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

IN THE MATTER OF the Application by NorthWestern Energy for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design	REGULATORY DIVISION DOCKET NO. D2018.2.12

RESPONSE BRIEF OF VOTE SOLAR

AND THE MONTANA RENEWABLE ENERGY ASSOCIATION

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TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

Cases

Montana Public Service Commission Decisions

Montana Statutes and Legislative Materials

Montana Rules and Regulations

Other Regulatory Commission Decisions

Secondary Sources

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Intervenors Vote Solar and the Montana Renewable Energy Association ("MREA") respectfully submit this post-hearing response brief.

INTRODUCTION

Montana families want the option to reduce their utility bills and increase their self-sufficiency by producing some of their electricity with rooftop solar. Technology advances now make that possible. When Montanans generate their own electricity at home, they buy less from the utility. While no company likes to lose sales to competition, monopoly utilities are especially unaccustomed to competition and too often respond by asking regulators to intervene and erect discriminatory price structures intended to undermine customer-owned solar. *See generally* Ari Peskoe, *Unjust, Unreasonble, and Unduly Discriminatory: Electric Utility Rates and the Campaign Against Rooftop Solar*, 11 Tex. J. Oil Gas & Energy L. 211, 213–18, 259–81 (June 2016) (discussing the perceived competitive threat to monopoly utilities by rooftop solar and the role of ratemaking as a utility defense against competition). The Montana Public Service Commission ("Commission") should refuse to be treated as a monopolist's rear guard and should, instead, protect Montanans' freedom to install solar and produce some of their own electricity without being unfairly penalized by the utility for doing so.[1]

While NorthWestern Energy's ("NorthWestern," "NWE," or "Company") opposition to the competition of consumer self-generation is not surprising, the facts in this case do not support the Company's assertion that customer solar generation[2] causes any meaningful cost-shift or subsidy that can justifying the Company's proposed separate classification and unfavorable rate design. First, the utility failed to meet its burden under the standards laid out by the Legislature in 2017 through House Bill No. 219 ("HB 219"). That legislation requires the Commission to determine whether to make any changes to current rate structures based only on an analysis of "utility system benefits" and the "cost to provide service to" net metered customers according to "minimum information required" by the Commission. HB 219, 65th Leg., Reg. Sess. §§ 1, 2(1), 3(1) (Mont. 2017).

It is undisputed that the Company's analysis did not comply with the Commission's explicit direction in the Minimum Information Requirements ("MIR") established in Docket No. D2017.6.49. That fact, alone, should preclude any findings by the Commission based on the

[1] The non-unanimous stipulation in this case resolves revenue requirement and class cost allocations but not issues related to customer-generators. Should the Commission approve the stipulation, it has no impact on issues related to customer-generators, notwithstanding a placeholder revenue allocation for customer-generators. NWE Opening Br. at 2 ("The stipulating parties did not agree to NorthWestern's proposals for a separate net energy metering class."), 15 ("[T]here remain significant issues that the parties did not resolve through stipulation. These issues include NorthWestern's proposal for a new net-metering class.").

[2] The Company's opening brief and testimony in this case focused on customers who use net billing to offset inflows with outflows during a billing period. The term "net metering" is often used to describe a net billing convention where inflows and outflows are netted before applying the retail rate to the net value. Unfortunately, Montana statutes define "net metering" to include all customer-generation regardless of whether a customer sends electricity to the grid and uses net billing. Mont. Code Ann. § 69-8-103(19). Not all customers who self-generate necessarily export nor use net billing. That will be increasingly true as battery storage expands. The Commission should be careful to not conflate customers who use net billing with all customers with their own generation. There was no evidence in the record of this proceeding related to customers who self-generate but do not export.

Company's analysis. Moreover, the analysis in the record by Vote Solar and MREA is the only benefit-cost analysis conducted according to the MIR and shows that the long-term benefits of customer-generators exceed their costs. That is consistent with other such studies done in other states.

The second factor the Commission may consider—cost of service to customer-generators—also shows that no change is needed to current net billing tariffs. Unlike the Company and Montana Consumer Counsel's ("MCC") cost of service studies, which used artificial load data and other assumptions prejudicial to customer-owned solar, Vote Solar and MREA's cost of service analysis shows that customer-generators cover their costs under current rates and rate structures. The Commission should note that a reduction in sales to customer-generators is not the equivalent to a cost-shift or subsidy where customer-generators also reduce their loads during the peak cost-causing hours. Therefore, while customers with solar do reduce the number of kilowatt hours they purchase from the utility, and therefore the total bills they pay—which is the whole point of investing in solar—those customer-generators also decrease their loads on the utility system during the important cost-causing hours used in a cost of service study. This reduction in cost offsets their reduced revenues, resulting in those customers covering their costs to the same degree as other customers in the residential customer class.

Because a correctly conducted benefit-cost analysis and cost of service study show no undue costs in excess of benefits, there is no basis to conclude that "customer-generators should be served under a separate classification of service . . . based on the commission's findings relative to: (a) the utility system benefits of the net metering resource; and (b) the cost to provide service to customer-generators." HB 219 § 2(1).[3] The Commission must therefore reject the Company's proposal to create a separate rate class.

Moreover, even if NorthWestern had met the statutory standard for separating customer-generators into their own class, its proposed three-part rate design is neither a necessary, nor fair, second step. If the Commission determines that current net metering billing conventions create costs that exceed benefits (despite the greater weight of evidence to the contrary), the Company's proposed demand charge rate structure is the wrong change to make.

Under net billing, two separate transactions take place. In the first transaction, the utility supplies the customer-generator with electricity from the grid. In the second transaction, the customer-generator supplies the utility with electricity that flows to the grid. The customer may pay for the first transaction (inflows of electricity) with credits he or she earned through the second transaction (exported electricity), but the nature of the service the customer receives from the utility is the same as that of all other customers. That is, the method of paying for inflows of utility electricity does not change the nature of that electricity or service. As the evidence in this case demonstrates, customer-generators are not different from other residential customers when they receive electrons; they are different only when they generate and send to the grid. Therefore, any change to rates for customer-generators should not treat them differently for their imports—when they are no different than other customers—but only for their exports.

Lastly, any changes to the current net metering tariffs should protect existing customers' reasonable reliance on, and response to, the price signals in the current net metering tariff. The Company proposed to determine grandfathering status based on the date of interconnection. The

[3] Other potential criteria for justifying a separate classification for customer-generators offered by NWE and MCC—such as a different overall load profile or shape and the existence of two-way power flow—are outside the express criteria set by the Legislature. *See, e.g.*, HB 219.

customer—and the small business who installs that customer's solar—must invest significant time and expense well before interconnection. There are a number of steps outside the customer's control between when the customer commits to solar and the interconnection. Therefore, if the Commission makes any changes to the current net metering tariff, it should grandfather customers who already invested time and money into installing solar by grandfathering customers who submit an application within 60 days of the Commission's final decision in this docket.

I. NorthWestern Failed to Show That an Analysis of Long-Term Benefits and Costs, Conducted Pursuant to the Commission's Minimum Information Requirements, Justifies Changing Current Tariffs.

A. NorthWestern's Benefit-Cost Analysis Does Not Comply with the Commission's Express Directives.

Contrary to Montana law, NorthWestern submitted a benefit-cost analysis ("BCA") that does not comply with the Commission's explicit Minimum Information Requirements ("MIR") ordered in Docket No. D2017.6.49. Ex. VS/MREA-1 (Kobor Dir.) at 44:6–14.[4] Each deviation from the Commission's MIR undervalued customer-owned solar, despite the Company's erroneous insistence that the BCA complied with the Commission's MIR, and any deviation was "on the side of ensuring a higher level of solar benefits." Ex. VS/MREA-1 (Kobor Dir.) at 6:10–12, 44:9–13; Hr'g Tr. 1471:10–15 (witness insisting that the BCA "actually met" the MIR), 1471:19–23 (claiming that errors were on the side of ensuring higher solar value), 1472:4–24 (witness admitting that the MIR required use of the QF-1 methodology for avoided energy and

[4] Pursuant to Mont. Code Ann. § 69-8-610(3), the Legislature authorized the Commission to "establish minimum information required for inclusion in a study conducted by a public utility" under the requirement in § 69-8-610(1)(a) to "conduct a study of the costs and benefits of customer-generators" to be considered in this rate case. The Commission established those minimum information requirements pursuant to that statutory authority through its Notice of Commission Action in Docket D2017.6.49 on August 9, 2017.

that the BCA did not use that method), 1474:1–8 (application of QF-1 method produces higher avoided energy than the Company's BCA), 1476:7–10, 1478:20–23 (MIR requires an Effective Load Carrying Capability ("ELCC") or similar method but Company's BCA does not contain an ELCC), 1478:24–1479:5 (MIR requires analysis based on long-term risk-free rates, which was not included in the Company's BCA), 1479:14–1480:6 (Company's BCA only contained analysis of distribution substation deferrals but no other distribution level avoided costs), 1499:1–1500:13 (the Company's BCA initially erred in adjusting capacity costs for losses, which produced a lower solar value), 1519:18–1520:16 (Company did not use method required by MIR for avoided energy that would have produced higher value). The combined result of the Company's deviations from the MIR is to systematically prejudice the Company's BCA against customer-owned generation. The Commission should not countenance NorthWestern's violation of the MIR and should not accept the biased results.

1. NorthWestern's Benefit-Cost Analysis Relies on an Opaque and Inaccessible Dispatch Model Instead of the Method the Commission Expressly Instructed it to Use.

The Commission explicitly instructed NorthWestern to "use the Commission's approved method for estimating avoided energy costs for purposes of setting the standard rates in NWE's QF-1 tariff, subject to the required CO2 scenarios" when conducting its BCA. Notice of Commission Action, Docket No. D2017.6.49, Attachment 1 ("Avoided Energy Costs") (Aug. 9, 2017). The QF-1 tariff uses a "proxy method" and specifically rejected the proprietary PowerSimm model. Ex. VS/MREA-1 (Kobor Dir.) at 53:11–13; Final Order No. 7500c, Docket No. D2016.5.39 (July 21, 2017). And yet, NorthWestern's BCA defiantly relied on the proprietary PowerSimm production cost model anyway. Ex. VS/MREA-1 (Kobor Dir.) at 55:1–9; *see also* Ex. NWE-42 (Shlatz Second Dir.), Exhibit ELS-2 at 10 of 40; Ex. NWE-50 (Babineaux Dir.) at MSB-11:6–9; Hr'g Tr. 1519:18–1520:8, 1682:21–1683:3, 1700:10–22.

NorthWestern argues that its BCA "used the Commission-approved methodology for determining avoided energy costs." NWE Opening Br. at 21. That is simply false. Whether or not the Commission approved using the PowerSimm model for some purposes, in an unrelated docket, it is not the method the Commission expressly ordered **for purposes of the benefit-cost analysis at issue in this case**. In fact, the PowerSimm method was specifically rejected in favor of the "proxy method" because its "simplicity and transparency . . . outweigh its insensitivity to changes in loads and resources." Final Order No. 7500c ¶ 26. NorthWestern's attempt relitigate those issues in a post-hoc justification for ignoring the MIR is inappropriate. NWE Opening Br. at 21. HB 219 requires the BCA to include the analysis directed by the Commission in the MIR, not whatever analysis the utility decides to include to serve its interests. HB 219 § 1(3).

