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

IN THE MATTER OF the Petition of Greycliff Wind Prime, LLC to Set Contract Terms and Conditions for a Qualifying Small Power Production Facility

REGULATORY DIVISION
DOCKET NO. D2015.8.64
ORDER NO. 7436d

FINAL ORDER

FOR GREYCLIFF:
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FOR THE INTERVENORS:
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FOR THE COMMISSION:
Will Rosquist, Administrator, Regulatory Division
Justin Kraske, Administrator, Legal Division
Neil Templeton, Rate Analyst
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BEFORE:
Bob Lake, Commissioner and Presiding Officer
Brad Johnson, Chairman
Travis Kavulla, Vice Chairman
Roger Koopman, Commissioner
Kirk Bushman, Commissioner
PROCEDURAL HISTORY


2. On August 20, 2015, the Commission issued a Notice of Petition and Intervention Deadline, setting an intervention deadline of September 3, 2015.

3. On September 4, 2015, Greycliff filed with the Commission a Motion for Summary Judgment on the Legal Issue of Whether NorthWestern Energy has an Obligation to Negotiate in the Absence of All Source Competitive Solicitation Set Forth in ARM 38.5.1902(5).

4. On September 9, 2015, the Commission granted intervention to the Montana Consumer Counsel (MCC) and NorthWestern Energy (“NorthWestern”). On September 10, 2015, the Commission issued Procedural Order 7436.

5. On September 18, 2015, Greycliff filed the Prefiled Direct Testimony of Robert Stanton Walker.

6. On September 21, 2015, the MCC filed a Response of the Montana Consumer Counsel to Greycliff Wind Prime, LLC’s Motion for Summary Judgment. On September 22, 2015, NorthWestern filed its Response Brief to Greycliff Wind Prime LLC’s Motion for Summary Judgment.


9. On January 15, 2016, the Commission issued an Order Denying Summary Judgment. The Commission directed Greycliff and NorthWestern to “negotiate for at least thirty days in an effort to mutually agree to contract terms and conditions, including an avoided cost
rate…” Order 7436b, ¶ 23 (Jan. 15, 2016). Also on January 15, 2016, NorthWestern filed its Supplemental Response Testimony and Exhibits.


11. The parties requested several extensions to the negotiation period, which were granted by Commission staff. On March 14, 2016, Greycliff filed a Notice that Negotiations with NWE have concluded without Agreement and Request to Re-Establish Procedural Schedule. On March 23, 2016, the Commission issued Procedural Order 7436c.


15. The Commission held work sessions on July 19, 2016 and September 13, 2016 in regard to this matter.

DISCUSSION AND FINDINGS OF FACT

Legally Enforceable Obligation

16. The Commission has adopted requirements for the establishment of a legally enforceable obligation (LEO). The requirements were set following a review of relevant statutes, and the tests utilized by other states. The Commission found that “the touchstone of a legally enforceable obligation … is an absolute, unconditional commitment to deliver energy, capacity, or energy and capacity at a future date.” Order 6444e, Dkt. D2002.8.100, ¶ 45 (June 4,
The Commission found that in order to establish an LEO, a qualifying facility 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 interconnection agreement.” *Id.* ¶ 47.

17. The Montana Supreme Court has found that the “Commission did not exceed its statutory authority in concluding that evidence of a utility’s refusal to negotiate, without more, is insufficient to establish that a qualifying facility has committed itself to the proposed project.” *Whitehall Wind, LLC v. Mont. Pub. Serv. Com.*, 2015 MT 119, ¶ 17, 379 Mont. 119, 347 P.3d 1273. However, the Court “decline[d] to opine whether the Commission’s LEO requirements, announced in its order, comply with the Public Utility Regulatory Policies Act (PURPA).” *Id.* ¶ 18.

18. Greycliff asserts that it incurred an LEO on July 2, 2015. Pet. Post Hr’g Br. 6 (June 10, 2016). On July 2, 2015, Greycliff sent a letter to NorthWestern, which included a signed contract (with a price term that Greycliff states is consistent with the avoided cost information available to it at the time), and a signed interconnection agreement. *Id.* Greycliff states that the contract had a beginning and ending date, as well as “sufficient guarantees to ensure Greycliff’s performance.” *Id.*

19. NorthWestern argues that Greycliff’s price term was not in fact consistent with NorthWestern’s avoided costs. NorthWestern states that Greycliff offered a “random, unsubstantiated rate” to serve as the utility’s avoided cost rate. NorthWestern Post Hr’g Br. 4-5 (June 24, 2016). Greycliff argues that it did the best it could with the information it possessed at the time. Pet. Post Hr’g Br. 7.

