NEWS RELEASE

March 21, 2017

RMP Energy Provides Operations Update Highlighting Elmworth Delineation Success, Updates Market Guidance and Reports Year-End Reserves and Fiscal 2016 Financial Results

Calgary, Alberta – RMP Energy Inc. ("**RMP**" or the "**Company**") (TSX: RMP) is pleased to provide an update on its first quarter 2017 field operations and to announce its year-end independent reserves evaluation in addition to its financial results for the fourth quarter and fiscal year ended December 31, 2016.

OPERATIONS UPDATE

Waskahigan Montney, West Central Alberta

At Waskahigan in the first quarter of 2017, RMP successfully drilled and completed a 100% working interest Montney 'step-out' horizontal oil well (13-30-63-23W5), located on the western flank of the Company's acreage position. The flow test result from the recently completed hybrid slick-water operation was strong. Production flow testing was for a 200-hour period (approximately 8 days). Over the last 72 hours of the production test, the 13-30 well tested at an average rate of approximately 760 bbls/d of 40-degree API crude oil and 1.5 MMcf/d of associated sweet solution gas for an oil-equivalent rate of approximately 1,000 boe/d. RMP expects to have the 13-30 well tied into company-owned infrastructure and placed on-production later this week. The Company expects to book and assign proved developed reserves to this well and recognize proved undeveloped and probable undeveloped reserves for future locations offsetting the 13-30 well, none of which were booked or assigned in the year-end 2016 independent reserves report.

At Waskahigan, the Company's hybrid slick-water completions have resulted in improved well productivity, and corresponding improvement in well project economics. In addition to the 13-30 well, the Company is budgeted to drill three more (3.0 net) Montney horizontal wells at Waskahigan this year. In the first quarter of 2017, the Company increased its acreage position by five (5.0 net) sections (3,200 gross acres), and its land base at Waskahigan now consists of 78.5 (77.6 net) sections (50,240 gross acres) of operated acreage. RMP estimates its future Waskahigan drilling inventory to consist of approximately 200 potential unbooked and undeveloped drilling locations (of which only 47 locations have assigned proved and/or probable reserves in the Company's year-end 2016 independent reserves report).

Elmworth (Gold Creek) Montney, West Central Alberta

At Elmworth (formerly known as Gold Creek) during the first quarter of 2017, the Company commenced the strategic delineation of the areal extent of the hydrocarbon-bearing Middle Montney reservoir oil window.

As follow-up to last year's successful exploration well (3-22-68-3W6), RMP drilled two more wells at Elmworth. A 100% working interest, exploration well (8-25-68-4W6) was drilled and completed with hybrid slick-water, approximately one township to the west of the Company's 3-22 well. The 8-25 well production test results were successful, with flow-back results indicating the discovery of a new oil pool and demonstrating the Middle Montney reservoir to be oil bearing and gas charged. The 8-25 well was drilled to a total measured depth of 4,523 metres, with 2,208 metres of horizontal section. The production flow test was for a 173-hour period (approximately seven days). Over the last 72 hours of the production test, the 8-25 well tested at an average rate of approximately 220 bbls/d of 45-degree API crude oil and approximately 1.0 MMcf/d of natural gas, resulting in an oil-equivalent rate of approximately 390 boe/d. Please refer to *Reader Advisories* at the end of this news release.

The Company also successfully drilled and completed its third, 100% working interest well in the Middle Montney oil window at Elmworth (4-18-68-2W6). Drilled from the same surface lease pad as the 3-22 well, the 4-18 well is a 'step-out' to the southeast. The 4-18 delineation well, drilled to a total measured depth of 4,935 metres with 2,518 metres of horizontal length, was fracture stimulated with hybrid slick-water. The production flow test was for a 165-hour period (approximately seven days). Over the last 72 hours of the production test, the 4-18 well tested at an average rate of approximately 200 bbls/d of 45-degree API crude oil and 2.3 MMcf/d of natural gas, resulting in an oil-equivalent rate of approximately 600 boe/d. Please refer to *Reader Advisories* at the end of this news release.

