the units under the LTI component of the Trust.

<b>Stock Options</b>	<b>Number of options</b>	<b>Weighted average exercise price</b>
Balance, January 1, 2010	5,872,533	11.93
Granted	281,000	12.39
Forfeited	(145,332)	12.39
Expired	(18,000)	15.46
Exercised	(38,334)	11.02
Balance, December 31, 2010	<b>5,951,867</b>	<b>11.93</b>
Granted	<b>1,966,367</b>	<b>12.30</b>
Forfeited	(52,667)	11.98
Expired	(39,833)	14.51
Exercised	(59,300)	12.53
Balance, September 30, 2011	<b>7,766,434</b>	<b>11.81</b>
Exercisable, September 30, 2011	<b>2,588,934</b>	<b>11.90</b>

<b>Restricted Units</b>	
Balance, January 1, 2010	93,259
Granted	88,265
Settled	(950)
Forfeited	(1,175)
Balance, December 31, 2010	<b>179,399</b>
Granted	<b>93,370</b>
Settled	(5,937)
Forfeited	(5,200)
Balance, September 30, 2011	<b>261,632</b>

<b>Vesting Date</b>	
2012	85,039
2013	85,958
2014	90,635
Total	<b>261,632</b>

**Performance Units**

Balance, January 1, 2010	259,950
Granted	281,050
Settled	(2,790)
Forfeited	(14,635)
Balance, December 31, 2010	<b>523,575</b>
Granted	<b>246,140</b>
Settled	<b>(8,120)</b>
Forfeited	<b>(7,600)</b>
Balance, September 30, 2011	<b>753,995</b>

**Vesting Date**

2012	<b>250,190</b>
2013	<b>264,097</b>
2014	<b>239,708</b>
Total	<b>753,995</b>

**Performance Units of the Trust<sup>1</sup>**

Balance, January 1, 2010	717,718
Performance factor adjustment <sup>2</sup>	167,639
Settled <sup>2</sup>	(492,027)
Forfeited	(11,945)
Balance, December 31, 2010	<b>381,385</b>
Performance factor adjustment <sup>2</sup>	<b>144,818</b>
Settled <sup>2</sup>	<b>(521,696)</b>
Forfeited	<b>(4,507)</b>
Balance, September 30, 2011	-

(1) All amounts have been adjusted to reflect the ratio of 0.8125 of a common share for each trust unit as specified in the Arrangement.

(2) For 2010 the performance units were settled at a performance factor of 1.5 times resulting in the issuance of an additional 167,639 common shares. For 2011 the performance units were settled at a performance factor of 1.375 times, resulting in the issuance of an additional 144,818 common shares.

**Units under LTI Component<sup>1</sup>**

Balance, January 1, 2010	100,956
Additional grant <sup>2</sup>	18,189
Settled	(104,348)
Forfeited	(1,837)
Balance, December 31, 2010	<b>12,960</b>
Additional grant <sup>2</sup>	<b>2,165</b>
Settled	<b>(10,820)</b>
Forfeited	<b>(1,000)</b>
Balance, September 30, 2011	<b>3,305</b>

**Vesting Date**

2011	<b>3,305</b>
Total <sup>2</sup>	<b>3,305</b>

- (1) All amounts have been adjusted to reflect the ratio of 0.8125 of a common share for each trust unit as specified in the Arrangement.
- (2) An additional 15 percent grant will be paid to LTI holders if a holder holds the shares they receive on the second anniversary date for one additional year. This would result in an additional 827 common shares being issued by the Company on the remaining outstanding grants.

**Interest and Finance Expense**

Interest and finance expense is comprised of the following:

(\$ thousands)	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Interest on bank debt	737	2,534	5,023	10,432
Interest on Debentures	6,727	3,827	17,875	13,222
Total interest and financing expense	<b>7,464</b>	<b>6,361</b>	<b>22,898</b>	<b>23,654</b>
Interest and finance expense (\$/boe)	<b>1.89</b>	1.63	<b>1.97</b>	2.15

Interest and finance expense during the Quarter increased 17 percent to \$7.5 million compared to \$6.4 million for the same period in 2010. The increase was the result of higher interest on Debentures due to the financing completed on March 7, 2011 which included \$200.0 million principal amount of 5.75 percent convertible unsecured subordinated debentures (the “5.75 percent debentures”) and the issuance of 14,400,000 common shares for gross proceeds of \$200.2 million (refer to *Liquidity and Capital Resources* below). Year-to-date interest and financing expense decreased three percent to \$22.9 million compared to \$23.7 million for the same period in 2010.

For the Quarter, interest on bank debt decreased 71 percent to \$0.7 million, which primarily includes standby fees on the undrawn portion of the credit facility. The decrease was due to lower average bank debt during the Quarter as a result of the March 7, 2011 financing and the Joint Arrangement with PETRONAS on August 2, 2011 (refer to *Joint Arrangement with PETRONAS* above). For the Quarter, interest on Debentures increased 76 percent as a result of the issuance of the 5.75 percent debentures on March 7, 2011.

The decrease in interest and financing expense for the year-to-date 2011 was a result of lower average bank debt, partially offset by an increase in interest on Debentures due to the issuance of the 5.75 percent debentures. Interest expense will be positively effected in the fourth quarter as a result of the repayment of the 6.25 percent convertible unsecured subordinated debentures on maturity on September 30, 2011.

## Depletion and Depreciation

As a result of the conversion to IFRS, Progress now depletes its property, plant and equipment based on its proved plus probable reserves as opposed to proved reserves that were used under the previous GAAP. Plant turnarounds and major overhauls are depreciated over four years. The carrying value of undeveloped land in exploration and evaluation assets that expire during the period is charged to depletion and depreciation expense.

For the Quarter, depletion and depreciation (“D&D”) expense increased eight percent to \$59.2 million compared to \$55.1 million for the same period in 2010. The increase was due to a higher charge from exploration and evaluation assets for land expiries in the Quarter as compared to the same period in 2010. For the nine months ended September 30, 2011 D&D expense decreased eight percent to \$169.5 million compared to \$183.8 million for the same period in 2010. Under IFRS for the first quarter of 2010, D&D expense included an impairment charge of \$19.7 million due to the impact of decreasing natural gas prices on the fair value of certain cash generating units (“CGUs”) of the Company. On a boe basis, D&D expense for the Quarter was \$14.99 compared to \$14.14 for the same period in 2010 and for the nine months ended September 30, 2011 was \$14.55 compared to \$16.69 for the same period in 2010.

## Taxes

The provision for deferred income taxes for the Quarter was an expense of \$55.1 million compared to a recovery of \$1.7 million in same period in 2010. For the Quarter, a deferred income tax expense of \$59.0 million was recognized in relation to a \$236.0 million gain on the sale of certain assets to PETRONAS in relation to the Joint Arrangement. For the nine months ended September 30, 2011 the provision for deferred income taxes was an expense of \$53.2 million compared to a recovery of \$10.9 million for the same period in 2010. This was primarily due to the deferred income tax expense on the gain relating to the Joint Arrangement and the year-to-date 2010 recognizing a deferred income tax recovery relating to an impairment charge of \$19.7 million as a result of the impact of decreasing natural gas prices on the fair value of certain CGUs.

Estimated total tax pool balances as at September 30, 2011 is approximately \$2.1 billion.

## Net Earnings and Comprehensive Earnings

The net earnings and comprehensive earnings for the Quarter of \$161.4 million were higher than the net loss and comprehensive loss of \$7.6 million for the same period in 2010. The higher net earnings for the Quarter was due to a gain of \$236.0 million (\$177.0 million net of deferred income taxes) on the sale of certain assets to PETRONAS in relation to the Joint Arrangement. The basic and diluted net earnings for the Quarter was \$0.70 per share and \$0.66 per share, respectively, and for the same period in 2010 the basic and diluted net loss was \$0.03 per share.

The net earnings and comprehensive earnings for the nine months ended September 30, 2011 of \$151.5 million were higher than the net loss and comprehensive loss of \$75.2 million for the same period in 2010. The increase was primarily due to the \$236.0 million gain on the sale of certain assets in relation to the Joint Arrangement as well as 2010 incurring a \$19.7 million impairment charge to D&D expense due to the impact of decreasing natural gas prices on the fair value of certain CGUs as well as an impairment charge of \$34.2 million relating to a decrease in the fair value of goodwill. The basic and diluted net earnings for the year-to-date 2011 was \$0.67 per share and \$0.66 per share, respectively, and for the same period in 2010 the basic and diluted net loss was \$0.38 per share.

## Dividends

Since January 15, 2009, Progress has declared quarterly cash dividends of \$0.10 per common share, including the Quarter. The total amount of dividends for the Quarter is approximately \$23.2 million (2010 - \$21.4 million), excluding dividends accrued for certain share based compensation grants. Progress has a dividend reinvestment plan (“DRIP”) whereby common shareholders can elect to receive their dividend in shares.

The number of shares issued is based on 95 percent of the average market price being the weighted average trading prices of the shares for the five consecutive trading days before the dividend payment date. On October 17, 2011 the Company issued 824,099 common shares in payment of \$10.1 million of dividends for shareholders that elected to participate in the DRIP. Progress intends to pay quarterly dividends, however these dividends are not guaranteed.

Subsequent to the Quarter the Board of Directors declared that the 2011 fourth quarter dividend will be maintained at \$0.10 per share. The dividend will be payable on January 16, 2012 to common shareholders of record as of December 31, 2011.

### Quarterly Financial Summary <sup>1</sup>

	Three Months Ended							
	Sept 30 2011	June 30 2011	Mar 31 2011	Dec 31 2010	Sept 30 2010	June 30 2010	Mar 31 2010	Dec 31 2009
<i>(\$ thousands, except per share amounts)</i>								
Petroleum and natural gas revenue <sup>2</sup>	114,037	117,340	117,115	107,957	105,305	115,859	113,471	86,145
Net earnings (loss) <sup>2</sup>	161,352	(11,436)	1,626	(104,184)	(7,644)	(22,832)	(44,708)	(20,075)
Per share basic	\$0.70	(0.05)	0.01	(0.49)	(0.04)	(0.11)	(0.27)	(0.12)
Per share diluted	\$0.66	(0.05)	0.01	(0.49)	(0.04)	(0.11)	(0.27)	(0.12)

(1) The 2010 and 2011 quarterly results have been adjusted to conform to IFRS. The quarterly results for 2009 have not been adjusted and reflect the results in accordance with the previous GAAP.

(2) *First quarter 2010* - Petroleum and natural gas revenue for the first quarter of 2010 increased over the fourth quarter of 2009 due to higher production and higher crude oil and NGL prices. The higher net loss for the first quarter of 2010 was the result of a \$19.7 million charge relating to the impairment of property, plant and equipment and a \$34.2 million impairment to goodwill, both due to the impact of decreasing natural gas prices.

*Second quarter 2010* - Petroleum and natural gas revenue for the second quarter of 2010 increased slightly from the first quarter of 2010 due to higher production as a result of the Foothills Acquisition, however this was largely offset by lower commodity prices. The net loss for the second quarter of 2010 was due to higher D&D expense due to the Foothills Acquisition, a \$9.6 million loss on the sale of its Central Alberta properties and an unrealized loss on financial instruments of \$7.9 million.

*Third quarter 2010* - For the third quarter of 2010, petroleum and natural gas revenue decreased from the second quarter of 2010 as a result of lower commodity prices through the summer season. The net loss was lower than the previous quarter due to an unrealized gain on financial instruments of \$1.1 million compared to a loss of \$7.9 million in the previous quarter.

*Fourth quarter 2010* - Revenues for the fourth quarter of 2010 were slightly higher than the third quarter due to higher crude oil and NGL prices. The higher net loss was due to an impairment charge to property, plant and equipment of \$119.9 million as a result of decreasing future natural gas prices.

*First quarter 2011* - Revenues for the first quarter of 2011 were higher than the fourth quarter of 2010 due to both higher production and slightly higher natural gas prices. Net earnings were higher primarily due to the \$119.9 million impairment charge recognized in the fourth quarter of 2010.

*Second quarter 2011* - During the second quarter of 2011, production was seven percent lower than the first quarter of 2011 due to a planned 15 day turnaround at the Spectra McMahon gas processing facility, however, higher crude oil prices and slightly higher natural gas prices, resulted in slightly higher revenues. The higher net loss for the second quarter of 2011 as compared to the previous quarter was primarily due to a \$6.6 million loss on divestitures, while the previous quarter had a \$5.2 million net gain on divestitures.

*Third quarter 2011* - Revenues for the Quarter decreased from the previous quarter due to lower commodity prices. Net earnings was higher as a result of a \$236.0 million gain (\$177.0 million net of deferred income taxes) on the sale of certain assets in relation to the Joint Arrangement.

## Capital Expenditures

During the Quarter, the Company invested \$113.8 million in total capital expenditures, which includes capital expenditures on exploration and evaluation assets and property, plant and equipment, compared to \$108.4 million in the same period in 2010. For the nine months ended September 30, 2011, the Company invested \$300.1 million compared to \$267.4 million for the same period in 2010.

(\$ thousands)	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2011	2010	2011	2010
Land acquisitions and retention	12,455	17,385	21,284	36,215
Geological and geophysical	864	911	8,336	8,164
Drilling and completions	84,783	76,041	213,186	181,095
Equipping and facilities	15,190	13,876	54,947	45,557
Turnarounds and overhauls	201	165	1,606	165
Corporate assets	132	578	291	802
Exploration and development capital	113,625	108,956	299,650	271,998
Net property acquisitions (dispositions)	134	(576)	486	(4,584)
<b>Total capital expenditures</b>	<b>113,759</b>	<b>108,380</b>	<b>300,136</b>	<b>267,414</b>
Joint Arrangement	(261,135)	-	(261,135)	-
Property Dispositions	(77)	-	(35,421)	-
Foothills Acquisition	-	-	-	387,087
Central Alberta Disposition	-	-	-	(44,473)
Total investing activities (before changes in non-cash working capital)	(147,453)	108,380	3,580	610,028

On August 2, 2011, Progress and PETRONAS entered into a strategic partnership to develop Progress' Montney shale assets. The Joint Arrangement resulted in the creation of an Upstream Joint Venture and an LNG Export Joint Venture. Under the Joint Arrangement, Progress sold 50 percent of its working interest in the Altares, Lily and Kahta areas to PETRONAS which consisted primarily of 75,000 net acres of undeveloped land. Progress received \$267.5 million in cash on closing and will receive an additional \$802.5 million over the next five years in the form of a capital carry whereby PETRONAS will pay 75 percent of Progress' share of future capital expenditures in the Upstream Joint Venture. A gain of approximately \$236.0 million was recognized for the disposition of Progress' 50 percent interest in the areas for the initial proceeds of \$267.5 million (\$261.1 million net of transaction costs of \$6.4 million). The remaining \$802.5 million will be recognized as a reduction to capital spending in proportion to the capital spent.

During the Quarter, the Company drilled 12 gross wells (12.0 net) in the Foothills region. For the nine months ended September 30, 2011, the Company drilled 40 gross wells (36.5 net) including 29 gross wells (26.2 net) in the Foothills region and 11 gross wells (10.3 net) in the Deep Basin region.

During the Quarter, at the Town South development pod (100 percent working interest), Progress drilled two horizontal wells targeting the upper and lower Montney. Town South has reached its 50 mmcf per day production target and will now evolve to a maintenance phase which implies the annual drilling of approximately six horizontal wells per year to sustain volumes at 50 mmcf per day.

At Gundy (100 percent working interest), Progress drilled four horizontal wells, one targeting the lower Montney and three in the upper Montney, in the Quarter. These wells were completed with an average rate of 5.3 mmcf per day. To accommodate the additional volumes, the Gundy processing facility, which is currently on stream at 25 mmcf per day will be expanded to 50 mmcf per day during the fourth quarter of 2011.

At the Town North pod development (100 percent working interest), Progress drilled and completed one horizontal well targeting the upper Montney. Progress now has seven producing horizontals in the Town North area, with both the upper and lower Montney being productive. Town North's first 25 mmcf per day processing facility was brought on stream early in the second quarter of 2011.

At Caribou (100 percent working interest), Progress drilled one horizontal well in the Quarter targeting the lower Montney which will be completed in the fourth quarter. A third well will be drilled in the fourth quarter. These wells will utilize existing infrastructure with a new Montney facility expected to be constructed in 2013.

At the Kobes development pod (30 percent working interest), Progress completed two horizontal wells with initial production averaging 8.9 mmcf per day from the two wells. As at Quarter end, the Kobes pod was producing approximately 10 mmcf per day, net to Progress. Progress operates the northern portion of the Kobes development, while the southern area is partner operated.

At Nig (50 percent working interest), approximately 25 kilometers east of Town, a horizontal well was drilled in the upper Montney and is currently being completed. The first horizontal in this area tested 4.6 mmcf per day and is expected to be on stream within a month.

