ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 West North Temple, Suite 330
Salt Lake City, Utah 84116

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IDAHO PUBLIC
UTILITIES COMMISSION

March 30, 2018

VIA OVERNIGHT DELIVERY

Diane Hanian
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702

Re: CASE NO. ~~PAC-E-18-01~~ GNR-U-18-01
IN THE MATTER OF THE APPLICATION REQUESTING AUTHORITY TO REDUCE RETAIL RATES BY $2.8 MILLION TO PASS A PORTION OF THE 2017 FEDERAL TAX REFORM ACT COST SAVINGS ONTO CUSTOMERS

Dear Ms. Hanian:

Please find enclosed an original and seven (7) copies of Rocky Mountain Power's Application in the above referenced matter, along with copies of the press release and customer bill insert. Enclosed is a CD containing the Application, attachments, and non-confidential work papers.

Informal inquiries may be directed to Ted Weston, Idaho Regulatory Manager at (801) 220-2963.

Very truly yours,

Joelle Steward

Joelle Steward
Vice President, Regulation

Yvonne R. Hogle (#8930)
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
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Attorney for Rocky Mountain Power

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UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION REQUESTING AUTHORITY TO REDUCE RETAIL RATES BY $2.8 MILLION TO PASS A PORTION OF THE 2017 FEDERAL TAX REFORM ACT COST SAVINGS ONTO CUSTOMERS	**CASE NO. PAC-E-18-01** **APPLICATION OF ROCKY MOUNTAIN POWER**

Rocky Mountain Power, a division of PacifiCorp ("Rocky Mountain Power" or "the Company"), in accordance with Idaho Code §61-502, §61-503, and RP 052, hereby respectfully submits this application ("Application") to the Idaho Public Utilities Commission ("Commission") pursuant to Order No. 33965 initiating an investigation into the impact of the federal income tax legislation enacted December 22, 2017, titled An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution of the Budget for Fiscal Year 2018 ("Tax Reform Act"), and the Company's proposed ratemaking treatment for the associated impacts.

This Application respectfully requests that the Commission issue an order authorizing a $2.8 million or approximately 1 percent rate reduction effective June 1, 2018, and creation of a deferred regulatory liability for the incremental income tax benefits arising from the Tax Reform Act until the effective date of new rates set in future ratemaking proceedings. The deferred regulatory liability and the Company's proposed ratemaking treatment will provide that customers obtain the benefits of the Tax Reform Act through lower and more stable rates.

I. PROCEDURAL BACKGROUND

On or about December 22, 2017, congress enacted the Tax Reform Act effective January 1, 2018. On January 17, 2018, the Commission opened an investigation[1] into the impact of the federal tax code revisions on utilities' costs and ratemaking, noting that a main feature of the Tax Reform Act was to reduce the federal corporate tax rate from 35 percent to 21 percent which could have a significant tax rate reduction materially decreasing many utilities' current tax expenses. If the new federal corporate income tax lowers a utility's tax expense, then the Commission would recalculate the utility's revenue requirement, make customer rates subject to refund, and allow benefits from the tax rate decrease to flow to the utility's customers.

The Order directed utilities to immediately account for the financial benefits from the tax rate reduction from 35 percent to 21 percent effective January 1, 2018, as a deferred regulatory liability and by Friday, March 30, 2018, file a report with the Commission identifying and quantifying all tax changes individually. The report must disclose: 1) the federal income tax components for the year 2017 as if the utility had been subject to Tax Reform Act's revisions to the tax code; 2) each utility must include proposed tariff schedules that show the revenue requirement impacts from the Tax Reform Act, with the differences between the law in effect on December 31, 2017, and the law in effect on and after January 1, 2018; 3) utilities may supplement their reports with further estimates or explanation of taxes under the new and old tax codes under normalized conditions if those utilities' rates are ordinarily set under normalized conditions; 4) utilities that operate in Idaho and in other states must separately calculate system-wide and Idaho-specific figures to show how the Tax Reform Act impacts total operations and Idaho operations.

[1] Case No. GNR-U-18-01 Order No. 33965.

II. OVERVIEW OF THE TAX REFORM ACT

The Tax Reform Act was enacted December 22, 2017, with the majority of the provisions becoming effective January 1, 2018. In general, the most notable items affecting the Company's revenue requirement include:

- A reduction in the federal corporate income tax rate from 35 percent to 21 percent;
- The requirement to normalize excess deferred income taxes associated with public utility property utilizing the average rate assumption method;
- The elimination of the allowance for bonus depreciation for public utility property;
- The repeal of the domestic production activities deduction; and
- The repeal of the deduction and imposition of certain limitations with respect to certain expenditures.

Below is a brief description of each of these items:

<u>Reduction in the Federal Corporate Income Tax Rate from 35 Percent to 21 Percent</u>

In regard to the reduction in the federal corporate income tax rate, the Tax Reform Act eliminates the progressive federal corporate income tax rate of 35 percent and replaces it with a flat rate of 21 percent, which impacts revenue requirement in two ways. First, it reduces the Company's income taxes. Second, it results in a reduction to the accumulated deferred income tax ("ADIT") liability to reflect the lower income tax rate due when the temporary differences reverse. This reduction ("Excess Deferred Income Taxes") is recorded by measuring the temporary differences at the new combined federal and state statutory income tax rate and comparing the result to the ADIT balance existing before the effective date of the income tax reduction before the rate change. The Excess Deferred Income Taxes are recorded to a regulatory liability resulting in no immediate net change to the rate base upon which a utility earns a return.

