Guide Exploration Ltd. Announces 2011 Fourth Quarter Results, 2011 Financial Results and Reserves Information and 2012 Capital and Operations Update

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CALGARY, March 16, 2012 - Guide Exploration Ltd. (TSX:GO) ("Guide" or the "Corporation") announces the financial results for the year ended 2011 and an update on its 2012 capital program.

The audited consolidated financial statements of the Corporation for the years ended December 31, 2011 and 2010 and the related management's discussion and analysis can be accessed on-line on SEDAR at www.sedar.com or on the Corporation's website at www.guidex.ca.

Highlights

- Revenues (before realized financial derivatives) for the fourth quarter of 2011 were $48.0 million with funds flow from operations of $24.8 million generated from daily average production of 4,458 barrels per day of crude oil and natural gas liquids and 43.3 Mmcf/d of natural gas. Currently, Guide is producing approximately 5,350 Bbl/d of oil and natural gas liquids and 63 Mmcf/d of natural gas.

- For the full year 2011, revenue totaled $188.2 million with funds flow of $98.6 million ($1.16 per share diluted) on average daily production of 4,070 barrels per day of crude oil and NGLs and 47.8 Mmcf/d of natural gas (34% Oil/NGLs weighting).

- Operating netbacks for the fourth quarter of 2011 averaged $24.15/BOE before realized gain on financial derivatives and $28.77/BOE after realized gain on financial derivatives.

- Operating expenses averaged $11.53/BOE in the fourth quarter of 2011 in line with annual operating expenses that averaged $11.59/BOE.

- Funds flow from operations in the fourth quarter of 2011 averaged $18.50/BOE before realized gain on financial derivatives and $23.12/BOE after realized gain on financial derivatives. Per unit funds flow were slightly ahead of funds flow from operations for full year 2011 of $17.20/BOE before the realized gain from financial derivatives and $22.43/BOE including the realized gain from financial derivatives.

- The Corporation drilled 54 (49.5 net) wells resulting in 43 (38.9 net) oil wells and 11 (10.6 net) natural gas wells, for a success rate of 100% during the year.

- Capital of $150.5 million was invested in exploration and development activities. In addition, $7.2 million was spent to acquire properties and $15.4 million was received on the sale of properties for a net disposition of $8.2 million.

- At December 31, 2011 $138.2 million was drawn on available bank credit facilities of $250 million and the Corporation had a working capital deficiency of $31.6 million.

- At December 31, 2011, Guide had outstanding, 92,407,135 Class A Shares, 8,728,333 share options with an average exercise price of $3.75 and 2,300,000 warrants.

- At year end 2011, Guide had 100 percent of its properties evaluated by Sproule Associates Limited ("Sproule"). Sproule has determined that year end 2011 proved and probable reserves totaled 38.1 million BOE including total proved reserves of 23.4 million BOE. Guide's proved reserves are weighted 38.7% to oil and natural gas liquids. Future development capital associated with Guide's reserves is $142.4 million (undiscounted) for the total proved case and $211.4 million (undiscounted) for the total proved plus probable case.

- Based on the net present value of future net revenue attributable to proved and probable reserves (at a 10% discount rate) as at December 31, 2011 as evaluated by Sproule and using year end debt and estimated undeveloped land value at an average of $95 per acre, the net asset value of Guide Exploration at year end 2011 was $520 million or $5.62 per share.

- A loss of $212.8 million ($2.50) per basic share was recorded, which included a non-cash impairment of property and equipment of $255.0 million. This impairment relates to the reduction in the fair value of certain cash generating units in Alberta and Saskatchewan, due to changes in development plans and forecast lower natural gas prices compared with the forecast at December 31, 2010. The impairments are described in more detail in Guide's audited consolidated financial statements and management discussion and analysis for the year ended December 31, 2011.

Subsequent to December 31, 2011

On January 24, 2012, the Corporation issued 12,000,000 Class A shares at a price of $3.05 per share on a bought deal basis. The gross proceeds of the financing were $36,600,000.

On January 31, 2012, Guide completed the previously announced acquisition of sweet natural gas assets in Northern Alberta for approximately $61.5 million. The properties are currently producing approximately 20 Mmcf/d.

2011 Year in Review

The year ended December 31, 2011 proved to be challenging to the staff and management of Guide as we re-evaluated development plans and engaged a new independent Reserve Evaluator, Sproule, to evaluate our reserves in light of changed development plans.

In setting a course for 2012 and the future, we will narrow our near term development focus to oil, continue to expand our land base for future exploration and development, and maintain a strong focus on cost control and efficiencies.

Guide has focused its near term development efforts on the oil rich Triassic sediment package over its large land position in the Peace River Arch with particular emphasis on its emerging Montney oil resource play at Normandville/Girouxville.

Drilling in the second half of 2011 delineated a broad, oil rich, fairway in the Montney that we believe covers at least 40 sections. In the latter half of 2011, we broadened our window of opportunity for future oil exploration and development by adding land and plays in both conventional reservoirs and in emerging tight rock plays. The $20 million flow-through share offering which was completed in November 2011 is planned to be used in part to target shale resource plays in the Duvernay and Nordegg.

2012 Capital and Operations Update

Guide achieved 2011 exit production volumes of approximately 4,835 barrels per day of crude oil and natural gas liquids and 43 Mmcf/d of natural gas. Including the Northern Alberta property acquisition, average field estimated sales production for February 2012 was 5,350 barrels per day of crude oil and natural gas liquids and 63 Mmcf/d of natural gas.

For 2012, capital and operating guidance remains relatively unchanged. Our oil focused development program of $120 to $130 million will key on the Peace Area oil properties at Normandville and Girouxville. We plan to drill approximately 30 oil wells on these properties in 2012, accounting for two-thirds of our development budget.

Guide's 2012 exploration budget of $20 million is fully funded by our November 2011 flow through share offering. This program targets a wide variety of prospects including resource plays in the Nordegg and Duvernay.

For 2012, we are guiding to production of between 15,500 to 16,300 BOE/d as follows:

Oil: 5,300 - 5,500 Bbl/d
NGLs: 400 - 450 Bbl/d
Gas: 59 - 62 Mmcf/d

Strong growth in oil production (40% year over year) is expected to push overall corporate growth to 8 - 10 percent.

Based on price forecasts of WTI US $95.00/Bbl, $2.50/GJ AECO, and an exchange rate of $0.97 US per dollar Canadian, we expect funds flow from operations of between $120 million and $130 million in 2012 ($1.15 to $1.25 per basic share).

Operational Update

During Q4 2011 and Q1 2012, we drilled 18 horizontal Montney oil wells on our Normandville and Girouxville properties. These 1,000 meter total vertical depth wells are currently being drilled horizontally to a typical measured depth of 2,500 meters to take advantage of a better horizontal oil new well royalty rate. Completion operations have evolved from fracture stimulations of 10 stages to 20 stages of 3 to 5 tonnes per stage, with plans to increase to 24 stages on future new drills. We have also recently commissioned our Q1 2012 Normandville oil battery expansion, effectively doubling the fluid and gas handling capacity.

The fairway for our Normandville/Girouxville Upper Montney oil resource play covers a prospective 40 to 50 net sections of land targeted to be developed with 4 to 8 horizontal wells per section. In 2011, Guide drilled 27 horizontal Montney oil wells on the play. Potential exists to improve the oil recovery factor with a pressure maintenance water and/or gas injection scheme. Timing to implement such a pressure maintenance scheme would be into 2013.

