

November 20, 2019

STAFF MEMORANDUM

TO: The Public Service Commission

FROM: Regulatory and Legal Staff

SUBJECT: Staff Memorandum, Docket 2018.02.012—NorthWestern Energy’s
Application for Authority to Increase its Retail Electric Utility Service Rates

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I. PURPOSE

This memorandum provides a general overview of party positions, staff analysis, and staff recommendation on the remaining unresolved issues in NorthWestern Energy Co.’s (“NorthWestern”) general electric rate case in Docket 2018.02.012.

II. BACKGROUND

This is NorthWestern's first electric rate case before the Montana Public Service Commission ("Commission") as a vertically integrated utility. Prior to this Application, it had been almost ten years since NorthWestern's last electric rate case as a distribution and transmission service provider.¹ In this intervening period NorthWestern has made significant investments to expand its generation assets (Colstrip Unit 4, Dave Gates Generating Station, Spion Kop Wind Farm, PPL hydroelectric purchases, Two Dot). While NorthWestern established individual revenue requirements for most of those generation assets through Montana's pre-approval statutes, this is the first comprehensive review of NorthWestern's operations as a combined generation, transmission, and distribution electric utility.²

On September 28, 2018, NorthWestern filed with the Commission an *Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of its Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design* ("Application").

NorthWestern requested approval of an increase in annual base electric rate revenue in the amount of \$34,861,573, a return on equity ("ROE") of 10.65%, and an overall rate of return of 7.42% (except for Colstrip Unit 4 ("CU4") which has a ROE of 10.0% and an overall rate of return of 8.25%).³

The requested increase in annual revenue equates to a 6.64% increase in electric transmission, distribution, and generation revenue. For a typical residential customer using 750 kWh per month of electricity, the total bill impact would be approximately \$6.37 per month, or 7.39%.⁴ NorthWestern also requested an interim increase of \$13,846,956.⁵

The Commission subsequently granted intervention to the Montana Consumer Counsel ("MCC"), Large Customer Group ("LCG"), Federal Executive Agencies ("FEA"), Walmart, Department of Environmental Quality ("DEQ"), Human Resource Council District XI and National Resource Defense Council ("HRC/NRDC"), Montana Environmental Information Center and Sierra Club ("MEIC/SC"), Northwest Energy Coalition ("NWECC"), the Northern Cheyenne Tribe ("Northern Cheyenne"), and Vote Solar and Montana Renewable Energy Association ("VS/MREA"). It granted late intervention to Leo and Jeanne Barsanti, and Talen Montana, LLC.

¹ *In re NorthWestern's 2009 Application*, Dkt. 2009.9.129.

² See *In re Colstrip Pre-Approval*, Dkt. D2008.6.69; *In re Dave Gates Pre-Approval*, Dkt. D2008.8.95; *In re Spion Kop Pre-Approval*, Dkt. D2011.5.41; *In re Hydro Asset Pre-Approval*, Dkt D2013.12.85.

³ Letter of Transmittal, 1, (Sep. 28, 2018).

⁴ *Id.*, 4.

⁵ *Id.*

In response, MCC proposed an overall \$17.3 million revenue requirement decrease, while LCG/FEA proposed an overall \$2.9 million decrease.⁶ In rebuttal NorthWestern's proposed revenue requirement was an increase of \$30.7 million. On February 26, 2019, the Commission authorized a \$10,544,411 interim rate increase for NorthWestern's electric services.⁷

On November 16, 2018, the Commission issued Procedural Order 7604b, which established a variety of procedural and substantive requirements for this docket. The order included an extensive explanation of the Commission's statutory authority to issue data requests to the parties in this proceeding.

On November 26, 2018, NorthWestern filed a Motion for Reconsideration and Clarification of Procedural Order ("Motion"). NorthWestern disputed the statutory justifications for Commission-issued data requests provided in the procedural order. NorthWestern argued that the Commission must conduct this proceeding as a contested case proceeding under the Montana Administrative Procedures Act ("MAPA"), that the Commission's role is to evaluate the evidence, and that constitutional requirements for a fair hearing do not allow the Commission to both introduce evidence as a party and evaluate the evidence as a judge. NorthWestern proposed that the Commission strike the provisions of Order 7604b authorizing Commission-issued data requests and, instead, conduct the proceeding as an impartial adjudicator pursuant to MAPA.

In response to NorthWestern's Motion, the Commission issued an Order on Reconsideration, Order 7604g, which addressed NorthWestern's objections to Commission-issued discovery. The Commission suspended most of the procedural deadlines in Order 7604b, but retained a scheduled staff on-site audit and deadlines for intervenor data requests. The Commission resolved to refrain from issuing its own data requests pending further consideration of its legal authority. The Commission requested briefing from the parties on the scope of its authority to obtain information from regulated entities and appropriate procedures for doing so.

On December 27, 2018, following the Commission's review of parties' briefing on the scope of Commission authority, the Commission issued a Notice of Commission Action reinstating the procedural deadlines in Order 7604b and extending the deadline for discovery to NorthWestern. The Commission also adopted the use of Inquiries pursuant to Mont. Code Ann. § 69-3-106 and Notices pursuant to Mont. Code Ann. § 69-2-102 as its primary information-gathering mechanisms. Accordingly, on January 4, 2019, the

⁶ Ex. MCC-1; LCG/FEA-3.

⁷ Order 7604r

Commission issued 102 inquiries to NorthWestern on a variety of subject areas where the Commission determined record evidence was lacking.

On January 22, 2019, NorthWestern filed a Motion for Oral Argument regarding the Commission's Notice of Commission Action of December 27, 2018, which adopted the use of Inquiries and Notices as information-gathering mechanisms. NorthWestern asserted that several recent district court decisions are relevant to a consideration of the Commission's authority to issue "data requests, now called 'inquiries.'" The Commission held oral argument on February 15, 2019.

On March 1, 2019, the Commission issued a Notice of Additional Issues which stated, "The Commission did not participate in [the] discovery process, contrary to historical practice, due to NorthWestern's objections." In addition, the Commission withdrew the inquiries it had issued to NorthWestern on January 4, 2019.

In its Notice, the Commission accepted NorthWestern's "representations that this case is unique in that a significant number of intervenors—more than the typical contested case proceeding before the Commission—are present" and accordingly withdrew its 102 inquiries of NorthWestern as that investigatory role was presumed to be performed sufficiently by the parties.⁸ In doing so, the Commission noted that its decision on the issue was not precedential for future Commission proceedings.⁹

Beginning May 13, 2019, the Commission held a ten-day evidentiary hearing at its headquarters in Helena, Montana.

The Commission received three settlements on various issues from the parties. On May 10, 2019, the Commission received an initial revenue requirement settlement between NorthWestern, MCC, LCG/FEA, and an amended settlement between the same parties, in addition to Walmart, on May 13, 2019. On May 13, 2019, the Commission also received a settlement agreement between NorthWestern, DEQ, MCC, and Walmart regarding NorthWestern's E+ Green tariff. On May 20, 2019, the Commission received a settlement agreement between NorthWestern and NWEA, regarding NorthWestern's electric demand-side management ("DSM") programs.

⁸ Not. of Add'l Issues, ¶ 23.

⁹ *Id.*, ¶ 22, citing *NorthWestern Corp. v. Mont. Pub. Serv. Comm'n*, Cause No. DV16-1236, Order Affirm Mont. Pub. Serv. Comm'n Decision ** 5–6 (Mont. 13th Jud. Dist. Ct. 2018) (finding a previous non-precedential determination regarding an outage a Colstrip Unit 4 did not bind the Commission in permitting NorthWestern to recover replacement power costs when another outage occurred several years later).

During a regularly scheduled work session on October 30, 2019, the Commission approved the Revenue Requirement and E+ Green settlements, and decided a variety of procedural matters regarding administration of this docket.

III. UNRESOLVED ISSUES¹⁰

Staff recommends the Commission address the unresolved issues specifically discussed below. They include: several minor issues, net-metering, fixed cost recovery mechanism, demand side management, various Colstrip-related issues, the WAPA/FEA proposal, hazard tree removal and related issues, Two Dot acquisition, jurisdictional cost of service study and FERC transmission revenue credit mechanism, the ELDS-1 street lighting tariff, the Spion Kop annual compliance filing, the after-hours reconnection charge, and various tariff revisions.

For a high level summary, staff recommends the following:

- Various Procedural Issues. Staff recommends rates become effective March 1, 2020; waive the 20-day deemed denied reconsideration deadline in Mont. Admin. R. 38.2.4806(5)–(6); decline to address NorthWestern’s motion to strike held in abeyance by Order 7604s ¶ 21; refund rates to customers over a one-year period from the effective date of new rates.
- Net-metering. The current net metering tariff needs revision and that the establishment of a net metering rate class is generally warranted. However, because NorthWestern failed to comply with significant elements of the Commission’s Minimum Information Requirements for its net metering benefit-cost analysis and because NorthWestern’s proposed rate structure for a new class rests upon a flawed methodology, the staff recommends against adoption of NorthWestern’s proposed three-part net metering rate. Instead, the staff recommends the establishment of a net metering class that incorporates a decrease in the rate at which exported energy from future net metering customers is valued.
- Fixed Cost Recovery Mechanism (decoupling). Staff recommends the Commission approve the mechanism, with no present ROE basis point reduction, yet require NorthWestern to report to the Commission at the conclusion of the pilot, at which time the Commission will determine what basis point reduction is necessary. Staff also recommends adoption of the proposed performance metrics found in Appendix A.

¹⁰ Staff Memorandums are not submitted as evidence to the Commissioners for purposes of Mont. Code Ann. § 2-4-614. Importantly, these specific staff recommendations are not the only decision reasonably supportable by substantial record evidence under Mont. Code Ann. § 2-4-704.

- Demand-Side Management Programs. Staff recommends approving the formation of a DSM advisory stakeholder group as proposed in the partial party settlement, as well as the use of a 10% adder. Staff also recommends rejecting the rate basing of DSM programs and use of the UCT.
- Colstrip Issues. Staff recommends not opening a Colstrip investigation docket, not require community transition funds, and not require additional reporting requirements at this time.
- WAPA/FEA Proposal. Staff recommends directing the parties to negotiate a crediting mechanism to present to the Commission for approval and, if the parties cannot reach an agreement, to initiate a contested case proceeding to resolve the issue.
- Hazard Tree Removal. Staff recommends NorthWestern continue its current hazard tree removal program at current spending levels and report to the Commission as appropriate.
- Two Dot Acquisition. Staff recommends the Commission indicate that the revenue requirement stipulation reflects incorporating Two-Dot into NorthWestern's base rates.
- Jurisdictional Cost of Service Study and FERC Transmission Revenue Credit. Staff recommends the Commission not require a jurisdictional cost of service study and continue the current FERC transmission revenue crediting mechanism.
- NorthWestern's ELDS-1 Tariff. Staff recommends the Commission direct NorthWestern to file a lighting tariff that is based on the lighting class revenue requirement for base rate revenues resulting from NorthWestern's ECOS study, adjusted to reflect the Commission-approved stipulation on revenue requirement.
- Spion Kop annual compliance filing. Staff recommends ending the Spion Kop annual compliance filing.
- After-Hours Reconnection Charge. Staff recommends adopting the \$150 after-hours reconnection fee.
- Various Tariff Revisions. Staff recommends adopting NorthWestern's various additional tariff revisions.

Importantly, there could be a variety of issues which were raised by the parties in this docket, but which staff does not recommend the Commission address.

A. Procedural Issues

Resolution of outstanding procedural issues:

- Effective date of rates. Staff recommends rates become effective March 1, 2020.
- Reconsideration of the “20-day deemed denied” deadline. Staff recommends the Commission waive the 20-day deemed denied deadline for motions for reconsideration found within Mont. Admin. R. 38.2.4806(5)–(6). This will allow the Commission sufficient time to review any motions for reconsideration given the already determined briefing schedule for motions for reconsideration.
- Order 7604s ¶ 21. The Commission held in abeyance NorthWestern’s motion to strike the testimonies of MEIC/SC witnesses Schlissel and Binz regarding the determination of Colstrip expenditures and expenses. Staff recommends the Commission decline to affirmatively rule on this issue because, at least for purposes of determining revenue requirements, the issue was previously resolved by the Commission’s October 30, 2019, decision regarding the revenue requirement settlement.
- Interim Order Refund. On March 3, 2019, in *Interim Order 7604r*, the Commission authorized NorthWestern to collect on an interim basis an additional \$10,544,411 annually in electric revenue based on a ROE of 9.8 percent. The rate increase resulting from the Stipulation is \$4,044,411 less than the interim rates that took effect April 1, 2019. By February 29, 2020, NorthWestern will have collected approximately \$3.74 million of this amount since April 1, 2019. Staff recommends the Commission order NorthWestern to refund to customers the difference between the current amount collected in interim rates that have been in effect since April 1, 2019, and the final rates approved in this docket that will take effect March 1, 2020, with 9.80 percent interest. This should result in a reduction of approximately \$0.46 per month in the typical residential bill. Staff recommends this monthly credit be refunded to customers over a one-year period beginning from the effective date of rates approved by the Commission in this decision. The un-refunded balance shall continue to collect interest at 9.80 percent.

B. Net Metering

Legal Framework

In 1999, the Legislature enacted SB 409, which established a policy and requirements for net metering. Mont. Code Ann. § 69-8-601 establishes the Legislature's findings that promoting net metering is in the public interest because it encourages investment in renewable energy, stimulates economic growth, and enhances the diversification of energy resources.

Customer electricity bill savings obtained through substituting customer-generated electricity for electricity purchased from the utility enhances the economic benefits of investments in behind-the-meter distributed generation. Net metering, by design, allows a customer-generator to receive credit at the full retail rate for energy produced, but not immediately consumed (i.e., exports or flows from the customer to the utility), as well as for energy production that reduces consumption of utility-delivered energy.

In 2017, the Legislature added to and clarified the Commission's authority regarding implementation of net metering in HB 219. HB 219 added Mont. Code Ann. §§ 69-8-610 and -611, which permit the Commission to prescribe a separate service classification for customer-generators, and approve class-specific rates, based on the study of costs and benefits of customer generators and findings in a general rate case relative to: 1) the utility system benefits of the net metering resource; and 2) the cost to provide service to customer-generators. The revised statutes also permit the Commission to approve separate rates for customer-generators' production and consumption and require separate metering subject to Mont. Code Ann. § 69-3-602 if the Commission finds separate metering to be in the public interest.

Nothing in Mont. Code Ann. §§ 69-8-610 and -611 exempts the rates established for a separate customer-generator service class from the provisions of § 69-8-601.¹¹ Thus, Commission ratemaking decisions regarding net metering must continue to meaningfully encourage investment in distributed, behind-the-meter renewable resources.

¹¹ VS/MREA contends that many small businesses in Montana and their employees are supported by NEM installation work, and that NorthWestern's net metering rate proposal would eliminate most or all of a residential customer's economic incentive to invest in rooftop solar (see Dir. Test. Andrew J. Valainis at 3-4 (Feb. 13, 2019); VS/MREA Resp. Br., at 41-42 (Jul. 31, 2019). NorthWestern argues that it is not within the Commission's statutory mandate to ensure a private industry continues to thrive in Montana, but observes that the Montana Legislature is the entity that sets policy directives that may benefit certain industries (see NorthWestern Repl. Br., at 48-50 (Aug. 28, 2019).

Party Positions

NorthWestern proposes a separate rate class for residential net-metering (“NEM”) customers.¹² It also proposes a three-part rate design comprising a monthly service fee, a volumetric rate, and a monthly demand charge.¹³ The demand charge would be applied to a NEM customer’s maximum one-hour demand during each month of the year.¹⁴

NorthWestern supports its proposal for a separate NEM rate class with the following assertions:

- NEM customers are over-compensated for the credit they receive for exporting power;
- The current rate structure does not reflect costs that NEM customers impose on the system;
- The load shapes of NEM and non-NEM customers are significantly different (i.e., average annual consumption of NEM customers is 24% lower; average monthly maximum demand of NEM customers is 16% higher);
- The cross-subsidy per NEM customer may fall in the range of \$402-464/year;¹⁵
- Low-income customers are disproportionately burdened by cost-shifts from NEM;
- Rate design principles support a three-part NEM rate design;
- Three western entities have established a separate NEM rate class.¹⁶

VS/MREA opposes NorthWestern’s NEM rate proposal. It criticizes NorthWestern’s logic for a new rate class and its cost of service and NEM benefits analyses. The MCC generally supports NorthWestern’s proposal, but takes issue with a couple elements of it. The DEQ opposes NorthWestern’s proposal in its entirety.

In the sections that follow, staff has organized the numerous issues raised by parties into four categories. Within each issue category staff focuses on the issues it considers most central to a Commission decision on NorthWestern adequately supported its proposal (i.e., met its burden of proof). After describing the issues within each category, staff provides analysis and recommendations.

¹² Dir. Test. Ahmad Faruqui at 7-8 (Sep. 28, 2018).

¹³ Dir. Test. Paul M. Normand (“Accounting and Marginal Costs of Service by Class, Class Revenue Targets, Rate Design,” Management Applications Consulting, Inc.) (Sep. 28, 2018).

¹⁴ Dir. Test. Faruqui at 41.

¹⁵ *Id.* at 19.

¹⁶ Hr’g Tr., at 1293-1294 (May 20, 2019).

- ***Category 1: Compliance with the Commission's Minimum Information Requirements***

House Bill 219 amended the net metering statutes to require NorthWestern to conduct a study on the costs and benefits of NEM systems before April 1, 2018, and then to submit the study to the Commission as part of a general rate case.¹⁷ HB 219 authorized the Commission to establish minimum information requirements to be addressed in NorthWestern's study ("Minimum Information Requirements"). After soliciting stakeholder input on the parameters of a benefit-cost study, the Commission issued "Minimum Information Requirements for Categories of Benefits and Costs" on August 9, 2017.¹⁸ NorthWestern contracted Navigant Consulting, Inc. ("Navigant") to prepare a benefit-cost analysis. Navigant's report was issued March 29, 2018, and included in NorthWestern's application in September 2018.

VS/MREA contends that NorthWestern failed to comply with the Minimum Information Requirements in multiple ways, including:¹⁹

1) Avoided energy cost

VS/MREA argues that NorthWestern used PowerSimm production cost modeling to calculate avoided energy costs, not the QF-1 tariff method mandated by the Minimum Information Requirements.²⁰ NorthWestern counters that the QF-1 methodology is incompatible with the requirement that NorthWestern must study a range of NEM adoption rates, as the QF-1 methodology cannot measure system impacts of adding various amounts of NEM generators.²¹ MCC testified that NorthWestern's benefit-cost study is generally in compliance and that the difference between the MIR requirements and NorthWestern's methods is likely not significant.²² DEQ states that NorthWestern failed to comply with the Commission's Minimum Information requirements in that it disregarded the requirement to use the QF avoided energy cost methodology and instead used the proprietary PowerSimm model.²³ Because NorthWestern did not make PowerSimm licenses available to intervenors, NorthWestern's calculation of avoided cost, the largest component of the benefit-cost analysis, was done without the opportunity for public oversight. Montana DEQ argues that the divergent calculations of avoided cost by

¹⁷ HB 219, Montana Legislature, effective (May 3, 2017); Mont. Code Ann. §§ 69-8-601 *et seq* (2017).

¹⁸ Notice of Commission Action, Dkt. D2017.6.49 (Aug. 9, 2017).

¹⁹ Cross-Intervenor Test. Briana S. Kobor, at 15-16 (Apr. 8, 2019).

²⁰ Dir. Test. Corrected Kobor, at 53-57 (Mar. 4, 2019); Response Brief VS/MREA at 5-8; Post-Hearing Brief Montana Department of Environmental Quality ("DEQ") at 5-6 (Jul. 31, 2019); Hr'g Tr. at 1519-1520.

²¹ Rebut. Test. John B. Bushnell, at 13 (Apr. 5, 2019); Reply Brief NorthWestern at 30.

²² DR VS/MREA-155(a) (Apr. 1, 2019).

²³ DEQ Resp. Br., at 6.

NorthWestern and VS/MREA, respectively, highlight the problem caused by NorthWestern's failure to observe a Commission requirement.

2) Avoided capacity cost

VS/MREA states that NorthWestern used the Southwest Power Pool ("SPP") method to calculate avoided capacity costs, not an Effective Load Carrying Capability ("ELCC") or similar assessment required by the Minimum Information Requirements. VS/MREA further states that the Commission declined to adopt NorthWestern's recommendation, made in the stakeholder input phase of determining the Minimum Information Requirements, to use the QF-1 method (which uses the SPP method) for determining avoided capacity costs.²⁴ NorthWestern does not directly address VS/MREA's assertion that it did not perform an ELCC assessment or equivalent, but defends its use of the SPP method. NorthWestern also surmises that an ELCC analysis would yield a result close to the QF-1-based capacity value of 6.1%, which Navigant used in the benefit-cost study.²⁵

3) Avoided transmission and distribution costs

VS/MREA asserts that NorthWestern used neither detailed marginal cost information for transmission and distribution costs, nor the regression method developed by National Economic Research Associates ("NERA"), as the Commission required.²⁶ Additionally, NorthWestern's distribution analysis applied an arbitrary cap to solar growth, required a 10% capacity exceedance for NEM customers, and was limited to 20% of total growth-related investment.²⁷ NorthWestern states that its methodology is more accurate and rigorous than the NERA method and that it did not include avoided distribution feeder costs because NEM solar cannot meet firm capability requirements.²⁸ MCC contends that NorthWestern's avoided transmission cost calculation utilizes generic deferral value and not company-specific data, so should not be used by the Commission.²⁹

- Category 2: Parties' Calculations of Net Benefits from the NEM Resource

Table 1 lists the most significant elements of a benefit-cost analysis for NEM customers and the respective values calculated for those elements by the respective parties. The table also provides the Utility Cost Test and Ratepayer Impact Measure results in each party's analysis. The table illustrates the quantitative differences in the calculations of the respective parties. This memo will not analyze each entry in the table, but rather focus on

²⁴ Dir. Test. Corrected Kobor at 61-71; Hr'g Tr. at 1471.

²⁵ Rebut. Test. Stanton at 4-5; Rebut. Test. Bushnell at 16-17; Hr'g Tr. at 1476-1478.

²⁶ VS/MREA Resp. Br., at 11-12; Hr'g Tr. at 1486-88; see also Hr'g Tr. at 1487:20-1489:11.

²⁷ VS/MREA Resp. Br., at 12-13.

²⁸ Hr'g Tr. at 1486; *Id.* at 1504-1505.

²⁹ Dir. Test. David Dismukes at pp. 20-21 (Feb. 12, 2019).

the methodological approaches taken by the parties to calculate values for the most significant—and most contested—avoided cost categories in the proceeding.

Table 1: Comparison of Benefit-Cost Calculations

Category	NorthWestern ¹	VS/MREA ²	MCC ³
Avoided energy cost	\$0.0310	\$0.0580	\$0.0290
Avoided capacity cost	\$0.0050	\$0.0375	\$0.0050
Avoided distribution cost	\$0.0020	\$0.0367	\$0.0020
Avoided transmission cost	\$0.0010	\$0.0180	\$0.0000
Avoided system losses	\$0.0020	\$0.0106	\$0.0020
Avoided carbon cost	Included	\$0.0070	\$0.0000
Avoided environ compliance	\$0.0050	\$0.0000	\$0.0000
Other benefits	\$0.0000	\$0.0080	\$0.0000
Subtotal benefits	\$0.0460	\$0.1758	\$0.0380
Reduced revenues	(\$0.1440)	(\$0.1198)	(\$0.1440)
Admin costs	(\$0.0030)	\$0.0000	(\$0.0030)
Utility Cost Test	\$0.0460	\$0.1758	\$0.0380
Ratepayer Impact Measure	(\$0.1010)	\$0.0560	(\$0.1090)
¹ Reply Brief NorthWestern, at 28 ² Dir. Test. Kobor, at 99 (Table 6) ³ Dir. Test. Dismukes, Exh. DED-3			

- ***Category 3: NorthWestern's Embedded Cost of Service Study***

1) Use of net load data or import/export load data

NorthWestern contends that it appropriately used net load data for NEM customers in its embedded cost of service study ("ECOS") given NEM customers have only one meter and, therefore, net information is all that is available.³⁰ NorthWestern argues that because transmission and distribution costs are driven by demand, and should be allocated based on demand, it is irrelevant that net loads, instead of separate inflows and outflows of energy, are used in the ECOS study.³¹

³⁰ Hr'g Tr. at 1289.