In addition to delineation drilling of its Montney acreage, RMP also secured strategic infrastructure in the Elmworth area for hydrocarbon egress. As previously disclosed, the Company has entered into gathering, processing and transportation agreements with a regional mid-stream service provider to handle RMP's Elmworth crude oil and natural gas production. The agreements encompass an area dedication and are not subject to take-or-pay commitments. The mid-stream company is in the process of installing a gathering system in order to connect their existing infrastructure to RMP's oil battery facility located at 2-23-68-3W6, which is presently undergoing construction. The Company's Elmworth natural gas will be processed at the mid-stream company's Patterson Creek Gas Plant, which will undergo expansion later this year with an expected capacity level of 150 MMcf/d. This gas plant will provide pipeline connections for sales gas into both the TransCanada and Alliance gas systems. Oil volumes will be transported downstream of the gas plant with connectivity to a Pembina crude oil sales terminal. Barring any unforeseen delays, the gathering pipeline and oil battery facility is scheduled to be commissioned and operational in May 2017.

At Elmworth, RMP has now successfully drilled and completed three (3.0 net) Middle Montney horizontal wells. The Company has a large undeveloped land base consisting of 79 (78.5 net) sections (50,560 gross acres) of operated acreage. RMP estimates that it has potentially in excess of 300 unbooked and undeveloped drilling locations at Elmworth (of which only six locations have assigned proved and/or probable reserves in the Company's year-end 2016 independent reserves report). With drilling and completion results to-date, and continued exploration and development activity, Elmworth has the potential to be a long-term production and reserves growth asset for RMP.

Updated Market Guidance and 2017 Capital Budget

For 2017, the Company is budgeting to incur $49 million in exploration and development capital expenditures. In addition to key infrastructure investment at Elmworth, the 2017 capital plan includes the drilling of three (3.0 net) Middle Montney horizontal wells at Elmworth, of which two have been drilled already, and four (4.0 net) Montney horizontal wells at Waskahigan, of which one has been drilled to-date. The focus of the capital budget for the first half of this year is to maintain corporate base production levels through a pared-back level of drilling operations at Waskahigan while de-risking and delineating its large Elmworth resource potential with the strategic objective of establishing additional inventory and scale for the Company. Infrastructure commissioning at Elmworth is expected to bolster RMP's base production levels thereafter, providing production momentum for the second half of this year and into fiscal 2018. For the second half of this year, the Company is forecasting production to average approximately 4,500 boe/d (weighted 42% light crude oil and NGLs).

YEAR-END 2016 RESERVES

The following provides information on RMP's crude oil, natural gas and NGLs reserves as of December 31, 2016, 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). The reported reserves at December 31, 2016 exclude reserves that were disposed of in connection with the sale of the Company's Ante Creek asset (the "**Ante Creek Disposition**"), which closed on November 15, 2016. The Company's year-end 2016 reserves highlights include the following:

- Total proved plus probable reserves at December 31, 2016 were 27.7 million boe. The Ante Creek Disposition (9.8 million boe), fiscal 2016 production (2.9 million boe) and a minor Pine Creek divestiture (1.2 million boe), partially offset by positive additions (net of revisions) of 3.1 million boe, resulted in lower reserves reported at year-end 2016 as compared to 38.5 million boe of proved plus probable reserves at December 31, 2015. Adjusting for production and the reserves disposed with the Ante Creek Disposition, total proved plus probable reserves increased year-over-year.

- Total proved reserves at December 31, 2016 were 16.4 million boe. The Ante Creek Disposition (6.6 million boe), fiscal 2016 production (2.9 million boe) and a minor Pine Creek divestiture (0.7 million boe), partially offset by positive additions (net of revisions) of 1.2 million boe, resulted in lower reserves reported at year-end 2016 as compared to 25.3 million boe of proved reserves at December 31, 2015. Adjusting for production and the reserves disposed with the Ante Creek Disposition, total proved reserves increased year-over-year.

