# NEWS RELEASE

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**FOR IMMEDIATE RELEASE**

# Enerplus Delivers Strong 2014 Operating Results and Low Cost Reserves Additions; Updates 2015 Strategy to Enhance Value and Balance Sheet Strength

*All financial information contained within this news release has been prepared in accordance with U.S. GAAP. This news release includes forward-looking statements and information within the meaning of applicable securities laws. Readers are advised to review the "Forward-Looking Information and Statements" at the conclusion of this news release. Readers are also referred to "Information Regarding Reserves, Resources and Operational Information", "Notice to U.S. Readers" and "Non-GAAP Measures" at the end of this news release for information regarding the presentation of the financial, reserves, contingent resources and operational information in this news release. A full copy of our 2014 Financial Statements and MD&A are available on our website at www.enerplus.com, under our profile on SEDAR at www.sedar.com and on the EDGAR website at www.sec.gov.*

Calgary, Alberta - Enerplus Corporation ("Enerplus") (TSX: ERF) (NYSE: ERF) is pleased to announce our results for the fourth quarter of 2014 as well as full year 2014 operating, financial and reserves results. We are also updating our outlook for 2015 with regard to our spending plans and our strategy to preserve our financial strength and enhance the value of our portfolio in the current commodity price environment.

**2014 KEY TAKEAWAYS:**

- **Production growth of 15% year-over-year (13% per share) to 103,130 BOE per day**
- **Strong funds flow growth of 14% year-over-year (12% per share)**
- **Conservative debt-to-trailing-twelve-month funds flow ratio at year-end of 1.3**
- **Proved plus probable reserves growth of 7% year-over-year (6% per share), replacing 175% of 2014 production, net of acquisitions and divestments, at a low FD&A cost of $8.62 per BOE**
- **Significant proved plus probable reserves additions of 75 MMBOE from development capital spending at an F&D cost of $9.80 per BOE representing a recycle ratio of 2.7**
- **Continued portfolio rationalization with non-core divestments representing 3,500 BOE per day of production and proceeds of $204 million at $19.65 per BOE**

**2015 KEY TAKEAWAYS:**

- **Further reduction in capital spending to $480 million (a 40% reduction from 2014 levels and a 24% reduction from previous 2015 guidance)**
- **A reduction in the monthly dividend from $0.09 per share to $0.05 per share (a 44% reduction) effective with the April 2015 dividend**
- **Non-core asset sales representing 1,900 BOE per day of production raising proceeds of $182 million**
- **Marcellus curtailment strategy to maximize value by restricting production until natural gas prices improve**
- **Reductions in capital spending and dividend, along with non-core asset sales, results in adjusted payout ratio of less than 100%**
- **Financial strength maintained with an expected debt-to-trailing-12 month funds flow ratio of approximately 2.2 at the end of 2015**

"In light of current market conditions, we believe it is prudent to defer activity, selectively restrict production and reduce our dividend to a more appropriate level until we gain more visibility to an improvement in costs and/or commodity prices" says Ian Dundas, President and Chief Executive Officer. "While these measures have modest implications to near-term funds flow, our primary focus is on balance sheet preservation and maximizing returns for our shareholders. This strategy positions us to re-establish profitable growth in the future and also consider acquisitions to complement our organic development inventory."

**RESERVES/RESOURCES:**

We delivered strong reserves/resources results in 2014:

- Proved plus probable ("2P") reserves grew by 7% to 429 MMBOE (50% oil and liquids). On a per share basis, 2P reserves increased by 6% year-over-year.
- Proved ("1P") reserves grew by 9% to 285 MMBOE, representing 66% of 2P reserves. Proved producing reserves represent 74% of total 1P reserves.
- 75 MMBOE of 2P reserves were added through our capital spending program replacing over 200% of 2014 annual production. Well performance in both North Dakota and the Marcellus continued to exceed the previous forecasts of our independent reserves engineers and resulted in significant positive technical revisions. Approximately 30% of additions were from crude oil and 70% from natural gas.
- 2P finding and development ("F&D") costs including future development capital ("FDC") continued to improve, decreasing by 13% to $9.80 per BOE. This represents a recycle ratio of 2.7 based on our operating netback of $26.46 per BOE, before hedging, in 2014.
- We sold various interests in non-core properties representing 11 MMBOE of 2P reserves at a value of $19.65 per BOE. Total 2P reserves additions, net of our divestment activities, were approximately 66 MMBOE, replacing 175% of 2014 annual production.
- 2P finding, development and acquisition ("FD&A") costs per BOE were $8.62 including FDC, relatively unchanged from 2013. On a three-year basis, 2P FD&A costs, including FDC, continued to improve, declining by 17% to $12.13 per BOE.
- 2P reserves in Fort Berthold, North Dakota increased 16%, including positive technical revisions, to 123 MMBOE, replacing over 300% of 2014 production at an attractive F&D cost of $16.87 per BOE. Based upon an average operating netback of $47.10 per BOE in 2014, this represents a recycle ratio of 2.8.
- 2P reserves attributable to our Marcellus shale gas assets increased 40%, including positive technical revisions, to 840 Bcf, replacing approximately 450% of 2014 production at a low F&D cost of approximately $0.50 per Mcf. With an average operating netback of $1.78 per Mcf in 2014, this represents a recycle ratio of 3.6.
- Canadian reserves were impacted by the sale of non-core properties. 2P additions were offset by dispositions and deletions of undeveloped locations resulting in an overall decrease of 15% year-over-year to 145 MMBOE.
- Economic best estimate contingent resources, within a portion of our portfolio, increased by 86 MMBOE from year-end 2013, to 449 MMBOE. This represents approximately 13 years of organic reserves replacement potential based on our 2015 forecast production volumes.
- Our 2P reserve life index remains virtually unchanged from 2013 at 10.7 years.

**2014 FINANCIAL AND OPERATING HIGHLIGHTS:**

**4th Quarter 2014:**

- Despite the fall in commodity prices, funds flow was essentially unchanged quarter over quarter at $213 million due to higher production volumes and the strength of our hedging program.
- Production continued to grow during the fourth quarter averaging approximately 105,600 BOE per day, up modestly from the previous quarter despite the sale of non-core production completed on September 30, 2014. Compared to the same period in 2013, fourth quarter production was up 12%. We continued to see

strong performance from our Bakken/Three Forks properties in North Dakota with average production increasing by 2,900 BOE per day from the previous quarter. Crude oil and natural gas liquids accounted for 44% of fourth quarter volumes.

- Natural gas production from the Marcellus increased 5% from the previous quarter, despite an average of 6,000 – 7,000 BOE per day of production voluntarily curtailed to preserve value in this low natural gas price environment. Overall, corporate natural gas production declined slightly quarter over quarter primarily as a result of non-core Canadian natural gas asset sales.

- Cash operating costs increased marginally from the third quarter to $10.75 per BOE due to continued production curtailments on our lower operating cost Marcellus properties. General and administrative expenses also increased quarter over quarter to $2.62 per BOE as a result of severance costs incurred in the quarter.

- We invested $181 million in capital projects during the quarter, down from $208 million in the previous quarter, primarily as a result of a slowdown in activity in the Marcellus. Over three quarters of the spending was directed to oil projects with a total of 25 net wells drilled and 18 net wells brought on-stream.

- Our adjusted payout ratio decreased to 113% compared to 122% in the previous quarter, driven by lower capital spending in the fourth quarter.