The treatment of the regulatory liability associated with property-related timing differences is governed by normalization rules.

Required Normalization of Excess Deferred Income Taxes

The Tax Reform Act provides that Excess Deferred Income Taxes on public utility property (*e.g.,* temporary differences that result from different depreciation methods and lives) must be normalized using the average rate assumption method ("ARAM") of accounting.[2] The ARAM reverses the Excess Deferred Income Tax Expense through regulated operating expense. Under the ARAM, the public utility identifies the reversal pattern (book depreciation turnaround vs. tax depreciation turnaround) and reverses the Excess Deferred Income Taxes beginning when the turnaround occurs, as illustrated in the following example:

Example DR/(CR) ARAM							
Year	Book Depreciation	Tax Depreciation	Book/Tax Difference	Tax Rate	Deferred Tax Expense	ADIT	
2016	100,000	200,000	100,000	35%	35,000	(35,000)	
2017	100,000	320,000	220,000	35%	77,000	(112,000)	
2018	100,000	192,000	92,000	21%	19,320	(130,400)	
2019	100,000	115,200	15,200	21%	3,192	(133,592)	
2020	100,000	115,200	15,200	21%	3,192	(136,784)	
2021	100,000	57,600	(42,400)	30.9186%	(13,109)	(123,675)	[1]
2022	100,000		(100,000)	30.9186%	(30,919)	(92,756)	[1]
2023	100,000		(100,000)	30.9186%	(30,919)	(61,837)	[1]
2024	100,000		(100,000)	30.9186%	(30,919)	(30,918)	[1]
2025	100,000		(100,000)	30.9186%	(30,918)	0	[1]
Total	1,000,000	1,000,000	(0)		(0)	(0)	

[1] Under ARAM, at the time of reversal, aggregate book/tax difference is $442,400 and ADIT is $136,784. The Average Rate at which the differences were accumulated is $136,784/$442,400 or 30.9186%. This is the rate at which the ADIT are to reverse under ARAM. The difference between the ARAM deferred tax expense and the tax expense that would have resulted if the book/tax difference for the year was multiplied by the enacted tax rate for the year is a permanent difference in the effective income tax reconciliation.

As shown above, the ARAM does not begin until the timing difference reverses. Thus, while an excess ADIT can be calculated at the time of the enactment of the rate change (in the

[2] Violations of the income tax normalization provisions associated with public utility property would result in (i) a prohibition against the public utility's claim to accelerated depreciation with respect to all public utility property, and (ii) imposition of an additional tax on the public utility wherein the tax for the taxable year will increase by the amount by which it reduces its excess tax reserve more rapidly than permitted under a normalization method of accounting.

above example, at the beginning of 2018), that excess would not begin to reverse until 2021, when book depreciation exceeds tax depreciation.

The non-property Excess Deferred Income Taxes are not subject to the income tax normalization rules imposed by the Tax Reform Act and can be used to satisfy other regulatory assets or deferred and amortized over a period prescribed by the regulatory jurisdiction.

Elimination of Allowance for Bonus Depreciation for Public Utility Property

The Tax Reform Act also eliminates the allowance for bonus depreciation on public utility property[3] acquired after September 27, 2017, that was not subject to a binding written contract as of that date.

Specifically, the Tax Reform Act eliminates the ability to take the additional first-year depreciation deduction for public utility property allowed under the former law[4] on property acquired after September 27, 2017, and not subject to a binding written contract as of such date and under the new law[5] for property placed-in-service after September 27, 2017, and before 2023 and related phase-down provisions which was not subject to a binding written contract as of such date.

This will have the effect of moderating the level of ADIT in the future and reducing near-term cash flow that would have otherwise been available through immediate expensing of property placed in service.

Repeal of the Domestic Production Activities Deduction

The Tax Reform Act repeals the domestic production activities deduction (commonly

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[3] Public utility property is that property that is used in providing electricity if the rates for furnishing those services are subject to ratemaking by a government entity or instrumentality or by a public utility commission.
[4] For example, the "former law" allowed for 50 percent for property placed-in-service in 2017, 40 percent for property placed in-service in 2018, and 30 percent for property placed-in-service in 2019.
[5] For example, the "new law" allows for 100 percent for property placed-in-service after September 27, 2017, and before 2023 and related phase-down provisions which was not subject to a binding written contract as of such date.

referred to as the section 199 deduction or the qualified production activities income deduction) effective January 1, 2018.

The purpose of the deduction was to provide a targeted corporate rate reduction that would allow U.S. companies to compete against international tax systems, while also drawing international companies to the United States and its tax structure. This was deemed unwarranted and repealed due to the significant reduction in the corporate federal income tax rate.

Repeal of the Deduction and Imposition of Limitations on Certain Expenditures

The Tax Reform Act repeals the deduction and imposes additional limitations on certain expenditures including transportation fringe benefits (except as necessary for ensuring the safety of an employee to safely commute between the employee's residence and place of employment), employee achievement awards, meals and entertainment, local lobbying, executive compensation, fines and penalties, and settlements, effective January 1, 2018.

III. ESTIMATED REVENUE REQUIREMENT IMPACTS

In compliance with Order No. 33965, the Company has estimated the revenue requirement impact of the Tax Reform Act utilizing the December 31, 2016, normalized Results of Operations filed with the Commission on April 30, 2017, which are the most current results available. These results were updated to include the federal income taxes calculated with the tax rate of 21 percent and compared to the results prior to accounting for the tax reform items identified above. These results will be updated for the calendar year 2017 Results of Operations, as directed by Order No. 33965, once completed.