Our 2011 Normandville/Girouxville Montney horizontal 10 stage oil type curve exhibits a 30 day average rate of 95Bbl/d oil and 245 Mcf/d associated gas, 3 month average rate of 85Bbl/d oil and 223 Mcf/d associated gas, and a 12 month average rate of 65 Bbl/d oil and 165 Mcf/d associated gas, with predicted cumulative production of 85 Mbbls oil and 200 Mmcf gas. With an on-stream capital cost of $1.7 million, the half cycle economic indicators are robust. This type curve is based on 18 wells we have drilled and completed in this manner in the area.

Our 2012 Normandville/Girouxville Montney horizontal 20 stage oil type curve exhibits a 30 day average rate of 120 Bbl/d and 300 Mcf/d associated gas and a 12 month average rate of 75 Bbl/d and 190 Mcf/d of associated gas, with predicted cumulative production of 110 Mbbls oil and 250 Mmcf gas. On-stream capital costs of $2.0 million provide very attractive half cycle economics. This type curve is based on 10 wells we have drilled and completed in this manner in the area.

One of the advantages of our Normandville/Girouxville Montney horizontal oil play is the moderate on-stream repeatable capital costs associated with the new drills.

Our Northwest Alberta Boyer, low decline, sweet gas asset acquisition closed on January 31, 2012. Boyer is meeting our expectations with current production at the 20 Mmcf/d level and we believe we can maintain production levels with minimal annual maintenance capital until such time that the price of natural gas increases and drives production and reserves expansion.

We hold an extensive acreage position in both the Duvernay and Nordegg. We expect to drill a Duvernay test on our lands in Q3 2012. Experience with drilling through the Duvernay in the targeted area has led us to believe the Duvernay will be 30 to 40% over pressured. The Duvernay in this area is also considered to be in the wet gas window.

Annual Information

($000s except per share amounts) 2011 2010

Financial

Petroleum and natural gas revenue 188,191 207,831

Funds flow from operations 1 98,585 100,478
Per share - basic 1.16 1.19
Per share - diluted 1.16 1.19

Net income (loss) (212,807) (1,083)
Per share - basic (2.50) (0.01)
Per share - diluted (2.50) (0.01)

Capital expenditures 150,495 136,330
Total assets 671,057 869,652
Net dispositions of oil and gas properties 8,258 114,158
Net debt 1,2 169,894 152,861
Total non-current financial liabilities 21,797 14,980

Shareholders' equity 394,990 580,006

Weighted average shares outstanding
Basic 85,192,616 84,770,976
Diluted 85,192,616 84,770,976

1See "Non-GAAP Measurements"

2Net debt includes bank indebtedness and working capital, but excludes financial derivatives and other liability

Results of Operations
Year ended December 31 2011 2010
4,394,732 BOE 5,401,855 BOE
($000s) $/BOE $/BOE
Revenues 188,191 42.82 207,831 38.47
Realized gain on financial derivatives 23,010 5.23 10,552 1.95
Royalties (35,600) (8.10) (44,060) (8.15)
GCA1 6,459 1.47 12,670 2.35
Transportation costs (8,325) (1.89) (8,806) (1.63)
Operating costs (50,934) (11.59) (51,405) (9.52)
Net 122,801 27.94 126,782 23.47
G&A (15,475) (3.52) (14,773) (2.73)
Restructuring costs - - (1,242) (0.23)
Interest costs (7,575) (1.72) (10,086) (1.87)
Exploration expenses (916) (0.21) - -
Capital and other taxes (250) (0.06) (203) (0.04)
Funds flow from operations2 98,585 22.43 100,478 18.60

1 GCA means Gas Cost Allowance

2 See "Non-GAAP Measurements"

Petroleum and Natural Gas Revenue (before royalties)
Year ended December 31 2011 2010
($000s) % %
Light oil 84,620 45 78,943 38
Heavy oil 26,782 14 23,481 11
NGLs 9,554 5 9,379 5
Natural gas 66,971 36 95,615 46
Royalty income 264 - 413 -
Total 188,191 100 207,831 100

Revenues for the year ended December 31, 2011 were $188.2 million, compared to $207.8 million during the prior year. Crude oil revenues increased $9.0 million, reflecting higher crude oil prices in 2011. Gas revenues decreased by $28.6 million in 2011 due to decreased production volumes and lower gas prices.

Light oil revenues were 45% of total revenues in 2011, compared to 38% in 2010.

Production
Year ended December 31
2011 2010
% %
Light oil (Bbls/d) 2,674 22 2,913 20
Heavy oil (Bbls/d) 1,021 9 1,065 7
NGLs (Bbls/d) 375 3 472 3
Natural gas (Mcf/d) 47,818 66 62,098 70
BOE/d (6:1) 12,040 100 14,800 100

Average production was 12,040 BOE/d during 2011, 19% lower than the average production of 14,800 BOE/d in 2010 impacted by the sale of the Puskwa property in the second quarter of 2010.

In 2011 oil and NGLs accounted for 34% of our average daily production compared with 30% in 2010.

Commodity Pricing and Marketing

Petroleum products are sold to major Canadian marketers at spot reference prices or prices subject to commodity contracts based on US WTI for crude oil and AECO for natural gas. As a means of managing the risk of commodity price volatility and improving netback cash flows, Guide has entered into several natural gas and crude oil financial contracts.

The Corporation has the following financial contracts in place as at December 31, 2011:
Natural Gas:

January 1, 2012 - December 31, 2012 22,500 GJ/d CDN $5.00/GJ
April 1, 2012 - October 31, 2012 5,000 GJ/d CDN $4.86/GJ

Crude Oil:

Costless Collars:
January 1, 2012 - December 31, 2012 500 Bbl/d WTI CDN $85.00-$90.00/Bbl

Other:
January 1, 2012 - December 31, 2012 527 Bbl/d WTI US $85.00/Bbl Put
January 1, 2012 - December 31, 2012 1,000 Bbl/d WTI US $85.00/Bbl Put
January 1, 2013 - December 31, 2013 1,527 Bbl/d WTI US $85.00/Bbl Call
January 1, 2013 - December 31, 2013 500 Bbl/d WTI US $85.00/Bbl Swaption
January 1, 2013 - December 31, 2013 73 Bbl/d WTI US $100.00/Bbl Call
January 1, 2014 - December 31, 2014 980 Bbl/d WTI US $85.00/Bbl Swaption
January 1, 2014 - December 31, 2014 500 Bbl/d WTI US $100.00/Bbl Call
Interest Rate Swap:

Notional Amount CAD $50 million Term: August 5, 2011 - August 5, 2013
Fixed rate 1.34% - Floating rate is reset against CAD-BA-CDOR on each 3 month anniversary

During 2011, Guide recorded realized gains of $23.0 million on financial contracts, compared to gains of $10.6 million in 2010. Spot prices for natural gas continued to be substantially lower than the prices Guide has secured using financial contracts. During the year ended December 31, 2011, oil contracts for 2012 were unwound, for which a cash payment of $3.9 million was received.

Based on the mark to market value at December 31, 2011, an unrealized loss on financial contracts of $0.5 million was recorded in 2011, compared to an unrealized gain of $9.0 million in 2010. If the contracts were unwound at December 31, 2011, the Corporation would owe a net amount of $1.1 million.

