Montana Department of Environmental Quality Comments to the Energy and Telecommunications Interim Committee regarding SJ 12

TO: Energy and Telecommunications Interim Committee
FROM: Energy Bureau, Montana Department of Environmental Quality
SUBJECT: Response to Review of Survey Responses for ETIC regarding SJ12
DATE: November 30, 2015

Background

During the 2015 Legislative Session, the Legislature passed SJ12. SJ12 tasked the Energy and Telecommunications Interim Committee (ETIC) with reviewing Montana's net metering policies to determine their general impacts and whether they foster cost shifts between different classes of electricity customers. In response to SJ 12, ETIC generated a set of survey questions at its June 2015 meeting to be answered by electricity sector stakeholders including electric utilities, cooperatives, and renewable energy advocates. At its September 2015 meeting, ETIC requested the Montana Public Service Commission (PSC), Montana Consumer Council (MCC), and the Montana Department of Environmental Quality (DEQ) review the responses to ETIC's survey and provide comment on the data provided.

The PSC provided comments to DEQ and MCC prior to the submittal deadline for responses to ETIC. DEQ seeks to minimize the number of duplicative observations by building on the comments provided by the PSC.

Overview of DEQ Comments to ETIC Survey Responses

1. Under SJ12, ETIC was empowered to review two related, but ultimately separate, questions regarding the costs and benefits of distributed generation (DG) and net metering. The first question is whether there is a cost shift for electricity customers in Montana as a result of the billing mechanisms used for net metered DG systems in Montana. The second question is in regards to the social costs and benefits of increasing the use of DG in Montana. Making a distinction between these two questions is important because the sets of information used to answer these two questions are different. Both questions require in depth analysis to answer adequately.
2. DEQ is in agreement with the PSC's comments regarding the overall inadequacy of the data provided by the survey respondents. The intention of the data that was sought through the survey was to determine whether a cost shift exists for electricity customers as a result of net metering, and if so, how large it might be, and whether it might be exacerbated by increasing the maximum size of a net metered system (as was considered during the 2015 Legislative

session). Additional information is necessary in order to determine if net metering results in a significant cost shift for any electricity customers in Montana. Some of this information may not be available at this time simply because it has not yet been measured or collected. For more information on what types of information are needed to determine the potential cost shift associated with net metered billing for DG we defer to the PSC's comments.

3. At low rates of market penetration, as is currently the case in Montana, both the benefits and costs of DG to the larger grid are relatively small as individual DG systems typically don't significantly impact the infrastructure decisions made by the owner of the electrical distribution system or the provider of the electricity. The relative size of the impacts and the number of benefits and costs created by DG grow with increased market penetration as clusters of DG systems in aggregate begin to affect the investment and operational decisions of electricity suppliers and transmission and distribution owners. Without data showing the relative density of DG systems on different sections of the Montana electrical grid and forecasts for how DG is likely to grow on various sections of the grid, it's not possible to determine at what point sections of the Montana grid might start seeing more significant impacts from DG.
4. As a result of the federal government's Clean Power Plan to regulate the carbon dioxide emissions of the electricity sector, the cost of emitting carbon dioxide and the benefits associated with avoided carbon dioxide emissions should be considered in any assessment of either the future customer cost shifts associated with net metered generation or the social costs and benefits of DG.
5. DG has a number of benefits that have led legislators from Montana and states across the country to implement policies to promote the use of DG technologies. These known benefits can include:
    - Reduced demand for electricity from the grid
    - Air pollution-free electricity generation
    - Greater resource diversity for meeting electricity needs
    - Increased price stability for electricity customers with DG
    - Greater customer and public awareness of electricity issues
    - Increased value of residential and commercial properties where DG is located
    - Decreased grid vulnerability from potential physical and cyber attacks

<u>Relevancy of Supplied Data</u>

- In determining whether net metering creates a significant cost shift for utility and cooperative electricity customers, it is critical to understand the value of the electricity generated by a DG system. In order to estimate the potential value of DG resources, knowing when and how much electricity is generated by net metered systems is crucial in order to estimate the value of electricity purchases avoided by electricity providers. No survey respondents provided this level of data, making a detailed assessment of the value of DG difficult to determine. Using the annual average wholesale price of power is not a suitable analog for this time of generation data

because renewable energy systems have predictable electricity generation patterns. As the share of electricity generated by net metered systems increases, where the electricity is generated will also be of increased importance in order to determine whether sections of the electricity grid are receiving additional benefits or costs as a result of the DG.