Moreover, even if the Commission had not already rejected the PowerSimm approach in favor of the QF-1 method in the MIR, it should do so anyway. Unlike the opaque PowerSimm dispatch model, the QF-1 proxy method is transparent, easy to replicate, and publicly accessible.

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

Final Order No. 7500c ¶¶ 23, 25 (internal citations omitted); *see also* Findings of Fact and Conclusions of Law for the Symmetry Finding in MTSUN Order No. 7535b ¶ 28, *Vote Solar v. Mont. Dep't of Pub. Serv. Regulation*, Cause No. BDV-17-0776 (Mont. Dist. June 18, 2019) ("The Court concludes that the use of PowerSimm model lacked transparency. In order for due process to be satisfied, the Commission must require all parties to have access to information it uses in making its final determinations of contested issues."). Using PowerSimm requires purchasing a license as well as permissions from the vendor. Hr'g Tr. 1701:3–17. While it may be theoretically possible for parties to obtain a license for PowerSimm, if the vendor agrees to provide one, it requires purchase at significant cost that makes it effectively inaccessible. Hr'g Tr. 1708:11–16, 1927:13–19. That creates a virtual black box that hides critical underlying inputs and evidence from the Commission and parties. Vote Solar and MREA were unable to access the relevant PowerSimm model or obtain relevant data from the model runs in this case. Ex. VS/MREA-1 (Kobor Dir.) at 55:10–56:10; NWE Responses to VS-MREA-062c, VS-MREA-077, VS-MREA-078; Hr'g Tr 1701:21–1702:16. In fact, NorthWestern's own consultants do not have a license, do not have access to, and appear to have also misunderstood the PowerSimm model when preparing their BCA report. Ex. VS/MREA-1 (Kobor Dir.) at 56:11–13; Hr'g Tr. 1474:9–1475:4, 1520:20–21; NWE Response to VS-MREA-058b.

Thus, the Company's PowerSimm model method not only violated the MIR, but deprives the parties and the public from accessing the evidence. Accordingly, the Commission must reject the Company's BCA.

2. NorthWestern's Benefit-Cost Analysis Used the "Southwest Power Pool Method" Instead of the Commission's Required Method to Underestimate Avoided Generation Capacity Costs.

Avoided capacity costs depend on two factors: (1) an assessment of the incremental cost of capacity to be avoided; and (2) the ability of customer-generators' solar to avoid that cost. Ex. VS/MREA-1 (Kobor Dir.) at 61:14–16. The Commission instructed NorthWestern to calculate avoided capacity costs for the BCA by "perform[ing] an Effective Load Carrying Capability or similar assessment of the capacity contribution of solar customer-generators." Notice of Commission Action, Docket No. D2017.6.49, Attachment 1 ("Avoided Capacity Costs"). The Company did not comply.

The Company again misleads by claiming that it "relied on the Commission-approved methodology to determine the capacity contribution of solar for purposes of determining the avoided capacity costs." NWE Opening Br. at 22. The Company did not rely on the methodology that the Commission approved **for purposes of the benefit-cost analysis in this case.** The Company's BCA did not include an ELCC or equivalent analysis. Hr'g Tr. 1478:20–23; Ex. VS/MREA-1 (Kobor Dir.) at 65:3–10; Ex. NWE-42 (Shlatz Second Dir.) at ELS-29; NWE Response to VS-MREA-026a.

An ELCC assessment measures the magnitude of load that can be added to a system by adding the generation being studied while maintaining the same level of reliability. Ex. VS/MREA-1 (Kobor Dir.) at 64:9–65:2. Rather than conducting that analysis, NorthWestern used the "Southwest Power Pool Method" ("SPP Method"). *Id.* at 65:3–10. Unlike the ELCC method, which looks at each hour during the year, the SPP Method uses generation during a very limited number of hours during the year, and generation occurring in a single peak month (only 22 hours out of 8760 or 0.25%). *Id.* at 65:14–66:4; Hr'g Tr. 1476:20–1477:21, 1478:2–10 (NWE witness describing how an ELCC looks at hour-by-hour loads and generation), 1523:18–1524:11; *see also* Order Vacating and Modifying Montana Public Service Commission Order Nos. 7500c and 7500d ¶ 12, *Vote Solar v. Mont. Dep't of Pub. Serv. Regulation,* Cause No. BDV-17-0776 (Mont. Dist. Apr. 2, 2019) ("In focusing only on a handful of peak demand hours (220 hours over a ten-year period) that reflect primarily infrequent wintertime spikes, the Commission overlooked evidence that NorthWestern lacks sufficient capacity to meet peak customer demand in <u>both</u> summer and winter. . . . [and] misapprehended the effect of evidence of <u>regional</u> peak demand.") (emphasis in original) (citations omitted). Thus, the narrow focus of the SPP Method on a few hours and a single peak month distinguishes it from the ELCC "or similar assessment of the capacity contribution of solar customer-generators" required by the Commission. Notice of Commission Action, Docket No. D2017.6.49, Attachment 1 ("Avoided Capacity Costs"); Ex. VS/MREA-1 (Kobor Dir.) at 68:7–71:6.

Moreover, the Commission effectively rejected the SPP Method by rejecting the QF-1 method for capacity when adopting the MIR. The Company advocated for the QF-1 method for avoided capacity—which is the SPP Method—in its comments to the Commission in the MIR docket. Ex. VS/MREA-19. However, the Commission did not adopt that recommendation, and instead, required use of the ELCC or similar. The Company's attempt to use the SPP Method from the QF-1 docket anyway improperly seeks to relitigate the argument it made, but which was not accepted, in the MIR docket.

It is also revealing that NorthWestern's own consultants disagreed with the SPP Method's result of zero capacity contribution value and encouraged NorthWestern to conduct an actual ELCC calculation. Ex. NWE-42 (Shlatz Second Dir.) at ELS-29 & Exhibit ELS-2 at 11 of 40; Hr'g Tr. 1478:11–19.[5] And while those consultants later tried to argue that their 6.1% capacity contribution is a reasonable estimate for what an ELCC study would produce, they provided no empirical evidence in support of that assertion. Hr'g Tr. 1521:22–1523:17. They conducted no ELCC analysis for NorthWestern and were not aware of ELCC studies for other utilities in the region by which to reach that conclusion. *Id.* It is simply not credible to allege what an ELCC analysis would produce without any evidence from an actual ELCC analysis. Moreover, the consultants' defensive contention that the SPP Method produces a sufficient proxy

[5] The NWE BCA used a 6.1% capacity contribution from the most recent QF-1 docket, rather than the zero contribution calculated by NWE with the SPP Method. Ex. VS/MREA-1 (Kobor Dir.) at 65:8–10; Ex. NWE-42 (Shlatz Second Dir.), Exhibit ELS-2 at 11 of 40; Hr'g Tr. 1522:11–1523:4.

for an ELCC study also conflicts with their own recommendation that NorthWestern actually conduct an ELCC study instead of simply relying on the SPP Method.

Like NorthWestern's other deviations from the MIR, the BCA's avoided capacity cost prejudiced customer solar generation. Using the SPP Method instead of an ELCC or equivalent analysis produced a much lower capacity contribution than would be expected from an ELCC, or equivalent, analysis. Ex. VS/MREA-1 (Kobor Dir.) at 71:1–6; Order Vacating and Modifying Montana Public Service Commission Order Nos. 7500c and 7500d ¶ 12, *Vote Solar v. Mont. Dep't of Pub. Serv. Regulation*, Cause No. BDV-17-0776 (Mont. Dist. Apr. 2, 2019) ("properly calculated for NorthWestern's high-demand hours in the summer and winter months, the average capacity contribution of solar resources is 36%, rather than 6.1%.").

3. NorthWestern's Avoided Transmission and Distribution Costs Did Not Use the Required Detailed, Location-Specific, Marginal Cost Data or the NERA Regression Method.

The MIR instructed NorthWestern to look at detailed avoided transmission and distribution system costs to "serve load pockets, distant generating resources, or elsewhere." Notice of Commission Action, Docket No. D2017.6.49, Attachment 1 ("Avoided Transmission and Distribution Capacity Costs"). The Commission further instructed that in the absence of detailed marginal cost information, NorthWestern must use "the regression method developed by National Economic Research Associates" ("NERA method"). *Id.* The NERA method is a regression that correlates historical capacity additions to increases in loads to derive the incremental cost of expanding the system to serve new increments of peak load. Ex. VS/MREA-1 (Kobor Dir.) at 74:8–11. The Company's BCA failed to use either: (1) detailed and accurate marginal cost information for transmission and distribution; or (2) the NERA method. *Id.* at 75:3–78:14. The Company's BCA's transmission and distribution avoided cost analysis was neither detailed nor accurate. The transmission analysis was speculative and not based on detailed and accurate information. Hr'g Tr. 2191:23–2193:6 (MCC witness Dismukes testifying that NorthWestern's avoided transmission analysis was not based on detailed marginal cost information and the Commission's instruction in that case required use of NERA method regression analysis). In fact, NorthWestern admits that the transmission analysis was, at most, a "high level" hypothetical cost based on an assumed project, at an assumed price, and a presumed deferral period. Ex. VS/MREA-1 (Kobor Dir.) at 75:8–10, 82:2–83:4; Ex. NWE-42 (Shlatz Second Dir.) at ELS-18:5 & Exhibit ELS-2 at 11 of 40; Hr'g Tr. 1487:20–1489:11.[6] It also looked at only nine future years out of 25 years in the BCA study period because of how the study was done. Hr'g Tr. 1486:21–1487:19 (describing lack of data after 2031 and requirement to beat a projected deficiency by three years, providing a window of only 2019–2028 for potentially deferred transmission costs).

The avoided distribution cost analysis failed to use detailed marginal cost information for the full distribution system, applied an arbitrary cap to solar growth that prevented it from deferring distribution capacity additions, and required customer-generation to be online three years before a projected capacity need and to exceed that capacity need by at least 10%—standards it does not hold itself to when meeting capacity needs with traditional wired solutions. Ex. VS/MREA-1 (Kobor Dir.) at 76:6–77:1; NWE Response to VS-MREA-099b–c; Hr'g Tr. 1480:7–1482:14 (describing the three year and 10% margin applied for the BCA but admitting that NorthWestern does not apply that same standard for all planning decisions), 1513:15–1516:4

[6] MCC witness Dismukes argued that because NWE's transmission cost analysis was speculative, the Commission should afford zero transmission value. Ex. MCC-4A (Dismukes Dir.) at 15:21–16:1. However, the MIR the Commission ordered in Docket No. D2017.6.49 clearly provide for use of a NERA regression analysis rather than default to zero value as Dr. Dismukes urges. Regardless, even if those components that Dr. Dismukes disputes were removed entirely, it does not change the conclusion that the benefits exceed the costs of customer-generation. Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 16:5–17:10 & Table 3.

(describing how the study capped solar at 30% of a substation peak load based on a series of unsupported "Navigant assumption[s]"). Moreover, the analysis was limited to 37% of substation additions, which in turn, account for only 20% of total growth-related investment. Ex. VS/MREA-1 (Kobor Dir.) at 77:4–78:9; Hr'g Tr. 1479:14–1480:6 (Company's BCA only contained analysis of distribution substation deferrals but no other distribution level avoided costs).[7]

Thus, while purporting to be a detailed marginal cost analysis, the Company's BCA was too simplistic, relied too heavily on assumptions rather than data, and was too incomplete to actually constitute a complete analysis based on "detailed marginal cost information" as the Commission intended in its decision in Docket No. D2017.6.49. Without a detailed and accurate analysis of marginal costs, the MIR required use of a NERA regression analysis—which the Company also failed to provide.

