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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA**

IN THE MATTER OF The Complaint By Oak Tree Energy LLC Against NorthWestern Energy For Refusing To Enter Into A Purchase Power Agreement	**DOCKET NO. EL11-006** **OAK TREE ENERGY, LLC'S POST-HEARING OPENING BRIEF**

OAK TREE ENERGY, LLC'S POST-HEARING OPENING BRIEF

I. INTRODUCTION

Oak Tree Energy, LLC (Oak Tree), acting by and through counsel, and pursuant to the South Dakota Public Utility Commission's (PUC) Post-Hearing Procedural Order entered on April 10, 2012, hereby submits its Post-Hearing Opening Brief.

II. EXECUTIVE SUMMARY OF ARGUMENT

The following is an executive summary of Oak Tree's arguments in this brief:

- The Oak Tree project will benefit NorthWestern Energy's (NWE) ratepayers over the 20-year life of the project.

- Avoided cost projections are based on the life of the project, not based on short-term snapshots of the current market place. Estimates of avoided costs should be based on fundamentals-based forecasts, where each factor is analyzed and assessed based on its contribution to the overall expected avoided cost for a utility.
- The Black & Veatch 20-year electric price forecast is a long-term, fundamentals based forecast. The gas price forecast, which is a main fundamentals-based driver in the Black & Veatch Energy Market Perspective for the South Dakota region, is superior to the Energy Information Information's (EIA) early natural gas price forecast for 2011 in that the EIA forecast did not assume coal plant retirements due to impending regulations on coal plant operations by the U.S. Environmental Protection Agency (EPA). EIA has acknowledged that it did not take into account these regulations in its early 2011 price forecast because the regulations were not yet final. Black & Veatch correctly assumed that over the next few years, those regulations will be final, 52,000 megawatts (MW) of coal plant will retire in the U.S. (some 44,000 of which are in the Eastern Interconnect, which includes South Dakota), and these retirements will have an upward pressure on gas and electric prices.
    - NWE's methodology for calculating avoided costs is certainly simple, but it is fundamentally flawed and biased in the direction NWE wants to move toward (namely a long-term rate that will not permit Oak Tree

to build its facility). There is no credibility to NWE's methodological approach as NWE chose to use *none* of the five methods outlined in the testimony of Bleau LaFave in his direct prefiled testimony. Instead, NWE claimed it is using a "hybrid" approach of several of these methods. However, NWE was not using a "hybrid" of any valid approach. Instead, NWE's "hybrid approach" is illegitimate for at least four reasons: (1) it attributes no value to sales by the utility of power in hours that the utility is long on energy except for the incremental value of operating NWE's coal plants thus violating the principle of avoided costs as set forth in the Public Utility Regulatory Policies Act of 1978 ("PURPA") and its implementing regulations; (2) it is based in large part on a natural gas forecast that does not assume any real increase in natural gas prices from 2016 to 2031, a completely unrealistic assumption[1]; (3) the method does not take into account any fundamental factors, such as the risk of coal plant retirement, the increased costs associated with horizontal drilling of shale bed exploration due to the decline in valuable non-natural gas fuels (i.e., "sweet spot" drilling), nor does it take into account the increased

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[1] Mr. Lewis's levelized gas price forecast of $5.14/MMBtu stands in stark contrast to the $9.50/MMBtu assumed by NWE's partner in the Big Stone coal plant. As evidenced in the Otter Tail Power Company, ("OTP" or "Company"), petition to the PUC [for approval of an Environmental Quality Cost Recovery Tariff ("Environmental Cost Recovery Rider"), pursuant to SDCL Chapter 49-34A, Sections 97 through 100, relating to approval of tariff mechanisms for automatic annual adjustment of charges for jurisdictional costs of new environmental measures], Otter Tail assumed that a gas fired combined cycle would be more expensive than modifying the Stone Creek plant. At http://puc.sd.gov/Dockets/Electric/2012/el12-027.aspx Attachment 3, page 380 of 479 Otter Tail shows the fuel cost for a new combined cycle combustion turbine of $66.44/MWH. A new combined cycle combustion turbine has a heat rate of approximately 7000 btu/kwh. Therefore Otter Tail is assuming the cost of gas is $9.50/MMBtu [$9.50/MMBtu times 7000 btu/KWH = $66.5/MWH. *See* SD PUC Docket No. EL12-027.

environmental costs associated with fracking; and (4) because it deprives the qualifying facility (QF), in this case, Oak Tree, of actual avoided costs based on market sales.

- Oak Tree incurred an LEO on February 25, 2011. There is no evidence in this record to the contrary. While there are concerns about the avoided cost forecast prepared by Mr. Lauckhart being too high relative to market as of February 25, 2011, that snap shot of recent downward prices is irrelevant to a properly conducted avoided cost determination. The question, whether it is a utility investment or whether it is power purchase agreement, is whether the price is a good deal for consumers over the life of the contract at the time the decision was made to go forward. Utilities make their investment decisions this way, and unless there is evidence the utility's investment decision was imprudent at the time it was made, the various state utility commissions permit the utility to recover these costs in rates over the useful life of the asset from ratepayers. The calculus is no different for Oak Tree. To do otherwise would be to discriminate against Oak Tree in violation of PURPA and the Federal Energy Regulatory Commission's ("FERC") implementing regulations, which prohibits rates that are discriminate against QFs. *See* 18 C.F.R. § 292.304(a).

III. ARGUMENT

A. The PUC's Approval of the Oak Tree Proposal Will Benefit NWE's ratepayers.

The value of a long-lived asset is determined by the benefits realized over the life of the project – not the value realized during the first year of its 20-year life expectancy. As is the case with most, if not all, commitments of this magnitude, the decision to go forward is based on the benefits that will be realized over the long term. The Oak Tree wind project is one of those commitments. Even though there may be slight upward pressure on rates immediately, in the out years there will be benefits, which will substantially outweigh any short-term negatives.

Value based on the life of the project is not a new or unique concept. In fact, NWE employs this same analysis when it decides to add additional resources to its portfolio. Prior to constructing the Aberdeen plant, NWE made the decision that Aberdeen would benefit both its ratepayers and shareholders based on an evaluation of the relative costs and benefits over the life of that plant. Furthermore, recently, when NWE decided to enter into the Spion Kop project in Montana, the decision was based on the determination that, over the life of the project, NWE shareholders and ratepayers will benefit. The same is true for the Oak Tree wind project.

Testimony provided during the hearing regarding the Spion Kop project in Montana was to show the PUC that when dealing with a comparable project NWE recognized, and even promoted, some of the same benefits to its ratepayers it now denies. In the Spion Kop proceeding, NWE representative Mr. John Hines testified as to the volatility of fuel markets and the ability to mitigate that risk with a wind project. *Examination of John Hines*, Montana PSC Docket D2011.5.54 Hr'g Tr. 62:15-19 (December 14, 2011). However, in this proceeding, NWE representative Mr. Wagner implied that a wind project does not present those benefits. EL11-006 Hr'g Tr. 349:21-25 (March 22, 2012) (hereinafter EL11-006 Hr'g Tr.). In the Spion Kop proceeding, Mr. Hines testified that wind projects provide the ability to hedge against potential environmental legislation. *Cross-Examination of John Hines*, Montana PSC Docket D2011.5.54 Hr'g Tr. 23:3-4 (December 14, 2011). In this proceeding, NWE dismisses any potential value to mitigating the risk to further environmental regulations. And, even though Montana and South Dakota's legislation regarding renewable portfolio standards (RPS) are essentially the same in that neither require the purchase of renewable energy if alternatives are less expensive, in the Spion Kop proceeding NWE wished to own its own generation and thus pushed for this resource, while in this this proceeding NWE does not wish to purchase output from Oak Tree.

Furthermore, although Oak Tree recognizes there are differences between Montana and South Dakota, these differences do not include issues such as natural gas being the marginal resource, the benefits of fuel price hedging, the benefits of resource diversity, the applicability of national environmental regulations, the fundamentals of supply and demand, the potential effect of carbon legislation on the national cost for electricity, and the effect of potential national RPS. NWE testified to these benefits in the Spion Kop proceeding, yet either minimized or ignored their effect in this proceeding.

Oak Tree's expert factored in the material market differences based in his avoided cost calculations in this proceeding, and explained the adjustments he made in accounting for the fact the Oak Tree project is located in South Dakota:

> The first adjustment is I'm using the price -- this bubble here, called a WAPA bubble I think, but this price, this bubble on the South Dakota-North Dakota border here. I'm not using the price I've got for Montana. I've got a different price for Montana. It just happens to be not that much different for a number of reasons. But the point is I'm using the fundamental analysis that drives the market here in South Dakota. So that's the first thing. I'm not doing it for Montana. I'm doing it for South Dakota.
>
> The second thing is the capacity price that we've talked about here is driven by the supply and demand or capacity in this region. Not Montana region. In this region.
>
> The third thing is in your -- in South Dakota you -- actually your NorthWestern is in the WAPA balancing authority. The WAPA balancing

> authority really provides regulating reserves for wind people at essentially what I'm going to call a socialized cost. They have a very good ability to provide regulating reserves and you get that advantage here. In Montana they have their own – NorthWestern has their own balancing authority. They've stated that it's really hard to do it. They think it costs them about $15 a megawatt hour. So in that instance we put that cost on top of their wind because that's what they need. If they're going to do the wind, we don't need do it here. So those are at least three fundamental differences we're using in the calculation.
>
> But really when we're talking about Montana and South Dakota we're talking about theories. I mean, does it make sense in Montana to assume there's going to be some greenhouse legislation coming down the road but not in South Dakota? Federal greenhouse legislation isn't going to apply to Montana if it doesn't apply to South Dakota? Those are the kinds of things I'm saying here needs to be some consistency in those kinds of thinking.

EL11-006 Hr'g Tr. 125:14-127:3.

Mr. Lauckhart took into account all the factors that matter in calculating a South Dakota-NWE specific price for Oak Tree. But the benefits, regardless of the ability to quantify them, remain the same whether the project is in Montana or South Dakota.

B. Determining the Value of a 20-year Asset is not an Exact Science, but in the Industry We Need to Make Such Estimates

1. <u>Mr. Lauckhart's Avoided Cost Calculation is a Standard, Fundamentals-Based Forecast</u>

On pages 9-10 of Mr. LaFave's direct and rebuttal testimony (NWE Exhibit 1), Mr. LaFave identified five different methods used in the industry to calculate avoided cost: (1) proxy unit/surrogate resource method; (2) component/peaker method; (3) differential revenue requirement method; (4) market estimates; and (5) bidding approach. Mr. LaFave further identified that he obtained these five methodologies from Edison Electric Institute (EEI). EL11-006 Hr'g Tr. 279:20-21.

Black & Veatch prepared a detailed 25-year electric price fundamentals-based forecast which was prepared as a national forecast in the fall of 2010, and which Mr. Lauckhart relied upon in preparing a "brown value" 20-year avoided cost forecast for NWE based on the expected hourly output of the Oak Tree facility. Mr. Lauckhart provided a 259 page overview of the methods and findings of this 25 year forecast. *See e.g.,* Oak Tree Exhibit 1, at pp. 4-5; EL11-006 Hr'g Tr. 40:24-45:8. Mr. Lauckhart's approach is one of the five approaches identified by Mr. LaFave in his testimony, namely, the market estimate approach. Mr. Lauckhart's avoided cost analysis modeled, over 20 years, the value of the sale of the generation in the South Dakota region every hour of every year, approximately 176,000 hours. See e.g., EL11-006 Hr'g Tr. 131:8-132:1. This was based on a very specific analysis of the South Dakota region within the Eastern interconnect, specifically the Midwest Reliability Organization (MRO) and the Midwest Independent System Operator. *See e.g.,* Oak Tree Exhibit 1, Attachment 5, p. 9. The methodology employed by Black & Veatch for its electric price forecast, and relied upon by Mr. Lauckhart in preparing his 20-year avoided cost forecast in this proceeding assumed that the specific issues that might differentiate Montana from South Dakota were taken into account in the fundamentals-based modeling for the South Dakota region (e.g., different price forecasts, different capacity assumptions, different balancing authorities), and those modeling assumptions that are national in scope (e.g., retirement of coal plants, shale gas drilling costs, increased EPA regulation of coal plants, potential carbon legislation, national RPS standards) are treated in the same fashion for South Dakota as there is no reason to assume national trends will not affect South Dakota. *See e.g.*, EL11-006 Hr'g Tr. 125:14-127:3. This market approach fundamentals-based analysis produced a "brown power" avoided cost (assuming no value for renewable energy credits or "RECs") over 20 years of $78.92/MWH.

Oak Tree is not requesting the full avoided cost that Mr. Lauckhart has calculated in this proceeding and which PURPA requires utilities to pay to QFs. As mentioned previously, Mr. Lauckhart calculated a "brown power" avoided cost for NWE commencing on February 25, 2011 and continuing for 20 years of $78.92/MWH. In addition, utilizing a method previously used several times by NWE in Montana,[2] Mr. Lauckhart also calculated a "green power" avoided cost of $70.10/MWH, but the green tags or renewable energy credits (RECs) would be transferred by Oak Tree to NWE. Oak Tree is instead asking for $54.40/MWH for 20 years, which levelizes at 65.12/MWH. Oak Tree decided to request less than full avoided cost in hopes this would trigger an agreement with NWE, but also because it wished to be reasonable and because Oak Tree felt it could earn a reasonable return on its investment if it could build its project at that rate. EL11-006 Hr'g Tr. 151:25-152:7. Mr. Lauckhart's testimony establishes the reasonableness of Oak Tree's offer to sell its output to NWE.

2. <u>All Forecasts Are Not Created Equal</u>

It is a truism that forecasts are likely to be incorrect. In fact, one would be hard pressed to find any forecast that is wholly accurate in predicting the future. However, this does not mean that all forecasts are of equal value. Nor does it mean that the PUC should ignore the relative experience and qualifications of the experts who have testified on electric prices and avoided cost in this proceeding. Typically, as with any endeavor, experience, effort, and conducting an exhaustive analysis of all potential effects on the future price of electricity make a great deal of difference in the potential reliability of any forecast.

The contrast here between the experience and methodology of the respective parties' expert witnesses is obvious. NWE offers three inexperienced witnesses who have never

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[2] NWE utilized the proxy unit/surrogate method in Dockets D2008.12.146 and D2010.7.77. *See* EL11-006 Hr'g Tr. 47:24-49:14.

prepared an avoided cost forecast despite the fact that NWE obviously has in house expertise to prepare one in the form of NWE employees Mr. Mark Stauffer and Mr. Tim Guldseth.[3] Mr. Lewis has prepared a 20-year electric price forecast but he has never testified before on that methodology and the methodology itself has never been approved by any regulatory authority as a valid approach to forecasting electric prices. EL11-006 Hr'g Tr. 405:17-25. Mr. LaFave also has never prepared a long-term avoided cost forecast. EL11-006 Hr'g Tr. 220:25-221:2. Mr. Green had never prepared an avoided cost forecast of any kind prior to this proceeding. EL11-006 Hr'g Tr. 439:7-19.

NWE's unfamiliarity with PURPA's requirements was also evident during cross examination. Mr. LaFave explained repeatedly that NWE only had to prepare a five-year avoided cost forecast because this was all FERC required. EL11-006 Hr'g Tr. 229:1-230:19. Mr. LaFave was unfamiliar with the fact that 18 C.F.R. § 292.302(b) is not a limitation on how long a utility is required to prepare an avoided cost forecast. 18 C.F.R. § 292.302(b) merely lists the sorts of information that NWE is required to make publicly available so as to enable QF project developers and state commissions to determine an appropriate avoided cost rate:

> b) General rule. To make available data from which avoided costs may be derived, not later than November 1, 1980, June 30, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:
>
> (1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not

[3] Mr. Stauffer was NWE's expert on avoided costs in MPSC proceedings D2008.12.146 and D2010.7.77. Mr. Guldseth was NWE's electric price forecast expert in D2011.5.41, the Spion Kop proceeding.

> more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;
>
> (2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and
>
> (3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

Thus, Mr. LaFave confounded the requirement to publish *data* regarding avoided costs with a requirement to *only* develop an avoided cost forecast for five years. There is no such limitation in PURPA, especially since, as noted at Section III.D, *supra*, a QF has a right to a long-term contract. Whether Mr. LaFave's position was due to ignorance or device is unknown, but it is plainly incorrect. Mr. Green was similarly confused regarding the requirements of 18 C.F.R. § 292.302)(b), testifying that FERC only required a five-year avoided cost forecast and that Mr. LaFave limited his assignment to preparing a five-year energy only avoided cost forecast. EL11-006 Hr'g Tr. 434:13-436:2. Contrary to the opinions of Mr. LaFave and Mr. Green, *nothing* in PURPA or its implementing regulations limits a utility's obligation to forecast only a five-year, energy only avoided cost.

In contrast to the demonstrable inexperience of NWE's three experts, Mr. Lauckhart has some 41 years of experience in the energy industry and has prepared numerous electric price forecasts and avoided cost forecasts in a variety of jurisdictions. *See* Oak Tree Exhibit 1, Attachment 1. Mr. Lauckhart also assists in preparing the very thorough and expensive Black & Veatch Energy Market Perspective. EL11-006 Hr'g Tr. 46:5-14. Mr. Lauckhart and

Black & Veatch did not prepare the Energy Market Perspective solely for this proceeding. EL11-006 Hr'g Tr. 53:23-25. It is an unbiased, fundamentals based forecast of all potential factors affecting electric markets, including the region in which NWE's South Dakota service territory exists. EL11-006 Hr'g Tr. 54:6-13; 125:14-127:3. Black & Veatch's Energy Market Perspective is summarized in a 259-page study of all factors in the prospective energy market over 25 years, and costs $500,000 to produce but can be purchased off the shelf for $15,000 by various entities, including banks who have used these forecasts to make investment decisions worth hundreds of millions of dollars. EL11-006 Hr'g Tr. 54:1-13. After preparing his "brown power" analysis utilizing Black & Veatch's Energy Market Perspective and his "green power" analysis utilized preparing NWE's own prior methodology, Mr. Lauckhart concluded that Oak Tree's offer of $65/MWH is lower than an independent look at NWE's avoided costs. In short, as stated previously, ratepayers will benefit from the Oak Tree project.

NWE's position appears to be, that regardless of the effort or cost that goes into preparing a forecast, since each involves the exercise of judgment by experts, NWE's avoided cost/electric price forecast is every bit as valid as Oak Tree's. *E.g.*, EL11-006 Hr'g Tr. 420:5-15. In other words, despite the fact that: (1) NWE witnesses have never prepared avoided cost or electric price forecasts in any proceeding that has resulted in an order; (2) the fact these witnesses do not appear to understand PURPA or its regulations; (3) the fact that none of these witnesses has ever testified on any of this subject matter previously, and (4) that no jurisdiction anywhere has ever adopted the "hybrid" approach to avoided cost proposed by NWE's witnesses in this proceeding, NWE's method and forecast are just as valid as Mr. Lauckhart's – after all, the argument goes, judgment is judgment.

This line of reasoning does not comport with human experience about how important decisions are typically made. We do not, for example, disregard experience when making investment decisions, medical decisions or anything else where the skill and experience of the person involved may determine a successful outcome. Human experience tells us that, generally, more experience is better. Furthermore, the contrast with Oak Tree's methodology and results could not be plainer. Mr. Lauckhart is a well-recognized, national expert, relying on a fundamentals-based forecast prepared by a nationally recognized forecasting service. The method used by Mr. Lauckhart is one of the methods identified by Mr. LaFave, whereas Mr. LaFave utilized none of the methodologies he, himself, identified in his testimony. All judgments are not equally trustworthy. There is no basis for accepting any of NWE's testimony on avoided cost as it plainly does not want to purchase from Oak Tree, and its experts appear to lack sufficient familiarity to explain a reasonable basis for NWE's forecast.

3. NWE's Simplified Methodology is Unreliable and Contrary to Law

Although NWE in Montana knows well how to prepare an avoided cost methodology utilizing one of the established methods identified by Mr. LaFave in his testimony, NWE instead chose to use a "simplified" approach in this proceeding. The result of the use of this "simplified" approach is revealing in not only the multiple errors it contains, but for the results it produces. Perhaps not coincidentally, all the errors in NWE's forecast in this proceeding all produce a downward effect on NWE's "electric price forecast."

The difference between NWE's approach to avoided cost in Montana and in South Dakota is startling. In Montana, during NWE's avoided cost rate development cases, it used the proxy unit/surrogate method for calculating avoided cost rates. *See* Oak Tree Exhibit 2, Attachment 1 (Final Order 7108e, Docket D2010.7.77 (October 19, 2011)). In the *Spion Kop* proceeding before the Montana Public Service Commission (MPSC), D2011.5.41, Mr. Todd A. Guldseth utilized yet another of the avoided cost forecast methods identified in Mr. LaFave's direct and prefiled rebuttal testimony. Mr. Guldseth utilized a differential revenue requirement model that produced electric price forecasts ranging from $68.04 to $91.15/MWH over a 25-year term. *See* Oak Tree Exhibit 2, Attachment 2, p. 8.

Mr. Guldseth developed this differential revenue requirement model regarding the value of Spion Kop by preparing two revenue requirement forecasts, one including the Spion Kop project in NWE's Montana service territory, and one that did not. *See* Oak Tree Exhibit 2, Attachment 2, pp. 18-26. This differential revenue requirement model was prepared using PCI GenTrader®. *Id.* Specifically, Mr. Guldseth prepared a "market sensitivity scenario." *Id.* at p. 8. According to the table in Mr. Guldseth's testimony the full cost of Spion Kop was $68.77/MWH, while the cost of the "sensitivity market scenario + RECs" was $75.52/MWH. *Id.*

As previously stated, instead of utilizing the differential revenue requirement model or the proxy unit/surrogate resource method in this proceeding, NWE chose to use *none* of the established methods for developing an electric price forecast. Instead, it utilized a "simplified" approach which produces a result that is well-below any reasonable estimate of avoided costs in South Dakota over a 20-year term. For example, the levelized cost of any resource other Oak Tree is significantly higher than NWE's nonfundamentals-based electric price forecast of $35.80 over 20 years for Oak Tree: :

- Mr. Guldseth "value of Spion Kop" = $75.52/MWH using comparative revenue requirement method.
- Lauckhart "value" of Oak Tree = $78.92/MWH used using the market forecast

method

- Oak Tree offer = $65.12/MWH
- Cost of Titan Wind = $65.27/MWH (adjusted to 2011 start date)
- NWE calculated "value" of Oak Tree = $35.80/MWH using "simplified" method.

Mr. Lauckhart testified that there is no fundamental difference in South Dakota (or anywhere else) that accounts for these differences other than NWE is manipulating the forecast to produce the result it wishes to achieve. *See* Oak Tree Exhibit 2, Prefiled p. 6.

The evidence of this manipulation in this record is overwhelming. First, unlike what NWE did in Montana when it wished to convince the MPSC to pre-approve its purchase of Spion Kop, NWE did not use one of the accepted methods of calculating avoided costs. Not surprisingly, NWE produced a much higher market forecast utilizing an actual avoided cost method in the Spion Kop proceeding, D2011.5.41, than the nonfundamentals-based forecast it chose to use in this proceeding. Second, NWE's failure to use a fundamentals-based forecast is contrary to accepted industry standards. The following colloquy establishes that NWE expert Steven Lewis knows that the industry utilizes fundamentals-based forecasts for making investment decisions:

> Q. [Mr. Uda] Okay. So would you agree with me that there are at least several entities that have these off-the-shelf price forecasts that can be purchased?
>
> A. [Mr. Lewis] Yeah. There's various places you can go to purchase a forecast based on this kind of a model.
>
> Q. Okay. Ventyx?
>
> A. Yes.
>
> Q. Wood Mackenzie?
>
> A. Yes.

Q. IHS Cambridge Energy Research Associates?

A. In fact, NorthWestern was buying the forecast from them at one point in time.

Q. Okay. And do these entities all use fundamentals-based forecasts?

A. I don't know if I could say all of them but I would expect at some level they're using a fundamentals-based forecast, yes.

Q. Okay. Is this, in your opinion, the industry standard for how these electric price forecasts are prepared?

A. It is a method for creating price forecasts. You know, what we do is offer basically the alternative, which is the utilizing information that can be gleaned through the marketplace as a way to leverage that information and use that as basically the seed or the foundation for a price forecast which is an alternative method which is recognized.

Q. But to your knowledge do any of these companies use the method that you've employed in this proceeding?

A. Not to my knowledge.

Q. Okay. Do you know whether banks look to these entities for price forecasts in doing their due diligence analysis for power projects?

A. Do the banks look to?

Q. Experts like Ventyx, Black & Veatch, Cambridge Research Associates?

A. Yes, they do.

EL11-006 Hr'g Tr. 378:1-379:12.

Mr. Lewis thus acknowledges the leading electric price forecasters such as Ventyx and CERA use, at some level, a fundamentals based forecast. He further acknowledges that banks rely on these forecasts in making investment decisions as to whether to finance generation. In contrast, there is no evidence in this proceeding, or anywhere else, that the alternative electric price method proposed by NWE in this proceeding has been used by any credible organization in any proceeding – much less been approved by a regulatory body for use in setting avoided cost rates. Even NWE has not previously used this electric price forecast method in Montana. EL11-006 Hr'g Tr. 382:24-383:19.

It is essential that future potential changes in the electric price markets are evaluated, their risks appropriately taken into account, and that every effort is made to get the forecast right based on what we know today about the effects of fundamental changes in the market. NWE's forecast in this proceeding is certainly simple, but it is riddled with error and wholly unreliable. The PUC should reject NWE's simplified approach as unreliable and inconsistent with avoided costs.

4. NWE's Price Forecast/Avoided Cost Forecast is Riddled with Error

(a) Errors with 2012-2013

There are three NWE witnesses who worked on calculating avoided costs in this proceeding; Mr. LaFave, Mr. Green, and Mr. Lewis. The methodology adopted by NWE in this proceeding for 2012-2013 is essentially this:[4] Mr. LaFave and Mr. Green determined what portion of their electric price forecast should be derived from Mr. Lewis's long-term electric price forecast and which portion should be based on the incremental costs of operating NWE's coal plants (or its percentage ownership interest in those plants). Assuming Mr. Lewis has an electric price forecast for 2012-2013 of $35/MWH, and the incremental cost of NWE's coal plants is $20/MWH, Mr. Green then estimated how much of the time that purchases from the Oak Tree facility will occur when NWE is long on power (generation exceeds load) and how much will occur when the utility is short on power (load

[4] Oak Tree uses these examples for illustrative purposes, although they are representative.

exceeds generation). For example, if NWE assumes these purchases take place 62% of the time when NWE is long on power and only 38% of the time when it is short, the avoided cost is adjusted by the percentage based on the rate. Thus, using this example for illustrative purposes only, NWE witness Green would state that the avoided cost is calculated as 62% multiplied by $20/MWH and 38% multiplied by $35/MWH, producing a total avoided cost for 2012-2013 of just $25.7/MWH.

It is important to understand what NWE is actually doing with these calculations for 2012-2013. NWE's calculations are not based on how it operates its system. When NWE is long on power, and the incremental cost of operating its coal plants is less than market price, NWE makes a sale of that generation to the market at a profit. When market is less than the incremental cost of operating its coal plants, NWE presumably backs down its generation to avoid selling at a loss. Using the foregoing example, assuming that NWE's incremental cost of operating its coal plants is roughly $20/MWH and market is $35/MWH, NWE makes roughly $15 per MWH on the sale. Mr. Lauckhart's "brown power" forecast assumes that in each hour, regardless of the price forecast in that hour, Oak Tree receives the value of its output at the market price. In hours where, for example, market is less than the incremental cost of NWE's coal generation, Mr. Lauckhart simply assigns that market price to the value of NWE's generation even if it is less than NWE's incremental cost of operating its coal plants (e.g., $20/MWH).

In contrast to Mr. Lauckhart's approach, NWE is proposing that Oak Tree only receive the market value when NWE is short on power (in the previous example $35/MWH); if NWE is long, Oak Tree only receives the incremental cost of operating NWE's coal plants (in the previous example, $20). However, this is not the value NWE receives from its sales;

even when it is long on power it is making sales unless market is lower than the incremental cost of operating its coal plants.

This approach for 2012-2013 is completely contrary to an appropriate measure of a utility's avoided costs. Regardless of whether Oak Tree's generation is valued in the market at a price above NWE's incremental cost of coal generation, NWE nonetheless reduces the value of Oak Tree's generation in the hours it is not purchasing from the spot market to the value of the incremental cost of the coal plant in the years 2012-2013. NWE apparently maintains this is appropriate because it claims it cannot pass the value of Oak Tree's generation on to ratepayers in hours it is long due to the operation of its Power Cost Adjustment (PCA) in its tariff. In other words, NWE is refusing to pay QFs what they are worth in the market because of NWE's claim that NWE's PUC-approved tariff prohibits them from sharing the value of sales with NWE ratepayers.

PURPA requires utilities to pay *full* avoided costs to QFs. *See Southern California Edison Co. v. FERC,* 443 F.3d 94 (D.C. Cir. 2006). The utility's avoided cost is "the cost to the electric utility of the electric energy which, but for the purchase from such [QF], such utility would generate or purchase from another source." 16 U.S.C. § 824a-3(d). NWE's position seems to be that it has no obligation to pay a QF full value for energy delivered to NWE in hours where NWE does not need to purchase energy to serve its ratepayers. This position is flatly contrary to PURPA's requirements: "[A] QF is always entitled to a payment reflecting avoided energy costs. This is so because a utility can always avoid costs associated with the production of energy by decreasing the operation of one or more of its own units or by foregoing an energy purchase and replacing that energy with energy from the QF." *Public Service Co. of Oklahoma v. State ex rel. Oklahoma Corp. Com'n,* 115 P.3d 861, 876 (Okla., 2005).

In this case, Oak Tree should be paid the value of its energy on the spot market regardless of whether NWE is long on power if a value is received from selling that power in the open market, regardless of what that value might be. This is the assumption that underpins the "market approach" to calculating avoided costs utilized by Mr. Lauckhart. Instead, NWE assumes that when it is long on energy, it will only pay Oak Tree the incremental cost of operating its coal plants, regardless of the price that NWE is paid in the market for that energy.

Furthermore, NWE's proposed avoided cost calculation also illegally discriminates against Oak Tree. PURPA prohibits discrimination in the payment of avoided cost rates to QFs. 16 U.S.C. § 824a-3(b); 18 C.F.R. § 292.304(a)(1). NWE does not recover *less* revenue for its shareholder when NWE makes market sales with ratepayer assets – indeed, it claims that its PUC-approved PCA clause prohibits NWE from transferring the benefits of these sales to its ratepayers. In other words, NWE is receiving in excess of its incremental costs for its own market sales, but is proposing to pay Oak Tree less that value. This "heads we win/tails you lose" approach to avoided cost violates PURPA's proscription on setting avoided cost rates in a way that plainly and obviously discriminates against QFs and violates PURPA.

Moreover, this discrimination is evident in that NWE is not using this methodology (or anything close, really) in its contract with Titan Wind. Evidence at hearing establishes that NWE is paying the Titan Wind Project (Rolling Thunder) a contract rate unreduced by NWE's costs of operating its coal plants in long hours. The Titan Wind project is paid, according to Mr. LaFave, at $51.90/MWH for 2009, $53.20/MWH for 2010, $54.53/MWH for 2011, \$55.89/MWH for 2012, culminating in a rate of \$83.97. *See also* NWE Exhibit 9. Ultimately, this stream of prices produces a levelized price over the 20 year term of \$65.20 adjusted to a 2011 start date. Oak Tree offered a proposed PPA for a 20 year term of \$65.12/MWH.

Further evidence of this discrimination is that NWE did not refuse to negotiate above its short-term avoided cost rate with Titan as it did with Oak Tree. *See e.g.,* EL11-006 Hr'g Tr. 247:25-248:13. There is no real distinction between the 20 MW Titan Wind project and the 19.5 Oak Tree project other than Oak Tree is a QF and Titan is not.

Finally, Oak Tree does not believe the PCA clause does or should operate in the fashion suggested by NWE. In Section No. 3, Sheet 33, NWE's tariff sheet for its PCA clause, the language states:

> (1) The applicable energy or demand charges shall be increased or decreased quarterly, by an adjustment amount per kilowatt-hour of sales (to the nearest 0.001¢) or KW of demand (to the nearest 1.0¢) equal to the difference between the delivered cost of energy, delivered cost of fuel, ad valorem taxes paid, the Commission approved fuel incentives pursuant to SDCL 49-34A-25 ("qualified costs") per kilowatt-hour of sales or KW of demand and the base cost per KWH or KW included in applicable standard base rates, if any.

In Section (2) of Sheet 33, the tariff defines "Qualified Costs" to include "(II) Delivered Cost of Fuel." In that part II (c) and (d) of the definition of qualified costs, an adjustment is required to be made if NWE's generation was used to make economy energy sales. In other words, an appropriate adjustment would be to remove the cost of the supply that created the energy that was sold from the rates to be charged to customers. If, as NWE contends, its power purchase costs are included as a supply cost, then pursuant to this tariff, NWE should be removing that power purchase expense from the fuel costs to be recovered in the Adjustment Clause if energy purchased was thereafter sold in wholesale markets.

However, there is nothing in Section 3, Sheet No. 33, that indicates that power purchased from QFs is supposed be included as a cost in NWE's PCA clause. Therefore, NWE should not be permitted to recover the costs of Oak Tree's sales through NWE's PCA. If NWE felt the purchase of power from Oak Tree would erode its earnings to the point NWE felt it would not earn its allowed rate of return it should do so through a general rate case rather than by attempting to capture these costs through its PCA clause. In filing a general rate case, NWE would be required to transparently demonstrate to its ratepayers and the PUC all of its costs rather than recovering them through what is, at best, an opaque tracking mechanism meant to protect NWE from regulatory lag in recovering its fuel costs on a quarterly basis. Generally, that is how utilities attempt to recover the costs of long term purchased power such as the cost of the Oak Tree PPA. A general rate case will require NWE to include the cost of Oak Tree's PPA in rates, but NWE will need to reflect the fact that it is making more spot market sales during night-time hours and those revenues should result in a reduction of the size of any potential short-term rate increase to NWE ratepayers.

In summary, NWE's PCA clause does not permit NWE to recover the cost associated with Oak Tree's PPA. There is no indication that it is appropriate for NWE's PCA clause to be used for this purpose, and the plain language of NWE's tariff does not appear to permit the use of this mechanism to recover power purchase expense. NWE should be required to file for a general rate case if it feels power purchases are eroding its revenue. If NWE is, however, using its PCA clause to recover it power purchase expenses, the PUC should take note since NWE is apparently not sharing the benefits of sales in hours it is long with NWE ratepayers.

(b) Problems with NWE's forecast for years 2023-2031

NWE's calculation starting in 2023 assumes that NWE will not acquire any additional baseload coal in the future, and thus NWE will be purchasing spot market power in every hour of the year starting in the year 2023. So starting in the year 2023, NWE, through the testimony of Mr. LaFave, uses Mr. Lewis's price forecast as the "incremental cost" (avoided cost) value. However, by 2023, the Lewis forecast is considerably lower than any other credible market forecast because of his assumption (not shared by any other forecast known to Oak Tree) there will be no real increase in natural gas prices starting in 2015 and continuing through 2031 (e.g., EL11-006 Hr'g Tr. 382:13) and because Mr. Lewis has not incorporated any costs associated with greenhouse gas legislation in the forecast used by Mr. LaFave in this period from 2015-2031.[5]

During the hearing, it was established that no gas price forecasting entity is assuming that there will be no real increase in natural gas prices from 2015-2031. EL11-006 Hr'g Tr. 384:17-21. This includes the Energy Information Agency (EIA) forecasts. EL11-006 Hr'g Tr. 384:22-385:25. The EIA forecast produces a substantially higher natural gas price forecast starting in 2016 through 2031 than does Mr. Lewis's forecast. EL11-006 Hr'g Tr. 386:1-9. The Northwest Power Conservation Council (NPCC) also assumes a real increase in natural gas prices from 2012 through 2031. EL11-006 Hr'g Tr. 84:10-13. Mr. Brian Rounds, PUC staff witness, also testified that he agreed that there will "probably be real increases in the price of natural gas." EL11-006 Hr'g Tr. 466:18-19. Further, as indicated previously, *infra*, at p.3, n.1, the $5.14/MMBtu levelized gas price forecast developed by Mr. Lewis in this proceeding stands in stark contrast to the $9.50/MMBtu assumption used by

[5] Mr. Lewis did prepare a gas price forecast that included a carbon adder but NWE chose not to use this forecast in calculating its electric price forecast of $35.80. EL11-006 Hr'g Tr. 399:12-400:6 This is not, however, what NWE did in Montana, where Mr. Guldseth included a carbon calculation in his market estimate calculations. Cross Examination of Todd Guldseth, Montana PSC Docket D2011.5.54 Hr'g Tr. 43:1-48:9 (December 15, 2011).

Otter Tail. See SD PUC Docket No. EL12-027. In that proceeding, in which NWE is an intervenor, Otter Tail is attempting to cost justify its decision to retrofit the Big Stone coal plant to enable it to comply with EPA regulations rather than building a new combined cycle combustion turbine. To do so, Otter Tail is attempting to convince the PUC that building new combined cycle gas generation would be more expensive than retrofitting Big Stone. Assuming NWE agrees with Otter Tail (and there is no reason to think it disagrees) with the premise of this filing, NWE appears to be taking mutually inconsistent positions before the PUC based on the result it wishes to achieve.

Mr. Lewis's forecast of natural gas prices, and his calculation of future electric prices, is not credible due to the lack of an assumption of real gas price increases starting in 2016. Moreover, the MPSC rejected the use of no real increase in national gas prices in D2010.7.77, NWE's avoided cost docket, stating that NWE, as here, offered no credible explanation for the decision not to forecast real increases in natural gas prices. The MPSC stated:

> The 2.3% escalator Stauffer compared to NWE's 2% escalator comes from EIA's 2011 Annual Energy Outlook (AEO). NWE Late Filed Exhibit No. 1. However, EIA predicts that natural gas prices will increase at a rate of 2.3% per year, from 2009 to 2035, in real terms (not counting inflation), as Figure 86 on p. 2 of the attachment to Late Filed Exhibit No. 1 indicates – the prices shown in Figure 86 are all in 2009 dollars . (See also NWE Reply Br. p. 6) In contrast, NWE predicts that prices will increase at a rate of 2% per year, from 2014 to 2029, in nominal terms (including inflation). Tr. p. 49. Economically, EIA's 2.3% real rate of increase and NWE's 2% nominal rate of increase are not comparable. *According to Appendix A Reference Case, Table A1, of EIA's 2011 AEO, EIA predicts that natural gas prices will increase at a rate of 4.1 percent per year, from 2009 to 2035, in nominal terms. NWE's nominal natural gas price forecast departs significantly from EIA's over the 25-year Option 1 rate period.*

(emphasis added) Oak Tree Exhibit 2, Attachment 2 (Final Order 7108e, Docket D2010.7.77, at ¶ 62, p. 20)

The MPSC did not rely on NWE's forecast as a result, stating that:

> However, the record indicates that to the extent NWE checked its forecast against EIA's, it might have misinterpreted EIA's predicted annual growth in natural gas prices and failed to realize how much lower its forecast is compared to EIA's. If NWE knew that its forecast diverges from most other industry forecasts, it did not attempt to explain or justify that divergence.

Id. at ¶ 63, p. 22.

This lack of credible explanation for NWE's decision to use a natural gas price forecast that assumes no real increase in natural gas prices is equally evident here. NWE has offered no explanation to the PUC – none – for its decision to forecast no real increase in natural gas prices starting in 2016 through 2031. Oak Tree is entitled under PURPA to full avoided cost, and the PUC should not reward NWE for its lack of transparency.

In contrast to Mr. Lewis, the gas price forecast methodology used by Black & Veatch starts with a fundamental natural gas price forecasting tool that takes supply and demand factors into account. The model used, GPCM, is widely used in the industry. At hearing, staff witness Brian Rounds expressed concern the EIA-AEO early bird gas price forecast in February 2011 was somewhat lower than the Black &Veatch gas price forecast in use at that time. EL11-006 Hr'g Tr. 460:23-461:23. However, as Mr. Lauckhart testified at hearing, the 2011 EIA forecast did not assume any existence of pending and planned increasing environmental restrictions on coal plants, and therefore did not assume coal plant retirements. EL11-006 Hr'g Tr. 503:2-505:5.

Mr. Rounds also testified at hearing he was not aware that the EIA forecast for 2011 did not contemplate retirement of coal plants. EL11-006 Hr'g Tr. 476:3. Mr. Rounds also agreed at hearing that it is likely that coal plants will retire, EL11-006 Hr'g Tr. 465:21-22 ("I think there's going to be a lot of coal plants that get shut down."),[6] and that, if these plants are shut down, it will have an upward pressure on electricity prices and on EIA's gas price forecast. EL11-006 Hr'g Tr. 476:12-14. In contrast to EIA, Black & Veatch performed comprehensive analysis of the pending and planned environmental restrictions on coal plants and identified 52,000 MW of coal plant that will likely be retiring by the year 2020. *See* Oak Tree Exhibit 1, Attachment 5, at p. 66-71. This, in turn, causes the Black & Veatch gas price forecast to be higher than the EIA forecast over the same period of time. The upshot is that the Black & Veatch gas price forecast during the fall of 2011, and which existed when Oak Tree sent its LEO letter to NWE on February 25, 2011, is based on an industry wide consensus that significant coal generation will be retiring and replaced with gas fired generation. *Id., e.g.,* at p. 113, 178, Therefore, the Black & Veatch gas price forecast was more fundamentally sound than the EIA forecast at that time because an assumption that coal plants will retire due to pending EPA regulations and the switch to natural gas fired generation is an assumption widely shared in the forecasting industry.

Mr. Lewis further assumes no change in the historical relationship of spot electricity prices to gas prices over the 20 year forecast period. While this is an easy assumption to make, there is no fundamental basis for it. The fact is that the historical relationship between energy and gas prices has changed dramatically in the past, and will likely do so in the future. As new technologies come on line, as gas price fundamentals change, as gas starts to compete with coal more directly in the future, the relationship will undoubtedly change. In other words, this is no more than a guess on Mr. Lewis's part, and it is not based on a thorough

[6] Mr. Rounds also testified that "I think you're probably right to look at what everybody else has come up with and say everybody else has come up with an increase and that's probably what's going to happen." EL11-006 Hr'g Tr. 477:2-5. Mr. Rounds further stated "My opinion is we'll probably see increasing in natural gas prices."

review of the market fundamentals as is the Black & Veatch Energy Market Perspective.

(c) 2014-2022 is equally flawed

NWE's methodology is also flawed in that Mr. LaFave prepared a very simplistic and unrealistic calculation of avoided cost for the years 2014-2022. It appears that Mr. LaFave's analysis simply took avoided cost from Mr. Green's forecast for 2013, and Mr. Lewis's electric price forecast number for 2023, and then drew a straight line between these prices for years between 2014-2023. This is simply an unrealistic and unfounded approach to calculating avoided costs. The fact that the approach is simple does not make it valid or supported by anything other than Mr. LaFave's apparently biased judgment. Mr. LaFave did not base this straight-line calculation on any fundamentals or anything that would normally go into a proper electric price forecast.

5. Criticism of Mr. Lauckhart's Inputs Are Unfounded

Another criticism of Mr. Lauckhart is that the forecast of natural gas prices was markedly lower on February 25, 2011 than it was when the Black & Veatch Energy Market perspective was released in the fall of 2010. Specifically, Mr. Rounds appears to believe that Mr. Lauckhart should have adjusted the gas price input into the model on February 25, 2011. Mr. Lauckhart addressed this criticism at hearing:

> Q. [Mr. Uda] And you were present for the testimony of Mr. Rounds. He had some concerns about the accuracy of your inputs. Do you have any reaction to that?
>
> A. [Mr. Lauckhart] Yeah. I think a couple of things on the accuracy of the inputs. As we all said, we made this forecast in November. Gas prices have come down. To decide in a year later that we weren't accurate because we didn't forecast those gas prices come down in my mind is not a reason to say our forecast is no good. We all know that gas prices go down. At the time we did this experts didn't think they were going to go down that far. And we know that sometimes they go down. As Mr. Lewis said we've seen it go down and

down and down sort of recently but if you go back the beginning of this decade it was going up and going up and going up. And as I showed in my one slide on our historical gas prices in the last 10 years they've been up and down. Just because we couldn't forecast in November last year the gas prices were going to be this low in the late summer last year in my mind doesn't say that the forecast is no good.

Q. Were you present for Mr. Rounds' testimony that he believes you should have done in February of 2011 taken another look at gas prices to include in your model, for example, the EIA forecast?

A. Yes.

Q. Okay. Do you have a reaction to that?

A. Yeah. I think that that is a good thing to think about. And in the industry we do this. You do a forecast, came out in November. February rolls -- you're not going to plan to do it again until another six months. But you continue to monitor the situation. If it's moved significantly that you would think oh, man, maybe I better redo it because people are relying on this, because things have changed enough that it might make a difference, you would. But to tell you the truth in February it had not moved enough. It just had not moved enough.

Q. So in your professional judgment in February of 2011when you were considering whether or not the gas price had moved significantly what factors, if any, were you weighing?

A. Well, you have a long-term gas price forecast. If you see that your first month was off, it's just like the Northwest Power Planning Council language I quoted. Well, is that a temporary thing or is there a fundamental shift that happened? There were some movements there. We didn't think it was a fundamental shift. We felt it was seasonal, abnormal impacts on supply and demand of gas.

Q. Did you consult with any of the other experts at Black & Veatch about that conclusion?

A. Yes. We constantly talk about whether or not things have changed enough that to be reputable in the due diligence business that we need to change things. And we don't. Which does raise the question about the EIA forecast that came out about that time with somewhat lower gas prices. We have some concerns ourself with the EIA forecast. The EIA does not retire coal plants. We don't believe that's a legitimate assumption. When you ask them why they don't, tell you the truth the EIA gets political pressure on what they're going to

> do. And their bottom line was if there's not a law that's already passed and firm and everybody understands it, we're going to not put it in our forecast. Well, our approach is not that same way. We think there's a good chance it will be passed. Whether it's probability based or whatever, we'll put some of that in our forecast.

EL11-006 Hr'g Tr. 502:6-504:25.

In other words, Mr. Lauckhart did not believe, exercising his professional judgment, that as of February 25, 2011, the date of Oak Tree's LEO letter, that gas prices had moved sufficiently downward to justify a change in the Black & Veatch gas price forecast input.

Mr. Lauckhart exercised appropriate caution by looking at the decline in natural gas prices, and then discussing the matter with his colleagues at Black & Veatch, thereafter deciding that falling gas prices were a temporary, seasonal issue. It turned out that the trend toward lower gas prices was more permanent than he, or anyone else, imagined. He points out that EIA did not retire any coal plants because the EPA's regulations were not yet in place, and they did not assume that utilities would switch to natural gas. This was not a reasonable assumption, and explains much if not all the difference in the early 2011 EIA forecast and the Black & Veatch 2010 Fall Energy Market Perspective.

Mr. Lauckhart continues to believe his "brown power" avoided cost calculation was a valid forecast as of February 25, 2011. Forecasts cannot be based on hindsight; they must be based on the exercise of sound judgment. More importantly, the PUC should remember that Oak Tree is not asking for the full "brown power" price as set forth in Mr. Lauckhart's calculations. Instead, Oak Tree seeks only $65.12 levelized over 20 years.

In contrast, the PUC staff seems to believe that because gas prices fell after the fall of 2010 that this situation will continue indefinitely and this means it is appropriate to revisit the avoided cost calculation on that basis. However, there was no reason to believe, and there is nothing in the record to the contrary, that as of February 25, 2011, the gas price forecast declines were a fundamental shift in the market. Nor is there any evidence that gas prices will not spike in the future as they have at several points in the past decade. Further, as indicated earlier in this Brief, the \$5.14/MMBtu levelized gas price forecast developed by Mr. Lewis in this proceeding stands in stark contrast to the \$9.50/MMBtu assumption used by Otter Tail to determine that fixing the Big Stone coal plant would be lower cost than building a new combined cycle combustion turbine. See SD PUC Docket EL12-027.

Like a utility, Oak Tree had to make a decision to go forward at a specific point based on the best information available to it at the time. There is no evidence in this record that Oak Tree did not do this. Utility investment is done in much the same way; the utility must decide at a specific point in time whether its investment decision makes sense. If the utility turns out to be incorrect on the price, the utility can still recover the increase in costs for prudently incurred assets that are used and useful to ratepayers. If Oak Tree's price proves to be too low, either because of lower than expected net capacity factors, or increased operation and maintenance costs, Oak Tree bears the risk that it will not be paid sufficient revenue. So, the risk of error of getting the initial investment decision wrong is different for a QF like Oak Tree than it is for NWE. If NWE underestimates the revenue requirement needed to pay for its investment, it has recourse to ratepayers. Oak Tree will not. Therefore, the PUC should bear in mind that Oak Tree is taking a significant risk in proposing to accept less than the full avoided cost that Oak Tree is entitled to under PURPA.

An important factor to keep in mind is that the proper comparison of avoided cost is not in the short term, but over the life of the proposed facility. Mr. Lauckhart's avoided cost calculations does assume lower prices in the early years of Oak Tree's output, but the fundamental assumptions in his calculations, based on Black & Veatch's fundamental analysis, indicate the price will increase substantially over time due to these factors. The relevant comparison is not what markets are doing right now, but rather what the energy markets will do over 20 years. This is a matter of professional judgment, and there is a risk of error. But as of February 25, 2011, Mr. Lauckhart used the best information available in calculating his "brown power" avoided cost, and Oak Tree offered its output at a significant discount over this price.

C. Oak Tree has a Right to Capacity Payments

NWE fundamentally misunderstands its obligation under PURPA Section 210(a) 16 U.S.C. § 824-3(a). FERC adopted 18 C.F.R. § 292.303(a) to implement this congressional directive:

> (a) Obligation to purchase from qualifying facilities. Each electric utility shall purchase, in accordance with 292.304, unless exempted by 292.309 and 292.310, *any* energy and capacity which is made available from a qualifying facility. (Emphasis added)

NWE is steadfastly refusing to buy any output from QFs, including capacity, even when it is apparent that as of February 25, 2011, NWE needed capacity. NWE made decisions after February 25, 2011 to build the Aberdeen gas generating facility to provide it with capacity, and to purchase, in September 2011, 11 MW of capacity from Basin Electric to serve NWE in the summer months. EL11-006 Hr'g Tr. 209:4-6; 340:2-11.

NWE had an obligation to purchase that capacity from Oak Tree under PURPA and NWE has testified that it was aware that Oak Tree was trying to sell its energy and capacity to NWE. EL11-006 Hr'g Tr. 127:13-17. NWE, though, did not even consider this alternative because it did not like Oak Tree's energy price—regardless of the fact that it is in the ballpark with every other recent wind contract involving NWE of which Oak Tree is aware.

Regardless, the fact remains that NWE needed capacity as of April 2011, and chose to build its own facility and buy additional output from Basin Electric.

The cost of the Basin Contract in the summer months was \$5/KW month[7] or \$5,000 a MW/month. Multiplying that capacity price by 4 MWs[8] per month produced a number of \$20,000 per month or \$120,000 over the sixth month summer season. In contrast, Oak Tree's avoided cost calculations made by Mr. Lauckhart reflected 4 MWs of capacity at \$17/KW year (\$17,000/MW year), producing a price of \$68,000. Just on this basis, Oak Tree could have saved NWE approximately (the figure is likely higher) roughly \$50,000 in the summer months of 2013 alone.

PURPA mandates the purchase of energy and capacity from QFs. If NWE had bothered to negotiate at all with Oak Tree (and, as set forth in Section III.E, NWE did not), it could have achieved a significant cost savings to its ratepayers. NWE's violation of PURPA thus likely harmed its ratepayers.

D. FERC's Rules State that QFs have the Right to Decide the Term of their Commitment; Oak Tree chose 20 years

FERC regulations make it clear that the QF under PURPA has a right to sell its output pursuant to a legally enforceable obligation over a specified term. 18 C.F.R. § 292.304(d) states:

> d) *Purchases as available or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either*:
>
> (1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of

[7] Mr. Wagner actually testified it was \$5/KW month for the first five MW of capacity from Basin, but for MW 6 through 11 it would be \$11 per KW/month.
[8] Mr. Lauckhart's actual calculation was that Oak Tree could provide 20 percent of its output in the form of capacity, or roughly 3.9 MWs (rounded to 4 in this example).

delivery; or

> (2) *To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term,* in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (i) The avoided costs calculated at the time of delivery; or
>
> (ii) The avoided costs calculated at the time the obligation is incurred.

(Emphasis added)

Courts have construed the language of the regulation to mean that the qualifying facility has the option of specifying how it will sell its output pursuant to a legally enforceable obligation or "LEO". In *New York State Electric & Gas Corp. v. Saranac Power Partners, L.P., et al*, 117 F.Supp.2d 211, 229 (N.D.N.Y. 2000), in granting defendants' motion to dismiss plaintiff's claims against FERC for refusing to revise or otherwise invalidate QF contracts that plaintiff utility claimed exceeded its current avoided cost, the Court noted:

> When FERC promulgated regulations pursuant to PURPA, it recognized that purchases between QF's and utilities might occur as the QF determined it had excess alternative energy to sell in which case rates for purchases would be based on the utility's avoided costs at the time of delivery of the power. *See* 18 C.F.R. § 292.304(d)(1). When the purchase occurred by way of a long-term contract, however, FERC gave the QF the option of basing the purchase rate on avoided costs calculated at the time it actually delivered energy to the utility over the course of the contract or as estimated at the time it signed the contract. *See* 18 C.F.R. § 292.304(d)(2). In neither case, however, do the rules regarding purchases mandate a rate in excess of avoided costs.

In *Smith Cogeneration Management, Inc. v. Corp. Com'n*, 863 P.2d 1227, 1240 (Okla.1993), in reciting the requirements of PURPA's implementing regulations, the Oklahoma Supreme Court noted that FERC Order 69 permits a QF to choose the specified term of its obligation pursuant to 18 C.F.R. 292.304(d)(2):

> The FERC's commentary in its preamble to the regulations, 45 Fed.Reg. 12224

(Feb. 25, 1980), relating to the combined effect of § 292.304(d) and § 292.304(b)(5) provides in pertinent part:

> "Paragraphs (b)(5) and (d) are intended to reconcile the requirement that the rates for purchases equal the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs ... Paragraph (d)(2) permits a qualifying facility to enter into a contract or other legally enforceable obligation to provide energy or capacity over a specified term ... this ... enables a qualifying facility to establish a fixed contract price at the outset of its obligation or to receive the avoided costs determined at the time of delivery ..."

In *JD Wind I, et al*, 130 FERC ¶ 61,127, Docket No. ELO9-77-001(February 19, 2010), FERC made it absolutely clear that QFs have an absolute *right* to long-term contracts:

> The Commission has, since then,[9] consistently affirmed the right of QFs to long-term avoided cost contracts or other legally enforceable obligations with rates determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred.

Id. at p. 10, ¶ 23, (citing e.g., *New York State Electric & Gas Corp.*, 71 FERC ¶ 61,027, at 61,115-16 (1995), order denying reconsideration, 72 FERC ¶ 61,067 (1995), appeal dismissed *sub nom. New York State Electric & Gas Corp. v. FERC*, 117 F.3d 1473 (D.C. Cir. 1997).

Thus, the QF has the right to choose the utility to which it will sell its generation and whether the QF will sell its generation as it becomes available, or whether it will sell the generation pursuant to a contract or legally enforceable obligation over a specified term. This construction of 18 C.F.R. § 292.304(d) comports with reality in that a right to sell output based on an avoided cost over a term specified by anyone other than the QF would undermine the purpose of the statute and deprive the QF of the right to determine its commitment to sell.

[9] FERC was referring to the date of adoption of Order 69 in 1980.

Any construction of 18 C.F.R. § 292.304(d) that permits a utility (as argued by NWE in response to Oak Tree's omnibus motion) or the state commissions (as argued by NWE at the hearing) to specify the term of a QF's commitment to sell its output, would completely eviscerate the intent of the regulation that a QF has the right to sell its output pursuant to a legally enforceable obligation. No QF could ever determine the price in advance of constructing its facility, or arrange for financing, or determine its return on investment, or any of the other normal business planning activities that must take place, if the QF cannot determine the length of its commitment.

FERC itself has implicitly rejected the notion that a utility or state commissions may determine the length of the term of the QF's commitment. FERC has held that QFs must have the ability to base their rates over a specified term in order to attract capital and obtain financing for their respective projects:

> The Commission's regulations, from the beginning, have given QFs the option of choosing to have rates calculated at the time the obligation is incurred. The intention of the Commission was to enable a QF "to establish a fixed contract price for its energy and capacity at the outset of its obligation." The Commission recognized that:
>
> > [I]n order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, *an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility.*

JD Wind I, et al, 130 FERC ¶ 61,127, Docket No. EL09-77-01, at p. 10, ¶ 23.

Thus, FERC understood that QFs cannot reasonably be expected to incur a legally enforceable obligation or commitment to sell its output if they do not know the term by which they will recover the investment (both capital and debt) in its plant. A QF cannot make an offer to sell at a specified price unless it knows, in advance, how long it will have to pay off its debt service and pay back its capital investors and make a reasonable return on its investment. Furthermore, if a QF determines, as here, that it needs $65/MWH levelized over 20 years, and either the utility or a state commission shortens the term, the project will not be financeable due to the amount of debt service that will have to be paid over a much shorter year. Giving the QFs the right to determine, in advance, their commitment only makes sense if the QF is the entity that determines the length of the commitment.

It is true that state commissions have established standard offer contracts at various lengths (typically 15 to 25 years). However, these standard offer contracts are created by state commissions to ease administration of potential contract disputes between QFs and the utilities, and are options a QF *may* utilize at their option. For example, in South Dakota, a QF that has a design capacity of 100 kilowatts (KW) or less has the option to sell pursuant to the standard offer rate. However, QFs such as Oak Tree must negotiate with the utility in order to obtain a contract to sell its output, and should negotiations fail, it must proceed to the PUC to have its rights adjudicated. But, in order for such negotiations to take place, the QF must first determine if it can reasonably construct and operate its facility at a certain price over a certain term. Giving a utility (or state commission), the right to change the length of the QF's commitment would preclude meaningful negotiation. The utility could simply refuse to agree to the length of the commitment, regardless of whether shortening the term destroys the QF's ability to obtain financing. If state commissions are allowed to do this, a state commission could destroy the QF's financing commitment simply by adopting a different term where debt service and return on investment may be repaid. Under NWE's view, no QFs would ever be able to be financed, and there would be no PURPA in South Dakota. For the PUC to adopt such an approach, at NWE's urging, would be a failure to implement section 210 of PURPA.

E. Precedent Setting

The PUC may be concerned that a ruling in Oak Tree's favor in this proceeding will bring about a number of similar filings from other wind developers. Oak Tree has two observations on this. First, it will be more difficult for wind projects to demonstrate cost effectiveness of new wind plants after the production tax credits (PTC) and bonus depreciation tax option expires. Second, if a wind plant can demonstrate that it is cost effective to South Dakota ratepayers even without the benefits of PTC, then ratepayers will be benefitted by these wind projects. The PUC could adopt a long-term avoided cost price that allows cost effective QFs to reach agreement with NWE without the need for individual complaints needing to be filed at the PUC. Such an appropriate filed long term avoided cost price would also make it easier for wind developers to determine if they have an economic project or not.

F. Oak Tree created an LEO on February 25, 2011 by virtue of its letter to NorthWestern on that date

The creation of a LEO is a matter of first impression before the PUC. PURPA's regulations and recent FERC decisions, however, provide the PUC with substantial guidance on the meaning of that term and what a QF must do to create an LEO. PURPA's regulations, adopted by FERC, provide QFs with certain rights under PURPA as set forth in 18 C.F.R. § 292.304(d):

> (d) Purchases ''as available'' or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:
>
> > (1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs

calculated at the time of delivery; or
To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying exercised prior to the beginning of the specified term, be based on either:

(i) the avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

It is the QF's decision whether to sell output to the utility pursuant to an LEO. As PURPA specifically states, "[e]ach qualifying facility shall have the option … to provide energy or capacity pursuant to a legally enforceable obligation over a specified term …" Thus, a QF has the right to sell its output to a utility pursuant to an LEO, has the right to determine the length of its commitment to sell its output to the utility, and the right to determine whether to base the LEO avoided cost calculation on the date the LEO was incurred or based on avoided costs as estimated at the time of the delivery. The individual states, under PURPA, have been left to grapple with the question of when and whether an LEO was incurred.

The phrase "legally enforceable obligation" is much broader than just a contract between a utility and QF. *Cedar Creek Wind, LLC*, 137 FERC ¶ 61,006 at P 36 (Oct. 4, 2011). FERC regulations and specifically Order No. 69[10] use the terms "contract" and "legally enforceable obligation" disjunctively to reinforce that a LEO includes, but <u>is not</u> limited to, a contract. *Id.* at P 35. FERC went on to state, "the phrase [legally enforceable obligation] is used to prevent an electric utility from avoiding its PURPA obligations by

[10] FERC Stats. & Regs. ¶ 30,128.

refusing to sign a contract, or ..., from delaying the signing of a contract, so that a later and lower avoided cost is applicable." *Id.* at P 36.

FERC's recent decisions in *Cedar Creek Wind, LLC*, and *JD Wind 1, LLC*, 129 FERC ¶ 61,148 (Nov. 19, 2009), have clarified FERC's view of how a QF under PURPA may establish an LEO. In both cases, although FERC declined enforcement action, it found that the Idaho and Texas commissions had acted "inconsistent with the requirements of PURPA and [FERC's] regulations implementing PURPA." *Cedar Creek*, 137 FERC ¶ 61,006 at P 1. In making that finding, FERC addressed many of the same issues that have been addressed in this matter.

FERC explained:

> Section 292.304(d) and the requirement that a QF can sell and a utility must purchase pursuant to a legally enforceable obligation were specifically adopted to prevent utilities from circumventing the requirement of PURPA that utilities purchase energy and capacity from QFs. The Commission explained:
>
> > Paragraph (d)(2) permits a qualifying facility to enter into a contract or other legally enforceable obligation to provide energy or capacity over a specified term. Use of the term "legally enforceable obligation" is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible facility merely by refusing to enter into a contract with a qualifying facility:
> >
> > Thus, under our regulations, a QF has the option to commit itself to sell all or part of its electric output to an electric utility. While this may be done through a contract, if the electric utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA. Accordingly, a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.

Cedar Creek Wind, 137 FERC ¶ 61,006 at P 32 (citations omitted).

In *Cedar Creek Wind, LLC*, FERC found that the Idaho PUC erred in deciding that the QF in that case had not created an LEO because no contract had been consummated between the QF and the utility and FERC went on to state:

> We disagree with Idaho PUC and find our discussion of PURPA in *JD Wind 1* particularly applicable, that the phrase legally enforceable obligation is broader than simply a contract between an electric utility and a QF and that the phrase is used to prevent an electric utility from avoiding its PURPA obligations by refusing to sign a contract, or as here, from delaying the signing of a contract, so that a later and lower avoided cost is applicable.

Id. at P 36.

In other words, what a utility may *not* do under PURPA is simply refuse to negotiate with a QF. This is precisely the situation that Oak Tree was faced with in this matter. In fact, Mr. LaFave testified that he *could not* negotiate with Oak Tree because Oak Tree was offering a rate in excess of NWE's then posted short-term avoided cost rate of roughly $20/MWH. EL11-006 Hr'g Tr. 248:9-14:

> *Q*: [Mr. Uda]But I'm saying on the price term. There was really never any negotiation possible. Your offer was essentially here's what our tariffed rate is, take it or leave it.
>
> *A*. [Mr. LaFave]As identified by PURPA, yes..[11]

Therefore, NWE refused to negotiate because it believed it could not vary from the terms of its tariff (or that PURPA prohibited negotiating above its short-term avoided cost rate). There is no basis for arguing that a short-term tariff that applied by its terms only to

[11] Interestingly, NWE witness Green disagreed with Mr. LaFave's obviously incorrect interpretation of NWE's obligations under PURPA:

> Q. [Mr. Uda] Do you agree with Mr. LaFave's position that if a qualifying facility approaches NorthWestern, that NorthWestern has no ability to negotiate at anything other than the posted avoided cost rate for projects of 100 kilowatt design or less?
> A. [Mr. Green] Less than 100. I guess from my reading of the FERC requirements I would suggest that I don't agree with that. EL11-006 Hr'g Tr. 436:4-11

projects of 100 KWs or less applied to Oak Tree. There is also no legal basis for contending that PURPA prohibited all negotiations because NWE claimed its short-term avoided cost tariff was less than the price offered by Oak Tree. Either NWE fundamentally misunderstands its obligations under PURPA, or it is engaging in artifice to explain its conduct.

After several attempts to initiate some type of negotiation, Oak Tree exercised its right, as a QF, to establish a LEO. NWE never made an actual proposal to buy output from Oak Tree, never asked any questions regarding the Oak Tree project, responded to Oak Tree's correspondence with only boilerplate language during a period of approximately nine months without substantial deviation, affirmatively misrepresented its actual avoided costs to Oak Tree, ignored the QF's right to a long-term avoided cost rate and offered only short-term avoided cost rates that were not based on FERC-required energy and capacity cost data as set forth in 18 C.F.R. § 292.302(b), and forced Oak Tree to file a complaint with the PUC to compel NWE to comply under a LEO. Consequently, it is now up to the PUC to determine the date the LEO was established.

The original intent of PURPA was "to reduce the dependence of electric utilities on foreign oil and natural gas, in part by encouraging development of alternative energy sources such as cogeneration and small power production facilities (qualifying facilities)." *Power Resources Group, Inc. v. Public Utility Com'n of Texas*, 422 F.3d 231, 233 (2005). One of the reasons section 210 of PURPA was adopted by Congress was that utilities refused to enter into power purchase agreements with non-utility producers. *JD Wind 1, LLC*, 129 FERC ¶ 61,148 at P 24. Furthermore, federal law requires good faith negotiation by a utility at all times. *See Central Iowa Power Cooperative*, 105 FERC ¶ 61,239 (2003), *reh'g denied*, 108

FERC ¶ 61,282 (2004). Therefore, if a utility is allowed to thwart its PURPA obligations simply by refusing to negotiate in good faith with a proposed QF then a state which requires negotiation as the sole mechanism by which a QF greater than 100 KW can obtain a contract is failing to implement PURPA.

In 1982, the PUC adopted Order F-3365 in which it stated:

> The Commission finds that rates for purchases from (sic) QF's with a design capacity of more than 100 KW should be set by contract negotiated between the QF and the electric utility. The Commission agrees with the recommendations of all parties that the Commission should play a minimal role in the negotiation of such contracts, a role limited to resolving any contract disputes which arise between the parties. The Commission finds such a limited role to be consistent with the provision of 18 C.F.R. Section 292.403(a) that an acceptable method of implementation of FERC's rules by a state regulatory authority is "an undertaking to resolve disputes between qualifying facilities and electric utilities ..."

In the Matter of the Investigation of the Implementation of Certain Requirements of Title II of the Public Utilities Regulatory Policy Act of 1978 Regarding Cogeneration and Small Production, Decision and Order F-3365 at 9 (December 14, 1982). Thus, it is at this point that the PUC must resolve the dispute between Oak Tree and NWE.

As stated previously, under PURPA, the *sine qua non* of the LEO issue is whether the QF obligated itself to sell its output to a utility. *See Cedar Creek Wind*, 137 FERC ¶ 61,006 at P 32. PURPA directs FERC to promulgate rules "it determines necessary to encourage cogeneration and small power production." *JD Wind 1, LLC*, 129 FERC ¶ 61,148 at P 20. A state commission, such as the PUC, "may comply with the statutory requirements by issuing regulations, by resolving disputes on a case-by-case basis, or by taking other actions reasonably designed to give effect to [the Commission's] rules." *Id.* See also *Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978*, 23 FERC ¶ 61,304 (May 31, 1983)). Consequently, any action taken by a state under PURPA must be in accordance with FERC's rules. *Id.*

The PUC has limited discretion to determine the LEO issue. In *Cedar Creek Wind,* FERC took issue with the notion that states have broad discretion in determining the LEO issue:

> Idaho PUC and other protesters interpret *West Penn's* discussion to give broad discretion to the states as to what constitutes a legally enforceable obligation and when such obligation is incurred. We disagree. While *West Penn* stands for the notion that the Commission gives deference to the states to determine the date on which a legally enforceable obligation is incurred, such deference is subject to the terms of the Commission's regulations. *West Penn* does not, as Idaho PUC argues, give states the unlimited discretion to limit the ways a legally enforceable obligation is incurred.

Cedar Creek Wind, 137 FERC ¶ 61,006 at P 35.

Specifically, FERC found that the state commissions may not impose additional requirements beyond those set forth in FERC's regulations implementing PURPA:

> Like the Public Utility Commission of Texas (Texas PUC) in *JD Wind 1*, the Idaho PUC has imposed requirements on QFs seeking to enter into agreements to sell electricity that are in addition to those contained in the Commission's regulations. In *JD Wind 1*, the Texas PUC refused to find that a legally enforceable obligation existed because, in its view, the QF was unable to provide "firm" power. The Commission disagreed with the Texas PUC and explained that the Commission's PURPA regulations do not contain any reference to "firm" power, and that Texas PUC's reliance on certain language in the regulatory text was incorrect. Similarly, Idaho PUC requires that a legally enforceable obligation can result from only a fully-executed contract. Like the requirement that a QF must provide "firm" power, the requirement of a fully-executed contract is absent from the Commission's regulations.

Id. at P 37.

Therefore, what individual states may *not* do, according to FERC, is impose additional requirements to those in the federal regulations. This is particularly important here as it is a case of first impression before the PUC.

When a LEO was created is an issue completely separate from a utility's avoided cost.

An LEO, as stated previously, is created by the QF committing to sell its output to a utility, period. NWE witness, Mr. LaFave, misinterprets FERC's regulations when he stated that an LEO "would also include a (*sic*) offer at or below the avoided cost and it would include obligations for delivery by the qualifying facility." EL11-006 Hr'g Tr. 263:16-18. The key under PURPA to creating an LEO is the commitment to sell; not the terms of the commitment. The terms can be worked out later between the parties or pursuant to PUC order.

Oak Tree has no other market for its electricity and therefore, on February 25, 2011, sent a signed contract obligating itself to sell its entire output to NWE. This was all Oak Tree was required to do under PURPA. NWE witness Mr. LaFave claims that the proposed contract tendered by Oak Tree to NWE failed to include key terms. However, the proposed agreement does not have to be executable in order for an LEO to be created. Again, it is the commitment to sell, not the terms of the commitment, which creates the LEO.

The PUC may also consider a recent case in which NWE was involved to direct their decision in this matter. *In the Matter of the Petition of Whitehall Wind, LLC, for QF Rate Determination*, Docket No. D2002.8.100, Order No. 6444e (June 4, 2010). In that decision the Montana PSC instituted a bright line rule that "[t]o establish an LEO, a QF must tender an executed power purchase agreement to the utility with a price term consistent with the utility's avoided costs, with specified beginning and ending dates, and with sufficient guarantees to ensure performance during the term of the contract, and an executed interconnections agreement." Oak Tree has tendered a signed contract to NWE that it believes is below NWE's actual avoided costs and it has executed an interconnection agreement. Thus, Oak Tree would meet the Montana requirements for creating an LEO.

On February 25, 2011 Oak Tree sent a letter to NWE committing to sell its entire output to NWE. In that letter, Oak Tree specified a term of 20 years and provided its calculation of NWE's avoided cost. As such, the PUC should declare that this commitment, which was Oak Tree's right pursuant to 18 C.F.R. § 292.304(d), created an LEO as of that date.

G. Oak Tree will assist NWE in meeting South Dakota's Renewable Portfolio Objective

Oak Tree's renewable energy will assist NWE to meet its renewable portfolio goal of 10 percent by 2015. NWE apparently does not intend to meet that goal, or if NWE does, it does not intend to do so before the expiration of the production tax credits (PTC) and the ability to utilized bonus depreciation at the end of 2012. If NWE intends to comply with this the renewable goal after the 2012 deadline may mean that whatever renewable resource that NWE would acquire will be substantially more costly to NWE ratepayers to Oak Tree. Oak Tree is not asking for full avoided costs, it is asking for less. In reality, it is asking for no more than what NWE is proposing to pay Titan Wind.

IV. CONCLUSION

For the reasons set forth herein, Oak Tree respectfully requests an order finding that NWE had an obligation to purchase energy and capacity from Oak Tree at the rate of $54.40 levelized for 20 years, or $65.12 levelized over that term.

Respectfully submitted this 18th day of April, 2012.

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing document was served electronically on this 18th day of April, 2012, upon the following:

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