In the Bubbles/Jedney area (100 per cent working interest), Progress continued delineation work on its North Montney lands, drilling one vertical well in the Quarter. The well tested both the upper and lower Montney with initial test rates of 1.7 mmcf per day. The Company holds approximately 60,000 net acres of undeveloped land in the Bubbles/Jedney area, located 25 kilometers northeast of the Town area, with plans for a first horizontal well in 2012.

As a result of incremental land acquisitions, infrastructure investments and commencement of the Upstream Joint Venture activities, the 2011 capital program has been expanded to \$400 million. Three rigs will be operating on the Upstream Joint Venture properties in the fourth quarter. The LNG Export Joint Venture has selected an engineering firm to undertake the technical detailed feasibility as well as initiate the site selection process.

On March 31, 2011, Progress sold its Two Creek, Alberta properties for approximately \$12.7 million, as well as certain royalty interests in the Copton, Alberta area for \$4.2 million. In April 2011, the Company sold its Fort St. John Plains North properties for approximately \$12.7 million, as well as certain properties in the Copton, Alberta area for approximately \$4.8 million.

On March 31, 2010, the Company acquired certain assets in the Foothills region, the Foothills Acquisition, for \$389.2 million, including \$2.1 million of transaction costs which were charged to other expenses in the statement of earnings. The net amount capitalized was \$387.1 million. The assets included production of approximately 7,300 boe per day, 91 percent natural gas, and approximately 188,000 net acres of undeveloped land.

To finance the Foothills Acquisition and a portion of the Company's 2010 capital investment program the Company issued 47,630,000 common shares at \$12.60 per share for total gross proceeds of \$600.1 million (\$588.8 million net of issue costs of \$11.3 million). The share issuance was comprised of a \$350 million subscription receipt private placement with the Canada Pension Plan Investment Board ("CPPIB") and a concurrent \$250 million subscription receipt bought-deal financing through a syndicate of underwriters. Each subscription receipt represented the right to receive one common share of Progress, without the payment of any additional consideration, on the closing of the Foothills Acquisition which occurred on March 31, 2010.

The private placement with CPPIB contains certain conditions in regards to their investment and ongoing relationship with Progress including:

- Governance - so long as CPPIB owns greater than 12.5 percent of the outstanding common shares they shall have the right to nominate one individual to be a director of Progress. If CPPIB owns greater than 10 percent of the outstanding common shares, Progress shall discuss

with CPPIB any proposed transaction for which the Company will require equity financing before implementing such transaction.

- Registration rights – if CPPIB holds 10 percent or more of the outstanding common shares, they shall have the right to require Progress at CPPIB’s expense, to prepare, file and obtain receipt for a final prospectus offering for the sale of any portion of the common shares held by CPPIB.
- CPPIB shall have the right to include common shares owned by CPPIB in a prospectus offering to the extent of 15 percent of such offering.
- Right to participate in future offerings – so long as CPPIB owns greater than 10 percent of the outstanding common shares, CPPIB shall have the pre-emptive right to participate in future offerings up to CPPIB’s pro-rata ownership interest immediately prior to the offering.

CPPIB, having greater than 12.5 percent of the outstanding common shares, nominated R. Scott Lawrence, Vice President, Head of Relationship Investments of CPPIB to the Progress Board of Directors. The Progress Board of Directors, upon review of Mr. Lawrence’s qualifications by the Corporate Governance and Nominating Committee, appointed Mr. Lawrence to the Board on October 12, 2010.

### **Goodwill**

For goodwill impairment tests under IFRS, goodwill that arises from a business combination is allocated to the specific CGUs that are expected to benefit from the business combination. The carrying value of the CGU including goodwill is compared to the fair value of the CGU and any excess of the carrying value over the fair value is considered an impairment. As the goodwill impairment is performed on a much smaller portion of the Company’s assets (i.e. at the CGU level), approximately \$371.4 million of Progress’ goodwill was impaired on the transition to IFRS on January 1, 2010 and was charged to the deficit on the opening IFRS statement of financial position.

As a result of continued decreases in natural gas prices and their impact on the value of the Company’s reserves for certain CGUs, an additional goodwill impairment of \$34.2 million was recognized at March 31, 2010.

As at September 30, 2011 the goodwill balance of \$9.0 million was the result of an acquisition that included the Company’s Town properties in the Foothills region of British Columbia. In accordance with IFRS, goodwill is not amortized but is subject to an annual impairment test. Goodwill may be tested for impairment between annual tests in certain situations.

## Liquidity and Capital Resources

<i>(\$ thousands, except per share amounts)</i>	<b>September 30 2011</b>	<b>December 31 2010</b>
Working capital deficiency (surplus) <sup>(1)</sup>	(89,702)	21,271
Bank debt	-	312,508
Convertible debentures	353,100	249,313
Total debt	263,398	583,092
Shares outstanding (thousands)	231,647	214,877
Market price per share, end of period	12.89	12.70
Market value of shares	2,985,930	2,728,938

(1) Excludes the fair value of financial instruments.

At September 30, 2011 the Company was undrawn on its credit facility of \$650.0 million as a result of the Joint Arrangement and the financing completed on March 7, 2011. Outstanding as at September 30, 2011 was \$353.1 million for the debt portion of the Debentures, partially offset by a working capital surplus of \$89.7 million, resulting in \$263.4 million of total debt.

On April 29, 2011 the Company amended and restated its bank credit facility to be a covenant-based facility rather than a borrowing base facility. This facility is a 3-year extendible revolving facility in the amount of \$650 million from a syndicate of lenders with an initial maturity date of April 29, 2014. The maturity date may, at the request of the Company and with the consent of the lenders, be extended on an annual basis. The facilities remain secured over substantially all of the assets of the Company and its material subsidiaries. The facilities bear interest at a rate based on bankers acceptance rates (or LIBOR, for US dollar borrowings) plus a specified margin, which margin varies based on the Company's senior debt to EBITDA ratio (as calculated below). The facilities contain customary restrictions on the disposition of assets and the granting of security, as well as on the making of distributions (including the declaration of dividends) if there is then a default under the facilities (or if a default would reasonably be expected to occur as a result of such distribution). The facilities also contain customary events of default, including on a change of control of the Company where lender consent was not obtained, which could occur if a person or persons acting jointly or in concert acquired more than 30 percent of the outstanding voting securities of the Company.

Under the terms of the bank credit facilities, Progress has provided its covenant that, on a rolling 4-quarter basis: (i) its consolidated senior debt will not exceed three times its consolidated EBITDA, increasing to 3.5 times upon the consummation of a material acquisition and for a period extending to the end of the second full quarter after completion of that acquisition. Senior debt is defined to exclude subordinated debt and non-recourse debt from total debt. EBITDA is calculated as net earnings before unrealized gains and losses on financial instrument contracts, interest and financing expense, acquisition costs, taxes, depreciation, depletion and accretion and any other non-cash amounts which are added back or deducted from net income in accordance with IFRS in the statement of cash flows; (ii) its consolidated total debt (excluding, for certainty, any convertible debentures) will not exceed four times its consolidated EBITDA (similarly calculated), and (iii) its consolidated senior debt will not exceed one-half of its total capitalization (calculated as the aggregate of consolidated total debt, the principal amount of convertible debentures and consolidated shareholders' equity), increasing to 55 percent upon the consummation of a material acquisition and for a period extending to the end of the second full quarter after completion of that acquisition.

Bank debt of nil as at September 30, 2011 was lower than December 31, 2010 bank debt of \$312.5 million due to the Joint Arrangement as well as the issuance of 14,400,000 common shares at \$13.90 per share for total gross proceeds of \$200.2 million (\$193.1 million net of issue costs of \$7.1 million) and the issuance of \$200.0 million principal amount of 5.75 percent convertible unsecured subordinated debentures (\$192.2 million net of issue costs of \$7.8 million) completed on March 7, 2011.

As at September 30, 2011 Progress had a working capital surplus of \$89.7 million compared to a working capital deficit of \$21.3 million as at December 31, 2010. The surplus was the result of a cash balance of \$134.8 million at September 30, 2011 which arose from the \$267.5 million received on the closing of the Joint Arrangement.

As at September 30, 2011 Progress had the following Debentures outstanding. Each Debenture may be converted into common shares at the option of the holder at the applicable conversion price per common share noted below. The Company may elect to satisfy the interest and principal obligations by the issuance of common shares subject to required regulatory approvals.

Debenture	Principal	Semi Annual Interest Payments	Conversion Price (\$/share)	Maturity Date
5.25%	200,000	April 30 and October 31	\$18.00	October 31, 2014
5.75%	200,000	June 30 and December 31	\$20.85	June 30, 2016

As at September 30, 2011 the Company had outstanding \$200.0 million principal amount of the 5.25 percent debentures and \$200.0 million principal amount of the 5.75 percent debentures for a combined total of \$400.0 million. The \$75.0 million of the 6.25 percent debentures were repaid in cash on maturity on September 30, 2011.

The Debentures have been classified as debt net of the fair value of the conversion feature which has been classified as part of shareholders' equity and net of issue costs. At September 30, 2011 the debt portion was \$353.1 million, net of unamortized issue costs. Issue costs are amortized over the term of the Debentures and the debt portion will accrete up to the principal balance at maturity. The accretion and amortization of issue costs are expensed within other finance expenses on the consolidated statements of earnings and comprehensive income.

Outstanding as at October 26, 2011 were the following:

	Shares Outstanding Or Issuable
Common shares	232,546,010
Convertible debentures	20,703,437
Stock options	7,681,734
Restricted Unit Awards	259,227
Performance Unit Awards	758,835
LTI component from the Trust	2,156

### ***Current economic conditions***

Despite the economic downturn and financial market volatility dating back to 2009, Progress continued to have access to both debt and equity markets in 2010 and into 2011. As noted above, on March 7, 2011 the Company issued 14,400,000 common shares at \$13.90 per share as well as \$200.0 million principal amount of the 5.75 percent debentures. On March 31, 2010 Progress raised \$600.1 million gross (\$588.8 net of issue costs) on the issuance of 47,630,000 common shares at \$12.60 per share and on October 23, 2009 the Company issued \$200.0 million principal amount of 5.25 percent debentures. At September 30, 2011 the Company had \$650.0 million available on its undrawn credit facility.

In addition to debt and equity markets, Progress entered into a Joint Arrangement with PETRONAS whereby Progress received \$267.5 million on August 2, 2011 and will receive an additional \$802.5 million over the next five years in the form of a capital carry whereby PETRONAS will pay 75 percent of Progress' share of future capital expenditures in the Upstream Joint Venture. This will enable Progress to accelerate its growth strategy and provide support for future capital programs.

The Company's investing activities for the Quarter consisted of expenditures on its capital program. Management anticipates that the Company will continue to have adequate liquidity to fund budgeted capital

investments through a combination of cash flow, equity and debt. Cash flow used to finance these commitments may reduce the amount of dividends paid to shareholders as dividends are not guaranteed.

### **Reduction of Stated Capital**

On May 11, 2011 the shareholders of Progress approved a special resolution to reduce the stated capital of common shares of Progress by an amount equal to the Company's deficit calculated as at January 1, 2010 in accordance with IFRS. As a result of two fundamental reporting differences between IFRS and the previous GAAP, the deficit increased from \$277.5 million under the previous GAAP to \$669.3 million under IFRS.

The first fundamental difference is how goodwill is tested for impairment. Under IFRS, goodwill that arises from a business combination is allocated to the specific CGUs that are expected to benefit from the business combination. For impairment testing the carrying value of the CGU, including goodwill, is compared to the fair value of the CGU and any excess of the carrying value over the fair value is considered an impairment. As the goodwill impairment is performed on a much smaller portion of the Company's assets (i.e. at the CGU level), approximately \$371.4 million of Progress' goodwill was impaired on the transition to IFRS on January 1, 2010 and was charged to the deficit on the opening IFRS statement of financial position.

The second fundamental difference relates to the discount rate used to measure the decommissioning obligations. Under the previous GAAP a credit adjusted risk free rate was used whereas under IFRS a risk free rate is used. As a result of discounting at a lower rate, the decommissioning obligation increased by \$26 million on transition with an offsetting charge to the deficit on the opening IFRS statement of financial position.

The combination of these two fundamental differences, together with the impact of distributions from the Company's previous income trust structure resulted in a deficit of \$669.3 million on the transition to IFRS. The impact of the reduction of stated capital was a reduction to share capital and offsetting reduction to the deficit of \$669.3 million on the statement of financial position.

### **International Financial Reporting Standards**

Note 16 to the interim consolidated financial statements presents reconciliations between the Company's 2010 previous GAAP results and its 2010 results under IFRS. The reconciliations include the consolidated statement of financial position as at September 30, 2010 and consolidated statements of earnings and comprehensive income and cash flows for the three and nine months ended September 30, 2010.

The following provides summary reconciliations of Progress' 2010 previous GAAP and IFRS results, along with a discussion of the significant IFRS accounting policy changes.

### Summary Statement of Financial Position Reconciliations

(\$ thousands)	As at January 1, 2010					
	Previous GAAP	E&E	Impairment	Decommissioning obligation	Other <sup>1</sup>	IFRS
Current Assets	63,970					63,970
Exploration and evaluation assets	-	206,487	-	-	-	206,487
Property, plant and equipment	1,979,765	(206,487)	-	-	-	1,773,278
Goodwill	414,655	-	(371,429)	-	-	43,226
<b>Total Assets</b>	<b>2,458,390</b>	<b>-</b>	<b>(371,429)</b>	<b>-</b>	<b>-</b>	<b>2,086,961</b>
Current liabilities	126,283	-	-	-	1,123	127,406
Bank debt and convertible debentures	519,451	-	-	-	-	519,451
Decommissioning obligation	39,423	-	-	26,151	-	65,574
Deferred income taxes	57,935	-	-	(6,538)	7,252	58,649
Shareholders' Equity	1,715,298	-	(371,429)	(19,613)	(8,375)	1,315,881
<b>Total liabilities and shareholders' equity</b>	<b>2,458,390</b>	<b>-</b>	<b>(371,429)</b>	<b>-</b>	<b>-</b>	<b>2,086,961</b>

(1) Other includes the addition of dividends declared on share based compensation awards and the deferred income tax impact related to convertible debentures with the offsetting charge to opening retained earnings or deficit, as well as the reclassification of current deferred taxes to long-term.

(\$ thousands)	As at December 31, 2010					
	Previous GAAP	E&E	Impairment	Decommissioning obligation	Other <sup>1</sup>	IFRS
Current Assets	85,406	-	-	-	-	85,406
Exploration and evaluation assets	-	307,132	-	-	-	307,132
Property, plant and equipment	2,432,398	(323,507)	(139,624)	26,337	37,758	2,033,362
Goodwill	414,655	-	(405,655)	-	-	9,000
<b>Total Assets</b>	<b>2,932,459</b>	<b>(16,375)</b>	<b>(545,279)</b>	<b>26,337</b>	<b>37,758</b>	<b>2,434,900</b>
Current liabilities	176,461	-	-	-	55	176,516
Bank debt and convertible debentures	488,054	-	-	-	-	488,054
Decommissioning obligation	42,297	-	-	52,163	(7,642)	86,818
Deferred income taxes	40,547	-	(34,906)	(8,465)	15,194	12,370
Shareholders' Equity	2,185,100	(16,375)	(510,373)	(17,361)	30,151	1,671,142
<b>Total liabilities and shareholders' equity</b>	<b>2,932,459</b>	<b>(16,375)</b>	<b>(545,279)</b>	<b>26,337</b>	<b>37,758</b>	<b>2,434,900</b>

(1) The property, plant and equipment ("PP&E") adjustment under "other" includes the impact of lower depletion as a result of using proved plus probable reserves (\$54.1 million), the net reduction to PP&E related to the Central Alberta disposition (\$17.0 million), the reclassification of transaction costs on the Foothills Acquisition (\$2.1 million reduction to PP&E) a net increase to PP&E related to property swaps of \$2.4 million, and an additional \$0.4 million capitalized regarding share based compensation. The increase to current liabilities under "other" relates to the recognition of dividends declared on share based compensation awards, which was mostly offset by the reclassification of current deferred taxes to long-term. The reduction to the decommissioning obligation relates to the Central Alberta disposition. The deferred income tax adjustment relates to the tax impact on the lower depletion of PP&E, the deferred tax treatment for convertible debentures and reclassification of current deferred taxes to long-term. The offset to these adjustments was through retained earnings or deficit.

## Summary Net Earnings Reconciliation

(\$ thousands)	2010				
	Annual	Q4	Q3	Q2	Q1
Net earnings/(loss) – previous GAAP	(62,438)	(21,491)	(18,423)	(23,288)	764
After-tax addition/(deduction):					
Operating expense <sup>1</sup>	356	230	126	-	-
General and administrative <sup>2</sup>	223	-	-	215	8
Share based compensation	(1,439)	(752)	(372)	(356)	41
Depletion and depreciation	28,247	6,033	10,157	7,563	4,494
Decommissioning obligation accretion	244	50	91	51	52
Gain/(loss) on divestitures	(5,728)	1,108	389	(7,225)	-
Property, plant and equipment impairment	(104,718)	(89,919)	-	-	(14,799)
Goodwill impairment	(34,226)	-	-	-	(34,226)
Other expenses (transaction costs)	(1,610)	-	-	(180)	(1,430)
Deferred income tax on debenture accretion	1,721	557	388	388	388
	(116,930)	(82,693)	10,779	456	(45,472)
Net loss – IFRS	(179,368)	(104,184)	(7,644)	(22,832)	(44,708)

(1) Relates to the capitalization of turnaround and major overhaul costs to PP&E.