- In NorthWestern Energy's (NWE) answer to question 20, it contended that net metered DG does not necessarily reduce transmission and distribution (T&D) losses and noted that one of the two necessary conditions for reducing T&D losses is that a utility must know how much net metered generation is occurring in real time so that it can adjust its power supplies accordingly. To adequately answer this question, ETIC may wish to request additional information from NWE regarding how the utility came to these conclusions. Transmission and distribution losses are the result of many factors, but as a general rule, one of the driving variables is the amount of electricity flowing across the transmission and distribution lines. If overall electricity demand is reduced by net metering generation, than a proportional amount of electricity losses should also be expected under normal operational circumstances.[1] Likewise, it's unclear to DEQ how the generation from net metered systems alters the basic mechanism by which electricity providers determine how much power is necessary to meet their customers' electricity demand in real time. Whether a customer is demanding less electricity through energy efficiency, conservation behavior, or net metered electricity generation, the mechanism for determining in real time how much electricity an electricity provider needs to supply is the same.

Conclusions

DEQ is in general agreement with the detailed comments submitted by the PSC. DEQ notes that when focused strictly on the potential cost shifts among ratepayers, significantly more and specific data is needed in order to conduct a comprehensive study and reach a reliable conclusion relative to the intent of SJ12.

[1] https://www.ferc.gov/legal/fed-sta/exp-study.pdf, pp. A-8.

MONTANA PUBLIC SERVICE COMMISSION
REGULATORY DIVISION
STAFF REPORT

DATE: November 30, 2015

TO: Energy and Telecommunications Interim Committee

FROM: Will Rosquist, Interim Regulatory Division Administrator
Bob Decker, Transmission and Public Policy Bureau Chief
Robin Arnold, Policy Analyst

SUBJECT: ETIC's request of September 15, 2015, for follow-up questions to stakeholders regarding the costs and benefits of net metering in Montana.

BACKGROUND

Net metering policy was a significant energy issue during the 2015 legislative session. Legislators and stakeholders discussed how to determine the benefits and costs of net metering. Ultimately, the Legislature passed SJ 12, which tasked the Energy and Telecommunications Interim Committee (ETIC) with reviewing net metering policy and related issues, including the economic impacts of net metering and the cost shifts, if any, between net-metering customers and customers who do not net meter.

At its June 2015 meeting, ETIC adopted a series of questions to pose to investor-owned utilities, cooperative utilities, renewable energy advocates, and organized electrical workers about various elements of Montana's net metering policy.

At its September 2015 meeting, ETIC requested that the Montana Public Service Commission (PSC), the Consumer Counsel, and the Department of Environmental Quality review the responses to ETIC's net metering questions. ETIC requested that these agencies examine how stakeholders assessed the costs and benefits of net metering and provide possible follow-up questions designed to allow ETIC to evaluate the assumptions, perspectives, sources, and methodologies used by the stakeholders. ETIC seeks to better understand the costs and benefits of net metering so that it can make an informed assessment of the current net metering policy.

This report responds to ETIC's request. It was prepared by the PSC's Regulatory Division staff. The conclusions and recommendations provided in this report do not necessarily reflect the views of the PSC or any commissioner. The report first provides summary findings, followed by a high-level analysis of key issues raised in the responses received by ETIC to its net metering questions. Finally, we suggest follow up questions for ETIC to ask stakeholders.

SUMMARY FINDINGS

We focused our review on information provided by the investor-owned utilities over which the Commission has regulatory jurisdiction. In addition, we reviewed the responses provided by the renewable energy advocates. Our review produced five primary conclusions:

1. The utilities have not comprehensively evaluated the system impacts of distributed generation sources, nor have they produced sufficient data for such an evaluation. As a result, it is difficult to reliably quantify the benefits and costs of net metering from the data provided to ETIC to this point;

2. The stakeholders, including the utilities, did not fully assess alternative methods for analyzing the reasonableness of current net metering policies;

3. The benefit and cost estimates stakeholders provided are incomplete and, in some cases, reflect questionable assumptions;

4. The utilities did not provide the costs of serving net metering customers, making it difficult to determine whether and to what degree customer-generators are subsidized through participation in net metering;

5. Methods for analyzing the benefits and costs of distributed generation sources are evolving in response to distributed generation activity in other states.

While it may not be possible to fully resolve these issues during the interim timeframe, the analysis below suggests a number of questions ETIC could pose to stakeholders, answers to which may be useful for evaluating policy options.

ANALYSIS

Net metering could be evaluated from a utility system cost perspective to assess whether it results in just and reasonable charges to customer-generators, pursuant to § 69-3-201, MCA.[1] This approach would treat customer-generators as consumers of utility services and analyze what rates these consumers should be charged so that their bills reasonably cover the costs of the services received. Such an analysis would require detailed information on the usage characteristics of customer-generators as a group as well as the costs a utility incurs to provide the various services customer-generators receive based on those usage characteristics.

[1] Section 69-3-201, MCA, requires all charges (rates and bills) for public utility service to be reasonable and just.