**Full Year 2014 - Operations:**

- We delivered annual production growth of 15% in 2014 (13% per share). Having increased our production guidance twice during 2014, we achieved our target of 102,000 – 104,000 BOE per day with daily production averaging 103,130 BOE. This is despite the sale of 3,500 BOE per day of non-core production and significant natural gas production curtailment in the Marcellus.

- Total average liquids production increased by 5% in 2014 to approximately 43,800 BOE per day representing 42% of our production mix in 2014. We continued to see significant increases in crude oil production from our properties in Fort Berthold, growing production by over 30% in 2014.

- Natural gas production increased by 23% to average 356 MMcf per day for the year, representing 58% of Enerplus' production mix. This growth was due to the acquisition of additional working interests in the Marcellus in the fourth quarter of 2013, and the success of our Marcellus development program throughout the year which resulted in a doubling of production, from 95 MMcf per day in 2013 to approximately 188 MMcf per day in 2014.

- Despite the growth in natural gas production, approximately 5,000 BOE per day of natural gas from the Marcellus was curtailed during the second half of 2014. These curtailments were driven by a strategy to restrict sales and maximize value until natural gas prices improve in northeast Pennsylvania.

- We continued to focus our portfolio in 2014 and concentrate on our core areas. We divested $204 million of non-core assets comprised of natural gas properties in the Deep Basin in Canada with production of approximately 3,100 BOE per day, the sale of our gross over-riding royalty interests at Jonah in Wyoming (400 BOE per day) and the balance of proceeds from the sale of our undeveloped Montney acreage in 2013. We redeployed a portion of the proceeds into our core areas through the acquisition of undeveloped land in the Deep Basin, in the Marcellus in Pennsylvania, and in Fort Berthold, North Dakota. Our acquisition and divestment activities realized net proceeds of $185 million in 2014.

**Full Year 2014 - Financial:**

- Funds flow grew by 14% year-over-year to $859 million driven by the increase in production volumes and higher average realized commodity prices. On a per share basis, this was a 12% increase.

- Net income increased to $299 million from $48 million in 2013 as a result of an increase in crude oil and natural gas sales and commodity hedging gains.

- Capital spending came in lower than our guidance of $830 million, totaling $811 million. We invested 85% of our budget on drilling and completion activities, with 88 net wells drilled and 68 brought on-stream across our asset base. Approximately 65% of our spending was directed to our crude oil assets with the majority invested at Fort Berthold, North Dakota.

- We maintained strong capital efficiencies in 2014, despite production curtailments in the Marcellus. Based upon our capital spending and the growth in production volumes from the fourth quarter of 2013 to the same period in 2014 (excluding curtailment), this reflects a capital efficiency of approximately $22,500 per daily BOE.

- Operating costs were $10.43 per BOE, down slightly from $10.48 per BOE in 2013, though above our guidance target of $10.25 per BOE primarily due to production curtailment of approximately 5,000 BOE per day at our lower operating cost Marcellus properties in the second half of 2014. Cash G&A decreased 13% to $2.22 per BOE, down from $2.54 per BOE in 2013. The weakening Canadian dollar also impacted both our reported operating and G&A costs.

- Our adjusted payout ratio was 118% in 2014 compared to 114% in 2013 as we saw a proportionately larger increase in our capital spending program as we elected to redeploy a portion of the proceeds from our non-core asset sales into our core assets. In addition, participation in our Stock Dividend Program ("SDP") decreased as we suspended the SDP in September 2014 to eliminate dilution. After adjusting for net acquisition and divestment proceeds, our adjusted payout ratio decreased to 97% in 2014.

- As a result of the growth in funds flow and the net proceeds from our divestment activities, our debt-to-trailing-twelve-month funds flow ratio decreased to 1.3 at year-end, down from 1.4 at year-end 2013. Less than 10% of our $1.0 billion bank credit facility was drawn at year-end.

**2015 OUTLOOK:**

- As a result of the continued decline in commodity prices since issuing our 2015 guidance in mid-December 2014, we are further reducing our capital spending outlook to $480 million. This reflects a 40% decrease in spending versus 2014 levels. We plan to defer capital spending across all of our core areas in 2015, preserving our opportunities until we see meaningful cost reductions and/or an improvement in commodity prices.

- We also plan to reduce our monthly dividend to $0.05 per share effective with the April 2015 dividend. We believe this is a more appropriate level in the context of current commodity prices and represents a 44% reduction from the current level of $0.09 per share.

- Subsequent to year end, we have entered into two agreements to sell additional non-core assets currently producing approximately 1,900 BOE per day (primarily crude oil) for $182 million. Our Pembina waterflood asset represents the majority of this transaction. Although this asset has a low decline, high operating costs and limited future upside potential (there are no contingent resources associated with this asset) have restricted capital allocation. The transactions reflect an attractive selling price of $96,000 per daily BOE. We expect these transactions to close early in the second quarter.

- Our commodity hedging program will also help to protect our funds flow and balance sheet in 2015. We have 52% of our forecasted net crude oil production after royalties hedged at just under US$92 per barrel for the first half of the year, and 26% hedged for the second half of the year at just under US$94 per barrel. In relation to these crude oil swaps, we have sold puts that effectively convert a portion of these swaps (approximately 13% of our forecasted net production) to a WTI monthly index price plus US$30.30 per barrel if actual WTI monthly average prices settle below US$62.23 per barrel. We also have approximately 40% of forecasted natural gas production after royalties protected at an average floor price of US$4.14 per Mcf in 2015.

- We expect our debt-to-trailing-twelve-month funds flow ratio will be approximately 2.2 times at the end of 2015, using a WTI price of US$55 per barrel, a NYMEX gas price of US$2.75 per Mcf, an AECO gas price of $2.50 per GJ and a US$/CDN exchange rate of 1.25.

- Under the same commodity price assumptions, the reduction in capital spending and the dividend, and including the proceeds from these non-core asset sales, results in an adjusted payout ratio of under 100% in 2015. We do not expect a material increase in debt year-over-year.

- With low NYMEX natural gas prices and continued wide basis differentials in the Marcellus, we anticipate production curtailments to persist throughout this region in 2015. We are planning for similar levels of curtailment as experienced during the fourth quarter (6,000 – 7,000 BOE per day) as we look to preserve value in this low commodity price environment. These curtailed volumes will have minimal impact on funds flow in the current price environment.

- Excluding the impact of curtailment, production volumes would be relatively flat year-over-year. Including curtailment, production volumes are expected to average between 93,000 – 100,000 BOE per day during the year, down approximately 6% from 2014 using the mid-point of this guidance.
- Operating costs in aggregate are expected to be down year-over year. However due to the decline in production, including the low cost Marcellus production curtailment, and the impact of the weakening Canadian dollar, we expect costs on a BOE basis to increase to $11.10 per BOE in 2015. Total G&A costs are also expected to decline in 2015, but on a BOE basis will increase slightly due to the same factors, averaging $2.40 per BOE.