20. NorthWestern also argues that another issue pertains to Greycliff’s request to change the Guaranteed Commercial Operation Date during the course of this docket. Greycliff asserts that it made the request to change the Guaranteed Commercial Operation Date “because NWE’s construction schedule for completing the interconnection with Greycliff’s project is 14 months.” *Id.* at 10. Greycliff also asserts that the delays in this docket necessitated a delayed Guaranteed Commercial Operation Date. *Id.*

21. The uncertainty of NorthWestern’s avoided costs at the time Greycliff asserts it incurred an LEO and the change in Guaranteed Commercial Operation Date cast doubt on
whether or not Greycliff did in fact incur an LEO on July 2, 2015, according to the Commission’s requirements in Order 6444. Namely, it is not apparent that Greycliff provided a “price term consistent with the utility’s avoided costs.” Moreover, to the extent an LEO was incurred on July 2, 2015, it appears to have been broken when the “specified beginning and ending dates,” in that LEO were later revised. A strict interpretation of the Commission’s LEO requirements suggests that either Greycliff did not incur an LEO or that it was voided by the change in the Guaranteed Commercial Operation Date.

22. NorthWestern controls much of the information needed to estimate its avoided costs. This puts QFs seeking to negotiate contracts, establish LEOs, or prepare petitions seeking a Commission-determined rate in a difficult position. In attempting to estimate NorthWestern’s avoided cost, a QF should not merely rely on a recent Commission avoided cost determination. Large QFs should request that NorthWestern provide a project-specific avoided cost calculation. NorthWestern must provide a reasonably transparent avoided cost calculation with a complete explanation of methods and assumptions in a reasonable amount of time.

23. Previously, the Commission has noted the problematic nature of NorthWestern’s expert testimony on avoided cost, which relies on proprietary modeling software. Discovery in this proceeding was complicated by objections to the lack of transparency in NorthWestern’s calculation. While the Commission did not find it necessary earlier in the proceeding and does not find it necessary now to rule on this matter in order to determine an appropriate avoided cost for the applicant, the Commission expects this issue to continue arising in future dockets. Greycliff’s Mot. in Limine (Dec. 30, 2015), see also Greenfield’s Renewed Mot. to Strike Testimony and to Compel Discovery, In re Greenfield Wind, LLC, Dkt. D2014.4.43, (Sept. 22, 2014). The Commission encourages parties going forward to substantiate evidence through transparent answers in the discovery process.

24. This docket reflects the significant challenges of establishing, at a single point in time, an avoided cost figure that is economically sound and defensible over the duration of long-term fixed rate power purchase agreements (PPA). If the goal is to set rates that are just and reasonable to the consumer, while preserving entrepreneurial opportunity for the developer, the Commission is aiming at a target that is constantly moving, based on a technology-driven market that is highly dynamic. Accordingly, the Commission considers Commission-established avoidable costs as generally the last resort under PURPA compliance requirements, and the least
desirable method of pricing QF-generated power in the marketplace. The Commission, therefore, encourages a robust bilateral negotiation process, centered around sound avoided cost principles, that can better accommodate the moving parts of an unknown and unpredictable energy future. Curtailment terms, contract length, market price indexing and other contract provisions can assign specific values to specific levels of risk and reward. PPAs established in this manner may vary greatly, but will often be more creative than contracts written by the Commission, which can ultimately benefit all parties and best serve the public interest.

**Avoided Cost**

25. Avoided costs are the incremental costs to an electric utility of energy and capacity which, but for the purchase from a qualifying facility (QF or QFs), the utility would generate itself or purchase from another source. Mont. Admin. R. 38.5.1901(2)(a) (2016).

26. The Commission must determine a just and reasonable rate for power purchased from Greycliff based on estimated costs that NorthWestern could avoid with such purchases over the long-term. Ideally, customers should be economically indifferent to purchasing Greycliff power compared to NorthWestern’s least-cost alternative plan for purchasing energy and capacity or building new generating resources.

27. In its Petition, Greycliff proposed an avoided cost rate of $50.35/MWh, which was based in part on the $50.49/MWh avoided cost rate approved by the Commission on April 10, 2015, in Order 7347a. Ex. GWP-1, 5. In rebuttal testimony, Greycliff provided alternative estimates of NorthWestern’s avoided costs that it contends support its proposed rate. Ex. GWP-2, 42.