(2) Relates to the reclass of dividends paid on the Trust LTI, previously treated as additional compensation.

On transition to IFRS on January 1, 2010 Progress used certain exemptions allowed under IFRS 1 First Time Adoption of International Reporting Standards. The exemptions used were as follows:

*Full Cost Accounting* – IFRS 1 allows an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity’s previous GAAP and to measure oil and gas assets in the development and production phases by allocating the amount determined under the entity’s previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date. Progress used the value of proved plus probable reserves to allocate its opening value of development and production assets.

*Business Combinations* – IFRS 1 allows an entity to use the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations.

*Share-based compensation* – IFRS 1 allows an entity an exemption on IFRS 2, “Share-Based Payments” to equity instruments which vested before Progress’ transition date to IFRS.

*Decommissioning Obligation* – As Progress elected to use the oil and gas exemption, a decommissioning obligation exemption was also used that allows for the re-measurement of decommissioning obligations on IFRS transition to be offset to retained earnings/deficit.

### Accounting Policy Changes and the Impact of Transition to IFRS

- Exploration and Evaluation (“E&E”) assets – On transition to IFRS Progress reclassified \$206.5 million of E&E assets that were previously included in the PP&E balance on the consolidated statement of financial position. This consisted of the book value of undeveloped land that relates to exploration properties. E&E assets are not depleted and must be assessed for impairment at the transition date and when indicators of impairment exist. There was no transitional impairment of the E&E assets. The cost of undeveloped land that expires or any impairment recognized during a period, is charged as additional depletion and depreciation expense.
- Property, plant and equipment (“PP&E”) – This includes oil and gas assets in the development and production phases. The Company has allocated the amount recognized under the previous GAAP as at January 1, 2010 to CGUs using reserve values.

- Divestitures – Under previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the deduction resulted in a change in the depletion rate of 20 percent or greater, in which case a gain or loss was recorded. Under IFRS, gains and losses are recorded on divestitures and are calculated as the difference between the proceeds and the net book value of the asset disposed. For the year ended December 31, 2010, Progress recognized a \$7.6 million (\$5.7 million after tax) net loss on divestitures under IFRS compared to nil under the previous GAAP.
- Impairment of PP&E assets – Under IFRS, impairment tests of PP&E must be performed at the CGU level as opposed to the entire PP&E balance which was required under the previous GAAP through the full cost ceiling test. An impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. The recoverable amount is determined using fair value less cost to sell based on discounted future cash flows of proved plus probable reserves using forecast prices and costs. There was no impairment to PP&E on January 1, 2010 under IFRS. In the first quarter of 2010, as a result of continued decreases in natural gas prices and the impact on future natural gas prices used in evaluating the Company’s reserves, Progress incurred a charge of \$19.7 million (\$14.8 million after tax) on the impairment of PP&E for certain CGUs. In the fourth quarter of 2010, an additional impairment charge of \$119.9 million (\$89.9 million after tax) was recognized due to continued decreasing natural gas prices. PP&E impairments can be reversed in the future if the recoverable amount increases.
- Impairment of goodwill – For goodwill impairment tests under IFRS, goodwill that arises from a business combination is allocated to the specific CGUs that are expected to benefit from the business combination. The carrying value of the CGU including goodwill is compared to the fair value of the CGU and any excess of the carrying value over the fair value is considered an impairment. As the goodwill impairment is performed on a much smaller portion of the Company’s assets (i.e. at the CGU level), \$371.4 million of Progress’ goodwill was impaired on transition at January 1, 2010 and was charged through the opening deficit on its opening IFRS statement of financial position. As a result of continued decreases in natural gas prices and their impact on the value of the Company’s reserves for certain CGU’s an additional goodwill impairment charge was recognized in the first quarter of 2010 of \$34.2 million. Goodwill impairments can not be reversed in the future.
- Decommissioning Obligation – Under the previous GAAP a credit adjusted risk free rate was used to measure the obligation. Under IFRS Progress has used a risk free rate given the expected cash flows are risky. The result of using a lower discount rate was an increase to the obligation on transition of \$26.2 million with an offsetting charge to the opening deficit, net of the deferred income tax effect of \$6.5 million.
- Depletion and depreciation expense – Under IFRS Progress has chosen to base the depletion calculation using proved plus probable reserves. This resulted in a decrease to depletion and depreciation expense in 2010 as compared to the previous GAAP and before the impact of the PP&E impairments described above which were recognized as additional depletion in the first and fourth quarters of 2010.
- Share based compensation –The major differences from the previous GAAP are the treatment of graded vesting awards as multiple separate awards with different lives and estimating forfeiture rates in advance as opposed to recognizing the impact when the forfeiture occurs. For awards in which employees are entitled to dividends declared over the vesting period, those dividends are charged to equity and recognized as a liability when declared. Progress recognized a \$1.7 million increase to dividends payable with an offsetting charge to equity at transition.

## **DISCLOSURE CONTROLS AND PROCEDURES**

The Chief Executive Officer (“CEO”) and the Chief Financial Officer (“CFO”) have designed, or caused to be designed under their supervision, disclosure controls and procedures (“DC&P”) and internal controls over financial reporting (“ICOFR”) as defined in National Instrument 52-109 Certification of Disclosure in Issuer’s Annual and Interim Filings in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with IFRS.

The DC&P have been designed to provide reasonable assurance that material information relating to Progress is made known to the CEO and CFO by others and that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by Progress under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The Company’s CEO and CFO have concluded, based on their evaluation as of the end of the period covered by the interim filings that the Company’s disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Company.

The CEO and CFO are required to cause the Company to disclose any change in the Company’s ICOFR that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company’s ICOFR. No changes in ICOFR were identified during such period that have materially affected or are reasonably likely to materially affect, the Company’s ICOFR. There were no changes to ICOFR as a result of the transition to IFRS.

It should be noted a control system, including the Company’s DC&P and ICOFR, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system will be met and it should not be expected that DC&P and ICOFR will prevent all errors or fraud.

### **Additional Information**

Additional information regarding the Company and its business and operations, including the annual information form (“AIF”) is available on the Company’s profile at [www.sedar.com](http://www.sedar.com). Copies of the AIF can also be obtained by contacting the Company at Progress Energy Resources Corp. 1200, 205 – 5th Avenue S.W., Calgary, Alberta, Canada T2P 2V7 or by e-mail at [ir@progressenergy.com](mailto:ir@progressenergy.com). This information is also accessible on the Company’s web site at [www.progressenergy.com](http://www.progressenergy.com).

## OUTLOOK

With a large number of wells completed and expected to come on stream during the fourth quarter, we are on track to exit 2011 at our previously announced guidance of approximately 50,000 boe per day. Achieving the exit rate will result in year-over-year production growth of approximately 15 percent.

As a result of incremental land acquisitions, infrastructure investments and the commencement of the North Montney Joint Venture activities, the 2011 capital program has been expanded to \$400 million.

The focus of our capital program for the remainder of the year will be the continued advancement of our highly economic Montney pod developments at Town South, Town North, Gundy, and Kobes. Additionally, activity on our North Montney Joint Venture lands in the Altares, Lily and Kahta will continue to increase as we enter this winter. We will continue to take advantage of the factors that make the North Montney attractive; the natural gas we produce is sweet and therefore does not require expensive sour gas processing; we attract a deep drilling royalty credit of approximately \$2 million per well; and, we produce approximately 20 barrels per million cubic feet of high-value natural gas liquids. Along with our experience in the area, continued improvement of drilling and completions technologies and strong initial production rates and recoveries, we are well positioned to deliver value for shareholders.

Along with the majority of other global commodities, North American natural gas prices weakened in the Quarter, as concerns about slowing economic growth weighed on markets. Comparatively, landed LNG prices in Japan rose approximately 20 percent in the Quarter to settle above USD\$17 per mmbtu. We remain optimistic about the long-term prospects for natural gas in North America. The partnership that we have established with PETRONAS, a global leader in LNG development and marketing, may provide Progress with the opportunity to gain direct exposure to Asian pricing, which would be unique amongst our peer group. The recent announcements, by the province of British Columbia, to grow a viable LNG industry is further evidence of momentum building for the large scale development of LNG facilities on the West Coast.

With a strong balance sheet, access to capital, a strong joint venture partner and large contiguous land positions in attractive plays, we are well positioned to execute on our strategic growth plan to reach 100,000 boe per day by the end of 2015.

On behalf of the Board of Directors,

          (Signed) "Michael R. Culbert"

Michael R. Culbert  
President & CEO  
October 27, 2011

**Forward-Looking Statements** Certain information regarding Progress set forth in this document, including Management's assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward looking statements. Such statements represent Progress' internal projections, estimates or beliefs concerning, among other things, an outlook on the estimated amounts and timing of capital investment, anticipated future debt, revenues or other expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. These statements are only predictions and actual events or results may differ materially. Although Progress believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, competitive, political and social uncertainties and contingencies. Many factors could cause Progress' actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Progress.

In particular, forward-looking statements included in this MD&A include, but are not limited to, statements with respect to our strategic plans; the terms of the Joint Arrangement with PETRONAS, including the timing and receipt of the \$802.5 million outstanding payment, the development of an LNG facility and the benefits to be derived from the Joint Arrangement; targeted 2011 exit production; anticipated average 2011 royalty rates and effect of government incentives on Progress' results of operations; future royalty rates; anticipated average operating expenses, transportation expenses and G&A expenses for 2011; terms of the Stock Option Plan, Performance Units Awards and Restricted Unit Awards; dividend policy and the amount and timing of payment of future dividends; drilling plans; plans for 2011 expanded capital program; terms of credit facility; effect of the Upstream Joint Venture on Progress' growth strategy and future capital programs; anticipated liquidity to fund budgeted capital; Progress' planned capital expenditure program; capital investment programs and effect on production growth; focus of capital program for remainder of 2011; future prospects; the focus of and timing of capital expenditures; projections of market prices and costs; the performance characteristics of the Company's crude oil and natural gas properties; Progress' future operating and financial results; supply and demand for crude oil and natural gas; drilling, access to Asian markets, industry and economic conditions, development and completion plans and the timing of and results therefrom; facility expansion plans; treatment under governmental regulatory regimes and tax laws; and estimated tax pool balances.

These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond the Company's control, including the impact of general economic conditions; volatility in market prices for crude oil and natural gas; industry conditions; volatility of commodity prices; currency fluctuation; imprecision of reserve estimates; liabilities inherent in crude oil and natural gas operations; environmental risks; incorrect assessments of the value of acquisitions and exploration and development programs; competition from other producers; the lack of availability of qualified personnel or management; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; failure to realize the anticipated benefits of the Joint Arrangement; stock market volatility; ability to access sufficient capital from internal and external sources and the other risks considered under "Risk Factors" in our annual information form for the year ended December 31, 2010 which is available on [www.sedar.com](http://www.sedar.com).

With respect to forward-looking statements contained in this MD&A, Progress has made assumptions regarding: current commodity prices and royalty regimes; availability of skilled labour; North American sulphur prices; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates and future operating costs.

Management has included the above summary of assumptions and risks related to forward-looking information provided in this MD&A in order to provide shareholders with a more complete perspective on Progress' current and future operations and such information may not be appropriate for other purposes. Progress' actual results,

performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that the Company will derive there from. Readers are cautioned that the foregoing lists of factors are not exhaustive. These forward-looking statements are made as of the date of this MD&A and the Company disclaim any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

***Non-GAAP Measurements*** Management uses the industry benchmark operating netback to analyze financial and operating performance. This benchmark as presented does not have any standardized meaning prescribed by IFRS and prior thereto, Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback is used by research analysts to compare operating performance and the Company's ability to maintain current operations and meet the forecasted capital program. Operating netback is the net result of the Company's revenue, net of realized gains and losses on financial instruments, and royalty, operating and transportation expenses as found in the accompanying interim financial statements.

**PROGRESS ENERGY RESOURCES CORP.**  
**CONSOLIDATED STATEMENTS OF FINANCIAL POSITION**

*(Unaudited)*

<i>(\$ thousands)</i>	September 30 2011	December 31 2010
<b>ASSETS</b>		
Current Assets		
Cash and cash equivalents	134,834	-
Accounts receivable	47,747	64,243
Prepaid expenses and deposits	7,902	6,568
Investments <i>(Note 15)</i>	4,797	10,667
Fair value of financial instruments <i>(Note 15)</i>	-	3,928
	195,280	85,406
Exploration and evaluation assets <i>(Note 6)</i>	296,668	307,132
Property, plant and equipment <i>(Note 7)</i>	2,123,102	2,033,362
Goodwill <i>(Note 8)</i>	9,000	9,000
	2,624,050	2,434,900
<b>LIABILITIES</b>		
Current Liabilities		
Accounts payable and accrued liabilities	81,714	80,095
Dividends payable	23,864	22,654
Convertible debentures <i>(Note 10)</i>	-	73,767
Fair value of financial instruments <i>(Note 15)</i>	2,849	-
	108,427	176,516
Bank debt <i>(Note 9)</i>	-	312,508
Convertible debentures <i>(Note 10)</i>	353,100	175,546
Decommissioning obligations <i>(Note 11)</i>	97,397	86,818
Deferred income taxes	69,435	12,370
	628,359	763,758
<b>SHAREHOLDERS' EQUITY</b>		
Shareholders' capital <i>(Note 12)</i>	2,119,792	2,561,870
Convertible debentures <i>(Note 10)</i>	33,725	20,706
Contributed surplus	26,121	23,673
Deficit	(183,947)	(935,107)
	1,995,691	1,671,142
	2,624,050	2,434,900

*The accompanying notes are an integral part of these consolidated financial statements.*

**PROGRESS ENERGY RESOURCES CORP.**  
**CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) AND COMPREHENSIVE EARNINGS**  
**(LOSS)**  
*(Unaudited)*

	Three Months Ended September 30		Nine Months Ended September 30	
<i>(\$ thousands, except per share amounts)</i>	2011	2010	2011	2010
<b>REVENUE</b>				
Petroleum and natural gas	114,037	105,305	348,492	334,635
Royalties	(14,045)	(16,038)	(42,696)	(52,844)
	99,992	89,267	305,796	281,791
Realized gain (loss) on financial instruments <i>(Note 15)</i>	(1,258)	5,735	2,710	8,718
Unrealized gain (loss) on financial instruments <i>(Note 15)</i>	(1,010)	1,143	(6,777)	7,781
	97,724	96,145	301,729	298,290
<b>EXPENSES</b>				
Operating	21,950	23,635	64,735	68,484
Transportation	13,748	12,623	38,853	35,008
Depletion and depreciation <i>(Note 6 and 7)</i>	59,228	55,089	169,530	183,798
Goodwill impairment <i>(Note 8)</i>	-	-	-	34,226
General and administrative	3,826	3,605	11,292	10,981
Share based compensation <i>(Note 12)</i>	2,408	2,812	7,297	9,259
Other expenses <i>(Note 7)</i>	-	-	-	2,146
	101,160	97,764	291,707	343,902
	(3,436)	(1,619)	10,022	(45,612)
Gain on joint arrangement <i>(Note 5)</i>	235,980	-	235,980	-
Gain (loss) on divestitures <i>(Note 7)</i>	55	519	(1,423)	(9,115)
	232,599	(1,100)	244,579	(54,727)
<b>FINANCE EXPENSES</b>				
Interest and finance expenses	(7,464)	(6,361)	(22,898)	(23,654)
Other finance expenses <i>(Note 13)</i>	(8,706)	(1,932)	(16,985)	(7,737)
	(16,170)	(8,293)	(39,883)	(31,391)
Earnings (loss) before taxes	216,429	(9,393)	204,696	(86,118)
<b>TAXES</b>				
Deferred income taxes (reduction)	55,077	(1,748)	53,154	(10,933)
<b>NET EARNINGS (LOSS) AND COMPREHENSIVE EARNINGS (LOSS)</b>	<b>161,352</b>	<b>(7,645)</b>	<b>151,542</b>	<b>(75,185)</b>
<b>NET EARNINGS (LOSS) PER SHARE <i>(Note 12)</i></b>				
Basic	\$0.70	(\$0.03)	\$0.67	(\$0.38)
Diluted	\$0.66	(\$0.03)	\$0.66	(\$0.38)

*The accompanying notes are an integral part of these consolidated financial statements.*