## SELECTED FINANCIAL RESULTS

| | Three months ended December 31, | | Twelve months ended December 31, | |
|---|---|---|---|---|
| | **2014** | **2013** | **2014** | **2013** |
| **Financial (000's)** | | | | |
| Funds Flow | $212,518 | $180,741 | $859,020 | $754,233 |
| Cash and Stock Dividends | 55,511 | 54,665 | 221,098 | 216,864 |
| Net Income/(Loss) | 151,652 | 29,626 | 299,076 | 47,976 |
| Debt Outstanding - net of cash | 1,134,894 | 1,022,308 | 1,134,894 | 1,022,308 |
| Capital Spending | 180,999 | 223,035 | 811,026 | 681,437 |
| Property and Land Acquisitions | 1,305 | 173,387 | 18,491 | 244,837 |
| Property Divestments | 17,945 | 168,050 | 203,576 | 365,135 |
| Debt to Trailing 12 Month Funds Flow | 1.3x | 1.4x | 1.3x | 1.4x |
| **Financial per Weighted Average Shares Outstanding** | | | | |
| Funds Flow | $1.03 | $0.89 | $4.20 | $3.76 |
| Net Income (Basic) | 0.74 | 0.15 | 1.46 | 0.24 |
| Weighted Average Number of Shares Outstanding (000's) | 205,519 | 202,257 | 204,510 | 200,567 |
| **Selected Financial Results per BOE**[1][2] | | | | |
| Oil & Natural Gas Sales[3] | $38.83 | $43.79 | $47.61 | $48.11 |
| Royalties and Production Taxes | (9.13) | (9.53) | (10.75) | (10.21) |
| Commodity Derivative Instruments | 4.71 | 1.90 | 0.09 | 0.81 |
| Operating Costs | (10.75) | (10.46) | (10.40) | (10.50) |
| General and Administrative | (2.62) | (2.28) | (2.22) | (2.54) |
| Share Based Compensation (Expense)/Recoveries | 1.40 | (1.06) | 0.03 | (0.71) |
| Interest, Foreign Exchange and Other Expenses | (1.23) | (1.51) | (1.42) | (1.71) |
| Taxes | 0.67 | 0.01 | (0.12) | (0.24) |
| Funds Flow | $21.88 | $20.86 | $22.82 | $23.01 |

## SELECTED OPERATING RESULTS

| | Three months ended December 31, 2014 | 2013 | Twelve months ended December 31, 2014 | 2013 |
|---|---|---|---|---|
| **Average Daily Production**[1] | | | | |
| Crude oil (bbls/day) | 42,818 | 37,731 | 40,208 | 38,250 |
| NGLs (bbls/day) | 3,487 | 3,813 | 3,565 | 3,472 |
| Natural gas (Mcf/day) | 355,709 | 315,739 | 356,142 | 288,423 |
| Total (BOE/day) | 105,591 | 94,167 | 103,130 | 89,793 |
| % Crude Oil & Natural Gas Liquids | 44% | 44% | 42% | 46% |
| **Average Selling Price**[2] | | | | |
| Crude oil (per bbl) | $67.13 | $ 77.77 | $84.53 | $ 83.99 |
| NGLs (per bbl) | 40.36 | 54.26 | 49.89 | 52.25 |
| Natural gas (per Mcf) | 3.12 | 3.26 | 3.81 | 3.26 |
| Net Wells drilled | 25 | 18 | 88 | 62 |

(1) Based on Company interest production volumes. See "Information Regarding Reserves, Resources and Operational Information – Presentation of Production and Reserves Information".
(2) Net of oil and gas transportation costs, but before royalties and the effects of commodity derivative instruments.

| | Three months ended December 31, 2014 | 2013 | Twelve months ended December 31, 2014 | 2013 |
|---|---|---|---|---|
| **Average Benchmark Pricing** | | | | |
| WTI crude oil (US$/bbl) | $73.15 | $97.46 | $ 93.00 | $ 97.97 |
| AECO– monthly index (CDN$/Mcf) | 4.01 | 3.16 | 4.42 | 3.16 |
| AECO– daily index (CDN$/Mcf) | 3.60 | 3.53 | 4.51 | 3.17 |
| NYMEX– last day (US$/Mcf) | 4.00 | 3.60 | 4.41 | 3.65 |
| USD/CDN exchange rate | 1.14 | 1.05 | 1.10 | 1.03 |

| **Share Trading Summary**<br>For the twelve months ended December 31, 2014 | **CDN* – ERF**<br>(CDN$) | **U.S.** - ERF**<br>(US$) |
|---|---|---|
| High | 27.05 | 25.37 |
| Low | 9.02 | 7.75 |
| Close | 11.19 | 9.60 |

* TSX and other Canadian trading data combined.
**NYSE and other U.S. trading data combined.

### 2014 PRODUCTION & CAPITAL SPENDING

| **Crude Oil & NGLs (Bbls/day)** | **Q4 2014 Average Production** | **2014 Annual Average Production** | **2014 Capital Spending ($million)** |
|---|---|---|---|
| Canada | 18,388 | 19,144 | $176 |
| United States | 27,917 | 24,629 | $344 |
| **Total Crude Oil & NGLs (Bbls/day)** | **46,305** | **43,773** | **$520** |
| **Natural Gas (Mcf/day)** | | | |
| Canada | 140,910 | 150,930 | $132 |
| United States | 214,799 | 205,212 | $159 |
| **Total Natural Gas (Mcf/day)** | **355,709** | **356,142** | **$291** |
| **Company Total (BOE/day)** | **105,591** | **103,130** | **$811** |

### 2014 NET DRILLING ACTIVITY***

| **Crude Oil** | **Horizontal Wells** | **Vertical Wells** | **Total Wells** | **Wells Pending Completion/ Tie-in *** | **Wells On-stream**** | **Dry & Abandoned Wells** |
|---|---|---|---|---|---|---|
| Canada | 30.2 | - | 30.2 | 5.0 | 25.7 | - |
| United States | 27.2 | - | 27.2 | 12.5 | 18.4 | - |
| **Total Crude Oil** | **57.4** | **-** | **57.4** | **17.5** | **44.1** | **-** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Natural Gas** | | | | | | |
| Canada | 11.2 | - | 11.2 | 4.4 | 6.4 | 0.3 |
| United States | 18.8 | 0.1 | 18.9 | 9.0 | 17.3 | - |
| **Total Natural Gas** | **30.0** | **0.1** | **30.1** | **13.4** | **23.6** | **0.3** |
| **Company Total** | **87.4** | **0.1** | **87.5** | **30.9** | **67.7** | **0.3** |

* Wells drilled during the year that are pending potential completion/tie-in or abandonment as at December 31, 2014.
** Total wells brought on-stream during the year regardless of when they were drilled.
*** Table may not add due to rounding.

## ASSET ACTIVITY

### U.S. Crude Oil

We continued to achieve industry-leading well performance within our Fort Berthold properties in North Dakota in 2014, reinforcing their top tier ranking. Our activities were focused on developing a better understanding of the resource potential and the optimal drilling density, advancing our completion design and improving capital efficiencies.

Through our successful development program, production volumes were up almost 30% in 2014 averaging 21,700 BOE per day. A total of 27 net wells were drilled throughout the year, including three high density pads focused on testing tighter well spacing and two wells testing the second bench of the Three Forks formation. Due to the changes made to our completion design, all of our operated wells exceeded our expected initial 30 days average production rates (IP30) and initial 60 days average production rates (IP60) by 20% on average. This outperformance and our focus on cost control drove a 25% improvement in capital efficiencies year-over-year. Approximately 18 net wells were brought on-stream during the year.

