Service Date: July 21, 2017

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

IN THE MATTER OF NorthWestern Energy's Application for Interim and Final Approval of Revised Tariff No. QF-1, Qualifying Facility Power Purchase	)))))	REGULATORY DIVISION DOCKET NO. D2016.5.39 ORDER NO. 7500c

FINAL ORDER

FOR NORTHWESTERN ENERGY:

John Alke, Attorney at Law, NorthWestern Energy, 208 North Montana Avenue, Suite 205, Helena, MT 59601

FOR THE INTERVENORS:

Vote Solar / Montana Environmental Information Center
Jenny Harbine and Aurora Janke, Attorneys at Law, Earth Justice, 313 East Main Street, Bozeman, MT 59703

FLS Energy / Cypress Creek Renewables
Michael J. Uda, Attorney at Law, 7 West Sixth Avenue, Power Block West, Suite 421, Helena, MT 59601

Montana Consumer Counsel
Jason T. Brown, P.O. Box 201703, Helena, MT 59620

BEFORE:

Brad Johnson, Chairman
Travis Kavulla, Vice Chairman
Roger Koopman, Commissioner
Bob Lake, Commissioner
Tony O'Donnell, Commissioner

COMMISSION STAFF:

Will Rosquist, Administrator, Regulatory Division
Justin Kraske, Administrator, Legal Division
Bob Decker, Policy Bureau Chief
Mike Dalton, Rate Analyst
Neil Templeton, Rate Analyst

PROCEDURAL HISTORY

1. On May 3, 2016, NorthWestern Corporation, doing business as NorthWestern Energy ("NWE" or "NorthWestern") filed an *Application for Approval of Avoided Cost Tariff Schedule QF-1* ("Application") with the Montana Public Service Commission ("PSC" or "Commission"). The proposed avoided cost rates would apply to Qualifying Facilities ("QF") with a nameplate capacity of three megawatts or less. Standard rates for purchases from QFs are based on NorthWestern's avoided costs, which are reviewed by the Commission, made available to the public, and applicable to all contracts with qualifying facilities which do not choose to negotiate a different rate. Mont. Admin. R. 38.5.1901(2)(j) (2016). In its Application, NorthWestern proposes to decrease the standard rates. NorthWestern requests that the Commission approve NorthWestern's new QF-1 tariff on both an interim and final basis.

2. On May 13, 2016, the Commission issued a *Notice of Application and Intervention Deadline* setting June 10, 2016, as the deadline for intervention. On May 17, 2016, NorthWestern filed a *Motion for Emergency Suspension of the QF-1 Tariff for New Solar Qualifying Facilities with Nameplate Capacities Greater than 100 kW* as well as the supporting affidavit of John B. Bushnell. On May 24, 2016, the Commission issued a *Notice of Emergency Motion and Opportunity to Comment and Request Hearing* ("Notice"). The Notice requested comments from interested persons and advised that "[u]pon its own motion or upon request by an interested party, the PSC may hold a hearing on June 9, 2016 at 2:00 p.m. at the PSC's business offices." The Commission issued a *Notice of Staff Action Setting Hearing* which confirmed that a hearing would be held on the previously scheduled day and time. On June 6, 2016, the Commission received written comments on NorthWestern's Motion from the Montana Consumer Counsel ("MCC"), FLS Energy ("FLS"), Vote Solar and Montana Environmental Information Center ("VS-MEIC"), Cypress Creek Renewables ("CCR"), and Pacific Northwest Solar ("PNWS"). On June 8, 2016, the Commission received written comments from the Montana Department of Environmental Quality. On June 9, 2016, the Commission held a hearing involving NorthWestern's motion. NorthWestern had several witnesses in attendance who testified in support of the motion.

3. On June 16, 2016, the Commission voted to grant NorthWestern's motion and suspend its obligation under QF-1 tariff option 1(a) standard rates for solar projects greater than 100 kW pending issuance of a final order. The Commission issued a *Notice of Commission*

Action on June 17, 2016. The *Notice of Commission Action* stated that NorthWestern is explicitly authorized, following issuance of this notice, to execute contracts with solar QFs greater than 100 kW, but no larger than 3 MW, at the standard tariff rate, if prior to the date of this notice, the QF had submitted a signed power purchase agreement and executed an interconnection agreement. The suspension will automatically expire on the service date of the issuance of the Commission's final order in this docket. The Commission stated that it would subsequently issue on order on the suspension which would further explain its decision.

4. On June 17, 2016, the Commission issued a *Notice of Staff Action Granting Intervention* to New Colony Wind, LLC, VS-MEIC, FLS, CCR, and the MCC. On June 27, 2016, via a *Notice of Staff Action*, the Commission clarified that requests for reconsideration should be held until after issuance of the order on the suspension motion.

5. On July 1, 2016, FLS filed an application seeking rehearing on NorthWestern's *Motion for Emergency Suspension*. On July 7, 2016, the Commission held a work session to discuss and act on FLS-CCR's request for rehearing pursuant to Mont. Admin. R. 38.2.4805. FLS-CCR's request for rehearing was denied. The Commission found that there were no material changes of fact or of law that have occurred since the conclusion of the hearing that would necessitate rehearing. The Commission further found that the public interest does not require the reopening of the proceeding. The Commission reiterated that parties may seek reconsideration subsequent to the issuance of a final order addressing NorthWestern's *Motion for Emergency Suspension*. The Commission made it clear that it is concerned by the allegations of FLS-CCR, specifically, that FLS-CCR had requested interconnection agreements from NorthWestern, and that NorthWestern did not meet its legal obligation to provide interconnection agreements in a timely fashion. The Commission made it clear that it intends to further investigate these allegations in the course of this docket.

6. On July 25, 2016, the Commission issued Order No. 7500 on NorthWestern Energy's Motion for Emergency Suspension of Tariff Schedule QF-1.

7. On August 4, 2016, VS-MEIC filed a *Motion for Reconsideration* of Order No. 7500. FLS-CCR also filed a *Motion for Reconsideration* on August 8, 2016. On August 25, 2016, the Commission issued a *Notice of Staff Action* denying both *Motions for Reconsideration* by operation of law.

8. On August 22, 2016, PNWS filed a *Request for Late Intervention*. The

Commission found good cause existed for PNWS to intervene and granted it intervention.

9. On September 2, 2016, the Commission issued Procedural Order No. 7500a establishing deadlines for discovery, intervenor testimony, identification of additional issues, and rebuttal testimony. Procedural Order No. 7500a established October 26, 2016, as the deadline for the Commission to identify additional issues. The Commission identified two additional issues, maximum contract length and performance standards. The Commission set deadlines to receive testimony from the parties on these two additional issues.

10. On December 16, 2016, the Commission issued an Order on NorthWestern's Motion to Compel and VS-MEIC's Motion to Strike. The Commission granted in part and denied in part NorthWestern’s Motion to Compel. The Commission ordered VS-MEIC to file a privilege log representing its privileged communications with FLS-CCR. VS-MEIC was also required to provide its communications with PNWS. The remainder of NorthWestern’s Motion was denied or mooted by VS-MEIC’s updated data responses to NWE-006 and NWE-007. The Commission denied VS-MEIC’s Motion to Strike NorthWestern’s Motion to Compel.

11. On December 29, 2016, a *Notice of Public Hearing* was issued. Parties filed prehearing memoranda pursuant to the requirements in the procedural order. The Commission held an evidentiary hearing on NorthWestern's application on January 18, 2017 and also accepted public comment. NorthWestern filed several post-hearing provides on February 1, 2017, as requested by the Commission during the hearing. Several of the intervenors objected to the contents of the post-hearing provides. On February 10, 2017, FLS-CCR filed a *Motion for Relief from QF-1 Suspension.* NorthWestern filed a post-hearing brief on February 17, 2017. The intervenor parties filed post-hearing response briefs on March 10, 2017. NorthWestern filed its reply brief on March 24, 2017.

12. PNWS filed a *Motion for Relief from Order No. 7500* on April 3, 2017. NorthWestern responded to both Motions for Relief from Order No. 7500.

13. The Commission held a work session on June 22, 2017 to discuss and act on NorthWestern's application. The Commission found good cause existed to extend the deadline to issue a decision by thirty days pursuant to Mont. Code. Ann. § 2-4-623. The deadline is 120 days from the time the matter is deemed submitted to the Commission. The final brief submitted by a party in this docket was received on April 13, 2017 therefore a decision is due by August 11, 2017. During the hearing on January 18, 2017, NorthWestern made a motion to move FLS-

CCR's expert witness Mr. Scott's testimony into the evidentiary record. Mr. Scott did not attend the hearing so FLS-CCR objected to the introduction of his testimony into the evidentiary record. The Commission held its decision on this motion in abeyance until the final order. The Commission voted to deny NorthWestern's motion. The Commission is frustrated that FLS-CCR's witness failed to attend the hearing. The Commission could have sanctioned FLS-CCR in some manner for failing to have all of its witnesses in attendance or having another witness sponsor that person's testimony. However, as it was unclear why the witness did not show up so the Commission will take no action here.

14. On July 7, 2017, WINData, LLC filed a late application for general intervention. The Commission acted on its request on July 20, 2017. The Commission denied WINData, LLC's motion for late intervention. WINData LLC failed to provide good cause why they should be allowed to intervene months after the hearing and expand the scope of the proceeding just two weeks prior to the issuance of the final order.

15. On July 19, 2017, NorthWestern filed a Motion for Rehearing or in the alternative a Motion for Reconsideration. The Motion for Rehearing is denied by operation of law based on the issuance of this final order.

DISCUSSION AND FINDINGS OF FACT

Avoided Energy Costs

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

17. The Commission must determine a just and reasonable rate for power purchased from QF-1 facilities based on estimated costs that NorthWestern could avoid with such purchases over the long-term. A just and reasonable rate is one that leaves customers economically indifferent to purchasing QF-1 power compared to NorthWestern’s least-cost alternative plan for purchasing energy and capacity or building new generating resources.