Although the utilities asserted that net metering customers do not fairly contribute to the recovery of system costs, they did not provide the results of cost studies showing that net metering results in unjust and unreasonable charges to customer-generators. Nor do they appear to have collected the consumption data needed to conduct such cost studies.

Another way to evaluate net metering is to assess the benefits and costs of the electricity generated by net metering customers. Under this approach, net metering is deemed a reasonable billing mechanism if the benefits exceed the costs. The utilities and renewable energy advocates used this approach to respond to several of ETIC's questions. In general, we find their comparisons of benefits and costs incomplete and imprecise. This may be largely due to inadequate data, which, in turn, is likely due to the relatively small number of net metering customers in the utilities' service areas. For example, just 0.4 percent of NorthWestern Energy's (NWE) Montana customers, and only four Montana-Dakota Utilities' (MDU) Montana customers, participate in net metering. Many of the follow-up questions we suggest below are intended to help the ETIC clarify differences in the benefit and cost information provided by the stakeholders.

The utilities identified cost shifting as a major problem with net metering. NWE p. 2; MDU p. 1. When a customer installs a qualifying power generator behind the utility's meter, the customer's consumption of utility-delivered electricity declines and the utility's revenue also declines, other things equal. In a static, short-run sense, it's true that the utility's recovery of some fixed system costs shifts to non-net metering customers as rates are adjusted through the regulatory process to provide the utilities adequate revenue.[2] This phenomenon is not unique to net metering; it also occurs, for example, with both customer price-induced and utility programmatic energy efficiency activity.[3]

However, in responding to ETIC's survey, the utilities did not address how, in a dynamic, long-run sense, the expanded use of distributed renewable generators affects total utility system costs or total societal costs. In other words, to the extent net metering promotes the private investment in distributed, renewable energy sources that the Legislature has encouraged, are there long-run cost savings? If long-run savings are projected, designing mechanisms to ensure all customers share in them equitably might be preferred to prohibiting cost-shifting, as the utilities recommended.

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[2] By "static" we mean an assumption that the physical and cost structures of the utility stay constant over time.
[3] Price-induced energy efficiency occurs when customers independently decide to purchase energy efficiency. Programmatic energy efficiency occurs when utility incentives and/or information motivate a customer's decision to purchase energy efficiency.

An important step toward resolving these issues is to comprehensively analyze how expanded use of distributed generators impacts the utility's future infrastructure needs and associated costs of providing service. In its comments on NWE's 2013 long-term resource plan, the Commission instructed NWE to conduct such an analysis. *Comments*, Docket N2013.12.84, ¶ 18 (May 26, 2015). (Preliminary results of that analysis might be available before the end of the legislative interim period.)

In their responses to ETIC's survey, the utilities asserted that customer-generators do not contribute adequately to fixed cost recovery, pointing out the on-demand nature of the electricity services they provide. The costs of the electricity services that utilities provide and customers receive cannot be measured adequately in terms of kilowatt-hours of energy alone; PSC rate-setting proceedings generally focus on the costs of three service categories: energy-related service, capacity-related service, and customer-related service. However, for both practical and economic reasons, many customers' bills are based primarily on their consumption of kilowatt-hours.

In simple terms, capacity-related service allows customers to change, at will, the rate at which they want the utility to provide the energy needed to operate various appliances and equipment. Utilities provide capacity service with resources that allow them to reliably satisfy whatever rate of consumption customers collectively impose, whenever they impose it.[4] The utilities asserted that, in contrast to energy efficiency, net metering does not affect customer-generators' consumption of capacity-related service, but only reduces their consumption of energy. NWE p. 18; MDU p. 4. If true, this could have implications for designing rates for net metering customers that effectively recover the costs of service. However, the utilities did not provide sufficient information to support this conclusion, and NWE has just begun to study the matter. NWE p. 21.

NWE also expressed concerns regarding the impact of net metering on regulation service requirements. It acknowledged that the issue needs further study. NWE p. 35. In fact, the variability in retail energy use without net metering contributes significantly to a utility's regulation service requirements. The question is whether and how behind-the-meter generation affects total regulation service requirements.

Both the utilities and renewable energy advocates addressed the question of subsidies. Federal and state tax incentives, as well as state Universal System Benefits programs reduce the price of solar and wind power systems. For example, information provided by the Montana Renewable Energy Association (MREA) indicates that federal and state tax incentives reduce the installed cost of a five-kilowatt solar PV system from $3.65 per

[4] Capacity-related service is also sometimes referred to as demand-related service. Demand, in this context, refers to the rate of energy consumption. Capacity refers to a utility's capability to reliably serve whatever the demand is, including the highest, or "peak," demand.

watt to $2.30 per watt, or about 37 percent. MREA p. 2. These incentives are a form of subsidy.