The revenue requirement impacts associated with the aspects of the Tax Reform Act (normalization of excess deferred income tax including the repeal of the domestic production activities deduction, imposition of limitations on the deductibility of certain expenditures, and the impact on wheeling revenues) are not included in this estimate at this time because they are either more complex in nature or require additional guidance or information. The impacts of these items will be provided in a later filing, as discussed below. Also, the impacts associated with the elimination of the allowance of bonus depreciation for public utility property will only impact future revenue requirement calculations as new property is placed into service.

To calculate the overall estimated revenue requirement a "price change" approach was utilized in which the Company reduced revenues to reflect the lower revenue requirement while maintaining the same earned return on equity before accounting for these tax changes. Due to certain regulatory differences in each jurisdiction in which PacifiCorp operates, the total Company results are not truly representative as they would only include any Idaho specific regulatory adjustments. The estimated revenue requirement impacts for total Company and Idaho allocated are shown in the table below:

Revenue Requirement Impact		
	Total Company	**Idaho**
Reduction of Federal Tax Expense	-$145,378,894	-$5,792,637
Reduction of State Tax Expense	-$7,213,058	-$391,975
Reduction of Deferred Tax Expense	-$33,534,940	-$4,123,334
Update of Uncollectables	-$325,785	-$18,037
Update of PUC Fees	-$431,879	-$23,911
Update of Cash Working Capital	-$75,850	-$1,043
Total Revenue Requirement Impact	**-$186,960,407**	**-$10,350,937**

The December 31, 2016 Idaho Results of Operations prepared to reflect the Tax Reform Act, including a summary of results, are provided as Rocky Mountain Power Attachment No. 1.

IV. PROPOSED ACCOUNTING TREATMENT FOR RATE REDUCTION AND STABILIZATION

This Application requests authorization to defer the benefits of the Tax Reform Act to a regulatory liability until the effective date of new rates set in future ratemaking proceedings.

Although the exact revenue requirement impact of the Tax Reform Act is still unknown, the Company proposes to implement a rate reduction of $2.8 million (approximately 1 percent) effective June 1, 2018, in order to start delivering benefits to customers while the Tax Reform Act impacts are being finalized and reviewed by stakeholders. This represents slightly over a quarter of the estimated impact and aligns the rate change with the effective rates for the Energy Cost Adjustment Mechanism. This preliminary rate change would lower rates for customers while the Company evaluates and finalizes the full impacts of the Tax Reform Act, including working with parties to develop a longer-term strategy to use the regulatory liability balance to help offset future known cost increase pressures such as; Lake Side II, the 2013 incremental depreciation rates, the 2018 depreciation study, Deer Creek Mine Closure costs, and other regulatory assets. The proposed strategy would also stabilize rates and allow customers to better predict future costs.

Idaho's December 2017 Normalized Results of Operations will be final by April 30, 2018, and filed with the Commission at that time. The same price change approach used for the December 2016 results will be used to determine the impact of the Tax Reform Act on the December 2017 Normalized Results of Operations. The Company proposes to provide the updated revenue requirement impacts and a calculation of the other estimated impacts not included in these comments, 45 days after the April 30, 2018 filing. The Company will true-up any under or over allocation of benefits in the Tax Reform Act regulatory liability. The Company will continue to defer the balance of the Tax Reform Act regulatory liability that remains after accounting for the reduction to rates proposed in this Application and may propose to offset known costs for rate stabilization purposes. Any offsets to the deferral balance would be subject to Commission approval. Any remaining amount in the deferral balance would be refunded to customers no later than the effective date of the Company's next general rate case.

In addition, Fitch, Standard & Poor's, and Moody's Investor Service ("Moody's") have all issued reports suggesting that the tax law changes may have the potential to negatively impact utility company credit metrics. Deferring part of the reduction will allow more time to analyze these impacts and adjust capital structure levels, as appropriate. At face value it is easy to assume that the primary impacts on the Company of the Tax Reform Act and its reduction of corporate rates from 35 percent down to 21 percent are entirely positive, but a closer analysis shows there are negatives in the case of regulated public utilities. A January 2018 report from The Brattle Group ("Brattle Tax Report") discusses several of these adverse effects.[6]

The Brattle Tax Report demonstrates that coverage ratios for utilities will tighten as earnings before interest and taxes ("EBIT") and earnings before interest, taxes, depreciation and amortization ("EBITDA") decrease, EBIT and EBITDA interest coverage is lowered and EBITDA to debt is also lowered. These reduced coverage ratios potentially result in ratings downgrades which may increase utilities' borrowing costs. The report goes on to show that utilities' realized earnings volatility is increased by a lower tax rate because the "cushion" provided by the impact of taxes on utility rates becomes smaller. This will make earnings more sensitive to reductions to EBITDA as the offsetting tax benefit goes from a 35 percent rate to a 21 percent rate. The Brattle Tax Report also states that cash flows may be deferred due to a lower tax rate on depreciation timing differences.

The same impacts noted in the Brattle Tax Report led Moody's to lower the outlook for 24 regulated utilities on January 19, 2018, based primarily on the Tax Reform Act's impacts on cash flows. On January 24, 2018, just after issuing its revised negative outlooks, Moody's, issued a

[6] *See* The Brattle Group, "Six Implications of the New Tax Law for Regulated Utilities", January 2018 (available at http://files.brattle.com/files/13011_six_implications_of_the_new_tax_law_for_regulated_utilities.pdf).