Approximately 24 MMBOE of 2P reserves were added at year end, including extensions and technical revisions, replacing over 300% of production at an average F&D cost of $16.87 per BOE (including FDC). The average expected ultimate recovery of our long horizontal wells increased by 50,000 barrels and is now 675,000 barrels of oil. Our Fort Berthold properties carried a total of 123 MMBOE of 2P reserves at December 31, 2014.

Our detailed resources assessment completed earlier in 2014 resulted in a significant increase in our estimate of discovered original oil in place. Using a 15% recovery factor, this resulted in an increase in future drilling locations based on higher well density. Our 2P reserves estimate at December 31, 2014 includes 84 net undeveloped locations with an average density of four wells per drilling spacing unit (a combination of Bakken and Three Forks wells). In addition, we added 76 MMBOE of economic best estimate contingent resources, an increase of almost 200% versus December 31, 2013. Our new best estimate of economic contingent resources is 115 MMBOE.

With the decrease in crude oil prices, we plan to reduce our capital activities in this region in 2015, preserving our drilling inventory and financial flexibility. Capital spending is expected to decline by 25% from 2014 levels to approximately $260 million. We are expecting to drop to one drilling rig in mid-2015 and plan to defer a number of well completions, creating an inventory of drilled wells for the future when costs or commodity prices improve. We anticipate 2015 production will be flat year-on-year.

### U.S. Natural Gas

The Marcellus continues to be the premier dry natural gas shale play in North America. Our well performance continued to surpass expectations in 2014 which, coupled with the acquisition of additional working interests in late 2013, resulted in a doubling of production year-over-year averaging 188 MMcf per day in 2014. This growth is despite increased levels of production curtailments during the latter half of the year.

Through our successful drilling activities, we replaced 450% of 2014 production, adding over 300 Bcf 2P reserves, including technical revisions, at a F&D cost of approximately $0.50 per Mcf (including FDC). Similar to Fort Berthold, our positive technical reserves revisions have been driven by strong well performance. A total of 840 Bcf of 2P reserves were independently assessed to our Marcellus properties at December 31, 2014 in addition to 1,400 Bcf of independently evaluated economic best estimate contingent resources, up 40% and 5% respectively from year end 2013.

A total of 19 net wells were drilled in 2014 with 17 wells brought on-stream. Average IP30 rates improved to 11 MMcf per day versus 10 MMcf per day in 2013, as tighter stage spacing and increased proppant continues to improve performance. Drilling costs declined 10% year-over-year and capital efficiencies improved by almost 30% from 2013 due to the reduction in well costs and higher production rates.

The improvement in capital efficiencies throughout the play has kept activity levels high, causing supply from the region to outpace pipeline takeaway capacity. Basis differentials in the area remained wide throughout 2014 and as natural gas prices started to weaken in the latter half of the year, production was restricted in order to preserve value until such time as realized prices improve. In the latter half of the year, approximately 5,000 BOE per day of natural gas production on average was curtailed and we expect that approximately 6,000 – 7,000 BOE per day of natural gas will be curtailed during 2015. The pace of activity began to slow in the fourth quarter of 2014 and this is expected to continue in 2015. We expect capital spending in the Marcellus to decline by roughly 75% from 2014 levels to approximately $40 million. Despite the drop in capital, we expect production will remain flat year-over-year after considering the impact of curtailments.

**Canadian Crude Oil**

We continued to invest in our crude oil waterflood portfolio in Canada during 2014 where we advanced key projects targeting the Ratcliffe, Lower Mannville, Glauconitic and Boundary Lake plays.

At Brooks, we drilled 14 wells in 2014 with an additional two wells rig released in early January 2015 targeting the Lower Mannville sands as part of a 55 well development program. Early production performance has been positive with average results in-line with our expectations. Given land expiries in 2016, we plan to continue with our program in 2015, assuming that well performance continues to meet our expectations.

At Medicine Hat, we continued to develop the Glauconite C waterflood during 2014 where we drilled seven injection and seven producing wells as part of a waterflood expansion project. Results from this drilling as well as our polymer project continue to exceed expectations. Technical work for our second polymer project is ongoing and the project is expected to be operational in the fourth quarter of 2015. We plan to advance our polymer project in 2015 under a reduced capital spending program.

**Canadian Natural Gas**

Our 2014 Canadian gas activities were directed to the Wilrich and the Duvernay. We drilled 3.2 net wells in the Ansell area targeting the Wilrich, and in the Willesden Green area we drilled two horizontal wells targeting the Duvernay.

In 2015, we have a modest capital program planned in the Wilrich in the Ansell area where we have seen superior well results previously. We plan to continue evaluating the performance of our two Duvernay horizontal wells and have minimal capital spending planned.

## 2015 UPDATED FORECAST GUIDANCE SUMMARY

We remain committed to creating value for our shareholders by providing a combination of income and profitable growth. In the current commodity price environment, we are particularly focused on preserving our balance sheet strength, reducing costs, and maximizing returns. We will continue to monitor commodity prices and economic conditions and will make adjustments to both our capital spending and dividend levels as necessary in order to preserve our financial flexibility. The following estimates do not include any acquisitions or further divestments, although both remain part of our strategy going forward.

| 2015 Updated Guidance | 2015E |
|---|---|
| Capital expenditures | $480 million |
| Annual average daily production* | 93,000 – 100,000 BOE/day |
| % crude oil and natural gas liquids at mid-point of guidance | 42% - 44% |
| Marcellus production curtailment | 6,000 – 7,000 BOE/day |
| Debt-to-trailing-12-month funds flow at year-end** | ~2.2x |
| Cash operating costs | $11.10/BOE |
| Cash G&A costs | $2.40/BOE |
| Royalties (including state fees) | 21% |
| U.S. cash taxes as % of U.S. cash flow | <1% |

*Daily production guidance after forecast Marcellus production curtailment.

**Based upon a WTI price of US$55 per barrel, a NYMEX gas price of US$2.75 per Mcf, an AECO gas price of $2.50 per GJ and a US$/$CDN exchange rate of 1.25.

| 2015 Differential/Basis Outlook | |
|---|---|
| Mixed Sweet Blend (MSW) | US$(5.00)/bbl |
| Western Canada Select (WCS) | US$(16.00)/bbl |
| U.S. Bakken | US$(9.50)/bbl |
| Marcellus Basis | US$(1.25)/Mcf |

*Before field transportation costs. Compared to US$ WTI crude oil and US$ NYMEX natural gas.

## INDEPENDENT RESERVES EVALUATION

All reserves information, including our U.S. reserves, has been prepared in accordance with Canadian National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101") standards. Independent reserves evaluations have been conducted on approximately 89% of the total proved plus probable present value (before tax, discounted at 10%) of our reserves at December 31, 2014. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 71% of our Canadian reserves and 100% of the reserves associated with our U.S. oil assets. McDaniel also reviewed the internal evaluation completed by Enerplus on the remaining 29% of our Canadian assets. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated all of our U.S. natural gas assets.

The following information sets out our gross reserves volumes at December 31, 2014 by production type and reserves category under McDaniel's forecast price scenarios. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit associated with a property. It should be noted that tables may not add due to rounding.