28. NorthWestern opposes the rate of $50.35/MWh, asserting that it was based on a negotiated price specific to a previous project and does not reflect NorthWestern’s current avoided cost. NorthWestern proposed a “carbon included” avoided cost rate of $35.65/MWh based on its current modeled costs. Ex. NWE-1, 14:11-16:23; Ex. NWE-6, 1. According to NorthWestern, market electricity and natural gas prices have decreased since the Greenfield proceeding. Ex. NWE-7, 7:13-8:3, Table 1. The parties generally agree on avoided capacity costs and inclusion of CO₂ emissions costs. Ex. GWP-2, pp. 38, 41; Ex. NWE-1, 8:6-11.

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1 This rate was proposed in revised supplemental response testimony. The “carbon-included” (i.e. including a carbon adder to the market forecast) rate proposed by NorthWestern in response testimony was $38.58/MWh.
29. Greycliff proposes using the Northwest Power and Conservation Council’s 7th Power Plan forecast of Mid-C electricity prices (NPCC forecast) to estimate long-term avoidable energy costs. It contends that the NPCC forecast is transparent, was developed using rigorous, fundamental analysis, and reflects structural changes in the industry. Ex. GWP-2 p. 33. It asserts that the Intercontinental Exchange (ICE) forward market prices, which NorthWestern relies upon, represent limited surveys of transactions with zero volume and do not incorporate fundamental information such as expected changes to federal regulations and other market structures. Id. at 36; Pet. Post Hr’g Br. 11-14. Based on the NPCC draft forecast of wholesale electricity prices at Mid-C, Greycliff estimated an avoided cost of $53.39/MWh. Ex. GWP-2, 42; Response to Data Request (DR) NWE-022 (May 18, 2016).

30. NorthWestern projected Mid-C electricity prices using ICE forward market prices through July 2020. Thereafter, it applied an escalation rate derived from the Energy Information Administration 2015 Annual Energy Outlook (AEO) nominal Henry Hub natural gas price forecast. Hr’g Tr. 140:6-141:23, 147:4-148:3 (May 31, 2016). NorthWestern asserts that the NPCC forecast Greycliff used was a draft version and that the final forecast is 9.5% lower. Hr’g Tr. 135:6.

31. Use of forward market prices such as those developed by ICE has been a consistent feature of NorthWestern’s market price forecasting approach for some time; the approach has been used in avoided cost rate setting since at least 2010. Order 7108e, Dkt D2010.7.77, ¶¶ 65-70 (Oct. 19, 2011); Order 7199d, Dkt D2012.1.3, ¶¶ 30-32 (December 7, 2012); Order 7338b, Dkt D2014.1.5, ¶ 18 (May 4, 2015). Forward market prices reasonably reflect near-term market fundamentals and expectations. The Commission has used AEO escalation rates to extend near-term forward prices in a way that captures an analysis of long-term market fundamentals. Order 7199d ¶ 28. This market price forecasting approach could use either AEO escalation rates or NPCC forecast escalation rates.

32. The Commission finds NorthWestern’s market price forecast to be reasonable given that it follows an approach approved in other QF dockets. The Commission adjusts the escalation rate to the 2015 AEO nominal Henry Hub forecast of 4.25% annual escalation for the period 2020 to 2040, rather than the 4.15% used by NorthWestern. Response to DR PSC-050c (April 20, 2016). This produces an avoided energy cost of $49.92 per MWh which is an estimate of the levelized Mid-C market value. The Commission rejects the use of the NPCC escalation
rate of 4.68% per year for 2020 through 2035, as the proposal to use the NPCC forecast emerged relatively late in the proceeding and deviates from past Commission practice.

33. Grefycliff opposes any adjustment to forecast Mid-C market prices to account for transmission costs. Grefycliff states that NorthWestern failed to justify the adjustment prior to hearing and violated Grefycliff’s due process rights. Pet. Post Hr’g Br. 15-16; Pet. Post Hr’g Reply Br. 13-15.

34. NorthWestern asserts that market-based power transactions in Montana reflect a discount to Mid-C prices based on an ability to partially avoid transmission charges associated with delivering power generated in Montana to Mid-C. NorthWestern estimated the discount to be $4.33/MWh plus an adder of 2% for line losses. Hr'g Tr. 144:13-145:2. NorthWestern conceded that the retirement of Colstrip Units 1 and 2 could affect the Montana basis differential, but it did not attempt to quantify the impact. Id. 137:20-138:11.

