BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	Docket No. 13-035-184

Direct Testimony of Dustin Mulvaney

On Behalf of Sierra Club

Phase II Cost-of-Service Issues

May 22, 2014

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1. <u>INTRODUCTION AND PURPOSE OF TESTIMONY</u>

Q Please state your name, business address, and position.

A My name is Dustin Mulvaney and I am a Principal with EcoShift Consulting, LLC. Our business address is 270 Canyon Oaks Ave., Santa Cruz, CA 95065.

Q Please describe EcoShift Consulting, LLC.

A EcoShift Consulting is a consulting firm that specializes in research on climate change and sustainability. We research and develop indicators for organizations and institutions and help them understand the relationship between policies and initiatives and environmental performance.

Q Please summarize your work experience and educational background.

A I co-founded EcoShift Consulting in 2008 and have prepared testimony before the CPUC since 2009 (for the Greenlining Institute). Since the fall of 2011, I have been an Assistant Professor in the Environmental Studies Department at San Jose State University. I was a National Science Foundation Postdoctoral Scholar in the Environmental Science, Policy, and Management Department at the University of California, Berkeley from 2009 until 2011. My PhD is in Environmental Studies from the University of California, Santa Cruz. I have an M.S. in Environmental Policy Studies and B.S. in Chemical Engineering from the New Jersey Institute of Technology. From 1997 through 1999 I was a process engineer for a Fortune 500 chemical manufacturer and from 1999 to 2001, I was engineering group leader for a startup bioremediation firm.

My full curriculum vitae is attached as Exhibit SC__DM-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you testified in front of the Utah Public Service Commission previously?

A No.

Q What is the purpose of your testimony?

A The purpose of this testimony is to respond to Rocky Mountain Power's (RMP or the Company) proposals to (1) impose a net metering facilities charge for residential customers participating in net metering,[1] and (2) increase the current fixed customer charge from $5.00 to $8.00 per month.[2] My testimony reports on my team's findings that demonstrate how net energy metering (NEM) installations result in avoided costs for RMP that exceed the proposed NEM charges and how adding fixed customer and NEM charges affect renewable energy adoption, energy consumption, and greenhouse gas emissions.

2. KEY FINDINGS AND RECOMMENDATION

Q Please summarize your key findings.

A Overall, using a straightforward simulation approach discussed below, I concluded that NEM facilities result in avoided costs and RMP's proposal to increase the customer charge and impose a net metering facilities fee will most likely result in substantial costs to RMP's grid and will negatively impact energy conservation efforts.

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[1] Steward Testimony at 21 *et seq*..
[2] Steward Testimony at 12 *et seq*..

Below I summarize the key findings that are detailed in the following sections.

<u>NEM facilities result in Avoided Costs</u>

- The benefits (avoided costs) of the NEM installations far outweigh RMP's proposed customer charge.
- The currently installed NEM facilities result in avoided costs of $1,413,367 during the test year period.
- The avoided costs per component are:
  - Avoided Cost of Energy - $1,157,080
  - Generation Capacity - $181,369
  - Ancillary Services - $11,437
  - Transmission and Distribution Capacity - $63,480
- The avoided costs per NEM customer bill is $56.27, while the NEM charge per customer bill is $4.25.
- The total amount raised through the proposed NEM charge during the test year period is $106,747, while the total avoided costs are $1,413,367.
- Over the years 2015 - 2040, assuming a conservative 6.8% growth rate for NEM installations through 2040 as is forecasted by the EIA, NEM in RMP's system will result in avoided costs of $139,540,642 while generating 1,899.7 GWh of clean electricity and saving 3,466,109,639 lbs of CO_2, 42,269,398 lbs of CH_4, and 51,654,154 lbs of N_2O from being emitted. NEM therefore avoids approximately 20,500,00 metric tons of greenhouse gas emissions.[3]

[3] The annual growth rate for Utah NEM installations is 44% from 2010 to 2013. The Energy Information Agency predicts a 6.8% growth for the USA from 2012 to. EIA. 2014. Annual Energy Outlook. Table 16A. Renewable energy generating capacity and generation. Available at: http://www.eia.gov/forecasts/aeo/er/pdf/tbla16.pdf

Integrating NEM facilities does not negatively impact the RMP electricity system

- RMP does not provide any evidence to support its assertion that NEM customers cause negative impact to the grid system.

- There is no empirical evidence that shows that NEM customers cause additional wear on grid equipment. To the contrary, lower operating temperature from relieved grid congestion suggests the opposite effect.

- Prudent utility T&D planning and system operations will likely mitigate any potential negative impacts from NEM integration.

Fixed charges discourage distributed power generation, energy efficiency, and conservation

- The proposed fixed charges will increase the cost per watt of solar by $0.19 to $0.34, which is equivalent to reducing the existing RMP solar incentive by 21–38%.

- Payback periods for rooftop solar installations will increase as a result of RMP's proposed customer charges.

- The proposed fixed charges increase the cost of rooftop system by between 43.5% and 7.25%, depending on the cost of system installation.

Fixed charges increase electricity consumption and greenhouse gas emissions

- The proposed rate changes would result in an increase in energy consumption of 52,740 MWh, or 0.85%, relative to a revenue neutral rate schedule without the increased customer charge. This increased consumption corresponds to an additional release of 21,740 Metric Tons of GHGs, which is equivalent to the emissions of roughly 5,540 homes in Utah.[4]

- With assumptions of higher price elasticities, consumption could increase by as much as 131,851 MWh, or 2.13%.

Q What is your recommendation to the Commission with respect to the proposed net metering facilities charge?

A I recommend that the Commission reject RMP's proposed net metering facilities charge because the benefits provided by residential net metering customers far outweigh any revenues that the new charge would take in. RMP's assertion that NEM customers are not paying their "fair share" is not true. NEM customers are creating a significant benefit for the system.

Q What is your recommendation to the Commission with respect to the proposed increase in the fixed customer charge?

A The Commission should reject RMP's proposed increase to the current fixed customer charge. Increasing the fixed charge will negatively impact RMP's system by reducing customer investment in rooftop solar facilities and other distributed generation, reducing energy efficiency and conservation measures, and increasing harmful emissions.