However, the utilities also asserted that net metering results in subsidized utility service to customer-generators. Net metering is a billing mechanism that applies when a customer installs a qualifying renewable energy generation source on property behind the utility's meter. Net metering customers are billed based on the net amount of energy delivered by the utility. Montana law promotes net metering in order to encourage renewable energy sources, stimulate economic growth, and diversify Montana's mix of energy resources. 69-8-601, MCA. Whether the net metering billing mechanism subsidizes utility service is a separate question from whether the qualifying generation sources are subsidized.

Again, the utilities did not provide the results of cost studies to show that net metering results in unjust and unreasonable charges to customer-generators, nor have they collected the consumption data needed for such cost studies. Without that information it is difficult to establish the degree to which net metering results in subsidized utility service.

Methods for analyzing the benefits and costs of distributed generation sources are evolving in response to distributed generation activity in other states. In the cover letter attached to its answers to ETIC's questions, NWE points to the Electric Power Research Institute's (EPRI) initiative regarding the integration of distributed generation. As part of that initiative, EPRI released a report that develops a comprehensive benefit-cost framework for grid-integrated distributed energy resources.[5] However, the utilities did not address, in their responses to ETIC's survey, the merits of such a framework. Nor have they applied it, or indicated that they plan to apply it, to assess the benefits and costs of distributed generation within their systems.

In addition, at its annual meeting in November 2015, the National Association of Regulatory Utility Commissioners (NARUC) created a new Staff Subcommittee on Rate Design. NARUC recognized that advances in metering technology make data available to better match costs to causation and provide customers more meaningful price signals. At the same time, growth in distributed generation is adding a new dimension to traditional electric utility rate design debates. NARUC's new staff subcommittee will:

> "…undertake necessary education and discussion, with the ultimate aim of developing a work product that identifies [a] range of options and makes available scholarly articles, consultancy reports, national laboratories' efforts, think tank proposals, and other substantive

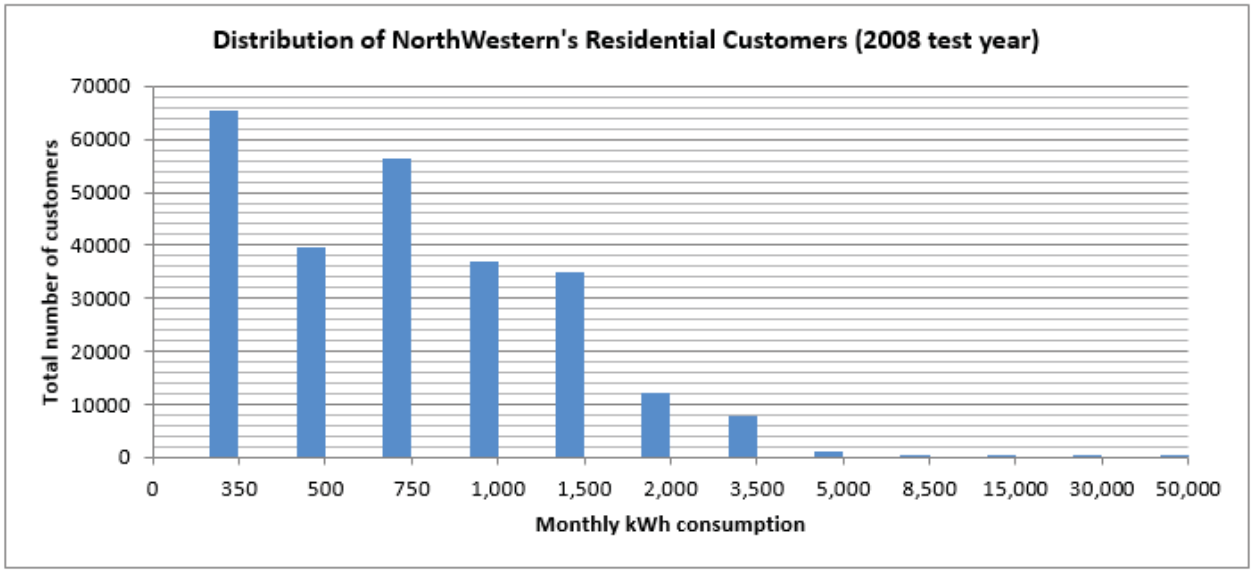
[5] *The Integrated Grid: A Benefit-Cost Framework*, Electric Power Research Institute, Feb. 2015.

approaches to rate designs that may be tailored to State needs and useful in adopting revised rate design methods.

SUGGESTED QUESTIONS FOR STAKEHOLDERS

This section suggests follow-up questions that ETIC could pose to various stakeholders. Many of the questions are directed to NWE because it, among the regulated utilities, has the most experience with net metering and its responses to ETIC's questions contained many assertions and numerical calculations. While posing these questions to stakeholders will not resolve all of the benefit-cost issues raised by their initial responses, the answers may assist the ETIC in assessing policy options.