³¹ NorthWestern Repl. Br., at 35.

VS/MREA argues that customer class definitions and rate design are related to the services provided to the customer, but that exported NEM generation is a service the customer provides, in a separate transaction, to the utility.³² Any decision to modify class definitions and/or rate designs should only occur after determining whether NEM customers impose an unreasonable cost-shift, which should be determined by calculating the NEM customers' share of costs—as well as the revenue received from NEM customers—based on the delivered load of those customers. VS/MREA argues that the question of whether the compensation that NEM customers receive for their net exports to the utility is undervalued or overvalued requires a separate analysis, because it involves a service provided to, not from, the utility.³³

2) Source of NEM customer load data

VS/MREA questions the source of the NEM customer load data used in the ECOS study, describing it as artificial and derived through a convoluted series of assumptions and adjustments, and contends that NorthWestern should have used load research sample data for NEM customers, like it does for all other residential customers in the study.³⁴ VS/MREA argues that NorthWestern's approach not only produced an incorrect load shape for NEM customers, but was unnecessary because NorthWestern had actual load data and a valid sample from NEM customers that NorthWestern's own witnesses relied on for other purposes.³⁵ NorthWestern's use of artificial load data in its ECOS study overstated the cost of service for NEM customers compared to costs based on the sample of actual loads for those customers.³⁶

NorthWestern contends that its ECOS study used the best available data source that met the needs of the analysis.³⁷ Because the ECOS study focused on class allocation, it needed more data than a sample of NEM customers could provide—the ECOS study makes calculations involving coincident and non-coincident peak ("CP" and "NCP," respectively) demand for the entire class. As such, the data from the National Renewable Energy Laboratory that was used in NorthWestern's NEM benefit-cost analysis had the appropriate load shapes for the ECOS analysis.³⁸

³² Cross-Intervenor Test. Kobor at 19.

³³ Dir. Test. Corrected Kobor at 18-19.

³⁴ VS/MREA Resp. Br., at 25.

³⁵ NorthWestern witness Faruqi used load research data from a sample of 49 NEM customers in his derivation of load shapes and development of NorthWestern's proposed three-part NEM rate; Hr'g Tr. at 1187-1188.

³⁶ VS/MREA Resp. Br., at 25-26.

³⁷ NorthWestern Repl. Br., at 36.

³⁸ *Id.*

MCC disagrees with VS/MREA's criticism of the development of NEM load data in the ECOS study, arguing that NorthWestern's analysis was not convoluted and was simply a scaling adjustment for residential load characteristics.³⁹ MCC summarizes NorthWestern's ECOS approach for NEM customers by explaining that a customer's NCP will not change due to the installation of a rooftop system, despite lowering the customer's total electrical needs; however, NEM production is assumed to have a significant effect on utility CP demand.⁴⁰

3) Peak load methodology for distribution demand costs

To address the continued dependence on the distribution system and the lowered utility revenues associated with NEM customers, NorthWestern includes as part of its proposed separate service classification a monthly distribution demand charge for future NEM customers.⁴¹ The demand charge is designed to recover an allocation of distribution demand costs to NEM customers based on their estimated NCP.

VS/MREA objects to NorthWestern's use of the NCP for the NEM customers, as opposed to the NEM customers' contribution to the NCP of the entire residential class, arguing that the NCP of NEM customers is irrelevant to distribution system cost causation. Further, NorthWestern's use of NEM demand on June 8 is inappropriate, as NEM customers' NCP did not occur on that date.⁴²

MCC disagrees with NorthWestern's allocation of all distribution plant facilities on the basis of class NCP, arguing that design motivation for distribution components depends on local diversity, which can vary between primary voltage commercial customers and secondary electric circuits. Therefore, because some facilities should be allocated with CP loads and others with NCP loads, MCC recommends a 50/50 weighting of NCP and 1 CP by class, which results in a lower demand charge for NEM customers than NorthWestern proposes.⁴³

VS/MREA disagrees with MCC's proposed weighted allocation of distribution system costs, as it relies upon an NEM NCP based on net load and uses an NCP date that does not reflect NEM cost causation.⁴⁴

4) Peak load methodology for transmission demand costs

³⁹ Cross Test. Dismukes at 54-55.

⁴⁰ *Id.*

⁴¹ *Id.* at 41.

⁴² VS/MREA Resp. Br., at 26-28; Hr'g Tr. at 1217-1225; Hr'g Tr. at 1246-1249.

⁴³ Dir. Test. Dismukes at 44-46.

⁴⁴ Cross-Intervenor Test. Kobor at 24-26.

In its cost of service study, NorthWestern utilized the “12CP” method to allocate transmission costs to the various rate classes.⁴⁵ For the NEM customer group, NorthWestern tabulated test year monthly coincident peak demand based on net load. For three months—May, July, and August—the net load-based demand figures were negative, i.e., the NEM group was exporting during the coincident peak period. Instead of using the negative net load numbers for those three months in calculating the average 12CP, NorthWestern applied the value of zero.⁴⁶

VS/MREA contends that assigning a zero value to NEM customers for three months effectively removed the exports from the study, thereby allocating costs to NEM customers based on usage, but denying any benefit to NEM customers for three months of net exports.⁴⁷ VS/MREA contends that on July 13, when NorthWestern’s transmission system was most constrained, NEM customers were net exporters and thus serving the loads of neighboring customers and lowering the amount of electricity load on NorthWestern’s constrained transmission system. VS/MREA repeats its opposition to the use of net load for cost allocation in the cost-of-service study, but argues that if that approach is used, it must be used consistently. VS/MREA concludes that NorthWestern’s method produces a 12CP allocator that is almost 20% higher than a 12CP calculation based on a consistent net load approach.

MCC states that NorthWestern’s capping three months at zero was appropriate.⁴⁸ It contends that VS/MREA’s argument ignores the fact that NEM customers still rely upon NorthWestern’s distribution and transmission system even when they operate as a net exporter, and that the utility will still incur investment costs regardless of which direction electricity flows.

- *Category 4: Additional Issues Related to NorthWestern’s Proposed NEM Class and Three-Part Rate*

NorthWestern’s positions on the preceding three issue categories feed into its proposal for a new NEM rate class and associated tariff. This category describes aspects of NorthWestern’s proposal that received substantial attention in the record and therefore warrant review by the Commission.

1) *Load shape as determinant for new NEM rate class*

NorthWestern asserts that there is empirical evidence that the load shapes of NEM customers differ significantly from that of the typical residential customer.⁴⁹ Those

⁴⁵ DR PSC-001, NWE MT Electric Allocators Rev 8-30-18.xlsx (Oct. 12, 2018)

⁴⁶ Hr’g Tr., at 1195-97.

⁴⁷ Dir. Test. Corrected Kobor at 35-37.

⁴⁸ Cross-Intervenor Test. Dismukes at 58.

⁴⁹ Dir. Test. Faruqui at 12.

differences in load shapes, combined with a mostly volumetric residential rate design, results in a significant shift in the recovery of power system infrastructure costs from NEM customers to non-NEM customers and justify the creation of an NEM customer class.

VS/MREA argues that NorthWestern's alleged differences in load shapes do not relate to cost recovery, and it is not load shape alone, but the cost-causing loads used in the cost of service study that should guide class definitions.⁵⁰ VS/MREA contends that NEM customers' loads fall within the range of variation in the residential class and that NorthWestern fails to provide any quantitative threshold at which differences in load shapes warrant separate class definition.⁵¹ NorthWestern counters that VS/MREA's analysis inappropriately compares average NEM loads with outliers in the residential class, while what is more important than the range of values in a class is the median.⁵²

VS/MREA further argues that load shape is not a basis for rate-setting provided in HB 219; rather, the Legislature mandated that separate classifications and rate treatment can be based only upon net benefits and cost of service analysis. VS/MREA asserts that HB 219 reflects the Legislature's intent that the Commission would not subject a NEM class decision to the general ratemaking standard.⁵³ NorthWestern counters that § 69-8-611 (codified from HB 219) does not specify the grounds upon which the Commission must base a new class decision and that the statute does not include the word "only" regarding the factors for a class-establishing decision.⁵⁴

MCC offers as one of its reasons for supporting a new NEM rate class the argument that NEM customers have distinct load profiles and overall usage characteristics.⁵⁵

2) *Demand charge for NEM customers*

NorthWestern argues that its proposed demand charge, intended to recoup fixed transmission and distribution costs, is consistent with established ratemaking principles; is a proven concept that has been offered to industrial and commercial customers, as well as residential customers in several states, for decades; is comprehensible to customers and may be expected to prompt customers to modify their electricity consumption patterns; and will promote the adoption of beneficial technologies like smart thermostats and batteries.⁵⁶

⁵⁰ Dir. Test. Corrected Kobor at 113-115.

⁵¹ *Id.*; VS/MREA Resp. Br., at 44-45.

⁵² NorthWestern Repl. Br., at 40.

⁵³ VS/MREA Resp. Br., at 43; HB 219 §§ 2(1), 3(1); *Id.* § 4(1), (3) [amending § 69-3-306, i.e., "Classifications of service for customer-generators must be determined in accordance with Title 69, chapter 8, part 6"].

⁵⁴ NorthWestern Repl. Br., at 39-40.

⁵⁵ Data Response VS/MREA-155(b) (Apr. 1, 2019).

⁵⁶ Dir. Test. Faruqui at 5-6.

NorthWestern's proposed demand charge of \$7.69/kW-month would amount to approximately \$45/month for the average NEM customer (while the volumetric rate for NEM customers, reflecting only supply costs and applying to both delivered and exported loads, would decrease to \$0.062807/kW).⁵⁷

As part of implementing its proposed new NEM tariff, NorthWestern states that it intends to develop both a customer education program and an internal training program.⁵⁸ The company contemplates the publication of fact sheets that address issues associated with net metering, including the demand charge.

VS/MREA argues that there is no empirical evidence that residential customers are able to respond to the type of demand charge proposed by NorthWestern; that the nature of residential customers and their loads do not allow demand charges to provide actionable price signals; and that a majority of utilities and regulatory commissions have rejected mandatory demand charges for residential customers.⁵⁹ VS/MREA contends that NorthWestern's cited research on the response of residential customers to three-part rates is dated; that the majority of three-part rates offered to residential customers are voluntary; and the few that do impose a mandatory demand charge consist primarily of rural cooperatives and municipal utilities.⁶⁰

VS/MREA further argues that there are no costs caused by an individual customer's peak use, which is what the proposed demand charge targets.⁶¹

MCC supports the proposed demand charge because, in addition to NorthWestern's analysis, other groups have found evidence that net metering leads to intra-class subsidies, and because NEM customers can be expected to have a relatively sophisticated understanding of the concept of electrical demand.⁶²

MCC finds fault, however, with NorthWestern's proposed demand charge because NorthWestern's cost recovery is based on the entire residential class, as opposed to the subgroup of existing NEM customers. In addition, NorthWestern's proposed NEM revenue requirement is \$1,690,723, yet NorthWestern's own revenue allocation and rate design

⁵⁷ This calculation is made by staff on the basis of direct NorthWestern testimony and revisions in NorthWestern's demand charge and volumetric rate proposed for NEM customers that were provided by NorthWestern in hearing and attributed to the stipulation reached on revenue requirement; see Dir. Test. Farurqui at 8; *Id.* at 63; Hr'g Tr. at 1276.

⁵⁸ Dir. Test. Bobbi L. Schroepel at 19 (Sep. 28, 2018); Rebut. Test. Schroepel at 14-15 (Apr. 5, 2019).

⁵⁹ Dir. Test. Corrected Madeline Yozwiak at 19-28 (Mar. 4, 2019); Response Brief VS/MREA at 33; Hr'g Tr. at 1927-1934; Response Brief VS/MREA at 35-37.

⁶⁰ Dir. Test. Corrected Yozwiak at 23, 28.

⁶¹ VS/MREA Resp. Br., at 38.

⁶² Dir. Test. Dismukes at 25-26 (see footnote #46, citing E3 and Edison Foundation Institute for Electric Innovation).

workpapers reflect a figure of \$1,186,271. Therefore, MCC recommends a demand charge of \$4.71/kW-mo., in contrast to NorthWestern's original proposal of \$8.64/kW-mo.⁶³

DEQ contends that the examples presented by NorthWestern of demand charges implemented by other utilities are not relevant to NorthWestern's proposal, either in terms of how the demand charges of other utilities are structured or the magnitude of demand charges assessed. DEQ further asserts that NorthWestern does not possess either the utility meter data for NEM customers or a detailed plan to provide adequate customer education to prospective NEM customers.⁶⁴

3) *Alternative rate structures*

NorthWestern describes an alternative to its proposed three-part NEM rate, a two-part rate comprising a variable energy charge of \$0.066/kW (equal to the energy charge of the three-part rate) and basic service charge of \$55.80/month. NorthWestern states that such a rate has the disadvantage of not providing customers with a price signal to manage peak demand.⁶⁵ VS/MREA counters that NorthWestern's two-part rate alternative is not designed based on established principles and describes the proposal as a foil against which the unpopular demand charge seems better.⁶⁶

VS/MREA offers that time-varying (or time-of-use, i.e., "TOU") rates can provide a useful tool to improve the link between cost causation and customer rates, while avoiding many of the issues with customer acceptability presented by residential demand charges.⁶⁷ NorthWestern contends that TOU rates have several disadvantages relative to three-part rates, arguing that a purely volumetric TOU charge would recover customer- and capacity-related costs, but reductions in load are still likely to create insufficient recovery of fixed costs.⁶⁸

VS/MREA recommends that, if the Commission decides to modify the current net metering tariffs, it should address the compensation paid for solar customers' exported electricity, a ratemaking option authorized by the Legislature in HB 219.⁶⁹ VS/MREA states that the

⁶³ Cross Test. Dismukes at 79-81. Note: The values cited here reflect calculations based on the revenue requirement as originally provided by NorthWestern. The revenue requirement has subsequently changed, resulting in amended demand charge recommendations from both MCC and NorthWestern, i.e., \$4.49/kW by MCC and \$7.69/kW by NorthWestern; see MCC Resp. Br., at 24 and NorthWestern Repl. Br., at 4-5.

⁶⁴ DEQ Resp. Br., at 7-10.

⁶⁵ Dir. Test. Faruqui at 42; *Id.* at 58 (Appendix E).

⁶⁶ Dir. Test. Corrected Kobor at 139.

⁶⁷ *Id.* at 140.

⁶⁸ Rebut. Test. Faruqui at 21.

⁶⁹ Response Brief VS/MREA at 31-32, citing HB 219 § 2(3) and Mont. Code Ann. §§ 69-8-603, 69-8-611(3).

Legislature authorized the Commission to separate inflows from outflows and set “separate rates for customer-generators production and consumption ... if it finds it is in the public interest and as part of a public utility’s general rate case” (quotation in original).

VS/MREA contends that, in hearing, NorthWestern agreed with VS/MREA that, if a rate is adopted pursuant to Mont. Code Ann. § 69-3-611(3), the exception described by statute is met and a full retail rate for net metered energy is not required. However, NorthWestern argues that no party in this case presented the option of an adjusted export rate to the Commission, and it is unclear if simply revising the production rate received by NEM customers would alleviate the cross-subsidy issue.⁷⁰

4) *Grandfathering*

NorthWestern states that the grandfather clause of HB 219 provides that a new NEM class applies to customers interconnecting on or after the date on which the Commission adopts a final order establishing the class.⁷¹ However, NorthWestern recognizes that the term “interconnecting” in the statute requires interpretation, and it therefore recommends that a NEM customer’s date of interconnection be considered as the date on which the local or municipal electric code official with jurisdiction documents approval.⁷²

Arguing that grandfathering policy should be based on dates within control of the NEM customer, not NorthWestern, VS/MREA proposes that NEM customers who submit an interconnection request within 60 days of the Commission’s rate case order should be grandfathered under the current NEM rates and structure.⁷³ Such a period would allow time for customers to be notified of policy changes and provide them with a fair opportunity to move forward with a NEM installation before the changes are implemented. VS/MREA argues that its proposed 60-day period does not conflict with HB 219, as the statute leaves discretion to the Commission to decide a specific date “on or after” a final order is issued.⁷⁴ NorthWestern counters that VS/MREA’s proposal for a 60-day interconnection request period is not allowed by HB 219.⁷⁵

⁷⁰ NorthWestern Repl. Br., at 46.

⁷¹ Rebut. Test. Joe Schwartzenberger at 12-17 (Apr. 5, 2019); Reply Brief NorthWestern at 50-52.

⁷² NorthWestern Repl. Br., at 51.

⁷³ Dir. Test. Valainis at 10-14; Dir. Test. Corrected Kobor at 143-151; HB 219, § 3(1); Hr’g Tr. at 1858-1861; Hr’g Tr. at 1899-1900.

⁷⁴ VS/MREA Resp. Br., at 46-47.

⁷⁵ NorthWestern Repl. Br., at 50-52.

*Staff Recommendation***- Compliance with Minimum Information Requirements**

Staff considered the following factors in evaluating VS/MREA's contention that NorthWestern did not comply with the Commission's Minimum Information Requirements in its cost-benefit analysis:

- The clarity of the Commission directive in the Minimum Information Requirements;
- The strength of NorthWestern's rationale for using an alternative analytical method not specified in the Minimum Information Requirements;
- Whether the Commission specifically considered in the development of the Minimum Information Requirements an alternative method subsequently used in the benefit-cost study; and
- What effort was made by NorthWestern to communicate with the Commission about using alternative study methods while the study was underway and before it was finalized.

Staff's application of these considerations to each of the contested benefit-cost categories follows:

1) *Avoided energy cost.* The Commission's directive on this topic—to use the Commission's approved method for estimating avoided energy costs in setting standard QF-1 rates—was explicit. NorthWestern contends that the QF-1 method cannot account for variations in solar adoption of NEM systems, which was also required by the Commission, and that the proxy resource used in the QF-1 approach is obsolete as a basis for calculation of NorthWestern's avoided energy cost. VS/MREA contends that NorthWestern's alternative method, i.e., one using PowerSimm modeling, is non-transparent. VS/MREA offers avoided energy cost estimates for various NEM adoption levels, but NorthWestern argues that those estimates far exceed the rates in the current QF-1 tariff.⁷⁶ There is no record of NorthWestern notifying the Commission during the benefit-cost study process about its decision to use a methodology not specified in the Minimum Information Requirements.

Staff concludes that NorthWestern did not comply with the Commission's requirement for this benefit category, nor did it provide notice to the Commission that it was adopting an alternative approach. While there is some validity to NorthWestern's rationale for not using the QF-1 avoided cost method, the method is not burdensome, and the Minimum Information Requirements represent *minimum* requirements that NorthWestern could have supplemented by providing and justifying preferred alternatives.

⁷⁶ Rebut. Test. Bushnell at 8-9.

2) *Avoided capacity cost.* The Commission's requirement states that NorthWestern "must perform an Effective Load Carrying Capability or similar assessment of the capacity contribution of solar customer-generators" and hold discussions with its electric technical advisory committee ("ETAC") regarding methodology, data needs, and other matters. NorthWestern used the QF-1 SPP method despite the Commission's decision not to adopt NorthWestern's recommendation for that approach during the development of the Minimum Information Requirements.⁷⁷ Without detailed explanation, Navigant contends that an ELCC analysis would yield a capacity value for NorthWestern closer to the 6.1% value from the QF-1 SPP calculation than the 21.5% value based on a capacity factor calculation used by VS/MREA.⁷⁸

Staff concludes that NorthWestern did not comply with the Minimum Information Requirements in estimating the avoided capacity cost benefit. Further, NorthWestern did not provide the Commission notice of its intent to deviate from the requirements and did not provide adequate evidence of the similarity of the QF-1 SPP method to an ELCC method. To the extent NorthWestern discussed deviating from the Commission's requirements with its advisory committee, NorthWestern's witnesses do not address those discussions in their testimony. Staff concludes that VS/MREA's alternative capacity value for NEM solar of 21.5% is unreliable because it is based on a method originally developed using wind resources outside NorthWestern's service area and, therefore, is not clearly similar to the ELCC analysis the Commission sought. Consequently, the Commission is left with no avoided capacity value calculation that complies with the Minimum Information Requirements or is derived from a methodology supported by substantial record evidence.

3) *Avoided Transmission and Distribution Costs.* The Commission required the use of either detailed marginal cost information or a regression method developed by National Economic Research Associates. NorthWestern contends that its methodology is more accurate than the NERA method and that it did not include avoided distribution feeder costs because NEM solar cannot meet firm capability requirements. However, it did not communicate with the Commission about how its preferred analytical method may have differed from the Minimum Information Requirements. VS/MREA finds fault with several inputs to NorthWestern's calculations, and MCC contends that NorthWestern's calculated avoided transmission cost was not based on company-specific data and should not be used by the Commission.

Overall, staff concludes that, while NorthWestern may have had valid reasons for wanting to deviate from the clearly articulated expectations in the Minimum Information Requirements, in several instances it is nonetheless noncompliant with little or

⁷⁷ *Id.* at 16-17.

⁷⁸ Rebut. Test. Stanton at 4-5.

unsatisfactory explanation. Staff finds it hard to excuse NorthWestern given the Commission's requirements establish *minimums* that NorthWestern could have supplemented in cases where it preferred alternative methods. Further, there is no record of NorthWestern having communicated with the Commission while the benefit-cost study was underway about deviations from requirements that it intended to make.

Due to NorthWestern's noncompliance with some key components of the Minimum Information Requirements, staff concludes that critical aspects of NorthWestern's benefit-cost analysis are procedurally unreliable, incomplete, and/or insufficient to demonstrate the avoided cost benefits of the NEM resource, which HB 219 requires the Commission to rely on to make fully reasoned and equitable decisions regarding service classification and rates for NEM customers. In other words, in keeping with the adjudicatory procedure the Commission applied in this case, NorthWestern failed to satisfy its burden of proof with regard to demonstrating the net benefits of the net metering resource.

- *NorthWestern's Embedded Cost of Service Study*

1) *Use of net load data or import/export data*

Staff agrees with VS/MREA that NorthWestern's use of net load data in its ECOS study and accompanying development of rates for a new NEM customer class is an inferior analytical approach because it fails to differentiate between two distinct transactions occurring between NEM customers and the utility: on one hand, NorthWestern's provision of residential electric service to a NEM customer when the customer's generator does not fulfill all load requirements (i.e., the "import" or "delivered load" transaction), and, on the other hand, the NEM customer's provision of energy to NorthWestern when the customer's generator is exceeding customer load and sending surplus generation to the grid (i.e., the "export" transaction).

NorthWestern's fusion of the two transactions through a net load approach lends itself to derivative—and ardently contested—representations of load profiles, CP demand, and NCP demand for NEM customers. Those representations, in turn, inform NorthWestern's cost of service analysis and proposed three-part rate for NEM customers, including a demand charge, which is based on the net load profile and demand calculations.