[4] Based on the EIA average monthly consumption in Utah of 793 kWh. Koichiro, I. 2010. "How do consumers respond to nonlinear pricing? Evidence from Household Electricity Demand," Energy Institute at Haas Working Paper, University of California Berkeley. Available at: http://are.berkeley.edu/fields/erep/seminar/s2010/Ito050510.pdf

3. THE AVOIDED COSTS ASSOCIATED WITH NEM INSTALLATIONS FAR EXCEED THE PROPOSED CUSTOMER CHARGES

Q Can the Company support its claim that NEM installations have an extra cost of service?

A No. RMP's core contention in this case is that the proposed NEM customer charge is justified to recover the costs of servicing NEM customers. Our study finds that the avoided costs associated with NEM installations (i.e. the benefits of net metering) far exceed the proposed customer charges, based on an analysis using widely accepted approaches to valuing NEM facilities.

Q Is RMP's proposed net metering facilities charge justified?

A No. The avoided costs associated with NEM customers are much greater than the revenue that would be collected by the proposed NEM charge. This means that RMP would be penalizing customers who are actually benefiting the entire system.

Q Do you agree with the Company's assertion that NEM customers are not paying their fair share of fixed cost recovery?

A No. The company argues that NEM customers do not pay their share of fixed cost recovery because the net billing process allows them to offset usage based on $/kWh, which the Company asserts does not account for fixed costs. In my testimony, I demonstrate that the benefits created by NEM customers for the entire system far exceed the amount of fixed costs that are not recovered.

Q How did you reach this conclusion?

A Before describing my analysis in detail, I will briefly describe the beneficial attributes of NEM installations and widely accepted methodologies for estimating their value.

Beneficial Attributes of NEM Installations: A Closer Look

Q Do NEM installations provide value to the system?

A Yes. There are numerous methodologies used to value NEM installations. The choice of methodologies and embedded assumptions can have a tremendous influence on the outputs produced by the study. The notion that NEM installations could have value is affirmed by the Federal Energy Regulatory Commission's (FERC) Avoided Cost Rule.[5] Avoided costs are the incremental costs to an electric utility of electricity generation or capacity.[6]

Different utility commissions have accepted various methodologies that include different elements of avoided costs. For example, California based their Feed-In-Tariff for distributed renewable energy resources on an avoided costs basis that included energy, generation capacity, ancillary services,[7] specified environmental costs, transmission and distribution capacity, and line and conversion losses.[8] Minnesota went beyond the avoided cost approach to estimate a value of solar, taking into account other avoided costs that the public benefits such as improved environmental quality and avoided health care costs. The table below lists the attributes in various studies that have attempted to value NEM facilities.

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[5] Electronic Code of Regulations. Title 18: Conservation of Power & Water Resources Part 292. Available at: http://www.ecfr.gov/cgi-bin/text-idx?SID=fe4e3b6302f4422cdf90d4e93d6a10e3&node=18:1.0.1.11.58.3.27.4&rgn=div8

[6] FERC. What are the benefits of QF status? Available at: http://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp (accessed May 12, 2014).

[7] According to the FERC, ancillary service are "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." U.S. Federal Energy Regulatory Commission. 1995. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Docket RM95-8-000, Washington, DC, March 29, 2009.

[8] California Public Utilities Commission. 2011. Workshop by E3. September 26. Available at: http://www.cpuc.ca.gov/NR/rdonlyres/90AA83C6-1AAC-4D7E-966E-299436C4A6BD/0/E3FITAvoidedCosts9262011.pdf

Table 1. Beneficial attributes of NEM facilities identified by previous researchers

Avoided Cost of Energy	
Lower costs for renewables purchases	Beach & McGuire 2013[9]
Reduced Operating & Maintenance cost	E3 2013[10], Chiradeja & Ramakumar 2004[11]; Norris et al. 2014; Hoff et al. 2006[12]
Deferred investments for facilities upgrades	Chiradeja & Ramakumar 2004[13]; Hoff et al. 2006; Gil & Joos 2008[14]; Norris et al. 2014
Reduced fuel costs, improved efficiency, enhanced productivity	Hoff et al. 2006; Norris et al. 2014; Chiradeja & Ramakumar 2004; Gil & Joos 2008
Generation Capacity	
Lower operating costs, peak shaving	Chiradeja and Ramakumar 2004; Pepermans et al. 2005; Pelland and Aboud 2008; Campbell et al. 2005; Norris et al. 2014; Alsema et al. 1984[15]
Enhanced system reliability and security	Hoff et al. 2006; Denholm et al. 2012; Beach & McGuire 2013, E3 2013; Madaeni et al. 2012[16] Chiradeja & Ramakumar 2004
Increased security for critical loads	Chiradeja & Ramakumar 2004, E3 2013
Responding to local coincident peaks	Chiradeja & Ramakumar 2004, E3 2013
T&D Capacity	
T&D avoided costs/capacity deferral	Hoff et al. 2006; Beach & McGuire 2013; Gil & Joos, 2008; E3 2013.
Relieved congestion	Chiradeja & Ramakumar 2004
Reduced T&D line losses	Hoff et al. 2006; Chiradeja & Ramakumar 2004; Beach & McGuire 2013

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[9] Beach, T., and McGuire, P. 2013. Evaluating the Benefits and Costs of Net Energy Metering in California. Crossborder Energy. January.

[10] E3. 2013. Draft California Net Energy Metering Evaluation - September 26. Available at: http://www.cpuc.ca.gov/NR/rdonlyres/BD9EAD36-7648-430B-A692-8760FA186861/0/CPUCNEMDraftReport92613.pdf

[11] Chiradeja, P. & Ramakumar, R. 2004. An Approach to Quantify the Technical Benefits of Distributed Generation. IEEE Transactions on Energy Conversion 19(4): 764–774.

[12] Hoff, T. et al. 2006. The Value of Distributed Photovoltaics to Austin Energy and the City of Austin. Prepared for Austin Energy by Clean Power Research, LLC.

[13] Chiradeja, P. & Ramakumar, R. 2004.

[14] Gil, H. and Joos, G. 2008. Models for Quantifying the Economic Benefits of Distributed Generation. IEEE Transactions on Power Systems 23(2): 327–236.

[15] Alsema, E., and van Wijk, A., Turkenburg, W. 1984. The capacity credit of grid-connected photovoltaic systems. Commission of the European Communities, Report EUR, 388–392.