35. The Commission finds that Mid-C market prices should be adjusted to account for a Montana basis differential. NorthWestern explained that Montana-traded electricity prices are lower on average than prices at Mid-C because the relative surplus of electricity in Montana and the cost of transmitting that supply to the liquid trading hub of Mid-C results in a discount to purchasers. While the Commission agrees with Grefycliff that more evidence that substantiates such an adjustment would be desirable, there is clear evidence that a basis differential exists and, in particular, an adjustment of ($4.56) per MWh is supported by record evidence developed in this docket. The Commission derived the ($4.56) per MWh value by comparing a levelized valuation of Grefycliff’s output at projected Mid-C prices to a valuation based on projected Montana purchase prices (when NorthWestern projected a resource deficiency) and net Mid-C sales prices (when NorthWestern projected a resource sufficiency). These price projections, and Grefycliff’s output in resource-deficient and sufficient periods, are included in NorthWestern’s responses to data requests PSC-012 and PSC-047. Incorporating a basis adjustment is consistent with the assumptions in NorthWestern’s 2013 and 2015 resource plans. N2013.12.84, Vol. 2, ch. 3, pp. 34-63; N2015.11.91, Vol. 2, ch. 2, Commodity Prices, pp. 6-26. In addition, the Commission has recognized a Montana basis differential in its decisions on NorthWestern’s purchase of hydroelectric facilities, and in its evaluation of NorthWestern’s off-system hedging practices in electric tracker dockets from 2012 through 2015. Dkt. D2013.12.85, Prefiled Direct Testimony of Joseph M. Stimatz, 21:19-24:4, Internal Exhibit_(JMS-2 and 3); Order 7323k, Dkt.
D2013.12.85 ¶¶ 26-30, 79-80 (September 26, 2014); Order 7219h, Dkt. D2012.5.49, ¶¶ 80-89 (Oct. 28, 2013); Order 7283h, Consolidated Dkts. D2013.5.33/D2014.5.46, ¶¶ 75-77 (May 13, 2016); Order 7418d, Dkt. D2014.7.58, ¶¶ 19-22 (April 13, 2016). While it is possible that the future closure of Colstrip generating units could affect the basis differential by reducing Montana’s supply of electricity, the Commission finds that it would be premature to simply eliminate it at this time.

36. Greycliff opposes the use of Colstrip Unit 4 (CU4) variable cost rather than market price to estimate avoided cost in periods when NorthWestern projects that it will have sufficient resource to satisfy its load serving requirements. Greycliff asserts that if NorthWestern were in a long position and CU4’s variable cost was less than market, NorthWestern would run CU4, sell the surplus power, and credit the revenue to customers. Thus, Greycliff contends that NorthWestern’s avoided cost should be based on market prices when NorthWestern is in a long position. Ex. GWP-2, 18-19.

37. NorthWestern contends that if it is projected to be in a long position and the variable cost of CU4 is less than the forecast market price, the CU4 variable cost should become the basis for the avoided cost because CU4 could be turned down to accommodate Greycliff’s power. NorthWestern argues that it has acquired a supply portfolio to protect its customers from the market, and to pay Greycliff market when the portfolio is long would re-expose customers to market risk. Hr’g Tr.102:8-105:10. NorthWestern asserts that customers should receive the benefit of any surplus sales revenues. Hr'g Tr. 109:8-110:5.

38. Given the market-based approach to estimating avoided energy costs that NorthWestern and Greycliff both use in this case, the Commission agrees with Greycliff that CU4 variable costs should not become the basis for avoided costs during periods when NorthWestern projects that it will be in a long position. A long-term fixed-price QF power purchase agreement is a fixed-price hedge similar to utility acquisition of a generating resource. When NorthWestern valued the acquisition of its hydroelectric resources, it valued all output at market prices, even when that output occurred in periods when NorthWestern projected that it would be in a long position. Dkt. D2013.12.85, Direct Testimony of Joseph M. Stimatz, pp. 6-7; Int. Exhibit_(JMS-3). Greycliff’s output will be evaluated using the same approach.

39. Greycliff opposes any adjustment to Mid-C market prices attributed to a difference in the quality (i.e., firm vs. non-firm) of the power provided by a wind project.
compared to generic market purchases.

40. NorthWestern proposes to adjust forecast market prices to reflect the diminished value of intermittent wind power compared to market purchases. Ex. NWE-1, 8:13-23. NorthWestern’s adjustment reflects an observed difference between a series of ICE day-ahead index prices and a corresponding series of Powerdex real-time index prices. Ex. NWE-6, p. 2. NorthWestern contends that the observed difference in prices represents a value difference between firm energy and non-firm, intermittent energy. NorthWestern acknowledged that a commitment to deliver day-ahead power is equivalent to a commitment to provide capacity and that the five percent capacity value attributed to wind QFs in NorthWestern’s QF-1 tariff can be viewed as an adjustment for intermittent value. Hr’g Tr. 88:19-89:16.

