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UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (RATTLESNAKE CANYON PROJECT)	)	**CASE NO. PAC-E-11 -01**
IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (COYOTE HILL PROJECT)	)	**CASE NO. PAC-E-11-02**
IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (NORTH POINT PROJECT)	)	**CASE NO. PAC-E-11-03**

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (STEEP RIDGE PROJECT)	)	**CASE NO PAC-E-11-04**
IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA ROCKY MOUNTAIN POWER FOR A DETERMINATION REGARDING A FIRM ENERGY SALES AGREEMENT BETWEEN ROCKY MOUNTAIN POWER AND CEDAR CREEK WIND, LLC (FIVE PINE PROJECT)	)	**CASE NO. PAC-E-11-05**

CEDAR CREEK WIND, LLC'S PETITION FOR RECONSIDERATION OF ORDER NO. 32260 AND REQUEST FOR EXPEDITED TREATMENT

Cedar Creek Wind, LLC, ("Cedar Creek") petitions the Commission to reconsider its Order No. 32260, issued June 8, 2011 (the "*June 8 Order*"), in which it disapproved five Firm Energy Sales Agreements (the "Agreements") between Rocky Mountain Power and Cedar Creek (collectively, the "Parties") with respect to Cedar Creek's Rattlesnake Canyon, Coyote Hill, North Point, Steep Ridge and Five Pine projects (collectively, the "Projects"). The Projects are qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Nevertheless, the Commission held that the Projects were not eligible to receive avoided cost PURPA contracts using published rates because the Agreements were not signed by both Parties prior to December 14, 2010, after which time such published rates no longer were to be made available to QFs exceeding 100 kW.

PURPA and its implementing regulations however are clear: it is the legally enforceable obligation of the QF to sell and of the electric utility to purchase from the QF at rates based on the electric utility's avoided costs "calculated at the time the obligation is incurred."[1] Indeed, the term "legally enforceable obligation" purposefully does *not* equate to a fully executed contract, precisely because this would rest the fate of PURPA in the hands of one party. Thus, insofar as the *June 8 Order* is expressly predicated on the fact that both Parties had not signed the Agreements prior to December 14, 2010, it turns the law on its head. And, because prior to December 14, 2010, a "legally enforceable obligation" *did* exist with respect to the Agreements under both federal and Idaho law, the *June 8 Order* as applied to Cedar Creek is unreasonable, unlawful, erroneous, and not in conformity with federal or Idaho law, and Cedar Creek therefore respectfully requests that the Commission reverse its determination and expeditiously approve the Agreements as submitted, without further briefing or proceedings.

I. PETITION FOR RECONSIDERATION

A. The Commission Erred in Holding that the Agreements Had to be Fully Executed by December 14, 2010

1. The Commission's Fully Executed Contract Requirement is Contrary to Federal Law as Applied to Cedar Creek

In the *June 8 Order*, the Commission concluded that the "primary issue to be determined in these cases is whether the Agreements – which utilize the published avoided cost rate – *were executed* before the eligibility cap for published rates was lowered to 100 kW on December 14, 2010, for wind and solar projects."[2] In so doing, the Commission adopted "a bright line rule: a Firm Energy Sales Agreement/Power Purchase Agreement must be executed, i.e., signed by both parties to the agreement, prior to the effective date of the change in eligibility criteria."[3] As

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1 18 C.F.R. § 292.304(d)(2)(ii).

2 *June 8 Order* at 9 (emphasis added).

3 *June 8 Order* at 10. The change in eligibility criteria reduced from 10 aMW to 100 kW the size of wind and solar QFs eligible for so called "published" avoided cost rates. Projects in excess of 100 kW

more fully explained below, Cedar Creek respectfully submits that the Commission's application of this bright line rule is contrary to federal law, specifically, the Federal Energy Regulatory Commission's ("FERC") regulations implementing PURPA, which expressly reject the notion that a QF must have a fully executed contract in hand to obtain its PURPA benefits.