4. NorthWestern's Benefit-Cost Analysis Also Lacked Other Required Components.

The Commission required NorthWestern to "include both embedded and marginal allocated class cost of service studies in its general rate application." Notice of Commission Action, Docket No. D2017.6.49, at 2–3. Contrary to NorthWestern's claim that witness Normand "provided both an embedded cost of service study . . . and a marginal cost of service study" for customer-generators, NWE Opening Br. at 25, that marginal cost of service **failed to include any separate marginal cost analysis for customer-generators**. NWE Response to VS-MREA-032c; Ex. VS/MREA-1 (Kobor Dir.) at 20:5–6, 22:8–13. NWE also failed to

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[7] In contrast, the Company's marginal cost of service study looked at marginal distribution system capacity beyond substations—"all the way down to lower voltages." Hr'g Tr. 1175:17–1176:2. Substation costs are only a fraction of the total demand distribution costs. Hr'g Tr. 1176:3–13.

calculate benefits and costs under a scenario with the discount rate set based on the risk-free rate of inflation in addition a scenario based on NWE's weighted average cost of capital. Ex. VS/MREA-1 (Kobor Dir.) at 45:6–16; *see also* Notice of Commission Action, Docket D2017.6.49, at 3 ("NWE should use scenarios which use the long-term risk-free rate and also its own marginal cost of capital as proxies for a reasonable discount rate.").

B. A Benefit-Cost Analysis Conducted Pursuant to the Commission's Minimum Information Requirements Shows Benefits of Current Net Metering Outweigh the Costs.

A benefit-cost analysis conducted according to the Commission's explicit instructions in the MIR shows that the benefits from solar customer's generation outweighs the costs. Ex. VS/MREA-1 (Kobor Dir.) at 6:12-17.[8] Vote Solar and MREA's analysis conducted according to the MIR demonstrates that NorthWestern's systematic violation of the MIR biased the conclusions in the Company's BCA and that a MIR-compliant analysis demonstrates that no change to customer-generators rates are justified under the applicable standard in HB 219.

1. Calculating the Avoided Energy Value from Customer-Generators as Instructed by the Commission Results in a Significantly Higher Value Than NorthWestern's Benefit-Cost Analysis.

Vote Solar estimated the value of avoided energy based on the MIR's instruction to apply the QF-1, or "proxy" method. Ex. VS/MREA-1 (Kobor Dir.) at 57:7–60:12. Because there was no publicly-available update to NorthWestern's 2015 resource plan at the time, Vote Solar and

[8] Vote Solar and MREA conducted their primary analysis based on current adoption levels of customer-generation to avoid the problems associated with both the forecast NWE obtained from the National Renewable Energy Laboratory ("NREL") and attempts by NWE's consultants to modify that forecast. Ex. VS/MREA-1 (Kobor Dir.) at 46:2–49:12. The current level of adoption provides more realistic data for the Commission to make the decision presently before it: whether or not to approve any changes to the current net metering program in the near term. *Id.* at 50:1–51:7. However, to provide the Commission with the full range of possible results, and consistent with the Commission's directive in Docket No. D2017.6.49, Vote Solar and MREA also provided results based on each of the adoption scenarios created by NWE's consultants. *Id.* at 51:3–7.

MREA used the combined cycle natural gas plant ("CCCT") from the most recent 2015 resource plan as well as the projected 2025 CCCT in-service date for the QF-1 "proxy" method calculations, while noting that if future resource plans change the resource and in-service date, "it would be appropriate to update the analysis accordingly." *Id.* at 57:12–16. Vote Solar and MREA witness Kobor then updated the CCCT costs based on NorthWestern's own numbers; 2018 pricing from Mid-C trading hub; 15-day strip prices provided by NorthWestern; and the U.S. Energy Information Administration's most recent published forecast of Henry Hub prices—all as directed by the Commission. *Id.* at 58:3–59:9; Final Order No. 7500c ¶ 42; Notice of Commission Action, Docket No. D2017.6.49, Attachment 1. The resulting values for avoided energy from customer-generators—calculated as instructed by the Commission—are included in the final results summarized in section I.C, below, and are significantly higher than the values of NorthWestern's BCA. Ex. VS/MREA-1 (Kobor Dir.) at 59:10–60:2.[9]

2. Avoided Generation Capacity Determined Pursuant to the Minimum Information Requirements Produces a Higher Value Than NorthWestern's Benefit-Cost Analysis.

Vote Solar and MREA calculated avoided capacity costs from customer-generators by using the capacity cost from NorthWestern's marginal cost of service study, plus the 15% reserve margin. Ex. VS/MREA-1 (Kobor Dir.) at 63:7–64:5. Those are generally consistent with updated costs for the same Aeroderivative Combustion Turbine that NorthWestern's BCA used. *Id.* at 62:11–63:3.[10]

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[9] MCC witness Dismukes offered several comments about the avoided energy and system losses calculations in the BCA—all of which misunderstand how avoided energy and losses are analyzed in a benefit-cost test. Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 13:3–14:4.

[10] NWE witness Bushnell criticized Vote Solar and MREA witness Kobor for updating the cost of the resource but not updating the timing of that resource based on the Company's most recent proposed new resource acquisition. Hr'g Tr. 1686:7–24. However, at the hearing, he acknowledged that Ms. Kobor could not have done so since the Company did not release that updated plan until after Ms. Kobor's

For the second step in calculating avoided costs, Vote Solar and MREA applied the capacity contribution value equivalent to an ELCC assessment. *Id.* at 64:6–73:7. Given the lack of an actual ELCC assessment, or the loss of load probability ("LOLP") data needed to conduct other similar analyses, Vote Solar and MREA used the Capacity Factor Method as the best available option available for replicating the results expected from an ELCC study. *Id.* at 71:7–72:4. The result of that analysis shows a significantly higher contribution to capacity than the Company's BCA: 21.5% compared to only 6.1%. *Id.* at 65:8–10, 72:11–12; Ex. NWE-42 (Shlatz Second Dir.), Exhibit ELS-2 at 11 of 40. Thus, if the Company had followed the MIR, the BCA would have shown a significantly higher avoided capacity benefit from customer-generators. Ex. VS/MREA-1 (Kobor Dir.) at 72:13–73:7.[11] The MIR-compliant capacity values are included in the tables below.

3. Applying the Required NERA Method Produces Higher Avoided Transmission and Distribution Costs Than NorthWestern's Benefit-Cost Analysis.

Vote Solar and MREA calculated the avoided transmission and distribution capacity costs based on the NERA method, as instructed by the Commission in the absence of "detailed marginal cost information" that the Company failed to provide. Ex. VS/MREA-1 (Kobor Dir.) at 79:1–81:15. Tellingly, while the Company's BCA omitted it, Vote Solar and MREA were able to locate marginal distribution and transmission capacity costs within the Company's marginal cost of service study that were based on analyses similar to the NERA method. *Id.* at 79:4–9, 85:1–

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testimony was filed, and Ms. Kobor's analysis used the resources in the plan available to her at the time. Hr'g Tr. 1686:22–1688:4.

[11] Vote Solar and MREA also included avoided losses in calculating capacity value, which the Company's BCA initially omitted. After Vote Solar and MREA's prefiled testimony and discovery to the Company, NorthWestern acknowledged that error and purported to correct it through a later revision. Hr'g Tr. 1465:17–21, 1466:12–19, 1467:9–25, 1499:1–1500:13.

21; Hr'g Tr. 1173:3–1175:7, 1935:3–1935:8. Unlike the speculative and incomplete analysis the Company did, the regression analysis Vote Solar and MREA produced "use an empirical, objective standard" that follows a "pretty consistent methodolog[y] and background[]" for calculating avoided costs—as MCC witness Dismukes acknowledged. Hr'g Tr. 2200:17–18, 23. Vote Solar and MREA applied a 21.5% capacity equivalence factor for solar generation to NERA method's unit costs of avoided capacity to derive the avoided transmission and distribution capacity cost values. Ex. VS/MREA-1 (Kobor Dir.) at 85:22–86:6. That capacity contribution is within the range of the Company's own estimated equivalence factors for solar and conservative, compared to the projected 33% of nameplate capacity that solar would generate during the hour of transmission system peak. *Id.* at 81:1–2, 86:2–4.[12] The avoided transmission and distribution costs calculated as directed in the MIR are higher than the Company's BCA and are included in the tables below.

4. Vote Solar and MREA Complied with the Commission's Direction on Avoided Losses, Environmental Compliance, and Societal Benefits.

Vote Solar and MREA also complied with the MIR by accounting for "[t]he marginal cost of energy lost over the transmission and distribution lines to get from centralized generation resources to load reflecting the seasonal variability of the [customer-generator] resource." Notice of Commission Action, Docket No. D2017.6.49, Attachment 1 ("Avoided System Losses"). While the Company's BCA applied line loss savings only to energy, avoided line losses also avoid generation, transmission, and distribution capacity. Ex. VS/MREA-1 (Kobor

[12] The Company's marginal cost of service study used summer peaks because summer peaks are becoming predominate or, in NWE witness Normand's words, "because if you look at the data and the range of data, what you find is that the summer is going to basically overtake." Hr'g Tr. 1177:25–1178:2. In addition, the summer thermal limits define capacity needs more than numerically higher winter peaks. Hr'g Tr. 1178:13–1179:1.

Dir.) at 88:10–89:6. Therefore, Vote Solar and MREA grossed-up the avoided cost values to account for the applicable avoided losses at each level. *Id.*

Vote Solar and MREA's BCA adopted the Company's avoided carbon cost values to reflect avoided environmental compliance costs and used the market price of renewable energy credits ("RECs") as the proxy value for the additional societal benefits of renewable generation. Ex. VS/MREA-1 (Kobor Dir.) at 90:10–91:7. There is no basis for excluding carbon costs from the analysis due to uncertainty, as MCC urges, since the BCA must necessarily make certain assumptions about the future because of its 25-year study period. Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 9:6–10:2. Moreover, the MIR required at least one scenario including carbon dioxide emission costs. Notice of Commission Action, Docket No. D2017.6.49, Attachment 1 ("Avoided Environmental Compliance Costs") (requiring consideration of scenarios including carbon costs and excluding carbon costs); *see also* Final Order No. 7505b, Docket No. D2016.7.56, ¶¶ 50, 58, 60–65 (Jan. 5, 2017) ("The Commission mostly rejects MCC's position to exclude the carbon dioxide emission price forecast" which MCC opposed "due to the speculative nature" but adjusts the onset date of carbon pricing by three years); *see also* Findings of Fact and Conclusions of Law For the Symmetry Finding in MTSUN Order No. 7535b ¶¶ 23–24, *Vote Solar v. Mont. Dep't of Pub. Serv. Regulation*, Cause No. BDV-17-0776 (Mont. Dist. June 18, 2019) (finding the Commission's decision to eliminate carbon pricing to be arbitrary); Order Vacating and Modifying Montana Public Service Commission Order Nos. 7500c and 7500d ¶ 18, *Vote Solar v. Mont. Dep't of Pub. Serv. Regulation*, Cause No. BDV-17-0776 (Mont. Dist. Apr. 2, 2019) (finding the Commission's decision to exclude future regulatory costs of carbon dioxide from QF-1 rates in Docket No. D2016.5.39 to be arbitrary). Vote Solar and MREA included these costs in the benefit-cost results included in the table below.