41. The Commission rejects NorthWestern’s adjustment to forecast market prices based on a firm/non-firm power quality distinction. NorthWestern did not adequately support the alleged distinction with references to established regulatory theory or standard utility practice. Response to DR PSC-014 (Dec. 9, 2015). Record evidence does not show that the observed difference between day-ahead and real-time price indices, if real, is attributable solely or partially to the quality of power generation underlying the prices. Nor has NorthWestern proposed similar adjustments in valuations of its own intermittent resources. Hr’g Tr. 111:9-15.

42. NorthWestern reduced its avoided cost figure by $5.40/MWh to remove the estimated cost of interconnecting the Greycliff facility to NorthWestern’s transmission network. Ex. NWE-3, 6:20-7:2; Ex. NWE-6. NorthWestern’s Transmission Department estimated the interconnection cost to be $3.6 million. Ex. NWE-3, 6:1-4. NorthWestern proposes that Greycliff would pay the interconnection cost initially, with full reimbursement from NorthWestern in accordance with the Federal Energy Regulatory Commission (FERC) rules and the Commission’s order. Id. 4:1-11, Order 7108e, ¶ 85. The cost of the facilities would be eventually subsumed into NorthWestern’s rate base and included in transmission rates. Hr’g Tr. 94:1-7. Ex. NWE-3, 5:15-17.

43. Greycliff testified that reducing avoided cost to compensate for interconnection costs would be discriminatory because a merchant plant would be entitled to full reimbursement of these costs, yet would not be assessed, as NorthWestern proposes, a deduction from the price of purchased energy. Hr’g Tr. 57:25-58:22. NorthWestern countered that a merchant generator, unlike Greycliff, would be subject to transmission charges, and reimbursement of its
interconnection costs is achieved through credits on those charges. For the Greycliff project, NorthWestern’s Supply Department, not Greycliff, is the transmission customer, and NorthWestern’s customers will be paying for the interconnection facilities. Hr'g. Tr. 99:19-100:17.

44. NorthWestern testified that it would not incur similar interconnection costs through either replacement purchases at market or delivery from existing resources. Ex. NWE-3, 5:4-12. NorthWestern admitted that it expects to incur interconnection network upgrade costs as it installs the resources proposed in its 2015 Resource Procurement Plan. Hr'g Tr. 97:10-13. It asserted that proposed resources are shaped, dispatchable resources that would not be delayed or avoided by the purchase of Greycliff power. Id. 96:7-21. NorthWestern admitted that its PowerSimm analysis of Greycliff used NorthWestern’s current portfolio and did not allow the displacement or postponement of the resources in that portfolio. Id. 129:12-130:12.

45. Under Commission precedent, Greycliff is ultimately responsible only for costs that exceed “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.” Order 7068b, Dkt. D2010.2.18, ¶ 83 (June 23, 2010). NorthWestern is required to evaluate transmission costs associated with avoidable resources or purchases, from which estimates of the incremental costs of QF upgrades may be informed. Id. ¶ 84.

46. In Docket D2010.2.18, the Commission found that “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.” Id. ¶ 83. In that case, the Commission determined that the wind developer (Kenfield) would not be responsible for any system mitigation costs, since NorthWestern had planned to acquire wind resources, and that, without persuasive evidence to the contrary, Kenfield-related interconnection costs in excess of alternative interconnection costs were assumed to be zero. Id. ¶ 87. Similarly, in Docket D2010.7.77, the Commission found that “without an estimate of network upgrade costs for [NorthWestern’s] avoidable resources it is not possible to apply ARM 38.5.1904.” Order 7108e ¶ 84.

47. A merchant generator is not strictly comparable to a QF, in that delivery of the
merchant’s product over the transmission system will not require network service. FERC orders have authority regarding transmission relations between NorthWestern and merchant plants. NorthWestern is not required to purchase electricity from a merchant at avoided cost. The appropriate comparison in this case is the cost treatment of QFs to the cost treatment of other energy supply resources under NorthWestern’s ownership or control. Therefore, regarding responsibility for interconnection network upgrade costs, comparisons to merchant plants are not controlling.

48. NorthWestern proposed that the entire $3.6 million in expected interconnection upgrade cost be treated as a reduction in avoided cost, whereas the Commission has established that only the incremental cost of such upgrades should be removed from avoided cost. An accurate estimate of such an increment in this case would require some knowledge of the expected cost of upgrades but for the purchase of power from Greycliff. Although that knowledge might be obtained through a differential revenue requirement analysis of the Greycliff project, including the expected upgrade costs of all current and future avoidable assets, the record here does not provide that analysis or other convincing evidence that power purchased from Greycliff would not displace or postpone some measure of additional upgrade cost associated with resources proposed in NorthWestern’s 2015 Resource Procurement Plan.