Sector Comment for regulated utilities in the US entitled "Tax reform is credit negative for sector, but impacts vary by company." The comment cited many of the same adverse impacts raised in the Brattle Tax Report, noting that while tax reform is neutral for utility earnings, it is negative for cash flow and that cash flow to debt ratio could decline by 150–250 basis points.

While the Company has not had its outlook revised to negative, the adverse impacts discussed by Moody's and The Brattle Group will likely impact the Company if all benefits are refunded to customers immediately. Deferring part of the reduction to rates to offset future rate increases will ease some of these negative impacts, and allow more time for the Company, the Commission, and the other parties to analyze the impacts and reach a solution that keeps the Company financially healthy. Deferring the remaining balance of the Tax Reform Act into a regulatory liability and allowing it to offset known cost increases discussed above gives the Company time to better consider potential adverse impacts from the Tax Reform Act and to adjust its capital structure as appropriate to account for them.

V. TAX IMPACT ON PRODUCTION TAX CREDITS

Internal Revenue Code ("IRC") provides that a wind facility will generate a production tax credit ("PTC") equal to an inflation-adjusted 1.5 cents per kilowatt-hour of electricity that is produced and sold to a third-party for a period of 10 years beginning on the date the facility is placed in-service for income tax purposes.[7] The current inflation-adjusted PTC rate for electricity generated from qualifying wind facilities in 2017 is 2.4 cents per kilowatt-hour.[8]

The annual amount of PTC passed onto customers is based on three factors: the megawatt-hours of energy produced at the qualifying wind facilities; the inflation-adjusted Internal Revenue Service ("IRS") rate; and the Company's tax bump-up rate. The Company's wind facilities were

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[7] IRC section 45(a).
[8] IRS Notice 2017-33.

placed in-service in 2006 through 2010, so beginning in 2016, as the first qualifying wind facilities reached their 10-year anniversary from their initial in-service date, the energy produced from those wind facilities no longer qualified for PTC. The number of qualifying wind facilities continues to decline each year as they reach their 10-year anniversary from their initial in-service date. Due to both the volatility of megawatt-hours produced from the wind facilities and the approaching end of the qualification period for each of the wind facilities the Commission authorized[9] tracking PTC in the Energy Cost Adjustment Mechanism ("ECAM").

The Tax Reform Act reduced the Company's tax bump-up rate applied to PTC from 1.61 percent to 1.33 percent, which reduces the value of the PTC. Since the actual value customers ultimately receive for PTC is not only impacted by the Company's corporate tax rate but also by the volume of energy produced and the inflation-adjusted cents per kilowatt-hour, rather than estimate the impact of the tax rate change here and true it up again in the ECAM for volumetric changes, in this Application the Company proposes excluding PTCs from this calculation and capturing all PTC components in the monthly ECAM deferral when the actual volume of PTC is known.

VI. RATE DESIGN

This Application also requests approval of a new Electric Service Schedule No. 197 – Federal Tax Act Adjustment, to pass the rate reduction associated with the Tax Reform Act back to customers. This credit would be a separate line item on customers' bills until the next general rate case. The $2.8 million rate reduction would be allocated to all retail tariff customers taking service under the Company's electric service schedules based on the rate base allocation to each customer class from the Company's cost of service study that was filed in Case No. PAC-E-11-

[9] Order No. 33440 in Case No. PAC-E-15-09 page 6.

12. This allocation is consistent with how federal income tax expense is allocated to customer classes on each class' share of rate base in the Company's cost of service study. Page 1 of Attachment No. 2 shows the Company's proposed rate spread for the new Electric Service Schedule No. 197.

The Company proposes per kilowatt-hour energy prices for Schedule No. 197 based upon the same kilowatt-hour volumes by class that are used in the Company's ECAM filings that are made each year. To determine these rates, the price for each rate schedule is calculated by dividing the allocated refund amounts by the corresponding annual energy for each rate schedule. To avoid impacting demand-side management programs, the Company proposes that Schedule No. 191, Customer Efficiency Services Rate Adjustment, would be applied to customers' bills prior to applying the proposed Schedule No. 197 sur-credit. Page 1 of Attachment No. 2 contains the calculations for the proposed rates for Schedule No. 197. Page 2 of Attachment No.2 shows the net impact by rate schedule of the Company's proposed refund.

VII. REQUEST FOR RELIEF

Gradualism and rate stability are longstanding ratemaking principles recognized by this Commission in setting rates. The Company's proposal to pass approximately 27 percent of the benefit to customers now and defer the remaining balance of the regulatory liability is intended to support these same principals. Reducing rates by the full balance of the Tax Reform Act benefits once the calculation of the impact is finalized would provide interim reductions, only to leave customers facing upward pressures on rates a short time thereafter. Significant changes in customer rates downward then upward in a matter of a few years does not meet the principle of gradualism, and is the opposite of rate stability. The deferred regulatory liability and the Company's proposed ratemaking treatment will provide that customers obtain the benefits of the Tax Reform Act through lower and more stable rates.

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission issue an order: (1) authorizing that this matter be processed by Modified Procedure; (2) approving a $2.8 million (approximately 1 percent) rate decrease effective June 1, 2018; 3) approve Electric Service Schedule No. 197; and 4) approve a new regulatory liability to defer the remaining impact of the Tax Reform Act.