NorthWestern contends that its rate class proposal and associated rate structure addresses cost-causation issues with NEM customers in both the import and export transactions between the utility and its NEM customers. However, as a major difference between NEM and non-NEM customers is the existence of exported energy, staff finds an analysis that separately evaluates the cost of service for delivered load and the system benefits of exported load, as recommended by VS/MREA, both fairer and more informative. An analysis that appropriately delineates between distinct transactions would allow for more

targeted and refined rate design options that rest solidly on a foundation of actual data for each of the transactions.

2) Peak load methodology for distribution demand costs

To arrive at its proposed distribution demand charge, NorthWestern uses the NCP demand of NEM customers to determine their share of distribution demand-related costs. Using its net load approach, NorthWestern determined that the NEM NCP occurred on June 8.

As discussed above, staff finds NorthWestern's net load-based method analytically inferior to a method that separately analyzes cost of service for delivered load and net benefits of exported load. Because net load data, as opposed to actual delivered load data for NEM customers, underlies NorthWestern's analysis, the results are not persuasive. For example, on a delivered load basis, staff finds that the NEM NCP of 7,123 kW occurred on January 5. In contrast, on a net load basis, NorthWestern determined a NEM NCP of 6,535 kW on June 8. Such discrepancies can impact the allocation of costs of service and result in distorted rates for the various transactions.

MCC's reason for opposing NorthWestern's method of allocating distribution costs and applying a 50/50 weighting of NCP and 1 CP has some merit, but, like NorthWestern, MCC calculates the NEM NCP based on net load.

Staff agrees with VS/MREA's delivered load approach to cost of service, but is not convinced that, in VS/MREA's allocation of distribution demand-related costs to the NEM customer group, the NEM customers' contribution to the total residential class demand is the relevant NCP measure. Staff interprets HB 219 to require an evaluation of the cost of serving NEM customers as if they were a separate customer group in order to determine whether that cost of service differs enough to warrant establishing a separate rate classification. Nonetheless, VS/MREA's observation that NorthWestern uses the residential employee subgroup's contribution to the broader residential class NCP in developing the employee group cost of service is an apparent inconsistency in NorthWestern's approach.

3) Peak load methodology for transmission demand costs

In its application of the 12CP method to apportion transmission costs to NEM customers, NorthWestern adjusted the coincident peak net load for NEM customers in the three months of the year when those customers had net exports to a value of zero. While NorthWestern argues that its "collaring" of those export-producing monthly loads was justified because NEM customers are still using the grid when exporting, staff agrees with VS/MREA that adjustments to zero for exporting months represent an inconsistency in NorthWestern's use of net loads in its cost of service analysis. While true that NEM customers utilize NorthWestern's distribution system in exporting energy, those same exports would have the effect of reducing demand on NorthWestern's transmission system.

NorthWestern's approach on allocating transmission costs is flawed, and it represents another reason why cost of service for NEM customers should be performed so as to evaluate each of the two distinct energy transactions that an NEM customer has with a utility—the NEM customers purchase of energy from the utility ("import") and the NEM customer's sale of energy to the utility ("export").

For the above reasons, staff finds that no party presents a definitive case for the cost of serving NEM customers on a delivered load basis. The implication of this finding is that NorthWestern again failed to satisfy its burden of proof regarding a primary element of HB 219

- ***Additional Issues Related to NorthWestern's Proposed NEM Class and Three-Part Rate***

1) Load shape as determinant for new NEM rate class

NorthWestern shows that the load shape for a typical NEM customer differs from that of a typical non-NEM customer, but does not sufficiently demonstrate how significant that difference is and, importantly, to what degree it should influence a decision whether to require a new rate class. VS/MREA argues, with supporting data, that NEM customers' loads fall within the range of variation in the residential class. NorthWestern counters that it is inappropriate to compare typical NEM load shapes to outliers in the residential class. While NorthWestern's argument has validity, staff finds that NorthWestern has not demonstrated a strong empirical connection between a differing NEM load shape and differing cost of service, as its analysis is based on a net load approach, which, as indicated above, is flawed.

2) Demand charge for NEM customers

Based primarily on the above discussions about NorthWestern's use of net load data in its ECOS analysis and its non-compliance with the Commission's Minimum Information Requirements in deriving avoided costs, staff concludes that NorthWestern did not demonstrate the reasonableness of its proposed demand charge for NEM customers and therefore recommends against approving NorthWestern's proposal. In addition, the fact that residential customers on NorthWestern's system do not have any actual experience being billed based on their demand, coupled with evidence that NorthWestern did not present a fully-formed plan for educating potential new NEM customers regarding demand billing, raise additional concerns with NorthWestern's proposal.

3) Alternative rate structures

NorthWestern presents an alternative rate structure—a two-part rate for NEM customers, comprising a variable, supply-based energy charge and a basic service charge—that represents another way of collecting the same revenues that would be collected by a

demand charge. Because staff finds significant flaws in the methodology underlying the demand charge, a repackaged design to achieve an unchanged revenue objective is inadvisable. Further, no party testified that assessing a basic service charge of that magnitude to NEM customers would be just and reasonable and compliant with net metering law; to the contrary, both NorthWestern and VS/MREA explicitly opposed such an approach.⁷⁹

VS/MREA's reference to TOU rates as a useful tool for improving the link between cost causation and customer rates is valid, but NorthWestern's argument that a TOU rate by itself would not sufficiently address all concerns with the allocation of fixed costs is equally legitimate. In any event, the record lacks sufficient discussion of TOU rates, which, like a demand charge, would involve a substantial rate re-design, and includes no detailed or quantitative proposal of any kind on the topic, particularly as to how TOU rates would combine with other measures in a revised NEM tariff. The TOU option is therefore not available for consideration in this docket.

Given the flaws in NorthWestern's net load-based approach to evaluating cost of service for NEM customers and benefits of customer-generation, which undermine the proposal for a demand charge, VS/MREA's acknowledgment that any changes in the current NEM tariff should occur in the export transaction provides an avenue by which the Commission can equitably begin to address NEM issues in this docket. Although, as NorthWestern observes, an adjusted export rate was not presented in detailed form by any party as an option in the proceeding, staff finds that the record contains a substantial foundation of information and justification for an adjustment to the export rate.

First, however, it is important to address whether a new rate class for NEM customers should be established. Staff concludes that a new rate class for NEM customers is warranted, provided that the accompanying rates adopted for the new class are logically, reasonably, and transparently derived from record evidence. This conclusion rests predominantly on the export transaction, which is an obvious, significant, and unique characteristic of NEM customers that is not shared by other customers in the residential class.

Staff's judgment on this matter rests squarely on the testimony of multiple witnesses, particularly as that testimony is focused on defining the problem with the current NEM tariff. Below are salient examples:

- "This current rate over-compensates NEM customers for the power they sell to the grid. The over-compensation occurs because the residential rate at which NEM customers are compensated includes not only the variable costs of electricity, which

⁷⁹ Dir. Test. Kobor at 139-140.

the NEM customers are selling to NorthWestern, but also costs associated with the transmission and distribution grid, as well as generation capacity costs and fixed costs of customer service, none of which NEM customers are selling to NorthWestern.” (NorthWestern witness Faruqui.⁸⁰)

- “This situation [of cross-subsidization] exists because net metering customers use less energy and are credited at the full retail rate for excess energy generated by their systems ...” (NorthWestern Reply Brief.⁸¹)
- “Specifically, residential NEM customers are allowed to export excess electricity production to the utility and receive netting through a bill credit for released electricity, a service provision that is not granted to non-NEM residential customers.” (MCC witness Dismukes.⁸²)
- “This fact—negative load—denotes an objective difference between net metering customers and non-net metering customers.” (NorthWestern Reply Brief.⁸³)
- “A new rate schedule is typically justified when a unique and easily identified group of customers possess significantly different requirements for service from the utility. This is typically observed through cost of service analyses wherein the cost to serve a subset of customers is found to be significantly different from other members of their rate schedule.” (MCC witness Dismukes.⁸⁴)
- “If no net metering class is created, new residential NEM customers will be overcompensated because they will receive a base rate value of approximately \$0.114 per kWh for their system production (both production used to offset their internal load and excess production discharged to NorthWestern’s system), based on NorthWestern’s residential pricing proposal in this proceeding.” (NorthWestern witness Schwartzberger.⁸⁵)
- “The [NorthWestern-proposed three-part] tariff is intended to ameliorate intraclass subsidies stemming from reductions in volumetric revenues from NEM customers. The Company claims that because NEM customers are currently compensated for the energy they sell back to the grid at a rate that includes not only energy costs but

⁸⁰ Dir. Test. Faruqui at 10.

⁸¹ NorthWestern Repl. Br., at 46.

⁸² Cross Test. Dismukes at 77.

⁸³ NorthWestern Repl. Br., at 41.

⁸⁴ Cross Test. Dismukes at 75.

⁸⁵ Dir. Test. Schwartzberger at 18-19.

also transmission, distribution, generation capacity, and fixed customer service costs, they are currently being over-compensated.” (MCC witness Dismukes.⁸⁶)

In stating the problem and justifying support for a new rate class, the aforementioned witnesses focus sharply on the issue of overcompensation for exported NEM energy. While some of the above proponents for a NEM rate class also refer to cost of service issues associated with NEM customers’ delivered load, those issues, as analyzed by staff in the preceding portion of this memo, present a much greater challenge of rationalization and quantification. In this proceeding, staff concludes that NorthWestern has not met the challenge, as the record lacks substantial evidence of the costs of serving NEM customers on a delivered load basis. However, staff’s recommendation does not preclude future adjustments to rates for delivered load services if more conclusive information is presented.

While the value of exported NEM energy with regard to fixed grid costs is a matter of dispute among parties, there is no disagreement that exported NEM production represents a direct supply of energy to NorthWestern’s system and that NorthWestern’s grid is being used to accept and distribute that exported NEM energy. Even so, the respective calculated values of that supplied energy (i.e., the sum of avoided energy cost and avoided generation capacity cost) by NorthWestern and VS/MREA differ greatly (\$0.0360/kWh by NorthWestern and \$0.0955/kWh by VS/MREA). Staff finds serious flaws in each of those calculations, but concludes that a reasonable proxy value for NEM exported energy has been offered in the record: \$0.062807/kWh, the supply charge determined through NorthWestern’s ECOS analysis, included by NorthWestern in its proposed three-part NEM rate, and referenced in the revenue requirement stipulation approved by the Commission.

Staff therefore recommends this adjustment in the rate paid for exported NEM energy:⁸⁷

Table 2: Staff NEM Recommendation Compared to Current Rate

Status quo NEM export rate (current tariff)	\$0.1113/kWh
Recommended NEM export rate	\$0.06281/kWh ⁸⁸
Change in NEM export rate	-\$0.04849/kWh

⁸⁶ Dir. Test. Dismukes at 24.

⁸⁷ These rates are illustrative and are based on staff’s best estimates of the residential rates that will result from implementation of the stipulation.

⁸⁸ The precise NEM export rate will reflect the residential class production fixed cost rate plus the PCCAM rate.

(Note: The monthly customer charge and the volumetric energy rate of the NEM rate class is equal to the respective monthly customer charge and the volumetric energy rate of the residential class.)

This recommended rate, a 44% decrease in what NorthWestern would otherwise “pay” for exported NEM energy under status quo net metering, falls evenly between the avoided energy/capacity costs calculated by NorthWestern and VS/MREA. It represents the fairest method that staff can identify to address the fundamental problem associated with the current NEM rate structure while also recognizing requirements of the net metering law.

A new NEM rate class that incorporates the described adjustment in the export rate reflects regulatory gradualism, in that it makes an initial modification—one that is significant, but not shocking—in a complex tariff structure. Based on the average export level of current NorthWestern customers, the adjustment would decrease monthly credits to NEM customers by approximately \$13/month, or \$156/year.⁸⁹ Staff estimates this would increase the payback period for a NEM system from approximately 16 years to approximately 19 years.

In conjunction with this recommended adjustment in NEM export rate, staff notes that the customer charge for the NEM rate class would be equal to that of the residential class. Staff also recommends that any uncredited balance of export-generated energy that exists at the end of a new NEM customer’s designated 12-month billing period is granted to NorthWestern. This recommendation reflects the statutory requirement that applies to existing NEM customers.⁹⁰

Staff further suggests that, if the Commission creates a new rate class and adopts the proposed export adjustment, it should emphasize that the new NEM class will be treated as all other established classes in future rate cases, i.e., it will be subject to all facets of regulatory analysis, including cost of service, revenue requirement, cost allocation, and rate structure. The Commission should encourage continued and enthusiastic engagement in the review and evolution of NEM rates.

4) Grandfathering

Staff agrees with NorthWestern’s reading of HB 219, i.e., that the grandfather clause of HB 219 provides that a new NEM customer class applies to customers interconnecting on or after the date on which the Commission adopts a final order implementing the new class. Staff further agrees with NorthWestern that the term “interconnecting” in the statute requires interpretation.

⁸⁹ Monthly impact = reduction in NEM export rate (\$0.04849/kWh) x average monthly export of NEM customer (268 kWh, per Dir. Test. Faruqui at p. 17) = \$13/month (\$156/year).

⁹⁰ Mont. Code Ann. § 69-8-603(4) (2007).

NorthWestern's recommends that a NEM customer be considered interconnected on the date on which the local electric code official with jurisdiction documents approval. Staff finds that recommendation problematic, as the record does not include information about whether local code approval occurs before or after an installation physically exists. That distinction is important, because if code approval can be made only after a system physically exists, the situation may arise wherein a customer who has planned to install a new NEM system that qualifies for grandfathered status may have completed all the necessary application steps with NorthWestern and made a significant investment in a completed system, but then be considered a member of a new NEM rate class because a final order is issued before local code approval is obtained.

Although the above scenario is unlikely, as a final order will probably be adopted in early winter, when little NEM construction activity would be anticipated and NorthWestern may have relatively few NEM applicants in its pipeline. However, to avoid such a scenario, staff recommends that "interconnecting" be defined to occur on the date on which NorthWestern makes formal approval of a customer's NEM application. Defining interconnection this way allows a customer who receives NorthWestern's approval for a NEM system after the Commission's final order to avoid making a significant installation investment before learning that the NEM system will fall into the new NEM rate class.

C. Fixed Cost Recovery Mechanism (Decoupling)

HRC/NRDC introduced a Fixed Cost Recovery Mechanism ("FCRM") proposal, commonly known as decoupling, which would make NorthWestern indifferent to the volume of its energy sales by breaking the link between energy sales and fixed cost recovery.

HRC/NRDC proposes a four-year pilot that would apply to the residential and GS-1 Secondary non-demand-metered classes. The proposal does not include NorthWestern's net-metering class, if such a class is adopted.

The FCRM would cover fixed costs related to NorthWestern's transmission, distribution, and production costs. Fixed transmission and distribution costs would be set and recovered using a revenue-per-customer approach, and revenues would be adjusted between rate cases based on test-year revenue requirements and actual customer counts. Fixed production costs would be held flat between rate cases. Sales would not be weather normalized between rate cases, which HRC/NRDC proposes will reduce the risk of under-recovery due to mild weather for NorthWestern and will reduce the risk of abnormally high bills for customers due to extreme weather.

The fixed costs covered by the FCRM would be recovered through a decoupling surcharge, which would be a volumetric rate. Accruals would be trued-up annually, with a soft cap of 3% to limit customer impacts (this would limit surcharges or rebates to approximately \$2.56/month for average residential customers and \$2.00/month for average GS1-Secondary

non-demand customers). HRC/NRDC also recommends requiring a third-party audit after three years of the study period, customer service and reliability standards, and commitments from NorthWestern to present alternative rate designs such as time-of-use and inclining block rates in its next rate case filing.

At the end of the four-year pilot, NorthWestern would be required to make a filing to renew, modify, or discontinue the FCRM.

Party Positions

While several states have adopted decoupling mechanisms to promote energy efficiency measures, HRC/NRDC witness Amanda Levin points to states such as New Jersey that are adopting decoupling to support customer benefits from electrification. She states that decoupling considers both savings and increased usage per customer, and ensures that customers are not overpaying between rate cases if a utility succeeds in promoting electrification.⁹¹

Levin also states that utilities that adopt decoupling mechanisms have seen greater cost control, with lower increases in operations and maintenance expenses post-decoupling. With decoupling, utilities earn less than authorized if costs are higher than expected.⁹²

HRC/NRDC witness Thomas Power testifies that fixed-cost recovery mechanisms incentivize utilities to be more confident in investing in energy efficiency, and less resistant to small-scale solar installations. An alternative way to deal with those same issues is to allow very high fixed monthly charges, however Power states that method is fairly harsh.⁹³

MCC opposes the FCRM. However it argues that if the FCRM is adopted, NorthWestern's ROE should be reduced by 25 basis points.

MCC witness Stephen Hill states that if decoupling lowers risk for NorthWestern, then its cost of capital also lowers with decoupling.⁹⁴ Hill's testimony also discusses a 2014 Brattle Group study that looked at the cost of capital impact for a group of electric utilities that showed the ROE decreased for each of the utilities.

MCC witness David Dismukes argued that decoupling essentially reimburses a utility for revenue not collected because of a mild winter, and that it should be focused on facilitating energy efficiency rather than being a glorified weather normalization clause.⁹⁵

⁹¹ Hr'g Tr., at 2373-2374.

⁹² *Id.*, at 2380.

⁹³ *Id.*, at 2043.

⁹⁴ *Id.*, at 2266

⁹⁵ *Id.*, at 2259.

In its post-hearing brief, MCC states that decoupling violates the matching principle and abandons the use of historical test years. MCC likens decoupling to single issue ratemaking, since it adjusts certain fixed costs on an annual basis while other costs remain tied to the historical test year used in the most recent rate case.⁹⁶ MCC also argues that decoupling would reduce NorthWestern's incentive to control costs, as it would guarantee NorthWestern a certain amount of revenue regardless of sales losses.⁹⁷ MCC believes that NorthWestern is already pursuing a sufficient amount of cost-effective energy efficiency programs, and that no incentives are required.⁹⁸

NorthWestern supports the FCRM as proposed by HRC/NDRC; however, NorthWestern witness Brian Bird stated that NorthWestern would not support the FCRM if it were accompanied by any reduction in ROE.⁹⁹ Bird points out that, of the utilities in the region that have adopted decoupling, only Avista has had a reduction in ROE of 10 basis points (Avista adopted decoupling in 2016).¹⁰⁰ NorthWestern also points to a 2011 Brattle Group study, which concluded that decoupling may increase utility risk.¹⁰¹

In its post-hearing reply brief, NorthWestern counters the MCC's argument about weather normalization. While NorthWestern agrees that weather is the largest risk addressed by the FCRM, it argues that the FCRM would benefit customers when winters are colder than average or summers are warmer than average by refunding over-collection of fixed cost revenues.¹⁰²

NWEC supports the implementation of the FCRM with no reduction in ROE, and states that a cost-of-capital study can be done after the pilot period.¹⁰³ NWEC believes that, if the FCRM is adopted and the demand-side management ("DSM") stipulation is accepted, using the Utility Cost Test ("UCT") to evaluate DSM measures would result in more measures being deemed cost-effective and would treat DSM more similarly to other supply resources.¹⁰⁴

DEQ did not provide testimony on the FCRM, but addressed the FCRM in its post-hearing brief. DEQ supports adoption of a pilot FCRM. The Legislature prioritizes acquisition of DSM resources and energy efficiency in statute, and DEQ believes that the FCRM would

⁹⁶ MCC Resp. Br., at 5-7.

⁹⁷ *Id.*, at 8-9.

⁹⁸ *Id.*, at 11.

⁹⁹ Hr'g Tr., at 107.

¹⁰⁰ *Id.*, at 304 (clarified on p. 363).

¹⁰¹ *Id.*, at 2272 (Hill counters that those conclusions have not been repeated, and the Brattle Group has since backed away any claims that decoupling raises the cost of equity, *see Id.*, at 2273).

¹⁰² NorthWestern Repl. Br., at 15-16.

¹⁰³ Hr'g Tr., at 1720.

¹⁰⁴ NWEC Resp. Br., at 8.

align customer and utility interest in acquisition of cost-effective DSM.¹⁰⁵ DEQ supports requiring NorthWestern to propose a residential time-of-use rate in its next rate case regardless of whether the Commission approves the FCRM.¹⁰⁶ DEQ also supports quantitative targets for utility acquisition of cost-effective energy efficiency if the FCRM is approved.¹⁰⁷

Recommendation

Staff recommends the Commission adopt the FCRM pilot as proposed by HRC/NRDC, without any reduction to the stipulated 9.65 percent ROE, as discussed below.

Decoupling is not a new concept in utility regulation. As noted by HRC/NRDC's witness Amanda Levin, decoupling mechanisms are currently used in 32 states. On the electric side, decoupled electric utilities serve over 40 percent of all customers of investor-owned utilities, over 43 million electric customers.¹⁰⁸ Utilities, regulators, and various consumer groups often wrestle with finding a balance between a utility's desire for revenue stability and predictability, consumer interest in rate stability and bill control, and public interest in rates that reflect cost of service and send appropriate price signals regarding conservation and efficiency. While the FCRM is not a panacea, it offers potential to provide more stability to customers and the utility between rate cases by moderating any over- or under-recovery of fixed costs, while retaining a connection between customer usage and their total bill. Staff finds the FCRM approach preferable to high fixed customer charges, which reduce customer bill control.

Under the proposed FCRM, differences between allowed and actual revenues would be trueed-up annually. The soft 3% cap should help to moderate bill changes from the annual adjustments (the maximum increase or decrease would be limited to \$2.56/month for residential customers, although any over- or under-recoveries from the 3% cap will carry forward to future years). The true-up can be designed to occur when other true-up mechanisms may result in rate adjustments in the opposite direction (e.g., the PCCAM). HRC/NRDC witness Power also presented calculations of the FCRM impacts on historic bills for NorthWestern customers and concluded that the FCRM adjustments (both positive and negative) are typically less than 3% of an average customer's bill.

MCC argues that decoupling shifts normal business risks to consumers and undermines cost-control incentives. MCC does not precisely define normal business risks, but staff assumes that MCC primarily refers to weather, economic, and customer-related events that

¹⁰⁵ DEQ Resp. Br., at 11-12.

¹⁰⁶ *Id.*, at 13.

¹⁰⁷ *Id.*

¹⁰⁸ Test. Levin, at 33.

reduce sales and fixed cost recovery. Regarding weather risk, the utility and consumers face risk from significant deviations from normal weather, so it is unclear if the FCRM would *shift* additional weather risk to consumers.¹⁰⁹ To the extent changes in economic conditions impact the utility's sales, some business risk may be shifted. However, as changes in economic conditions can also affect the number of customers, and since electricity demand, especially for residential customers, tends to be inelastic in the short run, it is unclear whether any shifted risk is significant and MCC did not present evidence of the potential magnitude of shifted risk.¹¹⁰

MCC is concerned that decoupling abandons test period ratemaking and violates the "matching principle." However, under the proposed FCRM, the allowed revenue recovery is matched to test-year cost of service and billing determinants in the most recently approved rate case; the fixed-cost-per-customer rate, which determines actual revenue, would not adjust between rate cases.

MCC is concerned that the FCRM would compensate NorthWestern for sales losses due to inefficiencies, and that any utility discipline imposed by regulatory lag will be removed. Staff is not convinced by evidence in the record that incentives for cost control have decreased for electric utilities that adopted decoupling; the basis for NorthWestern's actual revenue between rate cases remains linked to rates based on test-year cost of service, so the impacts of regulatory lag also remain. Since the FCRM is a pilot, and a third-party audit is required after the third year, presumably any increase or decrease in cost-control incentives would be analyzed in the audit.