5. A Benefit-Cost Analysis Should Only Include Interconnection an Administrative Costs That Can be Documented and Are Not Covered by Other Fees.

Although Company witness Faruqui claims that there are possible additional costs on the utility because of customer-generators' two-way flow of electricity, Hr'g Tr. 1293:22–23, 1294:5–6, there is no actual evidence of those costs on NorthWestern's system. Ex. VS/MREA-1 (Kobor Dir.) at 111:10–112:7; *see also* Ex. NWE-38 (Faruqui Dir.) at 10:1–3; Hr'g Tr. 1316:9–1317:18, 1401:9–1402:3 (hosting capacity of the existing system without costs for upgrades is site and utility specific). NorthWestern was unable to identify a single distribution investment necessitated by a customer-generator's two-way flow of electricity. Ex. VS/MREA-1 (Kobor Dir.) at 112:1–2; NWE Response to VS-MREA-014a. Moreover, the Company's BCA correctly concluded that there are no anticipated interconnection or integration costs associated with customer-generators for the next 25 years. Ex. VS/MREA-42 (Shlatz Second Dir.,) Exhibit ELS-2 at 21–22 of 40. Therefore, no interconnection costs should be included in the BCA.

The Company's BCA included application-related administrative costs as a cost of customer-generation. Ex. VS/MREA-1 (Kobor Dir.) at 94:9–95:2; Hr'g Tr. 1493:5–14, 1531:3–14. Those initial, one-time application costs do not appear to be the type of ongoing "marketing, advertising, evaluation, market research, and basic administration" envisioned by the Commission's decision in Docket No. D2017.6.49. Notice of Commission Action, Docket No. D2017.6.49, Attachment 1 ("Administrative Costs"). Moreover, even if they did constitute the type of costs the Commission referenced in the MIR, those costs are already recovered through the fee the Commission approved on June 7, 2019, in Docket No. D2016.9.66. Final Order No. 7621a, Docket No. D2016.9.66, ¶ 28 (June 7, 2019) (approving Rule No. 17 as proposed); Proposed Rule No. 17 Sheet No. R-17.4 (establishing an "Interconnection Request processing fee" to "cover reasonable costs for processing, minor studying, and evaluation of the

Interconnection Request").[13] That fee revenue offsets the administrative costs but were not reflected in the Company's BCA. Ex. VS/MREA-1 (Kobor Dir.) at 95:3–96:4. Now that the Commission has approved the application fee in another docket, NorthWestern's own witness agreed that the additional application fee revenue must also be included or the administrative costs removed from the analysis. Hr'g Tr. 1531:15–1532:6, 1545:25–1546:10. Accordingly, Vote Solar and MREA removed the application administrative costs from their corrections to the Company's BCA.

6. NorthWestern's Benefit-Cost Analysis Failed to Account for the Energy That Customer-Generators Provide to the Utility but Do Not Receive Credit for.

Under the current net metering rules, customer-generators must forfeit their generation provided to the utility at the end of each year. Mont. Code Ann. § 69-8-603(4); *see also* Hr'g Tr. 1897:11–1898:14. In other words, approximately four percent of the value of customers' generation is "wiped out" by the net metering statute. Hr'g Tr. 1423:21, 1897:11–1898:7. That artifact of the net metering statute results in uncompensated value flowing from the customer to the utility that must be picked up in a benefit-cost analysis, but which NorthWestern's BCA ignored. Hr'g Tr. 1532:7–24, 1897:11–1898:14. Vote Solar and MREA's analysis included the forfeit generation as a benefit to the utility.

C. A Benefit-Cost Analysis Consistent with the Commission's Direction in Docket No. D2017.6.49 Shows that the Benefits of Customer-Generation Exceed the Costs, and Therefore No Change is Justified Pursuant to HB 219 § 2(1)(a).

After making the necessary corrections to correspond to the Commission's instructions in Docket No. D2017.6.49, Vote Solar and MREA calculated the benefits and costs of customer-

[13] The Commission can take notice of these official filings that were approved by the Commission's final order and, therefore, constitute law. Mont. Code Ann. § 2-4-612(6); Mont. R. Evid. 202(b)(4), (6), (c)–(f).

generators to the NorthWestern system. Ex. VS/MREA-1 (Kobor Dir.) at 98–100. Those results are copied below:

Table 5: Vote Solar Benefit-Cost Study Results Current Adoption Scenario (levelized $/kWh)

	WACC Discount Rate	Long-Term Risk Free Discount Rate
Avoided Energy Cost	$0.0495	$0.0539
Avoided Generation Capacity Cost	$0.0346	$0.0364
Avoided Distribution Capacity Cost	$0.0339	$0.0357
Avoided Transmission Capacity Cost	$0.0166	$0.0176
Avoided System Losses	$0.0095	$0.0102
Subtotal Benefits	**$0.1441**	**$0.1538**
Avoided Carbon Cost	$0.0070	$0.0070
Other Benefits	$0.0008	$0.0008
Subtotal Benefits incl. Carbon and Societal	**$0.1519**	**$0.1616**
Reduced Revenues	($0.1155)	($0.1222)
Administrative Costs	$0.0000	$0.0000
Subtotal Costs	**($0.1155)**	**($0.1222)**
Utility Cost Test	**$0.1441**	**$0.1538**
Ratepayer Impact Measure	**$0.0286**	**$0.0316**
Utility Cost Test incl. Carbon and Societal	**$0.1519**	**$0.1616**
Ratepayer Impact Measure incl. Carbon and Societal	**$0.0364**	**$0.0394**

Table 6: Vote Solar Benefit-Cost Study Results Medium Adoption Scenario (levelized $/kWh)

	WACC Discount Rate	Long-Term Risk Free Discount Rate
Avoided Energy Cost	$0.0580	$0.0611
Avoided Generation Capacity Cost	$0.0375	$0.0390
Avoided Distribution Capacity Cost	$0.0367	$0.0383
Avoided Transmission Capacity Cost	$0.0180	$0.0188
Avoided System Losses	$0.0106	$0.0112
Subtotal Benefits	**$0.1608**	**$0.1684**
Avoided Carbon Cost	$0.0070	$0.0070
Other Benefits	$0.0008	$0.0008
Subtotal Benefits incl. Carbon and Societal	**$0.1686**	**$0.1762**
Reduced Revenues	($0.1198)	($0.1252)
Administrative Costs	$0.0000	$0.0000
Subtotal Costs	**($0.1198)**	**($0.1252)**
Utility Cost Test	**$0.1608**	**$0.1684**
Ratepayer Impact Measure	**$0.0410**	**$0.0432**
Utility Cost Test incl. Carbon and Societal	**$0.1686**	**$0.1762**
Ratepayer Impact Measure incl. Carbon and Societal	**$0.0488**	**$0.0510**

Those values, based on the Commission's MIR, differ significantly from the Company's BCA that systematically deviates from the MIR to prejudice customer-generation. The difference in each category between Vote Solar and MREA's MIR-compliant analysis and the Company's non-compliant analysis are shown below:

Comparison of Vote Solar and Navigant Benefit-Cost Study Results ($/kWh)

Category	Vote Solar	Navigant	Difference
Avoided Energy Costs	0.058	0.029	-50%
Avoided Capacity Costs	0.038	0.005	-87%
Avoided Distribution Costs	0.037	0.002	-95%
Avoided Transmission Costs	0.018	0.001	-94%
Total	**0.151**	**0.037**	**-75%**

Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 16 (Table 2).

These results demonstrate that the long-term benefits of customer-generation exceed the costs under each scenario and, in fact, exceed the current retail rate. *Id.* Contrary to NorthWestern's incorrect assertion that Vote Solar and MREA's analysis is "an outlier," NWE Opening Br. at 20, the results above are similar—and, in fact, more conservative—than other benefit-cost analyses conducted for customer-owned solar generation. The 2013 Rocky Mountain Institute meta study of distributed solar benefit-cost studies showed that of the 11 that used an approach similar to the Utility Cost Test, the average benefits in 2018 dollars were $0.1717/kWh, compared to the $0.1441/kWh Vote Solar and MREA calculated for the current adoption scenario. Ex. VS/MREA-1 (Kobor Dir.) at 101:3–10 & n.137.

There is no basis in the MIR-compliant evidence in this record to justify changing the rate structure for customer-generators.

II. An Accurate Cost of Service Study Demonstrates that Customer-Generators Cover Their Share of Costs Under Current Rates, and No Change is Justified Under HB 219.

The Legislature instructed the Commission to consider "the costs to provide service to customer-generators" when deciding whether separating customer-generators into a separate class is justified. HB 219 § 2(1)(b). To do so, the Commission must look at a cost of service study that analyzes the cost to serve customer-generators by applying the same methodology to all customers. Ex. VS/MREA-1 (Kobor Dir.) at 5:12–15. Such an analysis, using reasonable cost allocators and accurate load data, shows that customer-generators reduce their costs by reducing loads during the relevant cost-causing hours. Hr'g Tr. 1912:20–1913:5. As a result, even their reduced bills due to self-generation are sufficient to cover their costs under their current rate classification and rate structure and, therefore, no change is justified under HB 219.

A. NorthWestern's Embedded Cost of Service Study Uses Inaccurate Data and Assumptions for Customer-Generators.

1. NorthWestern's Embedded Cost of Service Study Conflates Costs of Service Provided to Customer-Generators in the Form of Delivered Energy with the Value of Services Received from the Customer in the Form of Exported Electricity.

The first step in correctly analyzing customer-generators in a cost of service study is to separate the service being provided by the utility to customer-generators from the service being provided by the customer-generator to the utility. Solar customers are both consumers of grid-supplied electricity from the utility, and providers of services to the utility through their exported electricity. Ex. VS/MREA-1 (Kobor Dir.) at 5:5–11. Those are distinct transactions that have separate costs and benefits. *Id.* at 14:10–14.[14] The cost to provide inflows of electricity from the

[14] Under NWE's current net metering tariffs, inflows from the utility to the customer are charged under the applicable residential REDS-1 tariff and outflows are credited under the Rule No. 16 tariff. Ex. VS/MREA-1 (Kobor Dir.) at 16:7–13. Those two flows offset for billing purposes, but are treated separately even under current tariffs.

utility to the customer must be determined by the actual inflow loads placed on the system by customers, not conflated with separate outflows that occur at other times. *Id.* at 5:15–19, 16:14–20, 18:2–19:12 & n.4.

NorthWestern and MCC's embedded cost of service analyses incorrectly conflate inflows and outflows—as if the cost to supply inflow electricity to a customer is changed if that customer later sends electricity to the utility—by netting the two flows and allocating costs to supply electricity inflow to the net of the bi-directional flows. *Id.* at 19:13–20:4, 24:14–15; NWE Response to VS-MREA-032b.[15] The cost of a transaction between utility and customer—in the inflow—is not changed by a later transaction between customer-generator and utility—in the outflow—so netting the flows when calculating the cost of the first transaction does not produce the true cost of the service. Ex. VS/MREA-1 (Kobor Dir.) at 24:15–17.[16]

2. NorthWestern's Embedded Cost of Service Study Failed to Weather-Normalize the Annual Usage Data for Customer-Generators While Doing so for Other Classes.