- Total proved developed producing reserves at December 31, 2016 were 6.8 million boe, as compared to 15.1 million boe at December 31, 2015. The Ante Creek Disposition (6.2 million boe), a minor Pine Creek divestiture (0.1 million boe) and fiscal 2016 production (2.9 million boe) were partially offset by positive additions (net revisions) of approximately 1.0 million boe. Adjusting for production and the reserves disposed with the Ante Creek Disposition, total proved developed producing reserves increased year-over-year.

- RMP's net asset value at December 31, 2016 is estimated at $2.19 per share (discounted at 10%). Refer to the detailed calculation under the *Net Asset Value* heading hereafter.

- Booked and assigned initial reserves at Elmworth (formerly Gold Creek) at December 31, 2016, of 4.7 million boe proved plus probable and 1.5 million boe proved.

- Achieved finding and development ("**F&D**") costs of $18.45 per proved plus probable boe, including changes in future development capital ("**FDC**"). Refer to the detailed calculation under the *Capital Expenditures Efficiency* heading hereafter.

Corporate Reserves Information

December 31, 2016 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	28.438	1,590.7	474.3	6,804.6
Proved developed non-producing	3.298	202.1	47.6	799.3
Proved undeveloped	34.684	2,496.6	480.8	8,758.0
Total Proved	66.419	4,289.4	1,002.7	16,361.9
Probable	41.285	4,037.5	421.1	11,339.5
Total Proved plus Probable	**107.705**	**8,326.9**	**1,423.8**	**27,701.4**

(1) Estimated using InSite's forecast prices and costs as of December 31, 2016.
(2) Includes conventional natural gas and shale gas.
(3) Substantially all tight oil.

December 31, 2016 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	$ 110,932	$ 90,689	$ 77,226	$ 67,625	$ 60,452
Total Proved	215,371	151,644	111,437	84,414	65,423
Probable	205,358	134,869	93,247	66,671	48,749
Total Proved plus Probable	**$ 420,729**	**$ 286,513**	**$ 204,684**	**$ 151,085**	**$ 114,172**

(1) Net present values reported are before taxes based on InSite's forecast prices and costs as of December 31, 2016. 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, 2016 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	%
2017	55.00	68.33	3.29	23.92	47.83	75.17	0.7500	2.0%
2018	60.00	72.32	3.24	25.31	52.07	79.55	0.7750	2.0%
2019	65.00	76.05	3.40	26.62	54.75	83.65	0.8000	2.0%
2020	70.00	79.54	3.72	27.84	57.27	87.50	0.8250	2.0%
2021	75.00	82.82	3.80	28.99	59.63	91.11	0.8500	2.0%
2022	80.00	88.60	3.95	31.01	63.79	97.46	0.8500	2.0%
2023	81.60	90.37	4.05	31.63	65.07	99.41	0.8500	2.0%
2024	83.23	92.18	4.20	32.26	66.37	101.39	0.8500	2.0%
2025	84.90	94.02	4.28	32.91	67.69	103.42	0.8500	2.0%
2026	86.59	95.90	4.37	33.57	69.05	105.49	0.8500	2.0%
2027	88.33	97.82	4.46	34.24	70.43	107.60	0.8500	2.0%
2028	90.09	99.77	4.54	34.92	71.84	109.75	0.8500	2.0%
2029	91.89	101.77	4.64	35.62	73.27	111.95	0.8500	2.0%
2030	93.73	103.81	4.73	36.33	74.74	114.19	0.8500	2.0%
2031	95.61	105.88	4.82	37.06	76.23	116.47	0.8500	2.0%
2032	97.52	108.00	4.92	37.80	77.76	118.80	0.8500	2.0%
2033	99.47	110.16	5.02	38.56	79.31	121.18	0.8500	2.0%
2034	101.46	112.36	5.12	39.33	80.90	123.60	0.8500	2.0%

Net Asset Value

The Company's net asset value details, as of December 31, 2016, are as follows:

(columns may not add due to rounding)	NPV 10%		NPV 15%	
(per share figures based on basic outstanding shares)	($000s)	$/share	($000s)	$/share
Proved plus probable reserves NPV (1,2)	$ 204,684	$ 1.36	$ 151,085	$ 1.00
Undeveloped acreage (3)	126,634	0.84	126,634	0.84
Net debt (4)	(885)	(0.01)	(885)	(0.01)
Net Asset Value	**$ 330,433**	**$ 2.19**	**$ 276,835**	**$ 1.83**

(1) Evaluated by InSite as at December 31, 2016. 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, 2016. 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 $890 per net acre. Reflects an independent third-party estimate of the fair market value of RMP's undeveloped acreage based on past Crown land sale activity, adjusted for tenure and other considerations.

(4) Working capital deficit net of deferred charge asset at December 31, 2016 (unaudited).

(5) Shares outstanding at December 31, 2016 total 150.97 million.

Capital Expenditures Efficiency

The following table provides an overview of RMP's finding and development ("**F&D**") costs for fiscal 2016. Generally the calculation of both F&D costs and finding, development and acquisition ("**FD&A**") costs includes incorporating changes in future development capital ("**FDC**") required to bring the proved undeveloped and probable undeveloped reserves on-production. Changes in forecasted FDC occur annually due to capital development activities, acquisition and/or disposition activities, undeveloped reserve revisions and capital cost estimates that reflect the independent reserves evaluators best estimate of what it will cost to bring the proved undeveloped and probable undeveloped reserves on-production. For fiscal 2016, the Company cannot calculate its FD&A costs, including changes in FDC, as the impact of the Ante Creek Disposition and the change in FDC more than offsets 2016 exploration and development expenditures. The Company, however, has calculated its F&D costs for its exploration and development capital expenditures, exclusive of its net acquisition/disposition activities.

	Fiscal 2016	
(amounts in $000s except reserve units and unit costs)	Proved	Proved + Probable
Exploration and development expenditures (1,2,3)	30,229	30,229
Acquisitions / (dispositions), net (1,2)	(89,426)	(89,426)
Total capital expenditures	**(59,197)**	**(59,197)**
Change in future development capital ("FDC"): (1)		
Exploration and development	12,588	23,432
Acquisitions / (dispositions), net	(19,352)	(30,595)
Aggregate F&D, including change in FDC (4)	**42,817**	**53,661**
Aggregate FD&A, including change in FDC (4)	(65,961)	(66,360)
Reserve additions (Mboe):		
Exploration and development	1,091	2,909
Acquisitions / (dispositions), net	(7,108)	(10,854)
F&D Costs ($/boe) (4)	**$ 39.25**	**$ 18.45**
FD&A Costs ($/boe) (4,5)	N/A	N/A

(1) 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 F&D costs related to reserves additions for that year.

(2) Capital incurred during 2016 at Ante Creek before the disposition ($10.5 million) has been included in "Acquisitions / (dispositions), net".

(3) Fiscal 2016 capital expenditures are unaudited and exclude non-cash capitalized share-based compensation expense of $1.5 million.

(4) Calculation includes changes in FDC.

(5) Due to the impact on reserves and FDC related to the Ante Creek Disposition, FD&A costs are deemed non-applicable ("N/A").

The following outlines F&D costs for the prior year of 2015, in addition to the average over the three-year period of 2014 to 2016, inclusive.

	Fiscal 2015		Three Year Average	
(amounts in $000s except reserve units and unit costs)	Proved	Proved + Probable	Proved	Proved + Probable
Total exploration and development expenditures [1,4]	97,003	97,003	314,337	314,337
Future development capital - ending period [2]	158,290	286,124	151,526	278,961
Less: Future development capital - beginning period [2]	(177,625)	(359,675)	(141,488)	(264,269)
Aggregate F&D, including change in FDC [4]	77,668	23,452	324,374	329,029
Total reserve additions (Mboe)	4,047.5	952.2	15,291.4	15,985.9
F&D Costs ($/boe)[3]	$ 19.19	$ 24.63	$ 21.21	$ 20.58

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

(2) FDC expenditures required to convert proved non-producing reserves and probable reserves to proved producing.