MCC argues that there is no need for decoupling, as NorthWestern already engages in significant DSM measures. However, the Commission has repeatedly encouraged NorthWestern to more fully evaluate DSM options.¹¹¹ Additionally, the Montana Legislature has signaled the need for additional encouragement for utilities to adopt DSM measures with the adoption of HB 597 in 2019.¹¹²

¹⁰⁹ *Id.*, at 16-17, 30.

¹¹⁰ See the Regulatory Assistance Project's *Revenue Regulation & Decoupling: A Guide to Theory and Application*, available at <http://www.raponline.org/document/download/id/902> (2011); referenced in RAP's *Electricity Regulation in the US: A Guide*, Levin Test. p. 5, footnote 1.

¹¹¹ See *Montana Public Service Commission Comments in Response to NorthWestern Energy's 2015 Electricity Supply Resource Plan*, Dkt. N2015.11.91 (Feb. 2, 2017), available at <https://svc.mt.gov/api/ecmruapi/api/File/xcC3FjqQ8-fugGWaX8kL2a1Lna27a0rGJFyVdCQWPsw6zASakcKMJpcSQ-666JNiH1VN1DPIQHfEBXEP2tb3QuJvrZKEZioxlFW7vfKc2ro>; and *Comments*, Dkt. N2013.12.84 (May 26, 2015), available at <https://svc.mt.gov/api/ecmruapi/api/File/xcC3FjqQ8-fugGWaX8kL2a1Lna27a0rGJFyVdCQWPsw6zASakcKMJpcSQ-666JNiH1VN1DPIQHfEBXEP2tb3QuJvrZKEZioxlFW7vfKc2ro>.

¹¹² HB 597 (effective July 1, 2020). Available at <https://leg.mt.gov/bills/2019/billpdf/HB0597.pdf>.

MCC argues that any consideration of decoupling should be deferred, as the issue was presented by HRC/NRDC after the intervention deadline. MCC argued this fact limited participation of potentially interested parties, and that NorthWestern is the only party with the opportunity to respond to the FCRM proposal in briefs. Staff disagrees with that argument. The MCC presented testimony opposing the FCRM, and addressed the proposal in its response brief. The Commission also traditionally grants late intervention to parties who present a reasonable justification for late intervention, such as issues that arise after the initial filing of a docket.

Staff agrees with HRC/NRDC that decoupling may allow NorthWestern to move beyond a business model based purely on kWh sales to one that provides services to address customer needs (services that include energy efficiency, demand response, and distributed generation).

The stipulated ROE is reasonable because it is based—at least in part—on the observable market data of similarly-situated utilities (i.e. proxy groups). NorthWestern demonstrated that roughly two thirds of the proxy group companies used in its analyses have either full or partial decoupling mechanisms.¹¹³ Similarly, roughly two thirds of the proxy group companies used by FEA/LCG have either full or partial decoupling mechanisms.¹¹⁴ About one third of the proxy group companies relied upon by the MCC in its analyses have either full or partial decoupling.¹¹⁵ Taken together, more than one-half of the companies used in the parties' cost of equity analyses have some sort of decoupling mechanism. Those analyses informed staff's recommendation to approve the stipulated ROE. Thus, at this time, staff considers any book-value risk reduction associated with decoupling to be included in the 9.65 percent ROE.

Staff agrees with MCC that decoupling reduces weather-related risk.¹¹⁶ However, staff is not convinced that this translates directly to a reduction in NorthWestern's cost of capital. While NorthWestern's book-value earnings may be less volatile as a result of decoupling, it is premature to conclude that this reduction in book-value risk would automatically translate to the capital markets.

Although staff is not recommending any reduction to the ROE at this time, it is appropriate to revisit the issue at a later date—after the pilot period concludes. At that time, the market and its participants (i.e., ratings agencies, investors) will have had time to respond to the

¹¹³ Ex. AMM-3 (Sept 28, 2018).

¹¹⁴ A comparison of Ex. AMM-3 and Ex. MPG-3 (Feb 13, 2019) indicates that 9/15th's of Gorman's proxy group have decoupling mechanisms.

¹¹⁵ A comparison of Ex. AMM-3 and Ex. SGH-2 (Feb 12, 2019) indicates that 6/15th's of Hill's proxy group have decoupling mechanisms.

¹¹⁶ Hr'g. Tr., at 2265.

FCRM. If the Commission were to then decide to reduce the ROE, that decision would be in direct response to the FCRM's impact on observable market data. Because any decision by the Commission at that time would be based on observable market data, any ROE adjustment would not be bound by the 25-basis-point parameter defined in the stipulation. Rather, the magnitude of the adjustment would be defined by the market(s). NorthWestern would submit a third-party audit of the FCRM to the Commission after a three-year study period, and would be required to file a rate case before the end of the four-year pilot to renew, modify, or discontinue the FCRM. The Commission should also adopt the customer service and reliability standards proposed by Levin (see FCRM Appendix A). When NorthWestern files its rate case at the end of the pilot period, the Commission should require NorthWestern to include an analysis of time of use rates and other alternative rate designs such as inclining block rates, in addition to any rate designs NorthWestern chooses to propose.

Staff agrees with MCC that the FCRM should function as more than a "glorified weather normalization clause." Therefore, staff recommends that the Commission pay particular attention to NorthWestern's DSM levels when the pilot period study is reviewed. If the Commission feels that additional encouragement is required, it can evaluate options such as adopting energy savings and peak-demand reduction goals, as authorized in HB 597.

Alternatively, if the Commission is concerned about the length of the FCRM pilot period, staff recommends that the Commission follow an approach similar to that adopted in Idaho, where the FCRM is established as a three-year pilot, with the option to extend the pilot for a few years before a decision is made about making the FCRM permanent or discontinuing the mechanism.¹¹⁷

In either instance, whether the proposed four-year pilot study is adopted or an alternative three-year pilot period, the Commission should reserve the right to order a review of the mechanism at any time, should it feel that the mechanism is not operating as intended. Also, if NorthWestern files a rate case at any time prior to the completion of the pilot period, it must include justification as to why the FCRM should be continued or discontinued.

D. Demand-Side Management Programs

Party Positions

Utilities are required by Montana statute to include DSM options in their supply resource planning and procurement processes. Currently, NorthWestern offers the following

¹¹⁷ Test. Levin, at 11-12, referencing ID PUC's [Order 30267](#), Case No. IPC-E-04-15, [Order 31063](#), Case No. IPC-E-09-28, and [Order 32731](#), Case No. IPC-E-11-19.

programs: E+ lighting for commercial and residential LED lighting, E+ Commercial Programs and Contractors for training and marketing energy efficiency measures to contractors, and E+ Commercial Electric Rebate Program, which includes incentives for motor rewinding.

NorthWestern currently uses a total resource cost ("TRC") test to evaluate the cost effectiveness of DSM programs. NorthWestern calculates the avoided cost value of energy saved and the total DSM program costs for its TRC test. NorthWestern explains that carbon cost adders have recently been included in DSM avoided costs, so the 10% environmental benefit adder that was previously included in the TRC is no longer being used. DSM measure and program lives are also being restricted to 15 years to comply with the Commission's Order 7500d in Docket D2016.5.39.

NorthWestern initially proposed to remove DSM costs from the electricity supply tracker in Docket D2017.5.39. Rather, NorthWestern proposed to record DSM expenditures as a regulatory asset amortized over a 15-year period. NorthWestern states that Commission rules require NorthWestern to treat DSM as a supply resource, and so it is reasonable for NorthWestern to treat DSM as an investment included in the asset base as capitalization allows NorthWestern to spread large expenditures over a reasonable time without rate fluctuation.

NWEC witness F. Diego Rivas does not believe that all cost-effective energy efficiency measures are being pursued by NorthWestern. For example, NorthWestern could be pursuing residential measures such as faucet aerators or smart thermostats, which were identified as cost-effective in NorthWestern's 2016 Electricity Energy Efficiency Market Potential Study. Rivas also believes that NorthWestern is incorrectly using the TRC test to calculate cost-effectiveness of efficiency measures. NorthWestern only uses the avoided cost value of energy saved as the benefit of the measure, while other utilities also include the reduction in transmission, distribution, generation, and capacity costs valued at a marginal cost for the periods where there is a reduction in load. Rivas suggests that the Commission should either direct NorthWestern to correctly apply the TRC or use the Utility Cost Test ("UCT"), which is the avoided energy and capacity costs plus transmission and distribution benefits, divided by the total program costs.

In response, MCC suggests that if NorthWestern is allowed to defer DSM costs, the amortization of the deferred DSM costs should commence by the end of the year in which the costs are incurred. MCC Witness Ralph Smith also recommends that a \$45 million threshold should be set for DSM deferral costs, to prevent accumulation of large amounts between rate cases. If the threshold is reached, it would trigger a requirement for NorthWestern to make a filing with a Commission that includes a plan for cost recovery.

MCC witness David Dismukes explains that NorthWestern provided few details on its DSM proposal, including how it proposes to defer its annual DSM expenses, whether or

not any return will be included with the expenses booked, or whether or not deferred investments will be amortized prior to the ultimate incorporation into rate base. There is also no cap on deferred costs or the ultimate size of the proposed regulatory asset. Dismukes recommends that the Commission continue to incorporate annual DSM expenses through the PCCAM, without being subject to the deadband or sharing percentages.

In reply, NorthWestern witness Crystal Lail states that NorthWestern is not opposed to keeping the DSM costs in the PCCAM, as long as recovery is 100% and not subject to the deadband and sharing percentages. NorthWestern is opposed to starting the amortization of deferred DSM costs at the end of the year in which the costs are incurred. Lail explains that Commission practice in Montana has been to begin depreciating assets in the year following the year the assets are placed into service. NorthWestern opposes Smith's suggestion to implement a \$45 million threshold for accumulated deferred DSM costs.

Additionally, NorthWestern witness Danie Williams states that NorthWestern did not revise its DSM acquisition target due to the Commission's decision to discontinue the lost revenue adjustment mechanism, but rather as a result of the Electricity Energy Efficiency Market Potential Study conducted by Nexant, Inc. That study showed more robust potential efficiency programs than what NorthWestern implements in Montana, because NorthWestern tries to focus on DSM programs that simplify offerings and set rebates at levels that drive customer participation. Administrative and promotional costs, which can often outweigh benefits, would not be cost-effective.

Williams explains that NorthWestern discontinued its DSM programs for residential electric customers, with the exception of lighting, because the programs were not cost-effective. In NorthWestern's Montana service territory, residential measures tend to result in relatively small per-customer energy savings. Williams states that the avoided cost for DSM has decreased since the Nexant study, from \$40.70/MWh to \$37.57/MWh, which decreases the margin available to absorb administrative costs.

Williams states that an Electric Potential study was completed by Nexant in 2017, and updates are expected to be completed in 2019. That study provides information to calculate capacity contribution for DSM resources.

DSM Stipulation

On May 20, 2019, the Commission received a stipulation between NorthWestern and NWEAC regarding capitalization and amortization of DSM costs. The following Stipulation paragraphs are relevant to this memo:¹¹⁸

“1. The Stipulating Parties agree that NorthWestern will create a small (no more than 10 people), advisory stakeholder group consisting of relevant and appropriate stakeholders selected by NorthWestern, which shall include at minimum representatives from the NWEAC, the MCC, and Commission staff, to discuss re-envisioning of the electric DSM programs offered by NorthWestern for the 2020-2021 program year (items to be discussed include branding, methods of marketing, cost-effectiveness calculations, energy savings estimates). The group shall make recommendations to NorthWestern for consideration in the development of the 2020-2021 electric DSM program offerings. Once the 2020-2021 program year commences, the group shall be disbanded. The Stipulating Parties will also include a 10% adder for electric DSM in its cost-effectiveness calculations beginning with the 2020-2021 program year, unless a different adder is required by Montana Administrative Rules and continue its work towards including a capacity value of electric DSM measures and/or programs in cost-effectiveness calculations.”

“2. With regard to recovery of electric DSM expenditures, the Stipulating Parties agree that NorthWestern shall record any DSM expenditures as a regulatory asset in the year the expenditures are incurred. NorthWestern shall also amortize these DSM expenditures over 10 years starting coincident with the Commission order that approves the expenditures for inclusion in rates at which time NorthWestern will earn a return of and return on all electric DSM expenditures at the Rate of Return approved by the Commission, including any adjustment to Return on Equity (“ROE”) for conservation investments pursuant to Montana Code Annotated Title 69, chapter 3, part 7. The Stipulating Parties agree that there should not be a threshold level of the DSM regulatory asset that triggers the need for a filing by NorthWestern.”

¹¹⁸ Because paragraphs 3 and 4 of the stipulation are merely statements of support for the FCRM, Commission approval of the stipulation would require implementation of just paragraphs 1 and 2. NWEAC Repl., at 5 (Jul. 31, 2019).

“The various provisions of this agreement are inseparable from the whole of the agreement between the Stipulating Parties. The reasonableness of the proposed settlement set forth in this Agreement is dependent upon its adoption, in its entirety, by the Commission. If the commission declines to approve this Agreement as agreed to herein by the parties, or if the Commission adds or removes any terms or conditions not agreeable to the parties, either party shall, at its sole option, have the right to withdraw from this Agreement with all of its rights reserved. The Agreement and all its parts shall then be null and void, and the parties shall not be bound by any provision of it, and it shall have no force or effect whatsoever. In such event, the existence or terms of this Agreement shall not be admissible in any proceeding before the Commission or any court for any purpose.”

Staff Recommendation

Staff recommends the Commission reject the DSM settlement, yet resolve the DSM issue substantially similar to that proposed in the settlement with the exception of: (1) continuing the Commission practice of expensing DSM costs within NorthWestern’s PCCAM, and not capitalizing them, and (2) continue to utilize the TRC test as opposed to the UCT, even if the Commission adopts the FCRM.

(Note: This recommendation repeals and replaces the staff recommendation on DSM from September 26, 2019.).

The first three sentences of Paragraph 1 of the Stipulation propose creating a stakeholder group to make recommendations on electric DSM programs. No party has objected to that portion of the Stipulation. Although staff recommends rejecting the Settlement, it recommends the Commission order NorthWestern to create the stakeholder group provided for in Paragraph 1.

The final sentence of Paragraph 1 addresses the incorporation of a 10% adder for electric DSM in NorthWestern’s cost-effectiveness calculations, beginning with the 2020-2021 program year. Prior to the 2015-2016 DSM program year, NorthWestern used a 10% factor to evaluate environmental benefits based on the Northwest Power Act of 1980, which states that conservation measures should be evaluated at 110% of the cost of an alternative resource. In the 2015-2016 DSM program year, NorthWestern discontinued the 10% factor in favor of a carbon cost adder in its DSM avoided costs calculations, based on the Carbon Penalty Forecast in its Electricity Supply Resource Procurement Plan. This translated to a carbon price of \$21.11/metric ton beginning in 2021 (and escalating at 5% annually) for the 2015-2016 DSM program year, and \$20.00/metric ton beginning in 2022 for the 2016-2018 DSM program years. No carbon adder was included in DSM avoided costs for the 2018-

2019 or 2019-2020 program years, based on Commission decisions to not include a carbon cost in avoided cost calculations for qualifying facilities.

Adopting a 10% adder for DSM in cost-effectiveness calculations would align with federal statute and the practice of the Northwest Power and Conservation Council. Even though staff recommends rejecting the Settlement, staff recommends the Commission require NorthWestern to adopt the previous 10% adder for DSM cost-effectiveness, as opposed to adopting a carbon adder, and related implementation timelines. Staff recommends that the DSM stakeholder group should consider if a 10% adder or some other method is appropriate when it discusses future DSM program offerings.

Paragraph No. 2 of the Stipulation allows for the capitalization of NorthWestern's DSM expenditures as a regulatory asset in the year the expenditures are incurred. NorthWestern cites Mont. Code Ann. §§ 69-3-702, -712, and 69-3-1206 in support of its position that inclusion of DSM costs in rate base is consistent with policy expressed by the Montana Legislature that utilities should be encouraged to invest in conservation resources.¹¹⁹ NorthWestern also cites to prior Commission orders to suggest that inclusion of DSM expenditures in rate base is consistent with Commission precedent.¹²⁰

NWEC also provided post-hearing briefing advocating approval of the DSM settlement.¹²¹ NWEC's brief focuses on a variety of policy-based reasons for capitalization of DSM expenditures. However at hearing, Rivas initially testified that, while he does not oppose capitalizing DSM costs, he prefers the current practice of expensing them.¹²² Rivas noted that capitalization of DSM could be expected to increase total costs for customers; limit additional DSM investment due to lengthy spread of recovery; create a regulatory asset that provides a rate of return for dollars spent instead of savings achieved; and lead to an increased cost of debt.¹²³ However, he also noted that capitalization spreads the cost out over a period of time that matches the flow of benefits and provides incentives for utilities to more aggressively pursue DSM resources.¹²⁴

MCC opposed the Stipulation, advocating for continued recovery of DSM expenditures as an expense. MCC contends that, because customers will pay for both the actual cost of DSM programs as well as a return on those costs (rather than the actual costs alone), capitalization will lead to increased DSM costs which, in turn will lead to increased rates.¹²⁵

¹¹⁹ NorthWestern In. Br., at 13 (Jul. 10, 2019).

¹²⁰ *Id.*, citing Dkt. D94.11.49, Order No. 5875, 6 (Oct. 31, 1995), and Dkt. D2014.6.53, Order No. 7375a, ¶ 56 (Oct. 15, 2015).

¹²¹ See generally NWEC Resp. Br., at 2-9 (Jul. 31, 2019).

¹²² Test. F. Diego Rivas, 5:4-7.

¹²³ *Id.* at 6:6-10

¹²⁴ *Id.* at 5:20-6:3.

¹²⁵ MCC Resp. Br., at 19 (Jul. 31, 2019).

It suggested that NorthWestern's proposal might violate the principal of intergenerational equity if another significant period of time elapses before NorthWestern's next rate case.¹²⁶ The MCC was also critical of the absence of a cap on deferred costs or the size of the regulatory asset.¹²⁷

Finally, MCC criticized the lack of detail in NorthWestern's proposal in that it provided little guidance as to how the change would be implemented. Specifically, MCC pointed out that NorthWestern did not explain how annual DSM expenses will be deferred or whether deferred investments would be amortized prior to their inclusion in rate base used for ratemaking.¹²⁸

LCG joined MCC in opposing the Stipulation, noting similar intergenerational inequity issues.¹²⁹ LCG also argued that NorthWestern's proposal to capitalize DSM costs is fundamentally at odds with the stated purpose of DSM programs.¹³⁰ To that end, LCG notes NorthWestern's statement that "DSM 'programs promote electric energy efficiency and conservation and are *important because they reduced NorthWestern's need to purchase or build electric supply resources.*'"¹³¹ LCG points out that while DSM programs avoid the need for additions to rate base for which customers would pay NorthWestern a return, capitalization of DSM expenditures creates the same ratemaking treatment for the DSM programs which NorthWestern purports would reduce the need for capital investments.

Based on the foregoing, MCC and LCG both argue that, in contrast to recovering the actual cost of, and return on, DSM, it is more appropriate for NorthWestern to continue dollar-for-dollar recovery of DSM costs as an expense within NorthWestern's PCCAM.

Staff recommends the Commission decline capitalizing DSM expenditures, but rather continue the Commission's current practice of expensing the costs within NorthWestern's PCCAM.

First, it is consistent with state law. The 2019 Legislature amended Mont. Code Ann. § 69-3-712(1). That legislation, which will become effective July 1, 2020, reads as follows: "[i]n order to encourage the purchase of or investment in conservation by a utility, the commission *may* include conservation purchases or investments *and demand-side management programs* eligible under 69-3-702 and in compliance with the criteria adopted under 69-3-711 and 69-3-1201 through 69-3-1209 in a utility's rate base."¹³²

¹²⁶ *Id.* at 21.

¹²⁷ Test. Ralph C. Smith, 81:1-82:2.

¹²⁸ Test. David E. Dismukes, 28:1-29:2.

¹²⁹ LCG Resp Br., at 19 (Jul. 31, 2019).

¹³⁰ *Id.*

¹³¹ *Id.*, citing NorthWestern In. Br., at 12 (emphasis in original).

¹³² Emphasis added.

This amended statute explicitly includes “demand-side management programs,” whereas the current statute does not. It also provides the Commission clear discretion in determining whether the stated expenditures should be included in rate base by replacing the word “shall” with “may”. This specific exclusion of “demand-side management programs” from the current statute leads staff to conclude that DSM expenditures are not subject to the compulsory inclusion in rate base suggested by the current version of Mont. Code Ann. § 69-3-712. Staff also concludes that when the newer version of §69-3-712 becomes effective (in July of 2020), the inclusion of DSM costs in rate base will be subject to Commission discretion based on amendment of the word “shall” to “may”. Staff therefore concludes that the Commission’s current practice is not contrary to Montana law.

Second, the issue is not properly before the Commission inasmuch as NorthWestern has not requested including any specific DSM investments in rate base. Instead NorthWestern’s request is prospective in nature in that it seeks permission to begin accounting for DSM expenditures in rate base which will take effect in its next general rate case filing. Thus, even if the Commission were to allow capitalized DSM costs, under the currently effective statute the Commission lacks the information necessary to perform the analysis required by §§ 69-3-712, -711, and -702 to decide whether specific DSM expenditures should be included in rate base. When NorthWestern files its next general rate case filing, the amended Mont. Code Ann. § 69-3-712 will be effective, and at that time, the Commission will review requests for inclusion of DSM expenditures in rate base based on its discretion.

At this point, for the reasons stated above, as well as those identified by MCC and LCG, staff recommends against the prospective inclusion of DSM expenditures not yet identified, and instead recommends maintaining the current practice of allowing for recovery of DSM expenditures through NorthWestern’s PCCAM. While staff recommends that the Commission reject the use of the UCT in this docket, it does recommend that the UCT, inputs to the TRC test, and any other potentially appropriate cost-benefit tests should be discussed in the DSM stakeholder forum and considered for future DSM proposals.

E. Colstrip Issues

Background

Colstrip is comprised of four generation units owned by a variety of utilities and merchant generators. NorthWestern currently owns a 30 percent interest in Colstrip 4. The various units, ownership interests, and expected closure dates and depreciation schedules are provided below:

Table 3: Colstrip Ownership

Generation Unit	Percent Ownership			
	CU1	CU2	CU3	CU4

Nameplate Capacity	358	358	778	778
Puget Sound	50%	50%	25%	25%
Portland General	0%	0%	20%	20%
Avista	0%	0%	15%	15%
PacifiCorp	0%	0%	10%	10%
Talen	50%	50%	30%	0%
NorthWestern	0%	0%	0%	30%

Table 4: Colstrip Scheduled Closure Dates and Depreciation Schedules

Scheduled Closure (CU1/CU2) and Current Depreciation Schedules (CU3/CU4)				
Generation Unit	CU1	CU2	CU3	CU4
Puget Sound	2019-2020	2019-2020	2027	2027
Portland General	N/A	N/A	2030	2030
Avista	N/A	N/A	2027	2027
PacifiCorp	N/A	N/A	2027	2027
Talen	2019-2020	2019-2020	N/A	N/A
NorthWestern	N/A	N/A	N/A	2043

NorthWestern acquired 79.29 MW of CU4 on March 31, 2007, from Mellon Leasing for \$58.6 million. On October 30, 2007, NorthWestern acquired an additional 142.71 MW of CU4 from SGE for \$128.4 million. As a result of these transactions, NorthWestern owns 222 MW, a 30% share, of CU4, for which it paid \$187 million. At the time of those transactions, NorthWestern asserted its CU4 interest was not public utility property subject to Commission jurisdiction, but rather was subject to FERC jurisdiction as wholesale merchant generation.