NorthWestern's cost of service analysis also failed to weather-normalize the annual load data for customer-generators, as it did for other customers, which results in inconsistent data and over-allocates energy costs to customer-generators. Ex. VS/MREA-1 (Kobor Dir.) at 25:3–15; Hr'g Tr. 1194:18–1195:5 (NWE witness Normand admitting that the annual usage data for customer-generators used in the cost of service study was not weather-normalized). While

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[15] MCC witness Dismukes and NWE witness Normand also revised net outflow loads to zero, which eliminates cost-reducing value that should be afforded to customer-generators if net load were consistently used to allocate costs. *See* Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 26:1–3; Hr'g Tr. 1196:4–1197:14. Using inflow data to allocate costs of providing the inflow service also avoids this flaw in the analysis conducted by MCC and NorthWestern.

[16] Vote Solar and MREA conducted their cost of service analysis by ensuring consistency and accuracy, rather than modifying it to achieve a preferred outcome. Therefore, Vote Solar and MREA's cost of service analysis corrected the error of using net load data to analyze the cost of inflows, even though the error benefits solar customers by implying a lower calculated cost to serve solar customers when compared to the correct approach. Hr'g Tr. 1886:1–18.

NorthWestern adjusted energy use data down for all other customers to account for the fact that 2017 temperatures were 0.6% colder than the 10-year mean, it failed to similarly adjust the annual energy use data down for customer-generators. As a result, NorthWestern overstates the energy-related costs allocated to customer-generators. Ex. VS/MREA-1 (Kobor Dir.) at 25:3–15.

3. NorthWestern Used Inaccurate Load Data.

Rather than using load research sampled data from customer-generators for its cost of service analysis of customer-generators, as it did for all other residential customers, NorthWestern's cost of service analysis created artificial load data for customer-generators through a convoluted series of assumptions and adjustments. Hr'g Tr. 1179:6–16, 1181:3–1186:22, 1218:1–1222:3, 1246:17–1249:15 (NWE witness Normand attempting to explain the method for deriving synthetized load data for customer-generators); Ex. VS/MREA-1 (Kobor Dir.) at 27:6–29:15. NorthWestern's opening brief attempts to explain and justify this convoluted, multi-step process to create synthesized load data for solar customers (complete with a graphic flow chart). NWE Opening Br. at 25–27. However, those contortions not only produced an incorrect load shape, but were unnecessary because the utility had actual load data and a valid sample from customer-generators that its own witnesses relied on it for other purposes. Ex. VS/MREA-1 (Kobor Dir.) at 26:1–27:12; Hr'g Tr. 1287:12–1288:21; Hr'g Tr. 1678:5–17 (NWE witness Schwartzenberger testifying that the Company has sampled interval data for both net metering and non-net metering residential customers).[17] The Company's

[17] The Company's cost of service witness, Mr. Normand, admitted that he determined loads differently for customer-generators than for other customers but claimed that he had to because he did not have sampled data for the customer-generators. Hr'g Tr. 1186:17–1187:8. Yet, he agreed that NWE witness Faruqui had sampled load data for customer-generators, and Mr. Normand had no dispute with how that sampling was conducted. Hr'g Tr. 1187:9–1188:9.

decision to use artificial load data prejudiced solar customers by overstating the cost of service compared to the cost based on the actual loads of those customers.

4. NorthWestern Allocated Distribution Demand Costs to Customer-Generators Based on Loads During an Hour that Does Not Reflect the Cost-Causing Peak Load Hour on the Distribution Equipment Serving Them, as the Utility Did for Other Residential Customer Subgroups.

NorthWestern also allocated distribution demand costs—which are driven by peak loads on distribution system equipment like substations, circuit feeders, and transformers—to customer-generators based on the hour when the disbursed customer-generator subgroup peaks, which has no relationship to the cost-causing peak time on the distribution system serving those customers. Ex. VS/MREA-1 (Kobor Dir.) at 30:6–32:13.[18] For a large, diverse class that dominates the loads on the distribution system components serving that class, the class's peak—called the class non-coincident peak ("NCP")—is typically used to allocate costs because it is presumed to approximate the peak loads on the distribution system components serving those customers. Ex. VS/MREA-1 (Kobor. Dir.) at 30:8–32:13; *see also* Hr'g Tr. 1189:9–1190:6.[19]

That is, class NCP is relevant to cost causation, and therefore to a cost of service study, only to the extent it approximates peak loads on the distribution system components. The subclass of customer-generators' NCP does not approximate the peak loads on the distribution system and is, therefore, irrelevant to cost causation and should not be used to allocate costs.

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[18] MCC witness Dismukes adjusted NWE's embedded cost of service study to account for a lower revenue allocation to customer-generators but maintained the unjustified use of that subgroup's NCP, which does not align with cost causing loads. Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 28:1–29:3. When the actual cost-causing loads that occur during the residential class peak hour are used to allocate costs, and the value of customer exports is recognized, customer-generators recover more than their cost to serve. *Id.* at 29–30 & Table 5.

[19] NWE cost of service witness Normand confirmed that the basis for using class NCP to allocate distribution system costs is because it reflects peak loading on the substations and circuits serving the customers. Hr'g Tr. 1189:9–1190:6.

The customer-generator subclass loads are very small compared to the overall class, and customer-generators are scattered throughout the service territory. Ex. VS/MREA-1 (Kobor Dir.) at 32:13–33:2.[20] Thus, a couple thousand customer-generators loads spread throughout NorthWestern's entire service territory are simply not going to drive the peak loading on distribution substations and circuits compared to the impact of the combined loads of the roughly 300,000 other residential customers. Hr'g Tr. 1192:15–25.

The Company should not have used the customer-generator subgroup peak on June weekdays at 8 p.m., when the load of all residential customers as a whole was half of its annual peak that occurred at a different time and in a different season. Ex. VS/MREA-1 (Kobor Dir.) at 34:4–12 & Table 1. Customer-generators were not causing the annual peak load on those substations and circuits at 8 p.m. in June. *Id.*; *see id.* at 33:3–8.

The Arizona Corporation Commission considered this issue and rejected a utility's attempt to allocate distribution costs to customer-generators' NCP instead of the hour of the combined NCP for the class as a whole:

> The Companies utilized the class NCP method which determined the NCP for the non-DG and DG classes separately to allocate the distribution costs between DG and non-DG customers. However, usage of the grid during times other than the net combined NCP of the DG and non-DG classes should not be factored into the allocation of the distribution costs as it does not drive distribution capacity costs. Since the combined NCP for the DG and non-DG customer classes occurs in the summer, the DG class NCP, based on exports in April, does not impact the cost of the distribution circuit as there is plenty of excess capacity at that time. . . . Because the net combined residential NCP occurs in July, this is the basis for allocating the distribution circuit costs, and it is irrelevant that the DG customers' NCP occurs in April because the circuit must be built to serve the maximum total residential capacity which occurs in July.

[20] As NWE witness Normand admitted, there is no a separate distribution system built for customer-generators; those customers are on the same circuits as non-generating customers. Hr'g Tr. 1190:7–16. The substation serving both types of customers experiences one peak load—based on "the summation of the loads"—not two different peaks. Hr'g Tr. 1192:7–19.

In the Matter of the Application of Tucson Elec. Power Co. for the Establishment of Just & Reasonable Rates & Charges, Docket No. E-01933A-15-0322, Decision No. 76899, 2018 WL 4600839, at *78–79 (Ariz. Corp. Commn. Sept. 20, 2018); *see also In the Matter of the Application of UNS Elec., Inc., for the Establishment of Just & Reasonable Rates & Charges*, Docket No. E-04204A-15-0142, Decision No. 76900, 2018 WL 4600840, *69–70 (Ariz. Corp. Commn. Sept. 20, 2018). Tellingly, NorthWestern recognizes this concept because it allocates distribution system costs to another residential subclass (NorthWestern employees) based on their load during the broader class NCP, not during the NorthWestern employee class NCP hour. Ex. VS/MREA-1 (Kobor Dir.) at 33:9–16.

B. An Accurate Cost of Service Analysis Shows that Solar Customers Cover Their Fair Share of Costs Under Current Net Metering.

Vote Solar and MREA adjusted NorthWestern's embedded cost of service study to correctly allocate costs to import loads (rather than net flows), to use actual load research sampled data instead of NorthWestern's contrived, artificial, load for customer-generators, to allocate costs to the actual cost-causing combined residential class NCP, and to apply the same weather adjustment to residential customers as was applied to all other customers. Ex. VS/MREA-1 (Kobor Dir.) at 37:7–40:10. That analysis used the same weighted, scaled, and weather-normalized sampled load data that NorthWestern witness Faruqui used. *Id.* at 38:10–18. The resulting, more accurate cost of service for customer-generators was then compared to revenues from those customers for their imports (*i.e.*, delivered loads). *Id.* at 40:11–41:16.

After separating customer inflows from outflows for the cost of service, those transactions must also be separated for determining revenues. The bills paid after netting inflows and outflows cannot be compared to the cost of service for only the inflows. Under net billing, customers "pay" the utility for the service they receive through a combination of: (1) money and

(2) cashing in credits earned for electricity the customer-generator provided to the utility during that month or in prior months. Looking only to the money paid by customers as revenue omits the value that those customers also provide to the utility by supplying electricity. There is no dispute that the electricity that customer-generators provide to the utility has some value—even if there is a dispute about what that value is.

NorthWestern and MCC assert that customer-generators do not cover their cost of service by looking only at what those customers pay to the utility in money, rather than what they provide to the utility in both money and electricity, which treats their generation as having no value. Ex. VS/MREA-1 (Kobor Dir.) at 41:3–10. Vote Solar and MREA's analysis, in contrast, correctly recognizes that there is value received by the utility in the exported electricity from customer-generators and, therefore, the credits that those customers later cash-in must be reflected as revenues. *Id.* at 41:11–16.

The corrected embedded cost of service study shows that customer-generators collect approximately the same portion of their cost of service as non-generating customers under current rates (88 vs. 89%) and would collect approximately the same portion of their costs under NorthWestern's proposed rates for residential customers (95 vs. 97%). Ex. VS/MREA-1 (Kobor Dir.) at 42:3–43:7 & Table 3. The de minimis difference (1 to 2%) is well within the range of the range of cost recovery of individuals and other subgroups within the residential class and does not justify a separate rate class under HB 219 § 2(1)(b).[21]

[21] NWE's proposed three-part rates would result in over-collection of costs from customer-generators: 121% compared to the 97% that residential customers collect on average under NWE's proposed rates. Ex. VS/MREA-1 (Kobor Dir.) at 42 (Table 3) (Revenue Under Proposed RENM-1), 43:8–44:2. NWE's proposed three-part rates for customer-generators are discussed further below. The over-recovery of costs through those rates is one of several reasons the proposed rates are unjustified.

