CALGARY, ALBERTA--(Marketwired - Mar 3, 2016) - RMP Energy Inc. ("RMP" or the "Company") (TSX:RMP) is pleased to provide information on its crude oil, natural gas and NGLs reserves as of December 31, 2015, as evaluated by the Company's independent qualified reserves evaluators, InSite Petroleum Consultants Ltd. ("InSite"). The evaluation of RMP's reserves was prepared in accordance with the definitions, standards and procedures prescribed in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook. Unless stated otherwise, all reserves referred to in this news release are stated on a company gross basis (working interest before deduction of royalties and without including any royalty interests). Reserves and operational highlights include the following:

- Record annual production. The Company achieved an annual record level of average daily production of 12,026 boe/d (weighted 46% light oil and NGLs), surpassing its previous record output of 11,782 boe/d in the prior year, in spite of incurring capital expenditures which were 48% lower year-over-year and drilling 15 horizontal oil wells (15.0 net) versus 24 (24.0 net) horizontal wells in fiscal 2014. RMP's fourth quarter 2015 production was 11,257 boe/d (weighted 46% light crude oil and NGLs).

- Increased reserves quality mix. Proved developed producing ("PDP") reserves increased 17% to 15.1 million boe on finding and development costs ("F&D") of $14.65 per boe, resulting in an operating netback recycle ratio of 1.6 times. PDP reserves represent 60% of total proved ("TP") reserves and 39% of total proved plus probable ("2P") reserves, as compared to 50% and 31%, respectively, at the prior year-end of December 31, 2014.

- Efficient capital budget execution. The Company's 2015 drilling program consisted of 15 horizontal oil wells, of which 14 were development locations previously booked in RMP's year-end 2014 reserves report as either proved undeveloped or probable undeveloped locations. Execution of the Company's 2015 capital budget resulted in a finding, development and acquisition ("FD&A") cost of $24.63 per proved plus probable boe ($19.19 per proved boe), including changes in future development costs ("FDC") year-over-year, resulting in an operating netback recycle ratio of approximately one times (1.2 times on a proved basis) for fiscal 2015.

  RMP's three-year, 'full-cycle' average FD&A cost is $22.12 per proved plus probable boe ($23.70 per proved boe), including changes in FDC. The Company's second half 2015 and year-to-date 2016 average drilling and completion costs for its Waskahigan hybrid slick water and Ante Creek wells were $4.0 million and $2.8 million, respectively, reflecting oilfield service cost deflation and improved efficiencies.

  RMP's drilling and completion costs for its two most recently-drilled Waskahigan hybrid slick water and Ante Creek wells, drilled in January 2016, were $3.4 million and $2.6 million, respectively (based on field estimates).

  In the first quarter of this year, RMP successfully drilled and completed two (2.0 net) Ante Creek Montney horizontal oil wells and one (1.0 net) Waskahigan Montney horizontal oil well. In addition, the Company also drilled an exploration well at Gold Creek in West Central Alberta. Drill and completion costs for the well were approximately $4.4 million (based on field estimates). RMP is very encouraged with the results from this well, with further details expected to be provided in the second quarter of this year, subsequent to forthcoming Alberta Crown land auctions. As an update to RMP's Ante Creek waterflood project, the Company recently received regulatory approval for its injection pilot. RMP expects to convert a producing horizontal oil well into a pilot waterflood injector in early July 2016 with water injection commencing soon thereafter.

- Reduced location bookings and decreased future development capital. The total proved plus probable reserves volume of 38.5 million boe (25.3 million boe proved) at December 31, 2015, reflects positive technical revisions of 1.3 million boe (1.0 million boe proved) offset by a reduction in reserves associated with previously-booked, future drilling locations. This reduction is attributable to significantly lower forecasted commodity prices which resulted in the Company paring-back its FDC plans along with downward revisions due to economic factors. Total proved plus probable and total proved reserves of 1.5 million boe and 0.3 million boe, respectively, were removed from the year-end 2015 reserves booking due to economic factors.

  Total undiscounted FDC at year-end 2015 decreased by $73.6 million to $286.1 million on a 2P basis, which includes 76 undeveloped 2P drilling locations, as compared to $359.7 million of 2P FDC and 95 undeveloped 2P drilling locations at year-end 2014. RMP's Gold Creek area in West Central Alberta did not have any reserves assigned as at December 31, 2015, as the Company's initial exploration drilling and completion operations were conducted in the first quarter of 2016 subsequent to year-end.