18. NorthWestern advocates the use of a “peaker” method to estimate avoided costs, wherein avoided capacity costs are based on the annualized cost of a utility’s least-cost capacity option and avoided energy costs are based on marginal energy costs. Ex. VS-7 (*PURPA: Making*

the Sequel Better than the Original, Edison Electric Institute, Dec. 2006.) at 10. NorthWestern estimates avoided capacity costs based on the capital and fixed operation and maintenance costs of a natural gas-fueled aeroderivative combustion turbine ("AERO") acquired in 2019. Ex. NWE-16, Reb. Test. Bushnell 17 (Dec. 12, 2016). It estimates marginal energy costs based on the results of PowerSimm modeling that estimates the impact on NorthWestern's net position of adding QF energy deliveries to the economically optimal resource portfolio ("EOP") that NorthWestern developed in its 2015 Resource Procurement Plan ("2015 Plan").[1]

19. With respect to estimating avoided energy costs, NorthWestern relies on PowerSimm modeling to quantify on an hourly basis the decreases in EOP short positions and increases in EOP long positions attributable to projected QF energy deliveries. In short positions, projected load exceeds supply from EOP resources and QF energy reduces market purchases. In short positions, NorthWestern measures its marginal energy cost as the projected Mid-Columbia ("Mid-C") wholesale electricity market price (adjusted for a market basis differential). Ex. NWE-6, Dir. Test. Hansen at 5. In long positions, energy supplied by EOP resources exceeds load and QF energy adds to surplus energy wholesale market sales. In long positions, NorthWestern measures its marginal energy cost as either the variable cost of the marginally dispatched resource or, if dispatchable resources are idle, zero. *Id.* at 6.

20. FLS-CCR contends NorthWestern's measurement of marginal energy costs violates industry best practice and subsidizes NorthWestern's shareholders and customers at the expense of QFs. According to FLS-CCR, NorthWestern's long position marginal energy cost violates economic dispatch principles by assuming, unrealistically, that plants that would be dispatched based on wholesale market prices instead will be backed down to accommodate QF energy. Ex. FLS-CCR-2, Dir. Test. Schiffman 14 (Jan. 18, 2017). FLS-CCR asserts that because NorthWestern can sell surplus energy the value of QF energy in long positions is the market price. *Id.* at 15. In addition, FLS-CCR questions the magnitude of NorthWestern's market basis differential and advocates for using the natural gas price forecast of the Northwest Power and Conservation Council ("NPCC").

21. VS-MEIC opposes the use of a peaker method to estimate avoided costs. VS-

[1] PowerSimm is a resource planning model developed by Ascend Analytics and used by NorthWestern to analyze the long-term costs and risks of alternative resource acquisition strategies for serving customer loads; *In re NorthWestern's 2015 Electricity Supply Resource Procurement Plan*, Dkt. N2015.11.91 (Mar. 31, 2016),; Ex. NWE-6, Dir. Test. Hansen 4-5 (Jan. 18, 2017).

MEIC contends that the peaker method assumes that a utility's system is in equilibrium and only a peaking resource could reduce system costs. Because NorthWestern claims its system has a capacity deficit, and because NorthWestern's 2015 Plan acquires resources other than peakers, VS-MEIC states that NorthWestern's system is not in equilibrium. Ex. VS-1, Dir. Test. Beach 18 (Jan. 18, 2017). However, if the peaker method is used, VS-MEIC states that marginal energy costs in long positions should be measured as the market price because higher-cost generation can be backed down and replaced with lower cost market power. *Id.* at 19.

22. MCC generally supports NorthWestern's peaker approach. Ex. MCC-1, Dir. Test. Stamatson 7-9 (Jan. 18, 2017). However, MCC states that marginal energy costs in long positions should be the market price when dispatchable generators are idle. *Id.* at 8.

23. Another method for estimating avoided costs is the "proxy" method. The proxy method assumes that power from QFs allows a utility to delay or displace a planned generating plant and it determines avoided costs based on the projected capacity and energy costs of the planned plant. Ex. VS-7 (*PURPA …)* at 9. The Commission applied a proxy method using a combined cycle natural gas plant ("CCCT") in Order 7199d to estimate avoided costs and establish NorthWestern's current standard QF rates. Order 7199d, Dkt. D2012.1.3, ¶ 18 (Nov. 20, 2012).

24. VS-MEIC provides avoided cost estimates for a 25-year period (2017-2041) based on a proxy method using NorthWestern's planned acquisition of an internal combustion natural gas engine ("ICE") unit in 2019. VS-MEIC reasons that use of this ICE unit is appropriate because it is the first new long-term resource acquired in NorthWestern's 2015 Plan. VS-MEIC applies the basic framework of the market-CCCT proxy method the Commission adopted in Order 7199d, substituting the ICE unit for the CCCT. VS-MEIC credits the proxy method with being the simplest of avoided cost methods and one that avoids the need to model long-term marginal energy costs. Ex. VS-1, Dir. Test. Beach at 11. VS-MEIC's proxy method relies on a natural gas price forecast based on two years of forward prices at the Alberta Energy Company ("AECO") trading hub as of September 1, 2016, escalated at the rate implied by EIA's *2016 Annual Energy Outlook*. *Id.* at 12. In years before the ICE comes on line, i.e., 2017 and 2018, VS-MEIC estimates avoided costs as 107% of projected annual Mid-C wholesale electricity market prices, reasoning that solar QFs deliver energy predominantly in heavy-load hours. *Id.* at 13. VS-MEIC also includes a $0.005/kWh adder in years prior to 2022 (when a CO_2

cost is assumed to occur in NorthWestern's 2015 Plan) to account for the value of market-based renewable energy credit ("REC" or "RECs").

Commission Decision

25. The Commission finds that the proxy method is reasonable and appropriate for estimating avoided costs because a primary objective in this case is to set standard tariff rates for relatively small QFs, rather than project-specific rates for large QFs. The proxy method is transparent, easy to replicate, and does not require the use of NorthWestern's proprietary computer model, PowerSimm. Accordingly, the proxy method provides a practical tool for estimating avoided costs for purposes of setting standard QF tariff rates on a periodic basis between QF-1 proceedings.

26. A disadvantage of the proxy method is that avoided cost estimates are unaffected by changes in NorthWestern's loads and resources between rate proceedings, which may result in increasingly inaccurate rates as additional QF or other generating capacity is acquired. As long as the amount of QF generating capacity acquired under standard rates between rate proceedings is relatively minor, the simplicity and transparency aspects of the proxy method outweigh its insensitivity to changes in loads and resources. The Commission finds that standard rates should be recalculated every six months between rate proceedings to reflect ongoing changes in wholesale electricity and natural gas prices. *See Infra* ¶ 39. The recalculated QF-1 tariff rates will apply prospectively to new QFs entering contracts after the effective date of the recalculated rates and will remain fixed for the QF's contract term, subject to the 5-year update described below. *Infra* ¶ 110.

27. The proxy method most recently applied by the Commission, in Order 7199d, produces avoided energy cost estimates similar to NorthWestern's PowerSimm-based peaker method. For example, a 25-year (2018-2042) levelized avoided cost estimate based on the proxy method using inputs from NorthWestern's 2015 Plan (including CO_2 costs) produces an avoided energy cost of $0.03857/kWh.[2] NorthWestern's 25-year (2018-2042) levelized PowerSimm-based avoided energy cost estimates (including CO_2 costs) range from $0.03736/kWh (for wind

[2] This estimate is derived using modified version of the spreadsheet in Ex. NWE-4, Int. Ex. JBB-1, and resource cost and market price information from NorthWestern's 2015 Plan. *See* 2015 Plan, Vol. 1, Tables 4-1 and 9-1. The method also relies on data response PSC-010, which is in the administrative record but was not introduced as evidence.

resources) to $0.03988/kWh (for solar resources). Ex. NWE-6, Dir. Test. Hansen at 4.

28. VS-MEIC's version of the proxy method in this case departs from the proxy method the Commission has used in previous dockets; VS-MEIC's version substitutes an ICE unit for the CCCT the Commission has used. The Commission finds that VS-MEIC's method inappropriately treats the ICE unit, which is identified in NorthWestern's 2015 Plan as a future acquisition to provide flexible capacity, as a baseload capacity and energy resource. VS-MEIC's method assumes the ICE unit operates at a 90% capacity factor for purposes of estimating the plant's total average unit costs, from which avoided energy costs are then derived. However, based on NorthWestern's 2015 Plan, the ICE unit would be expected to operate with an average capacity factor of about 23% over the planning period. DR VS-002, "Net Position Reports" (Jul. 9, 2016). While VS-MEIC uses the ICE unit in its proxy method because it is NorthWestern's next planned generating unit, NorthWestern's planning studies indicate that most of the time incremental energy from other sources would be available at a cost less than VS-MEIC's estimated avoided energy cost. The Commission finds that it would not be reasonable to estimate avoidable incremental energy costs for all time periods based on a resource that is projected to dispatch economically less than a quarter of the time.

29. For purposes of estimating avoided costs in this case, the Commission continues to rely on the market-CCCT proxy method applied in Order 7199d, with one change. In this case, the Commission calculates avoided energy costs separately for heavy-load and light-load hours to reflect the CCCT dispatch profile simulated in the 2015 Plan, which suggests that the CCCT operates primarily in heavy-load hours. 2015 Plan, Vol. 2, Ch. 7, "Net Position Reports." To accomplish this, the CCCT's simulated capacity factor, which averages 55% over the planning period, is used in the proxy model in place of the 90% capacity factor used in Order 7199d, and the CCCT's per-unit variable and energy-related fixed costs establish the avoided energy costs in heavy-load hours. In light-load hours, and in heavy-load hours before 2025 (when the CCCT comes on line), projected market prices establish the avoided energy costs. This adjustment increases avoided energy costs by $0.00532/kWh for solar QFs and $0.00389/kWh for wind QFs. This adjustment is appropriate, given NorthWestern's planning studies, and also reasonably accounts for solar's predominantly heavy-load hourly production profile, as observed by VS-MEIC. *See Supra* ¶ 24.

Commodity Price Forecasts

30. Market price forecasts for wholesale natural gas and electricity are model inputs that significantly impact avoided cost results from both the peaker and proxy methods. In this case, NorthWestern uses a forecast method approved by the Commission in Order 7199d. That method uses forward market prices at regional trading hubs—AECO for natural gas and Mid-C for electricity—for early years of the forecast period. In later years, when forward market transaction volumes decline (revealing lower liquidity) and indicative prices become less reliable, the early-year market price strips are projected into the future using escalation rates taken from the EIA's *Annual Energy Outlook* ("AEO").

31. NorthWestern initially used the commodity price forecasts from its 2015 Plan. Ex. NWE-6, Dir. Test. Hansen at 8. However, in rebuttal testimony, NorthWestern contends that the forecast in the 2015 Plan is stale and that more current information should be used. NorthWestern thus revised its initial avoided cost estimates to reflect commodity price forecasts based on forward market prices as of November 17, 2016. NorthWestern uses forward market prices through December 2019 and applies escalation rates from EIA's 2016 AEO thereafter. Ex. NWE-17, Reb. Test. Hansen at 9.