Moreover, even if there was evidence that customer-generators produce a lower return to the utility than the residential class as a whole, no party was able to identify a non-discriminatory standard for when such under-collection of costs justifies creating a new customer class and imposing different rates, rather than simply reflecting the fact that large and diverse customer classes inevitably produce a range of cost recovery by individuals and subgroups within that class. Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 31. As MCC witness Dismukes agreed, customers other than customer-generators receive intra-class subsidies because their consumption-based charges do not cover their costs. MCC Response to VS-MREA-156(a). In fact, one example of a large customer subgroup that fails to cover its costs is rural customers, which the record shows significantly under-recover their costs. Ex. VS/MREA-1 (Kobor Dir.) at 116:8–121:11. That is not the only example. Based on the load research data in the record, 25% of non-generating residential customers—representing more than 70,000 customers—recover a smaller portion of their costs than the average residential customer-generator. *Id.* at 132:3–20; Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 23:2–12. That reflects more than 40 times the total number of residential customer-generators. Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 23:11–12. Therefore, because some level of cross-subsidies is inherent in any rate design, the mere fact of a cross-subsidy would not distinguish customer-generators. They would only be distinct if the degree of cross-subsidy for customer-generators was larger than for other identifiable subgroups. There is no evidence that that is true. The Commission cannot single-out customer-generators for different rate treatment based on an alleged cross-subsidy where other subgroups receive much larger cross-subsidies but are not similarly subjected to the different rate treatment. Ex. VS/MREA-1 (Kobor Dir.) at 121:14–123:3; Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 23:13–24:9.

Because an accurate cost of service analysis shows that customer-generators currently recover their share of costs under their current rate classification and design, and because even if there were an under-recovery of costs, NorthWestern failed to identify an objective threshold for separating a subgroup as opposed to part of the natural variability of cost recovery within a diverse class, there is no basis to create a separate classification of customer-generators at this time.

III. The Commission Should Address Any Perceived Cost Under-Recovery from Customer-Generators Through Adjustment of Compensation for Exports, Rather Than by Creating a New Classification and Rate Design for the Customer's Imports of Utility Electricity.

As demonstrated above, an accurate benefit-cost analysis and cost of service study provide no basis under HB 219 § 2 to require a separate rate classification for customer-generators. If the Commission nevertheless decides to modify the current net metering tariffs, the Commission should address the compensation paid for solar customer's exported electricity, not change the rates or rate structure for the electricity the customer receives from the utility. The 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." HB 219 § 2(3); Mont. Code Ann. §§ 69-8-603, 69-8-611(3).[22] That option—sometimes called "inflow/outflow billing"—charges solar customers the same prices for the electricity received from the utility as all other customers pay, while crediting solar customers for their electricity outflows at a rate based on the value of that export rather than through a credit equal to the retail rate. *See, e.g., In the Matter, on the*

[22] NWE witness Schwartzenberger testified that Montana law requires NorthWestern to offer full retail rate net metering that credits exports at the full retail rate, but conceded that he had not taken into account the exception provided in Mont. Code Ann. § 69-8-603 for separate inflow and outflow rates pursuant to § 69-8-611(3). Hr'g Tr. 1562:19–1564:16. As he testified at hearing, if a rate is adopted pursuant to § 69-8-611(3), the exception is met and full retail rate net metering is not required. Hr'g Tr. 1564:12–16.

Commission's Own Motion, to Implement the Provisions of Sections 173 and 183(1) of 2016 PA 342, and Section 6a(14) of 2016 PA 341, Case No. U-18383, Order, 2018 WL 1967049, at *2, 7–8 & Exhibit A (Mich. P.S.C. Apr. 18, 2018); Ex. NWE-53 at Exhibit A § XVIII. That properly recognizes that customers with rooftop solar are like other customers when they are importing utility-supplied electricity, so should pay the same rates as other customers for that electricity. To the extent that customer-generators differ because of their exports, they should be treated differently by rates applied to those exports.

Implementing an inflow/outflow rate instead of a demand charge for solar customers provides additional benefits. It addresses the concern that under net metering, unused credits are forfeited, as well as the concern expressed by Dr. Faruqui and Dr. Dismukes that classic net metering overcompensates for customer exports by applying the retail rate for those exports. Hr'g Tr. 1293:20–21, 1294:5–6, 1301:15–20, 2253:21–24. In fact, it responds to NorthWestern's main argument that the value from customer-generation "is outweighed by the current credit that net metering customers receive" which is not addressed by a demand charge for inflows. NWE Opening Br. at 19. Implementing an inflow/outflow rate structure would also allow the Commission to set the outflow credit rate to be time sensitive to encourage solar customers to export during the hours where the generation is most valuable, and location sensitive to encourage solar where it can relieve congestion. *See, e.g.*, Hr'g Tr. 2237:8–2238:7, 2247:5–2249:6.

Demand charges imposed on the utility-supplied electricity the customer receives provide none of those additional benefits of an inflow/outflow rate and unfairly charge different prices for the import service solar customers receive just like every other customer instead of the export value that the Company claims is the problem.

IV. Even if the Commission Creates a Separate Rate Classification for Customer-Generators, It Should Reject a Demand Charge Rate as Inequitable, Unfair, and Unnecessary.

Even if the Commission determines that the benefit-cost analysis and cost of service study, when correctly done, justify separate rate classification for customer-generators pursuant to HB 219 §§ 2(1) and 3(1), the statute does not require or even suggest that the Commission must also impose a mandatory demand charge rate structure. Notwithstanding a single outlier in Kansas, **every other regulatory commission in the country has concluded that mandatory demand charges are inappropriate for residential customers—**whether they have solar or not. As the evidence demonstrates in this case, demand charges for residential customers do not provide an actionable price signal, do not improve the correlation of rates to costs compared to a two-part rate, are undemonstrated, and are wildly unpopular. Moreover, the rates proposed by NorthWestern for solar customers would destroy the economics of solar for most families and undermine the growing small business sector in Montana that sells and installs that solar.

A. Demand Charges are Inappropriate for Residential Customers.

NorthWestern relies on the testimony of Dr. Faruqui to justify a mandatory demand charge for customer-generators. However, there is weak, or no, empirical evidence that residential customers are able to respond to the type of demand charge proposed by NorthWestern. As Dr. Faruqui admitted, mandatory demand charges for residential customers are "new for residential customers, absolutely new." Hr'g Tr. 1418:4–5. Mandatory demand charges have been controversial and often reversed by policymakers. Furthermore, there is no improved correlation between a customer's charges under the proposed three-part rate and that customer's costs than under a two-part rate.

1. Demand Charges Do Not Provide an Actionable Price Signal for Residential Customers.

Contrary to NorthWestern's argument that demand charges are simple to understand, NWE Opening Br. at 27–29, the real issue is not the ability to comprehend the mechanics of a demand charge.[23] The larger problem with demand charges for residential customers is being able to understand **what to do about the charge**. Responding to a demand charge requires customers to know when their peak demand occurs, understand the loads that contribute to that peak, and be able to adjust those loads during all 730 hours in each month. Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 37:9–39:4.

There is also no recent evidence that mandatory demand charges are appropriate for residential customers. The four academic papers NorthWestern witness Faruqui cites are dated, relate to voluntary programs, and expressly state that their conclusions should not be applied to mandatory demand charges, which Dr. Faruqui nevertheless attempts to do. Ex. VS/MREA-2 (Yozwiak Dir.) at 22:8–23:14. Moreover, the Arizona Public Service Company demand rate Dr. Faruqui references is similarly irrelevant since it is not only voluntary, but was also specifically targeted to customers whose usage pattern would result in cost savings without any need to respond to the rate's price signals. *Id.* at 24:1–25:18.

The nature of residential customers and their loads means that residential demand charges provide no actionable price signal and are very unpopular. Ex. VS/MREA-1 (Kobor Dir.) at 135:5–15; Ex. MCC-4A (Dismukes Dir.) at 26:9–12; Hr'g Tr. 2195:19–2196:1. The limited

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[23] Tellingly, in a misdirected attempt to explain how demand charges are simple to understand, NorthWestern provides a convoluted and, ultimately, incorrect analogy to filling a bucket with water during the month. NWE Opening Br. at 29. Contrary to NorthWestern's description, its proposed demand charge does not add "more water . . . to the bucket to the next maximum level with all water being dumped from the bucket at the end of the billing cycle." *Id.* This confused analogy by the Company in attempting to provide "[a] simple way to think about demand charges"—and especially where the analogy is incorrect—exemplifies why demand charges are difficult for residential customers.

available data indicate that, at most, residential customers have the ability to respond by 10%, which leaves 90% of the demand charge incapable of response. Hr'g Tr. 1927:25–1929:4. There is no effective price signal in demand charges if customers cannot see and respond to them. Hr'g Tr. 1895:24–1896:2.

There is also no evidence that solar customers are better able to understand and respond to demand charges. Contrary to Dr. Faruqui's *ipse dixit* that the ability to understand "20-year rooftop solar leases or purchases" means solar customers can manage their loads during each hour of the month, there is no actual basis for that assumption. NWE Opening Br. at 29 (quoting Ex. NWE-39 (Faruqui Reb.) at 19:11–12). The Company provided no evidence that solar customers are better able to understand their loads and respond to a demand charge than other residential customers. Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 36:10–37:5, 39:5–14; Hr'g Tr. 1896:11–16. Nor is it a logical conclusion since the act of installing a solar panel on one's roof imparts no additional knowledge about demand management. Thus, just as a demand charge for residential customers would lead to widespread confusion—as if written in Sanskrit—it would also do so for customer-generators. Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 36:10–37:5; *see also* Ex. MCC-4A (Dismukes Dir.) at 26:5–12 (noting that imposing demand charges on residential customers "would lead to widespread confusion" and residential customers "will be unable to respond to the price signals imposed by a drastically altered rate structure").

2. The Vast Majority of Utilities and All But One Regulatory Commission Have Rejected Mandatory Demand Charges for Residential Customers, Including Solar Customers.

NorthWestern relies on the testimony of Dr. Faruqui to suggest that mandatory residential demand charges are common and approved by regulators. NWE Opening Br. at 27 (claiming that "other utility commissions have found" a mandatory demand charge for residential customers "to be appropriate."). Dr. Faruqui, in turn, relies on a list of utilities who purportedly have demand charges for residential customers. NWE Opening Br. at 30 (citing Ex. NWE-38, Appendix C). That list contains errors and, upon a closer examination, belies the point he tries to make.

First, it is important to put Dr. Faruqui's list of residential demand charges in perspective. Even if Dr. Faruqui had correctly identified the utilities with mandatory residential customer demand charges—which he did not—his list would still constitute a miniscule number in relation to the more than 3,000 retail electric utilities in the country that do not impose mandatory demand charges on residential customers. Hr'g Tr. 1359:2–13. Second, Dr. Faruqui's list includes both optional and mandatory rates and, even among the very small number of mandatory demand charges, incorrectly identifies a number of optional or conditional rates as mandatory.

Of the purported 60 charges he initially identified, Dr. Faruqui concedes that, at most, nine are mandatory. Ex. VS/MREA-2 (Yozwiak Dir.) 19:18–20:1; Hr'g Tr. 1359:10–13. Of those, one is no longer mandatory and three are not actually mandatory unless the customer has very high use. Ex. VS/MREA-2 (Yozwiak Dir.) at 20:1–13; Hr'g Tr. 1360:5–1366:9 (Dr. Faruqui was not aware of the actual tariffs listed in his exhibit); Ex. VS/MREA-8 (City of Templeton demand charge only applies to demands greater than 10 kW); Ex. VS/MREA-14 (Santee Electric Cooperative's "Rider for Net Metering" tariff available and does not impose demand charge); Ex. VS/MREA-15 (Salt River Project E-27 demand charge rate not mandatory and non-demand E-14 rate available); Ex. VS/MREA-16 (Swanton Village has demand charge only for customers with use greater than 1,800 kWh per month on a 12 month average basis); Ex. VS/MREA-17 (Vigilante Electric Cooperative demand charge is only 50 cents per kVA and only applies to demands greater over 15 kVA). Tellingly, of the very few utilities that imposed a demand charge for residential customers, some had to retract them because of the public response. Ex. VS/MREA-2 (Yozwiak Dir.) at 26:3–27:9; Hr'g Tr. 1853:15–20. The fact that there are so few actual mandatory residential demand charges out of more than 3,000 utilities demonstrates just how radical such rates are.