The following tables set forth the estimated gross and net reserves volumes and net present value of future net revenue attributable to the Corporation's reserves at December 31, 2014, using forecast price and costs. Enerplus also previously publicly disclosed our reserves on a "company interest" basis, being the gross volumes plus Enerplus' share of royalty interests in reserves. "Company interest" is not a term defined in NI 51-101 and therefore may not be comparable to reserves estimates disclosed by other issuers in accordance with NI 51-101. Following the disposition of our Jonah royalty interest properties in 2014, we no longer disclose reserves on a "company interest" basis. At year-end 2014, a calculation of "company interest" reserves would include an additional 2.0 MMBOE of 2P reserves.

### Reserves Summary

Enerplus' 2P reserves increased by 28.6 million BOE to 429.3 million BOE at year-end 2014, up from 400.7 million BOE at year-end 2013. The majority of reserves additions were associated with our Fort Berthold and Marcellus properties. These assets now represent 61% of total 2P reserves. Proved reserves as a percentage of total 2P reserves remained at approximately 66% year-over-year.

| Reserves Summary | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|
| **Gross** | | | | | | | |
| Proved producing | 68,361 | 26,858 | 95,219 | 6,149 | 268,390 | 386,620 | 210,536 |
| Proved developed non-producing | 5,509 | 13 | 5,522 | 456 | 9,840 | 70,010 | 19,286 |
| Proved undeveloped | 21,615 | 4,651 | 26,266 | 1,532 | 53,479 | 107,952 | 54,704 |
| Total proved | 95,485 | 31,522 | 127,007 | 8,137 | 331,709 | 564,583 | 284,525 |
| Total probable | 61,808 | 11,616 | 73,424 | 4,662 | 124,721 | 275,357 | 144,766 |
| **Proved plus Probable** | **157,293** | **43,138** | **200,431** | **12,798** | **456,430** | **839,940** | **429,291** |
| **Net** | | | | | | | |
| Proved producing | 56,907 | 21,454 | 78,361 | 4,698 | 239,194 | 309,371 | 174,486 |
| Proved developed non-producing | 4,378 | 12 | 4,390 | 352 | 7,759 | 56,014 | 15,370 |
| Proved undeveloped | 17,522 | 3,532 | 21,054 | 1,208 | 48,538 | 86,384 | 44,748 |
| Total proved | 78,806 | 24,998 | 103,804 | 6,256 | 295,491 | 451,770 | 234,604 |
| Total probable | 49,917 | 8,966 | 58,883 | 3,636 | 109,933 | 220,305 | 117,558 |
| **Proved plus Probable** | **128,723** | **33,964** | **162,687** | **9,892** | **405,424** | **672,075** | **352,161** |

## Reserves Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a gross basis, from December 31, 2013 to December 31, 2014:

**Proved Reserves - Gross Volumes (Forecast Prices)**

| CANADA | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|
| Proved Reserves at Dec. 31, 2013 | 29,163 | 30,806 | 59,969 | 6,203 | 336,199 | - | 122,204 |
| Acquisitions | - | - | - | - | - | - | - |
| Dispositions | (24) | - | (24) | (1,425) | (41,034) | - | (8,288) |
| Discoveries | - | - | - | - | - | - | - |
| Extensions & improved recovery | 612 | 2,265 | 2,877 | 533 | 28,208 | - | 8,112 |
| Economic factors | 200 | - | 200 | (5) | (8,200) | - | (1,171) |
| Technical revisions | (451) | 1,587 | 1,136 | (114) | 8,604 | - | 2,456 |
| Production | (2,930) | (3,136) | (6,066) | (860) | (53,116) | - | (15,778) |
| **Proved Reserves at Dec. 31, 2014** | **26,571** | **31,522** | **58,093** | **4,333** | **270,661** | **-** | **107,535** |

| UNITED STATES | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|
| Proved Reserves at Dec. 31, 2013 | 58,526 | - | 58,526 | 2,529 | 54,081 | 411,431 | 138,640 |
| Acquisitions | 64 | - | 64 | 4 | 36 | - | 74 |
| Dispositions | - | - | - | - | - | - | - |
| Discoveries | - | - | - | - | - | - | - |
| Extensions & improved recovery | 8,243 | - | 8,243 | 586 | 4,879 | 164,065 | 36,986 |
| Economic factors | 7 | - | 7 | - | 13 | - | 9 |
| Technical revisions | 10,651 | - | 10,651 | 1,078 | 8,067 | 57,767 | 22,702 |
| Production | (8,577) | - | (8,577) | (393) | (6,028) | (68,681) | (21,422) |
| **Proved Reserves at Dec. 31, 2014** | **68,914** | **-** | **68,914** | **3,804** | **61,048** | **564,583** | **176,990** |

| TOTAL ENERPLUS | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|
| Proved Reserves at Dec. 31, 2013 | 87,689 | 30,806 | 118,495 | 8,732 | 390,279 | 411,431 | 260,844 |
| Acquisitions | 64 | - | 64 | 4 | 36 | - | 74 |
| Dispositions | (24) | - | (24) | (1,425) | (41,034) | - | (8,288) |
| Discoveries | - | - | - | - | - | - | - |
| Extensions & improved recovery | 8,855 | 2,265 | 11,120 | 1,119 | 33,087 | 164,065 | 45,098 |
| Economic factors | 207 | - | 207 | (5) | (8,187) | - | (1,162) |
| Technical revisions | 10,200 | 1,587 | 11,787 | 964 | 16,671 | 57,767 | 25,158 |
| Production | (11,507) | (3,136) | (14,643) | (1,253) | (59,144) | (68,681) | (37,199) |
| **Proved Reserves at Dec. 31, 2014** | **95,485** | **31,522** | **127,007** | **8,137** | **331,709** | **564,583** | **284,525** |

### Probable Reserves - Gross Volumes (Forecast Prices)

| CANADA | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|
| Probable Reserves at Dec. 31, 2013 | 9,662 | 11,260 | 20,922 | 2,523 | 142,103 | - | 47,129 |
| Acquisitions | - | - | - | - | - | - | - |
| Dispositions | (10) | - | (10) | (469) | (13,075) | - | (2,658) |
| Discoveries | - | - | - | - | - | - | - |
| Extensions & improved recovery | 258 | 1,884 | 2,142 | 165 | 12,484 | - | 4,387 |
| Economic factors | - | - | - | (566) | (20,847) | - | (4,041) |
| Technical revisions | (733) | (1,528) | (2,261) | (323) | (31,307) | - | (7,801) |
| Production | - | - | - | - | - | - | - |
| **Probable Reserves at Dec. 31, 2014** | **9,177** | **11,616** | **20,793** | **1,330** | **89,359** | **-** | **37,016** |

| UNITED STATES | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|
| Probable Reserves at Dec. 31, 2013 | 52,678 | - | 52,678 | 3,106 | 32,342 | 189,430 | 92,746 |
| Acquisitions | 995 | - | 995 | 67 | 557 | - | 1,154 |
| Dispositions | - | - | - | - | - | - | - |
| Discoveries | - | - | - | - | - | - | - |
| Extensions & improved recovery | 4,157 | - | 4,157 | 291 | 2,421 | 38,835 | 11,324 |
| Economic factors | - | - | - | - | - | - | - |
| Technical revisions | (5,199) | - | (5,199) | (132) | 42 | 47,092 | 2,525 |
| Production | - | - | - | - | - | - | - |
| **Probable Reserves at Dec. 31, 2014** | **52,631** | **-** | **52,631** | **3,332** | **35,362** | **275,357** | **107,749** |

| TOTAL ENERPLUS | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|
| Probable Reserves at Dec. 31, 2013 | 62,340 | 11,260 | 73,600 | 5,629 | 174,446 | 189,430 | 139,875 |
| Acquisitions | 995 | - | 995 | 67 | 557 | - | 1,154 |
| Dispositions | (10) | - | (10) | (469) | (13,075) | - | (2,658) |
| Discoveries | - | - | - | - | - | - | - |
| Extensions & improved recovery | 4,415 | 1,884 | 6,299 | 455 | 14,905 | 38,835 | 15,711 |
| Economic factors | - | - | - | (566) | (20,847) | - | (4,040) |
| Technical revisions | (5,932) | (1,528) | (7,460) | (455) | (31,265) | 47,092 | (5,277) |
| Production | - | - | - | - | - | - | - |
| **Probable Reserves at Dec. 31, 2014** | **61,808** | **11,616** | **73,424** | **4,662** | **124,721** | **275,357** | **144,766** |