32. NorthWestern's projected natural gas prices reflect costs to transport gas from AECO to Montana over TransCanada and NorthWestern pipelines. *Id.* at 10. In addition, its projected electricity prices reflect a basis adjustment that accounts for observed differences between market prices at Mid-C and transactions prices, for both purchases and sales, in Montana. Purchases made in Montana from an in-state generator allow the selling party to avoid the transmission charges and line losses that would be incurred to ship power to Mid-C, whereas a sale at Mid-C nets the selling party the Mid-C price minus transmission costs and line losses. The transmission charges are based on the transmission tariffs of NorthWestern and the Bonneville Power Administration (BPA). NorthWestern discounts modeled Mid-C purchase prices by 30% of transmission costs and line losses, and discounts modeled sales prices by 45% of same. DR PSC-024. Because the cost of transmission tariffs and line losses is about $0.01/kWh, this results in a purchase price discount of about $0.003/kWh,and a sales adjustment of about $0.0045/kWh. *Id.*

33. MCC does not advocate for a specific vintage of commodity prices or a specific forecasting methodology. However, it observes that it would be preferable to update avoided cost

rates at least once every three years. Ex. MCC-2, Add. Iss. Test. Stamatson at 5.

34. VS-MEIC proposes commodity price forecasts using a methodology similar to NorthWestern's. VS-MEIC relies on two years of forward market prices as of September 1, 2016, and applies escalation rates based on EIA's 2016 AEO thereafter. Ex. VS-1, Dir. Test. Beach at 12. VS-MEIC adjusts AECO natural gas prices to reflect the cost of transportation to power plants on NorthWestern's system. *Ibid*. VS-MEIC adjusts Mid-C electricity market prices upward by 7% with the assertion that solar production avoids market purchases primarily during heavy-load hours. Ex. VS-1, Dir. Test. Beach at 13.

35. FLS-CCR argues that NorthWestern does not provide adequate data to support its Mid-C basis adjustment. FLS-CCR contends that NorthWestern's basis adjustment is more than double the typical adjustment amount used when modeling power deliveries to and from Montana. Ex. FLS-CCR-2, Dir. Test. Schiffman at 18. According to FLS-CCR, NorthWestern's historical transactions data show that the average price discount for Montana purchases is $0.00119/kWh and the price discount for Montana sales is $0.00294/kWh. Hr'g Tr. 243:9-244:21; Ex. FLS-CCR 3 (DR FLS-CCR-016). FLS-CCR contends these discounts should be used if the Commission rejects its recommendation to use the $0.001/kWh adjustment in the QF-1 tariff, Option 2. FLS-CCR Post Hr'g Br. at 8.

36. FLS-CCR recommends that the Commission use the commodity price forecasts in the NPCC 7th Power Plan (7th Power Plan). *Id.* It contends that the forecasts in the 7th Power Plan are fundamentals-based, objective, transparent, and preferable to the forecasts developed by NorthWestern. Ex. FLS-CCR-2, Dir. Test. Schiffman at 19.

<u>Commission Decision</u>

37. The Commission retains the market price forecasting approach approved in Order 7199d. Consistent with NorthWestern's 2015 Plan, market prices will be forecast using four years of forward natural gas and electricity price information. NorthWestern 2015 Plan, Vol. 1 at 4-1, 4-3. At the end of the forward market price period, NorthWestern will apply annual escalation rates derived from EIA's most recent AEO reference case forecast of natural gas prices at the Henry Hub.

38. The Commission agrees that market price expectations can be volatile between QF-1 rate proceedings, and that avoided cost rates that reflect outdated market price expectations

can convey improper price signals. Ex. NWE-4, Dir. Test. Bushnell at 7-8. To mitigate this concern while still providing QFs with fixed rates based on forecast avoided costs, the Commission requires NorthWestern to update the tariff rates twice a year to reflect current commodity price expectations.

39. NorthWestern will update QF-1 tariff rates in early August and early February of each year until the Commission has issued a final order in NorthWestern's next QF-1 rate proceeding. NorthWestern's updates will reflect a 15-day average of forward prices beginning July 1 and January 1, and will reflect escalation rates taken from the most recent EIA AEO. The use of a 15-day average of forward price information should mitigate concerns regarding strategic selection of a forward price strip and the potential for an anomalous market price to unduly influence the update. NorthWestern's compliance filing following this final order will follow this approach, and subsequent updates will be filed no later than 20 days after July 15 and January 15, respectively, of every year. NorthWestern's compliance filing and subsequent updates will include supporting work papers in electronic format. The Commission will treat the subsequent updates as compliance filings, and staff is authorized to process the tariff adjustments.

40. The Commission declines to use FLS-CCR's proposed NPCC commodity price forecast from the 7th Power Plan and selects the method adopted in prior QF dockets, finding that forward prices reasonably reflect near-term market fundamentals and that AEO escalation rates represent a valid analysis of long-term market fundamentals. Order 7436d, Dkt. D2015.8.64, ¶ 29-32; Ex. FLS-CCR-2, Dir. Test. Schiffman at 18. It is also unclear from the record whether the NPCC updates its forecast frequently enough to accommodate the six-month update schedule adopted by the Commission in this case.

41. The Commission declines to adopt VS-MEIC's proposed $0.005/kWh REC value adder in years prior to 2022. VS-MEIC provides little evidence based on today's market that supports that REC value, and NorthWestern indicates in rebuttal that it obtained a broker quote from December 5, 2016, which produced a bid/ask value for RECs in 2016-2017 of $0.00033-0.00038/kWh. Ex. NWE-17, Reb. Test. Hansen at 5. The Commission recognizes an established opportunity for negotiated transfer of RECs from a QF to NorthWestern, but the standard contract will neither require transfer of RECs nor specify compensation.

42. The Commission agrees with FLS-CCR that the historical data on NorthWestern's

Montana purchases and sales provide a reasonable indicator of the actual Montana/Mid-C basis differential. In a previous decision regarding the estimation of participation in NorthWestern's demand-side management activities, the Commission preferred an empirically derived estimate of the relative magnitudes of free-ridership and spillover to a purely theoretical derivation. Docket D2012.5.49, Order 7219h, ¶¶ 47-59 (October 28, 2013). The Commission will follow this precedent in this case, and prefers estimates of discounts to market sales and purchases that are reasonably derived from NorthWestern's records to estimates of discounts that are not supported by empirical evidence of market transactions. NorthWestern will apply a basis adjustment of $0.00162/kWh to forecasted Mid-C market prices, to reflect a volume-weighted average of the record data. DR FLS-CCR-016.

Avoided Capacity Costs

43. NorthWestern proposes to use an exceedance method to measure the capacity contribution of QF resources, which measures the capacity contribution of a QF based on the production level that is exceeded 85% of the time during the highest 10% of NorthWestern's peak-load hours ("85/10 exceedance method"). Ex. NWE-4, Dir. Test. Bushnell at 10-11. This method requires the compilation, on an annual basis, of the highest 10% of NorthWestern's peak-load hours (07:00-22:00 daily in the months of January, February, July, August, and December), together with the QF's generation during those hours. Once the highest 10% of peak-load hours is compiled for a year, the QF's capacity contribution equals the generation output amount exceeded in 85% of these load hours. As applied by NorthWestern, the average of the annual capacity contributions calculated over a multi-year period is used to measure a QF's capacity contribution.

44. NorthWestern proposes to make capacity payments via a "measure-and-pay" method, wherein the measured capacity contribution of a QF project would be calculated within the first 60 days following the meter read of the project's one year anniversary of operation, and the annual avoided cost capacity payment would be paid to the QF in its next billing cycle. Hr'g Tr. 69:9-11 (Jan. 18, 2017); Ex. NWE-4, Dir. Test. Bushnell at 13. In NorthWestern's proposal, a QF would choose, at the beginning of its contract, one of two options for calculating a five-year rolling average capacity contribution. *Id.* at 11-13. Under Option 1, the QF's capacity contribution would be measured using the 85/10 exceedance method for the first year of

operation, and the QF would be paid based on that one-year contribution. For contract year two, the capacity contribution would be based on the average of the first two years of capacity contributed under the 85/10 exceedance method. The pattern would continue until a five-year rolling average is achieved.

45. Under NorthWestern's Option 2, a default capacity value would be assigned to the QF until actual production data is available, after five years, to calculate an average. NorthWestern proposes default capacity values of 5% for wind, 9.6% for solar, and 36.9% for hydro. Ex. NWE-16, Rebuttal Test. Bushnell at 18.

46. NorthWestern proposes to base capacity payments to QFs on the capital and fixed operation and maintenance costs of a natural gas fueled peaker unit coming online in 2019, because it represents the lowest-cost, pure-capacity resource. Ex. NWE-16, Reb. Test. Bushnell at 16-17. NorthWestern estimates an AERO unit has a 25-year levelized capital and fixed operation and maintenance ("O&M") cost of $116.73/kW-year. Ex. NWE-16, Reb. Test. Bushnell at 17.

47. MCC supports NorthWestern's measure-and-pay proposal but prefers Option 1. MCC finds Option 2 unreasonable because the calculation includes default values that may not reflect a QF's actual contribution. Ex. MCC-1, Dir. Test. Stamatson at 9-10.

48. VS-MEIC contends that NorthWestern is both a summer and winter peaking utility and that the determination of a QF's capacity contribution should be based on a set of high-demand hours that are close to the system peak. According to VS-MEIC, those hours occur for NorthWestern in both the winter months and summer months. Ex. VS-1, Dir. Test. Beach at 24-25. VS-MEIC asserts that, in considering the top 10% of all of NorthWestern's high-load hours over the past 10 years (2006-2015), the percentage of high-load hours occurring during the summer months has increased for the past six years. *Id.* at 25. VS-MEIC asserts that NorthWestern's analysis of solar capacity contribution included information from only 2006 to 2009 and thus failed to capture the trend of more of the top 10% of high load hours occurring in the summer months in recent years. *Id.*

49. VS-MEIC recommends that the Commission retain the current method of paying solar QFs for capacity, which assigns avoided capacity costs, based on a combustion turbine, to energy deliveries during on-peak hours. This rate structure implies a capacity contribution for solar equal to 38% of nameplate, based on modeled energy production in on-peak hours for the

period 2006 through 2015. *Id.* at 25-26. VS-MEIC asserts that a 38% solar capacity contribution aligns with values assigned by neighboring utilities to solar projects, including Idaho Power (28% to 51%), PacifiCorp/East (34% to 39%), Public Service Company of Colorado (40%), and Avista (37% to 45%). *Id*. at 26. VS-MEIC notes that in California, capacity values of wind and solar are assigned using 70% exceedance over 1,825 peak hours per year, and that the Southwest Power Pool (SPP) uses a 60% exceedance approach measured over 10% of all hours rather than the top 10% of on-peak hours. *Id*. at 23-24.

