FOLEY
FOLEY & LARDNER LLP

ATTORNEYS AT LAW
777 EAST WISCONSIN AVENUE
MILWAUKEE, WI 53202-5306
414.271.2400 TEL
414.297.4900 FAX
WWW.FOLEY.COM

WRITER'S DIRECT LINE
414.297.5566
tmullooly@foley.com EMAIL

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November 13, 2015

Via Federal Express

Mr. Will Rosquist
Interim Regulatory Division Chief
Montana Public Service Commission
1701 Prospect Avenue
Post Office Box 202601
Helena, MT 59620-2601

Re: In the Matter of the Inquiry By the Montana Public Service Commission Into Its Implementation of the Public Utility Regulation Policies Act of 1978, Docket No. N2015.9.74

Dear Mr. Rosquist:

Enclosed for filing are an original and 10 copies of a Motion for Acceptance of Late Filing and the Late Filed Comments of Cypress Creek Renewables.

The Cypress Creek Renewables employee responsible for answering questions concerning this filing or for the inquiries to the appropriate members of the utility staff is:

David Bunge
Vice President of Development
Cypress Creek Renewables
3250 Ocean Park Blvd, Suite 355
Santa Monica, CA 90405
bunge@ccrenew.com

Cypress Creek Renewables' attorney in this matter is:

Thomas McCann Mullooly
Foley & Lardner LLP
777 East Wisconsin Avenue
Milwaukee, WI 53202-5306
tmullooly@foley.com

Very truly yours,

/s/ Thomas McCann Mullooly

Thomas McCann Mullooly

Enclosures

cc: Monica Tranel, Montana Consumer Counsel (via e-mail and FedEx)
Fred Robinson, Montana Department of Natural Resources & Conservation (via e-mail and First Class Mail)
Al Brogan, NorthWestern Energy (via e-mail and First Class Mail)
Michael J. Uda, Uda Law Firm (via e-mail and First Class Mail)
Ryan Shaffer, Meyer, Shaffer & Stephens, PLLP (via e-mail and First Class Mail)
Jeff L. Fox, Renewable Northwest (via e-mail and First Class Mail)
F. Diego Rivas, NW Energy Coalition (via e-mail and First Class Mail)
Lee Tavenner, Boulder Hydro (via First Class Mail)

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER of Inquiry by the Montana Public Service Commission Into Its Implementation of the Public Utility Regulatory Policies Act of 1978	))))	REGULATORY DIVISION DOCKET NO. N2015.9.74

LATE FILED COMMENTS OF
CYPRESS CREEK RENEWABLES

Pursuant to the Montana Public Service Commission's ("Commission") Notice of Inquiry and Opportunity to Comment dated September 24, 2015 and the accompanying Motion, Cypress Creek Renewables LLC ("CCR") respectfully submits the following comments in the above-captioned docket.

Introduction of
Cypress Creek Renewables LLC

CCR invests in and develops utility scale solar projects throughout the country, with a management team that has a combined track record of developing over 100 operational projects throughout the United States. CCR currently manages a portfolio of 40 MW of operating assets, is breaking ground on an additional 95 MW of assets, and has a development pipeline of over 1 GW, which it anticipates will be deployed over the next two to three years. CCR believes that solar energy is critical to ensuring that the United States has a cleaner, more affordable, and more reliable energy future.

In the past year, CCR has been an active solar developer in Montana. CCR has a number of projects under development and has been in negotiations with NorthWestern Energy ("NWE") during this period.

Overview of Comments

CCR commends the Commission for opening this proceeding and appreciates the opportunity to provide comments on issues of critical importance to renewable energy development in Montana. Continued implementation of the Public Utilities Regulatory Policies Act ("PURPA") is of vital importance to Montana consumers, Montana's regulated utilities, renewable energy developers, and the public at large. CCR focuses on developing viable solar projects that can compete in the market place and on a level playing field with other generation resources—which is, after all, what PURPA seeks to accomplish. Indeed, although PURPA is intended to spur the development of small generation resources (renewable or otherwise), it is intended to do so on an avoided cost basis. When implemented properly, PURPA will produce long-term benefits for consumers by promoting the development of QFs and ensuring that the cost of these projects is no greater than the marginal cost of energy from other, alternative resources. Because solar and wind renewable projects have low-to-no fuel costs, they provide additional long-term benefits to consumers.