**PROGRESS ENERGY RESOURCES CORP.**  
**CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY**  
*(Unaudited)*

<i>(\$ thousands)</i>	Shareholders' Capital	Convertible debentures	Contributed surplus	Deficit	Total Equity
Balance January 1, 2011	2,561,870	20,706	23,673	(935,107)	1,671,142
Net earnings for the period	-	-	-	151,542	151,542
Reduction of stated capital <i>(Note 12)</i>	(669,283)	-	-	669,283	-
Issue of shares (net)	194,864	-	-	-	194,864
Share based compensation expensed	-	-	7,297	-	7,297
Share based compensation capitalized	-	-	1,017	-	1,017
Share based compensation settlements	9,490	-	(9,490)	-	-
Issued on exercise of options	743	-	-	-	743
Convertible debentures – equity portion	-	(3,624)	3,624	-	-
Dividend reinvestment program	22,108	-	-	-	22,108
Dividends declared	-	-	-	(69,665)	(69,665)
Issue of 5.75% convertible debentures	-	16,643	-	-	16,643
Balance September 30, 2011	2,119,792	33,725	26,121	(183,947)	1,995,691
Balance at January 1, 2010	1,944,738	22,624	17,802	(669,283)	1,315,881
Net loss for the period	-	-	-	(75,185)	(75,185)
Issue of shares (net)	591,810	-	-	-	591,810
Share based compensation expensed	-	-	9,259	-	9,259
Share based compensation capitalized	-	-	1,160	-	1,160
Share based compensation settlements	9,513	-	(9,513)	-	-
Issued on exercise of options	422	-	-	-	422
Convertible debentures – equity portion	-	(1,918)	1,918	-	-
Dividend reinvestment program	9,159	-	-	-	9,159
Dividends declared	-	-	-	(64,878)	(64,878)
Balance September 30, 2010	2,555,642	20,706	20,626	(809,346)	1,787,628

*The accompanying notes are an integral part of these consolidated financial statements.*

**PROGRESS ENERGY RESOURCES CORP.**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(\$ thousands)	2011	2010	2011	2010
<b>OPERATING ACTIVITIES</b>				
Net earnings (loss)	161,352	(7,645)	151,542	(75,185)
Unrealized loss (gain) on financial instruments (Note 15)	1,010	(1,143)	6,777	(7,781)
Gain on joint arrangement (Note 5 and 7)	(235,980)	-	(235,980)	-
Loss (gain) on divestitures (Note 7)	(55)	(519)	1,423	9,115
Goodwill impairment (Note 8)	-	-	-	34,226
Other finance expenses (Note 13)	8,706	1,932	16,985	7,737
Depletion and depreciation (Note 6 and 7)	59,228	55,089	169,530	183,798
Decommissioning expenditures (Note 11)	(183)	(3,684)	(1,225)	(7,124)
Share based compensation (Note 12)	2,408	2,812	7,297	9,259
Deferred income taxes (reduction)	55,077	(1,748)	53,154	(10,933)
	51,563	45,094	169,503	143,112
Changes in non-cash working capital (Note 14)	3,649	4,189	13,306	4,259
	55,212	49,283	182,809	147,371
<b>FINANCING ACTIVITIES</b>				
Increase (decrease) in bank debt	-	39,749	(312,508)	(59,745)
Repayment of convertible debenture (Note 10)	(75,000)	-	(75,000)	(55,667)
Issue of shares (Note 12)	-	-	200,160	600,138
Share issue costs (Note 12)	(17)	(174)	(7,119)	(11,365)
Issue of 5.75% convertible debentures (Note 10)	-	-	200,000	-
5.75% convertible debenture issue costs (Note 10)	(17)	-	(7,799)	-
Exercise of options (Note 12)	96	159	743	422
Cash dividends	(16,064)	(17,201)	(46,347)	(51,575)
Changes in non-cash working capital (Note 14)	(1,203)	599	(851)	(8)
	(92,205)	23,132	(48,721)	422,200
<b>INVESTING ACTIVITIES</b>				
Joint arrangement (Note 5)	261,135	-	261,135	-
Proceeds from divestitures (Note 7)	77	-	35,421	44,473
Capital expenditures – property, plant and equipment (Note 7)	(60,011)	(52,977)	(183,322)	(145,344)
Capital expenditures – exploration and evaluation assets (Note 6)	(53,748)	(55,403)	(116,814)	(122,070)
Asset acquisition (Note 6 and 7)	-	-	-	(387,087)
Changes in non-cash working capital (Note 14)	18,836	35,965	4,326	40,457
	166,289	(72,415)	746	(569,571)
<b>CHANGE IN CASH AND CASH EQUIVALENTS</b>	129,296	-	134,834	-
Cash and cash equivalent, beginning of period	5,538	-	-	-
<b>CASH AND CASH EQUIVALENTS, END OF PERIOD</b>	134,834	-	134,834	-

The accompanying notes are an integral part of these consolidated financial statements.

**PROGRESS ENERGY RESOURCES CORP.**  
**NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS**  
*(Unaudited) (tabular amounts are in \$ thousands except for share and per share amounts)*

**1. REPORTING ENTITY**

Progress Energy Resources Corp. (“Progress” or the “Company”) is engaged in the exploration for, and the acquisition, development and production of, oil and natural gas reserves in the provinces of British Columbia and Alberta. The Company conducts many of its activities jointly with others and these financial statements reflect only Progress’ proportional interest in such activities. Progress was incorporated on April 8, 2004 under the name ProEx Energy Ltd. (“ProEx”) and commenced commercial operations on July 2, 2004. On January 15, 2009, in connection with a plan of arrangement, ProEx was renamed Progress Energy Resources Corp. The Company currently has one wholly owned subsidiary and is a partner in a general partnership.

**2. BASIS OF PREPARATION:**

**(a) Statement of compliance:**

These interim consolidated financial statements have been prepared in accordance with International Accounting Standard (“IAS”) 34, “Interim Financial Reporting”. These interim consolidated financial statements are for part of the period covered by the first International Financial Reporting Standards (“IFRS”) annual financial statements of the Company and IFRS 1, “First-time Adoption of International Financial Reporting Standards” has been applied. These interim consolidated financial statements do not include all of the information required for full annual financial statements. The impact of the new standards, including reconciliations presenting the change from previous GAAP to IFRS as at September 30, 2010 and for the three and nine months ended September 30, 2010, is presented in note 16.

The consolidated financial statements were authorized for issuance by the Board of Directors on October 27, 2011.

**(b) Basis of measurement:**

The consolidated financial statements have been prepared on the historical cost basis except for the following:

- (i) derivative financial instruments are measured at fair value; and
- (ii) held for trading financial assets are measured at fair value with changes in fair value recorded in earnings.

The methods used to measure fair values are discussed in note 4.

**(c) Functional and presentation currency:**

These interim consolidated financial statements are presented in Canadian dollars, which is the Company’s functional currency.

**(d) Use of estimates and judgments:**

The preparation of financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the interim consolidated financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. Significant estimates and judgments made by management in the preparation of these interim consolidated financial statements are as follows:

Amounts recorded for depletion and depreciation and amounts used for impairment calculations are based on estimates of petroleum and natural gas reserves. By their nature, the estimates of reserves, including the estimates of future prices, costs, discount rates and the related future cash flows, are subject to measurement uncertainty. Accordingly, the impact to the consolidated financial statements in future periods could be material.

Amounts recorded for decommissioning obligations and the related accretion expense requires the use of estimates with respect to the amount and timing of decommissioning expenditures. Other provisions are recognized in the period when it becomes probable that there will be a future cash outflow.

The estimated fair value of derivative financial instruments resulting in financial assets and liabilities, by their very nature are subject to measurement uncertainty.

Compensation costs recognized for share based compensation plans are subject to the estimation of what the ultimate payout will be using pricing models such as the Black-Scholes-Merton model which is based on significant assumptions such as volatility, dividend yield and expected term. Several compensation plans are also performance based and are subject to management's judgment as to whether or not performance criteria will be met.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. As such income taxes are subject to measurement uncertainty. Deferred income tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

### 3. SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the interim consolidation financial statements as at March 31, 2011. The significant accounting policies are described in note 3 of the March 31, 2011 interim consolidated financial statements.

#### (a) New standards and interpretations not yet adopted:

In May 2011, the IASB issued four new standards and two amendments. Five of these items related to consolidation, while the remaining one addresses fair value measurement. All of the new standards are effective for annual periods beginning on or after January 1, 2013. Early adoption is permitted.

IFRS 10, "Consolidated Financial Statements" replaces IAS 27 "Consolidated Separate Financial Statements". It introduces a new principle-based definition of control, applicable to all investees to determine the scope of consolidation. The standard provides the framework for consolidated financial statements and their preparation based on the principle of control.

IFRS 11 "Joint Arrangements" replaces IAS 31, "Interests in Joint Ventures". IFRS 11 divides joint arrangements into two types, each having its own accounting model. A "joint operation" continues to be accounted for using proportionate consolidation, where a "joint venture" must be accounted for using equity accounting. This differs from IAS 31, where there was the choice to use proportionate consolidation or equity accounting for joint ventures. A "joint operation" is defined as the joint operators having rights to the assets, and obligations for the liabilities, relating to the arrangement. In a "joint venture", the joint ventures' have rights to the net assets of the arrangement, typically through their investment in a separate joint venture entity.

IFRS 12 "Disclosure of Interests in Other Entities" is a new standard, which combines all of the disclosure requirements for subsidiaries, associates and joint arrangements, as well as unconsolidated structured entities.

IFRS 13 "Fair Value Measurement" is a new standard meant to clarify the definition of fair value, provide guidance on measuring fair value and improve disclosure requirements related to fair value measurement.

IAS 28 "Investments in Associates and Joint Ventures" has been amended as a result of the issuance of IFRS 11 and the withdrawal of IAS 31. The amended standard sets out the requirements for the application of the equity method when accounting for interest in joint ventures, in addition to interests in associates.

IAS 27 “Separate Financial Statements” has been amended to focus solely on accounting and disclosure requirements when an entity presents separate financial statements, due to the issuance of the new IFRS 10 which is specific to consolidated financial statements.

In November 2009, the IASB published IFRS 9, “Financial Instruments,” which covers the classification and measurement of financial assets as part of its project to replace IAS 39, “Financial Instruments: Recognition and Measurement.” In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through earnings. If this option is elected, entities would be required to reverse the portion of the fair value change due to a company’s own credit risk out of earnings and recognize the change in other comprehensive income. IFRS 9 is effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively.

The Company is currently evaluating the impact of adopting all of the newly issued and amended standards.

#### **4. DETERMINATION OF FAIR VALUES**

A number of the Company’s accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(i) **Property, plant and equipment and exploration and evaluation assets:**

The fair value of property, plant and equipment and exploration and evaluation assets recognized in a business combination, is based on market values. The market value of property, plant and equipment and exploration and evaluation assets is the estimated amount for which the assets could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm’s length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in property, plant and equipment) and intangible exploration assets is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

The market value of other items of property, plant and equipment is based on the quoted market prices for similar items.

(ii) **Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, cash dividends payable and bank debt:**

The fair value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, cash dividends payable and bank debt is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At September 30, 2011 and December 31, 2010, the fair value of these balances approximated their carrying value due to their short term to maturity or in the case of bank debt, the fair value approximates its carrying value as it bears interest at floating rates and the premium charged was indicative of the Company’s current credit premium.

(iii) **Derivatives:**

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the reporting date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use published information with respect to volatility, prices and interest rates.

(iv) **Convertible debentures:**

The convertible debentures trade on the Toronto stock exchange under the symbols PRQ.DB.B and PRQ.DB.C. The fair value of the convertible debentures is based on quoted market prices.

(v) Stock options:

The fair value of employee stock options is measured using a Black Scholes-Merton option pricing model. Measurement inputs include the share price on the measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

(vi) Restricted units and performance units:

The fair value of the Company's restricted units and performance units is measured using the quoted market price of the Company's common shares as at the date of grant.

## 5. JOINT ARRANGEMENT

On August 2, 2011 Progress and the Malaysian national oil and gas company, PETRONAS, entered into a strategic partnership to develop Progress' Montney shale assets in the Altares, Lily, and Kahta areas in the Foothills of northeast British Columbia (the "Upstream Joint Venture") and to pursue the development of a liquefied natural gas ("LNG") export facility (the "LNG Export Joint Venture") on the west coast of British Columbia. The Upstream Joint Venture is owned 50 percent by Progress and 50 percent by PETRONAS, and the LNG Export Joint Venture is owned 20 percent by Progress and 80 percent by PETRONAS.

On the creation of the Upstream Joint Venture, Progress sold 50 percent of its working interest in the Altares, Lily and Kahta areas to PETRONAS. Progress received \$267.5 million in cash on the closing of the transaction resulting in a gain of approximately \$236.0 million, net of the book value of the assets sold and transaction costs of approximately \$6.4 million, which includes \$0.8 million of compensation costs. Progress will receive an additional \$802.5 million over the next five years in the form of a capital carry whereby PETRONAS will pay 75 percent of Progress' share of future capital expenditures in the Upstream Joint Venture. The \$802.5 million will be recognized as a reduction to capital spending in proportion to the capital spent. Under the terms of the Upstream Joint Venture, any amount of the \$802.5 million that remains outstanding at the end of five years being August 2, 2016, will be paid to Progress in full. Such a payout, if any, would be recognized in earnings.

The LNG Joint Export Venture has launched a feasibility study to evaluate the potential of building and operating a new LNG export facility on the west coast of British Columbia. In accordance with a Support Agreement the production from the Upstream Joint Venture will be dedicated to the LNG Export Joint Venture. Until a positive investment decision is made, the production will be sold on a short term contract basis. If the investment decision has not been made within five years, the Upstream Joint Venture may freely market its production. The five years may be extended an additional two years if substantial progress has been achieved toward making a final investment decision.

Prior to making the final investment decision on the LNG export facility, PETRONAS has the option to participate in any security offering by Progress, public or private, of up to 10 percent of the offering. At the time of a successful LNG investment decision, Progress can require PETRONAS to purchase common shares from treasury on a private placement basis for the lesser of \$600 million or that number of common shares that would result in PETRONAS having an ownership interest of 10 percent of the issued and outstanding common shares of Progress. If Progress elects to require PETRONAS to purchase common shares that would result in them owning less than five percent of the issued and outstanding common shares, then PETRONAS will have the option to purchase common shares resulting in them having an ownership interest of 10 percent. If Progress elects to require PETRONAS to purchase common shares resulting in an ownership interest of between five and 10 percent, PETRONAS can elect to purchase common shares amounting to an additional five percent ownership interest. The proceeds will be placed in escrow and used to fund future capital expenditures of the Upstream Joint Venture. If PETRONAS holds an ownership of 10 percent or more of Progress, they have the right to nominate one individual to be a director of Progress.

## 6. EXPLORATION AND EVALUATION ASSETS

	<b>Total</b>
Balance, January 1, 2010	206,487
Additions	152,514
Asset acquisition ( <i>Note 7</i> )	83,442
Divestitures	(2,005)
Transfer to property, plant and equipment	(116,931)
Expiries (depletion expense)	(16,375)
Balance, December 31, 2010	<b>307,132</b>
Additions	<b>116,814</b>
Divestitures	<b>(18,559)</b>
Transfer to property, plant and equipment	<b>(95,812)</b>
Expiries (depletion expense)	<b>(12,907)</b>
Balance, September 30, 2011	<b>296,668</b>

Exploration and evaluation assets consist of the Company's exploration projects which are pending the determination of proved or probable reserves. Costs primarily consist of undeveloped land and drilling costs until the drilling of the well is complete and the results have been evaluated.

Amortization and impairment charge:

The cost of undeveloped land that expires during a period and any impairment of intangible exploration assets is recognized as additional depletion and depreciation expense.

## 7. PROPERTY, PLANT AND EQUIPMENT

<b>Cost or deemed cost</b>	<b>Total</b>
Balance, January 1, 2010	1,773,278
Additions	219,607
Transfer from exploration and evaluation assets	116,931
Asset acquisition	303,645
Impairment	(139,624)
Divestitures	(64,928)
Change in decommissioning obligations	28,531
Capitalized share based compensation	1,532
Balance, December 31, 2010	<b>2,238,972</b>
Additions	<b>183,322</b>
Transfer from exploration and evaluation assets	<b>95,812</b>
Divestitures	<b>(53,598)</b>
Change in decommissioning obligations	<b>14,551</b>
Capitalized share based compensation	<b>1,017</b>
Balance, September 30, 2011	<b>2,480,076</b>

<b>Accumulated depletion and depreciation:</b>	<b>Total</b>
Balance, January 1, 2010	-
Depletion and depreciation expense	(209,066)
Divestitures	3,456
Balance, December 31, 2010	<b>(205,610)</b>
Depletion and depreciation expense	<b>(156,623)</b>
Divestitures	<b>5,259</b>
Balance, September 30, 2011	<b>(356,974)</b>
<b>Net book value:</b>	<b>Total</b>
As at January 1, 2010	1,773,278
As at December 31, 2010	2,033,362
As at September 30, 2011	<b>2,123,102</b>

The calculation of 2011 depletion and depreciation expense included an estimated \$1,192.0 million (2010 - \$752.8 million) for future development costs associated with proved plus probable undeveloped reserves and excluded \$72.4 million (2010 - \$63.7 million) for the estimated salvage value of production equipment and facilities. Depletion and depreciation expense for property, plant and equipment for the three and nine months ended September 30, 2011 was \$53.2 million and \$156.6 million, respectively (2010 - \$53.1 million and \$172.7 million).