50. FLS-CCR believes that NorthWestern's assignment of a 9.6% capacity contribution default value to solar projects significantly underestimates the capacity contribution of solar. Ex. FLS-CCR-2, Dir. Test. Schiffman at 19. FLS-CCR states that neighboring utilities have recently adopted much higher estimates of solar capacity, including Idaho Power (28% to 51%), PacifiCorp (34% to 39%), and Public Service Company of Colorado (40%).[3] *Id*. FLS-CCR believes that NorthWestern's 85/10 exceedance approach unfairly subsidizes NorthWestern shareholders and ratepayers at the expense of QFs. According to FLS-CCR, data responses by NorthWestern indicate Dave Gates has a lower capacity contribution value than solar resources under the 85/10 exceedance methodology. Such a finding indicates an implicit subsidy towards utility-owned resources at the expense of QFs, because NorthWestern fully recovers its fixed and capital costs for Dave Gates through rates. *Id.* at 20.

51. NorthWestern responds that it is not appropriate to compare the capacity contribution of solar projects on NorthWestern's system to those of neighboring utilities because Idaho Power and Public Service of Colorado are summer-peaking utilities, and the analyses provided for PacifiCorp/East and Avista are summer-based. NorthWestern asserts that every peak-hour load on its system above 1,200 MW occurred in winter. Ex. NWE-16, Reb. Test. Bushnell at 4-5.

52. NorthWestern also applied its 85/10 exceedance method to the period 2006-2014, obtaining a capacity contribution of solar generation of 3.4% rather than the 9.6% value for 2006-2009. *Id.* at 6-7.

53. NorthWestern opposes the proposal of VS-MEIC to retain the current QF-1 tariff's rate structure for solar facilities, asserting that it does not accurately account for the

[3] FLS-CCR does not state whether its figure for PacifiCorp reflects its Eastern Balancing Area, Western Balancing Area, or entire system.

amount of reliable solar generation NorthWestern can count on during its highest on-peak hours over the year. *Id.* at 9. NorthWestern notes that if the VS-MEIC proposal were adopted for wind projects, a wind QF would receive a capacity contribution of 43.1%.[4] *Id.* at 10.

54. NorthWestern asserts that VS-MEIC misrepresents SPP's method for calculating the capacity contribution of intermittent resources. According to NorthWestern, SPP uses an Excel workbook template known as the Net Planning Capability calculation tool, which measures a resource's capacity contribution for a multi-year study period based on production in the top 3% of load hours in the annual peak month for each year in the study period, or approximately 22 paired load and output observations per year. The tool then calculates a 60% exceedance value based on all the load and output data for the multi-year study period. NorthWestern states that application of SPP's calculation tool to 10 years (2006-2016) of solar data and load data results in a solar capacity credit of 6.1%. NorthWestern states that it does not oppose use of the SPP method to determine QF capacity contributions in this proceeding. Ex. NWE-16, Reb. Test. Bushnell, at 11-12; Hr'g Tr. at 315:15-316:1, 339:16-340:21.

55. NorthWestern asserts that contracting with solar QFs will not result in the deferral or avoidance of planned ICE units because NorthWestern is a winter-peaking utility and solar QFs do not provide significant capacity during winter peak-load hours. It further contends that solar QFs, unlike ICE units, cannot provide automatic generation control services and, therefore, it is inappropriate to base avoided capacity costs on an ICE unit, since doing so would compensate solar QFs for services they do not provide. Ex. NWE-16, Reb. Test. Bushnell at 15.

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56. The Commission finds NorthWestern's proposal to base avoided capacity costs on an AERO unit to be reasonable. This results in an avoided cost of $116.73/KW-yr for a QF capable of matching the capacity provided by an AERO unit. While an AERO unit is not included in the preferred portfolio of NorthWestern's 2015 Plan, the Commission finds that the fixed costs of an AERO unit stand as a proxy for the pure, adequacy-related capacity value of the 2015 Plan's selected ICE unit. The Commission has used similar resources as a proxy for avoided capacity costs in past proceedings. Order 7108e, Dkt. D2010.7.77 ¶¶ 66-68 (Oct. 13, 2011); Order 7199d, Dkt. D2012.1.3, ¶ 18; Order 7436d, Dkt. D2015.8.64, ¶ 56 (Sep. 13, 2016);

[4] The Commission adopted a 5% capacity contribution for wind in Order 7199d.

Order 7505b, Dkt. D2016.7.56, ¶ 86 (Dec. 22, 2016).

57. The determination of an appropriate capacity contribution to attribute to solar QFs for purposes of designing avoided cost rates is a matter of first impression. The Commission is not persuaded that NorthWestern's application of the exceedance methodology is sufficiently supported by precedent or evidence in this docket and therefore declines to adopt that method in this case. NorthWestern's justification for its 85/10 method rests on the fact that it is consistent with the utility's proposal in a 2012 QF rate proceeding. In that case, the Commission declined to adopt the method for wind resources in favor of a capacity contribution determined by the NPCC, noting that NorthWestern's exceedance method included hours with loads that were not near peak levels. Order 7199d, Dkt. D2012.1.3, ¶¶ 52-53. In this case, NorthWestern acknowledged that it had performed no research since that time on alternative values, and that it knew of no regional transmission organizations or other utilities that used a similar value. Hr'g Tr. at 70.

58. In addition, the Commission finds that NorthWestern's method, which uses an average of multiple exceedance values, each calculated for a one-year period, is inferior to the SPP method, which measures exceedance over a single multi-year set of high-load hours and corresponding resource output. Using NorthWestern's method, a year with relatively low peak loads will receive the same weight as a year with extreme peak loads in the capacity contribution calculation. However, with the SPP method, while the same relatively low peak loads in a year of the study period will be included in the calculation, exceedance is measured on the ordered observations of the full multi-year study period, which better captures a resource's contribution to serving the highest peak loads.

59. The Commission also declines to adopt the proposals of VS-MEIC and FLS-CCR, which rely on solar capacity contributions used by neighboring utilities as a proxy for solar capacity contribution on NorthWestern's system. The Commission finds those neighboring utilities' values are insufficiently supported by record evidence regarding the rationale, theory, or methodologies that underlie them. Ex. NWE-16, Reb. Test. Bushnell at 4; Ex. VS-1, Dir. Test. Beach at 9; Ex. FLS-CCR-2, Dir. Test. Schiffman at 19.

60. VS-MEIC proposes to retain the QF-1 Option 1(a) rate structure for solar facilities, which attributes to those facilities a capacity value equal to their capacity factor during on-peak hours, or 38%. Ex. VS-1, Dir. Test. Beach at 25-26. The Commission finds, however,

that the current QF-1 tariff structure was established at a time when little to no solar QF development was occurring on NorthWestern's system, and that a more precise and statistically defensible method of measuring the capacity contribution of solar resources is now needed. Similar to the onset in 2008 of significant wind generation on NorthWestern's system, the potential for significant solar QF resource acquisition warrants a serious examination of its capacity value.

61. While other parties challenged NorthWestern's selection of exceedance method parameters, i.e., an exceedance level of 85% and a highest-peak-load-hours sample of 10%, they did not oppose the exceedance method *per se*. VS-MEIC justifies its proposals by referring to an exceedance method utilized in California that calculates monthly capacity values of wind and solar using a 70% exceedance over 1,825 peak hours per year. *Id.* at 23. VS-MEIC also refers to SPP's method, averring that its application to the top 10% of NorthWestern's on-peak hours over 10 years resulted in a solar capacity value of 39%. *Id.* at 23-24.

62. The SPP exceedance method also received attention from NorthWestern, whose portfolio in South Dakota operates within SPP's footprint and includes three wind resources for which the SPP method applies. Ex. NWE-16, Reb. Test. Bushnell, at 11-12. NorthWestern offered that it would not be opposed to using the SPP capacity method in Montana. *Id.* In addition, the record includes substantial explanation and instruction for use of the SSP method. Ex. NWE-16, Reb. Test. Bushnell, Int. Ex. JBB-5 and JBB-6; DR VS-032 (*SPP Planning Criteria, Revision 1.0, Effective Jan. 1, 2016*), (Jan. 1, 2017).

63. The Commission finds that the SPP method is suitable for determining the capacity values for QF-1 solar resources, given: 1) sufficient evidentiary context for the SPP method; and 2) the deference given to the method by VS-MEIC and NorthWestern. The method involves these steps: collection of data for hourly net output (from actual production or, if historical data is not available, applicable proxy sources); selection of net output data during the top 3% of load hours for the load-serving entity for each month of each year of an evaluation period; selection of the net hourly output value that can be expected from the facility 60% of the time or greater; calculation of the annual capacity value (which is the specific measure sought for the QF-1 tariff) by selection of the peak-load month of each year, then selection and aggregation of the top 3% of load hours for each of the peak-load months in the evaluation period; sorting of the resulting total of top 3% hourly values from highest to lowest, and; determination of the

facility's net capacity value, which is the facility output that corresponds with the 60th percentile of the sorted list.

64. In its comments on NorthWestern's 2015 Plan, the Commission stated that NorthWestern should measure its capacity needs in relation to the region's or interconnection's peak demand, while accounting for import limitations. *Comments*, Dkt. N2015.11.91, ¶ 24 (Feb. 2, 2017). It follows that NorthWestern's assessment of a resource's capacity contribution should focus similarly on regional peak demand periods. A disadvantage of the SPP method (and all exceedance approaches in this case) is that the underlying load and resource output data focus on NorthWestern's peak load hours, rather than regional peak load hours. Unfortunately, regional data are not in evidence.

65. Using the 10 years of solar and load data available in this docket, NorthWestern derived a solar capacity value of 6.1%. Ex. NWE-16, Reb. Test. Bushnell at 12; Int. Ex. JBB-6.