With that foundation, CCR will address the questions raised through the Notice of Inquiry.

1. Methods for Estimating Avoided Costs

<u>Questions for Stakeholders</u>

a. What Methods Are Reasonable for the Commission to Use to Estimate NWE's Long-term Avoided Costs and Set Rates for Small and Large QFs? Why Are Those Methods Preferred?

In setting avoided cost rates, it is critical that the Commission utilize a method that is public, transparent, and not subject to manipulation. Thus, using an avoided cost proxy method that can be reviewed by intervening parties and Commission staff may be the best of the identified options. CCR has reservations with avoided cost methodologies that utilize production cost simulation models because the software and expertise needed to run the models are, in practical terms, only available to NWE and perhaps to Commission Staff. Use of such models would put a high premium on the ability of Staff to carefully monitor and assess the model's inputs.

CCR recommends that the avoided cost formula be created in a public rulemaking docket (such as this one) and that it be subject to annual updates based on a pre-determined calendar cycle.

CCR also recommends that, rather than using a "snapshot" of avoided cost projections from a single year, the Commission instead average forward price projections gathered during each of the previous three years. This would smooth out the peaks and valleys that frequently occur under the "snapshot" approach. This would also eliminate any ability of a utility to cherry pick favorable projections windows. Three year averaging would also promote stability in avoided costs, as it would tend to result in a QF project obtaining similar avoided cost pricing, regardless of whether it enters into a QF contract with NWE before or after any particular annual update.

Three year averaging of avoided cost projections would also benefit NWE. Under the current system, in the period immediately preceding an annual avoided cost update (particularly one that lowers avoided cost rates), the utility can be inundated with requests for new projects. However, under an "averaging approach," it is likely that there will be volatility in avoided cost rates, which will mitigate the "rush" on QF contracts that often occurs before avoided cost updates.

b. What Methods Should the Commission Refrain From Using to Estimate NWE's Long-term Avoided Costs and Set Rates for Small and Large QFs? Why Should Those Methods Be Avoided?

The Commission should avoid methodologies that:

(1) are subject to manipulation by NWE because of the opaque, "black box" nature of any modeling or simulation;

(2) are more likely to result in significant and sudden increases or decreases in rates due to short term trends in fuel costs; and

(3) yield results that are not transparent or that QFs and Staff are unable to readily ascertain or audit with their own resources

c. Does NWE's acquisition of the PPLM Hydroelectric Resources Affect Which Methods Are Best Suited for Estimate NWE's Avoided Costs? If So, How?

With the PPLM acquisition, Montana ratepayers have assumed the risks and costs of ownership of baseload hydroelectric generation assets. Those costs include the full $870 million purchase price, including the acquisition premium, of the hydroelectric assets. Thus, any avoided cost model must include the full cost of the acquisition as borne by ratepayers if the internal cost of the acquisition to NWE is to be accurately reflected.

Stated differently, avoided cost models must not reflect only a subset of costs for hydroelectric generation. The $116,865,355 annual revenue requirement approved by the Commission (*PPLM Acquisition Order, at P 140*) should be divided among all the megawatt hours produced by the acquired facilities to properly reflect the cost of NWE's internal hydroelectric generation.

d. Is NWE's PowerSimm Planning Model Suitable for Applying Differential Revenue Requirements and Component/Peaker Methods? What, If Any, Concerns would You Have With Using PowerSimm to Estimate Avoided Costs Using These Methods?

As a developer, CCR's concern with PowerSimm is the lack of reasonable transparency associated with its use.

e. If PowerSimm Is Suitable for Applying Differential Revenue Requirements and Component/Peaker Methods, Does the Model Need to Make Use of Optimal Capacity Expansion Planning Capabilities in Order to Reasonably Calculate Applicable Costs? Why or Why Not?

No comment.

2. Standard Rate Design

<u>Questions for Stakeholders</u>

a. Should the Commission Set Separate Standard Rates for Small Solar, Hydroelectric and/or Other Eligible Generating Technologies That Reflect the Specific Generating Characteristics of Those Technologies? Why or Why Not?

The Commission should not set separate standard rates based solely on the technology of the QF in question. PURPA's regulations call for QF contracts to be based on the utility's avoided costs, as opposed to cost considerations associated with the QF itself. Thus, avoided cost rates should not vary based simply on the technology that is used by the QF.