#### **Joint Arrangement:**

On August 2, 2011, the Company entered into a joint arrangement with PETRONAS (refer to note 5), whereby Progress sold a 50 percent interest in certain areas for net proceeds of \$261.1 million (net of \$6.4 million in transaction costs). The book value of the assets disposed of was \$25.2 million comprised of \$16.1 million of exploration and evaluation assets and \$9.1 million of property, plant and equipment. This resulted in a gain of \$236.0 million for the three and nine months ended September 30, 2011.

#### **Divestitures:**

For the three and nine months ended September 30, 2011, the Company disposed of certain assets for gross proceeds of \$0.1 million and \$35.4 million, respectively. This resulted in a gain of \$0.1 million and a loss of \$1.4 million for the three and nine months ended September 30, 2011. On June 30, 2010 the Company disposed of its central Alberta properties for \$44.5 million, resulting in a loss of \$9.1 million.

#### **Acquisition:**

On March 31, 2010, Progress acquired certain crude oil and natural gas assets for \$387.1 million (excluding transaction costs) of which \$83.4 million was recognized in exploration and evaluation assets for the value of undeveloped land and \$303.7 was recognized in property, plant and equipment. Acquisition costs of \$2.1 million were charged to other expenses on the statement of earnings and comprehensive earnings for the nine months ended September 30, 2010. In addition, Progress recorded a decommissioning provision of \$16.7 million in relation to the acquired assets.

#### **Impairments:**

During 2010, as a result of decreasing natural gas prices, Progress recognized a \$139.6 million impairment relating to certain of the Company's CGUs. An impairment charge was taken at March 31, 2010 (\$19.7 million) and December 31, 2010 (\$119.9 million) and recorded as additional depletion and depreciation expense. The impairments were based on the difference between the period end net book value of the assets and the recoverable amount. The recoverable amount was determined using fair value less cost to sell based on discounted cash flows of proved plus probable reserves using forecast prices and costs and a discount rate of 10 percent.

## 8. GOODWILL

For the purpose of impairment testing, goodwill is allocated to the Company's CGUs that are expected to benefit from the acquisition on which the goodwill was recognized. On transition to IFRS on January 1, 2010, the recoverable amount, based on the higher of value in use and the fair value less cost to sell was determined to be lower than the carrying amount for the Deep Basin CGU and as a result Progress reduced its goodwill balance by \$371.4 million with the offset being charged to the opening deficit on the Company's statement of financial position. The nine months ended September 30, 2010 includes an additional impairment charge of \$34.2 million that was recognized in the first quarter of 2010 as a result of further decreases in forecasted natural gas prices and the impact on the recoverable amount of goodwill. The remaining goodwill of \$9.0 million relates to the Company's South Foothills, British Columbia CGU.

The basis on which the recoverable amount was determined for the purpose of the impairment test was fair value less cost to sell. This was determined based on discounted future cash flows generated from the related proved plus probable reserves and any excess fair value of undeveloped land over its carrying value within exploration and evaluation assets for that particular CGU. The key assumptions of the last test performed as at December 31, 2010 were:

- Proved plus probable reserves as determined by the Company's independent qualified reserves evaluator
- Forecast commodity prices as estimated by the independent qualified reserves evaluator taking into account future prices in effect at the time
- A 2 percent inflation rate
- Discount rate of 10 percent

## 9. BANK DEBT

	September 30 2011	December 31 2010
Direct advances	-	37,508
Banker's acceptances	-	275,000
Total bank debt	-	312,508

The Company's bank debt was repaid in full on March 7, 2011 as a result of the convertible debenture and common share financing described in notes 10 and 12.

On April 29, 2011 the Company amended and restated its bank credit facility to be a covenant-based facility rather than a borrowing base facility. This facility is a 3-year extendible revolving facility in the amount of \$650 million from a syndicate of lenders with an initial maturity date of April 29, 2014. The maturity date may, at the request of the Company and with the consent of the lenders, be extended on an annual basis. The facilities remain secured over substantially all of the assets of the Company and its material subsidiaries. The facilities bear interest at a rate based on bankers acceptance rates (or LIBOR, for US dollar borrowings) plus a specified margin, which margin varies based on the Company's senior debt to EBITDA ratio (as described below). The facilities contain customary restrictions on the disposition of assets and the granting of security, as well as on the making of distributions (including the declaration of dividends) if there is then a default under the facilities (or if a default would reasonably be expected to occur as a result of such distribution). The facilities also contain customary events of default, including on a change of control of the Company where lender consent was not obtained, which could occur if a person or persons acting jointly or in concert acquired more than 30 percent of the outstanding voting securities of the Company.

Under the terms of the bank credit facility, Progress has provided its covenant that, on a rolling 4-quarter basis: (i) its consolidated senior debt will not exceed three times its consolidated EBITDA, increasing to 3.5 times upon the consummation of a material acquisition and for a period extending to the end of the second full quarter after completion of that acquisition. Senior debt is defined to exclude subordinated debt and non-recourse debt from total debt. EBITDA is calculated as net earnings before unrealized gains and losses on financial instrument contracts, interest and financing expense, acquisition costs, taxes, depreciation, depletion and accretion and any other non-cash amounts which are added back or deducted from net earnings in accordance with IFRS in the statement of cash flows; (ii) its consolidated total debt (excluding, for certainty, any convertible debentures) will

not exceed four times its consolidated EBITDA (similarly calculated), and (iii) its consolidated senior debt will not exceed one-half of its total capitalization (calculated as the aggregate of consolidated total debt, the principal amount of convertible debentures and consolidated shareholders' equity), increasing to 55 percent upon the consummation of a material acquisition and for a period extending to the end of the second full quarter after completion of that acquisition.

## 10. CONVERTIBLE DEBENTURES

On March 7, 2011 the Company completed a convertible debenture and common share financing that included \$200.0 million principal amount of 5.75 percent convertible unsecured subordinated debentures and 14,400,000 common shares at \$13.90 per share as described in note 12. The 5.75 percent debenture issue costs were approximately \$7.8 million.

As at September 30, 2011 Progress had the following convertible unsecured subordinated debentures (the "Debentures") outstanding. Each Debenture may be converted into common shares at the option of the holder at the applicable conversion price per common share noted below. The Company may elect to satisfy the interest and principal obligations by the issuance of common shares.

Debenture	Principal	Semi Annual Interest Payments	Conversion Price (\$/share)	Maturity Date
5.25%	200,000	April 30 and October 31	\$18.00	October 31, 2014
5.75%	200,000	June 30 and December 31	\$20.85	June 30, 2016

The 6.75 percent debentures matured and were settled in cash on June 30, 2010. The 6.25 percent debentures matured and were settled in cash on September 30, 2011.

After October 31, 2012, the Company may redeem the 5.25 percent debentures in whole or in part provided the common shares weighted average trading price during a specified period prior to redemption is at least 125 percent of the conversion price. The Company may satisfy the payment of principal or interest in common shares under certain circumstances.

After July 1, 2014, the Company may redeem the 5.75 percent debentures in whole or in part provided the common shares weighted average trading price during a specified period prior to redemption is at least 125 percent of the conversion price. The Company may satisfy the payment of principal or interest in common shares under certain circumstances.

The Debentures have been classified as debt, net of issue costs and net of the fair value of the conversion feature at the date of issue which has been classified as part of shareholders' equity. The issue costs will be amortized over the term of the Debentures and the debt portion will accrete up to the principal balance at maturity. The accretion and amortization of issue costs are expensed within other finance expenses on the consolidated statement of earnings and comprehensive income. The fair value of the conversion feature was determined at the time of issue as the difference between the principal value of the debentures and the discounted cash flows assuming an 8.3 percent rate for the 5.25 percent debentures and 8.75 percent for the 5.75 percent debentures which were the estimated rates for debt with similar terms at the time. If the Debentures are converted to shares, a portion of the value of the conversion feature under shareholders' equity will be reclassified to shareholders' capital along with the conversion price paid.

Debtures	Nine Months Ended September 30							
	2011				2010			
	6.25%	5.25%	5.75%	Total	6.75%	6.25%	5.25%	Total
Principal, beginning of period	75,000	200,000	-	275,000	55,667	75,000	200,000	330,667
Issued	-	-	200,000	200,000	-	-	-	-
Matured	(75,000)	-	-	(75,000)	(55,667)	-	-	(55,667)
Principal, end of period	-	200,000	200,000	400,000	-	75,000	200,000	275,000
Debt portion, beginning of period	73,767	175,546	-	249,313	55,180	72,132	169,441	296,753
Issued	-	-	169,823	169,823	-	-	-	-
Accretion	745	3,388	2,261	6,394	258	736	3,306	4,300
Amortization of issue costs	488	1,253	829	2,570	229	487	1,253	1,969
Repayment	(75,000)	-	-	(75,000)	(55,667)	-	-	(55,667)
Debt portion, end of period	-	180,187	172,913	353,100	-	73,355	174,000	247,355
Equity portion, beginning of period <sup>1</sup>	3,624	17,082	-	20,706	1,918	3,624	17,082	22,624
Issued <sup>1</sup>	-	-	16,643	16,643	-	-	-	-
Expired	(3,624)	-	-	(3,624)	(1,918)	-	-	(1,918)
Equity portion, end of period <sup>1</sup>	-	17,082	16,643	33,725	-	3,624	17,082	20,706

1) Net of the related deferred income tax

The total interest charged to earnings for the three and nine months ended September 30, 2011 was \$6.7 million and \$17.9 million (2010 - \$3.8 million and \$13.2 million).

## 11. PROVISIONS – DECOMMISSIONING OBLIGATIONS

Decommissioning obligations were estimated based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the decommissioning obligations is approximately \$172.9 million which will be incurred over the next 40 years with the majority of costs incurred between 2018 and 2038. A risk-free rate of 2.8 percent (2010 - 3.5 percent) and an inflation rate of two percent were used to calculate the net present value of the decommissioning obligations.

The following reconciles the Company's decommissioning obligations:

	Nine Months Ended September 30 2011	Year Ended December 31 2010
Balance, beginning of period	86,818	65,574
Liabilities incurred	2,585	5,245
Liabilities acquired	-	16,714
Liabilities disposed	(4,900)	(7,641)
Liabilities settled	(1,225)	(2,500)
Change in discount rate	11,966	6,568
Accretion expense	2,153	2,858
Balance, end of period	97,397	86,818

## 12. SHAREHOLDERS' EQUITY

An unlimited number of voting common shares may be authorized and issued. Each common share is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any dividends from the Company and in the assets in the event of termination or winding-up of the Company. All common shares are of the same class with equal rights and privileges.

### Shareholders' Capital

#### Common Shares of Progress Energy Resources Corp.

	Nine Months Ended September 30			
	2011		2010	
	Number	Amount	Number	Amount
<b>Common Shares</b>				
Balance, beginning of period	214,876,567	2,561,870	165,283,517	1,944,738
Reduction of stated capital	-	(669,283)	-	-
Share based compensation	546,586	9,490	592,283	9,513
Dividend reinvestment program	1,764,465	22,108	751,996	9,159
Exercise of options	59,300	743	38,334	422
Issued for cash	14,400,000	200,160	47,630,000	600,138
Share issue costs (net of tax of \$1,823 and \$3,037, respectively)		(5,296)		(8,328)
Balance, end of period	231,646,918	2,119,792	214,296,130	2,555,642

On May 11, 2011, the shareholders of Progress approved a special resolution to reduce the stated capital of the common shares of Progress by \$669.3 million, an amount equal to the Company's deficit as at January 1, 2010 in accordance with IFRS. The deficit arose out of two fundamental reporting differences between IFRS and the previous GAAP, being the method of performing the impairment test for goodwill and the discount rate used to measure decommissioning obligations (refer to note 16) as well as the impact of distributions from the Company's previous income trust structure.

On March 7, 2011, Progress issued 14,400,000 common shares at a price of \$13.90 per share for gross proceeds of \$200.2 million (\$193.0 million net of issue costs). Pursuant to its existing subscription right, the Canada Pension Plan Investment Board ("CPPIB") agreed to subscribe for 2,116,800 common shares of Progress at a price of \$13.90 per share, for gross proceeds of \$29.4 million, which is included in the aggregate proceeds of the offering. The closing of the offering and CPPIB subscription were contingent upon one another.

On March 2, 2010, Progress issued 47,630,000 subscription receipts at a price of \$12.60 per subscription receipt for total gross proceeds of \$600.1 million (\$588.8 million net of issue costs). The financing was comprised of a \$350 million subscription receipt private placement with CPPIB and a concurrent \$250 million subscription receipt bought deal financing through a syndicate of underwriters. Each private placement subscription receipt and public subscription receipt represented the right to receive one common share of Progress, without the payment of any additional consideration, subject to the closing of the asset acquisition which occurred on March 31, 2010.

### Management of Capital Structure

Progress' objectives when managing its capital structure are (i) to maintain a flexible capital structure which optimizes the cost of capital at acceptable risk; and (ii) to manage capital in a manner which balances the interests of equity and debt holders.

In the management of capital, Progress includes share capital and total debt, which is made up of bank debt, convertible unsecured subordinated debentures and working capital (excluding the fair value of financial instruments). Progress manages the capital structure and makes adjustments in light of current economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, Progress may issue new common shares, issue new debt, issue new debt to replace existing debt with different characteristics, adjust exploration and development capital expenditures, and acquire or dispose of assets. During the first quarter of 2011, Progress issued 14,400,000 common shares at a price of \$13.90 per share, as well as issued \$200.0 million principal amount of 5.75 percent convertible unsecured subordinated debentures described in note 10. On April 30, 2011 the Company amended and restated its bank credit facility to be a covenant-based facility rather than a borrowing base facility. This facility is a 3-year extendible revolving facility in the amount of \$650 million from a syndicate of lenders with an initial maturity date of April 29, 2014.

The key measures that the Company utilizes in evaluating its capital structure are total debt to cash flow from operating activities (before changes in non-cash working capital) and the current credit available from its creditors in relation to the Company's budgeted capital program. Total debt to cash flow from operating activities (before changes in non-cash working capital) is calculated as total debt divided by cash flow from operating activities (before changes in non-cash working capital) and represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if cash flow from operating activities (before changes in non-cash working capital) stayed constant. At September 30, 2011 total debt was \$263.4 million and annualized cash flow from operating activities (before changes in non-cash working capital) for the nine months ended September 30, 2011 was \$226.0 million, resulting in a total debt to cash flow from operating activities (before changes in non-cash working capital) ratio of 1.2. This ratio is acceptable to the Company in light of the current natural gas price environment.

There were no changes in the Company's approach to capital management during the period.

Progress is not subject to externally imposed capital requirements.

#### Net Earnings (Loss) Per Share

The following table summarizes the weighted average shares used in calculating net earnings (loss) per share:

	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
<b>Basic Earnings (Loss) per Share</b>				
Net earnings (loss) for the period	161,352	(7,645)	151,542	(75,185)
Weighted average shares – basic	231,529,571	214,221,761	227,131,494	197,969,290
Net earnings (loss) per share – basic	\$0.70	(\$0.03)	\$0.67	(\$0.38)
<b>Diluted Earnings (Loss) per Share</b>				
Net earnings (loss) for the period	167,664	(7,645)	151,542	(75,185)
Weighted average shares – basic	231,529,571	214,221,761	227,131,494	197,969,290
Convertible debentures	20,703,437	-	-	-
Performance units	568,249	-	595,170	-
Stock options	260,830	-	421,576	-
Weighted average shares – diluted	253,062,087	214,221,761	228,148,240	197,969,290
Net earnings (loss) per share – diluted	\$0.66	(\$0.03)	\$0.66	(\$0.38)

An increase to the numerator of \$6.3 million for the three months ended September 30, 2011 is required to provide for the earnings impact of the Debentures. The Debentures are anti-dilutive for the nine months ended September 30, 2011. Shares potentially issuable on the exercise of outstanding stock options, restricted share units and performance units, and on the conversion of the Debentures for the three and nine months ended September 30, 2010 are anti-dilutive and are not included in the calculation of diluted weighted average shares.

### **Share based compensation**

The Company has established a share based compensation plan (the “Plan”) comprised of a Stock Option Plan, as well as a Share Unit Plan which includes both restricted unit awards and performance unit awards. Unless otherwise approved by the shareholders, the Company may grant up to a maximum of 1,700,000 common shares pursuant to the Share Unit Plan. The restricted unit awards are whole share awards that entitle the holder to that number of shares at the end of the vesting period. Performance unit awards are similar to the restricted unit awards, however, a performance factor is applied to the grant on the vesting date. Both the restricted unit awards and performance unit awards vest at the end of a three year period and include accumulated dividends paid over the vesting period, however for new employees, their initial grant will vest 20 percent on the first anniversary date, 30 percent on the second anniversary and 50 percent on the third anniversary. Under the Stock Option Plan, unless otherwise approved by the shareholders, the Company may grant up to a maximum of 10,000,000 stock options. The stock options granted under the Stock Option Plan prior to 2011 vest one third in each of the second, third and fourth year anniversary dates from the date of grant. Stock options granted in 2011 vest one third in each of the first, second and third year anniversary dates for the date of grant. The options expire in five years from the date of grant.