Subsequent to December 31, 2011, the Corporation entered into the following commodity financial derivative transactions:
Natural Gas:
New contracts
March 1, 2012 - December 31, 2012 5,000 GJ/d CDN $4.50/GJ
March 1, 2012 - December 31, 2012 5,000 GJ/d CDN $4.50/GJ

Crude Oil:
Other:
Contracts unwound
January 1, 2012 - December 31, 2012 527 Bbl/d WTI US $85.00/Bbl Put
January 1, 2012 - December 31, 2012 1,000 Bbl/d WTI US $85.00/Bbl Put

Fixed Price:
New contracts
February 1, 2012 - February 29, 2012 1,000 Bbl/d WTI US $91.25/Bbl
March 1, 2012 - June 30, 2012 1,000 Bbl/d WTI CDN $91.25/Bbl
March 1, 2012 - June 30, 2012 1,100 Bbl/d WTI US $94.00/Bbl
July 1, 2012 - December 31, 2012 1,000 Bbl/d WTI US $91.25/Bbl Call
July 1, 2012 - December 31, 2012 1,100 Bbl/d WTI US $94.00/Bbl Call

Costless Collar:
New contract
January 1, 2013 - December 31, 2013 500 Bbl/d WTI CDN $98.00-$102.00/Bbl

The new fixed price oil contracts have initial terms to June 30, 2012, at which time the counterparties may elect to extend the term of these contracts to December 31, 2012.

Also subsequent to December 31, 2011, the $50 million interest rate swap at 1.34% was unwound and a new contract was entered into with the following terms:
Interest Rate Swap:
Notional Amount CAD $75 million Term: February 6, 2012 - January 5, 2014
Fixed rate 1.19% - Floating rate is reset monthly against CAD-BA-CDOR

Prices (prior to financial derivatives and transportation charges)
Year ended December 31
2011 2010
Light oil ($/Bbl) 86.85 74.50
Heavy oil ($/Bbl) 71.81 60.41
NGLs ($/Bbl) 69.80 54.44
Natural gas ($/Mcf) 3.84 4.23

Prices realized in 2011 were higher for crude oil and NGLs, and lower for natural gas. Light oil prices increased 17%, heavy oil prices increased 19%, and NGL prices increased by 28%. The average price received for natural gas decreased by 9%.

The average gas price received by Guide during 2011 was $0.24/Mcf higher than the weighted average AECO price during the year, due to the heat content of the gas. The weighted average premium to AECO received in 2010 averaged $0.21/Mcf.

During the year ended December 31, 2011, the average light oil price received by Guide was approximately $8.00/Bbl lower than the posted Edmonton light oil par price, and the average heavy oil price received by the Corporation was approximately $23.00/Bbl lower than the weighted average posted Edmonton light oil par price. During 2010, the average light and heavy oil prices received by the Corporation were approximately $3.00 and $17.00 lower than the weighted average posted Edmonton light oil par price, respectively. The year over year changes reflect Guide's changing crude slate and the changing crude oil differentials seen in Western Canada.

During 2011 Guide realized a higher net commodity price for natural gas, and a lower net commodity price for crude oil, as a result of financial derivative contracts in place. The net price received for natural gas in 2011 was $1.43/Mcf or 37% higher due to financial derivative contracts. The 2011 net price received for crude oil was $1.43/Bbl or 1.7% lower due to financial derivative contracts.

Crude Oil Prices
Year ended December 31 2011 2010
$000s $/Bbl $000s $/Bbl
Crude oil 111,536 82.70 102,664 70.71
Realized financial contracts (1,920) (1.43) (3,811) (2.63)
Transportation (2,945) (2.18) (1,831) (1.26)
Net crude oil 106,671 79.09 97,022 66.82

Natural Gas Prices
Year ended December 31 2011 2010
$000s $/Mcf $000s $/Mcf
Natural gas 67,101 3.84 95,788 4.23
Realized financial contracts 24,932 1.43 14,646 0.65
Transportation (5,312) (0.30) (6,967) (0.31)
Net natural gas 86,721 4.97 103,467 4.57

NGL Prices
Year ended December 31 2011 2010
$000s $/Bbl $000s $/Bbl
NGL 9,554 69.80 9,379 54.44
Transportation (68) (0.50) (8) (0.05)
Net NGL 9,486 69.30 9,371 54.39

Performance by Property
Year ended December 31
2011 2010
Production Operating netbacks/
BOE 1 Funds flow
from operations2 Production Operating netbacks/
BOE1 Funds flow
from operations2
BOE/d % $ % BOE/d % $ %

Peace	6,845	57	22.42	60	7,672	52	18.59	51
Smoky	2,859	24	19.57	22	3,483	24	18.95	23
Cherhill	973	8	25.85	10	1,063	7	20.10	8
Worsley	563	5	7.80	2	857	6	7.89	2
Other	800	6	20.88	6	1,725	11	26.66	16
	12,040	100	21.24	100	14,800	100	19.11	100

1Operating netbacks/BOE exclude GCA and hedging gains and losses, and are calculated by subtracting royalties, operating costs, and transportation from revenues and dividing the result by the average production for the period

2See "Non-GAAP Measurements"

Peace Area

Peace area production averaged 2,257 Bbl/d of oil and NGLs and 27.5 Mmcf/d of natural gas during 2011. During the same period in 2010, production averaged 1,904 Bbl/d of oil and NGLs and 34.6 Mmcf/d of natural gas. The area contributed 60% to total funds flow from operating activities in 2011 based on 57% of production volumes. During 2011, crude oil and liquids production increased by 19% in the Peace area compared to 2010.

During the second half of 2010 Guide confirmed the viability of oil in the Normandville/Girouxville Montney fairway. This oil project was further advanced during 2011 with the drilling of 25 Montney oil wells. Guide plans to continue with this development in 2012 with a similar level of drilling activity, as well as a facility expansion.

A total of 39 (38.5 net) wells were drilled in the Peace area in 2011, of which 13 (12.7 net) wells were drilled in the fourth quarter. Up to a total of 30 (30.0 net) oil wells are planned in 2012.

Smoky Area

The Smoky area production averaged 497 Bbl/d of oil and NGLs and 14.2 Mmcf/d of natural gas during 2011. During the same period in 2010, production averaged 420 Bbl/d of oil and NGLs and 18.4 Mmcf/d of natural gas. In 2011, the Smoky area contributed 22% of funds flow from operations and 24% of production volumes.

The Corporation plans to continue drilling on this project at a measured pace and to closely monitor results. One (1.0 net) well was drilled within the Smoky area during the fourth quarter. In 2012 Smoky area activity will focus on mid-Montney oil at Bezanson and deep natural gas at Smoky Heights as well as the potential of the Duvernay shale in the area.

Cherhill Area

Production in the Cherhill area averaged 619 Bbl/d of oil and NGLs and 2.1 Mmcf/d of natural gas. During the same period in 2010, production averaged 688 Bbl/d of oil and NGLs and 2.2 Mmcf/d of natural gas. In 2011, the Cherhill area contributed 10% of the funds flow from operations and 8% of production volumes.

Assets at Alexis and St. Anne continue to be exploited and optimized. While no drilling occurred here during the fourth quarter, 2 (2.0 net) wells were drilled in 2011, and up to 6 (4.4 net) wells are planned for 2012.

Royalties

Year ended December 31	2011	2010
($000s, except as indicated)		
Crown	27,316	35,877
Freehold	4,644	4,063
GORR and other	3,640	4,120
Gross royalties	35,600	44,060
GCA	(6,459)	(12,670)
Net royalties	29,141	31,390
% of revenue	18.9	21.2
% of revenue net of GCA	15.5	15.1

Gross royalties were 18.9% of revenues during 2011, compared to 21.2% for the same period in 2010. By product, gross royalties were 18.4% for light oil, 16.6% for natural gas, 22.9% for heavy oil, and 28.5% for liquids. For the year ended December 31, 2010, gross royalties were 25.0% for light oil, 17.2% for natural gas, 22.6% for heavy oil, and 26.8% for liquids.