In early 2008, NorthWestern hired Credit Suisse Securities to evaluate and determine the fair market value of CU4 through a competitive sales process. Eleven parties submitted initial bids and seven bidders were selected to participate in Phase 2 of the process. Four Phase 2 bids were received ranging from \$360 million to \$404 million. Bicent Power was selected as the winning bidder with a bid of \$404 million and a sale transaction was announced on June 10, 2008. Bicent Power, a subsidiary of Beowulf Energy, was a special-purpose operating company formed in 2007 to acquire independent power producers.

On June 27, 2008, NorthWestern filed a request for Commission preapproval to include the 222 MW of CU4 as a retail electricity supply resource with a rate base of \$407 million.¹³³ The rate base figure of \$407 million included the Bicent bid of \$404 million, \$6.25 million for termination fees, and (\$3.25) million in avoided transaction costs. During the proceeding, NorthWestern indicated that as of November 30, 2007, shortly after the SGE acquisition, the original cost plant balance for its share of CU4 was \$67,277,872, the associated depreciation reserve was \$29,735,530, and net book cost was \$37,542,342.¹³⁴

MCC testified in the preapproval proceeding that the Commission had the option of rate-basing the CU4 interests at \$37.5 million, in addition to, if warranted, such portion of the acquisition premium of \$149.5 million (\$187 million less the \$37.5 million in net book) that NorthWestern establishes to be appropriate and in the public interest. Thus, the MCC opposed NorthWestern's \$407 million rate base proposal and instead advocated for a rate base ranging from \$37.5 to \$187 million.

On November 13, 2008, the Commission approved rate basing NorthWestern's share of CU4 at \$407 million, which was reflective of the bid-based market value.¹³⁵ The Commission also approved, for the life of the plant, a 10.0% return on equity ("ROE"), a 6.5% cost of debt, and a 50% equity/50% debt capital structure.¹³⁶ This equates to an overall allowed return for the life of the plant of 8.25%, as shown in the following table.

NorthWestern's Application presented a CU4 revenue requirement and rate base which continues to reflect the market transaction-based plant value the Commission approved in Docket D2008.6.69 (the preapproval case). Statements C and D of NorthWestern's Application show the following plant balances on NorthWestern's regulatory books as of December 31, 2017, for CU4.¹³⁷

Table 5: CU4 Plant Balances (Dec. 31, 2017)

CU4 Net Book December 31, 2017			
	Plant		
	Balance	Accumulated	
	(Orig. Cost)	Depreciation	Net Book
Intangible Plant	\$335,889,309	\$66,071,683	\$269,817,626
Generation Plant	\$88,031,667	\$23,608,775	\$64,422,892
Total	\$423,920,976	\$89,680,458	\$334,240,518

¹³³ *In re Colstrip Pre-Approval*, Dkt. D2008.6.69.

¹³⁴ DR MCC-019

¹³⁵ Order 6925f, Dkt. D2008.6.69, ¶ 251 (Nov. 13, 2008)

¹³⁶ *Id.*, ¶ 264.

¹³⁷ Actual CU4 Rate Base as of 12/31/2017 was \$303,981,607. This reflects the \$334,240,518 Net Book cost less deferred taxes.

The \$335.9 million in Intangible Plant is the difference between the original cost for CU4 plant on the books and the approved rate base of \$407 million. The Intangible Plant amount has been booked to FERC Account 114 – Electric Acquisition Adjustment. This amount does not change over time; it is the same amount that was originally recorded when rate basing was approved in the preapproval case.

In June 2019, Talen Energy Corporation and Puget Sound Energy announced early retirement of Colstrip 1 and 2, which are scheduled to be retired by the end of 2019.

Party Positions

The parties request a variety of Colstrip-related actions from the Commission. Specifically, the parties request the Commission to address remediation costs; open an investigation docket to consider various Colstrip-related retirement, remediation, and transition fund costs; and establish additional reporting requirements. Each issue is discussed in more detail below.

- Investigate Docket to Establish Remediation Costs

MEIC requests the Commission to require NorthWestern set aside funds sufficient to satisfy federal and state regulatory requirements to remediate groundwater contamination caused by the plant's coal-ash waste impoundments and appropriately close those impoundments.

Additionally, HRDC/NRDC witness Power testifies that typically the CU4 related plant costs would be recovered in NorthWestern's revenue requirement through depreciation. A depreciation rate is set based on the projected life of the plant and the plant costs are reduced each year by the annual amount of the depreciation. This allows shareholders to recover their initial investment and earn a return on the undepreciated balance. It also ensures that customers do not overpay and that customers receiving electricity from the asset are the customers paying the costs.

Regarding retirement costs, Power explains that these are costs to mitigate or remediate environmental damage caused by the operation of the facility over its lifetime. These costs are typically recognized as utility liabilities and recovered from customers over the life of the plant. These costs are added to the utility's rate base and then recovered in a utility's annual depreciation expense. Power states that an Asset Retirement Obligation ("ARO") is created when the legal requirement to mitigate any environmental damage is recognized. AROs are included in the cost of removal associated with plant decommissioning are recovered through depreciation rates, which also take into account any salvage value at the time of retirement. The difference between the cost of removal and the salvage is termed "net salvage."

Power asserts that retirement costs at the time of a generator's retirement should be relatively small if the depreciation rates over the life of the plant have properly and accurately included the ARO costs.

Power states there is a risk that when CU4 closes, NorthWestern will not have collected sufficient money from customers to cover plant costs and the costs of removal, including remediation. If CU4 closes within the next decade there will be a significant amount of unrecovered plant investment which NorthWestern will wish to recover from customers even though those customers will not be receiving electricity from the units.

Regarding the regulatory treatment of environmental cleanup costs, Power testifies that the combustion of coal produces a variety of pollutants that have to be removed from the exhaust of electric generators. This produces an ongoing flow of solid and liquid wastes, the waste streams are called coal combustion residuals ("CCR"), which are recovered and moved to storage ponds. If CU4 was to close there is no consensus as to what remediation regarding CCR should entail. Thus, it is unclear right now what a solution might cost. DEQ has estimated the cost for all of Colstrip at \$400 to \$700 million. Power states that NorthWestern has not addressed remediation, cost of removal, or decommissioning costs in this rate case and he believes this is a risky course of action. If CU4 is forced to shut down without this issue being dealt with, there will be significant environmental and decommissioning costs, none of which will have been recovered from customers.

Regarding, the risk associated with the early closure of CU4, Power states while NorthWestern has a 2042 retirement date for CU4, Puget Sound Energy has set a date of 2027, as established in UE-170033. Avista, in Idaho and Washington, has also set a date of 2027. Portland General Electric has set a date of 2030. Finally, PacifiCorp, in Docket UM-1968 before the Oregon Commission, is seeking to move the depreciable life of Colstrip units 3 and 4 from 2032 to 2027.

Accordingly, Power recommends that the Commission, as soon as possible after the conclusion of this rate case, open a CU4 docket in which all issues related to Colstrip will be examined. He maintains this is an important issue and urges the Commission to address it by playing an active role in finding a solution to the problem.

In response, NorthWestern witness Lail states that while NorthWestern recognizes the need for planning for those costs, NorthWestern did not request and does not support setting rates for the recovery of those costs in this rate case. She asserts those costs should be considered when a shut-down date for CU4 is established.¹³⁸ Additionally, NorthWestern notes that an ARO was established by NorthWestern related to its legal obligations related to CU4's ash ponds. NorthWestern has recorded this liability in its

¹³⁸ Reb. Test. Lail, at 28.

GAAP books, these costs are not included in its regulatory books for cost of service ratemaking because NorthWestern is not seeking recovery of those costs in this case.¹³⁹ Lail testified that, “Consistent with established ratemaking principles, when retirement obligation costs are determinable following establishment of an agreed-upon shut-down date and remediation methodology, NorthWestern will request Commission approval of recovery.”¹⁴⁰ Lail asserts, using Puget Sound Energy as an example, that until a shut-down date is established and a remediation plan is agreed upon by all parties, including the DEQ, that a liability is not determinable.¹⁴¹

Accordingly, Lail stated that she does not believe it is necessary to have a Colstrip-specific investigation docket, as NorthWestern plans to operate the facility through the end of its useful life and will seek to recover any unrecovered costs in a future rate case.¹⁴² This testimony is consistent with NorthWestern’s prior representations, where during the initial CU4 preapproval docket NorthWestern noted that it would seek to recover future costs related to CU4, such as remediation costs, in a future proceeding.¹⁴³

This representation is contrasted with NorthWestern witness Hines, who indicates that he supports the Commission opening an informational docket regarding Colstrip-related issues, but only if the docket is part of a non-contested case proceeding.¹⁴⁴ Hines testified on re-direct that he believes that if the Commission opens a separate docket, it needs to be “thoughtful as to what sort of information that they’re going to be wanting to solicit and what’s already available and in the context that some parties are likely to use that for furthering litigation.”¹⁴⁵

- *Community Transition Funds*

Both Northern Cheyenne and MEIC/SC request the Commission to require NorthWestern to contribute \$4.5 million to an interest-bearing account to support Colstrip community and worker transition in preparation for the eventual closure of Colstrip Units 3 and 4.

MEIC/SC provides several reasons why transition funding is necessary.

Transition funds are needed because of the need for worker retraining, economic redevelopment, and clean energy development: “The City of Colstrip, the workers

¹³⁹ *Id.*, at 29.

¹⁴⁰ *Id.*

¹⁴¹ *Id.*, at 32.

¹⁴² Hr’g Tr., at 717.

¹⁴³ “These costs will be legitimate operating and capital costs” that NorthWestern expects to recover “as part of CU4 future generation costs.” *In re Colstrip Preapproval*, Dkt 2008.6.69, Order 6925f, ¶ 43 (Nov. 13, 2008).

¹⁴⁴ Hr’g Tr., 2467–2468.

¹⁴⁵ Hr’g Tr., at 2528.

employed by Colstrip, and the surrounding community, are situated in a remote region of Montana and are dependent on the operation of Colstrip. This makes the Colstrip community acutely vulnerable to changes in Colstrip operation, especially plant retirement.”¹⁴⁶ MEIC witness Ronald Binz pointed out that Colstrip owners are reaping the benefits the local workforce provides and that some of the earnings should be channeled to ensure a fair outcome upon transition.¹⁴⁷

Binz also testified that Colstrip owners in Washington have already created a fund to mitigate the impact of closing CU Units 1–4.¹⁴⁸ For example he noted Puget Sound Energy’s settlement in Washington State in which Puget Sound Energy agreed to provide \$10 million for Colstrip transition.¹⁴⁹ Binz suggested that collecting community transition funds now would allow for interest to accrue until the funds are needed, without influencing retirement date.¹⁵⁰ The community can plan for expenditures of the funds ahead of time, rather than waiting for the plant to close.¹⁵¹ Binz testified that providing community transition funds supports intergenerational equity, meaning that future customers who do not benefit from Colstrip are not forced to pay for retirement costs.¹⁵²

Accordingly, MEIC/SC recommends NorthWestern set aside \$4.5 million for community transition funding for the CU4 closure.¹⁵³

Binz explained that if the Commission declines to reevaluate the CU4 asset as he has recommended, the community transition costs should not impose additional requirements on current customers. He explained that if the Commission adopts his primary recommendation regarding CU4, the Commission will have returned to cost of service regulation and he recommends the community transition funds be added to rates.¹⁵⁴ Binz also proposes using excess accumulation of deferred taxes (EADIT) to pay for the community transition fund.¹⁵⁵

At the hearing, Binz pointed out that Colorado just passed legislation to include transition funds in retirement plans.¹⁵⁶ He acknowledged transition planning funds are relatively a new issue regarding plant retirements, but notes that there is precedent in Montana with

¹⁴⁶ Test. Binz, at 45.

¹⁴⁷ *Id.*, at 46.

¹⁴⁸ *Id.*, at 46.

¹⁴⁹ *Id.*, at 47.

¹⁵⁰ *Id.*

¹⁵¹ *Id.*

¹⁵² *Id.*, at 47.

¹⁵³ *Id.*, at 48.

¹⁵⁴ *Id.*, at 48.

¹⁵⁵ *Id.*, at 48

¹⁵⁶ Hr’g Tr., at 2089

the practice.¹⁵⁷ Relatedly, Binz testified at the hearing that securitization to retire the debt in power plants would create savings that could then be dedicated to transition funds.¹⁵⁸

Northern Cheyenne provides several reasons for why transition funding is necessary. William Walksalong testifies that jobs at Colstrip are central to the Tribal economy. He states there are over 100 Tribal members who work at the power plant and mines. He asserts that each of those jobs directly supports approximately ten members such that the operation of the Power Plant directly benefits more than 1,000 Tribal members or ten percent of the on-Reservation population.¹⁵⁹

Walksalong also maintains that Colstrip and associated coal mines have both positive and negative impacts on the surrounding communities. The Tribe and its members are disproportionately reliant on those benefits and disproportionately harmed by the negative impacts such as air and groundwater pollution, crime, and lower quality of life.¹⁶⁰

Walksalong states that it is his understanding that part of NorthWestern's rate-setting process involves future planning for CU4 closure including how to account for the costs of operations, closure and remediation. He asserts he is aware of rate-setting cases for Puget Sound Energy and Avista Corp. where there have been substantial settlements that purport to compensate communities impacted by plant closures. Walksalong asserts the Tribe has been shut out of those processes in Montana and was not invited to be a member of the Governor's Colstrip Community Impact Advisory Group.¹⁶¹

Walksalong asserts that NorthWestern should not be allowed to benefit and profit from operations near the Reservation and then leave the Tribe and its members to bear the consequences of closure. Any plan must seek to minimize impacts on Tribal members and compensate for the impacts that occur including environmental and economic impacts.

This can be accomplished by prioritizing and giving employment preference to Tribal members; employ as many Tribal members as possible; assist the Tribe and the region in a transition to renewable energy to replace coal and buy the electricity generated by renewables at above-market rates; and by offering greatly reduced transmission costs to buyers.¹⁶²

Walksalong states NorthWestern should give job prioritization to Tribal members for closure and remediation. In addition, he asserts that NorthWestern should assist the Tribe

¹⁵⁷ *Id.*; see generally, *In re Avista/Hydro-One Merger*, Dkt. D2017.9.71, Order 7577a (Jun. 12, 2018).

¹⁵⁸ *Id.*, at 2090

¹⁵⁹ Test. William Walksalong, at 7, (Feb. 12, 2019).

¹⁶⁰ *Id.*, at 9.

¹⁶¹ *Id.*

¹⁶² Test. Walksalong, at 10–11.

and the region to transition to renewable energy sources that replace coal by agreeing to buy power at above-market rates and by offering greatly reduced transmission costs to outside buyers. Finally, Walksalong suggests that NorthWestern should fund a \$4.5 million transition fund.¹⁶³

Walksalong arrived at the \$4.5 million figure because that is the settlement amount Avista agreed to as part of its acquisition by Hydro One. Avista owns 15% of CU3 and 15% of CU4, which is equivalent to NorthWestern's 30% ownership in CU4. Walksalong indicated the \$4.5 million payment is proportionate to a \$10 million settlement paid by Puget Sound Energy.¹⁶⁴

Regarding community transition funds, NorthWestern witness John Hines states the recommendations are premature and focused on the wrong party. He asserts that there is not enough information in this docket that can be used to ascertain the reasonableness of these demands. Regarding the idea of providing the Tribe with subsidized power purchase rates for purchased power and transmission costs, Hines states NorthWestern is bound by law to comply with its tariffs, which in general ensure all customers are economically indifferent. Regarding a transition fund, Hines states that he believe that at this time the Sierra Club should be a responsible party for payments to the Tribe. Hines asserts that NorthWestern wants to continue operating Colstrip because it is a cost-effective and necessary piece of its generation portfolio.

- *Additional Reporting Requirements*

MEIC/SC and HRDC/NRDC recommend the Commission require additional reporting requirements on a variety of Colstrip-related issues.

HRDC/NRDC recommends that the Commission require NorthWestern to file a Colstrip status report every 6 months, or annually.¹⁶⁵ The status report would provide the most recent information concerning Units 3 and 4 remediation, including cost estimates, and would report, to the extent known, on the plans of the other utilities with respect to their interest in Colstrip Units 3 and 4.¹⁶⁶

MEIC/SC recommends the Commission require NorthWestern to report annually on the timeframe for retirement of both Colstrip Units 3 and 4 and NorthWestern's estimates of the costs associated with those retirements. Reporting should include: (1) the appropriateness of current depreciation rates and update its estimates of cost of environmental remediation associated with the retirement of Colstrip Units 3 and 4; and (2)

¹⁶³ *Id.*, at 11.

¹⁶⁴ Test. Walksalong, at 11.

¹⁶⁵ See *Hr'g Tr.*, at 2007–2008, indicating annual reporting is sufficient.

¹⁶⁶ Test. Power, at 85.

within 30 days of its occurrence, NorthWestern should provide notice to the Commission of any significant findings or events that alter the projections of the operating life of Colstrip Units 3 and 4. The notice should also contain NorthWestern's analysis of the impacts and its plans to address them, if any.

Hines states NorthWestern is opposed to MEIC/SC recommendations to require NorthWestern to provide regular reports regarding Colstrip's closure costs and operating life or initiate a new docket to address all issues related to Colstrip.¹⁶⁷ Hines asserts that the Commission should be concerned about Colstrip's future given the political attacks on coal-fired generation. He states that the MEIC and Sierra Club are unequivocal in their desire to close Colstrip and that the Sierra Club brags on its website that 286 coal plants are scheduled to be retired or already are retired and only 244 are left to go. Hines states that at this time NorthWestern has no plans to close Colstrip so it is premature to open a docket regarding its closure.¹⁶⁸

Staff Recommendation

Staff recommends the Commission decline to initiate a Colstrip investigation docket, nor require additional Colstrip reporting, nor require NorthWestern to commit to community transition funds at this time.

The Commission's earlier decision on the revenue requirement stipulation forecloses the Commission from addressing NorthWestern and intervenor arguments to amend Colstrip's rate base. This included both increasing Colstrip's rate base by NorthWestern's requested \$42 million in CU4 capital expenditures since 2008, and reducing Colstrip's rate base to MEIC/SC's estimated \$100 million current market value. The Commission decided it was unreasonable to address these issues for two reasons. First, because the revenue requirement settlement provided only an aggregate \$6.5 million total revenue requirement increase, it would be inappropriate to consider one specific generation-related rate base element in isolation from not only the various generation-specific revenue requirements (CU4, Dave Gates, Spion Kop, Hydro Assets, MT Generation, Non-PCCAM), but also the non-generation-specific revenue requirements (Transmission and Distribution, and Two Dot). Second, because the settlement language regarding the Colstrip rate base valuations is merely an agreement between the parties, the Commission determined no further action was required.

However, intervenor requests to establish an investigation docket regarding various Colstrip-related issues, to require NorthWestern to provide certain annual reports to the Commission, and to generally consider community transition funding, are all unresolved.

¹⁶⁷ Rebuttal Test. John Hines, at 17 (Apr. 5, 2019).

¹⁶⁸ *Id.*

As discussed below, although staff believes each issue has merit, staff recommends the Commission decline each request at this time.

There are at least two reasons why Commission action on any of these issues is prudent:

- The Commission lacks sufficient information on a variety of issues. NorthWestern's current depreciation schedule for CU4 is significantly longer than those currently in place for the remaining CU4 owners. As discussed above, the other unit 3 and 4 owners have depreciation schedules which are exhausted at latest by 2030. NorthWestern's current 2043 deadline (and with only a 30 percent ownership interest in one unit) casts significant doubt regarding the operation of Colstrip beyond 2027 or 2030. This operational concern supports Commission action on a variety of Colstrip-related issues. This risk is underscored by the fact that even though Puget Sound and Talen had previously agreed to retirement dates of 2022 for CU1 and CU2, in June of this year the companies announced retirement of both assets by 2020 due to unfavorable economics. This decreases confidence in even a 2027 or 2030 retirement date for the remaining generators. An investigation docket or annual reporting requirements could provide the Commission with valuable information regarding this significant operational risk. An investigation or additional reporting requirement would also inform important, insufficiently understood, Colstrip-related concerns, such as transition funding, potential remediation costs, allocation of liability, and future generation asset sales or purchases that could impact NorthWestern's CU4 ownership interest.
- Intergenerational inequity. Customer rates should reflect costs associated with utility plant that remains in service, and should limit costs for goods or services which are not. This ensures intergenerational equity: each generation of customers are charged for services based on the costs of the services they receive, as opposed to costs from preceding or succeeding generations. To do otherwise causes inequity: generations pay for goods or services that are either no longer in service (depreciation schedules extending beyond the operational life of an asset, or paying for cleanup costs from retired generation assets), or have yet to be placed in service (advancing funds used for large capital projects such as construction of new nuclear generation assets, which take several years or decades to finish).

There are at least two intergenerational equity issues presented. First, without Commission action, if CU4 closes earlier than 2043, customers would continue paying for NorthWestern's undepreciated CU4 rate base even though the asset is no longer in service. Given the large differences in depreciation schedules (2027 to 2043), and large net book rate base value (\$334 million as of Dec. 31, 2017), the customer impact could be substantial.

Second, without Commission action, succeeding generations could pay for cleanup costs associated with CU4 after the asset is no longer in service. NorthWestern has represented it is not presently recovering from customers any revenue for liabilities associated with CU4, and does not believe it necessary to do so until a retirement date has been established. This includes currently known liabilities (CU4 ash ponds), or potentially unknown liabilities. As the already known liabilities (\$400-\$700 million estimated liability between all owners) are substantial, yet NorthWestern is not recovering cleanup costs from current customers and with no firm CU4 retirement date, it is likely that customers will pay for cleanup costs after a CU4 retirement.

An investigation docket could mitigate these two intergenerational equity issues.

There are also at least three reasons why action is not prudent at this time:

- Actual remediation costs, apportionment of liability, and retirement dates are unknown. Although NorthWestern has established an ARO regarding its current coal ash pond liability for GAAP purposes, NorthWestern's exact liability is unknown. Additionally, there is no uniformly adopted retirement date for either CU3 or CU4. While the Commission could require NorthWestern to begin recovering in rates Colstrip-related remediation costs, not only would the amount of remediation costs be speculative, but so would the proper timing of rate recovery given the undetermined retirement date. The Commission also notes that this is a multi-jurisdictional issue, potentially involving not just various state agencies (DEQ and the Commission, for example), but also various federal agencies as well (the United States Environmental Protection Agency). This further supports delaying action on this issue for now.
- Additional remediation financing mechanisms are being developed. During the 2019 legislative session, the Legislature passed the Montana Energy Impact Assistance Act.¹⁶⁹ Generally, this bill allows utilities like NorthWestern to issue bonds to recover costs associated with retirement, replacement, or remediation of electric generation assets. The Commission is directed to adopt rules to implement this Act.¹⁷⁰ This mechanism could provide a viable alternative to traditional cost of service ratemaking to address any remediation and retirement costs associated with NorthWestern's ownership interests in CU4. It could be beneficial to delay a Commission investigation until after this rulemaking has concluded, to ensure the

¹⁶⁹ HB 467, *codified at* Mont. Code Ann. §§ 69-3-1601 through -1623.

¹⁷⁰ Mont. Code Ann. § 69-3-1604.

Commission has a broad range of available mechanisms to address Colstrip-related remediation and retirement costs.