On January 15, 2009 Progress Energy Trust (the “Trust”) and ProEx completed a plan of arrangement (the “Arrangement”) whereby ProEx acquired all of the issued and outstanding units of the Trust. The Trust unitholders received 0.8125 of a ProEx share for each trust unit held. Upon completion of the Arrangement, the Trust was liquidated and dissolved and Progress received all of the assets and assumed all of the liabilities of the Trust. Grants that were outstanding from the Trust and ProEx, which include performance units and units granted under the LTI Component as well as stock options of ProEx, will continue until their original vesting dates.

For the three and nine months ended September 30, 2011, \$2.4 million and \$7.3 million was charged to share based compensation expense (2010 – \$2.8 million and \$9.3 million) and \$0.3 million and \$1.0 million was capitalized (2010 – \$0.4 million and \$1.2 million) relating to the total performance units, stock options and shares under the LTI component.

## Stock options

As at September 30, 2011, there were 7,766,434 stock options outstanding. This includes stock options which were granted under the Plan and stock options that have continued from ProEx's original stock option plan.

The number and weighted average exercise price of stock options are as follows:

	Number of options	Weighted average exercise price
Balance, January 1, 2010	5,872,533	11.93
Granted	281,000	12.39
Forfeited	(145,332)	12.39
Expired	(18,000)	15.46
Exercised	(38,334)	11.02
Balance, December 31, 2010	<b>5,951,867</b>	<b>11.93</b>
Granted	<b>1,966,367</b>	<b>12.30</b>
Forfeited	<b>(52,667)</b>	<b>11.98</b>
Expired	<b>(39,833)</b>	<b>14.51</b>
Exercised	<b>(59,300)</b>	<b>12.53</b>
Balance, September 30, 2011	<b>7,766,434</b>	<b>11.81</b>
Exercisable, September 30, 2011	<b>2,588,934</b>	<b>11.90</b>

The following table summarizes stock options outstanding and exercisable at September 30, 2011.

Range of exercise price	Options outstanding			Options exercisable	
	Number outstanding at period end	Weighted average remaining contractual life	Weighted average exercise price	Number exercisable at period end	Weighted average exercise price
\$9.35 to \$11.99	5,446,034	2.49	11.78	1,974,900	11.30
\$12.00 to \$14.62	2,228,400	3.46	12.81	522,034	13.52
\$14.70 to \$15.78	92,000	0.87	15.35	92,000	15.35
	<b>7,766,434</b>	<b>2.75</b>	<b>11.81</b>	<b>2,588,934</b>	<b>11.90</b>

The Company accounts for its share based compensation plan using the fair value method. Under this method, a compensation cost is charged over the vesting period for stock options granted to officers, directors and employees with a corresponding increase to contributed surplus. Progress has estimated a 10 percent forfeiture rate for the stock options.

The fair value of the options granted during the three and nine months ended September 30, 2011 and 2010 were estimated on the date of grant using a Black Scholes-Merton option pricing model with weighted average assumptions and resulting values for grants as follows:

Assumptions	Three Months Ended September 30		Nine Months Ended September 30	
	2011	2010	2011	2010
Risk free interest rate (%)	<b>1.09</b>	1.92	<b>1.50</b>	2.32
Expected life (years)	<b>3.00</b>	3.83	<b>3.00</b>	3.83
Expected volatility (%)	<b>38</b>	47	<b>41</b>	47
Expected dividend yield (%)	<b>3.3</b>	3.4	<b>3.2</b>	3.2
Weighted average fair value of options granted (\$)	<b>2.55</b>	3.52	<b>2.85</b>	3.80

The expected volatility is calculated based on historical trading prices of Progress since the Arrangement was completed on January 15, 2009.

### Share units

The activity for the period January 1, 2010 to September 30, 2011 relating to the Company's Share Unit Plan which includes both restricted units and performance units as described above, is as follows:

<b>Restricted Units</b>	
Balance, January 1, 2010	93,259
Granted	88,265
Settled	(950)
Forfeited	(1,175)
Balance, December 31, 2010	179,399
Granted	93,370
Settled	(5,937)
Forfeited	(5,200)
Balance, September 30, 2011	261,632
<b>Vesting Date</b>	
2012	85,039
2013	85,958
2014	90,635
Total	261,632
<b>Performance Units</b>	
Balance, January 1, 2010	259,950
Granted	281,050
Settled	(2,790)
Forfeited	(14,635)
Balance, December 31, 2010	523,575
Granted	246,140
Settled	(8,120)
Forfeited	(7,600)
Balance, September 30, 2011	753,995
<b>Vesting Date</b>	
2012	250,190
2013	264,097
2014	239,708
Total	753,995

### Share Appreciation Rights (SARs)

ProEx had a Share Appreciation Rights (SARs) plan that allowed for the issuance of SARs to certain employees, which entitle the holder to receive a cash payment equal to the difference between the stated exercise price and the market price of common shares on the date of surrender. SARs vest equally over a three year period. The exercise price was based on the market price at the time of grant. At September 30, 2011, 65,000 (2010 – 65,000) SARs were outstanding at an average price of \$13.99. Compensation expense relating to the SARs for the three and nine months ended September 30, 2011 was nil (2010 – nil).

### Long Term Incentive Component of the Trust

Awards granted under the LTI component will vest over three years with 40 percent vesting on the second anniversary of the date of grant and 60 percent vesting on the third anniversary of the date of grant. An additional 15 percent grant will be paid if the holder holds the common shares they receive on the second anniversary date for one additional year. For the nine months ended September 30, 2011, 10,820 common shares were issued to settle LTI amounts that vested. As at September 30, 2011 3,305 common shares remain outstanding under the LTI component at an average value of approximately \$17.13 per share.

### Performance Unit Incentive Plan

The outstanding performance units that had been granted by the Trust vest at the end of a three year performance period at which time they will be converted to common shares, or the cash equivalent, and include the accumulated distributions of the Trust and accumulated dividends of the Company over the three year period. For new employees hired their initial grant vests 20 percent on the first anniversary date, 30 percent on the second anniversary and 50 percent on the third anniversary. The actual number of common shares paid is dependent upon a performance factor that is determined based on the Company's performance relative to its peers and ranges from 0.5 to 1.5 times the initial grant, except for performance units granted to the Trust's executives effective July 2, 2007 and 2008 which can range from 0 to 3 times. Payment may be in the form of cash or common shares, at the Company's option. Management anticipates, at the end of the performance period, accumulated distributions and dividends will be paid in cash and common shares will be paid from treasury. Actual performance factors will not be determined until the end of the three year performance periods.

#### Performance Units of the Trust<sup>1</sup>

Balance, January 1, 2010	717,718
Performance factor adjustment <sup>2</sup>	167,639
Settled <sup>2</sup>	(492,027)
Forfeited	(11,945)
Balance, December 31, 2010	381,385
Performance factor adjustment <sup>2</sup>	144,818
Settled <sup>2</sup>	(521,696)
Forfeited	(4,507)
Balance, September 30, 2011	-

(1) All amounts have been adjusted to reflect the ratio of 0.8125 of a common share for each trust unit as specified in the Arrangement.

(2) For 2010 the performance units were settled at a performance factor of 1.5 times resulting in the issuance of an additional 167,639 common shares. For 2011 the performance units were settled at a performance factor of 1.375 times, resulting in the issuance of an additional 144,818 common shares.

<b>Units under LTI Component<sup>1</sup></b>	
Balance, January 1, 2010	100,956
Additional grant <sup>2</sup>	18,189
Settled	(104,348)
Forfeited	(1,837)
Balance, December 31, 2010	<b>12,960</b>
Additional grant <sup>2</sup>	<b>2,165</b>
Settled	<b>(10,820)</b>
Forfeited	<b>(1,000)</b>
Balance, September 30, 2011	<b>3,305</b>

<b>Vesting Date</b>	
2011	<b>3,305</b>
Total <sup>2</sup>	<b>3,305</b>

- (1) All amounts have been adjusted to reflect the ratio of 0.8125 of a common share for each trust unit as specified in the Arrangement.
- (2) An additional 15 percent grant will be paid to LTI holders if a holder holds the shares they receive on the second anniversary date for one additional year. This would result in an additional 827 common shares being issued by the Company on the remaining outstanding grants.

### 13. OTHER FINANCE EXPENSES

Other finance expenses for the three and nine months ended September 30, 2011 and 2010 include the following:

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30</b>		<b>September 30</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Accretion of decommissioning obligations	677	677	2,153	2,105
Accretion of convertible debentures	2,409	1,370	6,394	4,300
Amortization of convertible debenture issue costs	946	580	2,570	1,969
Unrealized loss (gain) on investments (held for trading)	4,674	(695)	5,868	(637)
	<b>8,706</b>	<b>1,932</b>	<b>16,985</b>	<b>7,737</b>

### 14. SUPPLEMENTAL CASH FLOW INFORMATION

<b>Changes in non-cash working capital</b>	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30</b>		<b>September 30</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Accounts receivable	(11,113)	(2,098)	16,496	(5,037)
Prepaid expenses and deposits	(459)	4,795	(1,334)	3,638
Accounts payable	32,854	38,056	1,619	46,107
Change in non-cash working capital	<b>21,282</b>	<b>40,753</b>	<b>16,781</b>	<b>44,708</b>
Relating to:				
Investing activities	18,836	35,965	4,326	40,457
Financing activities	(1,203)	599	(851)	(8)
Operating activities	3,649	4,189	13,306	4,259

## 15. FINANCIAL INSTRUMENTS

### Fair Value of Financial Instruments

The following tables provide fair value measurement information for financial assets and liabilities as at September 30, 2011 and December 31, 2010. The carrying value of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, dividends payable and bank debt included in the consolidated statement of financial position approximate their fair value due to the short term nature of those instruments or the indexed rate of interest on the bank debt. These assets and liabilities, except cash and cash equivalents, are not included in the following tables. The fair value of the cash and cash equivalents, derivative natural gas contracts (“financial instruments”), investments and the convertible debentures as at September 30, 2011 and December 31, 2010 are as follows:

September 30, 2011	Carrying Amount	Fair Value	Quoted prices in active markets (level 1)	Significant other observable inputs (level 2)	Significant unobservable inputs (level 3)
<b>Financial assets:</b>					
Cash and cash equivalents	134,834	134,834	134,834		
Investments	4,797	4,797	4,797	-	-
<b>Financial liabilities:</b>					
Convertible debentures <sup>1</sup>	398,789	400,320	-	-	-
Derivative natural gas contracts	2,849	2,849	-	2,849	-

(1) Carrying value includes the debt and equity portion of the convertible debentures and excludes the deferred income tax impact of the debentures charged against the equity portion.

December 31, 2010	Carrying Amount	Fair Value	Quoted prices in active markets (level 1)	Significant other observable inputs (level 2)	Significant unobservable inputs (level 3)
<b>Financial assets:</b>					
Derivative natural gas contracts	3,928	3,928	-	3,928	-
Investments	10,667	10,667	10,667	-	-
<b>Financial liabilities:</b>					
Convertible debentures <sup>1</sup>	277,570	278,708	-	-	-

(1) Carrying value includes the debt and equity portion of the convertible debentures and excludes the deferred income tax impact of the debentures charged against the equity portion.

All of Progress’ cash and cash equivalents, derivative natural gas contracts and investments are transacted in active markets. Progress classifies the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

In light of the current economic conditions, the Company continues to monitor its accounts receivable and its allowance for doubtful accounts. As at September 30, 2011 there have been no impairment issues. The Company has an allowance for doubtful accounts of approximately \$0.9 million.

Investments include 8,300,000 Class A common shares of Seaview Energy Inc. (“Seaview”) and 431,379 shares of Crocotta Energy Inc. (“Crocotta”). Both investments have been classified as held for trading and are measured at fair value each reporting period. Based on Seaview’s closing trading price on September 30, 2011 of \$0.46 per share, an unrealized loss of \$4.4 million and \$6.1 million, respectively, were recognized for the three and nine months ended September 30, 2011 (2010 - \$0.6 million gain and \$0.3 million gain) on the revaluation of the shares to \$3.8 million at September 30, 2011 (2010 - \$9.5 million). The fair value of the investment in Crocotta, based on the closing trading price on September 30, 2011 of \$2.27 per share, was \$1.0 million (2010 - \$0.8 million), resulting in an unrealized loss of \$0.3 million and a gain of \$0.2 million, respectively, for the three and nine months ended September 30, 2011 (2010 - \$0.1 million and \$0.3 million gain).

### **Credit risk**

The Company’s accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. The Company routinely assesses the financial strength of its customers.

The Company may be exposed to certain losses in the event of non-performance by counterparties to commodity price contracts. The Company mitigates this risk by entering into transactions with highly rated major financial institutions.

At September 30, 2011, financial assets on the balance sheet are comprised of cash and cash equivalents, accounts receivables and held for trading investments.

The maximum credit exposure at September 30, 2011 is the carrying amount of cash and cash equivalents and accounts receivable of \$182.6 million combined. The cash and cash equivalents are held by a major Canadian chartered bank with an investment grade credit rating. As is common in the petroleum and natural gas industry in western Canada, receivables relating to the sale of petroleum and natural gas are received on or about the 25<sup>th</sup> day of the following month. The Company markets its production to customers with investment grade credit ratings, if available in the area of production, or seeks parental guarantees and letters of credit. Included in accounts receivable is \$30.2 million related to the sale of petroleum and natural gas and was received October 25, 2011. The Company’s most significant customer, a Canadian petroleum and natural gas marketer, accounts for \$8.3 million of the accounts receivable balance at September 30, 2011. The accounts receivable balance also includes \$16.0 million from joint venture partners relating to the recovery of their interest in operating costs and capital spent. The largest amount owing from one partner was \$4.8 million. As the operator of properties, Progress has the ability to not allocate production to joint venture partners who are in default of amounts owing. At September 30, 2011 the allowance for doubtful accounts was \$0.9 million.

### **Liquidity risk**

Liquidity risk relates to the risk the Company will encounter difficulty in meeting obligations associated with its financial liabilities. The financial liabilities on its statement of financial position consist of accounts payable, bank debt and the Debentures. As described in note 9, Progress amended and restated its bank credit facility in the amount of \$650 million to be a covenant-based facility rather than a borrowing base facility. The facility is a three year extendible revolving facility with a syndicate of lenders with an initial maturity of April 29, 2014. The Debentures mature on October 31, 2014 and June 30, 2016. The Company anticipates it will continue to have adequate liquidity to fund its financial liabilities through its future cash flows (see also “Management of Capital Structure” in note 12). The Company had no defaults or breaches on its bank debt or any of its financial liabilities. In addition, to achieve the objective of meeting obligations associated with its financial liabilities, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. As a result, the Company may adjust capital expenditures if necessary and may consider acquisition and disposition opportunities.

The following are contractual maturities of financial liabilities, including estimated interest payments at September 30, 2011:

September 30, 2011	Carrying Amount	Total Contractual cash flows	2011	2012	2013 to 2014	2015 and Beyond
<b>Non-Derivative Financial liabilities:</b>						
Accounts payable and accrued liabilities	81,714	81,714	81,714	-	-	-
Convertible debentures <sup>1</sup>	400,744	494,250	12,750	22,000	242,250	217,250
<b>Derivative Financial liabilities:</b>						
Natural gas contracts	2,849	1,235	1,235	-	-	-

1) Carrying value includes the debt and equity portion of the convertible debentures and the related interest payable as at September 30, 2011 and excludes the deferred income tax impact of the debentures charged against the equity portion.

### Market risk

Market risk is comprised of currency risk, interest rate risk and other price risks which consist primarily of fluctuations in petroleum and natural gas prices that could affect the Company's earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing return. The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

The valuation of the financial assets and liabilities on the balance sheet at September 30, 2011 would not be directly impacted by changes in currency rates. Currency rates influence petroleum and natural gas prices, however this influence on commodity prices and the resulting impact on financial assets and liabilities cannot be accurately quantified. In regards to commodity prices, the financial instruments directly affected by changes in commodity prices are the derivative natural gas contracts listed below. Assuming a \$0.25 change to the price per thousand cubic feet of natural gas, the fair value change in the natural gas contracts would have impacted net earnings for the three and nine months ended September 30, 2011 by approximately \$0.3 million based on the volumes and remaining terms of the contracts as at September 30, 2011 outlined below. The Company's financial instruments are not directly impacted by changes in crude oil prices. The results of the sensitivity should not be considered to be predictive of future performance. Changes in the fair value of the derivative natural gas contracts cannot generally be extrapolated because the relationship of change in certain variables to a change in fair value may not be linear.