(3) Calculation includes changes in FDC.

(4) 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 F&D costs related to reserves additions for that year.

Future Development Capital

The following table outlines the FDC required to bring proved undeveloped 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 [1]		
(amounts in $000s)	Total Proved	Total Proved + Probable
2017	$ 46,640	$ 63,490
2018	33,303	69,156
2019	39,106	64,180
2020	27,382	68,769
2021	5,094	13,366
Total undiscounted FDC	**$ 151,525**	**$ 278,961**
Total discounted FDC at 10% per year	$ 126,365	$ 226,418

(1) FDC as per InSite's independent reserves evaluation as of December 31, 2016 and based on InSite's forecast pricing as at December 31, 2016.

The Company expects to fund its FDC 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 FDC will not impact development of RMP's properties or the Company's reserves or future net revenue.

FINANCIAL RESULTS

For the year ended December 31, 2016, RMP reported funds from operations of $29.6 million ($0.20 per fully-diluted share) on revenue of $77.3 million and average daily production of 7,895 barrels of oil equivalent (42% light oil and NGLs weighted). Detailed results are as follows:

Financial Results	**Three Months Ended**			**Twelve Months Ended**		
(thousands except share and per boe data) (6:1 oil equivalent conversion)	**Dec. 31, 2016**	**Dec. 31, 2015**	**% change**	**Year 2016**	**Year 2015**	**% change**
P&NG revenue (1)	**13,371**	34,178	(61)	**77,322**	161,633	(52)
Funds from operations (2)	**3,373**	18,725	(82)	**29,584**	92,452	(68)
Per share - basic / diluted	**0.02**	0.15	(87)	**0.20**	0.75	(73)
Net loss	**(65,508)**	(32,380)	102	**(86,019)**	(84,795)	1
Per share - basic / diluted	**(0.43)**	(0.26)	65	**(0.59)**	(0.69)	(14)
Total capital expenditures	**(103,076)**	12,008	-	**(59,197)**	97,003	-
Net debt (3) - period end	**885**	117,956	(99)	**885**	117,956	(99)
Weighted average basic shares	**150,970,068**	124,790,535	21	**145,415,191**	123,220,485	18
Weighted average diluted shares	**150,970,068**	124,790,535	21	**145,415,191**	123,220,485	18
Issued and outstanding shares (4)	**150,970,068**	126,475,068	19	**150,970,068**	126,475,068	19
Operating Results						
Average daily production:						
Natural gas (Mcf/d)	**17,110**	36,352	(53)	**27,599**	38,606	(29)
Crude oil (bbls/d)	**1,500**	4,952	(70)	**2,983**	5,318	(44)
NGLs (bbls/d)	**301**	246	22	**312**	274	14
Oil equivalent (boe/d)	**4,652**	11,257	(59)	**7,895**	12,026	(34)
Average sales price (1):						
Natural gas ($/Mcf)	**2.79**	3.26	(14)	**2.22**	3.32	(33)
Crude oil ($/bbl)	**58.75**	50.13	17	**47.80**	57.86	(17)
NGLs ($/bbl)	**31.60**	19.83	59	**23.86**	25.06	(5)
Oil equivalent ($/boe)	**31.24**	33.00	(5)	**26.76**	36.82	(27)
Operating expenses ($/boe)	**9.67**	4.61	110	**5.92**	4.90	21
Operating netback (5) ($/boe)	**13.88**	20.95	(34)	**13.71**	23.65	(42)
Wells drilled: gross (net)	**-**	2 (2.0)	-	**8 (8.0)**	15 (15.0)	(47)

Table Notes:

(1) Petroleum and natural gas ("**P&NG**") revenue and pricing includes realized gains or losses from risk management commodity contract settlements.
(2) Funds from operations does not have any standardized meaning prescribed by International Financial Reporting Standards ("**IFRS**"). Please refer to the Reader Advisories at the end of the news release.
(3) Net debt is not a recognized measure under IFRS. Please refer to the Reader Advisories at the end of the news release.
(4) As of March 20, 2017, 151.0 million common shares were outstanding.
(5) Operating netback is not a recognized measure under IFRS. Please refer to the Reader Advisories at the end of the news release.