Even though staff recommends the Commission decline to initiate a Colstrip investigation docket, staff notes that the Commission retains the authority to initiate a non-contested case proceeding (*see generally* Mont. Code Ann. §§ 69-3-102, -103, -106), or a contested case proceeding (Mont. Code Ann. §§ 69-3-324, -330) to investigate these issues when it determines it is necessary to do so. Staff also notes that interested parties also have the right to request the Commission to initiate an investigation into these concerns under Mont. Code Ann. § 69-321 at any time.

F. WAPA/FEA Proposal

Party Positions

FEA represents Malmstrom Air Force Base (“Malmstrom”) located near Great Falls, Montana. FEA proposed a new tariff, or similar option, to allow Malmstrom to benefit from less expensive electricity provided by federally owned hydroelectric resources within the Western Area Power Administration (“WAPA”) service territory.¹⁷¹

WAPA is a federal Power Marketing Administrator within the U.S. Department of Energy that markets and transmits wholesale electricity at cost to market participants, and is not a retail supplier of either bundled or unbundled retail supply.¹⁷² WAPA is authorized to provide power to governmental entities like Malmstrom under the Pick-Sloan Missouri Basin Program. This program allows WAPA to enter into interagency agreements similar to, though different from, power purchase agreements.¹⁷³ Under Pick-Sloan, the Air Force (Department of Defense) and WAPA (Department of Energy) have entered into a 1963 interagency agreement which provides the Air Force with a specific allotment of WAPA power, which is currently under-utilized.¹⁷⁴

WAPA is currently revising its power allocations, which will likely result in an interagency agreement between WAPA and the Air Force for WAPA power allocations lasting until 2050.¹⁷⁵ FEA represents Malmstrom could receive up to 5 MW of power per month,

¹⁷¹ As a preliminary matter, this issue is not precluded by the Revenue Requirement Stipulation approved earlier by the Commission. Am. Stip. ¶ 13 (“The Amended Stipulation does not resolve . . . FEA’s proposal concerning their allocation of hydropower from the Western Area Power Administration . . .”).

¹⁷² Test. Collins, at 2; Test. Radecki, at 3–4.

¹⁷³ Test. Radecki, at 2.

¹⁷⁴ *Id.*, at 2; Hr’g Tr., at 1128, 1132.

¹⁷⁵ Test. Radecki, at 4, discussing the 2021 Power Marketing Initiative; Collins Dir. Test, at 3; *see also* Test. Radecki, at 9; Hr’g Tr., at 1113; *but see* Hr’g Tr., at 1131 (stating allocation was extended through 2015; possibly a misstatement for 2050)

amounting to approximately 21,000 MWh of power annually, from WAPA's pool of resources.¹⁷⁶

To receive the benefits of this power, FEA initially proposed a new NorthWestern tariff credit. This mechanism would provide Malmstrom a reduction for WAPA power either received by Malmstrom, or by NorthWestern at the point of interconnection between NorthWestern and WAPA transmission systems.¹⁷⁷ The credit would be calculated by the rates for hydropower facilities in NorthWestern's QF-1 tariff, adjusted for line losses.¹⁷⁸ This credit would reduce Malmstrom's electricity bill under its services received under NorthWestern's GSEDS-2 (Delivery Service) and ESS-1 (Supply Service).¹⁷⁹ Because this 5 MW capacity is less than Malmstrom's current energy needs, it would continue to utilize NorthWestern for additional energy.¹⁸⁰ While Malmstrom would pay WAPA a commensurate amount for the NorthWestern bill credit, the wholesale-at-cost WAPA power could reduce Malmstrom's total electricity costs compared to continuing to receive its power entirely from NorthWestern.¹⁸¹ FEA unsuccessfully attempted to resolve this issue with NorthWestern prior to the general rate case.¹⁸²

During the hearing and in post-hearing briefing, FEA amended its initial proposal. Instead of a crediting mechanism based on the QF-1 tariff, or a similar analog, FEA proposes the Commission direct FEA and NorthWestern to negotiate the terms of an agreement in good faith and jointly submit, within 6 months of the date of the Commission's order, a negotiated financial crediting agreement establishing rates for review by the Commission.¹⁸³

Regardless the mechanism, FEA provides several policy arguments to support its receipt of WAPA power. The resource would benefit customers by providing needed capacity to NorthWestern's capacity deficient system which indicates a negative 28 percent planning

¹⁷⁶ Test. Collins, at 4; Hr'g Tr., at 1139 (indicating no specific resource would provide power to Malmstrom, rather power would be dispatched from WAPA's pool of resources).

¹⁷⁷ Test. Collins, at 7, Ex. BCC-1 (indicating a general credit for received power, but not indicating which entity actually received the WAPA power); *see also* Hines Dir., at 4 ("Under this proposal, Malmstrom would receive the financial benefit of the federal hydropower, even though there is no physical delivery of the hydropower to Malmstrom's meters."), *and* Hr'g Tr., at 1105 (indicating a lack of clarity on whether the credit applied to receipt of WAPA power by Malmstrom, or by NorthWestern).

¹⁷⁸ Test. Collins, at 5, 7.

¹⁷⁹ *Id.*, at 7.

¹⁸⁰ Hr'g Tr., at 1108 (indicating Malmstrom's peak load is near 8 MWs); Hines Dir., at 7.

¹⁸¹ Test. Collins, at 13.

¹⁸² *Id.*, at 10 (indicating Malmstrom participated in NorthWestern's 2018 capacity RFI, by offering the WAPA power allocation to NWE as a potential capacity resource).

¹⁸³ FEA Repl. Br., at 2.

reserve margin.¹⁸⁴ This is doubly-important, FEA argues, because NorthWestern has 220 MW of long-term PPA capacity (non-QF) expiring between 2020 and 2026.¹⁸⁵ Importantly this resource would only be available for Malmstrom, as federal law precludes its assignment to third-parties; NorthWestern would not be able to purchase and resell the power to its customers.¹⁸⁶ This tariff also would not be precedent setting, as WAPA power is only available to Malmstrom.¹⁸⁷ Even if precedential, the specific facts are narrow which would preclude replication because WAPA infrequently re-allocates rights to its resource pool (low potential for additional WAPA power recipients), and because there are no additional air force bases which could receive WAPA power.¹⁸⁸ Finally, even though the mechanism is not fully developed, the parties can negotiate a crediting arrangement to resolve any potential adverse impacts.¹⁸⁹

FEA also proposes several legal arguments to support its ability to receive power from WAPA. The proposal is legal under state law, as Malmstrom will not become a choice or dual-supply customer, because it will continue to remain a retail customer of NorthWestern, but will only receive a credit for WAPA power received either directly by Malmstrom, or by NorthWestern at the point of interconnection with WAPA.¹⁹⁰ Similarly, wholesale deliveries of federal hydropower were not contemplated by Montana's reintegration act, and should not be precluded.¹⁹¹ Even if the proposal is illegal under state law, state law could be preempted by the U.S. Constitution.¹⁹² Similarly, the proposal is legal under federal law.¹⁹³

The LCG supports the FEA's efforts to supply Malmstrom with WAPA Power.¹⁹⁴ LCG argues that "a solution can be forged which benefits the FEA, NorthWestern, and all of NorthWestern's customers."¹⁹⁵ While financial and operational details "remain to be negotiated," the Commission "should find it has the authority to approve the arrangement

¹⁸⁴ Test. Collins, at 9.

¹⁸⁵ *Id.*, at 9-10, Ex. BCC-2.

¹⁸⁶ *Id.*, at 11.

¹⁸⁷ FEA Resp. Br., at 6.

¹⁸⁸ *Id.*, at 7 ("The reassignment of WAPA hydropower to a federal preference customer is a rare occurrence.").

¹⁸⁹ *Id.*, at 8 ("NorthWestern's witness Hines admitted it will not be difficult to calculate and collect the full transmission and distribution, supply, and administrative costs from Malmstrom."), *citing* Hr'g Tr., at 2,526.

¹⁹⁰ *Id.*, at 3 ("FEA proposes a purely financial transaction that does not change its customer status or alter NorthWestern's sale and delivery of power to Malmstrom."); *see also Id.*, at 11-13.

¹⁹¹ *Id.*, at 10.

¹⁹² *Id.*, at 14, *citing U.S. v. California*, 921 F.3d 865 (9th Cir. 2019).

¹⁹³ *Id.*, at 8-10.

¹⁹⁴ LCG Resp. Br., at 22.

¹⁹⁵ *Id.*, at 23.

proposed by the FEA and encourage the FEA and NorthWestern to find a solution that will allow Malmstrom to utilize its allocation of WAPA Power.”¹⁹⁶

LCG disagrees that a WAPA power arrangement is illegal. LCG notes that Montana’s Electric Utility Industry Generation Reintegration Act does not preclude any customers from their own cogeneration or self-generation.¹⁹⁷ LCG argues: “Given Malmstrom’s unique position as a *Federal customer* of NorthWestern’s with rights to an allocation of *Federal hydropower* from WAPA, it is reasonable for the Commission to find that Malmstrom is effectively self-generating a portion of its power supply.”¹⁹⁸ It is immaterial, LCG notes, that the power would need to be transmitted across NorthWestern’s system, because energy consumption can be met by “remote self-supply, in which power is obtained from an affiliated, off-site facility.”¹⁹⁹ Similarly, the Commission has broad service classification and supervisory and regulatory powers over NorthWestern which would support the relief Malmstrom requests.²⁰⁰

Not only does LCG argue that the transaction is legal, LCG argues that the transaction would provide benefits to Montana: it would mitigate against NorthWestern’s capacity deficit, it would add low-cost resources to NorthWestern’s power supply portfolio, and “is simply good policy for all Americans.”²⁰¹

In contrast, NorthWestern responds that the FEA’s proposal is illegal.²⁰² Specifically, in 2007 the Montana Legislature passed House Bill 25 which deleted the specific language in Mont. Code Ann. § 69-8-201 that permitted public agencies to choose alternative default electric suppliers.²⁰³ The revised Mont. Code Ann. § 69-8-201(1)(c) prevents dual-supply power supply like FEA is proposing. Because NorthWestern argues the Commission is statutorily precluded from allowing FEA to procure electricity from WAPA, “Malmstrom’s remedy is with the Legislature, not the Commission.”²⁰⁴

NorthWestern is similarly concerned with the hypothetical nature of the transaction, regarding its under-developed contract terms, energy valuation, establishing precedent,

¹⁹⁶ *Id.*, at 25.

¹⁹⁷ *Id.*, at 23, *citing* Mont. Code Ann. § 69-8-201(3).

¹⁹⁸ *Id.*, at 23.

¹⁹⁹ *Id.*, at 23, *citing* *Calpine Corp. v. F.E.R.C.*, 702 F.3d 41, 42 (D.C. Cir. 2012).

²⁰⁰ *Id.*, at 24, *citing* Mont. Code Ann. §§ 69-3-306, -330(3).

²⁰¹ *Id.*, at 24 (among other things, indicating that “Reducing Malmstrom’s power supply costs supports military readiness by allowing the base to utilize more of its budget to fund military priorities.”).

²⁰² NorthWestern In. Br., at 39; Test. Hines, at 6–7.

²⁰³ *Id.*, *citing* Ex. NWE-57 (“A customer referred to in subsection (4)(a) that is a public agency, as defined in 18-1-101, may enter into a power supply contract with the default supplier for default supply service for all or part of the public agency’s load.”).

²⁰⁴ *Id.*, at 40.

and impact to customers.²⁰⁵ NorthWestern also argues that FEA is effectively requesting a declaratory ruling.²⁰⁶ Yet because FEA did not follow the Commission's rules for declaratory rulings, the record lacks sufficient facts to issue a declaratory ruling, and because several of FEA's argument were only presented in post-hearing briefing the request must be denied.²⁰⁷

Similarly, MCC argues that "Rather than attempting to adjudicate the legality and terms of a new special tariff for Malmstrom based on the limited record in this case, the Commission should recognize that further negotiations and a stand-alone proceeding will likely be necessary."²⁰⁸

Staff Recommendation

On one hand, staff does not support FEA's mechanism:

- It could be illegal, because it would allow Malmstrom, a current existing NorthWestern residential customer, to choose an alternative supplier, WAPA, which is precluded by Mont. Code Ann. § 69-8-201(1)(c).
- Even if legal (i.e., because the arrangement can be construed as "self-generation" under Mont. Code Ann. § 69-8-201(3)), it is unclear what "self-generation" requires for this crediting mechanism.
- It could establish undesirable precedent, because establishing a crediting mechanism for "self-generated" power—even though the power is generated off-site and needs to be transmitted to NorthWestern's system—could reasonably be extended to a variety of other entities like multi-campus university systems, large businesses with dozens of intra- and inter-state locations, and other state and federal agencies. The exception could reasonably consume the prohibition against dual-supply.
- Even if permitted, there are administrative burdens in requiring NorthWestern to schedule WAPA power for Malmstrom under any agreement which requires variable power transmission.²⁰⁹

On the other hand, staff supports the mechanism:

²⁰⁵ Test. Hines, at 7.

²⁰⁶ NorthWestern Repl. Br., at 56.

²⁰⁷ *Id.*, at 56.

²⁰⁸ MCC Resp. Br., at 28.

²⁰⁹ Hr'g Tr., at 2509.

- It could be legal under state law. Mont. Code Ann. § 69-8-201 does not apply to retail customer self-generation, and Malmstrom's proposal (a federal agency) is to receive power from WAPA (a federal agency), which could reasonably be construed as self-generation. Mont. Code Ann. § 69-8-201(3).²¹⁰
- It could be legal under federal law. Even if illegal under state law (neither permitted "self-generation" under Mont. Code Ann. § 69-8-201(3) and prohibited dual supply under Mont. Code Ann. § 69-2-201(1)(c)), Montana's statutes could be preempted by the U.S. Constitution. Either the Commission lacks the power to determine who Malmstrom receives power from (Enclave Clause, U.S. Const. Art. I, § 8, cl. 17), or because the Pick-Sloan program which authorized Malmstrom to receive power from WAPA preempts any conflicting state action (Supremacy Clause, U.S. Const. Art. VI, cl. 2).
- It would help mitigate NorthWestern's current and increasing system capacity deficit.

Staff determines that, while reasonable and an efficient off-the-shelf resolution to Malmstrom's request, NorthWestern's QF-1 tariff does not provide the best proxy for valuing any received WAPA power.²¹¹ Rather a more tailored solution is necessary. Yet there is insufficient evidence to establish a new NorthWestern tariff with FEA's proposed crediting mechanism. For example, the record lacks sufficient understanding of:

- The controlling interagency agreement terms and conditions between the Air Force and WAPA.²¹² This includes an understanding of the amount of power Malmstrom requires, the appropriate transmission routes and costs to transmit WAPA power to a NorthWestern interconnection point, whether Malmstrom would actually receive WAPA power, and any related agreement terms including contract length and opportunity for price adjustments if necessary.
- Relevant NorthWestern transmission and distribution costs for WAPA power, if any, from the point of NorthWestern interconnection to delivery to Malmstrom.²¹³

²¹⁰ *Id.*, at 1091 (FEA Opening Statement: "Fundamentally this is one part of the federal government moving a resource from one location in the Air Force to another location and transferring funds from one federal account to another federal account with this arrangement memorialized by a federal interagency agreement. . . . This is not a purchase of electricity supply service from another provider after 2007.").

²¹¹ *Id.*, at 1096.

²¹² Test. Collins, at 3.

²¹³ Test. Radecki, at 6

FEA asserts that WAPA power is a firm energy resource.²¹⁴ This could allow WAPA power recipients to designate the power as a network resource, qualifying for Network Integration Transmission service rates under most utility Open Access Transmission Tariffs.²¹⁵ FEA asserts that WAPA power can be utilized to meet resource adequacy requirements within the Midcontinent Independent System Operator, or as an energy or capacity resource within the Southwest Power Pool.²¹⁶ This could allow WAPA and NorthWestern to schedule, manage, and coordinate issues regarding the resource.²¹⁷ However the record evidence is lacking to justify these representations. Additionally, after receipt of the power onto NorthWestern's system, it is unclear what additional transmission or distribution costs could be incurred.

Accordingly, staff recommends the Commission decline to establish a new tariff mechanism in this proceeding. Rather staff recommends, consistent with FEA's amended advocacy, to direct FEA and NorthWestern to negotiate the details of a possible mechanism, and within three months from the date of the Commission's Order on Reconsideration, present the mechanism to the Commission for approval.²¹⁸ If the parties cannot negotiate an agreement, then staff recommends the Commission initiate a contested case proceeding under Mont. Code Ann. § 69-3-324, and resolve FEA's proposal under Mont. Code Ann. § 69-3-330. Importantly, this recommendation or a similar analogue was supported by MCC²¹⁹, and is consistent with NorthWestern's advocacy that "a stand-alone proceeding will likely be necessary to address FEA's request."²²⁰

However, to remove barriers to good-faith negotiation which could arise from the different interpretations between the parties on the legality of the proposal, staff recommends the Commission include language in its final decision indicating that, while not reaching the issue, the Commission does not believe there are substantive legal obstacles to FEA's proposal.

G. Hazard Tree Removal & Related Issues

The Commission is extremely cognizant of the wildfire nightmare which has unfolded in California over the last several years leading to disastrous loss of life and property. The

²¹⁴ *Id.*, at 8.

²¹⁵ *Id.*

²¹⁶ Hr'g Tr., at 1131.

²¹⁷ *Id.*; Test. Radecki, at 8.

²¹⁸ FEA Repl. Br., at 2.

²¹⁹ MCC Resp. Br., at 28 ("Rather than attempting to adjudicate the legality and terms of a new special tariff for Malmstrom based on the limited record in this case, the Commission should recognize that further negotiations and a stand-alone proceeding will likely be necessary.").

²²⁰ NorthWestern Repl., at 54.

Commission is concerned about how a wildfire involving utility equipment and hazard trees due to pine beetle kill could lead to a similar situation and associated risks to NorthWestern and its customers in Montana.

On January 29, 2019, Pacific Gas and Electric ("PG&E") filed for bankruptcy to deal with billions of dollars in wildfire liability. The following is from the January 14, 2019 New York Times:

"Fire investigators determined PG&E to be the cause of at least 17 of 21 major Northern California fires in 2017. It is also suspected in some of the 2018 wildfires that have been described as the worst in state history, including one that killed at least 86 people and destroyed the town of Paradise.

PG&E said it faced an estimated \$30 billion liability for damages from the two years of wildfires, a sum that would exceed its insurance and assets. The bankruptcy announcement, in a filing with federal regulators, led the company's shares to plunge more than 50 percent.

The shares had already lost almost two-thirds of their value since a wave of wildfires in early November, and its bond rating had been downgraded to junk status by two rating agencies."

The wildfires in California have led to catastrophic property losses and loss of life, and the bankruptcy of the largest utility in the state. To avoid that situation in Montana, NorthWestern witness Curtiss Pohl addressed the hazardous tree issue in his direct testimony. Pohl testified that the Mountain Pine Beetle ("MPB") infestation in Montana has impacted NorthWestern's system for quite some time. Pohl states that as part of its normal vegetation management program, NorthWestern routinely removes trees from within its rights-of-way. However, by 2016, NorthWestern realized that, given the sheer number of MPB-impacted trees found outside of its rights-of-way, NorthWestern needed to find a solution beyond the scope of its normal vegetation management plan to address this risk.²²¹

Party Positions

Pohl testifies that NorthWestern began working with the appropriate groups, including the U.S. Forest Service, to develop a plan to remove these hazard trees. NorthWestern identified approximately 1,030 miles of Transmission and Distribution lines as severely impacted by the MPB. NorthWestern determined that the only way to mitigate fire and reliability risk along these miles was to clear-cut all of the trees on either side of the electric lines that could hit the lines, if they fell. In most cases, this amounts to approximately 100 feet on either side of the lines or a 200-foot-wide corridor. Pohl states that normal rights-of-way vary, but are generally 20 feet to 40 feet wide on distribution lines and 40 feet to 100

²²¹ Test. Curtis Pohl 11-12 (Sep. 28, 2019).

feet wide on transmission lines. NorthWestern's plan to address these 1,030 miles was not finalized until the first quarter of 2018, and work started in April 2018. NorthWestern's initial plan is estimated to cost \$18.5 million and take three years to address the immediate concern of the 1,030 miles. However, NorthWestern expects to be dealing with this hazard tree issue for quite some time beyond that. The MBP, along with other infestations, will continue to affect more areas, and NorthWestern's vegetation management crews will need to make multiple trips through these areas to remove trees as they become hazard trees.²²² Pohl states this will be an ongoing effort until NorthWestern can clear-cut all of the hazard trees that threaten its lines.

NorthWestern has proposed a revenue requirement adjustment to include \$3.5 million annually for hazard tree removal to mitigate the potential for disastrous wildfires.²²³

On November 9, 2018, the MCC, the LCG, HRC/NRDC, and the MEIC/NWEC filed a Joint Motion of Approval of Stipulation and Settlement Agreement in Docket No. D2018.4.24. – Investigation of the Impact of the Tax Cuts and Jobs Act on the NorthWestern Energy Revenue Requirement - Page 5, Section e. states as follows:

In Docket No. D2018.2.12, Northwestern has proposed an expense adjustment of \$3.5 million in the test period for hazard tree removal, as a known and measurable change based on the total estimate 2018 spending. In Docket No. D2018.2.12, the Stipulating Parties other than Northwestern agree not to oppose an adjustment for known and measurable change equal to actual 2018 expenditures for hazard and tree removal not to exceed \$3.5 million.

In response to MCC-247, NorthWestern indicated its 2018 actual expenditures on hazard tree removal were \$3,190,879.

In addition to NorthWestern's proposed hazard tree removal expenditures, the Commission directed the parties to respond to five additional issues related to hazardous tree management. Importantly, the Commission asked NorthWestern if it is able to insure itself and ratepayers against the risk posed by wildfire liability.

Regarding insurance, NorthWestern states that it purchases a tower of liability insurance, currently totaling limits of \$300 million for all liability. NorthWestern's liability insurance includes coverage for wildfire liability. The total premium for that insurance is \$4,395,576 for the July 2018 to June 2019 policy period. NorthWestern's primary insurance carrier is AEGIS. Four excess carriers provide NorthWestern coverage over the limit that AEGIS insures. During the 2018 renewal, NorthWestern and AEGIS negotiated an endorsement that allows a depleted aggregate to be replenished for a pre-determined price. That is,

²²² *Id.*, at 16 (other hazardous infestations include Spruce Bud Worm or the Douglas Fir Beetle).

²²³ Test. Glenda Gibson, Ex. GJG-1, at 4 Column Q. (Sep. 28, 2019).

NorthWestern may elect to add a second wildfire limit, if there is a large loss. To Brian Bird's knowledge, NorthWestern is the only utility that has negotiated this additional coverage with AEGIS. In recent conversations, AEGIS representatives gave expressed caution about wildfire risks, but indicated that it is not reducing coverage at this time.²²⁴

Bird states that regarding the situation in California where Pacific Gas & Electric has said that it faces an estimated \$30 billion liability for two years of wildfires, NorthWestern considers additional liability insurance every year. However, with California fire losses, wildfire coverage has become less available and more expensive. As part of its insurance renewal process, which is just starting, NorthWestern represented it is going to pursue purchasing higher limits. Bird states that NorthWestern has already been notified that one of its excess carriers is reducing its offered limits for all utilities with wildfire risks. NorthWestern asserts that, given the losses in California, it may be difficult to continue to replace, much less increase, the limits that NorthWestern purchases for wildfire coverage.²²⁵

Staff Recommendation

No party to this docket has opposed expenditures for the Hazard Tree program. As described above, several parties in this docket are on the record as not opposing further spending not to exceed the actual amount spent in 2018.