[16] Madaeni, S. Sioshansi, R. and Denholm, P. 2012. Comparison of Capacity Value Methods for Photovoltaics in the Western United States. NREL/ TP-6A20-54704. Golden, CO: National Renewable Energy Laboratory. Available at: www.nrel.gov/docs/fy12osti/54704.pdf

Ancillary Services	
Reactive power/voltage control	Chiradeja & Ramakumar 2004; Hoff et al. 2006; Campbell et al. 2005; Joos et al. 2000; Beach & McGuire 2013; Norris et al. 2014.
Regulation Up/Down	E3 2013
Spinning/Non-Spinning Reserves	Norris et al. 2014; E3 2013; Gil & Joos 2008; Joos et al. 2000; Chiradeja & Ramakumar 2004;
Uncertainties	
Fuel price hedge/disaster recovery	Hoff et al. 2006; Norris et al. 2014
Environmental/public health	
Reduced pollution, healthcare costs	Chiradeja & Ramakumar 2004; Hoff et al. 2006
Social Cost of Carbon	Norris et al. 2014

Q How did you consider potential NEM benefits?

A I evaluated the following attributes: Avoided Cost of Energy, Generation Capacity, T&D Capacity, and Ancillary Services. These categories describe beneficial attributes of NEM installations that are widely recognized and deserve a closer look. Before going into the specific analysis of RMP's application, I will address the general concepts and current research on these topics.

Avoided Cost of Energy

Q What is the Avoided Cost of Energy?

A The contribution of electricity from NEM means that other generation sources do not have to produce electricity, which can translate into fuel savings and other avoided energy costs. These are real costs, which are born by utilities, and can vary depending on the thermal performance of their generation plant and pricing of existing fuel contracts. Beach & McGuire 2013 prepared a report for Vote Solar that showed that NEM customers could lower the costs of the utilities purchase of specifically renewable electricity. Previous research affirms that NEM customers help the utility avoid costs. The question is how large are the avoided the costs? The answer usually resides in the assumptions about how to value these resources.

Q How are Avoided Costs determined?

A Various state PUCs have used different methodologies to calculate avoided costs. Common methods include: (1) proxy unit method, (2) peaker method, (3) difference in revenue requirement (DRR), (4) market based pricing, and (5) competitive bidding.[17] Utah uses a proxy approach that estimates avoided costs during "resources deficiency periods" and uses the "next plant that utility decides to buy or build based on integrated resource plan."[18] This approach assumes that "the utility's avoided costs are based on the projected capacity and energy costs of a specified proxy unit."[19] Because the proxy unit approach is not based on marginal costs to the system, and relies only on a generic generating unit, it is generally regarded as the simplest of the avoided cost methodologies.[20]

In cases where it is appropriate to estimate avoided costs during times of "resource sufficiency", Utah uses the DRR approach. Since NEM customers with rooftop solar do provide power during resource deficient periods, Ido not elaborate on DRR methods for estimating avoided costs during resource sufficient periods.

Q Is the proxy unit method appropriate?

A Generally yes, but the proxy model canunderestimate avoided cost rates. For example, the choice of electricity generating unit can drive the outputs of the

[17] Elefant, C. 2011. Reviving PURPA'S Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies In Supporting Alternative Energy Development and A Proposed Path for Reform. Report prepared for the Southern Alliance for Clean Energy. October 21, 2011.
[18] Ibid, page 16.
[19] Ibid, page 17.
[20] Ibid, page 17.

avoided costs models. When low marginal cost units, such as nuclear, are used as proxy units, avoided costs of energy are lower.

Generation Capacity

Q Please explain generation capacity benefits.

A Generation capacity is a core operating principle of modern electric utilities. There is value to having generation capacity, which should vary based on the resources' dispatchability. The value increases when generation capacity is available at times of critical loads. As such, a generator's capacity value is often described as its effective load carrying capability (ELCC). So its generation capacity is related to its availability for on-peak or off-peak dispatch. Given this value, generation capacity from rooftop solar NEM customers can have avoided generation capacity costs.

Q Has there been any research on the generation capacity value of NEM?

A Numerous studies have assessed how NEM generation might enhance systems reliability and security. Researchers from the National Renewable Energy Laboratory (NREL) have convincingly shown that solar photovoltaic (PV) capacity value is strongly correlated to the ratio between a utility's peak demand in the summer and in the winter. Higher summer to winter peak load ratios were associated with higher PV capacity values.[21] Other studies found that NEM capacity value is higher when considering the aggregated output of multiple PV systems. Alsema et al. (1984) found an increase in PV capacity value increased from 11–24% to 15–28% when the output of a single PV system was replaced by the aggregated output of five dispersed systems in the Netherlands.[22] They also

[21] Perez, R. et al. 2006. Update: Effective Load-Carrying Capability of Photovoltaics in the United States. NREL/CP-620-40068.

[22] Alsema, E., and van Wijk, A., Turkenburg, W. 1984. The capacity credit of grid-connected photovoltaic

found that aggregated distributed generation (DG) PV considerably reduced output intermittency. Pelland and Abboud (2008) compared the results from three different commonly used methods for capacity value and found significant variation in value, which appears to be correlated with the variations in the demand summer to winter peak ratio. In other words, PV capacity value is directly tied its capacity for "peak shaving."

NREL researchers compared various ways to measure the value of capacity credit for intermittent generators.[23] They focus on reliability aspects and relate the capacity credit to the "Loss of Load Probability" (LOLP). LOLP is one assurance for system reliability that has been built into utility regulation. LOLP studies are performed by utilities to determine how much capacity is required to reliably meet demand in any given hour. There are two important measurements that result from these studies: the LOLP, and the planning reserve margin. The industry standard for LOLP is to have enough generating resources such that firm load is expected to be interrupted for no more than one day in ten years ("1-in-10"). Generally these studies are conducted for only one calendar year; therefore, the 1-in-10 standard is reduced to 2.4 hours per year. The planning reserve margin is the amount of capacity, expressed as a percentage, that must exist above the expected annual peak demand. The minimum planning reserve margin is usually set to meet the 1-in-10 LOLP standard.

systems. Commission of the European Communities, Report EUR, 388–392.