DATED this 30th day of March 2018

RESPECTFULLY SUBMITTED,

ROCKY MOUNTAIN POWER

Yvonne R. Hogle

Yvonne R. Hogle
Assistant General Counsel

Proposed Tariff

Schedule 197–Federal Tax Act Adjustment

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 197

STATE OF IDAHO

Federal Tax Act Adjustment

APPLICATION: This Schedule shall be applicable to all retail tariff Customers taking service under the Company's electric service schedules.

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied the following cents per kilowatt-hour rate.

Schedule	1	-0.114¢ per kWh
Schedule	6	-0.080¢ per kWh
Schedule	6A	-0.080¢ per kWh
Schedule	7	-0.153¢ per kWh
Schedule	7A	-0.153¢ per kWh
Schedule	9	-0.058¢ per kWh
Schedule	10	-0.096¢ per kWh
Schedule	11	-0.179¢ per kWh
Schedule	12	-0.070¢ per kWh
Schedule	19	-0.111¢ per kWh
Schedule	23	-0.090¢ per kWh
Schedule	23A	-0.090¢ per kWh
Schedule	24	-0.080¢ per kWh
Schedule	35	-0.066¢ per kWh
Schedule	35A	-0.066¢ per kWh
Schedule	36	-0.124¢ per kWh
Schedule	400	-0.059¢ per kWh
Schedule	401	-0.058¢ per kWh

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

For information contact: Media Hotline 800-775-7950

Federal tax changes / Annual energy cost adjustment

Price decrease proposed for Idaho customers

BOISE, Idaho, April 2, 2018—Rocky Mountain Power has proposed a 1 percent overall decrease on bills for Idaho customers, resulting from the recent changes in the federal tax code. Typical residential customers using 800 kilowatt-hours per month would see a decrease of $11 on their annual electricity bill. Based on the company's preliminary analysis of the federal tax changes for Idaho customers, the company proposes a reduction of $2.8 million, or 1 percent and deferral of the remaining tax benefits to mitigate future rate impact for customers.

"Our customers already enjoy some of the lowest costs in the country, and we are pleased to be able to reduce those rates even more," said Cindy A. Crane, CEO and president, Rocky Mountain Power. "We appreciate members of state congressional delegations for their work in making this reduction from tax rates possible."

In a separate request, the utility is proposing no changes to customer bills in the annual energy cost adjustment and deferral of the $7.8 million balance. The energy cost adjustment mechanism is designed to track the difference between the company's actual expenses for fuel and other costs to provide electricity to customers, against the amount collected from customers through current rates.

Pending commission approval, the decrease from federal tax changes would take effect June 1, 2018. The proposal reduces rate schedules by 1 percent, with the following impact on each rate schedule:

Schedule	1	-0.114¢ per kWh
Schedule	6	-0.080¢ per kWh
Schedule	6A	-0.080¢ per kWh
Schedule	7	-0.153¢ per kWh
Schedule	7A	-0.153¢ per kWh
Schedule	9	-0.058¢ per kWh
Schedule	10	-0.096¢ per kWh
Schedule	11	-0.179¢ per kWh
Schedule	12	-0.070¢ per kWh
Schedule	19	-0.111¢ per kWh
Schedule	23	-0.090¢ per kWh
Schedule	23A	-0.090¢ per kWh
Schedule	24	-0.080¢ per kWh
Schedule	35	-0.066¢ per kWh
Schedule	35A	-0.066¢ per kWh
Schedule	36	-0.124¢ per kWh
Schedule	400	-0.059¢ per kWh
Schedule	401	-0.058¢ per kWh

The public will have an opportunity to comment on the proposal during the coming months as the commission studies the company's request. The commission must approve the proposed changes before they can take effect. A copy of the company's application is available for public review on the commission's website, and at the commission offices. Customers may also subscribe to the commission's RSS feed to receive periodic updates via email. The request also is available at the company's offices in Rexburg, Preston, Shelley and Montpelier as noted below:

Idaho Public Utilities Commission
www.puc.idaho.gov
472 W. Washington
Boise, ID 83702

Rocky Mountain Power offices

- Rexburg – 25 East Main
- Preston – 509 S. 2nd East
- Shelley – 852 E. 1400 North
- Montpelier – 24852 U.S. Hwy 89

# # #

Tax Reform Price Decrease

Rocky Mountain Power requests price decrease for customers.

On March 30, 2018, Rocky Mountain Power asked the Idaho Public Utilities Commission to approve a $2.8 million or approximately 1 percent decrease associated with the tax savings from the Tax Reform Act passed by Congress. The application asked the Commission to authorize a price reduction effective June 1, 2018, and create a tracking mechanism for any additional incremental benefits arising from the Tax Reform Act. The company's proposed treatment will provide that customers obtain the benefits of the Tax Reform Act through lower and more stable rates. Under Rocky Mountain Power's proposal, all customer classes will see a reduction to their bills. The proposal for consideration by the Commission would provide customers a 1 percent decrease now and mitigate future rate increases.