The stipulated revenue requirement increase of \$6.5 million in this docket is a "black box" settlement. That is, there is no information available to the Commission regarding whether the final stipulated revenue requirement included any agreement regarding the Hazard Tree Program. The Commission is cognizant of NorthWestern's past efforts to address the hazard tree dangers in its service territory and is also aware of the plans to continue those efforts in future years.

However, because of the significant importance of the Hazard Tree Program to both NorthWestern and the health and safety of Montana residents, staff recommends the Commission order NorthWestern to continue its Hazard Tree Program with minimum annual expenditures equal to the \$3.2 million spent in 2018. The Hazard Tree program is to be funded out of the revenue requirement approved by the Commission on Oct. 30, 2019, where NorthWestern was granted a \$6.5 million increase in its total revenue requirement. Staff also recommends the Commission order NorthWestern to present to the Commission, no later than 90 days after the issuance of the Final Order in this docket, the current status of its Hazard Tree Program and its future plans for 2020 and beyond. The Commission

²²⁴ Addl. Issues Test. Brian Bird 5-6 (Mar. 22, 2019).

²²⁵ *Id.*

should also order NorthWestern to file annual program progress updates, including annual expenditures, no later than January 31 of each year, beginning in 2021.

H. Two Dot Acquisition

Party Positions

In its initial Application, NorthWestern requested that the Commission authorize the inclusion of Two Dot Wind Farm in rate base and the proposed revenue requirement in base rates.²²⁶

Bleau LaFave presented testimony regarding the acquisition of the Two Dot Wind Farm. LaFave testifies that Two Dot is a wind farm located in Wheatland County, approximately six miles west of Harlowton, Montana. It consists of six General Electric ("GE") 1.6 megawatt ("MW") XLE turbines totaling, at the time of contracting, 9.72 MW of nameplate capacity. Two Dot connects directly to NorthWestern's transmission system and, prior to NorthWestern's purchase, sold its output to NorthWestern as a Qualifying Facility ("QF"). LaFave states that, prior to the purchase, NorthWestern has recovered its Two Dot costs by including them as QF power purchases in its electric tracker dockets.²²⁷

Since it began commercial operation on June 19, 2014, Two Dot has had a net Capacity Factor ("CF") of 36.82% or annual average production of 32,585 megawatt-hours ("MWh"). GE has maintained the turbines through a Facilities Maintenance Agreement. NorthWestern is not aware of any issues related to Two Dot's operations and maintenance history.²²⁸

Regarding NorthWestern's contractual obligations for the purchase of power from Two Dot,

NorthWestern executed the original PPA on August 19, 2011, which included a commercial operation date ("COD") of December 31, 2012, with a 25-year term following the COD, at a rate of \$59.00 per MWh. This rate was based on the rate that existed, at the time, in the Commission approved rate set forth in NorthWestern's Electric Tariff, Schedule QF-1.

On January 2, 2013, NorthWestern executed an amendment to the original PPA, changing the COD to December 31, 2013, and adding a 16 provision giving NorthWestern a Right of First Refusal ("ROFR"). The ROFR provision required the seller to offer to sell Two Dot to NorthWestern under the same terms and conditions as offered by a third party buyer before it could sell the facility to the third-party buyer.

²²⁶ NorthWestern App., at 5 (Sept. 28, 2018)

²²⁷ Test. Bleau Lafave, at 2 (Sept. 28, 2018).

²²⁸ *Id.*, at 3.

On May 16, 2014, NorthWestern executed another amendment to the original PPA. Two Dot requested the second amendment to transition from the original rate of \$59 per MWh to an equivalent tiered rate of \$49 per MWh for the first ten years of the PPA and \$75.78 per MWh for the remaining 15 years. The second amendment also changed the seller's information to reference NJR Clean Energy Ventures II Corporation ("NJR").²²⁹

On November 27, 2017, NJR notified NorthWestern that the ROFR provision in the PPA had been triggered and that NorthWestern had 30 days, or until December 27, 2017, in which to either accept or decline to buy Two Dot at the purchase price of \$18.5 million.

LaFave explained, in analyzing the purchase, NorthWestern modeled the costs and benefits of NorthWestern owning Two Dot versus continuing with the PPA purchases, with a specific focus on comparing the costs of ownership versus the cost of the remaining payments NorthWestern was legally obligated to make under the PPA. In addition, NorthWestern conducted due diligence on the facilities that included review of environmental issues, operational issues, land and easements, technology, regulatory matters, and other potential contractual obligations. The results of the purchase evaluation were that the purchase had benefits for both customers and NorthWestern. Based on that evaluation, on January 5, 2018, after a one-week extension due to the holiday season, NorthWestern notified NJR that it accepted the offer to purchase Two Dot for \$18,541,706, or \$1,907,582 per MW.

LaFave testifies that NorthWestern received FERC's approval for the purchase in May 2018 and the purchase closed on May 31, 2018. NorthWestern took operational control on June 1, 2018, and then rolled the asset into its parent company, NorthWestern Corporation. Since June 1, 2018, Two Dot has operated as expected and NorthWestern has not experienced any issues and the facility is producing similar to previous years.²³⁰

After the purchase was complete, NorthWestern requested, and the Commission approved, recovery of the costs of owning Two Dot on an interim basis in its annual electricity supply tracker in Docket No. 2017.07.057, Interim Order No. 7606. The interim bridge rate is equal to the QF PPA rate of \$49.00 per MWh for the output of Two Dot until a new rate is established in this case. NorthWestern proposed that if the new approved rate is lower than \$49.00 per MWh, the interim rate be trued-up to the approved rate and the over-collection refunded to customers; if the approved rate is higher than \$49.00 per MWh, the interim rate be approved as final.²³¹

²²⁹ *Id.*, at 4.

²³⁰ *Id.*, at 10

²³¹ Test. Bleau LaFave, at 15 (Sept. 28, 2018).

The Two Dot revenue requirement is \$2.7 million or 1.1% of the total Generation Stipulated Revenue requirement of \$250.0 million.²³²

Staff Recommendation

No party to this docket contested the inclusion of Two Dot in rate base or the revenue requirement in base rates. The overall impact of the purchase has been simply to move Two Dot costs in the monthly electric supply tracker from QF costs, to Two Dot fixed costs with no overall change in rates or customer impact. The change in the total electric utility revenue requested by NorthWestern was an increase of \$30,701,661. The revenue requirement filed for Two Dot shows a required reduction in its total revenue requirement of (\$4,656), or a *de minimis* change.²³³ Staff recommends approving the NorthWestern request to include Two Dot wind in rate base and its revenue requirement in base rates. The \$6.5 million stipulated revenue requirement increase approved in this docket is found to reflect the ordered treatment of the Two Dot Wind Farm.

Additionally, NorthWestern requested a fixed revenue requirement for Two Dot of \$2,732,522 and variable rate Production Tax Credits (“PTCs”) of \$1,706,359 for a net revenue requirement of \$1,706,359.²³⁴ Dividing the net revenue requirement by the annual production of 32,585 MWh equals a Two Dot rate \$52.37 per MWh. Per the testimony of Mr. LaFave, because the \$52.37 is higher than the interim bridge rate of \$49.00 per MWh, staff recommends the interim bridge rate approved in Interim Order 7606 should be approved as final.

I. Jurisdictional Cost of Service Study and FERC Transmission Revenue Credits

Party Positions

NorthWestern proposed to continue the current practice of crediting residential customers for its share of NorthWestern’s Montana transmission system costs (plant and expenses), which the Commission has required for the last ten years.²³⁵

This credit is determined by a two-step process. First, NorthWestern separately includes 100 percent of its Montana transmission costs (plant and expenses) in both its revenue requirement set by FERC for wholesale customers, as well as its revenue requirement set by

²³² Rebuttal Test. Glenda Gibson, at Exh. GJG-6 (Apr. 5, 2019).

²³³ *Id.*, at Exh. GJG-7.

²³⁴ *Ibid.* 14

²³⁵ Ex. NWE-16, p. 17; NorthWestern In. Br., at 35 (Jul. 10, 2019) (“For at least ten years, NorthWestern’s retail customers have been credited for transmission revenues that NorthWestern receives from its wholesale customers. The Commission accepted this crediting mechanism in both Docket No. D2007.7.82 and Docket No. D2009.9.129.”).

this Commission.²³⁶ FERC determines the appropriate portion of that amount that should be recovered from NorthWestern's FERC-jurisdictional wholesale customers. Second, the amount allocated by FERC to wholesale customers is then credited towards NorthWestern's Commission-jurisdictional retail customers in its revenue requirement in this case. Thus, 100 percent of transmission costs are included in the jurisdictional revenue requirement, and the normalized revenue generated by FERC OATT customers in the test year is included as a revenue credit that reduces retail customer rates.²³⁷

FERC's cost-allocation therefore functions as a *de facto* determination of the retail customer share of NorthWestern's transmission costs. NorthWestern asserts this method most fairly assigns costs to the appropriate customer class, while ensuring that the utility recovers all of its costs. Since both wholesale and retail customers use the transmission system, both customer classes should pay their appropriate share of the costs.²³⁸ No party in this docket disputed the revenue crediting methodology proposed by NorthWestern.

NorthWestern filed a transmission revenue requirement application with the FERC on May 1, 2019.²³⁹ The FERC credit filed in this docket is approximately \$54 million.²⁴⁰ NorthWestern states that once FERC issues a final order in response to NorthWestern's application, NWE proposes to true-up the revenue credit in this proceeding, effective upon the rate-effective date established in the FERC final order. NorthWestern would apply the updated FERC rates to the transmission volumes that were the basis for the normalized revenue credits in this proceeding.²⁴¹ A final order from FERC is not expected until sometime near June 2020.

In contrast to the NorthWestern's advocacy, MCC proposes the Commission order NorthWestern to conduct a jurisdictional cost of service study which allocates transmission costs among FERC-jurisdictional wholesale customers and retail customers independent from FERC methodology. MCC points out that efforts to more appropriately allocate costs between wholesale and retail customers have been made in a number of instances and will continue to be an issue moving forward. It notes that the Commission has previously found that "[p]roper allocation between jurisdictions is necessary to ensure that ratepayers are paying for their fair share of costs."²⁴² It further notes that, rather than rely on FERC to set wholesale rates (and by implication set retail rates as well), the Commission has an independent duty to determine transmission costs properly attributable to retail

²³⁶ *Id.*

²³⁷ Test. Michael Cashell, at 17 (Sept. 28, 2018).

²³⁸ *Id.*, at 18.

²³⁹ FERC Docket Nos. ER 19-1756-000, EL 18-104-000

²⁴⁰ Rebuttal Test. Glenda Gibson, at Exh. GJG-6 (Apr. 5, 2019).

²⁴¹ Test. Michael Cashell, at 17, 20 (Sept. 28, 2018).

²⁴² MCC Resp. Br., at 27 (Jul. 31, 2019) citing *In re: Mont. Power Co.*, Docket No. 88.6.15, Order No. 5360d, ¶ 479 (1989).

ratepayers.²⁴³ MCC acknowledges that the objective of a jurisdictional cost of service study would not be complete assurance of cost recovery for NorthWestern, but rather proper allocation of costs between jurisdictions. It also appears that the MCC does not advocate for implementation of any results of the cost of service study in this matter, but rather in NorthWestern's next general rate case.

In response, NorthWestern contends that the current system "most fairly assigns costs to the cost-causer while ensuring that the utility recovers all of its costs."²⁴⁴ It notes that no party has advocated for application, in this case, of an allocation methodology different from the status quo. Moreover, it notes that MCC's own witness testified that he did not suggest a change in this case.²⁴⁵ Further NorthWestern pointed out that Dismukes, MCC's witness, did not necessarily even recommend that the Commission mandate that the study results be applied in future cases.²⁴⁶

NorthWestern argues that the current methodology will likely benefit retail customers in that the rate proposed in the current FERC filing is "about 55 percent higher" than the current rate.²⁴⁷ Cashell testified that NorthWestern's investment in transmission has gone up substantially and therefore the revenue requirement will see a corresponding increase, which, in turn increases the revenue requirement credit to retail customers.²⁴⁸

NorthWestern points out that Dismukes conceded that, in theory, the current methodology should resolve any jurisdictional cost issues.²⁴⁹

NorthWestern also points out that there will be an expense to conduct a jurisdictional cost of service study, which would properly be included in customer rates.²⁵⁰ Thus, according to NorthWestern, the value of such a study is questionable when the MCC has fallen short of advocating for implementation of the study results. NorthWestern also argues that the study could result in increased costs being shifted to retail customers, or a scenario where NorthWestern either over- or under-recovers in instances where FERC and the Commission reach different conclusions as to allocation.

²⁴³ *Id.*

²⁴⁴ *Id.*, at 18.

²⁴⁵ NorthWestern In. Br., at 36 *citing* Hr'g Tr. 2152:25-2153:1.

²⁴⁶ *Id. citing* Hr'g Tr. 2180:23-2181:7.

²⁴⁷ *Id.*, at 37 *citing* Hr'g Tr. 626:13-21

²⁴⁸ *Id.*, at 36-37 *citing* Hr'g Tr. 591:20-24.

²⁴⁹ *Id.*, at 38 *citing* Hr'g Tr. 2174:7-12.

²⁵⁰ *Id.*, at 36 *citing* Hr'g Tr. 2181:14-24.

Staff Recommendation

Staff recommends the Commission maintain its current practice of crediting residential customers in NorthWestern's revenue requirement based on the FERC-approved methodologies.

Preserving this status quo most closely assures full transmission cost recovery for NorthWestern. If the Commission simply defers to FERC, barring subsequent divergent conclusions by FERC and the Commission as to the amount of transmission costs to be recovered from either customer class, the two revenue requirements assure recovery of all NorthWestern transmission-related costs.

However, if the Commission were to engage in a jurisdictional cost of service study and conclude that retail customers should recover more than what is credited from wholesale customers, then without subsequent FERC action to adjust its recovery from wholesale customers NorthWestern would under-recover its transmission-related expenses

In contrast, rather than guarantee complete recovery by NorthWestern, the proposal advanced by the MCC could result in greater accuracy when determining the amount of transmission costs which are caused by customers who fall within the jurisdiction of the Commission. However, severing the Commission's conclusion on this issue from that of FERC could result in NorthWestern either failing to recover (or recovering an amount greater than) its total transmission costs. In deciding this issue, the Commission must balance the interests of the utility in assuring complete recovery of transmission costs, against those of retail customers within the Commission's jurisdiction in accurately determining their allocation of transmission costs.

While the MCC is correct that the Commission's current methodology for allocating transmission costs to retail customers does rely in large part on FERC's allocation to wholesale customers which could be substantially in error, it does not point to any evidence, nor does it appear to contend that such an approach is unreasonable or that there are fundamental flaws in the manner FERC allocates transmission costs to wholesale customers. Rather, it appears the MCC's contention is that hypothetically, a jurisdictional cost of service study will allow the Commission to accurately and independently identify the share of transmission costs which should be allocated to retail customers.

Staff is concerned that, while attractive in theory, adoption of the MCC's approach may create more problems than solutions. For instance, it does not appear that the MCC has expressly advocated for implementation of the results of the proposed study in this or any future Commission proceeding. The prospect of committing resources—which will ultimately be the burden of retail ratepayers—to a cost of service study without the promise of any tangible benefit is problematic, particularly when the MCC has not pointed to any concrete flaw in the FERC's allocation methodology. Additionally, if FERC and the

Commission were to conduct their own independent analysis on this issue, it is entirely conceivable that each body will reach different conclusions as to appropriate allocations of transmission expenses. Ultimately, at this point, the benefits to be achieved by a jurisdictional cost of service study do not appear to outweigh the risks to all parties involved. Staff recommends the Commission reject the MCC's proposal in favor of the methodology currently in place.

However, staff recognizes the merit of the MCC's argument and therefore recommends that the Commission encourage the MCC to pursue its proposal in subsequent proceedings if it becomes aware of fundamental problems with FERC's methodology.

Finally, NorthWestern has committed to filing a true-up to the revenue credit in this proceeding upon issuance of a final order by the FERC. Staff recommends the Commission require NorthWestern to file this true-up with the Commission within 30 days of a final order from FERC.

J. NorthWestern's ELDS-1 Tariff & Related Street-Lighting Issues

Party Positions

Paul Normand, a Principal of Management Applications Consulting, Inc., filed testimony on additional issue no. 4, regarding street lighting. He explains how each of the rate components of the Lighting rate class were designed to achieve the proposed moderated base rate revenues. He states that in the accounting cost of service study (the ECOS), the Lighting Class in total was producing a higher rate of return – 6.80% compared to the total Company rate of return of 6.43%. Similar to the other rate classes producing a higher rate of return than the total Company rate of return, the Lighting Class's base rate increase was set at 4.02% for the total of all of the Lighting subclasses. The following are the Lighting subclasses:

- Light Non Choice Company Owned
- Light Non Choice Customer Owned
- Light Choice Company Owned
- Light Choice Customer Owned
- Light Metered Non Choice Customer Owned
- Light Metered Choice Customer Owned

Normand describes how the generation and generation property tax costs were determined for the lighting subclasses, and he states that the base rates (excluding property taxes) for each of the lighting rate components—billing, maintenance, operations, billed meter, and

ownership—were established uniformly for all subclasses by applying the base rate increase of 4.02% to present rates.

Normand states that the distribution base rate was calculated by subtracting all of the previously calculated proposed component revenues from the total proposed revenue target for the lighting class.

Normand explains that the generation costs for Non-Choice customers, the base rate, and property tax rates were set the same for all of the subclasses at a level to recover the Total Lighting base generation costs and generation property tax costs produced in the ECOS. The same procedure was performed in setting rates for all Non-Choice subclasses to recover the total Lighting ECOS costs for Two Dot base and their property tax costs and Transmission base and property tax costs. A uniform property tax rate was calculated for Distribution Choice and Non Choice based on the derived property tax levels from the ECOS results. The witness discusses the proposed rates for base distribution costs below.

Property tax rates for these separate rate components—Billing, Maintenance, Operations, Billed Meter, and Ownership Charge—were determined by spreading the ECOS costs based on present revenue levels.

Base rates (excluding property taxes) for each rate component—Billing, Maintenance, Operations, Billed Meter, and Ownership—were established uniformly for all subclasses by applying the base rate increase of 4.02% to present rates.

The Distribution base rate was then calculated by subtracting all of the previously calculated proposed component revenues noted above from the total proposed revenue target for the Lighting class.²⁵¹

In their pre-hearing memo, the Barsantis present several relevant contested issues:²⁵²

- Is the ownership charge in NorthWestern’s ELDS-1 tariff unreasonable or unjustly discriminatory?
- Should NorthWestern normalize the revenue requirements for street lighting customer classes to include known changes by 2020 resulting from the transition to LED street lighting?

²⁵¹ Addl. Issues Test. Paul Normand, at 1-3 (Mar. 22, 2019).

²⁵² In Mr. Doty’s pre-filed testimony (Test. Doty, at 18–19), he requested the Commission conduct an emergency rulemaking proceeding to address a variety of issues. Given that Mr. Doty’s testimony was not accepted into evidence, staff recommends the Commission decline to address this emergency rulemaking.

- Should NorthWestern be required to reduce its rate base for any high pressure sodium street lights removed from service after transitioning infrastructure to LED technology?
- Is NorthWestern recovering more than its original cost of its street lighting infrastructure, contrary to Mont. Code Ann. § 69-3-109, and if so subject to penalty under Montana's False Claims Act?
- Was the Commission's prior approval of ELDS-1 an illegal act?²⁵³

Staff Recommendation

Neither the Barsantis nor NorthWestern submitted post-hearing briefing on the Barsantis' contested issues. The Commission has already considered the Barsantis' arguments regarding whether the ownership charge is unreasonable or unjustly discriminatory, and whether NorthWestern is recovering more than its original cost of its street lighting infrastructure. *In re Gruba Complaint*, Dkt. D2010.2.14, Order 7084aa ¶¶ 33–60 (Feb. 15, 2019). Evidence in this docket does not merit revisiting either of these issues

Staff recommends the Commission decline to address the Barsantis' concerns regarding LED street lighting because the current rate case being discussed uses a historic test period of 2018. The LED replacement pilot project began in 2019, and is still in the early pilot phase. Further, no party provided substantial evidence supporting a rate base adjustment for a known and measurable change pursuant to Mont. Admin. R. 38.5.106 for the LED replacement project. Staff believes that any LED discussion is outside the scope of this docket.

With regard to the adjustment of charges within the lighting class, the staff recommends that the Commission direct NorthWestern to file a lighting tariff that:

- is based on the lighting class revenue requirement for base rate revenues resulting from NorthWestern's ECOS study, adjusted to reflect the Commission-approved stipulation on revenue requirement;
- adjusts all lighting class rate base rate charges uniformly by applying the change between the current class revenue requirement and the stipulation-derived class revenue requirement;
- adjusts the property tax component of the ownership charges by applying the change in the ownership charge's property tax allocation in the lighting class uniformly to all ownership rate charges.

²⁵³ Barsanti Pre-Hearing Memoranda.

K. Elimination of Spion Kop Annual Compliance Filing*Party Position*

NorthWestern requested the following:

When the Commission approved NorthWestern's acquisition of the Spion Kop Wind Project ("Spion"), it expressed concern about the risk of Spion under-performing relative to expectations and the limited site-specific wind speed data. In ¶ 132 of Order No. 71591 in Docket No. D2011.5.41, the Commission required NorthWestern to "to file annual compliance filings showing Spion Kop's net capacity factor and total energy output" and required a rate adjustment if, at the end of three years, Spion's average annual total energy output was less than 118,000 megawatt-hours ("MWh"). At the end of three years, Spion's average annual total energy output was 136,565 MWh. NorthWestern has submitted compliance filings showing that Spion produced 139,970 MWh, 143,192 MWh, 126,532 MWh, 130,070 MWh, and 131,819 MWh for the 12-month December through November reporting periods ending November 30 of 2013, 2014, 2015, 2016, and 2017 respectively. Spion's historical production has demonstrated that it has not under-performed expectations. NorthWestern requests that the Commission eliminate NorthWestern's obligation to make future annual compliance filings.²⁵⁴

Staff Recommendation

NorthWestern has made the required annual compliance filings since November 12, 2012. No party to this docket has voiced any opposition to the elimination of the compliance filings and staff also has no objection. Therefore, staff recommends the Commission eliminate the Spion Kop Annual Compliance Filing as ordered in Commission Order No. 71591.

L. After-Hours Reconnection Charge*Party Positions*

NorthWestern proposes to revise its tariff rules to reflect a fee to reconnect electric service after business hours. If approved, Tariff 5-11 would authorize NorthWestern to assess a fee of \$150 to a customer choosing to reconnect electrical service outside of business hours (Monday through Friday from 7:30 am to 5 pm).²⁵⁵

²⁵⁴ NorthWestern App., at 6 (Sept. 28, 2019).

²⁵⁵ Test. Bobbi Schroepfel, at 18 (Sept. 28, 2018).