1. ETIC's Question 4, as we interpret it, requests a frequency distribution for each customer class, along with an indication of where in the distribution an average net metering customer falls. The utilities, however, did not interpret the question similarly and thus did not provide the data that we think would be useful. Regulated utilities are required to provide such distributions to the Commission to illustrate rate impacts. For example, in the rate case docket NWE referred to (Docket No. D2009.9.129), NWE provided the following distribution for residential class energy usage.[6]



ETIC should request that the utilities provide such frequency distributions for kWh consumption, noncoincident peak KW demand, and coincident peak KW demand, if available, for each customer class. The utilities should also separately show the frequency distribution for net metered customers in each customer class. This

[6] PSC staff created the chart from the data submitted by NWE.

information will help ETIC visualize differences in the usage characteristics of net metering and non-net metering customers.

2. In their answers to Question 6, the utilities asserted that the revenue impact of net metering is a subsidy. ETIC should request that the utilities support these assertions by providing the results of marginal and embedded cost of service studies and planning studies that assess the long-run utility system cost impacts of distributed generation.

3. In its answers to Questions 7 and 14, NWE effectively asserted that net metering customers' consumption of capacity service is no different, as a group, than non-net metering customers in the same class. ETIC should request that NWE provide the load research data and analyses that support this assertion, including planning studies that assess the long-run utility system infrastructure impacts of distributed generation.

4. NWE does not separately meter the amount of energy exported to NWE's system from distributed generation. ETIC should request that NWE discuss whether there are alternative ways of reasonably estimating exported energy based on the number and capacity of generators, and the solar and wind resources available in different geographical locations.

5. In response to Questions 1 and 20(a)(4), NWE estimated that it provides about one MW of regulation service to integrate net metered power. ETIC should request that NWE explain in more detail how it determined that amount of regulation service when net metered generation is, according to NWE, not separately measured.

6. In response to Questions 9 and 11, NWE stated that it has initiated a study of net metering customers. ETIC should request that NWE specify the data it will collect in the study. For example, will it include sub-hourly energy consumption and production data for net metering customers (drivers of integration capacity requirements)? Will it allow NWE to more accurately determine the impact of net metering on participants' coincident and noncoincident peak demand? Will it include a control group of non-net metering customers? Answers to these questions could aid ETIC in considering and pursuing policy options.

7. In their answers to Question 18, the utilities addressed the operational issues associated with net metering. ETIC should request that the utilities discuss whether they have comprehensively analyzed their distribution systems, e.g., feeder-by-feeder, to identify areas where distributed generation can be accommodated without the need for significant upgrades and modifications. In addition, ETIC should request that the utilities comment on the degree to which the PSC's distributed generation

interconnection rules (ARM 38.5.8401-8413) mitigate the potential for significant distribution system cost impacts from net metering.

8. Question 10 to the utilities asked about the benefits of net metering, measured in terms of various types of avoidable costs. Aspects of NWE's answer resemble a benefit-cost comparison from a Ratepayer Impact Measure (RIM) perspective.[7] The RIM is one of several benefit-cost tests that utilities sometimes use to assess the cost effectiveness of certain resources, particularly energy efficiency programs. The PSC has long rejected the RIM as the sole measure of cost effectiveness (see ARM 38.5.8218(3)), and absent benefit-cost comparisons from other perspectives, notably Utility Cost, Total Resource Cost, and Societal Cost perspectives, NWE's analysis is incomplete.

Some of the assumptions in NWE's RIM benefit-cost comparison are questionable and/or unsupported. For example, in Exhibit 20(a)(1) NWE appears to measure the benefit of distributed generation using wholesale spot market prices. As a result, NWE calculated the benefit of distributed renewable generation installed in 2011 to be $0.029 per kWh in that year, and no more than $0.038 per kWh in the following three years. No value is attributed to generation after 2014. But in 2011, NWE determined, and the PSC agreed, that it was reasonable for NWE to pay $0.053 per kWh for 25 years to acquire its own intermittent wind generating plant. At that time, NWE determined that the benefit of avoiding market purchases for a 25-year period was at least $0.068 per kWh.[8]

Similarly, it is unlikely that NWE would say that the hydroelectric generators it purchased a year ago provide no tangible benefits to its customers because wholesale spot prices over the past year were less than the generators' per-unit average cost.

Later in its response, NWE concluded that distributed generation would not allow it to avoid future transmission and distribution capital costs, but did not support that conclusion with the results of capacity expansion planning studies, particularly regarding areas of the transmission and distribution network that may need upgrades because of load growth or other reliability issues. The same applies to NWE's conclusion that distributed generation adds to, rather than avoids, line losses.