Typical residential customers using 800 kilowatt-hours per month would see a decrease of approximately $11 on their annual electricity bill. The following is a summary of the impacts by customer class:

- Residential Schedule 1 – 1.1% decrease or -0.114¢ per kWh
- General Service Schedule 6 – 1.0% decrease or -0.080¢ per kWh
- General Service Schedule 9 – 0.9% decrease or -0.058¢ per kWh
- Irrigation Service Schedule 10 – 1.1% decrease or -0.096¢ per kWh
- Commercial & Industrial Heating Schedule 19 – 1.3% decrease or -0.111¢ per kWh
- General Service Schedule 23 – 0.9% decrease or -0.090¢ per kWh
- General Service Schedule 35 – 1.0% decrease or -0.066¢ per kWh
- Public Street Lighting – 0.4% decrease or -0.153¢ per kWh
- Tariff Contract 400 – 1.0% decrease or -0.059¢ per kWh
- Tariff Contract 401 – 1.0% decrease or-0.058¢ per kWh

The public can comment on the proposed rate change as the commission reviews the application. The commission must approve the proposed changes before they can take effect. A copy of the application is available for public review at the commission offices in Boise and on the commission's homepage at www.puc.idaho.gov. Customers may file written comments regarding the application with the commission or subscribe to the commission's RSS feed to receive periodic updates via email about the case. Copies of the proposal also are available for review at the company's offices in Rexburg, Preston, Shelley and Montpelier.

Idaho Public Utilities Commission
472 W Washington
Boise, ID 83702
www.puc.idaho.gov

Rocky Mountain Power offices
- Rexburg – 25 East Main
- Preston – 509 S. 2nd E.
- Shelley – 852 E. 1400 N.
- Montpelier – 24852 U.S. Hwy 89

For more information about your rates and rate schedule, go to **rockymountainpower.net/rates**.

Attachment 1

Revenue Requirement Impact Tax Rate Change

Attachment 1

Rocky Mountain Power

Revenue Requirement Impact - Tax Rate Change

RESULTS OF OPERATIONS SUMMARY

	Description of Account Summary:	DECEMBER 2016 NORMALIZED RESULTS IDAHO	TAX RATE IMPACT	21% TAX RATE DECEMBER 2016 NORMALIZED RESULTS IDAHO
1	Operating Revenues			
2	General Business Revenues	275,877,837	(10,350,937)	265,526,899
3	Interdepartmental	0	0	0
4	Special Sales	22,184,419	0	22,184,419
5	Other Operating Revenues	8,786,368	0	8,786,368
6		306,848,624	(10,350,937)	296,497,687
7				
8	Operating Expenses:			
9	Steam Production	72,678,335	0	72,678,335
10	Nuclear Production	0	0	0
11	Hydro Production	2,697,442	0	2,697,442
12	Other Power Supply	64,393,644	0	64,393,644
13	Transmission	12,746,654	0	12,746,654
14	Distribution	9,976,592	0	9,976,592
15	Customer Accounting	4,679,026	(18,037)	4,660,989
16	Customer Service & Infor	707,508	0	707,508
17	Sales	0	0	0
18	Administrative & General	5,969,892	0	5,969,892
19				
20		173,849,093	(18,037)	173,831,057
21				
22	Depreciation	39,513,171	0	39,513,171
23	Amortization	1,445,699	0	1,445,699
24	Taxes Other Than Income	9,419,087	(23,911)	9,395,176
25	Income Taxes - Federal	6,272,212	(5,792,637)	479,575
26	Income Taxes - State	1,379,845	(391,975)	987,870
27	Income Taxes - Def Net	11,709,416	(4,123,334)	7,586,083
28	Investment Tax Credit Adj.	(514,782)	0	(514,782)
29	Misc Revenue & Expense	(19,666)	0	(19,666)
30				
31		243,054,075	(10,349,894)	232,704,181
32				
33	Operating Revenue for Return	63,794,549	(1,043)	63,793,505
34				
35	Rate Base:			
36	Electric Plant in Service	1,604,997,849	0	1,604,997,849
37	Plant Held for Future Use	(0)	0	(0)
38	Misc Deferred Debits	24,731,137	0	24,731,137
39	Elec Plant Acq Adj	1,413,097	0	1,413,097
40	Pensions	0	0	0
41	Prepayments	2,673,038	0	2,673,038
42	Fuel Stock	13,695,755	0	13,695,755
43	Material & Supplies	13,108,463	0	13,108,463
44	Working Capital	1,068,159	(13,831)	1,054,329
45	Weatherization Loans	1,966,213	0	1,966,213
46	Miscellaneous Rate Base	0	0	0
47				
48		1,663,653,710	(13,831)	1,663,639,880
49				
50	Rate Base Deductions:			
51	Accum Prov For Depr	(516,134,599)	0	(516,134,599)
52	Accum Prov For Amort	(31,713,016)	0	(31,713,016)
53	Accum Def Income Taxes	(257,864,491)	0	(257,864,491)
54	Unamortized ITC	(81,444)	0	(81,444)
55	Customer Adv for Const	(1,637,825)	0	(1,637,825)
56	Customer Service Deposits	0	0	0
57	Misc. Rate Base Deductions	(10,534,154)	0	(10,534,154)
58				
59		(817,965,530)	0	(817,965,530)
60				
61	Total Rate Base	845,688,181	(13,831)	845,674,350
62				
63	Return on Rate Base	7.544%		7.544%
64				
65	Return on Equity	9.758%		9.758%