Under PURPA, a QF's right to sell at avoided cost rates arises out of a *legally enforceable obligation* – not solely from a fully executed contract.[4] FERC has made clear that a "legally enforceable obligation" and an "executed contract" are neither synonymous nor interchangeable; while all contracts constitute legally enforceable obligations, not all legally enforceable obligations are expressed only in fully executed contracts.[5] And FERC has repeatedly upheld this distinction: (i) a legally enforceable obligation can, and does, exist in the absence of a contract; (ii) under PURPA, QFs have the right to obtain the benefits of PURPA even where no contract is executed; and (iii) the phrase "legally enforceable obligation" was adopted expressly to prevent a utility from being able to circumvent PURPA's requirements simply by failing to sign a contract with the QF.[6]

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would no longer have the option of selecting the published avoided cost rates but would be restricted to using avoided cost rates determined via the Integrated Resource Plan Methodology.

4 18 C.F.R. § 292.304(d)(2). *See also* 18 C.F.R. § 292.304(b)(5); 18 C.F.R. § 292.304(e)(2)(iii) (specifying "[t]he terms of any contract *or other* legally enforceable obligation" as being among the factors affecting how the avoided cost rates "[t]o provide energy or capacity pursuant to a legally enforceable obligation for the deliver of energy or capacity over a specified term" are to be determined).

5 *See, e.g., Midwest Renewable Energy Projects, LLC*, 116 FERC ¶ 61,017 at P 15 (2006) (rejecting "the notion that the terms 'contract' and 'obligation' are synonymous"); *JD Wind I, LLC*, 129 FERC ¶ 61,148 at P 25 (2009).

6 *See, e.g., Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Statutes and Regulations, Regulations Preambles 2001-2005 ¶ 30,128, at 30,880 (1980) (subsequent history omitted); *JD Wind I, LLC*, 130 FERC ¶ 61,127 at P 7 (2010) (*order on reh'g*) (explaining that a QF's commitment to sell to a utility, and the utility's accompanying obligation to buy from the QF, "result either in contracts or in non-contractual, but binding, legally enforceable obligations").

The key consideration, then, in determining whether a PURPA obligation exists is not whether an agreement is fully executed, but whether, as was true here for Cedar Creek, the QF has committed through a legally enforceable obligation to sell power to the utility or, as also was the case here for Rocky Mountain Power, the utility is committed to entering into a legally enforceable obligation to buy that power. Consequently, and contrary to the Commission's formulation, the issue in this case is not when the purchasing utility signed the contract, but rather when the QF was *entitled* to a contract, because the QF's entitlement to avoided cost rates is set as of that date.[7] To conclude otherwise and allow one party's inaction to define whether a legally enforceable obligation existed would allow a QF's rights to be held hostage to a signature – precisely what the PURPA regulations are designed to prevent.

Indeed, under the *June 8 Order*, until both parties sign, a QF has no PURPA rights.[8] Hence, by imposing a bright line "signature" requirement the Commission's implementation of PURPA could not be more contrary to the PURPA regulations that expressly require a legally enforceable obligation, not a contract, *precisely* in order to prevent what has happened here; *i.e.*, a QF being prevented from receiving the benefit of its PURPA rights simply because the purchasing utility had not signed the contract. It is not at all surprising, then, that having asked the wrong question – namely, were the Agreements fully executed – and having applied the wrong standard, the Commission reached a legally infirm result.[9]

By substituting its "fully executed contract" standard for the "legally enforceable obligation" standard the Commission violated Cedar Creek's PURPA rights and by so doing

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7 18 C.F.R. § 292.304(d)(2)(ii).

8 *See June 8 Order* at 9.

9 The Commission's observation that other developers were able to submit fully executed agreements by December 14, 2010 does not change the fact that the legal standard applied by the Commission to disapprove the Cedar Creek Agreements was incorrect.

committed reversible legal error. Accordingly, Cedar Creek respectfully requests that the Commission reconsider its *June 8 Order*, apply the appropriate standard (which would not require any hearings or further factual development beyond that in the existing record, including this petition), and approve the Agreements without further proceedings.