The royalty rate for light oil decreased in 2011 compared 2010, reflecting a decrease in the maximum royalty rate effective January 1, 2011.

Total royalties, net of GCA, were 15.5% during 2011, compared to 15.1% during 2010.

Under the Drilling Royalty Credit ("DRC") incentive program, the Alberta Government applied up to $200 per meter for wells spud during the period April 1, 2009 to March 31, 2011 against net crown royalties payable. As at December 31, 2011, the Corporation had received in aggregate drilling credits totaling $23.4 million which were recorded as a reduction of property and equipment.

Operating Costs
Year ended December 31 2011 2010
Production Operating Costs Production Operating Costs
% % $/BOE % % $/BOE
Peace 57 55 11.27 52 52 9.50
Smoky 24 15 7.15 24 13 5.15
Cherhill 8 10 13.96 7 10 13.80
Worsley 5 6 15.46 6 9 14.33
Other 6 14 24.59 11 16 13.37
100 100 11.59 100 100 9.52

Operating costs were $11.59/BOE during 2011, an increase of 22% from $9.52/BOE in 2010. This increase was caused by the drop in daily production volumes, higher utility costs, and increased propane and fuel costs related to new oil wells on production.

Operating expenses by product were as follows:
Year ended December 31 2011 2010
($000's) $/BOE ($000's) $/BOE
Light oil 12,755 13.07 12,006 11.29
Heavy oil 6,913 18.54 6,016 15.47
NGLs 1,527 11.14 1,599 9.28
Natural gas 29,739 10.20 31,784 8.40
BOE 50,934 11.59 51,405 9.52

General and Administration Expenses
Year ended December 31 2011 2010
($000s) $/BOE $/BOE
Gross 21,034 4.78 20,016 3.71
Capitalized overhead (3,881) (0.88) (3,411) (0.64)
Overhead recoveries (1,678) (0.38) (1,832) (0.34)
Net 15,475 3.52 14,773 2.73

Gross general and administrative ("G&A") expenses in 2011 included $2.3 million of costs related to restructuring and associated retiring allowances.

Capital and Deferred Taxes

The 2011 and 2010 current tax provisions of $250,000 and $203,000, respectively, relate to Saskatchewan capital and resource tax, and were based upon revenues earned in Saskatchewan. It is not expected that Guide will pay income taxes in 2012.

The 2011 deferred income tax recovery was $43.1 million on a loss before tax of $255.7 million. A deferred income tax asset of $20.7 million was not recognized at December 31, 2011. A deferred income tax recovery of $10.9 million on a loss before tax of $11.7 million was recorded in 2010. The 2010 income tax recovery included an $11.8 million benefit relating to the disposal of properties.

Capital Expenditures
Exploration and evaluation assets, property and equipment ($000s)
Balance at December 31, 2010 816,647
Additions 150,495
Disposals (10,676)
Acquisitions 7,150
Net decommissioning liability additions (disposals) 6,003
Capitalized share-based compensation 1,005
Derecognition expense (7,538)
Non-monetary transactions 123
Depletion and depreciation (90,666)

Impairment of property and equipment (255,000)
Balance at December 31, 2011 617,543

Capital expenditures during 2011 were $150.5 million. Drilling and completions expenditures comprised 68% of capital activity. The Corporation drilled 54 (49.5 net) wells, resulting in 43 (38.9 net) oil wells and 11 (10.6 net) natural gas wells, for a success rate of 100% during the year.

On August 4, 2011, the Corporation purchased interests in certain natural gas properties in the Smoky area for cash consideration of approximately $6.9 million including closing adjustments.

On August 31, 2011, properties in the Western Montney area of British Columbia were sold for net proceeds of $12.7 million, resulting in a gain on disposition of $2.9 million.
Year ended December 2011 2010
($000s) % %
Land 13,180 9 6,807 5
Geological and geophysical 4,488 3 2,354 2
Drilling and completion 101,652 68 104,663 77
Plant and facilities 29,169 19 22,634 16
Inventory 1,267 1 (240) -
Other assets 739 - 112 -
Capital expenditures 150,495 100 136,330 100

Liquidity and Capital Resources

As at December 31
2011
2010
($000s)
Bank debt 138,248 135,682
Working capital deficiency 1 31,646 17,179
Total net debt 2 169,894 152,861

1Excludes fair value of financial derivatives and other liability

2 See "Non-GAAP Measurements"

Funding of Capital Program
Year ended December 31
2011 2010
($000s)
Issuance of Class A shares, net of costs 30,104 337
Repurchase of Class A shares (2,417) (4,154)
Funds flow from operations 1 98,585 100,478
Change in bank debt 2,566 (81,561)
Change in financing lease - (1,545)
Acquisition of properties (7,150) (17,791)
Disposals of properties 15,408 131,949
Change in working capital and other 13,399 8,617
150,495 136,330

1 See "Non-GAAP Measurements"

On September 16, 2011, the Corporation issued 2,300,000 units ("Units") for gross proceeds of $6.5 million under a private placement to the new management group of the Corporation and their designates. Each Unit consisted of one Class A share of the Corporation and one share purchase warrant ("Warrant"). Each Warrant entitles the holder to acquire one Class A share of the Corporation at an exercise price of $3.10 for a period of three years. The Warrants are not exercisable until the twenty day volume weighted average trading price of the Class A shares exceeds $5.00 per share.

On November 16, 2011 the Corporation issued 1,515,152 flow-through Class A shares at $3.30 per share by way of a private placement for gross proceeds of $5.0 million. The Corporation was required to incur qualifying development expenses of $5.0 million prior to December 31, 2011. As of December 31, 2011, all of the required qualifying expenditures had been incurred.

On November 24, 2011 the Corporation issued 5,634,000 flow-through Class A shares at $3.55 per share for gross proceeds of $20.0 million. The Corporation is required to incur qualifying exploration expenses of

$20.0 million prior to December 31, 2012. As of December 31, 2011, $2.0 million of the required qualifying expenditures had been incurred.

During the year ended December 31, 2011, under the Normal Course Issuer Bid, the Corporation purchased 1,022,100 Class A shares for $2,417,000, of which all shares were cancelled at December 31, 2011.

Subsequent to December 31, 2011, the Corporation entered into an agreement with a syndicate of underwriters to issue, on a bought deal basis, 12,000,000 Class A shares at a price of $3.05 per share for aggregate proceeds, before share issue costs, of $36.6 million. Closing of the offering occurred on January 24, 2012.

On January 31, 2012, the Corporation purchased interests in certain natural gas properties in the Boyer area of Alberta for cash consideration of $61.5 million. At December 31, 2011, a deposit of $6.1 million had been paid towards the transaction.

On February 15, 2012, the Corporation purchased interests in certain petroleum and natural gas properties in the Peace area of Alberta for cash consideration of $6.0 million.

Subsequent to December 31, 2011, the Corporation entered into an agreement to dispose of properties in the Senex area of Alberta for cash consideration of $11.0 million before closing adjustments, a 3% royalty interest, and reimbursement for a recently completed horizontal well. The transaction is expected to close on March 30, 2012.