Rocky Mountain Power

Revenue Requirement Impact - Tax Rate Change

RESULTS OF OPERATIONS SUMMARY

	Description of Account Summary:	DECEMBER 2016 NORMALIZED RESULTS TOTAL COMPANY	TAX RATE IMPACT	21% TAX RATE DECEMBER 2016 NORMALIZED RESULTS TOTAL COMPANY
1	Operating Revenues			
2	General Business Revenues	4,849,412,100	(186,960,407)	4,662,451,693
3	Interdepartmental	0	0	0
4	Special Sales	188,543,232	0	188,543,232
5	Other Operating Revenues	156,890,628	0	156,890,628
6		5,194,845,961	(186,960,407)	5,007,885,554
7				
8	Operating Expenses:			
9	Steam Production	1,097,839,165	0	1,097,839,165
10	Nuclear Production	0	0	0
11	Hydro Production	43,407,663	0	43,407,663
12	Other Power Supply	933,464,356	0	933,464,356
13	Transmission	203,579,752	0	203,579,752
14	Distribution	196,760,209	0	196,760,209
15	Customer Accounting	83,225,947	(325,785)	82,900,161
16	Customer Service & Infor	147,430,025	0	147,430,025
17	Sales	0	0	0
18	Administrative & General	129,290,071	0	129,290,071
19				
20		2,834,997,189	(325,785)	2,834,671,404
21				
22	Depreciation	685,658,224	0	685,658,224
23	Amortization	43,110,827	0	43,110,827
24	Taxes Other Than Income	189,907,252	(431,879)	189,475,374
25	Income Taxes - Federal	217,170,351	(145,378,894)	71,791,457
26	Income Taxes - State	38,566,895	(7,213,058)	31,353,837
27	Income Taxes - Def Net	95,232,305	(33,534,940)	61,697,365
28	Investment Tax Credit Adj.	(4,341,401)	0	(4,341,401)
29	Misc Revenue & Expense	(1,671,184)	0	(1,671,184)
30				
31		4,098,630,458	(186,884,557)	3,911,745,901
32				
33	Operating Revenue for Return	1,096,215,503	(75,850)	1,096,139,653
34				
35	Rate Base:			
36	Electric Plant in Service	26,629,771,885	0	26,629,771,885
37	Plant Held for Future Use	22,547,753	0	22,547,753
38	Misc Deferred Debits	865,417,015	0	865,417,015
39	Elec Plant Acq Adj	40,080,449	0	40,080,449
40	Pensions	0	0	0
41	Prepayments	50,778,346	0	50,778,346
42	Fuel Stock	211,420,957	0	211,420,957
43	Material & Supplies	229,709,714	0	229,709,714
44	Working Capital	31,674,639	(959,324)	30,715,315
45	Weatherization Loans	12,915,118	0	12,915,118
46	Miscellaneous Rate Base	0	0	0
47				
48		28,094,315,877	(959,324)	28,093,356,553
49				
50	Rate Base Deductions:			
51	Accum Prov For Depr	(8,687,212,954)	0	(8,687,212,954)
52	Accum Prov For Amort	(539,932,405)	0	(539,932,405)
53	Accum Def Income Taxes	(4,516,312,709)	0	(4,516,312,709)
54	Unamortized ITC	(550,126)	0	(550,126)
55	Customer Adv for Const	(32,263,649)	0	(32,263,649)
56	Customer Service Deposits	0	0	0
57	Misc. Rate Base Deductions	(453,552,927)	0	(453,552,927)
58				
59		(14,229,824,771)	0	(14,229,824,771)
60				
61	Total Rate Base	13,864,491,106	(959,324)	13,863,531,782
62				
63	Return on Rate Base	7.907%		7.907%
64				
65	Return on Equity	10.465%		10.465%

Attachment 2

Idaho Tax Act Rate Design

Attachment 2

TABLE A
ESTIMATED IMPACT OF PROPOSED ECAM ADJUSTMENT
FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN IDAHO
HISTORIC 12 MONTHS ENDED DECEMBER 2014