### Proved Plus Probable Reserves - Gross Volumes (Forecast Prices)

| CANADA | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|
| Proved Plus Probable Reserves at Dec. 31, 2013 | 38,825 | 42,066 | 80,891 | 8,726 | 478,302 | - | 169,334 |
| Acquisitions | - | - | - | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Dispositions | (34) | - | (34) | (1,894) | (54,108) | - | (10,946) |
| Discoveries | - | - | - | - | - | - | - |
| Extensions & improved recovery | 870 | 4,149 | 5,019 | 698 | 40,692 | - | 12,499 |
| Economic factors | 200 | - | 200 | (571) | (29,047) | - | (5,212) |
| Technical revisions | (1,183) | 59 | (1,124) | (437) | (22,703) | - | (5,345) |
| Production | (2,930) | (3,136) | (6,066) | (860) | (53,116) | - | (15,778) |
| **Proved Plus Probable Reserves at Dec. 31, 2014** | **35,748** | **43,138** | **78,886** | **5,662** | **360,020** | **-** | **144,552** |

| UNITED STATES | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|
| Proved Plus Probable Reserves at Dec. 31, 2013 | 111,204 | - | 111,204 | 5,635 | 86,423 | 600,861 | 231,386 |
| Acquisitions | 1,059 | - | 1,059 | 71 | 593 | - | 1,229 |
| Dispositions | - | - | - | - | - | - | - |
| Discoveries | - | - | - | - | - | - | - |
| Extensions & improved recovery | 12,400 | - | 12,400 | 876 | 7,301 | 202,900 | 48,310 |
| Economic factors | 7 | - | 7 | - | 13 | - | 9 |
| Technical revisions | 5,452 | - | 5,452 | 946 | 8,109 | 104,859 | 25,227 |
| Production | (8,577) | - | (8,577) | (393) | (6,028) | (68,681) | (21,422) |
| **Proved Plus Probable Reserves at Dec. 31, 2014** | **121,545** | **-** | **121,545** | **7,136** | **96,410** | **839,940** | **284,739** |

| TOTAL ENERPLUS | Light & Medium Oil (Mbbls) | Heavy Oil (Mbbls) | Total Oil (Mbbls) | Natural Gas Liquids (Mbbls) | Natural Gas (MMcf) | Shale Gas (MMcf) | Total (MBOE) |
|---|---|---|---|---|---|---|---|
| Proved Plus Probable Reserves at Dec. 31, 2013 | 150,029 | 42,066 | 192,095 | 14,360 | 564,725 | 600,861 | 400,720 |
| Acquisitions | 1,059 | - | 1,059 | 71 | 593 | - | 1,229 |
| Dispositions | (34) | - | (34) | (1,894) | (54,108) | - | (10,946) |
| Discoveries | - | - | - | - | - | - | - |
| Extensions & improved recovery | 13,271 | 4,149 | 17,420 | 1,574 | 47,993 | 202,900 | 60,809 |
| Economic factors | 207 | - | 207 | (571) | (29,034) | - | (5,203) |
| Technical revisions | 4,268 | 59 | 4,327 | 510 | (14,594) | 104,859 | 19,882 |
| Production | (11,507) | (3,136) | (14,643) | (1,253) | (59,144) | (68,681) | (37,199) |
| **Proved Plus Probable Reserves at Dec. 31, 2014** | **157,293** | **43,138** | **200,431** | **12,798** | **456,430** | **839,940** | **429,291** |

## Future Development Capital

Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the evaluators' best estimate of the capital required to bring the proved and proved plus probable reserves on production. The aggregate of the exploration and development costs incurred in the most recent year and the change during the year in estimated future development costs generally reflect the total finding and development costs related to reserves additions for that year.

The following is a summary of the independent reserves evaluators' estimated FDC required to bring the total proved and proved plus probable reserves on production:

| Future Development Capital | Proved Reserves | Proved Plus Probable Reserves |
|---|---|---|
| ($ millions) | | |
| 2015 | 429 | 563 |
| 2016 | 248 | 439 |
| 2017 | 227 | 423 |
| 2018 | 40 | 346 |
| 2019 | 29 | 133 |
| Remainder | 33 | 32 |

| | | |
|---|---|---|
| Total FDC Undiscounted | 1,006 | 1,936 |
| Total FDC Discounted at 10% | 873 | 1,606 |

**F&D AND FD&A COSTS –** *including future development capital*

| ($ millions except for per BOE amounts) | 2014 | 2013 | 2012 | 3 Year |
|---|---|---|---|---|
| **Proved Plus Probable Reserves** | | | | |
| **Finding & Development Costs** | | | | |
| Capital Expenditures | $811.0 | $681.4 | $852.8 | $2,345.3 |
| Net change in Future Development Capital | $(71.3) | $200.0 | $534.6 | $663.3 |
| Gross Reserves additions (MMBOE) | 75.5 | 78.1 | 57.3 | 210.9 |
| F&D costs ($/BOE) | **$9.80** | **$11.28** | **$24.21** | **$14.26** |
| **Finding, Development & Acquisition Costs** | | | | |
| Capital expenditures and net acquisitions | $625.9 | $561.1 | $726.4 | $1,913.5 |
| Net change in Future Development Capital | $(59.2) | $216.6 | $509.1 | $666.5 |
| Gross Reserves additions (MMBOE) | 65.8 | 93.0 | 53.9 | 212.7 |
| FD&A costs ($/BOE) | **$8.62** | **$8.36** | **$22.92** | **$12.13** |
| **Proved Reserves** | | | | |
| **Finding & Development Costs** | | | | |
| Capital Expenditures | $811.0 | $681.4 | $852.8 | $2,345.3 |
| Net change in Future Development Capital | $13.8 | $(106.4) | $248.3 | $155.7 |
| Gross Reserves additions (MMBOE) | 69.1 | 57.1 | 38.4 | 164.6 |
| F&D costs ($/BOE) | **$11.94** | **$10.08** | **$28.67** | **$15.20** |
| **Finding, Development & Acquisition Costs** | | | | |
| Capital expenditures and net acquisitions | $625.9 | $561.1 | $726.4 | $1,913.5 |
| Net change in Future Development Capital | $4.9 | $(112.8) | $241.3 | $133.4 |
| Gross Reserves additions (MMBOE) | 60.9 | 69.9 | 36.6 | 167.4 |
| FD&A costs ($/BOE) | **$10.36** | **$6.41** | **$26.44** | **$12.23** |

## Forecast Price Assumptions

The estimated reserves volumes and the net present values of future net revenues ("NPV") at December 31, 2014 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of January 1, 2015. These prices were applied to the reserves evaluated by McDaniel and NSAI, along with those evaluated internally by Enerplus and reviewed by McDaniel. The base reference prices and exchange rates used by McDaniel are detailed below.