2. The Commission's Imposition of an Executed Contract Requirement is Also Contrary to Commission Precedent Regarding QFs' Rights under PURPA

No doubt, FERC leaves it to the discretion of state commissions to establish *the date* on which a legally enforceable PURPA obligation is created. But state commissions are not authorized to define what a legally enforceable obligation is by ignoring the very distinction the PURPA regulations sought to make. If a legally enforceable obligation arose only upon contract execution, there would be nothing for state commissions to determine.[10] Prior to issuance of the *June 8 Order*, this Commission itself had recognized this crucial distinction, namely that it is the existence of a legally enforceable obligation – and not a signed contract – that first secures and protects the rights of QFs under PURPA, and on this basis, the Commission previously rejected the notion that a legally enforceable obligation is equivalent to a fully executed contract.

In fact, the Commission applied the correct *legally enforceable obligation* standard as recently as last year,[11] as well as in 2005 when the Commission last lowered the QF eligibility cap to 100 kW under virtually identical circumstances to those present here.[12] And strikingly, in

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[10] The Commission itself cited case law affirming this on page 9 of the *June 8 Order*, where the Commission quotes from *Rosebud Enterprises, Inc. v. Idaho Public Utilities Commission* (itself citing FERC precedent): "it is up to the States, not [FERC] to determine the specific parameters of individual QF power purchase agreements, including the date at which a *legally enforceable obligation is incurred* under State law." *Rosebud Enterprises, Inc. v. Idaho Public Utilities Commission*, 128 Idaho 609, 780-781, 917 P.2d 766, 623-624 (1996) (emphasis added and citing *West Penn Power Co.*, 71 FERC ¶ 61,153 (1995)).

[11] Order No. 32104 at 11-12 (2010).

[12] *E.g.*, Order No. 29839 at 9-10 (2005).

its 2005 orders – Order Nos. 29839, 29851, and 29872 – the Commission likewise lowered the posted rate eligibility cap from 10 aMW to 100 kW. But it did not impose a "fully executed contract" requirement on wind projects seeking to be grandfathered under the prior 10 aMW cap. Instead, relying on precedents it established in various complaints and grandfathering cases, the Commission applied the correct PURPA standard, namely a "legally enforceable obligation standard for published rate entitlement."[13]

Hence, in its prior cases the Commission found that because a *legally enforceable obligation* does not exclusively arise from the mere existence of a contract, the key date for purposes of determining whether such an obligation arose is not when the utility actually signed the contract, but when the legally enforceable obligation itself arose, thereby entitling the QF and obligating the utility to negotiate a contract with avoided cost rates effective as of the date the obligation was incurred.

Moreover, when previously considering whether QFs were eligible to receive published avoided cost rates, the Commission identified indicative criteria to determine *whether* such a legally enforceable obligation existed prior to the effective date of its decision on the eligibility cap. In cases where such criteria were met, a QF's contract was grandfathered in the Commission's decision. The Commission correctly recognized, there, that it did not matter that the contract had not yet been fully executed, and a QF that met these criteria was entitled to the published rates even if it did exceed the new eligibility cap (in 2005) or secure a fully executed agreement after the change in rates (in 2010). The Commission should have applied the same analysis to the PURPA Agreements and avoided the cost rate entitlement questions here.

[13] Order No. 29872 at 9 (quotations omitted).

According to the Commission in these prior decisions, a QF is entitled to the posted QF rates if, as of the applicable deadline, the QF had (i) submitted a signed power purchase agreement to the utility[14] and (ii) demonstrated "other indicia of substantial progress and project maturity," such as "(1) a wind study demonstrating a viable site for the project, (2) a signed contract for wind turbines, (3) arranged financing for the project, and/or (4) [made] related progress on the facility permitting and licensing path."[15] The purpose of the indicative criteria is not to create a rigid checklist but to demonstrate that the QF had expended sufficient time and resources on contract negotiations and project development so as to achieve a level of project maturity on the basis of which it reasonably could be expected to be brought on line within a reasonable period following contract execution.[16]

As recently as November 2010, just one month before issuing Order No. 32131 (the "*December 3 Order*") (ironically, in which order the Commission claims to have given "notice" of its determination here), the Commission likewise approved requests for grandfathering published avoided cost contracts, again recognizing that a QF could satisfy criteria other than by showing that it has a fully executed contract in order to demonstrate its entitlement to the previously-effective published avoided cost rates.[17] In fact, the Commission approved the requests based *solely* on circumstantial evidence indicating the QF's reliance on the existence of

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[14] As an alternative to submitting an executed power purchase agreement, a QF also could qualify for grandfathered treatment by submitting "to the utility [] a completed Application for Interconnection Study and payment of fee," and satisfying the other criteria described below. Order No. 29872 at 9.