ETIC should request that NWE provide forward-looking, comprehensive benefit-cost comparisons based on the following perspectives: Participant Cost Test, Ratepayer Impact Test, Utility Cost Test, Total Resource Cost and/or Societal Cost Test. ETIC

[7] The RIM perspective is also sometimes referred to as the non-participant perspective.
[8] Department of Public Service Regulation, *In the Matter of the Application of NorthWestern Energy for Approval to Purchase and Operate the Spion Kop Wind Project*, Docket No. D2011.5.41, Order 7159l, p 13.

should also request that NWE provide a thorough rationale for all assumptions, including supporting data and analyses.

9. In their responses to ETIC's questions, stakeholders differed on what costs and benefits should be attributed to net metering. NWE counted the federal income tax credit as a subsidy in its responses. However, in MREA's answer to Question 8, it excluded the federal income tax credit from societal benefits and costs. ETIC should request that MREA clarify how accounting for federal tax credits would change the numbers in its Table 5.

10. In response to Question 4, MREA stated that the 50kW cap is not large enough for commercial applications and listed some general examples of types of customers that would benefit from increasing the cap. NWE claimed that 99 percent of residential customers and 87 percent of commercial customers can already net meter their full loads under the current cap. ETIC should request that MREA estimate the numbers and types of customers that have been precluded from net metering by the 50kW cap and why.

11. In response to Question 7, MREA estimates a "solar time of production premium" benefit of net metering. The benefit represents the difference between solar production valued at NWE's retail supply rate and the same production valued at the retail supply rate adjusted by certain time-of-use factors from a NWE pilot program. ETIC should request that MREA clarify whether it considers the time-of-use retail supply rate a reasonable proxy for forward-looking avoidable supply costs and, if so, why.

12. Also in response to Question 7, MREA estimates NWE's lost transmission and distribution revenue for distributed generation exported to the grid. ETIC should request that MREA explain why, if it is applying the RIM test, it is reasonable to limit the lost revenue estimate to exported energy.

13. In response to Question 8, MREA lists installation sales revenue as an additional net metering benefit. For 2014, MREA estimated this revenue benefit to be $3,538,384, which approximates the pre-incentive installed cost it reported in response to Question 1.[9] ETIC should request that MREA explain why installation revenue should be considered a net economic benefit, given that the revenue to installers is also a cost to customer-generators, other utility customers (through USB charges), and tax payers (through federal and state incentives).

[9] The MREA spreadsheet calculation of the $3,538,384 benefit assumes an installed cost of 3.75 per watt.

DATE: December 11, 2015

TO: Energy and Telecommunications Interim Committee

FROM: Montana Consumer Counsel

SUBJECT: ETIC's request of September 15, 2015, for follow-up questions to stakeholders regarding the costs and benefits of net metering in Montana.

The Montana Consumer Counsel is generally in agreement with the Public Service Commission Regulatory Division Staff Report in response to the ETIC request for evaluation of stakeholder responses and follow-up questions. We also generally agree with DEQ's comments. MCC has some additional observations that are presented here.

A. Summary comments additional to those in the PSC staff report

- Distributed generation is a growing phenomenon in the electricity sector. Net metering is a particular way of compensating distributed generation customers for the energy produced by this customer-owned, behind the meter generation. It could be viewed as a rough proxy for netting the costs and benefits of providing service to customer-generators in order to credit them for the energy they produce, while appropriately allocating and collecting costs of the electricity grid that they still use. The different responses ETIC received to its inquiries generally reflect whether the respondent was focusing on the value of the net generation being compensated, versus the value of the electricity grid services still being provided that may not be measured in this energy flow netting process. ETIC may find it useful to bear this difference in mind in sorting out these perspectives and may want to continue to question whether both of these values are being fairly addressed.

- There are several separable issues under consideration which ETIC may find helpful to distinguish. The first, whether customer-owned distributed generation is beneficial and should be expanded, is more easily answered if one addresses the second, which is whether the current pricing of behind-the-meter rooftop solar and other customer-owned distributed generation is fair to all electric customers. Another set of issues that need to be distinguished is the forward looking, utility planning approach to evaluating distributed generation, versus the historic cost-allocation approach that assigns responsibility for utility fixed and variable costs. These differences also contribute to the contrasting responses that ETIC has received. Distributed generation advocates focus on incremental future grid planning, while utilities focus more on establishing cost assignment for the continuing use of the existing grid and embedded fixed cost recovery in general. In evaluating comments, ETIC may find it useful to consider the tension created by the fact that forward looking approaches may properly ignore sunk costs, while utility pricing is bound by regulatory and legal frameworks that not only cannot ignore sunk costs but must generally ensure that the utility recovers them.