### Currency risk

The Company does not sell or transact in any foreign currency, however, the United States ("US") dollar influences the price of petroleum and natural gas sold in Canada. Price fluctuations, as a result, can affect the fair value and future cash flows of derivative natural gas contracts, however, given it is an indirect influence, the impact of changing exchange rates cannot be quantified. The Company has derivative natural gas contracts outstanding at September 30, 2011 based on both Canadian and US natural gas market indices. The "basis hedges" outlined in the table below are the only instruments the Company had that are directly affected by changes in the US/Canadian exchange rate. A \$0.05 increase or decrease in the US/Canadian exchange rate would have resulted in a \$0.1 million change to net earnings for the three and nine months ended September 30, 2011 as a result of the change in fair value of the instruments net of deferred income taxes based on the terms of the instruments below. The Company's other financial assets and liabilities are not directly affected by a change in currency rates.

### Interest rate risk

The Company is exposed to interest rate risk on its outstanding bank debt and Debentures. The bank debt has a floating interest rate and consequently changes to interest rates would impact the Company's future cash flows. The Company had no interest rate swaps or hedges at September 30, 2011. Changes in market interest rates will result in fluctuations to the fair value of the Debentures given their fixed interest rates. An increase or decrease of one percent to the effective interest rate on the bank debt of the Company, would have impacted the three and nine months ended September 30, 2011 net earnings by nil and \$0.4 million, respectively.

## Commodity Price Risk

Commodity price risk is the risk that the fair value of financial instruments or future cash flows will fluctuate as a result of changes in commodity prices. Petroleum and natural gas prices are impacted by not only the relationship between the Canadian and US dollar but also world economic events that dictate the levels of supply and demand.

The Company has entered into several financial instruments for the purpose of protecting its cash flow from operations before changes in non-cash working capital. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. For the three months ended September 30, 2011 the Company's risk management program had a net realized loss of \$1.3 million (2010 - \$5.7 million gain). For the nine months ended September 30, 2011 the Company's risk management program had a net realized gain of \$2.7 million (2010 - \$8.7 million gain).

At September 30, 2011 the fair value of the derivative natural gas contracts, determined based on the amounts the Company would receive or pay to terminate the contracts was a liability of \$2.8 million (2010 - \$3.9 million asset), resulting in an unrealized loss of \$1.0 million and \$6.8 million for the three and nine months ended September 30, 2011 (2010 - \$1.1 million gain and \$7.8 million gain).

Contracts outstanding in respect to financial instruments are as follows:

### Natural gas

Contracts	Volume	Pricing Point	Strike Price \$/gj	Premium	Term
Bought Put Option	5,000 gj/d	AECO	\$3.610	\$0.3400	Feb 1/11 to Oct 31/11
Bought Put Option	5,000 gj/d	AECO	\$3.650	\$0.3350	Feb 1/11 to Oct 31/11
Bought Put Option	5,000 gj/d	AECO	\$3.830	\$0.3570	Feb 1/11 to Oct 31/11
Bought Put Option	10,000 gj/d	AECO	\$3.760	\$0.3400	May 1/11 to Dec 31/11
Bought Put Option	10,000 gj/d	AECO	\$3.785	\$0.3475	May 1/11 to Dec 31/11
Bought Put Option	10,000 gj/d	AECO	\$3.780	\$0.3500	May 1/11 to Dec 31/11

Contracts	Volume	Pricing Point	Strike Price \$/gj	Cost/ Premium	Term
Swap – call spread	5,000 gj/d	AECO	\$3.60 - \$4.60	\$0.26	Feb 1/11 to Oct 31/11
Swap – call spread	5,000 gj/d	AECO	\$3.65 - \$4.65	\$0.26	Feb 1/11 to Oct 31/11
Swap – call spread	5,000 gj/d	AECO	\$3.81 - \$4.81	\$0.26	Feb 1/11 to Oct 31/11

Contracts	Volume	Pricing Point	Differential	Term
Swap – basis hedge	30,000 mmbtu/d	Nymex	(\$0.5000)	May 1/11 to Dec 31/11
Swap – basis hedge	10,000 mmbtu/d	Nymex	(\$0.4950)	May 1/11 to Dec 31/11
Swap – basis hedge	10,000 mmbtu/d	Nymex	(\$0.6300)	Jan 1/12 to Dec 31/12
Swap – basis hedge	10,000 mmbtu/d	Nymex	(\$0.6250)	Jan 1/12 to Dec 31/12
Swap – basis hedge	10,000 mmbtu/d	Nymex	(\$0.6175)	Jan 1/12 to Dec 31/12
Swap – basis hedge	10,000 mmbtu/d	Nymex	(\$0.6150)	Jan 1/12 to Dec 31/12

Contracts	Volume	Pricing Point	Strike Price \$/gj	Term
Sold Calls	10,000 gj/d	AECO	\$7.575	Jan 1/11 to Dec 31/11
Sold Calls	10,000 gj/d	AECO	\$7.500	Jan 1/11 to Dec 31/11

## 16. TRANSITION TO IFRS

Progress' accounting policies under IFRS differ from those followed under the previous GAAP. These accounting policies have been applied for the three and nine months ended September 30, 2011 and the comparative information for the three and nine months ended September 30, 2010.

The adjustments arising from the application of IFRS to amounts on the statement of financial position on the transition date and on transactions prior to that date, were recognized as an adjustment to the Company's opening deficit category on the statement of financial position when appropriate.

On transition to IFRS on January 1, 2010 Progress used certain exemptions allowed under IFRS 1 "First Time Adoption of International Reporting Standards". The exemptions used were:

*Full Cost Accounting* – IFRS 1 allows an entity that used full cost accounting under its previous GAAP to elect, at the time of adoption to IFRS, to measure oil and gas assets in the development and production phases by allocating the amount determined under the entity's previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date. Progress has used reserve values as at January 1, 2010 to allocate the cost of development and production assets to CGUs.

*Business Combinations* – IFRS 1 allows an entity to use the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations. In respect of acquisitions prior to January 1, 2010, goodwill represents the amount recognized under the Company's previous GAAP.

*Share based compensation* – IFRS 1 allows an entity an exemption on IFRS 2, "Share-Based Payments" to equity instruments which vested before Progress' transition date to IFRS.

*Decommissioning Obligation* – As Progress elected to use the oil and gas exemption, a decommissioning obligation exemption was also used that allows for the remeasurement of decommissioning obligations on IFRS transition to be offset to retained earnings/deficit.

Statement of Financial Position (Reconciliation of Equity):

<i>As at September 30, 2010</i> <i>(\$ thousands)</i>	Previous GAAP	Effect of transition to IFRS	Note	IFRS
<b>ASSETS</b>				
Current Assets				
Accounts receivable	46,123			46,123
Prepaid expenses and deposits	6,797			6,797
Fair value of financial instruments	10,629			10,629
Investments	10,238			10,238
	<b>73,787</b>			<b>73,787</b>
Exploration and evaluation assets	-	312,292	(a)	312,292
Property, plant and equipment	2,406,218	(291,752)	(a,b,d,f,g,h,k)	2,114,466
Goodwill	414,655	(405,655)	(c)	9,000
	<b>2,894,660</b>	<b>(385,115)</b>		<b>2,509,545</b>
<b>LIABILITIES</b>				
Current Liabilities				
Accounts payable and accrued liabilities	99,971			99,971
Dividends payable	21,430	1,077	(e)	22,507
Convertible debentures	73,355			73,355
Deferred income taxes	2,730	(2,730)	(i)	-
	<b>197,486</b>	<b>(1,653)</b>		<b>195,833</b>
Bank debt	218,133			218,133
Convertible debentures	174,000			174,000
Decommissioning obligations	42,110	47,162	(d)	89,272
Deferred income taxes	43,554	1,125	(i)	44,679
	<b>675,283</b>	<b>46,634</b>		<b>721,917</b>
<b>SHAREHOLDERS' EQUITY</b>				
Shareholders' capital	2,555,579	63	(e)	2,555,642
Convertible debentures	28,257	(7,551)	(i)	20,706
Contributed surplus	19,386	1,240	(e)	20,626
Deficit	(383,845)	(425,501)	(b,c,d,e,f,h,i)	(809,346)
	<b>2,219,377</b>	<b>(431,749)</b>		<b>1,787,628</b>
	<b>2,894,660</b>	<b>(385,115)</b>		<b>2,509,545</b>

Reconciliation of consolidated statement of earnings (loss) and comprehensive income (loss) for the three months ended September 30, 2010:

<i>Three Months Ended September 30, 2010</i> <i>(\$ thousands, except per share amounts)</i>	Previous GAAP	Effect of transition to IFRS	Note	IFRS
<b>REVENUE</b>				
Petroleum and natural gas	105,305			105,305
Royalties	(16,038)			(16,038)
	89,267			89,267
Realized gain on financial instruments	5,735			5,735
Unrealized gain on financial instruments	1,143			1,143
Unrealized gain on investments	695	(695)	(j)	-
	96,840	(695)		96,145
<b>EXPENSES</b>				
Operating	23,800	(165)	(k)	23,635
Transportation	12,623			12,623
Depletion and depreciation	69,432	(14,343)	(f)	55,089
General and administrative	3,605			3,605
Share based compensation	2,439	373	(e)	2,812
	111,899	(14,135)		97,764
	(15,059)	13,440		(1,619)
Gain on divestitures	-	519	(h)	519
Interest and finance expenses	(8,311)	1,950	(j)	(6,361)
Other finance expenses	-	(1,932)	(j)	(1,932)
Loss before taxes	(23,370)	13,977		(9,393)
<b>TAXES</b>				
Deferred income taxes (reduction)	(4,947)	3,199	(i)	(1,748)
<b>NET LOSS AND COMPREHENSIVE LOSS</b>	<b>(18,423)</b>	<b>10,778</b>		<b>(7,645)</b>
<b>NET LOSS PER SHARE</b>				
Basic and diluted	(\$0.09)			(\$0.03)

Reconciliation of consolidated statement of earnings (loss) and comprehensive income (loss) for the nine months ended September 30, 2010:

<i>Nine Months Ended September 30, 2010</i> <i>(\$ thousands, except per share amounts)</i>	Previous GAAP	Effect of transition to IFRS	Note	IFRS
<b>REVENUE</b>				
Petroleum and natural gas	334,635			334,635
Royalties	(52,844)			(52,844)
	281,791			281,791
Realized gain on financial instruments	8,718			8,718
Unrealized gain on financial instruments	7,781			7,781
Unrealized gain on investments	637	(637)	(j)	-
	298,927	(637)		298,290
<b>EXPENSES</b>				
Operating	68,649	(165)	(k)	68,484
Transportation	35,008			35,008
Depletion and depreciation	196,050	(12,252)	(b,f)	183,798
Goodwill impairment	-	34,226	(c)	34,226
General and administrative	11,204	(223)	(e)	10,981
Share based compensation	8,571	688	(e)	9,259
Other expenses	-	2,146	(g)	2,146
	319,482	24,420		343,902
Loss on divestitures	-	(9,115)	(h)	(9,115)
Interest and finance expenses	(29,923)	6,269	(j)	(23,654)
Other finance expenses	-	(7,737)	(j)	(7,737)
Loss before taxes	(50,478)	(35,640)		(86,118)
<b>TAXES</b>				
Deferred income taxes (reduction)	(9,531)	(1,402)	(i)	(10,933)
<b>NET LOSS AND COMPREHENSIVE LOSS</b>	<b>(40,947)</b>	<b>(34,238)</b>		<b>(75,185)</b>
<b>NET LOSS PER SHARE</b>				
Basic and diluted	(\$0.21)			(\$0.38)

Reconciliation of consolidated statement of cash flows for the three months ended September 30, 2010:

<i>Three Months Ended September 30, 2010</i> <i>(\$ thousands)</i>	Previous GAAP	Effect of transition to IFRS	Note	IFRS
<b>OPERATING ACTIVITIES</b>				
Net loss	(18,423)	10,778		(7,645)
Unrealized gain on financial instruments	(1,143)			(1,143)
Unrealized gain on investments	(695)	695	(j)	-
Depletion and depreciation	69,432	(14,343)	(f)	55,089
Gain on divestitures	-	(519)	(h)	(519)
Convertible debentures accretion	1,370	(1,370)	(j)	-
Amortization of convertible debenture issue costs	580	(580)	(j)	-
Other finance expenses	-	1,932	(j)	1,932
Share based compensation expense	2,439	373	(e)	2,812
Decommissioning expenditures	(3,684)			(3,684)
Deferred income taxes (reduction)	(4,947)	3,199	(i)	(1,748)
	44,929	165		45,094
Changes in non-cash working capital	4,189			4,189
	49,118	165		49,283
<b>FINANCING ACTIVITIES</b>				
Increase in bank debt	39,749			39,749
Exercise of options	159			159
Cash dividends	(17,201)			(17,201)
Share issue costs	(174)			(174)
Changes in non-cash working capital	599			599
	23,132			23,132
<b>INVESTING ACTIVITIES</b>				
Capital expenditures – property, plant and equipment	(108,215)	55,238	(a)	(52,977)
Capital expenditures – exploration and evaluation assets		(55,403)	(a)	(55,403)
Changes in non-cash working capital	35,965			35,965
	(72,250)	(165)		(72,415)
<b>CHANGE IN CASH AND CASH EQUIVALENTS</b>				
Cash and cash equivalents, beginning of period	-	-		-
<b>CASH AND CASH EQUIVALENTS, END OF PERIOD</b>				
	-	-		-

Reconciliation of consolidated statement of cash flows for the nine months ended September 30, 2010:

<i>Nine Months ended September 30, 2010</i> <i>(\$ thousands)</i>	Previous GAAP	Effect of transition to IFRS	Note	IFRS
<b>OPERATING ACTIVITIES</b>				
Net loss	(40,947)	(34,238)		(75,185)
Unrealized gain on financial instruments	(7,781)			(7,781)
Unrealized gain on investments	(637)	637	(j)	-
Depletion and depreciation	196,050	(12,252)	(b,f)	183,798
Goodwill impairment	-	34,226	(c)	34,226
Loss on divestitures	-	9,115	(h)	9,115
Convertible debentures accretion	4,300	(4,300)	(j)	-
Amortization of convertible debenture issue costs	1,969	(1,969)	(j)	-
Other finance expenses	-	7,737	(j)	7,737
Share based compensation expense	8,571	688	(e)	9,259
Decommissioning expenditures	(7,124)			(7,124)
Deferred income taxes (reduction)	(9,531)	(1,402)	(i)	(10,933)
	144,870	(1,758)		143,112
Changes in non-cash working capital	4,259			4,259
	149,129	(1,758)		147,371
<b>FINANCING ACTIVITIES</b>				
Decrease in bank debt	(59,745)			(59,745)
Repayment of convertible debentures	(55,667)			(55,667)
Issue of shares	600,138			600,138
Cash dividends	(51,352)	(223)	(e)	(51,575)
Exercise of options	422			422
Share issue costs	(11,365)			(11,365)
Changes in non-cash working capital	(8)			(8)
	422,423	(223)		422,200
<b>INVESTING ACTIVITIES</b>				
Asset acquisition	(389,233)	2,146	(g)	(387,087)
Asset disposition	42,854	1,619	(h)	44,473
Capital expenditures – property, plant and equipment	(265,630)	120,286	(a,h)	(145,344)
Capital expenditures – exploration and evaluation assets		(122,070)	(a)	(122,070)
Changes in non-cash working capital	40,457			40,457
	(571,552)	1,981		(569,571)
<b>CHANGE IN CASH AND CASH EQUIVALENTS</b>				
Cash and cash equivalents, beginning of period	-	-		-
<b>CASH AND CASH EQUIVALENTS, END OF PERIOD</b>				
	-	-		-

## Notes to reconciliations

### (a) IFRS 1 election for full cost oil and gas entities

The Company elected to use an IFRS 1 exemption whereby the previous GAAP full cost pool was used to measure exploration and evaluation assets and development and production assets on transition to IFRS as follows:

- (i) exploration and evaluation assets were reclassified from the full cost pool to intangible exploration asset at the amount that was recorded under the previous GAAP; and
- (ii) the remaining full cost pool was allocated to the producing/development assets and components pro rata using reserve values.

This resulted in a transfer of \$206.4 million to exploration and evaluation assets and a corresponding decrease in property, plant and equipment on transition. As at September 30, 2010 the total exploration and evaluation assets were \$312.3 million, which included undeveloped land acquired in the first nine months of 2010, including undeveloped land of the Asset Acquisition (note 7), net of expiries.