[23] Milligan, M. and Parsons, B. 1997. Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators. NREL. Presented at Solar '97 Washington, DC April 27− 30, 1997.

Transmission & Distribution Capacity

Q Please describe transmission and distribution capacity benefits.

A Positive impacts from NEM customers on the transmission and distribution systems (T&D) may result in avoided T&D costs. Here avoided costs are equal to the costs not incurred by the utility, and ultimately ratepayers, because T&D upgrades may not be necessary. There are well established tools for estimating T&D avoided costs, including a tool developed by E3 before the California Public Utilities Commission. The avoided costs associated with T&D include capacity deferral,[24] relieved congestion,[25] and avoidance of losses.[26]

Q Has the benefit to the transmission and distribution capacity been studied?

A Yes. Sandia National Labs has produced evidence of T&D capacity deferrals due to distributed facilities.[27] Some capacity deferrals are based on load growth. Beck (2009) found a range of values of T&D capacity deferrals from \$0–0.08/kWh for several deployment scenarios for distributed solar PV in an Arizona utility. Hoff et al. (2003) found a range of \$0.05–0.037/kWh across different planning areas in Nevada, while Hoff et al. (2006) found the range to be \$0.01–0.002/kWh in Austin, Texas. Analysts from Crossborder Energy developed an avoided cost model and suggested avoided T&D costs of \$0.02–\$0.03 per kWh for a PV profile.[28]

Researchers at Lawrence Berkeley National Labs (LBNL), "estimated that, if one added avoided T&D costs of \$0.01 per kWh and avoided line losses of 10% to the

[24] Hoff, T. et al. 2006.
[25] Chiradeja, P. & Ramakumar, R. 2004.
[26] Hoff, T. et al. 2006.
[27] Eyer, J. 2009. Electric Utility Transmission and Distribution Upgrade Deferral Benefits from Modular Electricity Storage. Sandia National Labs. SAND2009-4070.
[28] Beach, T., and McGuire, P. 2013. Evaluating the Benefits and Costs of Net Energy Metering in California. Crossborder Energy, page 15, footnote 27.

MPR, the net cost of residential NEM was under $0.01 per kWh of solar production, or less than $0.02 to $0.05 per kWh of power exported. Using the same assumptions for the size of the CSI program that E3 used, these impacts are about one-quarter the size of those calculated by E3, and equate to an average impact on non-participating customers of 38 cents per month for the average residential customer."[29]

With the growing need to satisfy renewable portfolio standards, distributed solar PV can defer or avoid costs from T&D capacity upgrades required to access remote renewable energy resources. Kahn (2008) found that avoided T&D capacity costs ranged from $0.057–$0.132 if distributed solar PV was pursued instead of the Sunrise PowerLink transmission projects.[30] Similarly, LBNL researchers estimated the costs of meeting a 33% RPS in California in the range of $0.008–0.032/kWh.[31]

As electricity consumption increases there is also increasing congestion on T&D systems. T&D is increasingly overloaded, which affects the utility's ability to meet electricity demand and becomes a possible source of grid instability.

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[29] Beach, T., and McGuire, P. 2013. Evaluating the Benefits and Costs of Net Energy Metering in California. Crossborder Energy, page 15.

[30] Kahn, E. 2008. "Avoidable Transmission Cost is a Substantial Benefit of Solar PV." The Electricity Journal, 21(5): 41–50.

[31] Mills, A., Phadke, A. and Wiser, R. 2010. Exploration of Resource and Transmission Expansion Decisions in the Western Renewable Energy Zone Initiative. LBNL-3077E. Berkeley, CA: Lawrence Berkeley National Laboratory.

Ancillary Services

Q Please describe ancillary services.

A Ancillary services are those services that support effective transmission of electricity to customers.[32] There are numerous benefits to grid power control and power quality with NEM customers tied into the grid. Reactive power for example, which can also lead to reduced line losses, can be generated or consumed using capacitors or NEM installations. Similarly, NEM installations can help improve the voltage profile of electricity moving across radial lines.[33] Voltage profile improvement is another ancillary service that can be provided by NEM customers.[34]

Q Please describe the research on ancillary services with respect to NEM.

A Srisaen and Sangswangere 2006 simulated the impacts of solar PV on both radial and loop operated distribution systems, represented by voltage, active power, total losses, and power factor of the network are presented.[35] The simulation results show that implementation of the solar PV grid-connected system could improve the power quality of a distribution feeder.

The most comprehensive framework for estimating the value of ancillary services has been developed by E3. They describe their approach as estimating the "the marginal cost of providing system operations and reserves for electricity grid

[32] U.S. Federal Energy Regulatory Commission 1995, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, Docket RM95-8-000, Washington, DC, March 29.
[33] Chiradeja, P. and Ramakumar, R. 2004; Hoff, T. et al. 2006
[34] Chiradeja, P. and Ramakumar, R. 2004.
[35] Srisaen, N. and Sangswangere, A. 2006. Effects of PV Grid-Connected System Location on a Distribution System. Asia Pacific Conference on Circuits and Systems, IEEE.

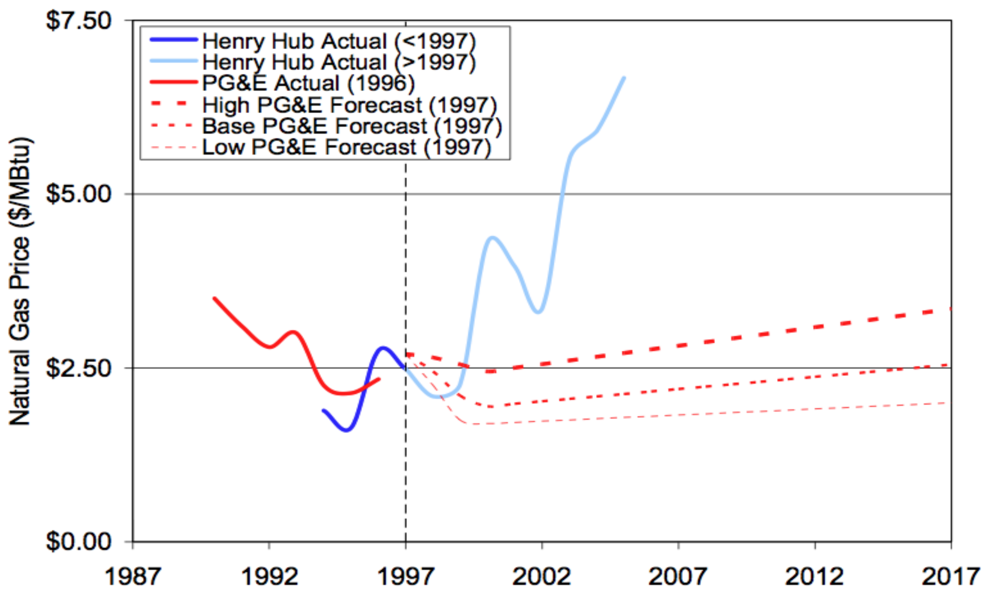
reliability."[36] E3 includes regulation up, regulation down, spinning reserves, and non-spinning reserves in the ancillary services category.