Moreover, the handful of mandatory residential demand charges consist primarily of unregulated cooperatives or municipal utilities, who have a small customer base and set their own rates, rather than utilities who must have rates approved by a supervising body such as this Commission. Ex. VS/MREA-2 (Yozwiak Dir.) 20:14–16; Hr'g Tr. 1359:14–17.[24] While NorthWestern cites Kansas—the only regulatory commission in the country to impose a mandatory demand charge for residential customers—it fails to acknowledge that many other commissions rejected such charges. NWE Opening Br. at 29–30 (citing the Kansas Corporation Commission's Final Order); Hr'g Tr. 1359:14–21. Regulatory commissions in Arizona, Nevada, and Oklahoma all heard and considered Dr. Faruqui's arguments and then rejected mandatory demand charges for residential customers (including for residential customers with generation). Hr'g Tr. 1353:19–22, 1354:8–22, 1356:10–17, 1358:6–16, 1933:10–1934:2.

Perhaps most important, mandatory demand charges for residential customers have proven extremely unpopular, leading the Illinois Governor to call them "insane." Ex. VS/MREA-2 (Yozwiak Dir.) at 27:10–11.

[24] NorthWestern also cites the Flathead Electric Cooperative's demand charge. NWE Opening Br. at 30. That charge was not included in Dr. Faruqui's list prior to hearing and was identified for the first time during hearing. Hr'g Tr. 1358:20–1359:1. NorthWestern conveniently omitted the fact that the charge only applies during on-peak hours and is a very small charge: $0.26/kW, compared to NorthWestern's proposed $7.69/kW charge that applies during all hours. *See* Flathead Electric Cooperative, *Rates & Service Fees*, https://www.flatheadelectric.com/account/rates-service-fees/.

3. NorthWestern's Proposed Demand Charge Provides No Better Price Signal or Connection Between Charges and Costs Than a Standard Two-Part Rate.

Demand charges also fail to provide any demonstrable improvement in setting charges for individual customers proportionate to that customer's costs—which is the main argument for them in the first place. While there may be superficial allure in a rate that includes a "demand" charge because certain cost allocations in the cost of service study are based on "demand," there is no actual connection between how demand costs are incurred and how the proposed demand charge is imposed. Hr'g Tr. 1879:23–1882:12. The mere use of the term "demand" to refer to both a charge on an individual customer's single peak hourly demand per month as well as a date- and time- specific class load used to allocate costs does not create a connection. Ex. VS/MREA-1 (Kobor Dir.) at 134:6–10; Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 33:19–35:5.

There are no costs caused by an individual customer's peak use—which is what the proposed demand charge would target. Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 34:2–8; MCC Response to VS-MREA-158; NWE Response to VS-MREA-038. As a result, when individual customer-generators' demands during the relevant cost-causing hours are compared to their charges on a rate imposed on the individual customer's peak demand (and not the cost-causing hour demands), a demand charge is not meaningfully more accurate at collecting revenues proportionate to cost causation than a two-part rate. Hr'g Tr. 1881:3–1882:12.[25]

[25] NorthWestern relies on Dr. Faruqui's comparison of net metering customer's average annual net consumption to their individual customer monthly maximum demands. NWE Opening Br. at 25. NorthWestern and Dr. Faruqui fail to acknowledge that such a comparison is irrelevant for purposes of the relevant analysis—"the cost to provide service to customer-generators." HB 219 § 2(1)(b). Neither the Company nor MCC could identify a single cost of providing service to customer-generators that is based on the individual customer's monthly maximum demand. MCC Response to VS-MREA-158; NWE Response to VS-MREA-038; Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 34:2–8. The relevant

As Dr. Faruqui admits, his proposed demand charges are, at best, approximations of costs but that designing a demand charge rate deviates from cost causation to meet practical realities of rate design. Ex. VS/MREA-1 (Kobor Dir.) at 128:1–9, 131:1–11; Ex. NWE-38 (Faruqui Dir.) at 36:15–19. The individual customer demands do not match the system demands that cause costs in time or magnitude. Dr. Faruqui admits that there are no costs actually caused by the peak demand for which the proposed demand charge would charge customers and no connection between the charge and the actual cost-causing peak demands on the system. Ex. VS/MREA-1 (Kobor Dir.) at 130:4–14; NWE Responses to VS-MREA-038, VS-MREA-047e, VS-MREA-107.

The proposed demand charge rate design produces effectively the same correlation between an individual customer's costs and what he would pay under the rate as the default two-part rate for residential customers produces: 0.945 versus 0.950. Ex. VS/MREA-1 (Kobor Dir.) at 131:8–135:4; Hr'g Tr. 1881:3–1882:12. NorthWestern's attempted rebuttal of this calculation illogically compares values from a cost of service study analyzing delivered loads with revenues from net loads that fail to provide value to exported electricity. Hr'g Tr. 1383:12–1385:4; Ex. VS/MREA-1 (Kobor Dir.) at 41:3–10. That is, NorthWestern failed to calculate cost of service and revenue using a consistent methodology (delivered load or net load) to both cost of service and revenues in calculating its correlation between costs and cost recovery. Ex. VS/MREA-1 (Kobor Dir.) at 41:3–10. If it had, it would have confirmed Ms. Kobor's analysis showing no meaningful difference in connecting rates to costs under the three-part rate.

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comparison is their reduction in the peak cost-causing hours, as Ms. Kobor analyzed in her cost of service analysis.

For all of these reasons, demand charges are inappropriate for residential customers—whether they have solar or not. The fact that a two-part rate does a virtually equivalent job of collecting revenues from customers proportionate to their costs means there is no justification for imposing the unpopular rate that most residential customers are incapable of responding to. Ex.VS/MREA-1 (Kobor Dir.) at 9:1–6. That is, a demand charge is all pain for no apparent gain.

B. Imposing a Demand Charge for Only Customer-Generators Would be Discriminatory.

NorthWestern witness Faruqui admitted that he advocates for demand charges for all customers. Hr'g Tr. 1348:11–14. He has testified in support of demand charges for all residential customers as well as for customers with generation. Hr'g Tr. 1350:6–1358:16. The arguments in support of demand charges for customer-generators are the same arguments he makes for demand charges for all customers. *Id.*; *Compare* Ex. NWE-38 (Faruqui Dir.) at 29–36, 37–38, *with* Ex. VS/MREA-12 at 4–9, 18–19, 22, Ex. VS/MREA-10 at 4–9, 14–15, 17–19, Ex. VS/MREA-9 at 5–11, 25–27, Ex. VS/MREA-11 at 4–8, Ex. VS/MREA-13 at 5–13. Specifically, he argues that there is a subsidy from high use customers to low use customers under two-part rates, which is not limited to customers with generation. Hr'g Tr. 1348:11–1349:17.[26] That is a general, overarching critique of the two-part rate; it is not limited to or unique to customer-generators. Therefore, a fundamental redesign of rates from two-part to three-part rates for

[26] Contrary to NorthWestern's argument that there in an "invisible cross-subsidy, or hidden tax" as a result of "the current rate structure of the residential class and how net metering customers use NorthWestern's electric grid differently," NWE Opening Br. at 17, it is the lower than average energy usage that creates the so-called cross-subsidy or hidden tax under a two-part rate. As NorthWestern explains, it is the recovery of "fixed cost" through volumetric rates that results in customers "pay[ing] less for the investments NorthWestern made on their behalf." *Id.* That is not unique to customer-generators (or net metering customers) but is true of all low use customers, which is why Dr. Faruqui argued elsewhere for three-part rates for all residential customers. Hr'g Tr. 1350:6–1358:16; Ex. VS/MREA-12 at 4–9, 18–19, 22; Ex. VS/MREA-10 at 4–9, 14–15, 17–19; Ex. VS/MREA-9 at 5–11, 25–27; Ex. VS/MREA-13 at 5–13.

residential customers in order to change the pricing structures should not be limited to customer-generators. Yet, no party argues that all residential customers should be forced onto a demand charge. MCC witness Dismukes testified that imposing a demand charge on residential customers would cause confusion and that "without a concrete and well-prepared rollout and educational campaign, I think a flash cut to a demand charge would probably meet with a lot of angry ratepayer phone calls to commissioners." Hr'g Tr. 2194:7–10, 2194:25–2195:14.

It would be unfair and inequitable discrimination to nevertheless force solar customers—whose inflows of electricity from the utility are within the range of all other residential customers—to pay for those inflows through a demand charge. A solar customer's decision to run an appliance or not, or to run two appliances simultaneously, has no different impact on the grid or costs than a non-solar customer's decision to do so. Therefore, those decisions should be priced the same. Hr'g Tr. 1931:11–18. In other words, the Commission cannot impose a demand charge on residential customer-generators because of their low use or low load-factor and not impose the same charge on non-generating low use and low load factor customers without engaging in discriminatory ratemaking.

C. NorthWestern's Proposed Rates for Customer-Generators Would Undercut the Savings Achieved by Montana Families Investing in Solar and Harm Montana's Renewable Energy Installation Small Businesses.

The proposed demand charge rates for Montana families that install solar would drive the economics of that choice underwater. Vote Solar and MREA analyzed the impacts of the proposed rate changes because, despite a clear requirement in state law for the utility to do so, the application contained no bill impact analysis for solar customers. Mont. Admin. R. 38.5.177(2); Ex. VS/MREA-1 (Kobor Dir.) at 104:3–11. The rate impact analysis shows that NorthWestern's proposed rates for solar customers would increase those customers bills 16.40% from what they would pay under current rates, compared to the proposed 7.39% increase for residential customers on average. Ex. VS/MREA-1 (Kobor Dir.) at 7:2–5, 107:1–10; *see also* Hr'g Tr. 1452:15–21; NWE Response to VS-MREA-11.[27] That would cut potential bill savings by 33% for an average customer-generator, resulting in a bill that is 28% higher than it would be under the rates for all other residential customers. Ex. VS/MREA-1 (Kobor Dir.) at 108:9–12; Hr'g Tr. 1373:9–1375:3. Those changes would render rooftop solar investments uneconomic for most Montana families. Ex. VS/MREA-1 (Kobor Dir.) at 108:13. In fact, some families—approximately 9%—would actually pay more in bills to NorthWestern after installing solar than they do before installing solar. *Id.* at 108:15–17. Company witness Faruqui also agrees that the rates the Company proposes will decrease the number of Montana customers who install solar. Hr'g Tr. 1378:24–1379:14.