66. VS-MEIC also applied SPP's method to calculate solar capacity value, but arrived at a value of 39%. However, that value resulted from VS-MEIC's application of a 60% exceedance to 10% of all hours, i.e., 876 hours per year. The Commission interprets SPP's method to rely upon the selection of top load hours from only the peak-load month of each year, i.e., 22 hours per year, in a multi-year measurement period and finds that VS-MEIC misinterpreted the SPP method.

67. The determination of a capacity value for renewable resources is a challenging task, as demonstrated by the number of calculation methods, together with the amount of attention given to them, in this docket. While parties raise legitimate questions about each approach, the Commission is persuaded that the SPP method should be used to establish a solar capacity value in this case, as it is based on the most appropriate statistical foundation and enjoys sufficient evidentiary support in the record. The Commission finds NorthWestern's SPP calculation of 6.1% to be a reasonable measure of capacity contribution for small solar resources in this proceeding.

68. The Commission declines to adopt NorthWestern's measure-and-pay approach because it would produce credible and significant risk of annual—and occasionally significant—variation in capacity payments, based on the prevalence of winter-peak and summer-peak years in the rolling five-year data set. A measure-and-pay system would require ongoing data-gathering and exceedance calculations which could be subject to disputes. The associated annual

data management and verification requirements would be excessive for relatively small solar facilities, i.e., those with nameplate capacity of 3MW or less.

69. Multiplying the solar capacity value rendered by the SPP method times the AERO-based unit capacity rate yields an avoided capacity cost rate of $7.12/kW-year (0.061 x $116.73/kW-year). Using a 38% on-peak capacity factor, the per unit on-peak-hours capacity rate for solar QFs is $0.00919/kWh ($7.12/kW-yr / (2038 hr/yr * 0.38)). Ex. VS-1, Dir. Test. Beach at 21. NorthWestern's current QF-1 tariff addresses two categories of resources: "Intermittent Wind QF" and "Hydroelectric and Other QF Resources." Based on production data for its small wind and hydro resources, NorthWestern proposes retaining the current 5% default capacity contribution for wind and introducing an 11.1% default capacity contribution for hydro. Ex. NWE-4, Dir. Test. Bushnell at 12.

70. Because the evidentiary record for small wind and hydro resources is wanting in this docket, the Commission retains currently adopted methodologies to determine the capacity contribution of those resource types. Though this approach will remain satisfactory in the near future, the Commission will review and, if necessary, revise the methodologies for calculating the capacity contributions of small wind and hydro resources in the next QF-1 docket. This order retains a 5% capacity contribution for wind, and does not amend the tariffed method for hydro.

Carbon Dioxide Emissions Adjustments and Environmental Attributes

71. NorthWestern proposes to offer QFs two standard rate options based on avoided cost estimates: one with a carbon dioxide emissions cost adder, and one without a carbon adder. If a QF chooses the option with a carbon adder, the QF must transfer the rights to its environmental attributes and RECs for the project to NorthWestern for the full contract period. *Id.* at 4. If the QF chooses the option without a carbon adder, the QF retains the rights to the environmental attributes, which allows it to separately contract for the transfer of those attributes to NorthWestern or other entities. *Id.* NorthWestern's proposed carbon adder, derived from its 2015 Plan, is $20.00/ton beginning in 2022, escalating at 4.15% per year thereafter. NorthWestern 2015 Plan, Vol.1 at 6-6.

72. MCC opposes a standard rate option that includes a carbon adder. Ex. MCC-1, Dir. Test. Stamatson at 10-11. MCC asserts that including uncertain future carbon costs in standard QF rates unnecessarily puts customers at risk. MCC supports tariff provisions that

require QFs to retain any environmental attributes and RECs associated with their projects. *Id.* at 12.

73. VS-MEIC advocates a with-carbon rate option that reflects the assumptions in NorthWestern's 2015 Plan. Ex. VS-1, Dir. Test. Beach at 14. However, VS-MEIC contends that RECs have a value to NorthWestern in years prior to 2022, when NorthWestern's 2015 Plan assumes a carbon cost occurs. VS-MEIC reasons that pre-2022 REC value results from a large number of states implementing more stringent renewable portfolio standard requirements and a growing demand for green power from major corporations and the U.S. military. *Id.* at 13. Therefore, in its proxy method calculation, VS-MEIC includes a REC value of $0.005/kWh beginning in 2017 and increasing at the rate of inflation until 2022. *Id.* at 14.

74. FLS-CCR does not advocate for a specific carbon adder, but supports the commodity price forecast developed by NPCC. Ex. FLSCCR-2, Dir. Test. Schiffman at 18. FLS-CCR contends that the NPCC commodity price forecast is fundamentally derived and therefore implicitly captures changing supply and demand conditions that could affect commodity prices, including environmental compliance policies. *Id.* at 19.

Commission Decision

75. The Commission will not include a carbon dioxide emissions adjustment to the avoided cost estimates used to set QF-1 standard rates. The Commission is persuaded by MCC's advocacy that including carbon costs, which are not currently priced and for which future pricing is highly uncertain, in avoided cost estimates unnecessarily puts customers at risk. Supra ¶ 72.

76. The Commission possesses the authority and technical fact finding expertise to appropriately balance the future risk of carbon costs to be borne by customers. *See* Order 7505c ¶ 41 (citing *Citizens Action Coal of Ind., v. Duke Energy Ind., Inc*., 9 N.E.3d 260, 2014 Ind. App. Unpub. LEXIS 388, *25 (Ind. Ct. App. 2014); *In re Quantification of Envtl. Costs Pursuant to Laws of Minn*. 1993, 578 N.W.2d 794, 799 (Minn. Ct. App. 1988); *Southwestern Electric Power Co. v. PUC of Tex.*, 419 S.W.3d 414, 418, 426-28 (Tex. App. 2011)). In this order, the Commission deviates from a precedent it has followed for several years with regard to the review of large QF and non-QF resource procurements by NorthWestern, including its preapproval of NorthWestern's hydroelectric acquisition in 2014. Docket D2013.12.85, Order 7323k (Sep. 25, 2014), ¶¶ 88-90. In a recent proceeding concerning a petition under Mont. Code Ann. § 69-3-

603(2)(a), the Commission made an adjustment to the carbon costs included in the avoided cost to reflect a new presidential administration and the anticipation that "federal legislation or regulation regarding carbon dioxide emission control" would be delayed. Order 7505c ¶ 40.

77. The reason for changing the Commission's practice relates to an assessment that the political forces that once indicated environmental regulatory action at the federal level was likely in the reasonably foreseeable future has diminished and, accordingly, the likelihood of carbon emissions regulation has decreased. The estimation of avoided costs necessarily entails an assessment of the probabilities, magnitudes, and associated risk of future events that may impact a utility's avoidable incremental costs of service, and the Commission exercises considerable discretion in performance of this task. In this case, the Commission's departure from prior practice regarding carbon costs represents a justifiable adjustment to a changed regulatory environment and is a reasonable recalibration of the Commission's expectations of the risk associated with unknown, and unknowable, potential regulatory actions at the federal level.

78. To ensure that the change in how carbon costs are considered in the determination of avoided cost for QF-1 resources is not discriminatory, the Commission will henceforth apply the above-described methodology for carbon costs to all future utility resource acquisitions until carbon dioxide emission regulation is either implemented or imminent.

79. A QF will retain its RECs under the tariffed rate. A QF and NorthWestern may negotiate a transfer of RECs to the utility, but the Commission reserves its right to review any proposed recovery of associated utility costs.

Interconnection Agreements

80. On June 16, 2016, the Commission suspended NorthWestern's obligation under QF-1 tariff Option 1(a) for solar projects larger than 100 kW pending a final order in this case. Notice of Comm'n Action, Dkt. D2016.5.39, at 1 (June 16, 2016). On July 1, 2016, FLS-CCR filed an application for rehearing, asserting that it would have signed interconnection agreements ("IA" or "IAs") for seven projects but for NorthWestern's failure to satisfy its obligation to timely provide executable IAs. App. For Rehearing, *Application of FLS-CCR Energy, Inc., for Rehearing on NorthWestern Energy's Motion for Suspension of the QF-1 Tariff for New Solar Qualifying Facilities with Nameplate Capacities Greater than 100 kW*, 2 (Jul. 1, 2016). It stated that on June 1 and June 8, 2016, it requested IAs for seven projects for which facilities studies

had been completed. FLS-CCR argued that NorthWestern was obligated under Section 3.5.7 of its Small Generator Interconnection Procedures (SGIP) to provide FLS-CCR with signed IAs for those projects within five business days, but failed to do so. *Id*. at 6.

81. In Order 7500 regarding QF-1 tariff Option 1(a) suspension, the Commission stated:

> "The Commission will investigate whether irregularities in NorthWestern's generator interconnection process may have unreasonably prevented QFs from achieving this [LEO] standard and may exempt additional QFs from the suspension in a future order. The Commission will also entertain, and will process separately, complaints filed by QFs regarding irregularities in NorthWestern's generator interconnection process."

Order 7500, Dkt. D2016.5.39, ¶ 47 (July 25, 2016).

82. NorthWestern contends that FERC Orders 2003 and 2006 require NorthWestern to file open access transmission tariffs with standard generator interconnection procedures and agreements for generators seeking interconnection with NorthWestern's system. Ex. NWE-7, Dir. Test. Mueller, at 4 (May 3, 2016). *Standardization of Generator Interconnection Agreements and Procedures*, 104 F.E.R.C. 61,103, Order 2003, Final Rule (Jul. 24, 2003); *Standardization of Small Generator Interconnection Agreements and Procedures,* 18 CFR Part 35, F.E.R.C. Order 2006, Final Rule, ¶ 1 (May 12, 2005). "When an electric utility is required to interconnect under section 292.303 of the Commission's regulations, that is, when it purchases the QF's total output, the state has authority over the interconnection and the allocation of interconnection costs." F.E.R.C. Order No. 2006, ¶ 516. The Commission has adopted FERC's interconnection procedures to govern the interconnections of QFs that are state-jurisdictional. Order 7108e, Dkt. D2010.7.77, ¶ 85. NorthWestern's tariff contains two provisions pertaining to the time frame for developing executable interconnection agreements. Section 3.5.7 states:

> Upon completion of the facilities study, and with the agreement of the Interconnection Customer to pay for Interconnection Facilities and Upgrades identified in the facilities study, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days.

Section 4.1 states:

> The Transmission Provider shall make reasonable efforts to meet all time frames provided in these procedures unless the Transmission Provider and the Interconnection Customer agree to a different schedule. If the Transmission Provider cannot meet a deadline provided herein, it shall notify the Interconnection Customer,

> explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

NorthWestern FERC Electric Tariff, Dkt. ER14-2469 (eff. July 22, 2014).