Line			Average		Present Rev ($000)			Proposed Rev ($000)			Change			
No.	Description	Sch.	Cust	MWH	Base	TAA	Net	Base	TAA	Net	Base	%	Net Rev	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	Residential Sales													
1	Residential Service	1	46,059	442,589	$49,602	$0	$49,602	$49,602	($504)	$49,098	$0	0.0%	($504)	-1.0%
2	Residential Optional TOD	36	13,484	235,152	$22,484	$0	$22,484	$22,484	($292)	$22,192	$0	0.0%	($292)	-1.3%
3	AGA Revenue				$3		$3	$3		$3				
4	Total Residential		59,543	677,741	$72,090	$0	$72,090	$72,090	($796)	$71,294	$0	0.0%	($796)	-1.1%
5	**Commercial & Industrial**													
6	General Service - Large Power	6	1,036	303,011	$23,667	$0	$23,667	$23,667	($240)	$23,427	$0	0.0%	($240)	-1.0%
7	General Svc. - Lg. Power (R&F)	6A	214	30,600	$2,616	$0	$2,616	$2,616	($26)	$2,590	$0	0.0%	($26)	-1.0%
8	*Subtotal-Schedule 6*		*1,250*	*333,611*	*$26,283*	*$0*	*$26,283*	*$26,283*	*($266)*	*$26,017*	*$0*	*0.0%*	*($266)*	*-1.0%*
9	General Service - High Voltage	9	17	121,001	$7,626	$0	$7,626	$7,626	($70)	$7,556	$0	0.0%	($70)	-0.9%
10	Irrigation	10	4,969	602,488	$54,316	$0	$54,316	$54,316	($579)	$53,737	$0	0.0%	($579)	-1.1%
11	Comm. & Ind. Space Heating	19	103	5,151	$438	$0	$438	$438	($6)	$432	$0	0.0%	($6)	-1.3%
12	General Service	23	6,634	153,848	$14,913	$0	$14,913	$14,913	($137)	$14,776	$0	0.0%	($137)	-0.9%
13	General Service (R&F)	23A	2,314	33,450	$3,376	$0	$3,376	$3,376	($31)	$3,345	$0	0.0%	($31)	-0.9%
14	*Subtotal-Schedule 23*		*8,948*	*187,299*	*$18,289*	*$0*	*$18,289*	*$18,289*	*($168)*	*$18,121*	*$0*	*0.0%*	*($168)*	*-0.9%*
15	General Service Optional TOD	35	3	1,893	$123	$0	$123	$123	($1)	$122	$0	0.0%	($1)	-1.0%
16	Special Contract 1	400	1	1,443,926	$86,967	$0	$86,967	$86,967	($849)	$86,119	$0	0.0%	($849)	-1.0%
17	Special Contract 2	401	1	107,486	$6,264	$0	$6,264	$6,264	($62)	$6,202	$0	0.0%	($62)	-1.0%
18	AGA Revenue				$478		$478	$478		$478				
19	Total Commercial & Industrial		15,293	2,802,855	$200,786	$0	$200,786	$200,786	($2,002)	$198,784	$0	0.0%	($2,002)	-1.0%
20	**Public Street Lighting**													
21	Security Area Lighting	7	193	267	$102	$0	$102	$102	($0)	$102	$0	0.0%	($0)	-0.4%
22	Security Area Lighting (R&F)	7A	136	107	$44	$0	$44	$44	($0)	$43	$0	0.0%	($0)	-0.4%
23	Street Lighting - Company	11	37	87	$40	$0	$40	$40	($0)	$39	$0	0.0%	($0)	-0.4%
24	Street Lighting - Customer	12	234	2,424	$436	$0	$436	$436	($2)	$434	$0	0.0%	($2)	-0.4%
25	AGA Revenue				$0		$0	$0		$0				
26	Total Public Street Lighting		600	2,884	$621	$0	$621	$621	($2)	$619	$0	0.0%	($2)	-0.4%
27	**Total Sales to Ultimate Customers**		75,435	3,483,480	$273,497	$0	$273,497	$273,497	($2,800)	$270,697	$0	0.0%	($2,800)	-1.0%

RATE SPREAD
ESTIMATED IMPACT OF PROPOSED ECAM ADJUSTMENT FROM ELECTRIC SALES TO ULTIMATE CONSUMERS DISTRIBUTED BY RATE SCHEDULES IN IDAHO HISTORIC 12 MONTHS ENDED DECEMBER 2014

Line No.	Description	Sch.	Average Customers	MWH	Present Rev ($000)	Rate Base[1] F101	Proposed TAA ($000)	Proposed TAA %	Proposed TAA Rate ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Residential Sales								
1	Residential Service	1	46,059	442,589	$49,602	18.0%	($504)	-1.0%	-0.114
2	Residential Optional TOD	36	13,484	235,152	$22,484	10.4%	($292)	-1.3%	-0.124
3	AGA Revenue				$3				
4	**Total Residential**		59,543	677,741	$72,090		($796)	-1.1%	
5	**Commercial & Industrial**								
6	General Service - Large Power	6	1,036	303,011	$23,667		($240)	-1.0%	-0.080
7	General Svc. - Lg. Power (R&F)	6A	214	30,600	$2,616		($26)	-1.0%	-0.080
8	*Subtotal-Schedule 6*		*1,250*	*333,611*	*$26,283*	*9.6%*	*($266)*	*-1.0%*	*-0.080*
9	General Service - High Voltage	9	17	121,001	$7,626	2.5%	($70)	-0.9%	-0.058
10	Irrigation	10	4,969	602,488	$54,316	20.7%	($579)	-1.1%	-0.096
11	Comm. & Ind. Space Heating	19	103	5,151	$438	0.2%	($6)	-1.3%	-0.111
12	General Service	23	6,634	153,848	$14,913		($137)	-0.9%	-0.090
13	General Service (R&F)	23A	2,314	33,450	$3,376		($31)	-0.9%	-0.090
14	*Subtotal-Schedule 23*		*8,948*	*187,299*	*18,289*	*6.0%*	*(168)*	*-0.9%*	*-0.090*
15	General Service Optional TOD	35	3	1,893	$123		($1)	-1.0%	-0.066
16	Special Contract 1	400	1	1,443,926	$86,967	30.3%	($849)	-1.0%	-0.059
17	Special Contract 2	401	1	107,486	$6,264	2.2%	($62)	-1.0%	-0.058
18	AGA Revenue				$478				
19	**Total Commercial & Industrial**		15,293	2,802,855	$200,786		($2,002)	-1.0%	
20	**Public Street Lighting**								
21	Security Area Lighting	7	193	267	$102		($0.4)	-0.4%	-0.153
22	Security Area Lighting (R&F)	7A	136	107	$44		($0.2)	-0.4%	-0.153
23	Street Lighting - Company	11	37	87	$40		($0.2)	-0.4%	-0.179
24	Street Lighting - Customer	12	234	2,424	$436		($1.7)	-0.4%	-0.070
25	AGA Revenue				$0				
26	**Total Public Street Lighting**		600	2,884	$621	0.1%	($2)	-0.4%	
27	**Total Sales to Ultimate Customers**		75,435	3,483,480	$273,497	100.0%	($2,800)	-1.0%	-0.080
						Tax Act Rev	$ (2,800)	-1.0%	

[1] Rate Base Cost allocator from 2010 cost of service study.

Attachment 2