- Much of the information requested by ETIC and not provided by respondents is simply not available at the present time, and will be costly and time-consuming to obtain. This information is necessary to answering the question of how best to price distributed generation. Net metering should be evaluated in comparison with alternative ways of pricing customer-owned generation. A utility cost perspective via an allocated cost of service study is the standard way to functionalize, classify, and allocate costs in order to design rates to recover a utility's revenue requirement, and is how current rates were calculated. Comparing usage data of customers with distributed (behind-the-meter) generation to customers without distributed generation, as well as differences in the cost of service to them, would allow one to make a determination as to whether or not the two groups are similar enough to remain as one customer class or if they should be separated. This requires detailed data collection and utilities should be directed to gather this data.

- In the interim period until such time as it becomes possible to conduct an allocated cost of service study, regulators might be asked to review whether there are benchmarks that establish reasonable alternate ways of pricing customer-owned distributed generation, and that would better balance the values described in the first bullet and protect both customer-generators and non-participants. For example, it might be reasonable to consider valuing the generation at avoided cost (calculated in the light of NorthWestern's current resource and load situation), adjusted for avoidance of average distribution system losses and the value of renewable energy credits (RECs). While still far from perfect, such a benchline price might reduce the impacts of shifting the allocation of embedded fixed cost responsibility to other customers. Alternatively, regulators could consider other approaches that would in some way acknowledge a T&D charge, using the allocated cost rates that currently appear on every residential customer bill as a legacy of customer choice.

- There is a long history in utility rate making studies used to determine cost causation and the corresponding cost allocation among customer classes. The methodologies used in these cost allocation studies have evolved through years of contested case dockets. Customer-owned distributed generation is a new factor that has not yet been fully incorporated into these methods. Decisions on pricing distributed generation should not ignore these historic precedents. Further, the process of evaluating the data needed to establish just and reasonable rates for distributed generation should make use of these time-tested methods.

- ETIC may want to consider the desirability of separating the question of incentives from the question of how to price distributed generation. Appropriate incentive levels could then be transparently set based upon a decision on whether and how much the rate of implementation should be speeded up and how much additional incentive would be required to achieve that. It would also then be easier when examining incentives for and costs of DG to be mindful of items outside of utility rates. For example, there are tax credits at the federal and state level, and the USB program. Appropriate pricing of the costs imposed on the utility by DG customers, and the cost to serve their loads and to provide backup service as needed, should be examined.

B. Further discussion

Many of the questions and stakeholder responses fail to distinguish between two separate issues: the benefits and costs of customer-owned distributed generation, and the benefits and costs of the use of net metering, in comparison with alternatives, to incentivize and to compensate customers for the energy produced by their rooftop PV or wind systems. Two of the tests that have been discussed, the total resource test and the societal test, address the desirability of distributed generation. Attributes of distributed generation such as carbon reduction and certain other asserted benefits such as avoidance of the need for distribution system enhancements or the potential capability to provide regulation and other ancillary services (via potentially costly advanced inverters and advanced meters) are relevant to the overall desirability of investment in distributed generation, including wind and rooftop solar. A benefit exceeds costs approach to valuing distributed generation compares a state of the world with distributed generation to a state of the world without distributed generation. By contrast, the net metering approach to pricing and cost recovery is most usefully evaluated not in comparison with a world without net metering but in comparison to alternative ways of compensating and, if necessary, providing appropriate incentives to customers with generation equipment on the customer side of the meter. Externalities shared by alternative pricing methods are unhelpful in distinguishing among them.

The question of a fair pricing method is at least as pressing an issue as the question of the overall benefits and costs of distributed generation. Fairness should be seen in terms of whether customers are paying the costs of the services they require as well as whether benefits are shared equitably, or whether, as pointed out by the Commission staff paper, the benefits are disproportionally received by customers with behind-the-meter generation and costs disproportionally shifted to other non-participating customers. If a pricing method can be found that is fair, then the question of the overall merits of distributed generation becomes mainly a matter of determining the appropriate level of incentives and how to provide them. ETIC's questions addressing the advisability of the net-metering approach to DG are extremely important and it is clear that the information requested was not fully provided or was provided in a less than useful format.

The issue of alternate pricing methods to compensate owners of distributed generation systems is important because fixed costs comprise a high proportion of NorthWestern Energy's (or any vertically integrated utility's) revenue requirement. These costs are associated in part with the transmission and distribution infrastructure and also in part with the generation assets that NorthWestern has acquired as it has reintegrated its utility system. They include capital cost depreciation and recovery, other operating costs that do not vary with the level of generation or sales, and federal, state and local taxes including those collected through the tax tracker. Fixed costs have been an issue of great concern to regulators and to the legislature throughout the tumultuous evolution from Montana Power's transition to restructuring and the subsequent elimination of choice and the transition back to a vertically integrated utility. In the initial restructuring, Montana Power's stranded generation costs were explicitly acknowledged and directly assigned to both choice and non-choice customers. The disaggregated rate structure that separately identifies T&D rates remains on NorthWestern's bills to this day. When the legislature set the stage for reintegration of the utility, it did two things to promote success: it eliminated smaller customer choice and it granted preapproval authority, which together sought

to remove the risk that customers might flee to alternative sources of power and that NorthWestern might be forced to write down its new generation assets. NorthWestern's success at reintegration contributed to, among other things, a very significant increase in its fixed cost assets, from $1.65 billion at the end of 2004 to $3.86 billion at the end of 2014. Net metering, in essence, encourages a measure of customer choice that has otherwise been closed off by the legislature.