Fourth Quarter 2016 Highlights

- In connection with the Company's strategic initiatives review undertaken last year, RMP completed the transformational disposition of its crude oil and natural gas interests in the Ante Creek area of West Central Alberta for net cash proceeds of $109.2 million, after normal and customary closing adjustments (the "**Ante Creek Disposition**"). The assets sold in the Ante Creek Disposition, which closed mid-fourth quarter on November 15, 2016, included reserves, land acreage, infrastructure facility and pipeline interests. Net disposition proceeds were used to eliminate the Company's outstanding bank indebtedness. The Ante Creek Disposition resulted in the recognition of a gain on disposition of $35.5 million.

- Fourth quarter 2016 production averaged 4,652 boe/d (weighted 39% light oil and NGLs), lower from the preceding third quarter production due to the intra-quarter Ante Creek Disposition on November 15, 2016 and the Pembina and Alliance sales pipeline service outages in early-October 2016 (as previously disclosed). RMP's fiscal 2016 average daily production was 7,895 boe/d, comprised of crude oil and NGLs production of 3,295 bbls/d and natural gas output of 27.6 MMcf/d

- Fourth quarter petroleum and natural gas revenue amounted to $13.4 million (including a realized hedging loss of $1.1 million). Approximately 67% of the Company's revenue was derived from crude oil and NGLs sales. Petroleum and natural gas revenue for fiscal 2016 amounted to approximately $77.3 million (including a realized hedging loss of $1.2 million).

- Fourth quarter petroleum and natural gas royalties amounted to $1.7 million (12% of petroleum and natural gas sales excluding realized hedging results), as compared to $3.4 million (15% of petroleum and natural gas sales) in the third quarter of 2016.

- Fourth quarter field operating costs on an oil-equivalent per unit basis were $9.67/boe, as compared to the preceding third quarter 2016 per-unit expense of $5.58/boe. In the fourth quarter, battery facility 'turnaround' maintenance activity conducted during the aforementioned sales pipelines service outages affected per-unit costs by approximately $1/boe. Additionally, the Ante Creek Disposition resulted in the Company's reported per-unit operating costs to increase, since the Ante Creek field had a lower per-unit operating cost profile than RMP's other producing assets as a whole. RMP continues to be highly-focused on delivering meaningful operating cost reductions and efficiency gains across its field operations.

- Fourth quarter transportation costs were $3.64/boe on an oil-equivalent basis, which reflects oil sales pipeline tariffs, gas sales pipeline firm service tolls, and pipeline fuel surcharges. This compares to the $3.51/boe of reported per-unit transportation cost for the preceding third quarter of 2016.

- Fourth quarter general and administrative ("**G&A**") expenses amounted to $2.2 million, as compared to $1.6 million in the preceding third quarter of 2016. As a result of year-end G&A activities associated with the independent reserves report and the fiscal financial statement audit, fourth quarter 2016 gross G&A costs were $835 thousand higher than the preceding third quarter. Personnel retention costs in connection with the corporate strategic review process undertaken in 2016 also contributed to the quarter-over-quarter increase. RMP continues to maintain an efficient organizational structure and presently employs 19 head office personnel and engages the services of two consultants on a part-time basis. For 2017 the Company's personnel have taken a 10% salary decrease, in addition to the 10% compensation reduction put in-place last year.

- In fiscal 2016, the Company incurred approximately $40 million on its 2016 exploration and development program. RMP undertook a light oil-focused exploration and development capital program in 2016, albeit to a lesser scale due to a pared-back capital expenditures budget reduced in response to lower commodity prices. In 2016, a total of eight (8.0 net) Montney horizontal crude oil wells were drilled, as compared to a drilling program in fiscal 2015 of 15 (15.0 net) horizontal wells. RMP's 2016 drilling program encompassed four (4.0 net) wells at Waskahigan, three (3.0 net) wells at Ante Creek and one (1.0 net) exploration well in Elmworth (formerly known as Gold Creek). The Company also completed an asset acquisition at Elmworth in June 2016 for $10 million.