That said, it is appropriate and consistent with federal regulations (*see* 18 CFR § 292.304(e)) for QF purchase rates to reflect factors such as expected reliability, dispatchability, and peak period availability. Such factors may differ depending on the type or size of the generator. The outcome after considering such factors should result in pricing for energy and capacity that is as consistent as possible. For example, 1 MW of capacity should be priced the same, even if the formula for determining the quantity of a unit's production capacity reflects something other than the nameplate capability of each unit.

The goal of determining purchase rates should be the same regardless of the technology—to set capacity and energy prices that fairly and adequately represents the value that a QF generator provides to ratepayers and the utility, which is the cost of the capacity and energy that the utility and ratepayers would otherwise incur, but for the existence of the QF.

b. What Contract Length Is Sufficient to Enable a Viable QF project to Obtain Financing?

Contract lengths of 20 to 25 years are preferred, both from a lender standpoint and from the standpoint of the ratepayers, who will have a longer term hedge against fuel costs. At present, a contract length of 15 years is the minimum term required to enable a viable QF project to obtain financing.

c. Does a 25-year Standard Rate Contract Length Impose Undue forecast Risk on Consumers? If So, Why?

A 25-year contract length does not impose undue forecast risk on consumers. Provided that the avoided cost calculation is done correctly on the front end, the length of the contract—where fuel inputs are negligible and the costs for the QF output do not change based on moment-to-moment conditions—provides an appropriate hedge for the consumer against long-term trends in the costs of carbon-based fuels and costs that may be assessed against carbon-based fuels.

d. Comment On the Reasonableness of Shortening the Maximum Contract Length in NWE's Standard QF Tariff Schedules.

Contracts lengths of 25 years might be of interest for a utility's resource planning and can be acceptable to a QF. Thus, to have such a length as an option would be appropriate.

e. To What Extent Should the Length of a Standard Rate QF Contract Reflect the Economic Life of Alternative Resources NWE Is Planning to Acquire?

The standard contract length need not reflect the full economic life of an alternative resource. Rather, the standard contract length should be based on a term that is adequate for a QF to acquire financing. If the utility believes that it would be preferable to lock up a resource for its entire viable economic life, that should be an option available to the utility, subject to negotiation with the QF.

f. Should Standard Rates Reflect Avoided Costs Levelized for the Length of the Contract? Why or Why Not?

Levelizing costs generally has the impact of slightly increasing payments in the early years of a contract while slightly reducing payments during the final years of a contract. There is nothing contrary to PURPA regulations with using such an approach. Indeed 18 CFR § 292.304(a)(5) recognizes that the use of estimated costs—which may vary during particular time periods from the precise avoided cost that may apply during that time period—does not run afoul of PURPA's avoided cost pricing goal.

Using levelized pricing over the length of a contract can help QFs obtain financing for their projects. The somewhat higher prices in the early years of the contract can be a lynchpin for obtaining financing. Ratepayers benefit over the long-term by paying lower prices in the later years—prices below the initially predicted avoided costs. It would be appropriate in CCR's view that the option whether or not to choose levelized pricing be available to QFs.

g. Montana Law Requires the Commission to Encourage Long-term Contracts for Purchase of Electricity by Utilities From QFs (Mont. Code Ann. § 69-3-604(2)). How Should the Commission Interpret or Define "Long-term?"

The Commission should interpret the phrase "long-term" to mean that the contracts must be of a length that is adequate to actually allow renewable energy projects to be constructed and brought online. From a practical perspective, if a contract is so short in duration that it does not allow a QF to obtain financing in the marketplace, then it is inadequate to encourage QF development and does not meet PURPA's statutory intent.

h. Should Standard Rates Include Performance Standards and Automatic Rate Adjustments for Failure to Meet the Standards? Provide Any Specific Recommendations You Have for Such Standards and Rate Adjustments.

Performance standards and automatic rate adjustments, if designed properly, can be appropriate. On this issue, it is critical that the performance standards apply to items that are within the control of the operator of the generating facility and that are not simply the result of factors outside the operator's control.