Fixed costs are collected from residential customers almost entirely through the volumetric per kWh charge. However, as energy use rises or falls or as excess DG production is fed into the utility grid, we can only be sure that the variable costs of operation of the generating plants or the cost of spot market purchases or sales change. Under the net-metering arrangement, participants are compensated at the full retail rate and fixed cost responsibility is proportionally shed. As noted by the PSC Regulatory Staff Report, fixed costs not collected from net-metered customers will be addressed in the next rate case by a compensating price increase for all residential customers. This will be paid almost entirely by non-participants, because participants are few in number and because only their consumption net of DG production will be charged. This is a persistent effect that will be repeated in every rate case and impact all non-net-metered customers.

Another potentially important issue that needs to be addressed by regulators, and that would be addressed by a full allocated cost of service study with detailed information on customer-owned distributed generation, is the cost of providing backup service. If a new large industrial customer approached the utility with a plan to provide all of its own generation but wanted to be connected to the utility grid for emergency backup service, no one would argue that the costs of such backup service would be adequately compensated by simply charging for the energy provided during backup times. Rather, the cost of providing backup service would be addressed directly.

One approach to creating an alternate pricing method to compare with net metering would be to create a separate billing category for customers with distributed generation on the customer side of the meter and to conduct an allocated cost of service study including that new customer class. It has been argued that net-metered customers are no different than Demand Side Management (DSM) customers, who also may shed responsibility for some fixed costs and should not be singled out for special treatment. This analogy appears to be misplaced for several reasons: first, the magnitude of load loss is generally limited in most cases to a modest percentage of load for DSM customers but can be up to 100 percent in net-metered customers; second, the load reduction in DSM customers is spread widely across the clock and calendar and tends to reduce peak load as well, while the load reduction in DG customers fluctuates with the sun (and the wind) and may be uncorrelated or inconsistent with either customer peak loads or system peak loads; and third, there is no equivalent provision of standby or backup service for DSM customers. An allocated cost of service study focusing on the cost of serving customer-owned DG customers vs non-DG customers is a crucial first step in devising a fair pricing mechanism. The value of distributed generation associated with carbon-free renewable generation is an important attribute that must be considered in the overall evaluation of DG and whether and how to promote its installation. Regulators should address whether this is an appropriate concern in the comparison of alternative methods for pricing the output of on-site distributed generation systems. One should not assume that net-metering is the only pricing and compensation method

available and that it should be judged only by whether it should be expanded. These two questions should be evaluated separately.

ETIC may want to consider another aspect of carbon values with respect to distributed generation. Recent studies have argued that utility scale solar generation is significantly cheaper than distributed rooftop PV systems. In other words, utility scale renewable energy can provide the same carbon benefits as customer-owned distributed generation at lower costs, and would be consistent with the utility mandate to provide power at the lowest cost.

C. Additional questions that should be posed to stakeholders

1. NorthWestern should provide a year by year list of behind-the-meter DG installations since the inception of the program. To the extent NorthWestern has or can estimate the following information, for each installation NorthWestern should provide the type (wind or solar), size and date of the installation; the amount, if any, of USB assistance committed to each installation; the federal, state and other tax incentives contributing to reducing the net cost to the customer; the connected load of the customer; and any information that NorthWestern has on the gross and net production of the installation.

2. NorthWestern should provide examples of planned improvements on the distribution system that would be delayed by the installation of DG systems. In each case each example should indicate the amount and location of DG that would be required to defer the planned improvement for one year, for five years, and for 10 years, and should estimate the value of the deferral benefit for each deferral term.

3. NorthWestern should provide estimates of the amount and value of regulation or other specific ancillary services that could be provided by DG, along with a description of the advanced inverter, control, and/or metering equipment necessary to provide the services and the cost of the equipment, installation and operation.

4. NorthWestern should also provide an explanation, with a clear and transparent methodology, of how it arrived at a requirement of 1 MW of regulation capacity to accommodate 6 MW of net-metered generation, in response to ETIC question 20-a.4. If NorthWestern simply applied the standard 18 percent ratio it used for wind before the Genivar study, it should explain how the fluctuations in PV solar installations requiring regulation service compare with those experienced by wind farms.