- At year-end 2016, RMP was not drawn on its bank credit facility. The Company is presently drawn approximately $7 million on its bank line of credit, with a current debt-servicing rate of 3.4% (per annum). The Company's bank credit facility has a maximum borrowing base limit of $40.0 million and the lender's annual borrowing base re-determination is scheduled to occur in June 2017. RMP's working capital deficit at December 31, 2016 was $885 thousand.

- Fourth quarter funds from operations was $3.4 million ($0.02 per basic share). Funds from operations for fiscal 2016 was approximately $30 million ($0.20 per basic share). The Company's fourth quarter 2016 operating netback was $13.88/boe. For fiscal 2016, RMP's realized operating netback was $13.71/boe.

- For the year ended December 31, 2016, RMP reported a net loss of $86.0 million, as compared to a net loss of $84.8 million in fiscal 2015. The Company's earnings in fiscal 2016 was impacted by the non-cash impairment charge on the carrying value of its property, plant and equipment of approximately $80 million, net of the gain on the Ante Creek Disposition. The non-cash impairment charge primarily related to RMP's Greater Waskahigan Cash Generating Unit ("**CGU**"), which prior to the Ante Creek Disposition included the Waskahigan, Ante Creek and Grizzly Montney fields. As a result of the transformational Ante Creek Disposition, the Ante Creek field was removed from this CGU, which resulted in the CGU to be assessed for indicators of impairment and subsequent recognition of such.

The Company's audited consolidated financial statements and associated Management's Discussion and Analysis for the year ended December 31, 2016 is available on RMP's website at *www.rmpenergyinc.com* within "*Investors*" under "*Financials*". Additionally, these documents have been filed today on the *System for Electronic Document Analysis and Retrieval* ("**SEDAR**"). These documents can be retrieved electronically from the SEDAR system by accessing RMP's public filings under "*Search for Public Company Documents*" within the "*Search Database*" module at *www.sedar.com*.

ANNUAL SHAREHOLDERS MEETING

RMP's annual meeting of shareholders is scheduled for 3:00 p.m. on Tuesday, June 6, 2017 in the McMurray Room of the Calgary Petroleum Club, located at 319 - 5th Avenue S.W., Calgary, Alberta.

For more information, please contact:
RMP ENERGY INC.

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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

Forward-Looking Statements

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, the terms of certain gas processing and oil transportation agreements entered into by RMP with a regional mid-stream service provider, including the anticipated timing of completion of the installation of a gathering system by such mid-stream service provider; the anticipated timing of commissioning RMP's oil battery facility; expected construction at the Patterson Creek Gas Plant, including the anticipated timing thereof, expected capacity level upon completion and pipeline connections; anticipated number of drilling locations; the Company's belief that Elmworth has the potential to be a long-term production and reserves growth asset for RMP; RMP's drilling and completion plans, including the anticipated timing that the 13-30 well at Waskahigan will be tied into company-owned infrastructure and placed on production, the Company's expectation that reserves will be booked to such well and future locations offsetting the well, and expected total budgeted number of wells to be drilled at Waskahigan in 2017; the Company's capital budget for 2017, including the amount and focus thereof and anticipated drilling plans; the Company's expectation that production additions from the Waskahigan drilling program will maintain base corporate production levels; the Company's expectation that infrastructure commissioning at Elmworth will bolster RMP’s base production levels and provide production momentum for the second half of 2017 and into 2018; the Company’s forecasted production for the second half of 2017; anticipated timing of the Company providing its market guidance for the balance of the year; RMP's plans to fund its FDC requirements from internally-generated cash flow from operations and, as appropriate, from its existing committed bank credit facility, equity or debt financing and RMP's expectation that the costs of funding the FDC will not impact development of RMP’s properties or its reserves or future net revenue; anticipated timing of the Company's next borrowing base determination under its credit facility; and other matters. In addition, 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.