Q Are there other recognized benefits from NEM installations?

A Yes. There is research on the value of NEM related to uncertainties based on natural gas fuel price hedging and disaster recovery. Hoff et al. (2006) prepared a study for Austin, Texas, that included the value of NEM installations as a hedge on fuel price uncertainties. The premise is that there are significant price variations with conventional power plants that require fuel inputs, compared to solar, wind and other renewables that do not require fuel for operations. Natural gas prices in particular are subject to significant volatility due to market fluctuations, storage dynamics natural disasters, or political instabilities.[37] The value of solar PV study performed for the city of Austin, Texas uses a risk-neutral approach that evaluates several scenarios with high, low, and base case prices for natural gas.[38] As they point out in Figure 1, natural gas price volatility is notoriously difficult to predict.

[36] E3. 2010. Introduction to the Net Energy Metering Effectiveness Evaluation. Prepared for the California PUC, Appendix A, Page 7.
[37] EIA. 2007. An Analysis of Price Volatility in Natural Gas Markets. http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2007/ngprivolatility/ngprivolatility.pdf
[38] Hoff, T. et al. 2006, page 90.

Figure 1. Natural gas price volatility



To compensate for the price uncertainty Hoff et al. (2006) draws on the Black-Sholes model, a widely used model used in the finance sector for pricing futures contracts and other derivatives. The basic idea of Black-Sholes in the context of NEM generation is that solar PV could be added to a utility's portfolio as a hedge against the volatile electricity costs associated with natural gas prices. The Hoff et al. (2006) study looked at the value of solar PV to Austin Energy as a hedge against natural gas price increases, compared to the value of selling the price risk hedge benefit. In this case the price risk hedge benefit is the revenues obtained by selling the futures contract for natural gas no longer needed for electricity generation.

Several value of solar studies also include the benefits of disaster recovery. In the Minnesota study, disaster recovery is the cost to restore a local economy, but requires integration of system parts that are not common today (behind the meter storage, for example).

Q Did RMP include environmental and social costs in its analysis?

A No, but those are benefits that should be considered. Other PUC proceeding dealing with NEM facilities have added social and environmental costs into the analyses. For example, in the Minnesota PUC hearing to set a tariff for NEM electricity generation from rooftop solar PV installations,[39] the PUC determined that the value should include the social cost of carbon, a metric developed and used by the US Environmental Protection Agency (EPA) to determine the value of reducing greenhouse gas emissions.[40]

Reduced Criteria Air Pollutants (CAPs) are also important environmental attributes of NEM customers. CAPs include nitrogen oxides, sulfur dioxide, volatile organic compounds, and particulate matter of various micron sizes (PM2.5 and PM10 being the most common). NEM electricity generation displaces CAPs that would otherwise be generated by fossil fuel power plants. Table 2 below shows 2010 data collected by GAO for nitrogen oxide and sulfur dioxide emissions rates for electricity generation in Utah.[41]

Table 2: GAO Estimate of Emissions Factor for Nitrogen oxides and Sulfur dioxide emissions.

Number of units	Nitrogen oxides emissions rate (lbs/MWh)	Sulfur dioxide emissions rate (lbs/MWh)
26	3.13	1.1

[39] Minnesota Value of Solar: Methodology. Clean Power Research. January 31, 2014 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BEE336D18-74C3-4534-AC9F-0BA56F788EC4%7D&documentTitle=20141-96033-02
[40] EPA. 2014. The Social Cost of Carbon. http://www.epa.gov/climatechange/EPAactivities/economics/scc.html
[41] GAO. 2012. GAO-12-545R Air Emissions and Electricity Generation at U.S. Power Plants. http://gao.gov/assets/600/590188.pdf

Data on PM_{10} emissions are more difficult to come by, so I estimated an emissions factor by collecting data by the Commission for Environmental Cooperation of North America Council, the trilateral environmental institution established by the North American Free Trade Agreement. Their database contained 14 power plants (4 coal, 1 oil, 9 natural gas) representing about 25% of power generation. I estimated PM_{10} emissions rates for each power plant, and averaged it to estimate a PM_{10} emissions rate of 0.219 kg PM_{10}/MWh.[42]

Q What do you conclude from the body of research related to the benefits of NEM?

A As I discussed above, there is a substantial amount of literature and research that has been conducted to look at the potential benefits of NEM systems. RMP's unsupported assertion that NEM customers are harming the system goes against much of this research. Before the Commission approves any additional fees that would affect net metered facilities, it should consider the multiple monetary and reliability benefits that NEM provides, and not only the costs as asserted by RMP.

4. RESULTS OF AVOIDED COST ANALYSIS

Q Did you analyze the NEM benefits at issue in this proceeding?

A Yes. I studied the Avoided Costs (i.e. benefits) resulting from the 15,567.59 kW of NEM customers with solar PV installed in RMP's service territory. In my analysis, avoided costs consist of the following widely recognized components:

- Avoided Cost of Energy
- Generation Capacity
- Ancillary Services

[42] The Commission for Environmental Cooperation of North America (CEC) Council. 2010. North American Power Plant Emissions. (Accessed April 29, 2014) http://www2.cec.org/site/PPE/pm10emissions?page=1&order=field_plant_state_value&sort=desc

- T&D Capacity

The primary scenario analyzed in my model assumed that demand not met by NEM generation is met by one of RMP's natural gas plants, meaning the average monthly heat rates and fuel prices are used as inputs. Ancillary Service and T&D Capacity costs are taken from data provided by RMP during the course of this proceeding, and generation capacity values are determined by a combination of publicly available data and data provided by RMP. For full details of data, sources, and assumptions, see Exhibit SC_DRM-2.