49. In this docket, NorthWestern is not planning or proposing to acquire new wind resources, so it is not strictly analogous to previous proceedings. Nonetheless, NorthWestern has failed to provide an estimate of incremental interconnection costs greater than zero but less than $3.6 million, and it has not substantially supported its assertion that incremental costs should equal the entire estimated cost of the Greycliff interconnection upgrade. The Commission finds that there is insufficient information in this record to support the inclusion of interconnection costs in the avoided cost calculation.

50. NorthWestern estimated Greycliff integration costs to be $0.52/MWh for regulation reserves, $0.61/MWh for spinning reserves, and $1.09/MWh for supplemental reserves, for a total integration rate of $2.22/MWh. Ex. NWE-6, p. 1. The regulation rate was based on the incremental costs of operating the 45 MW of Dave Gates Generating Station (DGGS) allocated to the regulation of wind resources, applied to 18% of Greycliff’s nameplate capacity, or 4.5 MW. Id. NorthWestern derived the spinning and supplemental reserves rates from NorthWestern’s current Transmission Tariff, escalated at 2% annually and levelized. Ex.
NWE-1, 9:12-18.

51. Greycliff proposed an integration rate of $1.49/MWh, based upon wind integration charges in NorthWestern’s WI-1 Tariff, and contingency reserve charges in its CR-1 Tariff. Ex. GWP-2, pp. 10-11. NorthWestern responded that the WI-1 and CR-1 tariffs do not apply to QFs exceeding 3 MW in size and that Greycliff failed to adjust for spinning reserves. Ex. NWE-5, 8:7-9:13. NorthWestern states that the zonal factor applied to Greycliff under the zonal regulation method observed in the WI-1 Tariff would be 5% rather than 18%, which was originally proposed by NorthWestern and that the levelized cost of regulation reserves would be $0.14/MWh rather than $0.52/MWh. DR PSC-017d. It argues that a rate based on 5% would underestimate the cost of regulation reserves for Greycliff and violate customer indifference. NWE Resp. Br. 25 (date).

52. The Commission adopted the zonal regulation method used to set WI-1 rates based in part on a finding that concentrated wind development increases integration costs. Order 7199d ¶ 65. The method derived three rates for three zones defined according to lineal distance from the Judith Gap wind project. The method addressed a “need for long-term integration rates that reflect the higher costs of additional wind development near Judith Gap.” Id.

53. The same finding indicated a need for more intensive analysis of the integration costs of wind development. “In addition, uncertainties about how actual wind development will proceed and deviate from the results in the GENIVAR Study, and uncertainties about the pace and effectiveness of shorter scheduling intervals indicate a need to closely monitor QF development and NWE’s balancing area performance so that appropriate rate adjustments can be implemented and uneconomic resource decisions can be avoided.” Id.

54. A later finding indicated that NorthWestern had not met its burden to accurately monitor the incremental integration cost of additional wind development and its impact on the integration capacity of DGGS.

Although this issue has been percolating for many years, NorthWestern is still unable to accurately estimate its own integration capacity requirements, and has still not evaluated the geographic diversity effects of existing wind resources. NorthWestern’s estimates of remaining DGGS capacity rest on results from the GENIVAR study, but the development of wind on its system has not resembled any of the scenarios studied, and DGGS does not actually operate the way it was modeled. NorthWestern does not appear to have made any substantial progress toward evaluating current wind integration requirements or planning for future requirements. In this proceeding,
NorthWestern did not provide sufficient information for the Commission to change the wind integration component of standard avoided cost rates.

Order 7338b ¶ 25.

55. The record in this proceeding provides no indication that NorthWestern has accurately estimated either the incremental cost of integrating Greycliff or the impact of Greycliff on the integration capacity of DGGS. The Commission adopts the rate of $0.14/MWh for regulating reserves rather than NorthWestern’s proposed rate of $0.52/MWh. This change would reduce the total cost of integration from $2.22/MWh to $1.84/MWh.

56. NorthWestern estimated an avoided capacity cost of $1.98/MWh, based upon the ownership cost of an 18 MW reciprocating internal combustion engine (RICE) generator and a 5% capacity contribution. The RICE unit was projected to be installed in 2019, with a levelized avoided ownership cost of $151.37 per kW-year from 2019-2042. Ex. NWE-4, pp. 4-6; Ex. NWE-6, p. 3. Greycliff testified that this value is an appropriate alternative to its own estimate of $1.78/MWh, based upon the avoided capital cost of a simple cycle gas turbine and a 5% capacity contribution. GWP-2, pp. 38, 41. The Commission finds that NorthWestern’s avoided capacity rate of $1.98/MWh is reasonable. Based on the above findings, the Commission finds that NorthWestern’s avoided costs associated with the purchase of energy and capacity from the Greycliff wind project produce a levelized rate of $45.49 per MWh for the 25 year contract term.