- Improved Waskahigan well bookings. Waskahigan Montney per-well booking (undeveloped location) at year-end 2015 increased to 210 thousand boe of proved plus probable reserves per well location (on average), reflecting the strong results derived from the Company's application of the hybrid slick water completion technique.

- Long-life reserves base. RMP's reserves base reflects a reserve life index for total proved plus probable reserves of 9.4 years (based on annualized fourth quarter 2015 production). Year-end 2015 reserve life index for total proved reserves was 6.1 years (based on annualized fourth quarter 2015 production).

Corporate Reserves Information

December 31, 2015 Reserves Summary [(1)] (company gross reserves)

	Natural Gas [(2)]	Oil [(3)]	NGLs	Oil Equivalent
(Columns may not add due to rounding)	(Bcf)	(Mbbls)	(Mbbls)	(Mboe) (6:1)
Proved developed producing	56.766	5,084.0	516.3	15,061.3
Proved developed non-producing	1.418	66.6	17.5	320.4

Proved undeveloped	38.604	3,051.8	401.2	9,887.0
Total Proved	96.788	8,202.4	935.0	25,268.7
Probable	45.962	5,325.5	281.0	13,266.9
Total Proved plus Probable	142.750	13,527.9	1,216.0	38,535.6

(1) Estimated using InSite's forecast prices and costs as of December 31, 2015.
(2) Includes conventional natural gas and shale gas.
(3) Substantially all tight oil.

December 31, 2015 Net Present Value Summary [(1)] (company gross reserves)
(Columns may not add due to rounding)

Discount factor:	0%	5%	10%	15%	20%
Proved developed producing	$ 294,970	$ 242,508	$ 207,025	$ 181,606	$ 162,573
Proved developed non-producing	4,333	3,324	2,617	2,107	1,729
Proved undeveloped	117,205	69,463	40,910	22,738	10,620
Total Proved	416,508	315,295	250,552	206,452	174,921
Probable	254,422	162,270	110,154	78,045	57,010
Total Proved plus Probable	$ 670,930	$ 477,565	$ 360,706	$ 284,497	$ 231,931

(1) Net present values reported are before taxes based on InSite's forecast prices and costs as of December 31, 2015. No provision for bank debt interest and general and administrative expenses have been made within the net present values.

A summary of InSite's escalated price forecast assumptions as of December 31, 2015 are as follows:

YEAR	WTI @ Cushing	Edm Par Price 40 API	AECO-C	Propane	Butane	Condensate	Exchange Rate	Inflation Rate
	$US/bbl	$C/bbl	C$/GJ	$C/bbl	$C/bbl	$C/bbl	$C/$US	%
2016	45.00	55.64	2.86	11.13	41.73	61.21	0.7300	2.0%
2017	55.00	68.33	3.45	20.50	51.25	75.17	0.7500	2.0%
2018	65.00	78.23	3.94	31.29	58.68	86.06	0.7800	2.0%
2019	70.00	81.22	4.08	40.61	60.91	89.34	0.8100	2.0%
2020	75.00	85.06	4.27	42.53	63.79	93.56	0.8300	2.0%
2021	80.00	88.71	4.44	44.35	66.53	97.58	0.8500	2.0%
2022	82.50	91.54	4.74	45.77	68.65	100.69	0.8500	2.0%
2023	85.00	94.37	4.83	47.18	70.78	103.81	0.8500	2.0%
2024	86.70	96.26	4.93	48.13	72.19	105.88	0.8500	2.0%
2025	88.43	98.18	5.02	49.09	73.64	108.00	0.8500	2.0%
2026	90.20	100.15	5.13	50.07	75.11	110.16	0.8500	2.0%
2027	92.01	102.15	5.23	51.07	76.61	112.36	0.8500	2.0%
2028	93.85	104.19	5.34	52.10	78.14	114.61	0.8500	2.0%
2029	95.72	106.28	5.44	53.14	79.71	116.90	0.8500	2.0%
2030	97.64	108.40	5.55	54.20	81.30	119.24	0.8500	2.0%
2031	99.59	110.57	5.66	55.28	82.93	121.63	0.8500	2.0%
2032	101.58	112.78	5.77	56.39	84.58	124.06	0.8500	2.0%
2033	103.61	115.04	5.88	57.52	86.28	126.54	0.8500	2.0%