Q What did you find?

A The results of the study over the test year period indicate that **the avoided costs of the NEM installations exceed the proposed customer charge**. The average avoided costs per NEM customer bill is \$56.27, while the NEM charge per customer bill is \$4.25. Figure 2 illustrates the average monthly avoided costs per component, and Figure 3 illustrates this comparison on a monthly basis.

Figure 2. Average Monthly Avoided Costs per NEM Customer Bill July 2014–June 2015

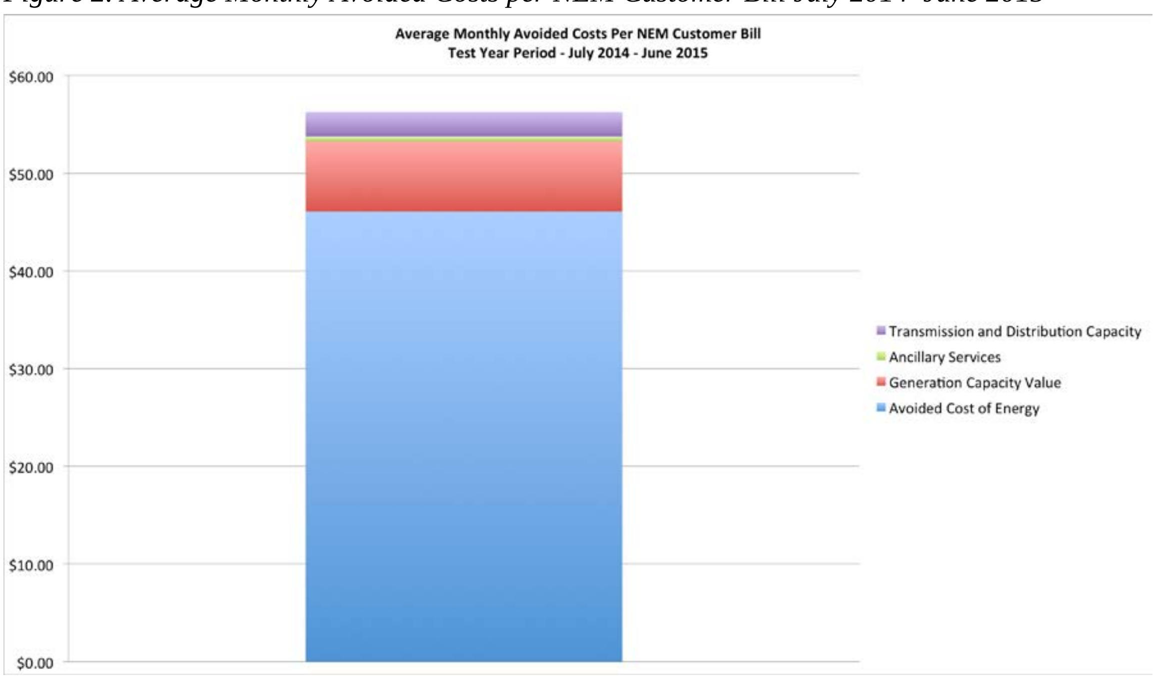
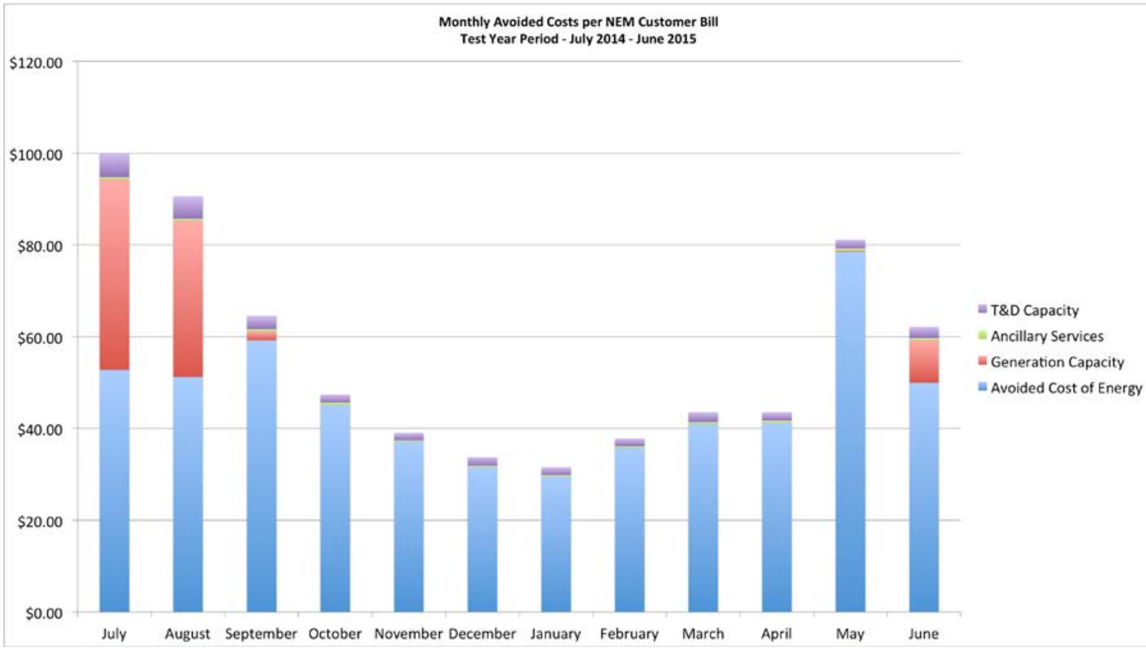


Figure 3. Monthly Avoided Costs per NEM Customer Bill, July 2014–June 2015.