NorthWestern witness Bobbi Schroepfel explains the proposed after-hours fee appropriately assesses the additional cost associated with sending personnel to reconnect services after hours.²⁵⁶ Schroepfel asserts that NorthWestern provides customers multiple opportunities to help them avoid needing an after-hours disconnect.²⁵⁷ She states that due to union contracts, the employee incurs a minimum of two hours of overtime for an after-hours call out and that overtime rate for two hours is the rate being proposed of \$150. A rate of \$150 per after-hours reconnection, multiplied by an average of 2,520 after-hour reconnections, would result in direct costs of \$378,000 per year, on average. The Reconnect Charge is designed to recover those direct costs from the customers that cause the costs to be incurred.²⁵⁸

Schroepfel further testified that NorthWestern's proposed reconnection charge proposal is consistent with other public utilities' after-hours fees in Montana. Specifically, she cites Montana Dakota Utilities, Fall River Electric Cooperative, Fergus Electric Cooperative Missoula Electric Cooperative, and McCone Electric Cooperative as all having similar charges.²⁵⁹

David Dismukes, testifying on behalf of the MCC, states that NorthWestern, beyond its statements concerning its practice of handling arrearages, provides no explanation on its current motivations for seeking the proposed tariff change. NorthWestern merely states that it feels it is "appropriate" to assess an after-hour reconnect fee given all of the opportunities it provides its customers with help to avoid needing an after-hours reconnect.²⁶⁰

Dismukes further states that NorthWestern shows that after-hours reconnection requests have remained steady over the past five years, and that 2018 saw NorthWestern's lowest reported number of after-hours service reconnections in the past five years, just 1,461. Furthermore, Dismukes asserts the Commission should recognize the small percentage of reconnection requests that are placed after-hours currently. Over the past five years, there have been an average of 2,520 after-hours requests annually. During the same period, NorthWestern has averaged 13,879 total service connections annually. This means that after-hours reconnection requests account for less than 18.2% of all reconnection requests. In 2018, after hours requests accounted for slightly more than 10.6% of all reconnection requests.²⁶¹

²⁵⁶ *Id.*

²⁵⁷ *Id.*

²⁵⁸ Rebuttal Test. Bobbi Schroepfel, at 10 (Apr. 5, 2019).

²⁵⁹ *Id.*, at 11-13.

²⁶⁰ Test. David Dismukes, at 64 (Febr. 12, 2019).

²⁶¹ *Id.*

Dismukes recommends that the Commission reject the proposed \$150 reconnection charge. He argues the proposal is a solution in search of a problem. After-hours reconnections are a small fraction of total service reconnection requests, and there is no noticeable trend in the occurrence of such requests. In short, there is no evidence that suggests that after-hours reconnection requests are anymore of a problem now than in past years wherein the Company operated without such a fee, with little incident.²⁶²

NorthWestern witness Joseph Janhunen provided information for 2017, stating revenue collections for after-hour reconnects were approximately \$49,000. However, he could not state how many actual after-hours reconnects were performed. He indicated the 2017 figure is similar to, but slightly higher than, prior years. This revenue of \$49,000 was included in the revenue requirement NorthWestern filed in its application.²⁶³

MCC does not believe a reconnect fee is necessary and would simply add to NorthWestern revenues. Dismukes also states the stipulation was accepted without certainty as to the reconnection fee.²⁶⁴ When asked if NorthWestern does not charge an after-hours reconnect fee to the customers requesting that service, would all customers pay for those expenses, Dismukes responded, "That's correct." He states their objection has less to do with the philosophy of charging customers, but rather feels the rate is arbitrary and unsupported.²⁶⁵

Staff Recommendation

Staff recommends NorthWestern's proposal to place in tariff a charge for after-hour reconnects be approved. The hearing testimony of NorthWestern witness Janhunen indicates that NorthWestern is currently charging customers for after-hour reconnects as indicated by the \$49,000 in 2017 revenues. However, because the revenue was only \$49,000, it is not clear how many customers were charged, or the rate they charged. Currently, if not all after-hour reconnect customers are charged a reconnect fee, then the direct costs associated with those reconnects are being paid for by the general body of ratepayers, not the customers that caused the cost to be incurred. For that reason, staff believes the charge is appropriate and fair. In addition, the charge is consistent with other electric utilities in Montana. Finally, Staff does not agree with the argument by the MCC that after-hours reconnections are a small fraction of service reconnections. Looking at the 5-year average, almost one in five reconnections were after hours.

²⁶² *Id.*, at 65

²⁶³ Hr'g Tr., at 1056-1060 (May 17, 2019).

²⁶⁴ *Id.*, at 2154 (May 23, 2019).

²⁶⁵ *Id.*, at 2176-2177 (May 23, 2019).

M. Tariff Revisions*Party Positions*

NorthWestern proposes to make changes to tariff Rule Nos. 1, 3, 5, 6, 27, 8, and 13.

NorthWestern provided red-lined versions of the proposed tariff revision. A description of the proposed changes for each of these tariff rules follows.²⁶⁶

Rule No.1

NorthWestern proposes to add a definition for “Loads of Uncertain Duration” at paragraph 1-6 for clarification purposes and to coordinate with changes proposed in tariff Rule No. 5 as discussed below.

Rule No. 3

The proposed changes to paragraph 3-1 acknowledge that there are instances when the utility requires a service agreement (a new service, for example) and instances when it does not (activating an existing service, for example), and clarifies customers’ obligations.

Rule No. 5 (excluding Rule No. 5-11 discussed above)

The first proposed change in paragraph 5-2 is for clarification. The second change in that paragraph is to clarify who owns the easement and it reflects current practice. The first proposed change in paragraph 5-3 is for clarification, acknowledges that a service agreement is not always required, and is consistent with the proposed change to paragraph 3-1 in Rule No. 3, explained above. The change proposed at the bottom of paragraph 5-3 adds a cross-reference to related provisions in paragraph 8-2 B in Rule No. 8. NorthWestern proposes to delete paragraph 5-4 C because it is obsolete. The proposed changes to paragraph 5-6 E are for clarification purposes. The changes proposed in the title of section 5-7 and first part of paragraph 5-5 coordinate with the definition of “Loads of Uncertain Duration” proposed on Rule No. 1 as discussed above. The change at the bottom of the paragraph specifies that proposed new paragraph 5-11 applies to Loads of Uncertain Duration. The changes to paragraph 5-7 B are for clarification purposes. The change in paragraph 5-9 B.1.a. is for clarification purposes and reflects NorthWestern’s current practice. The remaining changes in paragraph 5-9 are for clarification purposes.

Rule No. 6

NorthWestern proposes to adjust the residential line extension allowance in paragraph 6-1 A from the current flat rate of \$500 to \$400. This allowance is based on multiplying the applicable proposed base transmission and distribution rates by the average annual

²⁶⁶ Test. Schwartzenberger, at 23-28 (Sept. 28, 2019).

residential customer energy usage.²⁶⁷ In sections 6-1 B 1 and 2, the tariff requires that the extension allowances for the General Service and Irrigation demand and non-demand customers be determined by multiplying the applicable allowance rates (specified in the tariff) by NorthWestern's estimate of the annual kWh consumption of the customer. The proposed allowance rates are also computed on Exhibit__ (JS3 6). For the non-demand classes, the applicable transmission and distribution revenues are totaled and divided by the total load for those classes. The resulting proposed non-demand General Service and Irrigation allowance rate is \$0.05 shown at line 30, Column B in Exhibit__ (JS-6). The current rate is \$0.04. The computation for the demand classes is the same. As shown at 8 line 31, Column B, the proposed demand General Service and Irrigation allowance rate is \$0.04, the same as the current rate for these customers. Recognition of one year of revenues as an allowance against line extension costs for these General Service and Irrigation customers is consistent with the treatment of Residential customers. The proposed addition at the end of section 6-2 and new section 6-14 reflect Senate Bill 374 passed by the 2017 Legislature and codified in §§ 69-17 5-121, 69-5-122(4)(c), and 69-5-123, MCA. The addition to the second paragraph under section 6-6 A is for purposes of clarification. The update to the hourly rate in section 6-6 D is the Supervisor/Engineer hourly rate included in NorthWestern's 2018 Movement of Structures Cost Schedule submitted in Docket No. N2018.1.3. NorthWestern engineers develop the estimates for line extensions.

Rule No. 7

There are two proposed changes. The first corrects the code title in the last line of section 7-1. NorthWestern proposes the change to section 7-4 A to update a very specific dated lighting-related power factor requirement to a more broad-based current practice power factor requirement. In the early days of inefficient ballast type fluorescent lighting, tariff language specifying a minimum power factor of 90% ensured that customer lighting equipment would perform to the common minimum acceptable power factor of 90%. This proposed change replaces the specific lighting performance requirement with a general customer equipment requirement to operate above 90% power factor, which is still considered the common minimum acceptable level at or above which supplemental power factor correction methods are not required.

Rule No. 8

The proposed changes are minor corrections and clarifications.

Rule No. 13

NorthWestern proposes to update section 13-11 to reflect Administrative Rule of Montana ("ARM") 38.5.1411. The ARM was substantially revised by the Commission in 2010.

²⁶⁷ Refer to Exhibit__ (JS-6), line 29, Column B.

NorthWestern has not filed an update to Rule No. 13 to reflect the Commission-approved ARM. This was unintentional. NorthWestern's practice has, however, been compliant with the revised rule. The proposed change to paragraph 13-16 is necessary so that NorthWestern is able to comply with the first part of the rule, which requires the Utility to determine if a tenant occupies the residence. Finally, NorthWestern proposes to update the NorthWestern logo on all sheets of Rule No. 13.

Staff Recommendation

The revisions to tariff Rules Nos. 1, 3, 5, 6, 2 7, 8, and 13 described above were uncontested in this docket. No party to this docket filed testimony regarding the proposed changes. Staff has evaluated the proposed tariff revisions and recommends approval.

IV. Appendix

A. Appendix A: FCRM Proposed Performance Metrics

Proposed Customer Service and Reliability Metrics Customer Care and Billing Metrics:

Customer Care and Billing Metrics:

- Customer Complaint Rate: No more than 0.8 complaints/inquiries per 1,000 customers (as filed with MT PSC).
- Customer Complaint Response: NorthWestern will respond to the MT PSC and/or attempt to directly engage customers (i.e., contact in order to attempt to resolve the matter) that file complaints or make inquiries within 3 business days after receiving the complaint/inquiry. If first contact does not result in successful engagement with a customer, NorthWestern will attempt to engage at least once more within the three days. NorthWestern is to achieve a 90% adherence of this metric.
- Call Abandonment Rate: NorthWestern will maintain an annual abandon rate of less than 5% inbound customer interactions during core business hours. An abandon interaction is defined as a customer that opted to speak with an agent of NorthWestern, and the customer, after waiting 30 seconds or longer, ends the interaction prior to speaking with an agent. Customer interactions that result in a customer terminating a call under 30 seconds are not considered abandons. Core business hours are 7:00 am to 6:00 pm, Monday to Friday (excluding holidays).
- Percentage of Meters Read: NorthWestern will achieve an annual average of at least 96% of total meter reads based on actual meter reads. Percentage of Meters Read measures the percentage of actual meter reads as opposed to estimated meter reads during a given time period. The difference between the total meter reads and the number of reads estimated is the number of actual reads during a given time period.
- Reporting: NorthWestern will file a report with the Montana Public Service Commission, copied to parties in D2018.2.12, no later than 60 days after January 1 of each year the decoupling pilot is operable. The report will, for those metrics for which NorthWestern has prior year's data, display 3 full years of performance results (i.e., reporting year and the two preceding years).
- Omni-channel Project (Future Metric) NorthWestern is currently in the implementation, testing, and training phases of a project that will replace its' existing IVRs (Interactive Voice Response), phones, reporting, telecommunication carriers, adherence, scheduling, and it can provide the foundation for new customer interaction 43 channels, voice analytics and the ability to provide customers with post transactional surveys. NorthWestern expects the project to go live in the second quarter of 2019. As a condition of the FCRM pilot, NorthWestern with stakeholder input, will develop a set of metrics regarding customer interactions outside the traditional phone metrics used. To allow for time to establish baseline levels prior to

developing customer care metrics, these future metrics, after review and Commission approval, would be established and implemented by the start of 2021. Future metrics could include, but are not limited to, metrics around: next call prevention; post transactional survey responses (agent net promoter score, etc.); system availability.

Reliability Metrics:

- NorthWestern Energy tracks and currently reports on three reliability metrics to the MPSC: SAIDI, SAIFI, and CAIDI:
 - SAIDI (System Average Interruption Duration Index): the average amount of time a typical customer is out of power on a sustained outage (more than 5 minutes) annually.
 - SAIFI (System Average Interruption Frequency Index): the average number of sustained outages a typical customer incurs annually.
 - CAIDI (Customer Average Interruption Duration Index) –the average time a customer is out of power if they have an outage in a given year.
- NorthWestern measures these metrics including MED's and excluding MED's.

Levin recommends that the metrics be measured as a three-year average and suggest the below targets, which are based on historical performance. These targets would ensure that NorthWestern Energy maintains reliability at historical levels and that the FCRM does not negatively impact the utility's performance.

Table 6: Proposed Reliability Metrics

	Excluding MED's	Including MED's
SAIDI	140 Minutes	206 Minutes
SAIFI	4.33	1.53
CAIDI	115 Minutes	145 Minutes

Reporting: NorthWestern will file a report with the Montana Public Service Commission, copied to parties in D2018.2.12, no later than 60 days after January 1 of each year the decoupling pilot is operable. The report will display 3 full years of performance results (i.e., reporting year and the two preceding years)

B. Appendix B: FCRM Calculation

Determining Fixed Costs:

Each general rate case would establish the two key factors to be used in the Fixed Cost Recovery Mechanism (FCRM): the (1) fixed Transmission & Distribution (T&D) cost per customer-month and (2) fixed production cost.

Step 1: Establishing the "Fixed T&D cost per customer-month":

Step 1a. Determine T&D-related revenue -This will be the non-production related revenue requirement from the test year for the applicable class.

Step 1b. Determine fixed customer charge revenue -fixed customer charge revenue is equal to the revenue from the customer charge in the test year for the applicable class.

Step 1c. Determine Authorized T&D Fixed Cost Recovery- TDFCR is equal to the T&D related revenue (step 1a) minus customer charge revenue (step 1b).

$$(TDFCR): \text{Authorized T\&D Fixed Cost Recovery} = TDRR_{c,ty} - CC_{c,ty}$$

Where

$TDRR_{c,ty}$ is the class T&D-related revenue requirement for customer group c as authorized in rate case;

$CC_{c,ty}$ is the revenue collected from the customer charges for group c in the test year;

Step 1d. Determine authorized T&D Fixed Cost per Customer-month – FCC is equal to the TDFCR (step 1c) divided by the number of customers in the test year multiplied by 12 [months].

$$(FCC): \text{Fixed Cost per Customer-month} = TDFCR_{f(customers_{ty} * 12)}$$

Where

$Customers_{c,ty}$ is the test period number of customers served for group c ;

Step 2: Establishing the "Fixed Production Cost":

Step 2a. Determine production-related revenue-This will be the production related revenue requirement from the test year for the applicable class.

Step 2b. Determine variable cost revenue – variable cost revenue is equal to the total costs related to variable energy costs (e.g. fuel costs) in the test year for the applicable class.

Step 2c. Determine Authorized Production Fixed Cost Recovery- PFCR is equal to the production related revenue (step 2a) minus variable cost revenue (step 2b).

$$(PFCR): \text{Authorized Production Fixed Cost Recovery} = PRR_{c,ty} - VC_{c,ty}$$

Where

$PRR_{c,ty}$ is the class production-related revenue requirement for customer group c as authorized in rate case;

$VC_{c,ty}$ is the test year variable (e.g. fuel) cost in the revenue requirement for group c ;

Calculating Monthly Deferral:

After a rate case, these authorized factors would be used to calculate and track FCRM deferrals on a monthly basis. These deferrals would be held in a balancing account over a 12-month recovery period, at which point the final deferred revenue amount approved for recovery or rebate would be surcharged or rebated via volumetric charges during the subsequent 12 months.

Monthly deferrals would be calculated through a four-step process each month:

Step 3. Determine allowed T&D revenue per month - multiply the actual number of customers by the applicable TDFCR (step 1d) for each applicable class.

Step 4. Determine total allowed revenue per month - add the fixed production cost (PFCR; step 2c) to the customer-adjusted allowed T&D revenue determined in Step 3 for each applicable class.

Step 5. Determine total actual revenue per month - the recorded actual month revenue from kWh sales for each applicable, excluding revenue collected through riders and the customer charge.

Step 6. Determine the monthly deferral value - take the difference between the actual (step 5) and allowed (step 4) decoupled revenue. The resulting balance will be deferred by the company in a balancing account with interest on the deferred balance accruing at commission-approved rate.

$$\text{Deferral}_{c,t} = (FCC_c * C_{c,t}) + (PFCR_c) - (\text{Energy kWh Rate} * \text{kWh}_{c,t}^{\text{billed}})$$

Where

$\text{Deferral}_{c,t}$ is the decoupling deferral for customer group c in month t ;

FCC_c is the fixed T&D cost per customer-month for group c ;

$PFCR_c$ is the fixed production cost for group c ;

$C_{c,t}$ is the number of actual customers in group c during month t ;

$\text{kWh}_{c,t}^{\text{billed}}$ is the billed sales to customer group c in month t .

Allocating Deferred Costs Annually:

Once a year, the deferred balance amount (negative or positive) would be allocated to the applicable class using forecasted sales. The utility will start collecting or refunding the deferred balances of the account resulting from the previous year through a per-kWh charge or credit through the end of the subsequent 12-month period, with a symmetrical cap on the annual kWh charge equal to three percent of the average monthly bill. Any amount over the cap (surcharges or rebates) would be carried over to the next year.

$$FCRM \text{ Adjustment (in } \frac{\$}{kWh} \text{)} = \frac{\sum_{t=1}^{12} (\text{Deferral}_{c,t} * crt)}{kWh_{c,ny}}$$

If the ...

- *IFCRM Adjustment* average monthly customer kWh* is \leq (*estimated average monthly bill* * 0.03), no change to the calculation is needed.
- *IFCRM Adjustment* average monthly customer kWh* is $>$ (*estimated average monthly bill* * 0.03), the applied FCRM adjustment (surcharge or rebate) will instead be the per-kWh rate that is equal to 3 percent of the average bill, with any excess positive or negative deferrals recorded and kept in the balancing account until the next annual adjustment.

Where

crt is the carrying charge on the balancing account;

kWh_{c,ny} is the forecasted sales for the next year, where the rate adjustment will be applied.

Any deviations from the projected sales used to derive the per-kWh rates applied to charge or refund the CRM deferred balances will be accounted for in the subsequent annual reset of the FCRM, effectively truing-up the deferred balances. In other words, the FCRM will reconcile the authorized fixed costs that should be collected from the applicable classes and the fixed costs per-kWh that it is actually collecting based upon the sales to those customers.

C. Appendix C: DSM Stipulation**STIPULATION AND SETTLEMENT AGREEMENT
OF NORTHWESTERN ENERGY AND THE NORTHWEST ENERGY COALITION**

NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern") and the NW Energy Coalition ("NWECC") (collectively "Stipulating Parties"), by and through their undersigned representatives, hereby submit to the Montana Public Service Commission ("Commission") this Stipulation and Settlement Agreement ("Agreement").

For settlement purposes, a fair and equitable resolution has been reached by the Stipulating Parties on the issues raised in this Docket concerning NorthWestern's electric Demand Side Management ("DSM") measures and/or programs, including capitalization and cost- effectiveness ("Settled Issues"). To reach a fair and equitable resolution of the issues that were raised or could have been raised by the Stipulating Parties regarding the Settled Issues, the Stipulating Parties stipulate and agree as follows:

1. The Stipulating Parties agree that NorthWestern will create a small (no more than 10 people), advisory stakeholder group consisting of relevant and appropriate stakeholders selected by NorthWestern, which shall include at minimum representatives from the NWECC, the MCC, and Commission staff, to discuss re-envisioning of the electric DSM programs offered by NorthWestern for the 2020-2021 program year (items to be discussed include branding, methods of marketing, cost-effectiveness calculations, energy savings estimates). The group shall make recommendations to NorthWestern for consideration in the development of the 2020-2021 electric DSM program offerings. Once the 2020-2021 program year commences, the group shall be disbanded. The Stipulating Parties will also include a 10% adder for electric DSM in its cost-effectiveness calculations beginning with the 2020-2021 program year, unless a different adder is required by Montana Administrative Rules and continue its work towards including a capacity value of electric DSM measures and/or programs in cost- effectiveness calculations.
2. With regard to recovery of electric DSM expenditures, the Stipulating Parties agree that NorthWestern shall record any DSM expenditures as a regulatory asset in the year the expenditures are incurred. NorthWestern shall also amortize these DSM expenditures over 10 years starting coincident with the Commission order that approves the expenditures for inclusion in rates at which time NorthWestern will earn a return of and return on all electric DSM expenditures at the Rate of Return approved by the Commission, including any adjustment to Return on Equity ("ROE") for conservation investments pursuant to Montana Code Annotated Title 69, chapter 3, part 7. The Stipulating Parties

agree that there should not be a threshold level of the DSM regulatory asset that triggers the need for a filing by NorthWestern.

3. The Stipulating Parties support implementation of the Fixed Cost Recovery Mechanism ("FCRM") pilot recommended by the Human Resource Council and National Resources Defense Council with no adjustment to the ROE. The Stipulating Parties support consideration of whether such an ROE adjustment would be appropriate if the FCRM was to become permanent as part of the study process envisioned by the pilot. If the study suggests a potential ROE adjustment might be appropriate, such potential ROE adjustment would be considered in NorthWestern's next electric rate review following the completion of the pilot.
4. Contingent upon implementation of the FCRM pilot, the Stipulating Parties support the use of both the Total Resource Cost Test and Utility Cost Test for electric DSM measure and program cost-effectiveness calculations. If measures and/or programs pass either test at a threshold of 0.9 or above (including the 10% adder), they shall be considered cost-effective. The Stipulating Parties agree that if any measures and/or programs fail to meet cost-effectiveness after the 2020-2021 program year and the reason the programs are not cost-effective is due to matters other than ramping costs, NorthWestern shall make best efforts to implement changes that result in such measures and/or programs becoming cost-effective, including but not limited to: increased/decreased incentive levels, administrative costs/investments changes, increased/decreased marketing, etc., and if unable to achieve cost-effectiveness, such measures and/or programs will be removed from the electric DSM offerings.

The Agreement resolves all issues raised by the Stipulating Parties regarding the Settled Issues.

Except as specifically noted below, no individual Stipulating Party's position in this docket is accepted by any other Stipulating Party by virtue of its entry into this Agreement, nor does it indicate any Stipulating Party's acceptance, agreement, or concession to any rate making principle or legal principle embodied or arguably embodied in this Agreement.

The Stipulating Parties stipulate to the admission into the evidentiary record of all pre-filed testimony and exhibits of the witnesses for the Stipulating Parties to support the reasonableness of the Agreement and shall refrain from cross-examining any remaining witnesses of the Stipulating Parties regarding the Settled Issues. The Stipulating Parties shall each call one witness at hearing to support this Agreement.

The various provisions of this Agreement are inseparable from the whole of the

agreement between the Stipulating Parties. The reasonableness of the proposed settlement set forth in this Agreement is dependent upon its adoption, in its entirety, by the Commission. If the Commission declines to approve this Agreement as agreed to herein by the parties, or if the Commission adds or removes any terms or conditions not agreeable to the parties, either party shall, at its sole option, have the right to withdraw from this Agreement with all of its rights reserved. The Agreement and all its parts shall then be null and void, and the parties shall not be bound by any provision of it, and it shall have no force or effect whatsoever. In such event, the existence or terms of this Agreement shall not be admissible in any proceeding before the Commission or any court for any purpose.

The Stipulating Parties acknowledge that this Agreement is the result of a voluntary, negotiated settlement between them pursuant to ARM 38.2.3001, and agree that this Agreement, inclusive of the compromises and settlements contained herein, is in the public interest.

This Agreement may be executed in one or more counterparts and each counterpart shall have the same force and effect as an original document, fully executed by the Stipulating Parties. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signatures page(s).