The Corporation has $250 million in credit facilities available, consisting of a $225 million extendible 364 day revolving term facility and a $25 million non-revolving facility. The $25 million facility is available subject to mutual approval of the banking syndicate and the Corporation, including repayment terms. Collateral for the facilities consists of a demand debenture for $500 million collateralized by a first floating charge over all of the property and equipment of the Corporation. At December 31, 2011, an amount of $138.2 million was drawn against the revolving credit facility (December 31, 2010 - $135.7 million).

The facilities bear interest at the bank's prime or banker's acceptance rates plus a rate margin. The margins range from 1.25% per annum to 5.25% per annum, based upon the Corporation's debt to cash flow ratio. For the year ended December 31, 2011, the effective interest rate was 5.1% (December 31, 2010 - 5.8%).

An annual review is scheduled to occur on or before May 28, 2012. The level of the borrowing base will be determined by the bank syndicate based upon their review of, among other things, the Corporation's reserves and the value thereof, utilizing commodity prices determined by the bank syndicate which will be different than that utilized by the Corporation's independent reserve evaluator.

Impairment of Property and Equipment

At December 31, 2011 the Corporation recorded an impairment expense of $255.0 million related to property and equipment (December 31, 2010 - $Nil). The recoverable amounts of the Corporation's CGUs were estimated at fair value less costs to sell, based on the value of the after-tax cash flows from oil and gas reserves discounted at 10%, using reserves estimated by independent reserve evaluators, and the fair value of undeveloped land determined internally.

Impairments were recorded at each of the Corporation's CGUs with the exception of Peace, resulting from a reduction in the estimated volumes of oil and gas reserves, as well as a weakening of the forward price curve for natural gas as at December 31, 2011 as compared to December 31, 2010.

Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves. Future price estimates are used in impairment testing. Commodity prices have fluctuated widely in recent years due to global and regional factors, including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors. Changes in the economic environment could result in significant changes to the discount rate used to calculate net present values.

A one percent increase in the assumed after tax discount rate would result in an additional impairment of approximately $5.0 million as at December 31, 2011, while a 10% decrease in the forward commodity price estimates would result in an additional impairment of approximately $102.0 million.

Sensitivity Analysis

The following table shows sensitivities to 2012 budgeted funds flow from operations as a result of

fluctuations in product prices, production volumes and other market factors. The table is based on budgeted 2012 production volumes, adjusted for the January 31, 2012 acquisition of properties.
Change to annual funds flow from operations Change $000s $/share2
Price per barrel of oil (US$ WTI)1 $ 1.00 700 0.01
Price per mcf of natural gas (C$ AECO)1 $ 0.10 800 0.01
Oil production volumes 100 Bbl/d 2,200 0.02
Gas production volumes 1 Mmcf/d 300 0.00
Exchange rate (US/Canadian) $ 0.01 1,300 0.01
Interest rate on debt 1 % 1,100 0.01

1After adjustment for estimated royalties

2Based on basic shares outstanding at December 31, 2011, adjusted for the January 24, 2012 share issuance.

Contractual Obligations
$ Total 2012 2013 2014 2015 2016 Thereafter
Bank loan 138,248 138,248 - - - - -
Operating leases 10,065 1,830 1,830 1,830 1,830 1,830 915
Firm transportation agreements 6,135 2,810 2,027 1,028 270 - -
Flow-through share expenditures 18,000 18,000 - - - - -
Capital commitments 1,500 1,500 - - - - -
Total 173,948 162,388 3,857 2,858 2,100 1,830 915

At December 31, 2011 the Corporation is committed to future minimum lease payments of $10.1 million under an operating lease for office space, and $6.1 million in firm contracts relating to the transportation of natural gas.

On November 24, 2011 the Corporation issued 5,634,000 flow-through Class A shares at $3.55 per share for gross proceeds of $20.0 million. The Corporation is required to incur qualifying exploration expenses of $20.0 million prior to December 31, 2012. As of December 31, 2011, $2.0 million of the required qualifying expenditures had been incurred.

At December 31, 2011, the Corporation has entered into contracts for drilling rig services under which the Corporation is committed to using services totaling $1.5 million during the four months ending April 30, 2012.

Litigation

The Corporation is involved in various claims and legal actions arising in the normal course of business. The Corporation does not expect that the outcome of these proceedings will have a material adverse effect on the Corporation as a whole.

Fourth Quarter Results

Q4 2011 compared to Q3 2011
December 31 September 30
Three months ended 2011 2011
1,074,473 BOE 1,076,198 BOE
($000s) $ $/BOE $ $/BOE
Revenues 48,037 44.71 44,026 40.91
Realized gain on financial derivatives 4,970 4.62 9,795 9.10
Royalties (8,625) (8.03) (8,290) (7.70)
GCA1 943 0.88 2,612 2.43
Transportation costs (2,021) (1.88) (2,041) (1.90)
Operating costs (12,386) (11.53) (12,689) (11.79)
30,918 28.77 33,413 31.05
General and administration (3,726) (3.47) (4,665) (4.34)
Interest costs (1,798) (1.67) (1,874) (1.74)
Exploration expenses (477) (0.44) (23) (0.02)
Capital and other taxes (78) (0.07) (62) (0.06)
Funds flow from operations2 24,839 23.12 26,789 24.89

1GCA means Gas Cost Allowance

2See "Non-GAAP Measurements"

Funds flow from operations decreased by $2.0 million or 7% during Q4 2011 compared to Q3 2011. Higher crude oil production volumes and prices were more than offset by a loss on oil financial derivative contracts in Q4 2011 compared to a gain in Q3 2011, as well as lower natural gas production volumes and prices during Q4 2011.

During the three months ended December 31, 2011, crude oil production and NGL averaged 4,458 Bbls/d in Q4 2011, a 13% increase from 3,962 Bbls/d in Q3 2011. Natural gas production was 43.3 Mmcf/d in the fourth quarter of 2011, a 7% decrease from 46.4 Mmcf/d in the third quarter of 2011.

Natural gas prices, before financial derivative contracts and transportation, averaged $3.37/Mcf in Q4 2011, 13% lower than the $3.87/Mcf received in Q3 2011. Excluding transportation and financial derivative contracts, crude oil prices averaged $85.82/Bbl in Q4 2011, 12% higher than the $76.32/Bbl realized in Q3 2011.

The $4.8 million decrease in realized gains on financial derivative contracts in Q4 2011 reflects primarily a loss on oil derivative contracts in Q4 2011, compared to a gain on these contracts in Q3 2011. The $6.9 million gain on natural gas derivative contracts during the quarter resulted in a $1.73/Mcf increase in the realized gas price. The $1.9 million loss on oil derivative contracts during Q4 2011 resulted in a $5.15/Bbl decrease in the realized price for crude oil.

Operating costs were $12.4 million during the fourth quarter of 2011 and $12.7 million during Q3 2011. On a per unit basis, operating costs were $11.53/BOE in the fourth quarter of 2011, a 2% decrease from $11.79/BOE during the three months ended September 30, 2011.