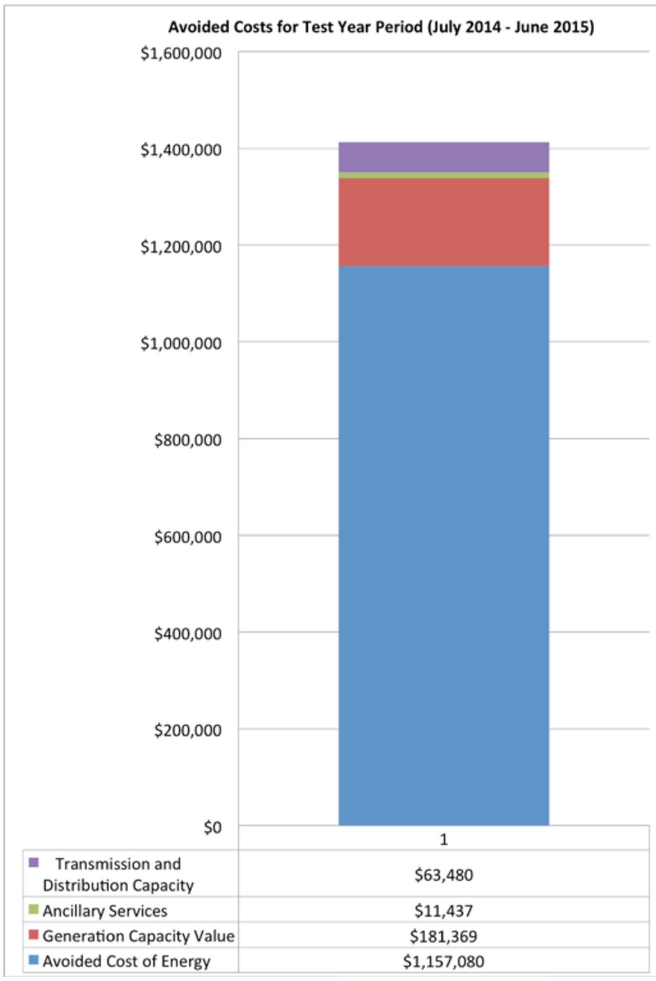


In aggregate, I found that the currently installed NEM facilities result in avoided costs of $1,413,367 during the test year period**.** This is attributed to the following components:

- Avoided Cost of Energy - $1,157,080
- Generation Capacity - $181,369
- Ancillary Services - $11,437
- Transmission and Distribution Capacity - $63,480

Figure 4 illustrates that these avoided costs are distributed across the component categories.

Figure 4. Avoided Costs for Test Year Period, July 2014–June 2015.



For each kWh generated from NEM facilities, the avoided costs are $0.06091/kWh, broken down as:

- Avoided Cost of Energy - $0.049858/kWh
- Generation Capacity - $0.007815/kWh
- Ancillary Services - $0.000493/kWh
- Transmission and Distribution Capacity - $0.002735/kWh

Q **What did you conclude from these results?**

A My analysis indicates that the total avoided costs over the test year period ($1,413,367) far exceed the total amount raised through the proposed NEM charge during the test year period ($106,747).

Q **Did you perform any other analysis of NEM benefits?**

A In addition to evaluating the avoided costs over the test year period, I modeled the avoided costs over the years 2015–2040. I conservatively assumed a 6.8% growth rate of NEM installations based on EIA forecasts, and 0.50% annual reduction in solar PV output due to degradation. I found that NEM installations will result in estimated avoided costs of $57,532,112 while generating 1,899.7 GWh of clean electricity, displacing 3,466,109,639 lbs of CO_2, 14,630,471 lbs of CH_4, 17,878,764 lbs of N_2O, and approximately 7,106,983 metric tons of greenhouse gas emissions.[43] I also found that NEM customers will displace 208 metric tons of particulate matter (PM_{10}). It is worth noting that solar PV generation can be highest during the late winter when Utah receives non-attainment designations from the EPA for PM_{10}.

Figure 5 compares the cumulative avoided costs over the years 2015–2040 with the cumulative revenues raised through the proposed NEM charge (assuming the charge does not change).

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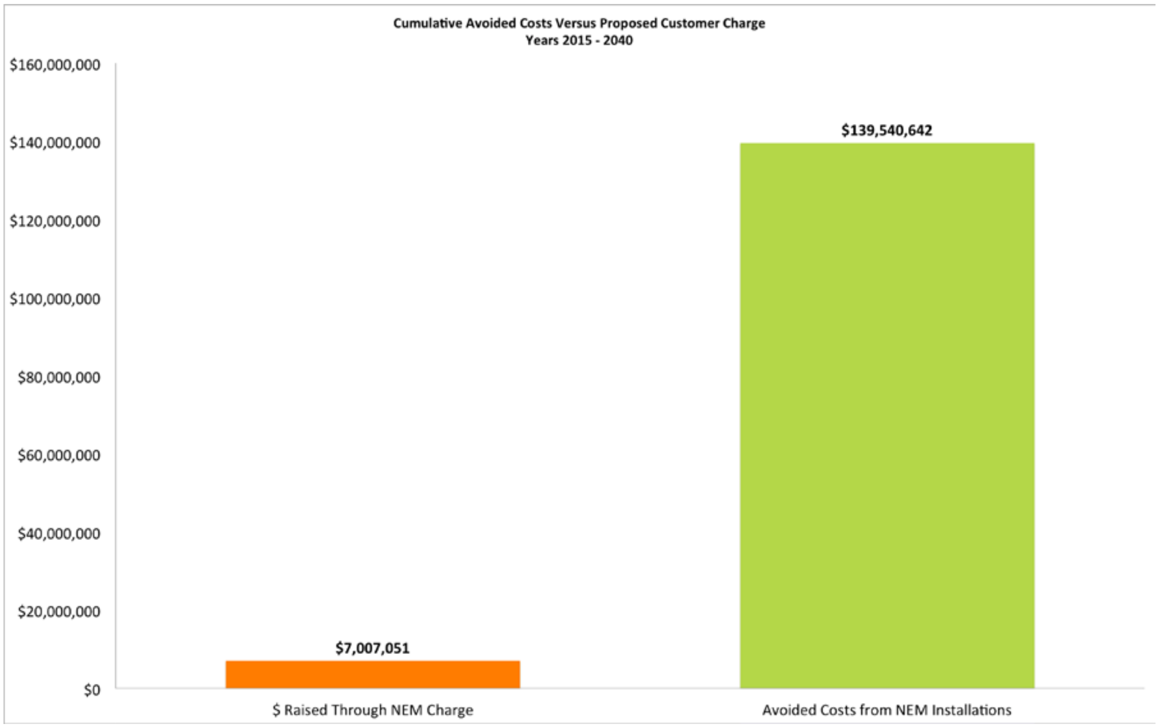
[43] EIA. 2014. Energy Outlook. http://www.eia.gov/forecasts/aeo/er/pdf/tbla16.pdf

Figure 5. Cumulative Avoided Costs versus Proposed Customer Charge, 2015–2040.