**McDaniel January 2015 Forecast Price Assumptions**

| | WTI Crude Oil US$/bbl | Light Crude Oil[1] Edmonton CDN$/bbl | Alberta Heavy Crude Oil 12° API CDN$/bbl | Henry Hub Gas Price US$/MMBtu | Natural Gas Alberta Spot @ AECO CDN$/MMBtu | Exchange Rate US$/CDN$ |
|---|---|---|---|---|---|---|
| 2015 | 65.00 | 68.60 | 51.10 | 3.30 | 3.50 | 0.860 |
| 2016 | 75.00 | 83.20 | 62.00 | 3.80 | 4.00 | 0.860 |
| 2017 | 80.00 | 88.90 | 66.20 | 4.05 | 4.25 | 0.860 |
| 2018 | 84.90 | 94.60 | 70.50 | 4.30 | 4.50 | 0.860 |
| 2019 | 89.30 | 99.60 | 74.20 | 4.55 | 4.70 | 0.860 |
| Thereafter | (2) | (2) | (2) | (3) | (3) | 0.860 |

(1) Edmonton Light Sweet 40 degree API, 0.3% sulphur content crude.
(2) Escalation is approximately 5% in 2020 and 2% per year thereafter
(3) Escalation is approximately 6.5% in 2020, declining to 3.5% in 2024 and approximately 2% per year thereafter.

## Net Present Value of Future Production Revenue

The following table provides an estimate of the net present value of Enerplus' future production revenue after deduction of royalties, estimated future capital and operating expenditures, before income taxes. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves.

These forecast price assumptions reflect a reduction in the prices for our portfolio of crude oil and also a decrease in the prices of natural gas at AECO and Henry Hub when compared to the price assumptions used at December 31, 2013. As a result, despite a 7% increase in our 2P reserves at December 31, 2014, the estimated before tax NPV using a 10% discount rate decreased by 12%.

**Net Present Value of Future Production Revenue – Forecast Prices and Costs** *(before tax)*

| Reserves at December 31, 2014, ($ Millions, discounted at) | **0%** | **5%** | **10%** | **15%** |
|---|---|---|---|---|
| Proved developed producing | 5,276 | 3,594 | 2,745 | 2,241 |
| Proved developed non-producing | 390 | 206 | 129 | 88 |
| Proved undeveloped | 1,256 | 512 | 208 | 54 |
| **Total Proved** | **6,923** | **4,312** | **3,082** | **2,383** |
| Probable | 5,011 | 2,240 | 1,274 | 822 |
| **Total Proved Plus Probable Reserves (before tax)** | **11,934** | **6,552** | **4,356** | **3,205** |

## Contingent Resources

In addition to reserves, an assessment of the additional resource potential within a portion of our asset base has identified 449 million BOE of economic best estimate contingent resources ("contingent resources") as of December 31, 2014. This represents a year-over-year increase of 86 million BOE primarily due to additions and revisions in our Fort Berthold area. This increase is despite converting approximately 54 million BOE of contingent resources to reserves. Based upon our forecast production volumes for 2015, this would represent approximately 13 years of organic reserves replacement potential within a portion of our portfolio today.

- 115 million BOE of contingent resources attributable to both the Bakken and Three Forks at Fort Berthold, up from 39 million BOE at year-end 2013. 15 million BOE of previously assessed contingent resources were converted to reserves in 2014 and 91 million BOE of new contingent resources were added due to an increased estimate of OOIP. This assessment assumes a well density of up to four wells per drilling spacing unit within the Bakken and up to three wells per spacing unit within the first bench of the Three Forks formation only. We believe further upside potential may exist through both increased drilling density and also drilling into the lower benches of the Three Forks.
- 59 million BOE of contingent resources attributable to improved oil recovery and enhanced oil recovery in our Canadian waterflood assets, unchanged from 2013. Approximately 4 million BOE of previously assessed contingent resources were converted to reserves in 2014.
- 1.4 trillion cubic feet of contingent resources associated with our Marcellus shale gas assets, up from 1.3 trillion cubic feet at year-end 2013. This includes an increase of 271 billion cubic feet from positive revisions to average estimated ultimate recoveries. Approximately 203 billion cubic feet of previously assessed contingent resources were converted to reserves in 2014.
- 243 BcfGE of contingent resources associated with our Wilrich deep gas assets in Canada, down slightly from 253 BcfGE at year-end 2013. Approximately 10 BcfGE of contingent resources were reclassified to reserves in 2014 as a result of our successful drilling activities.

At this time, there has been no assessment of the resource potential from our Duvernay land position.

The following table provides a breakdown of contingent resources associated with a portion of Enerplus' assets which are economic using current cost structures and McDaniel's forecast commodity pricing as at January 1, 2015. The evaluation of the contingent resources associated with the Wilrich and our leases at Fort Berthold was conducted by Enerplus and audited by McDaniel. NSAI has independently assessed our Marcellus shale gas assets and provided the estimate of contingent resources. The contingent resources evaluation associated with a portion of our waterflood properties was completed internally by qualified reserves evaluators.

| Contingent Resources | "Best Estimate" Economic Contingent Resources | Net Drilling Locations |
|---|---|---|
| **Canada** | | |
| Waterfloods –incremental and enhanced oil recovery potential on a portion of waterfloods (MMBOE) | 59.3 | 106 |
| Wilrich Natural gas - Wilrich (BcfGE) | 242.6 | 49 |
| **Total Canada (MMBOE)** | **99.7** | **155** |
| **United States** | | |
| Fort Berthold - Bakken/Three Forks crude oil (MMBOE) | 114.5 | 186 |
| Marcellus Shale Gas - (Bcf) | 1,407.9 | 144 |
| **Total United States (MMBOE)** | **349.2** | **330** |
| **Total Company (MMBOE)** | **448.9** | **485** |

## LIVE CONFERENCE CALL

We plan to hold a conference call hosted by Ian C. Dundas, President and CEO, today, February 20, 2015 at 9:00 a.m. MT (11:00 a.m. ET) to discuss these results. Details of the conference call are as follows:

Date: Friday, February 20, 2015
Time: 9:00 am MT/11:00 am ET
Dial-In: 647-427-7450
1-888-231-8191
Audiocast: http://www.newswire.ca/en/webcast/detail/1470417/1636767

To ensure timely participation in the conference call, callers are encouraged to dial in 15 minutes prior to the start time to register for the event. A telephone replay will be available for 30 days following the conference call and can be accessed at the following numbers:

Dial-In: 416-849-0833
1-855-859-2056 (toll free)
Passcode: 64911598

Electronic copies of our 2014 year-end MD&A and Financial Statements, along with other public information including investor presentations, are available on our website at www.enerplus.com. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

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## *INFORMATION REGARDING RESERVES, RESOURCES AND OPERATIONAL INFORMATION*

*Currency and Accounting Principles*

*All amounts in this news release are stated in Canadian dollars unless otherwise specified. All financial information in this news release has been prepared and presented in accordance with U.S. GAAP, except as noted below under "Non-GAAP Measures".*