CCR notes that the solar irradiation forecasting capability of the solar energy industry is fairly mature; many projects have been financed and many PPAs have been implemented with current forecasting tools. Thus, developers should not suffer a penalty if severe weather changes alter these predictions. Nonetheless, it is appropriate for QF developers to bear the risk of weather, in that contracts should not pay them for energy which was never produced and delivered, where such failure is caused solely by a lack of sunlight.

i. Should the Commission Approve a Full Standard Power Purchase Agreement? Why or Why Not?

As the Commission considers this issue, it should be aware that CCR, over the course of many months and with significant effort, was able to successfully negotiate a PPA with NWE.

3. Market Price Forecasting Methods

Questions for Stakeholders

a. Is the Commission's Current Practice for Blending Forward Market Price Information and EIA's Long-term Reference Case Forecasts Reasonable? If Not, What Changes Do You Recommend and Why?

CCR believes that using multi-year projections for estimating avoided costs and setting rates is appropriate. As discussed above, the use of only a single snapshot can result in inappropriate peaks and valleys in pricing, which has a deleterious impact on all market participants.

As noted, CCR believes that it would be appropriate to not only to use competing price forecasts, but to also blend current forecasts with the most recent forecasts from prior years, as this approach will create greater stability in avoided cost rates.

b. Should the Commission Consider a Range of Possible Future Prices (As Opposed to a Single Price Forecast) When Estimating Avoided Costs and Setting Rates? If So, What Sources Should the Commission Look to for Alternative Price Forecasts and How Should the Commission Treat the Multiple Forecasts in the Rate Setting Process (E.g., Should They Be Averaged or Weighted)?

Yes. Each year, the Commission should determine the best available current forecast of avoided costs. For ratesetting, it should then blend that forecast with the forecasts that were obtained in the previous two years.

c. Since Forward Market Prices Can Change, Sometimes Significantly, Over Short Periods of Time, Would an Average of Recent Forward Price Information Be Preferable As a Starting Point for Developing a Price Forecast Than a "Snap-shot" Taken at a Particular Point in Time? Why or Why Not?

As discussed above, an average of forward price information is preferable to a single snapshot taken at a particular point in time. CCR recommends that the Commission average price forecasts from the previous three year period when setting avoided cost rates, which would involve three snapshots taken on a given date over that period of time. Importantly, NWE should not have discretion to select retroactively the date for these snapshots; rather, the Commission should select the date ahead of time.

d. Is the Commission's Current Approach to Accounting for Estimates of the Incremental Costs of CO_2 Emissions in Long-term Standard Rates for Small QFs Reasonable? If Not, Why and How Should the Approach Be Modified?

The Commission devoted extensive resources and consideration to this issue during its review of the PPLM acquisition. It should continue to use the estimates of the incremental costs for carbon emissions developed in that docket (Docket No. D2013.12.85) until such time as those forecasts have been proven wrong.

The Commission should avoid creating a new method for estimating carbon costs that would apply solely when determining QF avoided costs. The incentives that NWE would have in any proceeding devoted to such an endeavor would diverge so widely from the incentives NWE had during the PPLM acquisition proceeding that it would be difficult to expect a just and reasonable outcome could be achieved.

e. Should NWE Receive All or a Portion of the Renewable Energy Credits Produced by a QF If the Purchase Rate Includes the Incremental Cost of CO_2 Emissions?

RECs should not automatically be included in PPA pricing. Inclusion of RECs should be subject to negotiation, if both the QF and NWE desire.

f. Is a Forecast of Regional (E.g., Mid-Columbia) Market Prices, Alone, a Reasonable Basis for Standard Avoided Cost Rates? Why or Why Not?

A forecast of regional market prices is an important component to use when determining standard avoided cost rates and can be the crucial component in such an analysis. However, many assumptions would have to be made (e.g., the assumption that transmission is available and that the generation will be sufficient) for that forecast alone to be the sole basis for avoided cost rates. Such assumptions would need to be subject to question. Further, market forecasts may not extend far enough into the future to provide a full basis on their own for the avoided cost rates.

4. Resource Capacity Values

<u>**Questions for Stakeholders**</u>

a. Is the Current Practice of Setting Standard Rates for Wind QFs Based on an Assumed 5% Capacity Value Reasonable? If Not, Why?