### (b) Impairment of property, plant and equipment (“PP&E”)

In accordance with IFRS, impairment tests of PP&E must be performed at the CGU level as opposed to the entire PP&E balance which was required under the previous GAAP through the full cost ceiling test. An impairment is recognized if the carrying value exceeds the recoverable amount for a CGU. For Progress, the recoverable amount is determined using fair value less cost to sell based on discounted future cash flows of proved plus probable reserves using forecast prices and costs. There was no impairment to PP&E on transition on January 1, 2010. Included in the adjustments in the reconciliation of equity as at September 30, 2010 is a charge of \$19.7 million for the impairment of PP&E for certain CGUs which was recognized through depletion and depreciation expense in the first quarter of 2010. In the fourth quarter of 2010, an additional impairment charge of \$119.9 million was recognized as additional depletion and depreciation expense due to continued decreasing natural gas prices. PP&E impairments can be reversed in the future if the recoverable amount increases.

### (c) Impairment of goodwill

In accordance with the standard, goodwill has been allocated to the specific CGUs that are expected to benefit from the acquisitions for the purpose of impairment testing. As a result, the impairment test for goodwill is now performed on a smaller portion of the Company’s assets than under the previous GAAP. The impact of the impairment test under IAS 36 on January 1, 2010 resulted in a write-down of goodwill of \$371.4 million with a corresponding increase to the deficit on the statement of financial position. In addition, the reconciliation of equity as at September 30, 2010 and the reconciliation of comprehensive income (loss) for the nine months ended September 30, 2010 include an additional impairment charge to goodwill of \$34.2 million that was recognized in the first quarter of 2010 due to continued decreasing natural gas prices.

### (d) Decommissioning obligations:

Under the previous GAAP asset retirement obligations were discounted at a credit adjusted risk free rate of eight to nine percent. Under IFRS the estimated cash flows to abandon and remediate the wells and facilities has been risk adjusted therefore the provision is discounted at the risk free rate in effect at the end of each reporting period. The change in the decommissioning obligations each period as a result of changes in the discount rate will result in an offsetting charge to PP&E. Upon transition to IFRS the impact of this change was a \$26.2 million increase in the decommissioning obligations with a corresponding increase to the deficit on the statement of financial position as at January 1, 2010.

As at September 30, 2010 the adjustment to the decommissioning obligations was \$47.2 million reflecting the adjustment on transition as well as the additional liabilities incurred on the asset acquisition described in note 7 and related capital activity for the first nine months of 2010. The adjustment also reflects an increase to the liability of \$10.8 million due to a decrease in the risk free rate from transition to September 30, 2010.

As at December 31, 2010 the decommissioning obligations was \$44.5 million higher than under the previous GAAP due to the change in discount rate and its impact on the liabilities incurred or acquired during 2010.

As a result of the change in the discount rate, the decommissioning obligation accretion expense decreased by \$0.1 million and \$0.3 million for the three and nine months ended September 30, 2010 as the lower discount rate more than offset the impact of the higher obligation. In addition, under the previous GAAP, accretion of the discount was included in depletion and depreciation expense. Under IFRS it is included in other finance expenses.

(e) Share based compensation:

Under the previous GAAP, the Company recognized an expense related to share based compensation on a straight-line basis through the date of full vesting and did not incorporate a forfeiture rate at the grant date. Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate at the date of grant and update it throughout the vesting period. Adjustments to the performance factor are measured using the original grant date price under IFRS as opposed to treating the adjustment like an additional grant on the adjustment date. The impact on transition was an increase to contributed surplus of \$0.8 million with an offsetting increase to the opening deficit. For the three and nine months ended September 30, 2010, an additional share based compensation expense of \$0.4 million and \$0.7 million, respectively, was recognized as compared to the previous GAAP to reflect the changes under IFRS.

Dividends are accrued when declared for grants outstanding under the Company's share unit plan and performance units from the Trust which resulted in a \$1.8 million increase to dividends payable on transition with an offsetting charge to the opening deficit. A total of \$1.1 million of dividends was accrued as at September 30, 2010 in relation to the share based compensation plans.

An adjustment of \$0.2 million was recognized for the three and nine months ended September 30, 2010 for certain dividends related to share based compensation, which were previously treated as additional compensation through general and administrative expenses. The adjustment was made to reclassify the dividends to dividends and dividend payable from general and administrative expenses.

(f) Depletion policy:

Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion policy under the previous GAAP was based on units of production over proved reserves. In addition depletion was done on the Canadian cost centre under the previous GAAP. IFRS requires depletion and depreciation to be calculated based on individual components (ie. Fields or combinations thereof).

There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the IFRS 1 election as discussed in note "a" above.

For the three months ended September 30, 2010 depletion and depreciation expense decreased \$14.3 million as compared to the previous GAAP. Depleting the oil and natural gas interests over proved plus probable reserves resulted in a decrease to depletion and depreciation of \$13.6 million and an additional \$0.7 million decrease was the result of reclassifying the accretion on decommissioning obligations to other finance expenses.

For the nine months ended September 30, 2010, the net decrease to depletion and depreciation expense was \$12.3 million. This was comprised of a reduction to the expense of \$29.9 million due to using proved plus probable reserves to deplete PP&E, an additional reduction of \$2.1 million for the reclassification of the accretion on decommissioning obligations to other finance expenses, partially offset by the additional \$19.7 million that was charged to depletion and depreciation on the impairment of PP&E as noted in note "b" above in the first quarter of 2010.

For the year ended December 31, 2010 depletion and depreciation was reduced by \$37.7 million as a result of changes to the depletion calculation, however this was more than offset by the \$19.7 million impairment recognized in the first quarter of 2010 and an additional \$119.9 million PP&E impairment recognized in the fourth quarter of 2010.

For exploration and evaluation assets, the cost of undeveloped land that expires during the period is charged as additional depletion and depreciation expense.

(g) Business combinations

In accordance with IFRS, internal transaction costs incurred on a business combination are expensed. Under the previous GAAP, these costs were capitalized as part of the acquisition. As a result \$2.1 million was charged to other expenses for transaction costs incurred on the Asset Acquisition for the nine months ended September 30, 2010.

(h) Gains and losses on divestitures

Under the previous GAAP, proceeds from divestitures were deducted from the full cost pool without recognition of a gain or loss unless the deduction resulted in a change in the depletion rate of 20 percent or greater, in which case a gain or loss was recorded. Under IFRS, gains and losses are recorded on divestitures and are calculated as the difference between the proceeds and the net book value of the asset disposed. For the three and nine months ended September 30, 2010, Progress recognized a \$0.5 million gain and a \$9.1 million net loss primarily as a result of the sale of its central Alberta properties. On the statement of cash flows for the nine months ended September 30, 2010, the proceeds for the central Alberta disposition were increased by \$1.6 million for a second minor disposition in central Alberta, previously deducted from the full cost pool.

(i) Deferred income taxes:

The adjustment to deferred income taxes on transition relates to both the opening adjustment to the decommissioning obligations and the treatment of temporary differences on convertible debentures. The opening adjustment for the decommissioning obligations was charged through the deficit on the statement of financial position thereby creating a temporary difference on the liability. The deferred income tax impact of the opening adjustment was a deferred income tax asset of \$6.5 million.

Under IFRS, the equity portion of the convertible debenture is treated as a temporary difference and deferred income tax is recognized. As the discounted amount is accreted up to the principal balance over time, the accretion results in a reversal of the temporary difference and reduction to the deferred tax liability originally recognized. A deferred income tax liability of \$6.5 million was recognized on transition.

Under IFRS there is no requirement to separate the portion of deferred income taxes related to current assets or liabilities. The amounts previously classified as current have been reclassified to long-term.

Adjustments to deferred income taxes have been made in regards to the adjustments noted above that resulted in a change to the temporary difference between tax and accounting values.

(j) Finance expenses

Under IFRS, finance expenses are separately reported in the statement of earnings and comprehensive income. Interest and financing expenses and other finance expenses are now reported below the first group of expenses on the statement of earnings and comprehensive income. Other finance expenses include the accretion and amortized issue costs of the Debentures, the accretion on the decommissioning obligations and unrealized gains or losses on investments.

(k) Major turnaround and overhaul expenditures

Under IFRS Progress capitalizes the cost of major plant turnarounds and overhauls and depreciates these costs over their useful life. Previously these were charged to operating expenses. For the three and nine months ended September 30, 2010 \$0.2 million was capitalized for major plant turnarounds and overhauls.

## 2011 SELECTED QUARTERLY INFORMATION

### FINANCIAL HIGHLIGHTS

(unaudited)

(\$ thousands except per share amounts)

	2010				2011		
	March 31	June 30	Sept. 30	Dec. 31	March 31	June 30	Sept. 30
<b>Income Statement</b>							
Petroleum and natural gas revenue	113,471	115,859	105,305	107,957	117,115	117,340	114,037
Cash flow <sup>1</sup>	46,803	51,215	44,764	59,115	63,320	54,618	51,563
Per share – diluted <sup>2</sup>	0.28	0.24	0.21	0.27	0.29	0.24	0.22
Cash dividends declared <sup>3</sup>	21,415	21,945	22,886	21,594	23,087	23,184	23,395
Per share	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net earnings (loss)	(44,708)	(22,832)	(7,644)	(104,184)	1,626	(11,436)	161,352
Per share – basic	(0.27)	(0.11)	(0.04)	(0.49)	0.01	(0.05)	0.70
Per share – diluted	(0.27)	(0.11)	(0.04)	(0.49)	0.01	(0.05)	0.66
<b>Capital Investment</b>							
Total capital expenditures	120,773	38,261	107,689	100,817	140,340	46,037	113,759
Asset Acquisition <sup>4</sup>	387,703	(616)	-	-	-	-	-
Asset Dispositions <sup>5</sup>	-	(44,473)	680	140	(17,028)	(18,316)	(77)
Joint Arrangement <sup>6</sup>	-	-	-	-	-	-	(261,135)
<b>Total Debt</b>							
Working capital deficiency (surplus)	44,456	20,424	59,320	21,271	23,339	14,209	(89,702)
Bank debt	139,074	178,384	218,133	312,508	0	0	0
Convertible debentures	298,902	245,405	247,355	249,313	421,350	424,761	353,100
Total debt	482,432	444,213	524,808	583,092	444,689	438,970	263,398
Shareholders' capital	2,537,951	2,542,271	2,555,642	2,561,807	2,763,811	2,103,250	2,119,792
Common Shares (thousands except where otherwise stated)							
Shares outstanding, end of period	213,014	213,330	214,296	214,877	229,851	230,529	231,647
Weighted average shares - basic	165,896	213,259	214,222	214,787	219,334	230,397	231,530
Weighted average shares - diluted	166,763	214,004	214,735	215,430	220,179	232,000	253,062
Common Share Trading Statistics (\$)							
High	14.70	12.97	12.95	13.15	14.84	15.65	14.14
Low	11.25	10.67	10.86	10.30	11.88	13.60	11.55
Closing	11.77	12.37	11.67	12.70	13.96	13.73	12.89
Share volume traded (thousands)	49,171	58,964	42,396	41,164	47,742	53,836	45,676

- (1) Cash flow represents the cash flow from operations before changes in non-cash working capital, which as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculation of similar measures for other entities.
- (2) For the three months ended September 30, 2011 the Debentures are dilutive for earnings per share but anti-dilutive for cash flow per share. For the cash flow per share amount, the dilutive number of shares is 232,358,650.
- (3) The dividends declared include distributions and dividends that grantees are entitled to on the vesting of the Share Unit Plan, the Long Term Incentive Plan and the Performance Unit Incentive Plan.
- (4) Foothills asset acquisition on March 31, 2010.
- (5) West Central Alberta asset disposition on June 30, 2010.
- (6) Joint arrangement entered into on August 2, 2011.

## 2011 SELECTED QUARTERLY INFORMATION

Operational Highlights (unaudited)	2010				2011		
	March 31	June 30	Sept. 30	Dec. 31	March 31	June 30	Sept. 30
<b>Daily Production</b>							
Natural gas (mcf/d)	178,993	226,898	222,540	225,594	233,488	209,202	224,629
Crude oil (bbls/d)	1,812	2,014	1,872	2,127	2,033	2,122	2,037
Natural gas liquids (bbls/d)	3,426	3,690	3,373	2,974	3,408	3,747	3,462
Total daily production (boe/d)	35,070	43,520	42,335	42,700	44,356	40,736	42,937
<b>Average Realized Prices</b>							
Natural gas (\$/mcf)	5.27	4.03	3.78	3.68	3.85	3.91	3.73
Crude oil (\$/bbl)	75.33	72.97	69.79	74.79	82.89	99.21	89.99
Natural gas liquids (\$/bbl)	52.68	56.40	51.35	60.48	67.85	66.57	61.27
<b>Highlights (\$/boe)</b>							
Weighted average sales price <sup>(1)</sup>	35.95	29.25	27.04	27.48	29.34	31.65	28.87
Realized gain (loss) on financial instruments	(0.28)	0.97	1.47	1.88	1.21	(0.23)	(0.32)
Royalties	(6.30)	(4.27)	(4.12)	(3.93)	(3.13)	(4.35)	(3.56)
Operating expenses	(6.12)	(6.45)	(6.07)	(5.58)	(5.38)	(5.75)	(5.56)
Transportation expenses	(3.02)	(3.24)	(3.24)	(3.22)	(3.13)	(3.41)	(3.48)
Operating Netbacks	20.23	16.26	15.08	16.63	18.91	17.91	15.95
General and administrative expense	(1.12)	(0.97)	(0.93)	(0.77)	(0.97)	(0.97)	(0.97)
Stock based compensation expense	(0.86)	(0.94)	(0.72)	(0.71)	(0.71)	(0.55)	(0.61)
Goodwill impairment	(10.85)	-	-	-	-	-	-
Unrealized gain (loss) on financial instruments	4.61	(2.00)	0.29	(1.71)	(1.03)	(0.45)	(0.26)
Gain (loss) on divestitures	-	(2.44)	0.14	0.38	1.29	(1.79)	0.01
Gain on joint arrangement	-	-	-	-	-	-	59.74
Other expenses	(0.60)	(0.05)	-	-	-	-	-
Depletion and depreciation	(21.90)	(15.05)	(14.14)	(46.14)	(14.60)	(14.03)	(14.99)
	(10.49)	(5.19)	(0.28)	(32.32)	2.89	0.12	58.87
Interest and finance expenses	(3.01)	(1.96)	(1.61)	(1.82)	(1.91)	(2.10)	(1.89)
Other finance expenses	(1.40)	(0.35)	(0.52)	(0.60)	(0.38)	(1.83)	(2.20)
Net earnings (loss) before taxes	(14.90)	(7.50)	(2.41)	(34.74)	0.60	(3.81)	54.78
Deferred income taxes (reduction)	(0.74)	(1.73)	(0.45)	(8.22)	0.19	(0.72)	13.93
Net earnings (loss)	(14.16)	(5.77)	(1.96)	(26.52)	0.41	(3.09)	40.85

<sup>(1)</sup> Includes sulphur net revenue with no associated production as no conversion exists for tons to boe.

**CORPORATE INFORMATION OF  
PROGRESS ENERGY  
RESOURCES CORP.**

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Gary E. Perron <sup>(1)(3)</sup>  
Senior Vice President and  
Managing Director  
BMO Nesbitt Burns  
Calgary, Alberta

Terrance D. Svarich<sup>(2)(4)</sup>  
President  
Devsun Ltd.  
Calgary, Alberta

<sup>(1)</sup> Member of Audit Committee  
<sup>(2)</sup> Member of Reserve Committee  
<sup>(3)</sup> Member of Compensation  
Committee

<sup>(4)</sup> Member of Corporate Governance and Nominating  
Committee

Environment, Health and Safety matters are addressed by  
the entire Board of Directors

**EXECUTIVE**

Michael R. Culbert  
President and CEO

Daniel C. Topolinsky  
Executive Vice President,  
Exploration and Development

Neil O. Horbachewski  
Vice President, Engineering

Greg W. Kist  
Vice President, Marketing,  
Corporate and Government  
Relations

Art A. MacNichol  
Senior Vice President,  
Finance & Chief Financial  
Officer

Gary A. Miller  
Vice President, Operations

Cindy R. Rutherford  
Vice President, Land

James L. Stannard  
Senior Vice President,  
Development

Max Vorobiev  
Vice President, Engineering

Gary R. Bugeaud  
Secretary

**CORPORATE OFFICE**

1200, 205 – 5th Avenue S.W.  
Calgary, Alberta T2P 2V7  
Telephone: (403) 216-2510  
Fax: (403) 216-2514

**TRUSTEE AND TRANSFER AGENT**

Computershare Trust Company  
of Canada  
Calgary, Alberta

**STOCK EXCHANGE**

The Toronto Stock Exchange  
trading symbols:  
Common Shares- PRQ  
5.25% Debentures – PRQ.DB.B  
5.75% Debentures –PRQ.DB.C

**SOLICITOR**

Burnet, Duckworth & Palmer LLP  
Calgary, Alberta

**AUDITOR**

KPMG LLP  
Calgary, Alberta

**CONSULTING ENGINEERS**

GLJ Petroleum Consultants  
Calgary, Alberta

**INVESTOR RELATIONS**

Greg Kist  
Vice President, Marketing,  
Corporate and Government  
Relations  
403-539-1809  
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