Net G&A expenses of $3.7 million in Q4 2011 were 20% lower than the expenses of $4.7 million in Q3 2011, due primarily to corporate restructuring costs incurred during the third quarter.
Quarterly Highlights
(unaudited)
2011
2010
Production Q4 Q3 Q2 Q1 Q4 Q3 Q2 Q1
Light oil (Bbl/d) 3,018 2,343 2,503 2,832 2,600 2,517 3,295 3,249
Heavy oil (Bbl/d) 1,028 1,245 863 948 985 1,009 1,108 1,161
Natural Gas (Mcf/d) 43,325 46,416 48,257 53,398 57,459 59,186 67,689 64,165
Liquids (Bbl/d) 412 374 346 368 394 433 537 527
BOE/d 11,679 11,698 11,755 13,048 13,556 13,823 16,222 15,631
Total BOE produced 1,074,473 1,076,198 1,069,717 1,174,344 1,247,108 1,271,739 1,476,256 1,406,752
Daily BOE of production per million Class A shares - basic 132 139
140
155
161
163
191
184

Prices (prior to financial derivatives and transportation charges)
Light oil ($/Bbl) 88.40 80.14 95.58 83.14 76.44 71.26 72.53 77.47
Heavy oil ($/Bbl) 78.23 69.16 75.80 64.08 60.32 58.13 57.76 64.91
Crude oil ($/Bbl) 85.82 76.32 90.51 78.41 72.01 67.50 68.82 74.17
Natural Gas ($/Mcf) 3.37 3.87 4.10 3.98 3.81 3.75 4.07 5.22
NGLs ($/Bbl) 70.26 66.79 74.44 67.84 58.06 49.48 53.41 56.80

Per BOE ($)
Revenues 44.71 40.91 44.95 40.91 36.88 34.82 37.44 44.28
Royalties, net of GCA (7.15) (5.27) (9.01) (5.23) (4.42) (4.16) (6.71) (7.59)
Transportation costs (1.88) (1.90) (1.93) (1.87) (1.67) (1.66) (1.64) (1.56)
Operating costs (11.53) (11.79) (12.64) (10.51) (10.11) (10.20) (9.03) (8.88)
Net 24.15 21.95 21.37 23.30 20.68 18.80 20.06 26.25
G&A (3.47) (4.34) (3.67) (2.69) (3.38) (3.09) (2.07) (2.54)
Restructuring costs - - - - - (0.05) (0.81) -
Interest expense (1.67) (1.74) (1.91) (1.58) (1.32) (1.45) (2.42) (2.14)
Exploration expenses (0.44) (0.02) (0.19) (0.18) - - - -
Capital and other taxes (0.07) (0.06) (0.05) (0.05) (0.06) (0.05) 0.02 (0.07)
Realized gain (loss) on financial derivatives 4.62 9.10 3.25 4.06 1.10 1.90 3.61 1.02
Funds flow from operations 1 23.12 24.89 18.80 22.86 17.02 16.06 18.39 22.52

1See "Non-GAAP Measurements"
Quarterly Highlights

(unaudited)
2011

Q4
Q3
Q2
Q1
Financial ($000s)
Petroleum and natural gas revenue, before royalties 48,037 44,026 48,086 48,042
Operating costs (12,386) (12,689) (13,517) (12,342)
General & administrative expenses (3,726) (4,665) (3,928) (3,156)
Restructuring costs - - - -
Interest expense (1,798) (1,874) (2,046) (1,857)
Impairment of property and equipment (255,000) - - -
Impairment of goodwill - - - -
Funds flow from operations 1 24,839 26,789 20,115 26,842
Per share, basic 1 0.28 0.32 0.24 0.32
Per share, diluted 1 0.28 0.32 0.24 0.32
Earnings (loss) (227,147) 17,132 10,505 (13,297)
Per share, basic (2.57) 0.20 0.13 (0.16)
Per share, diluted (2.57) 0.20 0.13 (0.16)
Total assets 671,057 898,110 880,379 885,286
Weighted average outstanding Class A shares-basic 88,406,663 84,364,096 83,980,083 83,980,083
Weighted average outstanding Class A shares-diluted 88,406,663 84,364,096 83,980,083 83,980,083

1 See "Non-GAAP Measurements"
Quarterly Highlights
(unaudited)
2010

Q4 Q3
Q2
Q1
Financial ($000s)
Petroleum and natural gas revenue, before royalties 45,995 44,279 55,273 62,284
Operating costs (12,612) (12,978) (13,328) (12,487)
General & administrative expenses (4,212) (3,930) (3,063) (3,568)
Restructuring costs - (59) (1,183) -
Interest expense (1,645) (1,849) (3,578) (3,014)
Impairment of property and equipment - - - -
Impairment of goodwill (25,333) - - -
Funds flow from operations 1 21,227 20,425 27,146 31,680
Per share, basic 1 0.25 0.24 0.32 0.37
Per share, diluted 1 0.25 0.24 0.32 0.37
Earnings (35,055) 577 14,587 18,808
Per share, basic (0.41) 0.01 0.17 0.22
Per share, diluted (0.41) 0.01 0.17 0.22
Total assets 869,652 886,847 861,436 1,010,720
Weighted average outstanding Class A shares-basic 83,983,158 84,869,236 85,143,751 85,098,939
Weighted average outstanding Class A shares-diluted 83,983,158 84,869,236 85,143,751 85,098,939

1 See "Non-GAAP Measurements"

Significant factors and trends that have impacted the Corporation's results during the above periods include:

Production in 2011 averaged 12,040 BOE/d compared to 14,800 BOE/d in 2010. The 19% reduction relates primarily to a decline in natural gas production, reflecting the Corporation's capital program being weighted towards oil projects. In addition, the Puskwa light oil properties were sold in the second quarter of 2010.

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices.

Operating costs were $11.59/BOE during 2011, an increase of 22% from $9.52/BOE in 2010. This increase was caused by the drop in daily production volumes, higher utility costs, and increased propane and fuel costs related to new oil wells on production.

Petroleum products are sold to major Canadian marketers at spot reference prices or prices subject to commodity contracts based on US WTI for crude oil and AECO for natural gas. As a means of managing the risk of commodity price volatility and improving netback cash flows, Guide has entered into several natural gas and crude oil financial contracts. The $24.9 million gain realized on natural gas derivative contracts in 2011, which increased $10.3 million from 2010, raised the effective gas price received during the year by $1.43/Mcf to $5.27/Mcf, before transportation.

At December 31, 2011 the Corporation recorded an impairment expense of $255.0 million related to property and equipment (December 31, 2010 - $Nil). The recoverable amounts of the Corporation's CGUs were estimated at fair value less costs to sell, based on the value of the after-tax cash flows from oil and gas reserves discounted at 10%, using reserves estimated by independent reserve evaluators, and the fair value of undeveloped land determined internally.

Reserves

The reserves information is based upon an independent reserve evaluation prepared by Sproule effective December 31, 2011 ("Sproule Report"). The following presentation summarizes the Corporation's crude oil, natural gas and natural gas liquids reserves and net present values of future net revenues for the Corporation's reserves using forecast prices and costs based on the Sproule Report. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101.

Further detailed information in respect of Guide's reserves will be included in Guide's Annual Information Form for the year ended December 31, 2011, which is expected to be filed on SEDAR on or before March 30, 2012.