Net Asset Value

The Company's net asset value details, as of December 31, 2015, are as follows:

(columns may not add due to rounding)	NPV 5%		NPV 10%	
(per share figures based on fully-diluted shares)	($000s)	$/share	($000s)	$/share
Proved plus probable reserves NPV [(1,2)]	$ 477,565	$ 3.41	$ 360,706	$ 2.58
Undeveloped acreage [(3)]	153,418	1.10	153,418	1.10
Net debt [(4)]	(117,956)	(0.84)	(117,956)	(0.84)
Proceeds from stock options and warrants [(5)]	52,809	0.38	52,809	0.38
Net Asset Value (fully-diluted)	$ 565,836	$ 4.04	$ 448,977	$ 3.21

(1) Evaluated by InSite as at December 31, 2015. Net present values do not represent fair market value of the reserves.

(2) Net present values ("NPV") reported are before taxes based on InSite's forecast prices and costs as of December 31, 2015. No provision for bank debt interest and general and administrative expenses have been made within the net present values.

(3) Independently-evaluated with average acreage value of $734 per acre.

(4) Net debt as at December 31, 2015, including working capital deficit (unaudited).

(5) Fully-diluted shares at December 31, 2015 total: including common shares of 126.48 million, 11.56 million stock options and 2.02 million stock warrants.

Capital Expenditures Efficiency and Future Development Costs ("FDC")

	Fiscal 2015	
(amounts in $000s except reserve units and unit costs)	Proved	Proved + Probable
Exploration and development expenditures	$ 97,003	$ 97,003
Acquisitions / (dispositions)	0	0
Total capital expenditures [1]	$ 97,003	$ 97,003
Future development cost - ending period [2]	158,290	286,124
Less: Future development cost - beginning period [2]	(177,625)	(359,675)
All-in FD&A total, including change in FDC [3]	$ 77,668	$ 23,452
Total reserve additions (Mboe)	4,047.5	952.2
FD&A Costs ($/boe)	$ 19.19	$ 24.63

(1) Fiscal 2015 capital expenditures are unaudited and exclude non-cash capitalized share-based compensation expense of $2.2 million.

(2) Future development capital expenditures required to convert proved non-producing and probable reserves to proved producing reserves.

(3) 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 will not reflect total finding and development costs related to reserves additions for that year.

The following outlines finding, development and acquisition ("FD&A") costs for the prior year of 2014, in addition to the average over the three-year period of 2013 to 2015, inclusive.

	Fiscal 2014		Three Year Average	
(amounts in $000s except reserve units and unit costs)	Proved	Proved + Probable	Proved	Proved + Pro
Exploration and development expenditures [1]	$ 187,105	$ 187,105	$ 416,390	$ 416,390
Acquisitions / (dispositions)	(7,359)	(7,359)	47,770	47,770
Total capital expenditures	$ 179,746	$ 179,746	$ 464,160	$ 464,160
Future development cost - ending period [2]	177,625	359,675	158,290	286,124
Less: Future development cost - beginning period [2]	(141,488)	(264,269)	(110,293)	(205,081)
All-in FD&A total, including change in FDC [3]	$ 215,883	$ 275,152	$ 512,157	$ 545,203
Total reserve additions (Mboe)	10,152.6	12,124.4	21,609.0	24,644.4
FD&A Costs ($/boe)	$ 21.26	$ 22.69	$ 23.70	$ 22.12

(1) Excludes non-cash capitalized share-based compensation expense.

(2) Future development capital expenditures required to convert proved non-producing reserves and probable reserves to proved producing.

(3) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that ye estimated future development costs generally will not reflect total finding and development costs related to reserves additions for th year.

The following table outlines the future development costs ("FDC") required to bring proved and probable undeveloped reserves on-production. The FDC has been deducted in the estimation of future net revenue attributable to total proved reserves and total proved plus probable reserves (using forecast prices and costs).

Future Development Capital Costs[1]		
(amounts in $000s)	Total Proved	Total Proved + Probable
2016	$ 35,450	$ 44,650
2017	31,824	54,009
2018	44,829	69,226
2019	29,024	77,946
Total undiscounted FDC	$ 158,290	$ 286,124
Total discounted FDC at 10% per year	$ 128,031	$ 224,664

(1) FDC as per InSite's independent reserves evaluation as of December 31, 2015 and based on InSite's forecast pricing as at December 31, 2015.