[15] *Id.* at 8 (quoting Order No. 29839 at 9-10).

[16] *Id.* at 10-11. The Commission did not require that the QF satisfy *each* of these indicia, but had intended only to provide example "criteria that could be looked to to assess project maturity." Order No. 29951 at 5.

[17] Order No. 32104 at 11-12.

a contract and the parties' representations even though the QF did not proffer any written documentation of such agreement prior to the March 16, 2010 effective date.[18]

Similarly, and perhaps even more analogous to the circumstances here, in July 2010, the Commission approved a QF contract between Idaho Power Company and Cargill, which, while fully negotiated prior to the March 16, 2010 effective date for new published avoided cost rates, was not actually signed until May 4, 2010, due solely to the same reason that the Agreements were not executed by December 14, 2010: namely, the utility had to complete its "Sarbanes-Oxley review process and [] routine internal approval...."[19] The Commission approved the contract which incorporated the prior published avoided cost rates, based on the utility's representation – again, as Rocky Mountain Power has done here – that all outstanding contract issues had been resolved by that date and, but for the utility's internal review process, the contract would or could have been signed prior to the March 16, 2010 deadline.[20]

In short, these and the 2005 eligibility cap orders further demonstrate that the Commission's "fully executed contract" requirement in its *June 8 Order* is squarely at odds not only with federal law but with the Commission's own precedent in virtually the exact circumstances as those present in this case.[21] Inexplicably, though, in the *June 8 Order*, the

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18 *Id.* at 12.

19 Order No. 32024 at 3.

20 *Id.* at 4.

21 The Commission argues in the *June 8 Order* that "[b]ecause published avoided cost rates remain unchanged and only the eligibility size has changed, grandfathering criteria applied to <u>rate</u> changes are not applicable here." *June 8 Order* at 10. This assertion is belied by the Commission's treatment of similarly-situated QFs when it last reduced the eligibility cap in 2005. The Commission acknowledged in 2005 that the same criteria Cedar Creek argues are applicable here, were appropriate for the change in eligibility cap then. Furthermore, for the Commission to argue that changing the eligibility cap, and thus the rates that a QF is entitled to be paid for its power, does not constitute a "rate change" ignores the reality of what the Commission, and the utilities, are doing to affected QFs. Were QFs that are deemed ineligible for the published avoided cost rates able to obtain those same rates under the Commission's Integrated Resource Planning avoided cost determinations, there would be no issue here. However, as

Commission ignored its own history, and rejected the established "legally enforceable obligation" standard in favor of the new bright line "fully executed contract" rule. And it did so without explaining why it abruptly rejected and departed from its precedent, and changed how it applied the PURPA regulations. Thus, the Commission's misapplication of its own law renders the *June 8 Order* both unreasonable and unlawful insofar as it denied a QF its PURPA benefits, and did so without explanation.[22] Consequently, as the Commission already has ruled that the aforementioned criteria are sufficient to establish a "legally enforceable obligation," any QF that met those criteria prior to December 14, 2010 should similarly have been grandfathered and entitled to receive the previously published rates.

3. Although the Commission Gave Notice of the December 14, 2010 Effective Date, it *Did Not* Give Notice of its Intention to Require that Affected QFs Have Fully Executed Contracts by that Date in Order for them Still to Use the Published Avoided Cost Rates

Contrary to the Commission's assertion in the *June 8 Order*, the Commission did not previously hint at, much less state, the new bright line "executed contract" requirement in the *December 3 Order*. Rather, the *December 3 Order* was a procedural order directing only (as relevant here) "that the Commission's decision regarding *whether* to reduce the published avoided cost eligibility cap [would] become effective on December 14, 2010."[23] No doubt, if

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documented in Dana Zentz's affidavit submitted in this proceeding (the "Zentz Affidavit"), the prices available to the Projects under that process are 35% lower than the published avoided cost rates that were previously available. Zentz Affidavit at 9. By changing the eligibility cap rules, the Commission is by definition changing the rates that QFs are paid, and any grandfathering criteria that would appropriately be applied to "rate changes" should also be applied here, just as the Commission has done in the past.

22 At a minimum, the Commission must provide a reasoned explanation of its departure from its governing precedent. Absent such an explanation, the *June 8 Order* plainly is unreasonable and in violation of Idaho law. *E.g.*, *Intermountain Gas Co. v. Idaho Public Utility Comm'n*, 97 Idaho 113, 119, 540 P.2d 775, 781 (1975).

23 *December 3 Order* at 9 (emphasis added). On February 7, 2011, the Commission issued Order No. 32176, which temporarily reduced the cap from 10 aMW to 100 kW, effectively rendering projects in excess of 100 kW ineligible for the posted avoided cost rates as of December 14, 2010. The Commission

such a reduction were to occur, it would be effective on December 14, 2010. But *nowhere* in the *December 3 Order* does it state that such reduction would be applied to *any* QF purchase agreement not fully executed by such date.

Nor did the *December 3 Order* specify any requirements or even milestones that a QF would have had to meet by the December 14, 2010 effective date in order for it not to lose the right it otherwise would have had to receive the published avoided cost rates. In fact, it did *not* state, imply, or otherwise lead one reasonably to conclude that the Commission would or even might reject its own precedent, much less violate PURPA, by requiring that a QF have a fully-executed contract in order to receive the published rates. In sum, although the *June 8 Order* by reference to *Rosebud Enterprises* recognizes that the proper question under PURPA is, "when was a legally enforceable obligation incurred?", the Commission nevertheless chose to ignore PURPA's requirement that a QF's right to an avoided cost based contract be honored as of such time as a legally enforceable obligation first arose.[24] Instead, it decided not to approve the Agreements because insofar as they were not fully executed (*i.e.*, signed by both parties) until December 22, 2010, they were not effective prior to December 14, 2010, the date on which the eligibility cap was reduced to 100 kW.[25]

In so holding, though, the Commission erroneously asserted that because the *December 3 Order clearly* gave notice that any such change would be effective on December 14, 2010, and that the Order made it equally clear that the Commission would apply the "bright line rule" or, presumably *any* such rule as the Commission otherwise might have come to adopt in the *June 8*

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subsequently implemented the eligibility cap on a final basis in Order No. 32262, entered on June 8, 2011.

24 18 C.F.R. § 292.304(d)(2)(ii) (entitling a QF to rates based on "avoided costs calculated *at the time the obligation is incurred*" (emphasis added)).

25 *June 8 Order* at 9. The Commission concluded that because the Projects all were larger than 100 kW, they were not entitled to receive the published avoided cost rates.

Order as to what would happen in cases where both parties had not signed a purchase contract by December 14, 2010. Yet, the *December 3 Order* contains absolutely no notice of any such possible requirement. And, as noted above, just one month earlier, the Commission reached the directly opposite result, a result that was consistent with years of Commission precedent. What is clear, then, is that the *December 3 Order* was, or only could have reasonably been interpreted to be, purely a procedural order that did not reduce the eligibility cap, nor specify how a reduction not yet decided on its merits would be implemented.

Insofar as the *December 3 Order* certainly did *not* state or even imply that the Commission would change its prior Orders and now require a QF to have a fully executed contract to receive the published rates, the effect of the *June 8 Order* is to retroactively apply that standard without notice or due process *via* an order issued more than 6 months after it announced the December 14, 2010 deadline. Therefore, by failing to provide potentially affected QFs the notice required under Idaho law, regardless of whether the appropriate notice period was simply the 30-day notice required when the Commission is performing its legislative function of setting rates,[26] or the more extensive notice required under Idaho's Administrative Procedure Act,[27] the Commission has acted in an unreasonable and unlawful manner that is not in conformity with the requirements of Idaho law. The *June 8 Order* must therefore be reversed.

B. The Agreements Should be Approved Because a Legally Enforceable Obligation Under Applicable Commission Precedent Existed Between Cedar Creek and Rocky Mountain Power as of December 14, 2010

The Commission's precedents and criteria for determining a QF's eligibility to receive published avoided cost rates, together with the relevant undisputed record of this proceeding,

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26 IDAHO CODE ANN. § 61-307; *see also A.W. Brown Co. Inc. v. Idaho Power Co.*, 121 Idaho 812, 819, 828 P.2d 841, 848 (Idaho 1992).

27 IDAHO CODE ANN. § 67-5201 *et seq.*

leave no doubt that the Parties were under a legally enforceable obligation prior to the December 14, 2010 deadline, and as such, the Agreements should have been allowed to be based on the published rates available to QFs up to 10 aMW prior to that date, and should have been approved.

As Rocky Mountain Power acknowledged, the Parties "had completed negotiation of all terms of the Agreements for Cedar Creek's five projects prior to December 14, 2010."[28] Having finished their negotiations and agreeing that neither party had any additional substantive changes to the Agreements' provisions, the parties agreed on Friday, December 10, 2010, that the documents were ready for execution. Cedar Creek therefore finalized the Agreements, executed them, and delivered signed originals to Rocky Mountain Power on December 13, 2010, one day prior to the aforementioned effective date. It is also undisputed that when Cedar Creek executed the Agreements and delivered them to Rocky Mountain Power on December 13, 2010, the only remaining task was for Rocky Mountain Power to complete its administrative processing.[29] Regrettably, Rocky Mountain Power did not execute the Agreements until December 22, 2010, and did not file them for Commission approval until January 10, 2011, almost one month after their having been tendered by Cedar Creek.

But negotiation history aside, FERC and Commission precedent is clear that the signature history is irrelevant if a legally enforceable obligation existed. And it is undisputed that Cedar Creek executed the Agreements and submitted them to Rocky Mountain Power prior to the

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[28] *June 8 Order* at 7.

[29] *See* Order No. 32024 at 3-4 (approving grandfathered avoided cost rates for a QF where only the utility's administrative processing of its contract prevented that contract from being executed prior to the change in rate eligibility). During the period of administrative processing, Rocky Mountain Power made a number of undisputedly nonmaterial revisions to the Agreements, but this fact is not germane to the determination of whether a "legally enforceable obligation" existed prior to the December 14, 2010 date because it speaks to the wrong question, that is, when the Agreements were fully executed as opposed to when a legally enforceable obligation first arose.

Commission's December 14, 2010 deadline.[30] Hence, this satisfies the first criterion previously articulated by the Commission in Order Nos. 29839, 29851, and 29872, namely that the QF had *submitted* a signed power purchase agreement to the utility as of the announced effective date.[31]

In addition to having delivered signed Agreements to Rocky Mountain Power establishing its intent to be legally bound by such Agreements, by December 14, 2010 the Projects also had demonstrated many other "indicia of substantial progress and project maturity."[32] Specifically, by December 14, 2010 Cedar Creek had completed, or made substantial progress toward completing, virtually all of the critical path development milestones for each of the Projects, including those specifically identified by the Commission as demonstrating sufficient "substantial progress and project maturity" to establish a legally enforceable obligation.

1. <u>Cedar Creek had more than two years of wind data</u>: By the end of September, Cedar Creek had completed two years' worth of wind studies for the Projects and provided such data to Rocky Mountain Power as part of its due diligence efforts.

2. <u>Cedar Creek had arranged a term sheet with a major turbine provider</u>: By October 2010, Cedar Creek had commenced negotiations with Siemens and on that substantive basis received on December 3, 2010 a proposed term sheet for the wind turbines, the provisions of which are now largely reflected in the current, substantially complete Turbine Sale Agreement (which, consistent with current industry practice regarding turbine sales, would have been signed upon the approval of the of the Agreements). Through its affiliates, one of Cedar Creek's

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30 Additionally, as set forth above, and wholly aside from these preexisting criteria, as of December 13, 2010, the Projects were obligated to sell to Rocky Mountain Power at the published avoided cost rates available for QF projects of up to 10 aMW and Rocky Mountain Power plainly was under a legally enforceable obligation to continue in good faith to negotiate and execute a contract with the then published avoided cost rates.

31 *E.g.*, Order No. 29839 at 9-10.

32 Order No. 29872 at 8.

two owners had negotiated the purchase of wind turbines from Siemens for a number of other wind projects.[33]

3. Cedar Creek had a verbal agreement with one lender to provide approximately $240 million in financing: In October 2010, Cedar Creek commenced discussions with potential lenders as to the Project's financing. Following extensive due diligence efforts, Cedar Creek continued serious discussions with three lenders. Through this process, Cedar Creek negotiated two term sheets (as many lenders require a cosigned power purchase agreement for board approval of term sheet issuance). By early December 2010, Cedar Creek reached verbal agreement with a lender that provided a term sheet shortly after Rocky Mountain Power signed the Agreements, on the basis of which Cedar Creek held execution-ready agreements for financing (but for some minor changes still to be made to a few exhibits) at the time of the Commission's rejection of the Agreements.

4. Cedar Creek had already obtained two required Special Use Permits: By March 2010, Cedar Creek had obtained the two primary county Special Use Permits ("SUP") required to build and operate the Projects. Specifically, on August 25, 2008, Cedar Creek obtained the first SUP to install a total of 66 turbines. On March 24, 2010, Cedar Creek obtained the second Special Use Permit from Bingham County to build and operate an additional 33 wind turbines at the Projects.

5. Cedar Creek had full site control: By November 12, 2009, Cedar Creek had full control of the sites for the Projects through wind lease agreements with multiple land owners.[34]

6. Cedar Creek had submitted interconnection requests, executed binding agreements and made six figure deposits to maintain the required interconnect in-service date: Cedar Creek submitted its interconnection request on December 19, 2008, and obtained its Large Generator System Impact Study and Facilities Study reports on July 22, 2009 and March 18, 2010, respectively.[35] In addition, Cedar

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[33] Unlike 2005 when wind turbines were in short supply and early reservations were the norm, in today's market the practice is not to consummate turbine sale agreements and incur substantial reservation fees until the developer has an approved power purchase agreement in hand.

[34] FERC defines "site control" by reference to the definition of that term in the Standard Large Generator Interconnection Procedures, which is as follows:

> documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purposes; or (3) an exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

[35] *See* Zentz Affidavit, p. 5, 6.

Creek executed an Engineering & Procurement Agreement with Rocky Mountain Power on September 15, 2009, pursuant to which it tendered a $100,000 deposit. Cedar Creek was provided with a draft large generator interconnection agreement ("LGIA") on April 15, 2010, although Rocky Mountain Power has since required Cedar Creek to enter into a QF-specific LGIA. [36]

7. Cedar Creek had submitted formal requests for and posted six figure deposits to secure transmission: On January 11, 2010 Cedar Creek submitted to PacifiCorp an OASIS request for 99 MW of long term firm point-to-point transmission service, and posted a security deposit of $200,475 roughly one week later. Cedar Creek executed a Long Term Point to Point Transmission Service agreement with PacifiCorp in May 2010.[37]

Lastly, as of December 14, 2010, Cedar Creek had in total invested $1.2 million to support its obligations to deliver the Projects – fully permitted, constructed and operating – by the commercial operation dates specified in the Agreements. Cedar Creek's investment has since grown to roughly $3.5 million, and in order to meet an October 1, 2012 commercial operation date would have increased much more had the Agreements not been rejected. Collectively, then, the Projects reflected the work of real, mature development efforts, significant financial investments, and irrevocable commitments.

In short, there is no question that as of December 14, 2010 the Projects were more than sufficiently mature so as to require Rocky Mountain Power to negotiate and eventually execute a contract pursuant to PURPA. Both FERC and Commission precedent required this legally enforceable obligation to be honored as of December 14, 2010 and Rocky Mountain Power eventually to formally execute the Agreements. Thus, because a legally enforceable obligation existed as of December 14, 2010, Cedar Creek is entitled to receive the then published avoided cost rates for projects up to 10 aMW, and the Agreements therefore should be accepted and approved by the Commission without further hearings or other proceedings.

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36 *Id.*

37 *Id.* at p. 6, 7.

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