Gross reserves are the total of the Corporation's working interest share before deduction of royalties owned by others and without including any of the Corporation's royalty interests. Net reserves are the total of the Corporation's working interest reserves after deducting amounts attributable to royalties owned by others, plus the Corporation's royalty interest reserves.
Summary of Reserves
Oil and NGLs (Mbbls) Natural Gas (Mmcf) Total (MBOE)
Gross Net Gross Net Gross Net
Proved developed producing 4,407.4 3,540.5 44,064.7 37,617.5 11,751.5 9,810.1
Proved developed non-producing 391.8 306.6 10,823.4 9,359.4 2,195.8 1,866.5
Proved undeveloped 4,261.1 3,638.6 31,282.1 27,867.0 9,474.8 8,283.1
Total proved 9,060.3 7,485.7 86,170.2 74,844.0 23,422.0 19,959.8
Probable 6,692.2 5,336.8 47,972.4 40,920.1 14,687.6 12,156.8
Total proved plus probable 15,752.6 12,822.5 134,142.6 115,764.1 38,109.6 32,116.6

Note: totals may not add due to rounding
Net Present Value of Future Revenue Before Income Taxes as of December 31, 2011 ($MM)
Discounted at:
Reserves category Undisc 5% 10% 15%
Proved developed producing 358.7 300.6 266.4 242.1
Proved developed non-producing 47.0 33.2 25.7 21.1
Proved undeveloped 197.1 151.5 117.8 92.7
Total proved 602.9 485.2 409.9 355.8
Probable 430.4 303.2 232.5 186.6
Total proved plus probable 1,033.2 788.5 642.4 542.5

Note: Net present value of future revenues does not represent fair market value. Totals may not add due to rounding. The after tax net present value of Guide's reserves reflects a tax burden on the properties on a stand-alone basis utilizing the Corporation's tax pools. It does not consider the business-entity-level tax situation or tax planning and the estimated value at the level of the business entity may be significantly different. Guide's consolidated financial statements and Management's Discussion & Analysis should be consulted for information at the level of the business entity.
Net Present Value of Future Revenue After Income Taxes as of December 31, 2011 ($MM)
Discounted at:
Reserves category Undisc 5% 10% 15%
Proved developed producing 358.7 300.6 266.4 242.1
Proved developed non-producing 47.0 33.2 25.7 21.1
Proved undeveloped 197.1 151.5 117.8 92.7
Total proved 602.9 485.2 409.9 355.8
Probable 327.8 231.5 177.8 143.2
Total proved plus probable 930.7 716.7 587.7 499.0

Note: Net present value of future revenues does not represent fair market value. Totals may not add due to rounding.

The forecast prices and inflation factors used in the Sproule Report were an average of the forecast prices and inflation factors as published by Sproule Associates Ltd., GLJ Consultants Ltd., McDaniel & Associates Consultants Ltd. and AJM-Deloitte as at December 31, 2011 (the "Consultants' Average Forecast Prices"). The following is a summary of the price forecast for the first five years as provided in the Consultants' Average Forecast Prices.
Pricing assumptions WTI @ Cushing ($US/Bbl) Henry Hub (Louisiana) Natural gas ($US/Mcf) Alberta Spot Natural gas
($Cdn/GJ) USD/CAD Exchange
2012 98.14 3.72 3.23 0.99
2013 98.60 4.42 3.84 0.99
2014 99.01 4.90 4.30 0.99
2015 101.08 5.60 4.94 0.99
2016 102.33 5.98 5.27 0.99
5 year average 99.83 4.92 4.32 0.99

Reconciliation of Company gross reserves by principal product type - forecast prices and costs
LIGHT AND MEDIUM OIL HEAVY OIL
FACTORS Gross Proved
(Mbbl) Gross Probable
(Mbbl) Gross Proved Plus Probable
(Mbbl) Gross Proved
(Mbbl) Gross Probable
(Mbbl) Gross Proved Plus Probable
(Mbbl)

December 31, 2010 5,242 8,386 13,628 7,032 5,873 12,905

Extensions 169 74 243 185 513 698
Improved Recovery 88 37 125 166 30 196
Technical Revisions 2,328 (3,152) (824) (5,305) (5,254) (10,559)
Discoveries 0 0 0 0 0 0
Acquisitions 0 0 0 0 0 0
Dispositions (121) (150) (271) 0 0 0
Economic Factors (65) (20) (85) 2 (20) (18)
Production (974) 0 (974) (373) 0 (373)

December 31, 2011 6,668 5,175 11,842 1,708 1,142 2,850

NATURAL GAS LIQUIDS NATURAL GAS
FACTORS Gross Proved
(Mbbl) Gross Probable
(Mbbl) Gross Proved Plus Probable
(Mbbl) Gross Proved
(MMcf) Gross Probable
(MMcf) Gross Proved Plus Probable
(MMcf)

December 31, 2010 891 731 1,622 135,967 79,731 215,698

Extensions 0 0 0 0 0 0
Improved Recovery 14 4 18 1,313 438 1,751
Technical Revisions (66) (350) (416) (31,314) (28,606) (59,919)
Discoveries 2 0 3 475 42 517
Acquisitions 15 3 17 2,648 498 3,145
Dispositions (18) (12) (30) (1,910) (2,658) (4,568)
Economic Factors (16) (1) (17) (3,624) (1,473) (5,097)
Production (137) 0 (137) (17,385) 0 (17,385)

December 31, 2011 685 376 1,061 86,170 47,972 134,143

At December 31, 2011, future development capital was $142.4 million for gross proved reserves and $211.4 million for gross proved plus probable reserves. Components of the future capital for gross proved plus probable reserves include 2012 - $60.8 million (including 34.8 net wells), 2013 - $81.0 million (including 56.9

net wells), 2014 - $49.1 million (including 38.6 net wells), 2015 - $18.2 million (including 12 net wells) and thereafter $2.3 million (with no further drilling).

Net Asset Value
December 31, 2011
forecast prices
5% discount rate
($MM) December 31, 2011
forecast prices
10% discount rate
($MM)
Net present value of future revenues of reserves, discounted, before tax 1 788.469 642.436
Undeveloped land (²) 47.236 47.236
Bank debt (138.248) (138.248)
Working capital deficiency (31.646) (31.646)
Net asset value 665.811 519.778
Basic common shares outstanding (000's) 92.407 92.407
Net asset value per share ($/share) 7.21 5.62

1 Derived from the Sproule Report.

(²) Internally valued by Guide (Undeveloped land at an average of $95/Acre or $235/Ha)

At December 31, 2011, the net asset value of the Corporation is estimated at $5.62 per basic share outstanding. This estimate is based on the net present value of future revenues of gross proven and probable reserves, discounted at 10%, before tax of $642.4 million, undeveloped land value of $47.2 million, net debt of $169.9 million and outstanding basic shares of 92.4 million. This net asset value does not include any value for the asset acquisition which was completed on January 31, 2012.

Bank Credit Facilities

The Corporation has $250 million in credit facilities available, consisting of a $225 million extendible 364 day revolving term facility and a $25 million non-revolving facility. At December 31, 2011, an amount of $138.2 million was drawn against the revolving credit facility.