83. NorthWestern contends that Section 4.1 of its Standard Generator Interconnection Procedures (SGIP) allows for alternative timeframes that, with a customer's agreement, can deviate from the default time frames specified in the tariff. Hr'g Tr., at 119-120. Ms. Mueller testified that "if we are not able to meet certain timeframes in the tariff, that we will communicate with the customer what we will do and what dates we will be able to meet….A lot of times, by the time we complete the study, we've already exceeded the date the customer requested the project to be on line, a lot of the dates are very aggressive and the schedules are not even feasible, to me. So we have no choice but to work out some new dates with the customer." *Idem.* NorthWestern maintains that the interconnection customers agreed to alternative timeframes and, therefore, those agreed-upon alternative timeframes supersede the default deadlines in the tariff. DR PSC-021a-e (Sep. 9, 2016).

84. NorthWestern states that an executable interconnection agreement must specify construction timeframes feasible for both NorthWestern and the customer. The type of coordination between parties required to establish feasible construction timeframes generally precludes the provision of executable IAs within the default five-day timeframe in Section 3.5.7 of the SGIP. NorthWestern contends that a 30-day timeframe is needed to develop an executable IA following completion of the facilities study. DR PSC-022a, c-d (Sep. 9, 2016); Hr'g Tr., at 116-123. NorthWestern has not filed to change its tariff, although it has considered it and is currently working on revising the tariff. Hr'g Tr., at 123. NorthWestern also has not hired additional staff to process incoming interconnection requests. Hr'g Tr., at 385-386.

85. Order 7500 provided parties notice that the Commission would review whether NorthWestern appropriately applied its interconnection procedures. Order 7500, Dkt. D2016.5.39, ¶ 47. However, in the subsequent proceeding no party contested NorthWestern's testimony regarding its compliance with the SGIP provisions, including its use of alternative timeframes for preparation of executable IAs that deviate from the five-day default timeframe specified in the tariff. In addition, no party alleged that NorthWestern did not follow these procedures prior to the Commission's suspension of QF-1 tariff Option 1(a) rates. Hr'g Tr., at 129-135.

Commission Decision

86. The question of whether NorthWestern obtained agreements for alternative timeframes from the interconnection customers pursuant to Section 4.1 of its SGIP tariff is a question of fact that the Commission cannot definitively resolve based on the record. The voluminous email correspondence between NorthWestern and QFs contains no evidence of written agreements regarding alternate time frames. DR PSC-022b. Asked directly whether agreement of the QFs had been obtained, NorthWestern replied affirmatively, stating that it occurred verbally at face-to-face meetings. DR PSC-021b-c. During testimony at the hearing, Ms. Mueller was more tentative about whether NorthWestern had affirmatively solicited the QFs' agreement or whether NorthWestern merely informed the QFs at meetings that compliance with the default five-day tariff deadline was impossible and the QFs passively let the alternative time frames unfold. Hr'g Tr., at 119 ("we will communicate with the customer what we will do and what dates we will be able to meet"). Ultimately, NorthWestern, faced with a large number of interconnection requests, systematically could not meet the tariff's default deadline and relied on the alternative deadline process. NorthWestern did not file for a revision to the default tariff time frame, and did not hire additional personnel. Hr'g Tr., at 123-124 and 385-386.

87. However, after alleging that NorthWestern failed to satisfy its obligation to timely provide executable IAs, and after the Commission granted an opportunity to present evidence supporting their allegation, the QF intervenors ultimately did not pursue the matter further. As a result, the record consists of NorthWestern's uncontested version of events, which does not support a finding that the scope of exemptions from the Commission's suspension of the QF-1 tariff Option 1(a) rates in Order 7500 should be altered.

88. Subsequent to the Commission's issuance of Order 7500, FERC issued a declaratory order finding that a requirement for QFs to have a signed IA to create a LEO is inconsistent with PURPA and FERC's rules implementing PURPA. FERC concluded that such a requirement puts a utility in control of the formation of a LEO rather than the QF, the entity FERC stated should have that control. FERC indicated that requiring a QF to tender an executed IA is inconsistent with PURPA because it allows the utility to control or block whether and when a LEO exists – e.g. by delaying the facilities study or by delaying the tendering by the utility to the QF of an executable IA. *FLS Energy, Inc.*, 157 FERC ¶ 61,211 at P 23 (2016).

89. However, FERC has also issued Orders 2003 and 2006, which implement requirements that, according to FERC, "reduce interconnection time and costs…and help remedy undue discrimination" in the interconnection process. F.E.R.C. Order No. 2006, Dkt. RM02-12-000, ¶ 1 (May 12, 2006). FERC has touted its SGIA rules as a tool that prevents incumbents from blocking the interconnection of projects. "This Final Rule both fulfills the Commission's duty to remedy undue discrimination when covered by this rule and, when not covered by this rule, provides a model that state regulators may wish to use as a starting point for developing their own procedures and agreement." F.E.R.C. Order No. 2006, ¶ 513. The agency opined, "The very purpose of the Small Generator Final Rule is to expedite interconnections of Small Generating Facilities by removing unnecessary delays." F.E.R.C. Order No. 2006, ¶ 193. "We expect the SGIP and SGIA adopted here will resolve most disputes, minimize opportunities for undue discrimination, foster increased development of economic Small Generating Facilities, and protect system reliability." FERC Order No. 2006, ¶ 15. Subsequently, this Commission adopted the FERC model rule in its entirety, applying it to all small generators within its jurisdiction, including all of the QF projects relevant to this proceeding. Order 7108e, Dkt. D2010.7.77, ¶ 85 and F.E.R.C. Order No. 2006, ¶ 1. The Commission therefore operates under the expectation that, if followed, this tariff "fulfills" our duty relative to discrimination and that the tariff does not permit a utility to unnecessarily delay a QF's interconnection. Nevertheless, FERC contends in its declaratory order that requiring QFs to follow the very procedure intended to remedy discrimination and delay gives the utility the power to do just that. It is therefore, FERC declared, impermissible to make the consummation of an IA under those procedures a precondition of the LEO.

90. FERC's views on these interconnection matters appear self-contradicting, and the FERC declaratory order does not offer any guidance on how to reconcile them. The Commission gives deference to FERC's opinion that the SGIA tariff, so long as it is followed by the utility, effectively prevents the blocking of the interconnection process.

91. In any case, FERC's express concern was with a utility delaying the tendering of the IA, but the evidence from this contested case proceeding does not support that claim. Here, the Commission specifically investigated whether irregularities occurred in FERC-approved interconnection process that would have precluded a QF from developing a project. No evidence of irregularities emerged through the testimony of the parties in this docket. Therefore, in

addition to the existence of FERC-approved procedures designed to remedy discrimination in the generator interconnection process, the Commission's contested case process investigated whether, despite FERC's requirements, discrimination of QF generators may have occurred. The investigation found no evidence that NorthWestern failed to follow FERC's approved process. The Commission declines to find that NorthWestern violated its own transmission tariffs in tending the interconnection requests of the protesting parties. Although the evidence in this case does not show that NorthWestern unduly prevented QFs from obtaining IAs by unilaterally adopting time frames different from those in its tariff, the evidence is not sufficient to prove that NorthWestern did not. Accordingly, if another authority determines, based on other evidence, that NorthWestern did violate its tariffs with regard to the IA process for solar projects, any cost NorthWestern incurs as a result is not recoverable from customers.

92. Finally, the Commission decided in Order No. 7500, following a noticed hearing on NorthWestern's request to suspend QF-1 rates for solar facilities, to suspend for a limited time a completely optional standard rate for solar projects between 100 kW and 3 megawatts. FERC requires standard rates only for QFs up to 100 kW. The Commission by administrative rule has decided to expand standard rates to projects up to 3 megawatts, which is larger than what PURPA requires. Mont. Admin. R. 38.5.1902. The Commission is permitted by Mont. Admin R. 38.2.305 to waive any or a portion of its administrative rules for good cause. Order No. 7500 suspended standard rates for solar projects between 100 kW and 3 megawatts and therefore temporarily waived the Commission's rule for good cause requiring standard rates up to 3 megawatts until this contested case concluded to allow the Commission to reset the avoided cost rate based on the record evidence in this proceeding. In its declaratory ruling, FERC took issue only with the Commission's LEO test, but did not address the Commission temporary suspension of the standard rate for solar projects above 100 kW, as FERC does not require a standard rate for that size of projects. FERC also specifically did not address any alleged jurisdictional interconnection issues, as those issues are clearly within the Commission's jurisdiction to review, as the Commission has done here.

<u>Contract Length</u>

93. In its *Notice of Additional Issues* of October 26, 2016, the Commission requested additional testimony on the maximum available contract length in Tariff Schedule QF-1.

94. NorthWestern asserts that the 25-year maximum contract length currently offered in the QF-1 tariff imposes undue forecast risk on customers. NorthWestern states that a 10-year maximum contract term would effectively mitigate forecast risk exposure. Ex. NWE-9, Add. Iss. Test. LaFave at 3-5 (Nov. 9, 2016). NorthWestern submitted a comparison of contract lengths in other states which range from one to thirty years. Contract lengths of greater than fifteen years often do not contain fixed price rates for the duration of the contract length.

95. MCC also asserts that the 25-year maximum contract length imposes undue risk on customers. The MCC testified that it recommends a shorter contract length in order to reduce customer and QF exposure to forecast risk. Ex. MCC-2, Add. Iss. Test. Stamatson at 4 (Nov. 9, 2016). MCC advocates for a maximum length of five to seven years, with rates recalculated at least every three years. *Id.*at 3-5.

96. FLS-CCR states that the cash flow profiles associated with contracts shorter than 15-20 years would not make economic sense. Ex. FLS-CCR-1, Add. Iss. Test. McConnell at 3-4 (Nov. 9, 2016).

97. VS-MEIC asserts that renewable QF development has generally occurred only when 15-30 year contract lengths have been offered and with at least 50% of the contract price fixed. Ex. VS-3, Add. Iss. Test. Beach at 2-5 (Nov. 9, 2016); DR PSC-049b (Dec. 5, 2016). VS-MEIC asserts that long-term contracts provide customers a fixed-price hedge against volatile natural gas prices and operational risk. It supports a 20-year maximum contract length with fixed energy prices for 15 years followed by five years at market-indexed prices; it supports fixing the price for capacity for the entire length of the contract. Ex. VS-3, Add. Iss. Test. Beach at 10-15.