As a solar developer, CCR does not have a direct stake in terms of the Commission's use of the 5% capacity value for wind.

b. Can the Commission Set Reasonable Standard Rates Without Calculating Technology-specific Capacity Values Using Estimation Methods Such as Effective Load Carrying Capability or Exceedance? If So, How? Are There Reputable Sources of Estimates of Average Capacity Values for Various Generating Technologies That, Although Not Specific to NWE's System, Could Be Used for Setting Standard Rates? If So, Please Identify Such Sources.

CCR notes that solar energy industry is fairly mature in its ability to accurately predict performance and production over the term of a PPA. Many factors are specific to each generator, such as the type of solar panel, its placement, and the specific forecasts for solar irradiation.

c. Should QFs, Whether or Not They Are Eligible for Standard Rates, Be Required to Contractually Commit to Provide a Quantity of Capacity in Order to Receive a Capacity Payment, With Penalties or Rate Reductions If Delivered Capacity Falls Short? How Could the Commission Align Such a Requirement With FERC Rules Requiring Consideration of the Aggregate Value of QF Capacity? See 18 C.F.R. § 292.304(e).

QFs should be paid for the capacity they provide. It is appropriate for a contract to estimate the amount of capacity that will be provided. Such estimates should provide a window for the amount of expected performance, and specify the implications of exceeding or falling short of that expectation. Specific implications would be better addressed in a proceeding designed to adopt a *pro forma* agreement.

d. Can the Commission Set Reasonable QF Rates Absent Technology-specific Information Regarding Integration Requirements and Costs? If So, How?

Yes, the Commission can set reasonable QF rates absent technology-specific information regarding integration requirements and costs. To the extent that there are significant integration requirements or costs that are brought to the Commission's attention by a utility, the Commission can examine such claims in a new proceeding and could apply any resulting charge on a going forward basis in new QF contracts.

That said, CCR is skeptical that adequate information would currently be available to appropriately justify any charge based on assertions that integration of solar QFs has a cognizable impact on a utility's actual avoided costs.

e. Are There Reputable Sources of Estimates of the Average Integration Requirements for Various Generating Technologies That Could Be Used for Setting Standard Rates? If So, Please Identify Such Sources.

To CCR's knowledge there are no reputable sources for accurate estimates or calculations of actual integration costs, despite the fact that charges pertaining to this subject have been implemented in some jurisdictions. A study by the National Renewable Energy Laboratory ("NREL") titled "A Review of Variable Generation Integration Charges" is a good source of relevant information. *See* http://www.nrel.gov/docs/fy13osti/57583.pdf.

5. Requirements for Creating a "Legally Enforceable Obligation"

<u>**Questions for Stakeholders**</u>

a. Are the Commission's Requirements for Creating a LEO Reasonable? If Not, Identify and Explain Any Needed Changes.

No. To establish an LEO under the current regime, an QF must tender to the utility an executed power purchase agreement with a price term that is consistent with the utility's avoided cost. The agreement must contain "sufficient guarantees to ensure performance" during the contract term, and must be accompanied by an executed interconnection agreement. *See* Docket No. D2002.8.100, Order No. 6444e, at ¶ 47 (June 4, 2010).

These pre-conditions to the establishment of an LEO are unreasonable and should be changed, for several reasons. First, requiring an executed PPA gives the utility the power to circumvent PURPA by prolonging PPA negotiations solely for the purpose of delaying the ripening of the obligation under PURPA to purchase power from the QF. Further, requiring the PPA to contain "sufficient guarantees to ensure performance" is an impossibly ambiguous condition that can be exploited by utilities such as NWE to deny the existence of an LEO. That is, utilities can use this vague condition as an excuse for delaying both contract negotiations and the ultimate execution of the PPA with a QF that is otherwise entitled to an LEO.

Requiring a QF to have an executed generation interconnection agreement as a condition precedent to an LEO is likewise unreasonable. Executing an interconnection agreement is an expensive and time-consuming process that can require months—and sometimes years—of studies and analysis. In practical terms, an executed interconnection agreement may obligate an interconnection customer to significant further upgrade costs and typically obligates the interconnection customer to specific timelines. In both cases, this is putting the cart before the horse, as the absence of a PPA or LEO removes the justification for such spending and removes the most important factor (a targeted commercial operation date acceptable to the offtaker) for establishing construction timelines. Thus, requiring a QF to obtain an executed interconnection agreement is an unjust and unreasonable requirement for establishing a LEO.