*Barrels of Oil Equivalent*

*This news release also contains references to "BOE" (barrels of oil equivalent), "MBOE" (one thousand barrels of oil equivalent), "MMBOE" (one million barrels of oil equivalent) and "BcfGE" (one billion cubic feet of natural gas equivalent). Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs and when converting oil and NGLs to BcfGEs. BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.*

*Presentation of Production and Reserves Information*

*Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under IFRS and Canadian industry protocol oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. In order to continue to be comparable with our Canadian peer companies, the summary results contained within this news release presents our production and BOE measures on a before royalty company interest basis.*

*All production volumes and revenues presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest. Unless otherwise specified, all reserves volumes in this news release (and all information derived therefrom) are based on "gross reserves" using forecast prices and costs. "Gross reserves" (as defined in NI 51-101), being Enerplus' working interest before deduction of any royalties. Our oil and gas reserves statement for the year ended December 31, 2014, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, is contained within our Annual Information Form for the year ended December 31, 2014 ("**our AIF**") which is available on our website at www.enerplus.com and under our SEDAR profile at www.sedar.com. Additionally, our AIF forms part of our Form 40-F that is filed with the U.S. Securities and Exchange Commission and is available on EDGAR at www.sec.gov. Readers are also urged to review the Management's Discussion & Analysis and financial statements filed on SEDAR and as part of our Form 40-F on EDGAR concurrently with this news release for more complete disclosure on our operations.*

*Contingent Resources Estimates*

*This news release contains estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, oil and gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") as "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 ultimate recovery rates, 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. All of our contingent resources estimates are economic using established technologies and based on McDaniel's January 1, 2015 forecast prices. Enerplus expects to develop these contingent resources in the coming years however it is too early in their development for these resources to be classified as reserves at this time. There is no certainty that we will produce any portion of the volumes currently classified as "contingent resources". The "contingent resources" estimates contained herein are presented as the "best estimate" of the quantity that will actually be recovered, effective as of December 31, 2014. A "best estimate" of contingent resources means that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.*

*For additional information regarding the primary contingencies which currently prevent the classification of our disclosed "contingent resources" associated with our Marcellus shale gas properties, our Fort Berthold properties, our Wilrich natural gas properties and a portion of our Canadian crude oil properties as reserves and the positive and negative factors relevant to the "contingent resources" estimates, see our AIF, a copy of which is available under our SEDAR profile at www.sedar.com, and our Form 40-F, a copy of which is available under our EDGAR profile at www.sec.gov.*

*F&D and FD&A Costs*

*F&D costs presented in this news release are calculated (i) in the case of F&D costs for proved reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves in the year, and (ii) in the case of F&D costs for proved plus probable reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding and development costs related to its reserves additions for that year.*

*FD&A costs presented in this news release are calculated (i) in the case of FD&A costs for proved reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves including net acquisitions in the year, and (ii) in the case of FD&A costs for proved plus probable reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves including net acquisitions in* *the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding, development and acquisition costs related to its reserves additions for that year.*

*See "Non-GAAP Measures" below.*

***NOTICE TO U.S. READERS***

*The oil and natural gas reserves information contained in this news release has generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. Reserves categories such as "proved reserves" and "probable reserves" may be defined differently under Canadian requirements than the definitions contained in the United States Securities and Exchange Commission (the "**SEC**") rules. In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross (or, as noted above with respect to production information, "company interest") volumes, which are volumes prior to deduction of royalty and similar payments. The practice in the United States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. Canadian disclosure requirements require that forecasted commodity prices be used for reserves evaluations, while the SEC mandates the use of an average of first day of the month price for the 12 months prior to the end of the reporting period. Additionally, the SEC prohibits disclosure of oil and gas resources in SEC filings, whereas Canadian issuers may disclose oil and gas resources. Resources are different than, and should not be construed as reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, contingent resources, see "Contingent Resources Estimates" above.*

***FORWARD-LOOKING INFORMATION AND STATEMENTS***

*This news release contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "should", "believe", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this news release contains forward-looking information pertaining to the following: expected 2015 average production volumes and the anticipated production mix; the proportion and average production volumes associated with operator-led curtailments in the Marcellus; future development and drilling locations, plans and costs, and timing of related production; anticipated operating and cash G&A costs; future capital spending levels, its allocation among our assets and its impact on production; future royalty and production and U.S. cash taxes; future debt to trailing twelve month funds flow and adjusted payout ratios; the performance of and future results from Enerplus' assets and operations; the volumes and estimated value of Enerplus' oil and gas reserves and contingent resources volumes and future commodity price and foreign exchange rate assumptions related thereto; future acquisitions and dispositions, expected timing thereof and use of proceeds therefrom; and the life of Enerplus' reserves.*

*The forward-looking information contained in this news release reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that Enerplus will conduct its operations and achieve results of operations as anticipated; that Enerplus' development plans will achieve the expected results; current commodity price and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of Enerplus' reserves and resources volumes; the continued availability of adequate debt and/or equity financing, cash flow and other sources to fund Enerplus' capital and operating requirements, and dividend payments as needed; availability of third party services; and the extent of its liabilities. In addition, our 2015 guidance contained in this press release is based on the following assumptions: WTI price of US$55 per barrel, a NYMEX gas price of US$2.75 per Mcf, an AECO gas price of $2.50 per GJ and a US$/CDN exchange rate of 1.25. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.*

*The forward-looking information included in this news release is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes in commodity prices; changes in realized prices for Enerplus' products; changes in the demand for or supply of Enerplus' products; unanticipated operating results, results from Enerplus' capital spending activities or production declines; curtailment of Enerplus' production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans by Enerplus or by third party operators of Enerplus' properties; increased debt levels or debt service requirements; inaccurate estimation of Enerplus' oil and gas reserves and resources volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners; and certain other risks detailed from time to time in Enerplus'* *public disclosure documents (including, without limitation, those risks identified in our AIF and Form 40-F described above).*

*The purpose of certain financial outlook information included in this news release, including with respect to our 2015 guidance for debt to trailing twelve month funds flow ratio, is to communicate our current expectations as to our performance in 2015. Readers are cautioned that it may not be appropriate for other purposes. The forward-looking information contained in this news release speaks only as of the date of this news release, and none of Enerplus or its subsidiaries assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.*

***NON-GAAP MEASURES***

*In this news release, we use the terms "funds flow", "adjusted payout ratio", "capital efficiency", "recycle ratio" and "netback" as measures to analyze operating performance, leverage and liquidity. "Funds flow" is calculated as net cash generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Adjusted payout ratio" is calculated as cash dividends to shareholders, net of our stock dividends, plus capital spending (including office capital) divided by funds flow. "Capital efficiency" is calculated as the change in production from the fourth quarter of the previous year to the fourth quarter of the current year divided by total capital expenditures from the fourth quarter of the previous year up to and including the third quarter of the current year. "Netback" is calculated as oil and gas revenues after deducting royalties, operating costs and transportation expenses. A "recycle ratio" is calculated as finding and development costs divided by operating netback.*

*Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "funds flow", "adjusted payout ratio", "capital efficiency", "netback" and "recycle ratio" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures are not measures recognized by U.S. GAAP and do not have a standardized meaning prescribed by U.S.GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers. For reconciliation of these measures to the most directly comparable measure calculated in accordance with U.S. GAAP, and further information about these measures, see disclosure under "Non-GAAP Measures" in our 2014 MD&A.*

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation