Service Date: June 23, 2010

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

*****

IN THE MATTER of the Petition of	)	
Kenfield Wind Park I, LLC and KWP-LC7,	)	UTILITY DIVISION
LLC to Set Terms and Conditions for	)	DOCKET NO. D2010.2.18
Qualifying Small Power Production	)	ORDER NO. 7068b
Facility Pursuant to §69-3-603, MCA	)	

FINAL ORDER

Appearances

FOR THE PETITIONER:

Kenfield Wind Park I, LLC and KWP-LC7, LLC
Michael J. Uda, Doney, Crowley, Bloomquist, Payne, Uda, P.C., Diamond Block, Suite 200, 44 West 6th Avenue, Helena, MT 59624-1185

FOR THE RESPONDENT:

Northwestern Energy
Charles Hansberry and Stephen R. Brown, Garlington, Lohn & Robinson PLLP, P.O. Box 7909, 199 West Pine, Missoula, MT 59807-7909

FOR THE INTERVENORS:

Montana Consumer Counsel
Mary Wright, P.O. Box 201703, 111 North Last Chance Gulch, Suite 1B, Helena, MT 59620

BEFORE:

GREG JERGESON, Chairman
KEN TOOLE, Vice-Chairman
GAIL GUTSCHE, Commissioner
BRAD MOLNAR, Commissioner
JOHN VINCENT, Commissioner

COMMISSION STAFF:

Neil Templeton, Rate Analyst, Economist & Rate Design Bureau
Will Rosquist, Rate Analyst, Economics & Rate Design Bureau
Mike Lee, Chief, Economics & Rate Design Bureau
Al Brogan, Staff Attorney, Legal Division

INTRODUCTION AND BACKGROUND

1. In this order, the Montana Public Service Commission (PSC or Commission) addresses the petition of Kenfield Wind Park I, LLC and KWP-LC7, LLC (collectively Kenfield), to have the PSC set terms and conditions for contracts between Kenfield and NorthWestern Energy (NWE) for power produced by Kenfield. The petition was filed pursuant to § 69-3-603, MCA, which provides that if a qualifying facility (QF) and a public utility are unable to mutually agree to the rate the public utility will pay for the QF's electricity, or conditions related to the public utility's purchases from the QF, the PSC must determine the rates and conditions, "upon petition of a [QF] or a utility or during a rate proceeding involving the review of rates paid by a utility for electricity purchased from a [QF]." The PSC must, "render a decision within 120 days of receipt of the petition or before completion of the rate proceeding."

2. Section 210 of the Public Utility Regulatory Policies Act (PURPA) (Public Law 95-617) requires the Federal Energy Regulatory Commission (FERC) to adopt rules that encourage QFs. PURPA requires public utilities to purchase energy and/or capacity from QFs at rates that do not discriminate against the QFs, are just and reasonable to electric consumers, and are in the public interest. PURPA, and FERC's rules implementing PURPA, do not allow a rate that exceeds the "incremental cost" to the electric utility of alternative electric energy.[1/] PURPA defines incremental cost as the cost to the electric utility which, but for the purchase from the QF, the utility would otherwise incur to generate or purchase energy and/or capacity from another source.

3. Section 69-3-601 *et seq*., MCA, also requires public utilities to purchase from QFs. Montana law authorizes several options for setting the rates paid to QFs, one of which is, "avoided cost over the term of the contract." § 69-3-604(4)(a), MCA.

PROCEDURAL HISTORY

4. On February 19, 2010, Kenfield filed its petition.

[1/] FERC's rules implementing PURPA state that if a rate paid to a QF is based on estimates of avoided cost over the specific term of a contract, the rate does not violate this condition if it differs from the avoided cost at the time of delivery. See 18 CFR § 292.304(b)(5).

5. On February 25, 2010, the PSC issued both a Notice of Petition and Procedural Order No. 7068. The notice identified Kenfield and NWE as parties to this docket.

6. On March 3, 2010, the Montana Consumer Counsel (MCC) filed its petition for intervention.

7. On March 26, 2010, NWE and MCC submitted prefiled testimony.

8. On April 6, 2010, the PSC issued a Notice of Staff Action modifying the procedural order to allow additional time for NWE to respond to data requests. The notice stated that Kenfield had agreed to waive the 120-day statutory deadline by seven days.

9. On April 15, 2010, the PSC issued a Notice of Commission Action in which it ruled on three discovery disputes and denied a NWE motion to amend testimony.

10. On April 20, 2010, the PSC issued Protective Order No. 7068a.

11. On April 21, 2010, the PSC issued a Notice of Public Hearing.

12. On April 29, 2010, the PSC issued a Notice of Commission Actions in which it denied a NWE motion for reconsideration of one of the PSC rulings on a discovery dispute in the April 15 NCA and granted Kenfield's motion to compel NWE to respond to certain data requests.

13. On May 3, 2010, the PSC issued a Notice of Staff Action modifying certain deadlines in Procedural Order No. 7068.

14. On May 5, 2010, the PSC issued a Notice of Commission Action granting the petition of Sagebrush Energy, LLC, for late intervention.

15. On May 6, 2010, the PSC issued a Notice of Commission Action denying NWE's motion for a protective order regarding certain maps.

16. On May 17, the PSC issued a Notice of Commission Action allowing NWE to withdraw certain testimony and to offer replacement testimony, denying Kenfield's motion to strike certain NWE testimony, granting Kenfield's motion to file supplemental rebuttal testimony, denying NWE's request to conduct discovery on same, denying NWE's request for oral argument on a Kenfield motion, and waiving certain PSC administrative rules in response to a request from Sagebrush Energy.

17. The public hearing was held May 20, 24, and 26, 2010, in Helena.

18. The parties filed simultaneous post-hearing initial briefs on June 7, 2010 and simultaneous reply briefs on June 11, 2010.

KENFIELD'S PETITION

19. According to the petition, the Kenfield projects are two proposed 10-MW nameplate capacity wind projects located near Chester that are separately incorporated but share a common manager and president, Bret Kenfield. The projects were studied as a single 20-MW project for purposes of establishing interconnection costs. Kenfield seeks a "financeable" contract with NWE, and said it considered itself bound to the terms of the power purchase agreements (PPAs) it proposed to NWE on October 23, 2009.

20. Kenfield stated it was not able to negotiate with NWE acceptable terms and conditions, including interconnection agreements, for the sale of its output.

21. Kenfield recounted the history of negotiations and related correspondence between it and NWE from 2008 until filing of the petition. According to Kenfield, as of January 2008, NWE had acknowledged receipt of Kenfield's proposals for two 10-MW wind projects. In August 2008 NWE proffered a draft PPA for the Kenfield Wind Park I project after which Kenfield offered comments and minor changes. In January 2009, NWE proposed an interconnection agreement that allocated to Kenfield $13,821,879 in system mitigation costs for the transmission network, including the new Great Falls to Three Rivers 230 KV line and the 100 KV upgrades from Harlowton to Judith Gap Tap to Judith Gap Auto. NWE's proposal did not contain a provision for the repayment to Kenfield of system mitigation costs. Kenfield disputed the allocation of transmission system mitigation costs to it, citing to ARM 38.5.1904, which requires QFs to pay for interconnection costs attributable to their projects, and to the definition of "interconnection costs" at ARM 38.5.1901(2)(d), which clarifies that such costs do not include transmission system network upgrades or any other costs not directly attributable to the QF.

22. On October 23, 2009, Kenfield sent draft PPAs, including interconnection agreements, to NWE seeking reply by November 6, 2009. These letters requested a contract rate of $75/MWh and a wind integration charge of $5/MWh, with Kenfield

retaining all of the environmental attributes including the renewable energy credits (RECs) associated with the projects. Kenfield estimated the result was an effective rate of $76 to $80/MWh. NWE rejected the Kenfield offer, but countered with an offer of $64.76/MWh, including the RECs, and an integration charge of $8.35 based on the PSC's decision in Docket D2009.1.4. According to Kenfield, this offer would result in an effective all-in rate of $46 to $50/MWh, which would be insufficient for Kenfield to obtain financing for the project. On December 8, 2009, Kenfield responded by saying the parties were at an impasse and that further negotiations were pointless as no 20-MW project can pay $13 million for interconnection and be profitable. Kenfield said that NWE notified Kenfield on December 14, 2009, that the NWE offer would be rescinded unless Kenfield agreed to its terms by December 18, 2009. On December 16, 2009, Kenfield rejected NWE's offer and proposed instead a rate of $91/MWh (escalating at 2% annually), minus a $5.19/MWh integration charge, and sale of the Kenfield RECs to NWE. Kenfield stated the effective rate reflected in this proposal was $76 to $80/MWh. In response, NWE asked Kenfield to explain why it had increased the proposed PPA rate by $6/MWh (from $85/MWh to $91). Kenfield maintained that the proposal's price was actually reduced from the previous Kenfield offer when the value of the RECs assigned to NWE was factored in. According to Kenfield, it informed NWE the Kenfield projects are financeable at $85/MWh but not at $75/MWh.

23. Kenfield said it further reduced its proposed PPA rate, from $91 to $85/MWh levelized over 20 years, in a January 5, 2010, letter to NWE. In that letter, Kenfield proposed to assign all the environmental attributes of the projects to NWE and included a wind integration charge of $5.19/MWh. NWE rejected the offer and did not respond with a new proposal of its own.

24. On January 20, 2010, Kenfield asked NWE if NWE's position on Kenfield's share of interconnection costs would change and if the interconnection cost disagreement should be resolved by the PSC. On January 25, 2010, NWE responded that the sides continued to disagree on the cost allocation methodology for system mitigation costs and that NWE had not changed its cost allocation methodology position as it applies to Kenfield.

25. Kenfield identified these contract terms as the ones to be resolved in this proceeding: the contract rate; the appropriate wind integration charge; and interconnection costs to be paid by Kenfield, including resolution of the question of whether NWE's QF Small Generator Interconnection Agreement (QFSGIA) is consistent with either state or federal law.

26. Kenfield requested the PSC set a 20-year levelized $91/MWh rate with 2% annual escalation. According to Kenfield, this rate is based on NWE's 2007 Resource Procurement Plan (RPP), which does not include subtractions for integration and interconnection costs. NWE would own the RECs and environmental attributes. Kenfield requested that the PSC require NWE to assess to Kenfield the actual cost of interconnecting only the Kenfield projects.

NWE AND MCC ANSWER TESTIMONY

NWE

John Hines

27. John Hines, NWE's chief Energy Supply officer, argued the PSC should reject Kenfield's proposed $91/MWh (with 2% escalation), 20-year avoided cost rate and $5.19/MWh wind integration charge. NWE disagreed with Kenfield's position that the rate be set at a level that makes the project financially viable because that policy would result in ratepayers paying more for renewable power than is necessary when NWE has available lower cost renewable resources. Hines said Kenfield's position is also inconsistent with the principle of basing QF payments on NWE's avoided costs because the prices for wind project proposals that NWE is currently reviewing as a result of its recent Renewables Request for Information (RFI) are materially lower than the Kenfield project price. He added that the price indicators in NWE's 2007 RPP and the Northwest Power and Conservation Council's (NPCC's) 2010 Mid-C forecast are less than the proposed Kenfield rate.

28. Hines testified the PSC should set the Kenfield contract rate at the current QF-1 tariff rate, which, at the time of Hines' testimony, included a $49.90/MWh fixed-rate option or a market price option. He said the rate should be reduced to reflect wind

integration costs consistent with the PSC's orders in D2007.12.152 (Two Dot Wind), and in D2008.5.48 and D2009.1.4 (United Materials of Great Falls).

29. Hines said if the PSC decides to set a contract rate higher than the current QF-1 rate, then that price should be consistent with recent pricing indicators, which Hines said came from the NWE Renewables RFI, the NPCC's Mid-C 20-year forecast, NWE's 2007 RPP wind cost, and the recent Turnbull Hydro contract with NWE. Hines mentioned that another alternative for setting the contract rate would be to use the adjusted wind values from the 2007 RPP.

30. Hines explained that the price that NWE offered Kenfield in November 2009, which was above the existing QF-1 tariff rate, was rejected by Kenfield and that, since that time, NWE has obtained market information that shows that new renewable projects in Montana that are similar in size to Kenfield's and that include RECs can be acquired through competitive solicitations at less cost than the price Kenfield seeks.

31. Hines proposed a wind integration price signal in 2011 of $11.69/MWh, based on the operating costs of the Mill Creek Generating Station (MCGS) above the 60-MW historical level of regulation need, adjusted for revenue credits and spread equally to all wind resources.

<u>Carolyn Loos (testimony subsequently adopted by John Leland)</u>

32. Loos, who is responsible for NWE's interconnection processes, argued Kenfield inappropriately intertwined the FERC SGIA requirements and the Montana QF interconnection requirements. She said NWE received in 2006 the Kenfield interconnection request for a single 19.5-MW project with one point of interconnection and noted that Kenfield has not requested to modify its original small generator interconnection request for a 19.5 MW project to two 10-MW projects.

33. Regarding the issue of energy resource versus network resource, Loos explained that, although NWE has historically interpreted the FERC small generator interconnection process to require QF or non-QF projects less than 20 MW to be studied as network resources, when NWE reviewed FERC Order No. 2006 in 2008, NWE concluded that a small generator under FERC jurisdiction should be studied as an energy resource unless the generator specifically requests to be a network resource. In October

2008, Kenfield notified NWE that Kenfield was a network resource and a QF. NWE Transmission later wrote to all small generators in the interconnection queue to ask that they specify whether they were network or energy resources and whether they were FERC-certified QFs.

34. NWE issued the Kenfield final facility study and draft QF interconnection agreement in January 2009. Loos said that the cost allocation calculation of $13.8 million in system mitigation costs to Kenfield only included projects that were senior in the interconnection queue to Kenfield. She explained that Kenfield's prorated share of the costs falls to $6.2 million after appropriate projects that are junior in the interconnection queue are included, as required by NWE's Cost Allocation and Refund Methodology business practice.

35. Loos stated that NWE's processing of Kenfield's interconnection request complied with ARM §38.5.1901(2)(d) and §38.5.1904(2)(c). She said NWE interpreted ARM §38.5.1904(2)(c) to require NWE to study a QF as network resource and that NWE's interpretation is further supported by the FERC definition of "Network Resource Interconnection Service" (NRIS). She added that since Kenfield's output would serve native load customers, both ARM §38.5.1904(2)(c) and NRIS require that it be able to deliver its output to the network. Loos contended that QFs cannot be studied for Energy Resource Interconnection Service (ERIS) because ERIS allows a QF to use nonfirm transmission capacity to serve network customer load; thereby the QF output could not be reliably delivered to the transmission system and to load.

36. Loos said ARM 38.5.1904(2)(c) and 38.5.1904(3) unambiguously require that system mitigation costs be borne by the QF. According to Loos, the generator must advance network mitigation costs, but only at the time when construction of the necessary facilities is imminent.

37. Loos stated that Kenfield's additional 20 MW interconnected to the Chester 69 kV substation is only feasible with system improvements, and that Kenfield contributes to the power flows on the proposed 230 kV line from Great Falls to East Helena to Three Rivers and also on the 100 kV lines from Harlowton to Judith Gap Tap to Judith Gap.

38. Loos explained that NWE adopted the FERC's interconnection process to provide guidance missing from the PSC's QF rules and that process requires NWE to develop a cost allocation methodology to allocate network costs for all interconnection projects – NRIS and ERIS. NWE's cost allocation methodology requires proportional cost allocation to each customer that contributes to the need for system mitigation. Loos said NWE understood that FERC had accepted the PJM cost allocation methodology that is similar to NWE's methodology.

39. Loos disagreed with Kenfield's argument that NWE's QFSGIA is discriminatory because it denies QFs reimbursement that they would get as network resources under the FERC SGIA. She said ARM 38.5.1904(2)(c) requires NWE to evaluate a QF as a network resource and it also requires a QF to reimburse NWE for "special or additional facilities." Unlike the FERC, the PSC rule does not require a refund back to the QF.

Frank Bennett

40. Frank Bennett is an electric and natural gas supply specialist in NWE's Energy Supply group. He recounted from NWE's perspective the discussions and negotiations between NWE and Kenfield over the three years leading up to Kenfield's petition.

41. Regarding the wind integration issue, Bennett pointed out that the PSC, in Dockets D2003.7.86, D2007.12.152 and D2008.5.48, made wind integration costs an obligation of QF wind generators and set wind integration rates based on NWE's wind integration costs.

42. Bennett testified that adhering to avoided cost principles as required by PURPA means that consumers should be indifferent to QF power purchase costs.

Mark Stauffer

43. Mark Stauffer, a resource planning analyst in NWE's Energy Supply group, testified about current avoided cost values for wind energy found in: (1) the results of NWE's Renewables RFI ($68/MWh); (2) the NPCC's 20-year forecast ($74/MWh); (3) the NWE 2007 RPP wind cost ($66/MWh); and (4) the Turnbull Hydro

project ($70/MWh). He added that all energy prices he referenced are in 2010 nominally levelized values.

44. Regarding the Renewables RFI, Stauffer reported that the weighted average price of the final four bids in that process is $68/MWh, including the RECs, and the projects' average annual capacity factor is about 40 percent. He said NWE will also obtain from the RFI bids projects that qualify as community renewable energy projects under § 69-3-2003, MCA.

45. Regarding NPCC's Mid-C forecast of $74/MWh, Stauffer argued it provides a good representation of the value of fully integrated wind energy, including implicitly RECs, but he said the cost of integrating wind should be deducted from the $74 to make it comparable to raw wind energy.

46. Regarding the $66/MWh cost of new wind as calculated in NWE's 2007 RPP, Stauffer observed that the cost is very close to the RFI wind cost and noted that both assume REC ownership and do not include wind integration costs. Stauffer provided the inputs used to derive the 2007 RPP value and said that, because Kenfield provided no documentation of how it calculated its $91/MWh cost ($105/MWh nominal), he could not address it directly.

47. Regarding the Turnbull Hydro contract price of $70/MWh, Stauffer said it included all environmental attributes, including RECs. He said Turnbull is a bit more expensive than the Renewable RFI projects as it produces capacity capability and firm energy and therefore does not require integration.

<u>Ray Brush</u>

48. Ray Brush, manager of NWE's Colstrip 500 kV project, explained that North American Electric Reliability Corp.'s (NERC's) Control Performance Standard 2 (CPS2) requires that at least 90 percent of NWE Transmission's total monthly 10-minute Area Control Error averages must be within a range of about +24.3 to -24.3 MW. Through experience, NWE has found that it needs additional regulating reserve equal to 18% of the nameplate capacity of a new wind resource to meet CPS2.

49. Brush described the wind integration studies in which NWE has been involved over the past few years, including NWE's current ongoing collaborative process

with wind stakeholders to determine the regulation needs for increased penetration of wind resources.

MCC

50. Dr. Larry Nordell, MCC staff economist, testified that the Kenfield projects appear to be good candidates for NWE's resource portfolio, but their costs, and the cost to ratepayers, should be compared with the costs of other resource alternatives.

51. Nordell said that, for all intents and purposes, the Kenfield projects appear to be a single project, not two separate 10-MW projects. He observed the projects have been and will be planned, financed, and studied for interconnection purposes as one single project, the owners are family members, and management of them as a single project would be more efficient. Nordell recommended that, if the PSC rejects Kenfield's claim to be two separate projects, then the PSC should dismiss the petition and encourage Kenfield to participate in the competitive bidding process for QFs that exceed the 10-MW threshold for the standard offer rate. Nordell argued that the PSC should not set a case-specific standard offer rate for Kenfield.

52. Nordell contended the appropriate forum for setting a new standard offer rate is in a dedicated docket, not in a proceeding in response to a specific QF developer's petition like this one. He claimed that the Kenfield's proposed contract price and wind integration charge are both unreasonable. According to Nordell, whether or not the Kenfield project is financially feasible at the standard offer rate is irrelevant to PURPA's requirement that the rate be set based on avoided costs. Nordell said Kenfield's reliance on the wind cost estimates in the 2007 RPP for setting a contract rate is inappropriate because they are uncertain planning numbers that cannot be used as proxies for future prices and to use them would transfer the risk of the uncertain prices to ratepayers. Nordell also argued that risk would be inappropriately transferred to ratepayers if Kenfield's proposed $5/MWh wind integration charge is locked into a long-term contract.

53. Nordell testified that allocating transmission system mitigation costs to the parties contributing to the need for it is appropriate. He argued that if ratepayers pay the mitigation costs and Kenfield gets the same avoided cost rate as other QFs, then

ratepayers would be better off buying QF power located on NWE's system where additional generation could be accommodated without a need for mitigation.

54. Nordell concluded by recommending that, if the PSC does not reject the petition, then the PSC should not set a Kenfield contract rate it until establishes an updated QF rate. He added that, because of the uncertainty over wind integration costs, these costs should be set annually based on the actual costs of regulation, including MCGS costs. He recommended that the PSC reconsider its action to raise the standard offer threshold from 3 MW to 10 MW because the Kenfield project shows that projects of this size do not require special treatment through the standard offer contract. He said NWE has ample incentives to contract with projects of this sort and that the PSC should ensure that there is a reciprocal incentive to negotiate on the part of QF developers and to reduce their incentive to petition the PSC when negotiations become difficult.

KENFIELD REBUTTAL TESTIMONY

Bret Kenfield

55. Bret Kenfield, the developer of the Kenfield projects, asserted there are two separate Kenfield projects because they are separately owned and they are located more than a mile from each other. He stated that the NWE supply and transmission sides of the business were both aware that he was proposing two 10-MW projects. He disputed NWE witness Bennett's testimony that he had made just one telephone call to NWE about the contract requirements and the interconnection size. He disagreed with Bennett's characterization of his efforts to revise NWE's August 2008 proposed contract.

56. Kenfield identified two areas of concern about his negotiations with NWE: (1) delays introduced by NWE into the process, such as when NWE Transmission stopped processing the Facility Studies Agreement in March 2008 on the day it was supposed to be completed because NWE decided it must conduct another study at the system impact level; and (2) NWE Energy Supply's actions that call into question whether NWE ever intended to negotiate with Kenfield, such as providing him with vague contract terms with no specifics as to price, wind integration and refund policies.

Richard Lauckhart

57. Richard Lauckhart, a consultant on electricity issues, described his concerns about NWE's compliance with federal and state PURPA avoided cost requirements, NWE's pricing alternatives for Kenfield, NWE's proposed wind integration charges, and the QFSGIA.

58. Lauckhart said there were flaws in NWE's calculations related to NWE's four sources of current avoided cost information. Regarding the Renewables RFI, Lauckhart argued that, by not requiring bidders to submit binding bids, NWE provided an incentive for bidders to "lowball" their bids. He contended that the non-binding $68/MWh average price from the RFI is too low for a new wind project to be financially viable. Regarding the NPPC's Mid-C forecast price of $74/MWh, Lauckhart argued that power provided from a wind plant cannot be compared to spot market power purchases for purposes of basing a utility's avoided cost and that NPPC itself indicated as much. Regarding NWE's calculation of an avoided wind cost of $67/MWh from NWE's 2007 RPP, Lauckhart stated NWE's O&M numbers should have been escalated from 2007 to 2010 dollars prior to performing the nominal levelization.[2/] He disputed as too high NWE's use of a 40% capacity factor for wind projects in its calculations. He asserted, too, that a recent study of wind O&M costs showed that these costs are significantly higher than the $16.7/MWh used in NWE's 2007 RPP. Regarding NWE's use of the Turnbull Hydro contract as a source of avoided cost information, Lauckhart argued it was a one-of-a-kind project that was able to use existing infrastructure to reduce its costs, which most new renewable resources cannot do.

59. Lauckhart indicated there is no need to address wind integration charges in this proceeding if the PSC bases the Kenfield QF contract price on the 2007 RPP, which did not include wind integration charges in its wind plant cost estimates. However, he responded to NWE's testimony on wind integration costs by contending that NWE incorrectly testified that regulating reserves are required to integrate wind. According to Lauckhart, governor controls on generators are the primary tool to ensure load and resource balance, not regulating reserves. He said that, while regulating reserves are one

[2/] NWE witness Stauffer revised his pre-filed testimony at hearing (Tr. p. 461) to correct the value of $67/MWh to $66/MWh. (Ex. MAS-2) way to integrate wind without violating the CPS2 standard, others also exist such as governor controls, quick start units, schedule changes with neighboring balancing authorities, and better wind forecasting.

60. Regarding NWE's QFSGIA, Lauckhart pointed out that FERC does not require a QF to be a network resource rather than an energy resource. He claimed that NWE's studies to date indicate the existing transmission system can accommodate the Kenfield projects without upgrading the system and added that, even though it is not certain that the new transmission line will ever be built, it is holding up progress on the Kenfield project. According to Lauckhart, FERC policy is that all the projects that contribute to the need for the system mitigation costs should pay a share of their costs, and those contributions are eventually refunded. NWE does not propose any refund to Kenfield.

61. Lauckhart concluded the PSC should set a $92.50/MWh contract rate for Kenfield based on the cost of wind projects in NWE's 2007 RPP and including RECs. Since this RPP rate did not include the cost of contingency reserves, wind integration or system mitigation, Lauckhart argued Kenfield should not have to pay such costs.

62. In his supplemental testimony, Lauckhart asserted that the results of a CPS2 study he conducted based on actual 2009 data from NWE showed NWE's claim that it needs 18% of nameplate capacity of new wind resources to integrate wind plants in order to meet the CPS2 standard is incorrect. Lauckhart concluded from his study that NWE integrated the Judith Gap and Horseshoe Bend wind resources with additional reserves equivalent to 8.3% of those resources' nameplate capacity. According to Lauckhart, NWE overstates the costs of integrating wind.

<u>Brian Jackson</u>

63. Brian Jackson, an engineering consultant for Kenfield, testified that smaller wind projects like Kenfield often have higher construction and O&M costs on a percentage basis compared to large projects, but are easier for the utility to integrate. He said that, based on his analysis of the Kenfield project, he predicted a net capacity factor of 30%. He added that the capacity factor is a moving target that depends on various factors.

MCC RESPONSE TESTIMONY

64. Nordell disputed NWE's proposed method of calculating the cost of regulation from MCGS because, if approved by the PSC, he claimed it would result in retail load and transmission customers paying four times as much per MW for regulation as it would charge to wind resources. Nordell contended that if MCGS regulation costs were equally shared, the charge for wind regulation per MWh of wind generation would be $33.96 for the 85 MW scenario and $32.97 for the 89 MW scenario. According to Nordell, NWE's wind regulation estimate of $11.69 for Kenfield would result in an annual cost shift of $1.4 million to retail load and transmission customers while Kenfield's proposed $5 wind integration charge would result in an annual cost shift of $1.8 million.

65. Nordell concluded that under NWE's methodology, Kenfield's proposed $5 wind integration charge is too low by a factor of 85 percent, and that NWE's methodology would violate PURPA by shifting costs from QFs to ratepayers and would provide an inaccurate cost signal to parties engaged in resource planning. He recommended the PSC reject Kenfield's proposed contract rate and wind integration charge, direct NWE to recalculate the MCGS cost of regulation using his methodology, and set the cost of MCGS regulation services as the regulation charge for all wind QFs until NWE has acquired as much wind generation as MCGS can accommodate. Nordell reiterated his opinion that Kenfield is a single 20-MW project and thus ineligible for a standard offer contract. However, if the PSC finds Kenfield has two separate projects, Nordell recommended that, given the update to the QF-1 tariff as reflected in the order in Docket D2008.12.146, the PSC should reject Kenfield's petition and direct Kenfield to seek a contract with NWE under the new QF-1 tariff or, alternatively, the PSC should apply the new standard offer rate to set Kenfield's rate as requested in the petition.

DISCUSSION, DECISION AND FINDINGS

66. The issues to be decided by the PSC in this docket are: (1) whether Kenfield is one 20 MW wind project or two separate 10 MW projects; (2) Kenfield's responsibility for interconnection costs; and (3) the contract rate under which Kenfield

will sell electricity to NWE, including the appropriate wind integration charge, if any. Each issue is addressed in turn below.

Determination of whether Kenfield is 1 or 2 projects

67. ARM 38.5.1902(5) provides, in part:

> A long-term contract for purchases and sales of energy and capacity between a utility and a qualifying facility greater than 10MW in size shall be contingent upon selection of the qualifying facility by a utility through an all-source competitive solicitation conducted in accordance with the provisions of ARM 38.5.2001 through 38.5.2012. Between competitive solicitations, purchases and sales of energy and capacity between a utility and a qualifying facility greater than 10MW in size shall be accomplished in accordance with the short-term standard avoided cost tariff approved by the commission or through negotiation of a short-term written contract. The utility shall recompute the short-term and long-term standard tariffed avoided cost rates following public review and comment on each least cost plan filing, ARM 38.5.2001 through 38.5.2012.

The Commission recently ruled that this portion of ARM 38.5.1902(5) is a valid implementation of PURPA.

68. Kenfield has asserted that it is two separate projects, each of which is equal to 10 MW in size. Petition at 2. The MCC has argued that Kenfield is a single 20 MW project. Ex. MCC-2 at 11-12. NWE contends that the preponderance of the evidence indicates that Kenfield is a single 20 MW project. NWE Init. Br. at 3-5.

69. ARM 38.5.1902(5) establishes a bright line for eligibility for long-term standard offer contracts. Creation of such a bright line also creates the possibility that someone will game the system to be on what it perceives to be the advantageous side of the bright line. When FERC, in RM06-10-000, created a rebuttable presumption that QFs 20 MW or smaller do not have non-discriminatory access to energy and capacity markets, FERC also recognized the concern raised by intervenors that QFs would game the 20 MW bright line rule. FERC responded:

> The Commission will not allow for gaming of this 20 MW rebuttable presumption. If parties are concerned that a QF has engaged in such gaming with regard to the certification or siting of a particular facility, we encourage those parties to bring their concerns to our attention. In any such proceeding, we will consider all relevant factors, including, but not limited to, ownership, proximity of facilities, and whether the facilities

> share a point of interconnection. For purposes of evaluating proximity of facilities with regard to alleged gaming of this rebuttable presumption, we will not be bound by the one-mile standard set forth in 18 C.F.R. § 292.204(a)(2).

Order 688, ¶ 77 (October 20, 2006).

70. Similarly, the PSC considered all relevant factors in determining whether Kenfield is two projects eligible for long-term standard offer contracts or one project eligible for a short-term standard offer contract until selected in a competitive solicitation.

71. Kenfield began development as a single project of the Kenfield family. After the PSC raised the size limit for long-term standard offer eligibility, Kenfield chose to designate itself as two 10 MW projects for purposes of electricity supply but remained a single project for purpose of interconnection. The following chart identifies and discusses various relevant factors:

FACTOR	INDICIA OF 1 PROJECT	INDICIA OF 2 PROJECTS	OTHER CONSIDERATIONS
Ownership		2 Legal Entities	Ownership without equity investment is hollow at best. There is no indication that any LLC members have provided equity investment. The ownership is affiliated in that all members of both entities are close members of one family. Some evidence that members have not complied with the formalities required by separate legal ownership, i.e. inadequate leases, failure to develop or provide operating agreements, one person appearing to make all development decisions and take all actions for both entities.
Interconnection	Single interconnection request.		FERC has not authorized multiple projects to share interconnection. Shared interconnection would be economically beneficial to QFs.
Operations	Appears to be no separate operations by either entity.		All operations appear to have been done by Bret Kenfield or Brian Jackson
Financing	Appears to be a single, limited attempt at obtaining financing for the project.		Only evidence of attempt to obtain financing is that Brian Jackson has talked to a Midwestern bank and that Mr. Kenfield spoke with a Mr. Greenman.

72. Establishment by the PSC of a bright-line rule that separate ownership establishes separate projects would be easy to interpret and apply. However, such a rule would provide significant opportunity for a developer to game the system by artificially dividing a single endeavor into multiple projects. Considering the totality of the circumstances will be more difficult to interpret and apply, but provides a better method for the PSC to police and prevent gamesmanship with regard to the size of the project.

73. The PSC adopts a process whereby it will consider the totality of the circumstances when determining whether a project is a single project or more than one project. In this case, after consideration of the relevant factors, the PSC concludes that Kenfield is a single 20 MW project.

Interconnection issues

74. FERC's rules implementing PURPA define "interconnection costs" as:

> the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, <u>to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources.</u> Interconnection costs do not include any costs included in the calculation of avoided costs.

18 CFR § 292.101(b)(7) (emphasis added).

The PSC's definition of interconnection costs in ARM 38.5.1901(2)(d) is identical to FERC's definition.

75. FERC's rules also address QFs' obligations to pay for interconnection costs. 18 CFR § 292.306 states:

> a) *Obligation to pay*. Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority…may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.
>
> b) *Reimbursement of interconnection costs*. Each State regulatory authority…shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

76. Similarly, the PSC's rules governing QFs' interconnection cost-related obligations state:

> (2) A qualifying facility shall be fully responsible for interconnection costs and shall:
> …
> (c) Reimburse the utility for special or additional interconnection facilities, including control or protective devices, time of delivery metering, and reinforcement of the utility's system to receive or continue to receive the

> power delivered under the contract. Such reimbursement may be accomplished by means of amortization over a reasonable period of time within the term of the contract and such costs must be reasonable according to industry standards.
> (3) Interconnection costs undertaken by the utility shall be reimbursed by the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

ARM 38.5.1904.

77. Several PSC orders from the 1980s also address interconnection costs. In Order 4865, Docket No. 81.2.15, the PSC observed that issues related to payment for interconnection costs were settled in rules and that pursuant to ARM 38.5.1904 a QF must reimburse the utility for interconnection facilities the utility installs for the QF, although such reimbursement can occur over time. The PSC also determined that once intertie is accomplished between a utility and a QF, the utility, not the QF, is financially responsible for alterations or modifications, "that are necessitated by a change in the utility's system voltage." Order 4865, ¶¶ 55-57.

78. In Order 5017, Docket No. 83.1.2, the PSC made a number of statements that are potentially relevant to Docket No. D2010.2.18. The PSC highlighted the issue of whether QFs allow utilities to avoid incremental transmission and distribution costs and reduce reserve requirements. The PSC noted that it had directed the utilities to investigate whether QFs allow them to avoid line losses, transmission and distribution costs, and reserve requirements in Order 4865, but the utilities had failed to do so. The PSC stated, "it is inconsistent to exclude transmission-related avoided costs in the avoided cost calculation, but at the same time, to require each QF to pay for interconnection costs." Order 5017, ¶ 76. The PSC also stated that QFs must be responsible for all costs up to the point of interconnection, which is the point where a QF interconnects with the utility's existing grid system. *Id.*, ¶¶ 80, 85. The PSC emphasized, "upgrades required for interconnection to the utility grid system, at the time that the QF interconnects, shall be the cost burden of the QF. Later upgrades to maintain reliable and dependable service are solely the utility's responsibility." *Id.*, ¶ 86. Finally, the PSC found that there should be a sharing of interconnection costs between initial QFs

and subsequent QFs or customers, but left to utilities the design of such refunds. *Id.*, ¶ 90.

79. Finally, in Order 5091b, Docket No. 84.10.64, the PSC declined to tariff avoided transmission costs, but stated that if transmission investments are avoidable, QF payments should reflect those avoided costs. Order 5091b, ¶ 126.

80. Exhibit NWE-6 (CDL-4) (Carolyn Loos's prefiled direct testimony, adopted by John Leland at the public hearing) is NWE's QFSGIA. Attachment 1 in the QFSGIA is a glossary of terms used in the agreement. The QFSGIA defines "Interconnection Facilities" as:

> The Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. <u>Collectively, Interconnection Facilities include all facilities and equipment between the [QF] and the Point of Interconnection</u>, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the [QF] to the Transmission Provider's Transmission System and/or Distribution System. <u>Interconnection Facilities are sole use facilities</u>…. (Emphasis added)

The QFSGIA defines "Network Upgrades" as:

> Additions, modifications, and upgrades to the Transmission Provider's Transmission System required <u>at or beyond the point at which the [QF] interconnects with the Transmission Provider's Transmission System</u> to accommodate the interconnection of the [QF] with the Transmission Provider's Transmission System. (Emphasis added)

The term "interconnection costs" in the PSC's and FERC's QF rules encompasses the costs associated with both interconnection facilities and network upgrades.

81. In this case, Kenfield objects to NWE's approach to determining Kenfield's responsibility for certain interconnection costs. Specifically, Kenfield disputes how NWE proposes to treat system mitigation costs in the QFSGIA. Petition, p. 10 & Ex. KWP-1, p. 15. That is, Kenfield does not dispute its responsibility for the cost of interconnection facilities on its side of the point of interconnection or certain network upgrades. Kenfield finds NWE's QFSGIA discriminatory, in part because while NWE

refunds non-QF small generators for any system mitigation costs those generators advance to NWE under the terms of the FERC-jurisdictional SGIA, NWE's QFSGIA does not provide for such refunds. *Id*. NWE counters that its QFSGIA applies PSC rules governing QF-related interconnection costs and that those rules require Kenfield to pay for system mitigation costs. NWE asserts that ARM 38.5.1904 unambiguously requires QFs to pay for system mitigation costs. Ex. NWE-6, p. 10.

82. The dispute between Kenfield and NWE on the issue of interconnection costs appears to be rooted, at least in part, in the separation between NWE's transmission and supply business functions mandated by FERC Order 888. NWE's transmission function is responsible for managing the interconnection process for new electricity generators, while NWE's supply function must implement PURPA. Whatever the cause, in this case NWE's reading of PSC rules governing QF interconnection costs is incomplete.

83. The PSC's (and FERC's) definition of QF-related interconnection costs expressly limits such costs to those in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. However, NWE's 2007 RPP, from which the PSC determined NWE's wind project-specific avoided costs, did not estimate system mitigation costs associated with the generic wind resource. Tr. p. 486. Similarly, it does not appear that the Renewables RFI bid-related costs include any interconnection costs, system mitigation-related or otherwise. Tr. p. 467. Accordingly, since NWE does not identify those interconnection costs for Kenfield that are in excess of the corresponding costs which NWE would otherwise incur for avoidable resource acquisitions or purchases, the PSC cannot determine Kenfield's interconnection cost responsibility under PSC rules.

84. Based on the totality of the PSC's QF interconnection rules and prior findings by the PSC in Order Nos. 4865, 5017, and 5091b, the PSC clearly requires utilities to evaluate transmission costs, such as system mitigation, associated with their avoidable generation resources or purchases. Only after incorporating those costs, along with the generation/purchase-based avoided costs, into total QF payments is it reasonable

to require the QF to reimburse the utility for the QF's related interconnection costs, because only then would any net interconnection costs paid by the QF exceed the interconnection costs the utility would otherwise incur. Other things equal, this approach is economically efficient because, theoretically, only QF's that can both produce at or below the utility's avoided generation/purchase cost and impose interconnection costs less than or equal to the utility's avoidable generation/purchase alternative should be built. Obviously, this approach is consistent with PURPA because it holds ratepayers indifferent and contributes to minimizing the costs of service.

85. Although the PSC cannot determine the system mitigation costs Kenfield is responsible for (if any) under the PSC's QF interconnection rules, the PSC must still resolve the interconnection cost issue in this case. One option considered by the PSC was to reserve the interconnection cost issue and seek additional information from the parties through additional testimony and, possibly, an additional hearing, sufficient for the PSC to apply its rules. Although this option might have provided the best way to get the information the PSC needs to apply its rules in this case, it is not possible given the 120-day statutory timeline for this proceeding.

86. A second option the PSC considered was to apply FERC's SGIA approach. With this approach Kenfield would advance NWE system mitigation costs at the time NWE actually undertakes such mitigation, but NWE would refund the costs to Kenfield over a period of time. Two drawbacks to this option, however, are that the parties did not address the merits of FERC's SGIA approach compared to the approach in FERC's and the PSC's QF interconnection rules in this proceeding and the approach proposed in this option appears to conflict with the economic rationale underlying the PSC's QF interconnection rules.

87. The third option considered by the PSC, and the one adopted in this order, is to determine that Kenfield is not responsible for any system mitigation costs. While this option exposes ratepayers to such costs if Kenfield goes forward, given that NWE's planned wind resources could also involve system mitigation costs the level of exposure may not be significantly different. This option is somewhat analogous to the PSC's treatment of wind integration costs in rate Option 3, Order 6973d, Docket D2008.12.146. It assumes that there is not a significant difference in the system mitigation costs and

risks ratepayers face with NWE's planned wind resources compared to Kenfield, and therefore the Kenfield-related interconnection costs that exceed the interconnection costs for NWE's alternative generation/purchase are considered to equal zero.

88. Given the procedural and record constraints facing the PSC in this docket, including NWE's unwillingness to provide information in response to PSC data requests, that limited the PSC's ability to determine the optimal approach to the issue of QF interconnection costs, the PSC expects to more fully address it in NWE's next QF-1 tariff filing case. The PSC directs NWE to thoroughly address the merits of applying FERC's SGIA interconnection approach to QF resource acquisition in its next QF-1 tariff filing. NWE should contrast FERC's SGIA approach with the approach outlined in PSC rules in terms of economic efficiency and customer impacts. Accordingly, the interconnection approach adopted in this order for Kenfield is not necessarily indicative of how the PSC will address QF interconnection cost issues in future cases.

Contract rate

89. Because the PSC has determined that the Kenfield project is one 20 MW project, ARM 38.5.1902(5) applies. Pursuant to the rule, Kenfield, a project greater than 10 MW in size, must be selected by the utility in a competitive solicitation process to obtain a long-term power purchase agreement with NWE. Between competitive solicitations, Kenfield may obtain a short-term contract under one of the applicable options in the QF-1 avoided cost tariff.

90. Although it is not necessary to discuss the contract rate issues further in this order, the PSC will do so in order to provide guidance to QFs and NWE in future contract negotiations. Had the PSC determined that Kenfield consisted of two separate 10 MW projects, the PSC would have set the avoided cost rate in this case at the level set in Order 6973d. That is, NWE would have been directed to offer Kenfield its choice from the three rate options the PSC approved in Order 6973d in Docket D2008.12.146. Order 6973d set an avoided cost rate for wind generation equal to $69.21/MWh. Order 6973d, ¶147. The assumed net capacity factor (NCF) of 38% in the rate was based on NWE's 2007 RPP and the NPCC's 6th Northwest Power Plan. This rate does not involve

a separate wind integration charge and does not include network upgrade-related interconnection costs. RECs go with the purchased power.

91. Both NWE and Kenfield relied on NWE's 2007 RPP as a basis for their avoided cost estimates. This approach is consistent with rate Option 3 in Order 6973d.

92. A primary point of contention between the parties was the proper capacity factor. In this docket the term "capacity factor" has been used very loosely, with confusing results. Gross capacity factor (GCF) refers to the ratio of power measured at the turbines to the product of nameplate capacity and annual hours (8760). NCF is the ratio of power measured at the interconnection point to the product of nameplate capacity and annual hours. NCF equals GCF reduced by line loss, array loss, and down time. Tr. pp. 233-237. Typically, NCF is the item of interest in a power purchase agreement, because the product of NCF, nameplate capacity, and annual hours equals power at the interconnection point, or power available for purchase.

93. If a facility has an historical record of operation, historical NCF may be determined through measuring output at the point of interconnection. Projecting NCF in future years may be accomplished through applying some sort of estimator, for instance an averaging of NCF's in past years, to the available data. In this case it is clear that variability of the wind resource plays a large part in the projection of power production, but turbine response to the wind resource and expected losses are understood to some degree.

94. If the facility does not have a data history, then expected GCF is typically obtained by applying wind data to the turbine manufacturer's power curve to forecast power production for a single turbine, and summing over the total number of turbines. Wind data is typically obtained from instruments mounted on meteorological (met) towers. Expected NCF is expected GCF corrected for expected loss. In this case the variability of the wind resource will have significant effect on the uncertainty of the estimate of NCF, but several other factors will also increase uncertainty in the estimate. These factors include uncertainty in the met tower data, uncertainty in the transformation of this data from 50 meter wind measurements at the met tower location into wind estimates at 80 to 100 meters at the proposed location of a turbine, uncertainty in the

model that converts these wind estimates into estimates of power generated by the turbine, and uncertainty in line loss, array loss, and availability.

95. In Order 6973d, the PSC determined the Option 3 standard rate of $69.21/MWh using a ratio with a fixed NCF of 38% in the denominator. If the NCF were allowed to vary, the calculated power purchase rate would vary inversely with NCF. But NCF is primarily a function of turbine type and quality of the wind resource. Generally speaking, better turbines are more expensive and provide higher capacity factors.[3/] Higher quality wind sites also produce higher capacity factors. These relations suggest that the power purchase rate should not vary inversely with NCF. Allowing the established rate to vary inversely with the estimated NCF of individual projects might encourage poor site selection and lower engineering standards. This unattractive outcome suggests that individual power purchase rates should not be increased to compensate for lower value net capacity factors.

96. The primary avoided cost rate issue in this docket was whether the fixed 38% NCF assumed in NWE's 2007 RPP and the NPCC 6th Northwest Power Plan, and which the PSC applied in Order 6973d, is set too high to accurately reflect the costs NWE can avoid by procuring Kenfield's wind generation. Kenfield requested that the PSC substitute a 30% NCF in place of the 40% used in NWE's 2007 RPP. The PSC finds no reason to discard the 38% NCF the PSC used in Order 6973d.

97. The inherent variability and error involved in estimating NCFs preclude precise prediction of the energy production of wind plants before they are constructed. Errors in measurement and the variability in wind resources also hinder accurate projections of future energy production from existing wind plants. It may take many years of actual data from (at least) several wind plants in various locations before such a thing as "representative Montana wind NCF" is established with reasonable precision.

98. The PSC determined the proper NCF to use when NWE's 2007 RPP is the basis for the avoided cost estimate in Order 6973d. Order 6973d explains that a 38% NCF better reflects the assumptions in NWE's 2007 RPP compared to the 30% capacity factor Kenfield assumes. The evidence in this docket (D2010.2.18) was sparse and

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[3/] Kenfield witness Jackson testified that using a Clipper 100 meter rotor rather than a Clipper 96 meter rotor might increase the expected NCF by four percentage points. Tr. p. 244.

poorly documented. The evidence does not demonstrate that the assumed NCF of 38% underlying rate Option 3 in Order 6973d is either too high or too low. Therefore, the PSC does not believe the evidence demonstrates that rate Option 3 reflects an inaccurate estimate of the avoided cost of wind generation to NWE. Accordingly, the PSC would not have set a higher, individual rate for Kenfield based on a lower NCF assumption. Kenfield's estimated achievable NCF is not relevant to NWE's avoided cost if the wind resource NWE would otherwise acquire is expected to have a higher capacity factor. Kenfield's proposed 30% NCF represents a significant departure from the NCF assumed in NWE's 2007 RPP.

99. As with the contract rate issue, if the PSC had needed to resolve the wind integration charge issue in this docket, it would have determined that the evidence in this docket was not sufficient to support a deviation from the wind integration approach the PSC adopted in Order 6973d. Long-term wind integration costs remain uncertain. As explained in Order 6973d, the three standard rate options reflect the risks and opportunities that NWE, its customers, and the QF community all face today.

100. The PSC notes that the 50-MW installed capacity limit on new wind QFs is intended to trigger a review of NWE's avoided costs, QF rates, and QF resource acquisition experience to ensure the proper balancing of interests inherent in implementing PURPA.

CONCLUSIONS OF LAW

1. All findings of fact that are properly conclusions of law and that should be considered as such to protect the integrity of this Order are incorporated herein and adopted as such.

2. The Commission has provided adequate public notice of all proceedings, and an opportunity to be heard to all interested parties in this docket. § 69-3-104, MCA.

3. The Commission supervises, regulates, and controls public utilities pursuant to Title 69, Chapter 3, MCA. § 69-3-102, MCA.

4. The Commission implements and enforces the provisions of the Public Utility Regulatory Policies Act. 16 U.S.C. § 824a-3(f).

5. NWE is a public utility subject to the jurisdiction of the Commission. § 69-3-101, MCA.

6. The rates for purchases provided by this order are just and reasonable to the electric consumers of NWE and do not discriminate against QFs. 16 U.S.C. § 824a-3(b).

ORDER

IT IS HEREBY ORDERED that:

1. The PSC will consider the totality of the circumstances when determining whether a QF project is a single project of 10 MW or less in size or more than one project.

2. Kenfield is a single 20 MW project.

3. The Kenfield project is not responsible for any transmission system mitigation costs.

4. The Kenfield project is not entitled to a long-term contract unless it is selected in a competitive solicitation, but is entitled to sell electricity to NWE pursuant to the short-term contract options provided in Order No. 6973d.

5. The PSC directs NWE to thoroughly address the merits of applying FERC's SGIA interconnection approach to QF resource acquisition in its next QF-1 tariff filing. NWE should contrast FERC's SGIA approach with the approach outlined in PSC rules in terms of economic efficiency and customer impacts.

Done and dated this 22nd day of June 2010 by a vote of 5 to 0.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

GREG JERGESON, Chair

KEN TOOLE, Vice Chair

GAIL GUTSCHE, Commissioner

BRAD MOLNAR, Commissioner

JOHN VINCENT, Commissioner

ATTEST:

Verna Stewart
Commission Secretary

(SEAL)

NOTE: Any interested party may request the Commission to reconsider this decision. A motion to reconsider must be filed within ten days. See 38.2.4806, ARM.