With respect to forward-looking statements contained in this news release, RMP has made assumptions regarding, but not limited to: conditions in general economic and financial markets; effects of regulation by governmental agencies; current and future commodity prices and royalty regimes; future exchange rates; royalty rates; future operating costs; availability of skilled labor; availability of drilling and related equipment; timing and amount of capital expenditures; the impact of increasing competition; the price of crude oil and natural gas; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company's conduct and results of operations will be consistent with its expectations; available pipeline capacity; that the Company will have the ability to develop the Company's properties in the manner currently contemplated; that the Company will be able to drill, complete and tie-in wells in the manner and on the timing described herein; current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated; and the estimates of the Company's production and reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects.

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; obtaining required approvals of regulatory authorities; unexpected drilling results; the Company's is unable to achieve its objectives; changes in capital expenditures, reserves or reserves estimates and debt service requirements; the occurrence of unexpected events involved in the exploration for, and the operation and development of, oil and gas properties, including hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; changes or fluctuations in production levels; delays in anticipated timing of drilling and completion of wells; lack of available capacity on pipelines; the lack of availability of qualified personnel; uncertainties associated with estimating oil and natural gas reserves; that the Company isn't able to book any reserves related to the 13-30 well at Waskahigan or other wells off-setting such well; and ability to access sufficient capital from internal and external sources. Many of these risks and uncertainties and additional risk factors are described in the Company's Annual Information Form which is available at www.sedar.com. 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.

Oil and Gas Matters

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.

This news release may disclose drilling locations in three categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; and (iii) unbooked locations. 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, 2016 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.

This news release contains a number of oil and gas metrics, including F&D, FD&A, operating netback, net asset value and reserve additions, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon. 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. 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 F&D costs related to reserves additions for that year. 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 operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this news release, should not be relied upon for investment or other purposes.

Any references in this news release to production test rates, flow-back results, flow test results and production flow test 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. Furthermore, neither a pressure transient analysis or a well-test interpretation has been carried out yet, and as such, test results should be considered to be preliminary until such analysis or interpretation has been completed.

In this news release, references to the Company's 2016 reserves are based on a report prepared by InSite with an effective date of December 31, 2016 prepared in accordance with definitions, standards and procedures prescribed in NI 51-101 and the Canadian Oil and Gas Evaluation Handbook and based on InSite forecast pricing effective January 1, 2017.

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. It should not be assumed that the estimates of future net revenues presented herein represent the fair market value of the reserves.

Financial Matters

This news release contains certain financial measures, including operating netback, net debt and funds from operations, which do not have standardized meanings or standard methods of calculation nor are recognized measures under IFRS and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such financial measures have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon. Operating netback refers to realized wellhead revenue less royalties, operating expenses and transportation costs per barrel of oil equivalent. The Company believes that this financial netback measure is useful supplemental information to analyze operating performance and provide an indication of the results generated by the Company's principal business activities. Investors should be cautioned that this measure should not be construed as an alternative to other measures of financial performance as determined in accordance with IFRS. 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. The Company's method of calculating net debt may differ from other companies, and accordingly, they may not be comparable to similar measures used by other companies. As an indicator of the Company's performance, the term funds from operations contained within this news release should not be considered as an alternative to, or more meaningful than, cash flow from operating, financing or investing activities, as determined in accordance with IFRS. This term is not a recognized measure, does not have a standardized meaning nor is it a financial measure under IFRS. Funds from operations is widely accepted as a financial indicator of an exploration and production company's ability to generate cash which is used to internally fund exploration and development activities and to service debt. This measure is widely used by shareholders and investors in the valuation, comparison and investment recommendations of companies within the natural gas and crude oil exploration and production industry. As disclosed within this news release, funds from operations represents cash flow from operating activities before: any expensed corporate acquisition-related costs, any decommissioning obligation cash expenditures, changes in non-cash working capital from operating activities and non-cash changes in deferred charge. The Company presents funds from operations per share whereby per share amounts are calculated consistent with the calculation of earnings per share.