The level of the borrowing base will be determined by the bank syndicate based upon their review of, among other things, the Corporation's reserves and the value thereof, utilizing commodity prices determined by the bank syndicate which will be different than that utilized by the Corporation's independent reserve evaluator. An annual review is in progress. The Corporation does not anticipate a significant change in the amount of these credit facilities.
GUIDE EXPLORATION LTD.
Consolidated Statements of Financial Position

($000's)

December 31,
2011

December 31, 2010 January 1,
2010

ASSETS

CURRENT
Accounts receivable 21,259 28,829 41,270
Deposits and prepaid expenses 9,258 3,361 6,190
Fair value of financial derivatives 22,997 20,815 4,241
53,514 53,005 51,701

Exploration and evaluation assets 10,145 - -
Property and equipment 607,398 816,647 881,937
Goodwill - - 25,333
671,057 869,652 958,971

LIABILITIES

CURRENT
Accounts payable and accrued liabilities 62,163 49,369 55,531
Financing lease - - 1,545
Bank loan 138,248 135,682 217,243
Other liability 3,554 - 3,775
Fair value of financial derivatives 2,250 6,411 13,789
206,215 191,462 291,883

Decommissioning liabilities 48,055 39,947 38,228
Fair value of financial derivatives 21,797 14,980 -
Deferred income taxes - 43,257 49,245
276,067 289,646 379,356

SHAREHOLDERS' EQUITY

Share capital 606,256 586,626 595,559
Contributed surplus 48,742 40,581 30,174
Retained earnings (deficit) (260,008) (47,201) (46,118)
394,990 580,006 579,615
671,057 869,652 958,971

GUIDE EXPLORATION LTD.
Consolidated Statements of Earnings (Loss) and Comprehensive Income (Loss)

Year ended December 31
($000s, except per share amounts) 2011 2010

INCOME
Petroleum and natural gas revenue 188,191 207,831
Royalties, net of gas cost allowance (29,141) (31,390)
Realized gain on financial derivatives 23,010 10,552
Unrealized gain (loss) on financial derivatives (474) 8,972
Gain on disposal of assets 4,732 -
Other income 123 334
186,441 196,299

EXPENSES
Operating 50,934 51,405
Transportation 8,325 8,806
General and administration 15,475 14,773
Restructuring costs - 1,242
Share-based compensation 2,509 4,447
Interest 7,575 10,086
Exploration expenses 916 -
Accretion 3,173 2,984
Derecognition expenses 7,538 9,069
Depletion and depreciation 90,666 79,886
Impairment of property and equipment 255,000 -
Impairment of goodwill - 25,333
442,111 208,031

Loss before taxes (255,670) (11,732)

Income taxes

Capital and other taxes 250 203
Deferred income tax recovery (43,113) (10,852)
(42,863) (10,649)
NET LOSS AND COMPREHENSIVE LOSS

(212,807) (1,083)

NET LOSS AND COMPREHENSIVELOSS PER SHARE

Basic (2.50) (0.01)
Diluted (2.50) (0.01)
Weighted average Class A shares - basic 85,192,616 84,770,976
- diluted 85,192,616 84,770,976

GUIDE EXPLORATION LTD.

Consolidated Statement of Changes in Equity

($000s)

Share
Capital

Contributed
Surplus
Retained
Earnings (Deficit)

Total

Balance, January 1, 2010 595,559 30,174 (46,118) 579,615

Share-based compensation - 6,380 - 6,380
Options exercised 460 (123) - 337
Shares purchased and cancelled (8,304) 4,150 - (4,154)
Tax deduction of share issue costs (1,089) - - (1,089)
Comprehensive loss - - (1,083) (1,083)

Balance, December 31, 2010 586,626 40,581 (47,201) 580,006

Share-based compensation - 3,514 - 3,514
Tax deduction of share issue costs (197) - - (197)
Issue of common shares 26,891 - - 26,891
Shares purchased and cancelled (7,064) 4,647 - (2,417)
Comprehensive loss - - (212,807) (212,807)

Balance, December 31, 2011 606,256 48,742 (260,008) 394,990

GUIDE EXPLORATION LTD.
Consolidated Statements of Cash Flows
Year ended December 31
($000s) 2011 2010

Cash provided by (used in):

OPERATING ACTIVITIES
Net loss (212,807) (1,083)
Items not requiring cash:
Deferred income tax recovery (43,113) (10,852)
Impairment of goodwill - 25,333
Impairment of property and equipment 255,000 -
Depletion and depreciation 90,666 79,886
Derecognition expenses 7,538 9,069
Accretion 3,173 2,984
Share-based compensation 2,509 4,447
Other income (123) (334)
Gain on disposal of assets (4,732) -

Unrealized gain (loss) on financial derivatives 474 (8,972)
Abandonment costs (1,068) (491)
Change in non-cash working capital 6,036 3,378
103,553 103,365

FINANCING ACTIVITIES
Issue of common shares, net of costs 30,104 337
Repurchase of common shares (2,417) (4,154)
Financing lease payments - (1,545)
Bank loan (repayment) 2,566 (81,561)
30,253 (86,923)

INVESTING ACTIVITIES
Exploration and evaluation expenditures (10,145) -
Additions to property and equipment (140,350) (136,330)
Acquisitions of oil and gas properties (7,150) (17,791)
Disposals of oil and gas properties 15,408 131,949
Change in non-cash working capital 8,431 5,730
(133,806) (16,442)

CHANGE IN CASH - -
CASH, BEGINNING AND END OF PERIOD - -

SUPPLEMENTAL INFORMATION

Cash interest paid 7,665 9,599
Cash taxes paid 187 371

Guide has approximately 104.4 million Class A shares issued and outstanding which trade on the Toronto Stock Exchange under the symbol "GO".

ADVISORIES

Forward Looking Statements:

Certain information regarding Guide Exploration Ltd. in this news release including management's assessment of future plans and operations, drilling plans, production estimates and commodity mix, ability to maintain decline at Boyer with minimal capital, type curves for Guide's horizontal Montney wells, Guide's tax status, use of proceeds from financing, drilling and completion costs of certain wells, timing of implementation of pressure maintenance scheme, capital expenditures and the allocation thereof, 2012 funds flow from operations and 2012 funds flow from operations per share and the assumptions relating thereto. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, wells not performing as expected, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Included herein is an estimate of Guide's 2012 funds flow from operations and 2012 funds flow from operations per share and is based on the various assumptions as to production levels, commodity prices and other assumptions stated herein. To the extent such estimate constitutes future oriented financial information or a financial outlook, they were approved by management of Guide on January 26, 2012, and such future oriented financial information or financial outlook is included herein to provide readers with an understanding of Guide's anticipated funds flow from operations based on the assumptions described herein estimated and information on funds anticipated to be available to fund Guide's operations, and exploration and development program and readers are cautioned that the information may not be appropriate for other purposes.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Corporation believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Corporation can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Corporation operates; the timely receipt of any required regulatory approvals; the ability of the Corporation to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration results; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interst rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; and the ability of the Corporation to successfully market its oil and natural gas products. Readers are cautioned that the foregoing list of factors and assumptions is not exhaustive. Additional information on these and other factors that could affect Guide's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), at Guide's website (www.guidex.ca). Furthermore, the forward looking statements contained in this news release are made as at the date of this news release and Guide does not undertake any obligation to update publicly or to revise any of the included forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Non-GAAP Measurements:

This news release contains terms commonly used in the oil and gas industry, such as funds flow from operations, funds flow from operations per share, and operating netback. These terms are not defined by Generally Accepted Accounting Principles ("GAAP") and should not be considered an alternative to, or more meaningful than, cash provided by operating activities or net earnings as determined in accordance with GAAP as an indicator of Guide's performance. Management believes that in addition to net earnings, funds flow from operations is a useful financial measurement which assists in demonstrating the Corporation's ability to fund capital expenditures necessary for future growth or to repay debt. Guide's determination of funds flow from operations may not be comparable to that reported by other companies. All references to funds flow from operations throughout this news release are based on cash flow from operating activities before changes in non-cash working capital and abandonment expenditures. The Corporation calculates funds flow from operations per share by dividing funds flow from operations by the weighted average number of Class A shares outstanding. Guide uses the term net debt. This measure does not have any standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures presented by other companies.

Type Curves:

Information on type curves for wells in certain areas, as included herein, are illustrative of the Corporation's expectations for the results for the average well of that type. Actual results for wells drilled may vary from the results predicted from the type curves for such wells and such variations may be material.

BOES:

Disclosure provided herein in respect of barrels of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1; utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

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