That level of rate increase would decimate the rooftop solar industry by eliminating most or all of a residential customer's economic incentive to invest in rooftop solar. With the margins for customer savings through solar already narrow in Montana, the drastic change NorthWestern proposes would decimate the 35 to 40 Montana-based small businesses in the state's renewable energy industry who install small generation systems. Ex. VS/MREA-4 (Valainis Dir.) at 3:19–4:4, 7:6–9:19; *see also* Hr'g Tr. 1410:13–1411:15 (utility witness discussing economics of rooftop solar relative to the retail rate), 1414:10–13 (noting that the payback period for solar even under current rates is very long), 1428:7–9 (Dr. Faruqui is "amaz[ed]" there is any significant adoption rate given the 17-year payback period under current rates), 1453:12–19 (proposed rates would increase the payback period for solar by 30 percent), 1940:14–1941:4.

[27] MCC witness Dismukes agrees that the rate increase for any class, including customer-generators, should be limited to 1.25 times the overall system average increase. Ex. MCC-4A (Dismukes Dir.) at 56:12–13; MCC Response to VS-MREA-164. As Dr. Dismukes testified, the Company's proposed rate for customer-generators results in an increase that is "inconsistent with the concept of gradualism." Ex. MCC-4A (Dismukes Dir.) at 56:5–9.

The unfounded arguments that only rich people invest in rooftop solar are demonstrably false. Most solar installations are occurring in middle class neighborhoods, and middle-income customers are increasing as a share of all installations. Ex. VS/MREA-4 (Valainis Dir.) at 5:3–6:3, 6:12–7:5. In fact, the share of low-income customers in NorthWestern's customer-generator subgroup is almost exactly the same as the share among non-generating residential customers as a whole (3.4% vs. 3.8%). *Id.* at 6:4–11. The trend towards greater solar participation by middle and lower income customers is increasing as equipment prices decline. Changing the structure of rates for solar customers now would grandfather the early adopters and freeze out new customers just as new customers are trending towards middle and lower income customer segments. *Id.* at 6:20–7:5.

V. The Other Arguments Raised by NorthWestern for a Separate Customer-Generator Class Fail as a Matter of Law and for Lack of Evidence.

NorthWestern and MCC also argued that a difference in load shapes between the average customer-generator and the overall residential class could justify different rate treatment for customer-generators. That is not a basis provided by HB 219, which mandates that different rate treatment only be based only upon a benefit-cost analysis and cost of service analysis. HB 219 §§ 2(1), 3(1). To ensure the Commission applied only that standard, the Legislature amended the general standard for defining customer classes to ensure that the Commission's determination for customer-generators was not subject to the general standard for determining customer classification. HB 219 § 4(1), (3) (amending Mont. Code Ann. § 69-3-306 to provide that "Classifications of service for customer-generators must be determined in accordance with Title 69, chapter 8, part 6" and not the generally applicable standard based on "the quantity used, the time when used, and any other reasonable consideration"). Moreover, even if the Commission were to apply a general standard, the differences NorthWestern identifies do not exist or cannot justify different treatment based on the evidence in this case.

NorthWestern's load shape argument looks only at averages of the customer-generator subgroup compared to the average of the residential class as a whole, which hides the diversity and overlap in the loads of the individual customers in each group. Ex. NWE-38 (Faruqui Dir.) at 16 (Figure 2); Ex. VS/MREA-1 (Kobor Dir.) at 114:15–115:5; Ex. VS/MREA-2 (Yozwiak Dir.) at 4:10–12; Hr'g Tr. 1323:15–1325:5. By definition, an average hides the range of loads within the class being averaged. Ex. VS/MREA-2 (Yozwiak Dir.) at 4:15–17. A large, diverse class has a wide range of loads that are not reflected in averages and comparing a small subgroup—like customer-generators—to an average of a much larger and diverse group falsely implies that the subgroup is outside the range of the group as a whole. Ex. VS/MREA-2 (Yozwiak Dir.) at 4:13–5:15. That is why Dr. Faruqui admits that averages, alone, are not sufficient and that the dispersion—or range—of customer loads within an average should also be considered. Hr'g Tr. 1347:1–16. Yet, Dr. Faruqui failed to present the dispersion, or range, of customer loads and looked only at the averages. Hr'g Tr. 1347:17–20.

When one looks at the dispersion, or range, of the diverse customers within the residential class as a whole, customer-generators are well within that range. The loads that customer-generators put on NorthWestern's system—the electricity NorthWestern supplies and not the electricity generation that NorthWestern receives—are well within the wide range of diversity within the large residential class as a whole. Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 18:9–11; Ex. VS/MREA-2 (Yozwiak Dir.) at 6:10–10:2; Hr'g Tr. 1345:20–1346:5 (the distribution of capacity factors for customer-generators and non-generating customers also overlap).[28] NorthWestern witness Faruqui agrees that there is a large overlap in the electricity inflow rates of customer-generators and non-generating customers. Hr'g Tr. 1325:18–1326:3.[29]

Additionally, despite arguing that a difference in load shapes requires separating customer-generators into their own class, NorthWestern fails to identify an objective standard for when a load shape is sufficiently different to justify a separate class instead of simply within the normal range of distribution within a large diverse class. Ex. VS/MREA-1 (Kobor Dir.) at 114:10–14; Ex. VS/MREA-2 (Yozwiak Dir.) at 18:15–18. The Commission cannot apply a metric for a non-discriminatory determination that one subgroup should be segregated for different rate treatment unless it can define the threshold and apply it to all customers. Furthermore, even if it had defined a threshold for the degree of difference from a class average load shape that justifies separate rate treatment, it would be under-inclusive if limited to just customer-generators. There are ten times as many non-generating residential customers with the same load shape as current customer-generators—which would require creating a separate class for those customers if load-shape is used to define customer class. Ex. VS/MREA-2 (Yozwiak Dir.) at 10:10–11:11; Ex. VS/MREA-3 (Kobor Cross-Intervenor) at 18:11–12; Hr'g Tr. 1344:1–1345:5 (even at 100% growth in customer-generation, there would be five times as many non-generating customers with the same load shape as total customer-generators). Those customers

[28] This is the same analysis that NWE witness Faruqui did in Idaho to look at customer-generator loads within the diverse class as a whole, with the only difference being that Vote Solar and MREA looked at the actual loads of the customers being served by the utility, and Dr. Faruqui included both loads and exported electricity. Hr'g Tr. 1331:22–1334:14; Ex. VS/MREA-6 at 13–14.

[29] Dr. Faruqui relied on the same argument in Idaho: that the difference in load shapes justifies different class treatment of customer-generators. Hr'g Tr. 1335:6–1338:22. The Idaho Public Utilities Commission rejected that argument, as well as Dr. Faruqui's claims of a cost shift, and based its decision to separate customer-generators into a separate class solely on the basis of their bi-directional flow. Ex VS/MREA-7 at 15. That is not a basis that this Commission can use to separate customer-generators into their own class under HB 219 §§ 2(1) and 3(1).

must also be segregated for different rate treatment if load shape, alone, justifies separate rate treatment. So must the other distinct subgroups within the residential class that exhibit the same, or greater, difference in load shape from the class as a whole than customer-generators. Ex. VS/MREA-1 (Kobor Dir.) at 7:17–19; Ex. VS/MREA-2 (Yozwiak Dir.) at 13:11–18:8; Hr'g Tr. 1890:18–1893:5.

A difference from the class-wide average is not a valid basis to separate classes. It is not one of the criteria provided in HB 219, hides the diversity of loads within the average, and cannot constitute a non-discriminatory neutral basis for different rate treatment without subjecting numerous non-generating groups of customers who exhibit the same or greater differences in load shape as well.

VI. While There is Not a Basis to Change Rates for Customer-Generators at This Time, If the Commission Were to Do so, It Should Base Grandfather Status on Activities Within the Customers' Control and Protect all Customers Actively Pursuing Solar at the Time.

As set forth above, no change to customer-generator classification or rate structure is justified in this case. However, even if it were, the Commission should grandfather customers who relied on existing policy in making long-term investments by grandfathering customers who submitted interconnection applications through a period extending 60 days from the Commission's final order. Ex. VS/MREA-1 (Kobor Dir.) at 9:11–19.

The Legislature required the Commission to grandfather existing customers from any changes to the rate classifications and rate structures for customer-generators. HB 219 § 3. The Legislature left to the Commission to decide the specific date after which newly interconnected systems are no longer grandfathered, provided that it is "on **or after** the date on which the commission adopts a final order implementing the new classifications." HB 219 § 3(1) (emphasis added). That authorizes the Commission to set the grandfathering date 60 days after its final order and use the interconnection application as the grandfathering action because such interconnections would occur "after the date on which the commission adopts a final order." [30, 31]

Establishing grandfathering for applications submitted within 60 days of the Commission's final order better fulfills the goals of grandfathering (1) that existing customer-generators' investments will not be undermined; and (2) that customers investing in new generation will know the terms of their service when they submit their application and commit to purchase, which happens well before the actual interconnection. Ex. VS/MREA-1 (Kobor Dir.) at 145:3–8; Ex. VS/MREA-4 (Valainis Dir.) at 10:19–11:2. The actual interconnection date or local jurisdiction approval date—as NorthWestern proposes to use for grandfathering—are outside of customers' control. Ex. VS/MREA-1 (Kobor Dir.) at 145:9–146:11; Ex. VS/MREA-4 (Valainis Dir.) at 11:3–13:14. The process between a customer's initial contact with a solar installation business and when the system is installed and ready to be interconnected can be several months. Hr'g Tr. 1966:21–1967:11. Therefore, a customer must commit time and money well in advance of interconnection and grandfathering should, therefore, also attach to customer action occurring prior to interconnection; specifically grandfathering should attach when the customer submits an application for interconnection after committing to a solar investment. Ex. VS/MREA-1 (Kobor Dir.) at 146:12–148:6; Hr'g Tr. 1859:3–21. To ensure that all customers who have committed to invest in solar are included, the Commission should

[30] Despite NorthWestern's insistence that customers must be interconnected by the date of the Commission's final order to be grandfathered, the Company proposes a conflicting grandfathering date that includes customers who are not interconnected by that date. Hr'g Tr. 1567:13–1569:1. If the law allows a grandfathering date other than physical interconnection—which is necessary to accept the Company's grandfathering proposal—there is no logical basis to suggest it does not also allow the date Vote Solar and MREA propose.

[31] Even if the statute did not allow the date for the end of grandfathering treatment to be "after the date" of a final order, the Commission could still provide a later end date by delaying the date of an order on the portion of the case adopting new classification for customer-generators. HB 219 § 3(1).

allow customers who apply for interconnection within 60 days of the Commission's final order to qualify, as other states have done. Ex. VS/MREA-1 (Kobor Dir.) at 147:9–148:6, 150:3–12.

CONCLUSION

For the foregoing reasons, Vote Solar and MREA respectfully request that the Commission:

- Reject NorthWestern's request for separate rate treatment of customer-generators because NorthWestern's benefit-cost analysis and cost of service studies were conducted incorrectly and correct analyses show that benefits outweigh costs and that customers with generation adequately recover their cost of service under current rates.
- Address any concerns regarding the current net metering structure by modifying the export credit rate, rather than treating customer-generators differently for the electricity they import from the utility.
- If the Commission changes any rate structures for customer-generators, grandfather all customers who submit an application to interconnect within 60 days of the Commission's final order.

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CERTIFICATE OF SERVICE

I hereby certify that on the 31st day of July, 2019, the **RESPONSE BRIEF OF VOTE SOLAR AND THE MONTANA RENEWABLE ENERGY ASSOCIATION** was e-filed with the Montana Public Service Commission and served by first-class mail, postage prepaid, and electronic mail, unless otherwise noted, on the following:

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