Contract Terms

57. Greycliff proposes a definition of “Emergency Condition” that includes a requirement that if NorthWestern’s energy purchases from Greycliff contribute to an emergency situation, any curtailment of Greycliff is nondiscriminatory. Pet. Post Hr’g Br. 25-26. NorthWestern proposes a more general definition to mean any condition or situation imminently likely to endanger life, property, or system security. Id. 26. Greycliff contends that NorthWestern’s version could allow uncompensated curtailment of Greycliff power whether Greycliff’s operation was contributing to the emergency situation or not. Id.

58. NorthWestern argues that its definition is based on FERC’s definition of a system emergency under 18 C.F.R. §292.101(b)(4), which includes any condition on a utility’s system that is likely to result in disruption of service to customers or endanger life or property. NorthWestern Post Hr’g Br. 26.

59. Mont. Admin. R. 38.5.1903(1) states that a utility must purchase energy made
available by a QF except during a system emergency “if such purchase would contribute to the emergency.” Consistent with this rule, NorthWestern can only curtail or interrupt the delivery of energy from Greycliff if Greycliff’s output is contributing to an emergency and curtailment or interruption is necessary to address a system emergency as defined in 18 C.F.R. §292.101(b)(4). The Commission adopts Greycliff’s proposed language.

60. Greycliff’s proposed language for curtailment right at § 6.7.1 places restrictions on when NorthWestern can curtail power from Greycliff, allowing curtailments when they are “consistent with 18 C.F.R. §292.304(f) and decisions of the Federal Energy Regulatory Commission interpreting this regulation.” Pet. Post Hr’g Br. 27-28. Greycliff asserts that FERC’s PURPA regulation permit curtailment only during system emergencies, or under light load conditions when the QF is selling its output “as available”. Id. 28.

61. NorthWestern’s proposed curtailment language at § 6.7.1 allows it to curtail the delivery of energy from Greycliff at any time and for any reason deemed necessary by NorthWestern. Id. NorthWestern argues that Greycliff’s position is based on FERC’s decision in Pioneer Wind Park I, LLC, which is a declaratory order that is not binding law and does not override Commission rules. NorthWestern Post Hr’g Br. 26-27. NorthWestern also states that its language provides that it may curtail the QF for any reason, but if the reason for curtailment is not included in the definition of uncompensated curtailment, it must compensate the QF for the curtailed power. Id. 27.

62. Any curtailment should occur only with identifiable and reasonable cause. The Commission adopts Greycliff’s proposed language at § 6.7.1.

63. Greycliff proposes language in § 6.7.4 to prohibit NorthWestern from curtailing power from Greycliff during light loading periods. Pet. Post Hr’g Br. 28-29. Greycliff argues that curtailment during light loading periods is prohibited by PURPA and FERC’s implementing regulations under 18 C.F.R. §292.304(f). Id.

64. NorthWestern proposes language at § 6.7.4 to state that it is not obligated to accept or pay for energy from Greycliff if, due to operational circumstance, the purchase would result in costs greater than those which NorthWestern would incur otherwise. Id. 28. The section would only apply under conditions of light loading when NorthWestern would have to cut back base-load generation to purchase energy from Greycliff followed by an immediate need to meet a sudden high peak in demand. Id. 28-29. NorthWestern argues that this is in line with
Mont. Admin. R. § 38.5.1903(1), which allows a utility to curtail purchases if they will result in costs greater than those the utility would incur if it did not make such purchases during light loading periods. NorthWestern Post Hr’g Br. 26-27. NorthWestern also believes that Greycliff did not establish an LEO, and therefore must sell its power on an as available basis. Id.

65. The economic effects of QF power sales to a utility during light loading periods can, and should, be addressed in the development of the contract rate. The Commission finds that although Greycliff does not have an LEO, the Commission is setting long-term contract terms and conditions. The Commission adopts Greycliff’s proposed language at § 6.7.4.

66. NorthWestern defines uncompensated curtailment to allow it to curtail Greycliff energy during light loading periods without compensation. Pet. Post Hr’g Br. 30. Greycliff argues that this action would be plainly unlawful. Id. The definitions of both parties include the events of scheduled or unscheduled outages of the wind facility or the NorthWestern System, but Greycliff’s definition includes language to exclude outages resulting from “negligence, intentional act, or other mis-, mal-, or nonfeasance” by Northwestern. Id. 29-30.