The Company expects to fund its future development cost requirements from internally-generated cash flow from operations and, as appropriate, from its existing committed bank credit facility, equity or debt financing. It is anticipated that the costs of funding the future development costs will not impact development of RMP's properties or the Company's reserves or future net revenue.

Abbreviations

bbl or bbls	barrel or barrels	Mcf/d	thousand cubic feet per day
Mbbl	thousand barrels	MMcf/d	million cubic feet per day
bbls/d	barrels per day	MMcf	Million cubic feet
boe	barrels of oil equivalent	Bcf	billion cubic feet
Mboe	thousand barrels of oil equivalent	psi	pounds per square inch
boe/d	barrels of oil equivalent per day	kPa	kilopascals
NGLs	natural gas liquids	GJ/d	Gigajoules per day
		WTI	West Texas Intermediate

Reader Advisories

Any references in this news release to initial and/or final raw test or production rates and/or "flush" production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter. These test results are not necessarily indicative of long-term performance or ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company.

The information in this news release contains certain forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "approximate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "would" and similar expressions. More particularly and without limitation, this news release contains forward looking information relating to: forecasted commodity prices; foreign exchange rates and inflation rates; future development capital costs and RMP's expectations regarding the funding of such future development capital costs and the impact of funding such costs on the development of RMP's properties; RMP's reserves and future net revenue; the Company's field estimated drilling and completions costs for its Waskahigan, Ante Creek and Gold Creek first quarter 2016-drilled wells; and the timing of its waterflood injector pilot start date. These statements involve substantial known and unknown risks and uncertainties, certain of which are beyond the Company's control, including: the impact of general economic conditions; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; fluctuations in commodity prices and foreign exchange and interest rates; stock market volatility and market valuations; volatility in market prices for oil and natural gas; liabilities inherent in oil and natural gas operations; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; and obtaining required approvals of regulatory authorities. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, such forward-looking statements and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur or, if any of them do, what benefits that the Company will derive from them. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement. Except as required by law, the Company undertakes no obligation to publicly update or revise any forward-looking statements.

This press release contains metrics commonly used in the oil and natural gas industry, such as "operating netback recycle ratio", "finding and development costs", "finding, development and acquisition costs", "operating netbacks", and "reserve life index". These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons.

Both F&D and FD&A costs take into account reserves revisions during the year on a per boe basis. The aggregate of the costs incurred in the financial year and changes during that year in estimated FDC may not reflect total finding and development costs related to reserves additions for that year. F&D costs both including and excluding acquisitions and dispositions have been presented in this news release because acquisitions and dispositions can have a significant impact on our ongoing reserves replacement costs and excluding these amounts could result in an inaccurate portrayal of our cost structure. Recycle ratio is measured by dividing the operating netback by appropriate F&D or FD&A cost per boe for the year. As described below, field operating netback or operating netback is calculated using realized wellhead revenues less royalties, operating expenses and transportation costs calculated on a per boe equivalent basis. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare RMP's performance over time.

Statements relating to "reserves" are forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

This news release may disclose drilling locations in four categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; iii) unbooked locations; and, iv) an aggregate total of (i), (ii) and (iii). Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by InSite as of December 31, 2015 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells is ultimately dependent upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

In this news release RMP has adopted a standard for converting thousands of cubic feet ("mcf") of natural gas to barrels of oil equivalent ("boe") of 6 mcf:1 boe. Use of boes may be misleading, particularly if used in isolation. The boe rate is based on an energy equivalent 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 than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value.

In this news release, the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and net revenue for all properties due to the effects of aggregation. Estimates of reserves have been made assuming that development of each property, in respect of which estimates have been made, will occur without regard to the availability of funding required for that development.

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 will not reflect total finding and development costs related to reserves additions for that year.

Net debt refers to outstanding bank debt less deferred charge plus working capital deficiency (or minus working capital surplus), excluding unrealized amounts pertaining to risk management contracts. Net debt is not a recognized measure under IFRS and does not have a standardized meaning.

Field operating netback or operating netback refers to realized wellhead revenue less royalties, operating expenses and transportation costs per barrel of oil equivalent. Field operating netback or operating netback is not a recognized measure under IFRS and does not have a standardized meaning.

As of the date of this news release, the preparation and audit of the Company's annual 2015 financial statements is not yet complete, and accordingly all financial amounts referred to in this news release are unaudited and represent RMP Management's estimates. Readers are advised that these financial estimates may be subject to change.

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