98. NorthWestern contends that hedging benefits are avoided costs and, therefore, they should not be included in QF rates. NorthWestern further asserts that intermittent resources do not provide hedging benefits because their energy output is uncertain. Ex. NWE-18, Reb. Test. LaFave, at 5-6 (Dec. 12, 2016).

<u>Commission Decision</u>

99. The principal objective of PURPA is to encourage the development of certain types of electric generators—small renewables and co-generation—by providing a market for the QF electric energy and capacity. Order No. 69, 45 Fed. Reg. 12214, 12221 (Feb. 25, 1980) (*see also FERC v. Mississippi*, 456 U.S. 742, 751 (1982)). By requiring public utilities to purchase

electric energy and capacity from QFs, PURPA provides for competition between traditional public utility generating facilities and QFs, which facilitates more efficient use of energy resources. *Id.* at 12222. By limiting payments to QFs to the public utility's avoided cost, PURPA provides for just and reasonable rates for a public utility's customers.

100. In its adoption of rules implementing PURPA, FERC recognizes that, like public utilities, QFs need sufficient certainty with regard to the opportunity to recover and earn a reasonable return on their investments in electric generating facilities. *Id.* at 12224. To provide for such certainty, FERC requires that QFs have the option of selling their energy and capacity to public utilities pursuant to long-term contracts at rates based on estimates of a public utility's avoided cost over the term of the contract. *Id.;* 18 C.F.R. §292.304(b)(5), (d). In *Windham Solar,* FERC stated that its LEO regulations are intended to reconcile the requirement that purchases equal avoided cost with the need for QFs to be able to enter contracts based on estimates of future avoided costs. *Windham Solar, LLC,* 157 F.E.R.C. 61,134, 61,475 (2016) FERC stated, "[g]iven this need for certainty with regard to return on investment," along with Congress's directive to "encourage" QFs, "a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors." *Id.* at 61,475–61,476. The order also noted that "our regulations, do not, however, specify a particular number of years for such legally enforceable obligations." *Id.*at 61,476, n.13 (citing 18 C.F.R. § 292.304(d)(2) (2016)). While Montana law requires the Commission to encourage long-term contracts "in order to enhance the economic feasibility of [QFs]," the law does not define "long-term." Mont. Code Ann. § 69-3-604(2).

101. The parties in the docket filed testimony discussing the various contract lengths in other states. The Idaho Public Utilities Commission ("Idaho PUC") has limited the length of certain PURPA contracts to two years. Order on Reconsideration, In the Matter of Idaho Power Company's Petition to Modify Terms and Conditions of PURPA Purchase Agreements, Case No. IPC-E-15-01, Order 33419 (Nov. 5, 2015). Prior to this decision, the Idaho PUC had set different PURPA contract terms of 35 years, 20 years, and as short as 5 years. Id. at 13 (citing Order No. 33357 at 11). Further, because the Idaho PUC "must consider contract terms in calculating avoided cost rates – especially the length of the contract" the Commission found that "setting the length of the contract is a necessary requirement that falls to the Commission." Id. at 14, 16. The Petitioners argued that FERC regulations require "long-term, fixed price contracts"

relying on FERC's Order No. 69 that states QFs have a "need for certainty with regard to return on investment in new technologies." Id. at 14 (quoting 45 Fed.Reg. at 12,224 (1980)).

102. The Idaho PUC also found that the "must purchase" provision of PURPA requires the utility to purchase QF power and "as long as PURPA remains the law, the ability for QFs to earn a return remains." *Id.* at 16. The shortening of the contract was a means to ensure avoided costs remain just and reasonable and in the public interest and serves to "maintain a more accurate reflection of the actual costs avoided by the utility over the long-term." *Id.* at 16–17. . The Idaho PUC found that the ability to ensure avoided cost rates remain accurate is best accomplished through successive contracts less than twenty years, "without the risk of violating FERC regulations or unreasonably burdening customers." *Id.* at 19. The Idaho PUC also found that it was reasonable and logical to set the length of the IRP contracts at two years to coincide with the two-year planning cycle for the IRP process. *Id.* at 8.

103. In North Carolina, the utilities had been offering long-term levelized capacity payments and energy payments for five-year, ten-year and 15-year periods as standard options to QFs contracting to sell 5 MW or less capacity. Ex. MCC-2, Add. Iss. Test. Stamatson at 8 (Nov. 9, 2016). North Carolina statute provides that the terms of any contract entered into between a utility and a new solar electric facility "…shall be of sufficient length to stimulate development of solar energy." *Id.* at 20 (citing N.C. Gen. Stat. § 62-133.8(d) (2017)). The North Carolina Utilities Commission ("NCUC") rejected utility proposals to eliminate ten and 15-year levelized rates in 2002 and 2004. *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchase from Qualifying Facilities – 2014*, Dkt. E-100, SUB 140, Order Setting Avoided Cost Input Parameters, 19 (N.C. Pub. Util. Comm'n (Dec. 31, 2014). In 2004, one utility argued that the long-term projections of costs are inherently unreliable and proposed limiting renewing projects to five-year levelized rates. *Id.*

104. The NCUC stated that "establishing avoided cost rates based upon the best information available at the time and making such rates available in long-term fixed contracts, as required by Section 210 of PURPA should leave the utilities' ratepayers financially indifferent between purchases of QF power versus the construction and rate basing of utility-built resources." *Id.* at 21. However, the NCUC recognized it must balance federal and state public policy that QFs "be encouraged against the risks and burdens that long-term contracts place on customers." *Id*. When considering whether or not to extend the maximum standard contract term

to 20 years, the NCUC found that a 20 year contract "may tilt the balance too much in the QFs' direction and increase the risks and burdens to ratepayers" and decided not to extend the maximum term length to 20 years. *Id.* The NCUC once again found no evidence to justify altering earlier decisions on term length and related provisions, holding that utilities should continue to offer long-term levelized capacity payments and energy payments for five-year, ten-year, and 15-year periods. *Id.* at 19–22. The NCUC found that five, ten, and 15 year contract lengths were consistent with PURPA while also considering ratepayer interests.

105. Montana law similarly recognizes the Commission's authority over PPAs between the utility and QFs, including the need to provide sufficient certainty with regard to the opportunity for QFs to recover investments in qualifying electric generating facilities. Mont. Code Ann. § 69-3-604 (2015). Montana law requires the Commission to encourage long-term contracts "in order to enhance the economic feasibility" of QFs and to set rates "using the avoided cost over the term of the contract." *Id.* Neither PURPA, nor FERC rules implementing PURPA, nor Montana mini-PURPA, precisely define the meaning of "long-term." Mont. Code Ann. § 69-3-604(2). However, the definition of "long-term" appears in the Commission's rules on default electric supplier procurement guidelines that provide policy guidance on long-term electricity supply resource planning and procurement. Mont. Admin. R. 38.5.8201(2) (2016). "Long-term" is defined as: a time period at least as long as a utility's electricity supply resource planning horizon. Mont. Admin. R. 38.5.8202(7) (2016).

> "'Planning horizon' means the longer of: (a) the longest remaining contract term in a utility's electricity supply resource portfolio; (b) the period of the longest lived electricity supply resource being considered for acquisition; or (c) ten years.

Id. at 38.5.8202(8). This rule suggests that "long-term" is minimally understood as ten years. FERC has not set a specific contract length requirement for QF PPAs, but does allow state commissions to consider contract length when determining avoided cost. 18 C.F.R. § 92.304(e)(2)(iii).

106. This Commission, like the Idaho PUC, has a history of authorizing QF contracts for terms as long as 20 to 35 years. Just as the Idaho PUC recognized it must consider contract terms in calculating avoided cost rates, specifically the length of the contract, this Commission finds that setting the length of the contract is a necessary requirement that falls to the Commission. The Commission recognizes that FERC regulations require "long-term, fixed price

contracts" and that QFs have a "need for certainty with regard to return on investment in new technologies." FERC reg; 45 Fed.Reg. at 12,224 (1980).

107. The low prices that appear in near-term market forecasts relative to previous forecasting suggest that the market is increasingly saturated with energy. Price escalators in outer years serve to inflate those prices, which may not occur if the current trend of oversupply continues. "The prices derived by using an escalation factor past the point where the forward strip loses liquidity merely escalate the last data point based on actual market transactions by whatever inflationary expectations are at the time of the original forecast." Ex. MCC-2, Add. Iss. Test. Stamatson at 4. "This is essentially basing a forecast on another forecast, compounding the forecast error…." *Id.* Even though the Commission affords a great deal of consideration and due process to the evaluation of the appropriate escalators, they are in the end hypothetical, and the very use of them for a multi-decadal contract shifts this forecasting risk to consumers, and not to investors in power projects. This is the same risk that the Commission identified in *Greycliff* and again grappled with in *Crazy Mountain*. Order 7436d ¶ 37 (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"); *In re Greycliff Wind Prime, LLC*, Docket D2015.8.64, Order 7436e ¶ 18 (Oct. 21, 2016) ("As with any long-term fixed-cost resource acquisition whose economic justification depends on projections of market prices, there is a risk that actual market prices will diverge from the projections, rendering the acquisition decision more or less economic in hindsight."); *In re Crazy Mountain*, Order 7505b ¶¶ 66–84 (discussing long period adjustments and market price risk from QF power); *In re Crazy Mountain*, Order 7505c ¶¶ 25–35 (discussing using the Long-1 adjustment as a proxy for market price forecast risk).

108. The Commission finds the testimony of the MCC very persuasive that extended contract lengths are excessively risky for utility ratepayers and are subject to substantial forecasting error. Ex. MCC-2, Add. Iss. Test. Stamatson at 4-5 (Nov. 9, 2016). The MCC pointed to the Idaho and North Carolina contract length policies and encouraged the Commission to consider implementing some type of reduction to protect consumers and establish more accurate avoided cost rates as those states have attempted to do. *Id at* 6-8. NorthWestern also encouraged the Commission to consider shorter contract lengths for similar reasons. Just as the Idaho PUC and the NCUC determined 20-year contracts were unreasonable and inconsistent with the public

interest, and also recognizing that neither PURPA nor its implementing regulations specify a mandatory length for PURPA contracts, this Commission also finds contract lengths of 25 years are unreasonable and inconsistent with the public interest, and subject the ratepayer to excessive risk. The Commission will depart from its recent precedent of 25 year contracts and finds that a ten-year contract for QF PPAs is just and reasonable and the ten-year length is consistent with direction from other Commission rules defining "long-term." *Supra* ¶103. This Commission finds the ability to ensure avoided cost rates remain accurate is best accomplished through successive contracts without the risk of violating FERC regulations or unreasonably burdening customers. The Commission's departure from 25 year contracts is described below.