67. Consistent with the finding above, the Commission finds that uncompensated curtailment during light loading periods will not be permitted unless Greycliff output contributes to a system emergency. The Commission finds that Greycliff’s proposed language to exclude outages resulting from “negligence, intentional act, or other mis-, mal-, or nonfeasance” by Northwestern is redundant and not necessary to include.

68. NorthWestern states that a QF is “legally responsible for payment of both interconnection network upgrade costs and transmission service upgrade costs.” NorthWestern Post Hr’g Br. 28. Greycliff’s language proposes to reimburse NorthWestern for costs consistent with the Large Generator Interconnection Agreement, but NorthWestern states that agreement only reimburses interconnection network upgrade costs and not transmission service costs.

69. FERC Order 69 directs that utilities cannot discriminate with respect to interconnection costs. The Commission finds that transmission network upgrade costs should be treated the same as transmission interconnection network upgrade costs. The QF should be responsible for any costs that exceed costs that NorthWestern would otherwise incur but for purchases from the QF. Similar to interconnection upgrade costs, NorthWestern has not shown what transmission service upgrade costs it would otherwise incur.

70. Greycliff proposes language at § 8.5 that would prevent the termination of the
contract, regardless of a repeal of PURPA. Pet. Post Hr’g Br. 30-31. NorthWestern proposed that the Commission would have authority to amend or terminate the contract if PURPA is repealed or amended. Id. 31. Greycliff argues that since PURPA is a federal regulation, only Congress can retroactively repeal or amend the law, not the Commission. Id.

71. The Commission is not compelled to project its own or other legal obligations in the event of repeal or amendment of PURPA, and rejects inclusion of language at § 8.5 or at any other section that references this event.

CONCLUSIONS OF LAW


73. PURPA requires electric utilities to offer to purchase electricity from QFs, and that the rates for such purchases be “just and reasonable to the electric customers of the electric utility and in the public interest,” and to not discriminate against QFs. 16 U.S.C. § 824a-3(b). “Nothing in [PURPA] requires any electric utility to pay more than the avoided cost for purchases.” 18 C.F.R. § 292.304(a).

74. “Avoided costs” are “the incremental costs as determined by the commission to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.” 16 U.S.C. § 824a-3(d); Mont. Admin. R. 38.5.1901(2)(a).

75. PURPA delegates broad authority to state regulatory commissions, which “play the primary role in calculating avoided cost rates and in overseeing the contractual relationship between QFs and utilities…” Indep. Energy Producing Assoc., Inc. v. Cal. Pub. Utilities Commn., 36 F.3d 848, 856 (9th Cir. 1994) (citing 16 U.S.C. § 824a-3(f)).

76. “[I]f a qualifying small power production facility and a utility are unable to mutually agree to a contract for the sale of electricity or a price for the electricity to be purchased by the utility,” either the QF or the utility may petition the Commission to set terms and conditions, including rates for sales of energy and capacity. Id. § 69-3-603 (“The commission shall determine the rates and conditions of the contract upon petition”).

77. Mont. Admin. R. 38.5.1902(5) states that “[a]ll purchases and sales of electric
power between a utility and a qualifying facility shall be accomplished according to the terms of a written contract between the parties or in accordance with the standard tariff provisions as approved by the commission.”

78. Mont. Admin. R. 38.5.1903(2)(b) states that each utility shall purchase energy and capacity made available by a QF at a standard rate or if the QF “agrees, at a rate which is a negotiated term of the contract between the utility and the facility and not to exceed avoided costs to the utility.”

79. Mont. Admin. R. 38.5.1905(2) states that utilities “shall purchase available power from any qualifying facility at either the standard rate determined by the commission… or at a rate which is a negotiated term of the contract between the utility and the qualifying facility.”

80. FERC’s rules state nothing in the rules “[l]imits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required” or “[a]ffects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.” 18 C.F.R. 292.301.

ORDER

IT IS HEREBY ORDERED THAT:

81. A just and reasonable determination of costs avoided by NorthWestern’s purchase of Greycliff power is $45.49 per MWh on a 25-year levelized basis.

82. Upon receiving a request from a large QF, NorthWestern must provide a reasonably transparent avoided cost calculation with a complete explanation of methods and assumptions in a reasonable amount of time.

DONE AND DATED this 13th day of September, 2016, by a vote of 3 to 2. Commissioners Bushman and Lake dissenting.
BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

BRAD JOHNSON, Chairman

TRAVIS KAVILLA, Vice Chairman

KIRK BUSHMAN, Commissioner (Dissenting)

ROGER KOOPMAN, Commissioner

BOB LAKE, Commissioner (Dissenting)

ATTEST:

Sandy Scherer
Administrative Assistant

(SEAL)