Moreover, the fact that a project does not have executed interconnection agreement does not mean that it is a "speculative, paper proposal," as the Commission stated in Order No. 6444e. Indeed, in other jurisdictions, regulated utilities and independent power producers alike plan and seek approval for major generation projects long before executing interconnection agreements with independent transmission operators—and even before completing studies that are necessary to identify transmission constraints or the upgrades that would be required to mitigate those constraints. These projects are certainly not regarded as "speculative," so it would be unreasonable and unfairly discriminatory to label a QF project as such.

CCR recommends that the Commission repeal these requirements and establish more definitive and reasonable procedures by which a QF could obtain an LEO. Specifically, once the QF has notified the utility of the pertinent details regarding its project (including a submitted interconnection request) and tendered a draft power purchase agreement it is willing to execute, the utility should have a specific number of days to respond as to the completeness of the submission and as to any substantive areas the utility wishes to negotiate. CCR recommends a timeline of 20 business days. The QF should be given 5 business days to respond, and the utility an additional 5 business days for any final reply or to proceed with execution. If the utility unreasonably delays negotiations or refuses to execute the PPA within 10 business days after this point, the LEO should be considered as established.

The Commission should set a mechanism for the QF to file the unexecuted LEO agreement. This should not be a complaint proceeding. Rather, the filing would create a rebuttable presumption that an LEO has been established. If the utility wishes to rebut that presumption, it would bear the burden of bringing a complaint and demonstrating that the QF had not followed the appropriate process or had not provided the required information. To resolve these disputes in a timely manner, CCR recommends that the Commission establish an expedited dispute resolution process that would allow the specific type of complaint to be resolved in 45 days or less.

b. Do a QF's Rights to Bilaterally Negotiate and Create a LEO Weaken, or Render Ineffective, the Competitive Bidding Rule? Why or Why Not?

No. According to Commission staff's August 11 memorandum in this docket, "utilities and QFs always have the right to negotiate the terms of energy and capacity to a utility." At the same time, QFs have historically been unsuccessful when participating in the competitive solicitations that the Commission has established. Thus, if QFs have always had the right to independently negotiate PPAs with utilities, but have historically been unsuccessful in the competitive solicitation process, it is difficult to understand how the former could weaken the latter.

More importantly, according to FERC's declaratory order in *Hydrodynamics, Inc.*, 146 FERC P 61,193 (Mar. 20, 2014), the Commission's competitive solicitation process cannot be the only means by which a large QF (*i.e.*, greater than 10 MW) can obtain an LEO. In other words, regardless of whether the ability to create an LEO through bilateral negotiations weakens the competitive bidding process, the Commission must (according to FERC's declaratory order in *Hydrodynamics*) allow an LEO to be created through such negotiations.

c. Should the Commission Consider Repealing the Competitive Solicitation Rule? Why or Why Not?

To the extent the competitive solicitation process is the only means by which a large QF can establish an LEO and obtain long-term avoided cost rates, the Competitive Solicitation Rule should be repealed because it is inconsistent with *Hydrodynamics*.

d. If a Utility Has Issued a Competitive Solicitation for Energy or Capacity That Is Open to QFs, Would It Be Reasonable for LEO Determinations Made After Issuance of the Solicitation to Assume That the Solicited Resources Will Be Added to the Utility's Resource Portfolio As a Result of the Solicitation Process? Why or Why Not?

The mere issuance of a competitive solicitation should not result in a conclusion that all resources sought in the solicitation have been obtained. Experience from such processes in other jurisdictions shows that not all requested resources end up being brought on line.

e. If You Answered "Yes" to Part (d), Discuss the Implications of That Assumption for Estimating Avoided Costs.

CERTIFICATE OF SERVICE

I hereby certify that the original and 10 copies of Comments of Cypress Creek Renewables in the Matter of Inquiry by the Montana Public Service Commission Into Its Implementation of the Public Utility Regulatory Policies Act of 1978, Docket No. N2015.9.74 have been sent via FedEx to the Montana Public Service Commission and that 3 copies have been sent via FedEx to the Montana Consumer Counsel. The Comments have also been e-mailed and mailed (via First Class Mail) to the parties in this proceeding, and e-mailed to psc_utilitycomment@mt.gov.

Dated this 13th day of November, 2015.

David R. Zoppo
Attorney for Cypress Creek Renewables