109. The Commission finds that shortening of the contract is not intended to inhibit a QF's ability to recover its investment, but functions as a means to ensure avoided costs remain just and reasonable and in the public interest and maintains a more accurate reflection of the actual costs avoided by the utility over the long-term." Further, the "must purchase" provision of PURPA requires the utility to purchase QF power as long as PURPA remains the law and as long as QF projects continue to offer power to utilities. As long as PURPA remains the law, the utility will be required to purchase QF power after the contract is up in ten years.

110. Nothing in PURPA, FERC's rule implementing PURPA, or Montana law establish the meaning of "long-term." Based on the testimony from the MCC, NorthWestern, and other parties in this docket, the definition of long term in the Commission's rules, and the Commission's review of permissible contract lengths in other states, the Commission finds that establishing a maximum contract length of ten years provides sufficient encouragement for QF development while adequately mitigating forecast risk for customers, provided the rates in any contract exceeding five years is subject to adjustment at the conclusion of the fifth year to match the then-effective QF-1 tariffed rate.

111. The Commission's practice is to not impose conditions on QFs that do not consistently apply to other power supply resources. "The methods used to attribute value to energy and capacity that would be produced by a resource the utility plans to own must be consistent with methods used to attribute value to energy and capacity that would be produced by a QF, if avoided cost-based rates are to be nondiscriminatory." Docket D2015.8.64, Order 7436e (Nov. 4, 2016), ¶ 16.

112. The Commission has previously rejected methods of estimating avoided costs for

QFs that deviate from the methods used to evaluate other utility resource acquisitions, and has approved avoided cost methods that have been applied to evaluate non-QF resources. Docket D2015.8.64, Order 7436d ¶ 38, ¶ 41 (rejecting adjustments to forecast prices because NorthWestern did not "proposed similar adjustments in valuations of its own intermittent resources"), ¶ 35 (finding that an adjustment to the basis differential between Montana and Mid-C forward market pricing is reasonable because it has been consistently applied); Docket D2015.8.64, Order 7436e (Nov. 4, 2016), ¶¶ 15-17 (rejecting "different treatment of QFs" versus NorthWestern-owned resources and observing "NorthWestern's approach to calculating avoided costs is out of sync with its approach to evaluating alternative resources"); Docket D2016.7.56, Order 7505b (Jan. 5, 2017), ¶ 77 (accepting a novel adjustment because NorthWestern had begun to "use[d] a spreadsheet-based model to evaluate the expansion of its Ryan Dam facility which values its output in a way which is identical to one part of the adjustment that NorthWestern proposes for [a QF]"), ¶ 84 (with respect to the same adjustment, holding "in order to ensure fair evaluation of QF resources, the Commission expects that the utility will model all resources in this way"); Docket D2016.7.56, Order 7505c ((April 18, 2017)) ¶ 28 (observing a QF "notes, correctly, that it would be impermissible to rely on the Ryan Dam model if NorthWestern's own resources were not subjected to this same modeling"); and ¶ 56 (ordering "NorthWestern shall model all new electricity supply resources or additions to existing resources consistent with" the Ryan Dam methodology). The Commission rejects discriminatory treatment of QFs and requires symmetric treatment of non-QF resources with respect to measures adopted for QFs.

113. The Commission finds that a 25-year maximum contract length exposes customers to undue market forecast risk. *Supra* ¶¶ 107-109. In combination with the inaccuracy of long-term forecasts, a 25-year contract increases the possibility that customers will pay above-market prices for the output of QFs. However, as the Commission observed when it previously confronted this issue, NorthWestern's own resources are "contributing to the very risk that they purportedly seek to offset here." Docket D2016.7.56, Order 7505b (Jan. 5, 2017), ¶ 73. There is "no persuasive evidence to demonstrate that the market forecast risk of a long-term QF PPA differs significantly from the market forecast risk of a company-acquired generating resource." *Id.* at ¶ 74.

114. Accordingly, it would not be even-handed for the Commission to address this issue only with respect to QFs when the problem also occurs with non-QF resources, and often to

a greater degree. Addressing excessive forecast risk necessarily requires symmetrical treatment of QFs and non-QFs so that, in limiting contract lengths, the Commission does not engage in discriminatory rate making for QFs. *Infra* ¶ 130. Therefore, the Commission finds that, going forward, any resource the utility acquires or contracts with must be subject to the same standard.[5] Thus, if NorthWestern buys or builds a power plant or enters a contract with any power supplier for purposes of serving utility customers, it must demonstrate that the cost of the resource's energy and capacity are justified relative to a ten year projection of market prices or the cost of alternative ten year sources of energy and capacity. The Commission will not initially authorize NorthWestern rate revenue for more than ten years for such resources. Instead, at the end of the ten year period the Commission may provide for subsequent rate revenue based on a consideration of the value of the asset to customers and not necessarily based on the costs of the resource. This approach protects consumers systematically from market forecast risk and ensures non-discriminatory treatment of QFs and other potential utility resources, as required by PURPA.

<u>Performance Standards</u>

115. NorthWestern opposes the development of performance standards by the Commission, arguing that the Commission lacks authority to establish terms of a power purchase agreement (PPA) and that utilities and independent power producers have been negotiating PPAs for years and are capable of representing their respective interests. Ex. NWE-9, Add. Iss. Test. LaFave at BJL-7.

116. MCC judges performance standards to be unnecessary, as the manner in which QFs are paid, i.e., by volumetric output, sufficiently incentivizes QFs to perform. Ex. MCC-2, Add. Iss. Test. Stamatson at 9.

117. VS-MEIC states that performance standards may be appropriate, but must not unlawfully discourage energy production or constrict project financing and should accommodate natural variability, typical operating circumstances, and normal degradation of solar panels. VS-MEIC objects to the Commission authorizing performance standards, as NorthWestern has not proposed them and that entities perhaps interested in the subject but not parties to this docket had no notice that performance standards would be an issue. Ex. VS-3, Add. Iss. Test. Beach at 15-16.

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[5] This does not apply to assets already owned or under contract, whether QFs or non-QFs.

118. FLS-CCR states that performance standards must allow for short-term variation in productivity and must not negatively affect project financing. Ex. FLS-CCR-1, Add. Iss. Test. McConnell at 4.

Commission Decision

119. Because no party advocated for performance standards, the Commission declines to establish performance standards for the QF-1 tariff in this proceeding.

CONCLUSIONS OF LAW

120. The Commission is invested with the "full power of supervision, regulation, and control" of public utilities. Mont. Code Ann. § 69-3-102. NorthWestern is a public utility subject to the Commission's jurisdiction. *Id*. § 69-3-101.

121. PURPA requires electric utilities to offer to purchase electricity from QFs at rates that are "just and reasonable to the electric customers of the electric utility and in the public interest," and which do 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).

122. "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).

123. 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)).

124. "[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. Mont. Code Ann. § 69-3-603 ("The commission shall determine the rates and conditions of the contract upon petition").

125. "When an electric utility is required to interconnect under section 292.303 of the

Commission's regulations, that is, when it purchases the QF's total output, the state has authority over the interconnection and the allocation of interconnection costs." F.E.R.C. Order No. 2006, ¶ 516.

126. FERC’s declaratory order is advisory only and is non-binding unless and until it is upheld by a federal district court. The Commission may decide to re-evaluate its LEO test in a future proceeding, based on FERC's guidance. However, the decision by FERC does not undermine the use of that test in this case as a fair and reasonable basis for determining which solar QFs should be allowed to contract at the standard QF-1 rate in place at the time the Commission suspended that rate. Only the federal court system can make such a determination as to the lawfulness of the LEO standard. *See Portland General Electric Company v. FERC*, __ F.3d_ (D.C. Cir. 2017). The D.C. Circuit explained recently that “FERC could avoid a great deal of confusion and waste of judicial resources by not using words like ‘shall’ and ‘must,’ and by making clear in its orders—as opposed to later in this court—that its discussions of PURPA-related issues are advisory only.”

127. 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.”

128. 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.”

129. 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.”

130. Rates for purchases shall not discriminate against QFs. 18 C.F.R. § 292.304(a)(1)(ii). A QF may elect to be paid a rate based on forward projections at the time the QF incurs an obligation to sell its output. 18 C.F.R. § 292.304(d)(2)(ii). Such a rate for purchase is the product of a forecast for a given length of time. Imposing symmetrical treatment on utility-owned assets and other contracts for energy and capacity is therefore a necessary condition of the Commission’s decision to abbreviate the contract length available to QFs.

131. 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

132. The Commission sets the new avoided cost rates as discussed in this Order. These rates are established using the proxy method, calculating avoided energy costs separately for heavy-load and light-load hours, forecasting market prices based on four years of forward price information and annual EIA escalation rates following that four year period. No carbon dioxide emissions adjustment will be made to the avoided cost estimates. QFs will retain their RECs. NorthWestern must file compliance tariffs which implement the rate decisions in this Order by August 4, 2017.

133. The Commission denies the Motions for Relief from QF-1 Suspension of FLS/CCR and PNWS as they failed to meet the safe harbor provision established by the Commission in Order No. 7500, they failed to present evidence to the Commission of irregularities in NorthWestern's interconnection process, and the Commission suspended an optional program for standard rates in Order No. 7500.

134. The Commission sets a maximum contract length of ten years. Contracts that exceed five years are subject to adjustment at the conclusion of the fifth year to match the then-effective QF-1 tariffed rate. The adjusted rate will be the tariffed rate corresponding to a contract term equal to the initially-chosen contract term minus five years.

135. The Commission adopts symmetrical treatment to non-QF resources consistent with *Supra* ¶ 114 of this Order until otherwise ordered.

DONE AND DATED this 22nd day of June, 2017, by a vote of 5 to 0. Vice Chairman Kavulla dissenting on paragraphs 75-79 involving carbon cost and Commissioner Lake dissenting on paragraphs 114 and 135 involving symmetrical treatment.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

BRAD JOHNSON, Chairman

TRAVIS KAVULLA, Vice Chairman

ROGER KOOPMAN, Commissioner

BOB LAKE, Commissioner

TONY O'DONNELL, Commissioner

ATTEST:

Mike Maas
Administrative Assistant

(SEAL)