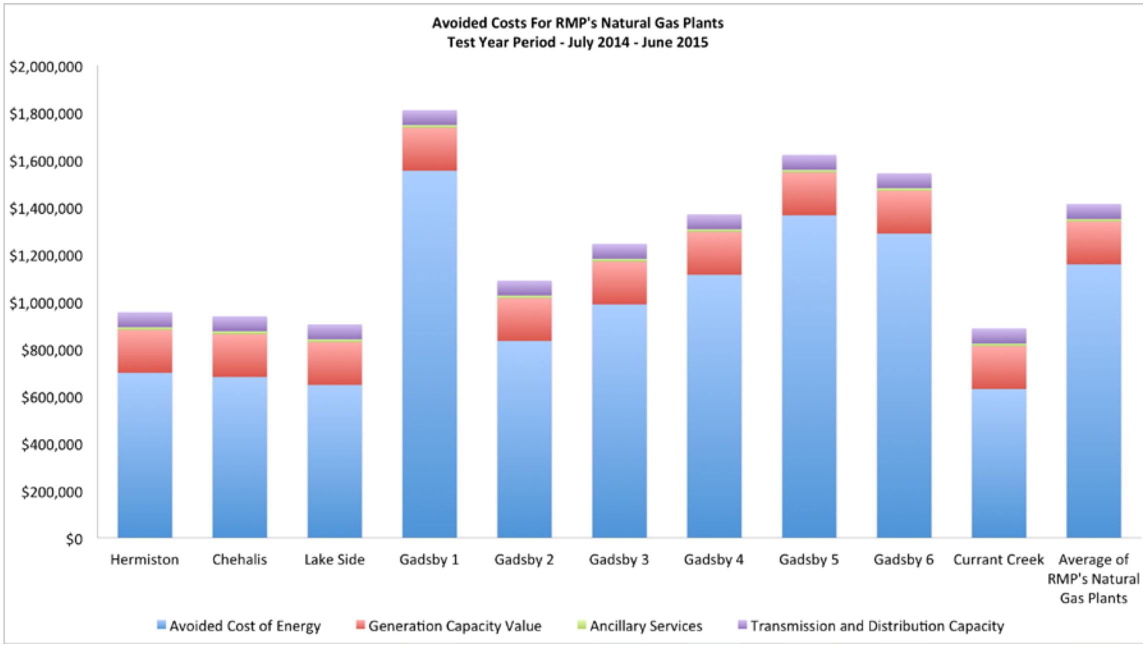
Q What does this tell you about RMP's proposed NEM charge?

A These results demonstrate that there is no justification for the proposed NEM charge, and a compelling case could be made that RMP should be paying the owners of NEM installations. The assertion that NEM customers are not paying their "fair share" is not true. NEM customers are creating a significant benefit for the system.

Q Could the estimates of avoided costs vary?

A Yes. The primary scenario I analyzed uses an average of RMP's natural gas plant heat rates and fuel prices. Figure 6 demonstrates how the avoided costs vary depending on the natural gas plant that NEM generation supplants. This is important because the plants with the highest avoided costs are most likely to be the replacement power plants.

Figure 6. Avoided Costs for RMP's Natural Gas Plants, July 2014–June 2015



Q **Can you provide a more accurate estimate of avoided costs?**

A No. A more accurate and comprehensive understanding of the avoided costs to the electricity grid cannot be properly understood without deploying appropriate metering equipment.

Q **What evidence did the Company rely on to support the NEM facilities charge?**

A The proposed NEM facilities charge is not based on any evidence from analyses of load data and the impact of NEM customers on coincident loads. A proper assessment of the costs and benefits of integrating power from NEM customers would require that RMP have a better understanding of how NEM power might contribute benefits to the grid. Yet, it is not clear that RMP keeps and/or analyzes meaningful records of coincident peak load profiles by customer class across substations in their distribution network to understand avoided or incurred costs from NEM customers. Adequately understanding the costs and benefits of NEM customers requires appropriate advanced metering equipment to understand specifically how NEM customers might have costs or benefits.

Q Can you explain what information is lacking?

A Meters of NEM customers are only checked monthly, so the detailed demand and consumption data on a 15 minute or even on a 1 minute basis needed for such analysis is not being collected and/or analyzed. To effectively evaluate the cost/benefits of distributed generation to the electric grid, at the very least, load research should be done by utilities on statistically significant samples of solar PV installations. This would require the installation of smart metering infrastructure on the solar PV system as well as on the residential main service. This also requires that utilities have SCADA or if possible Distribution Management system data available on a coincident interval basis.

Q What should the Commission rely on if it does not have that data available?

A My team's modeling shows a very strong benefit in favor of NEM installations. Better data could certainly refine the estimates made in this testimony, but in the absence of better data, the Commission should assume that there is a benefit to the system from NEM installations. Unless and until the Company can provide reliable data proving that there is a net system cost, the Commission should avoid implementing any charges that would discourage NEM growth.

5. INTEGRATING NEM CUSTOMERS DOES NOT NEGATIVELY IMPACT THE RMP SYSTEM

Q Do you agree with the Company's assertion that NEM negatively impacts its distribution network?

A No. Integrating high levels of NEM solar PV penetration into the electrical grid will not negatively impact the grid system as RMP suggests. The level of NEM solar PV penetration is the ratio of power output from the NEM facilities to the maximum load on the distribution feeder. Characteristics of NEM customers actually may positively impact the RMP grid, although there is little empirical evidence available for this case to illustrate either scenario. Below I outline some of the technical literature that supports the claim that NEM customers are beneficial, and I identify some of the areas where data should be collected to understand system cost of NEM customer.

Q Please summarize the Company's argument about NEM's impacts

A RMP claims that NEM customers incur costs to the utility that justifies their proposed NEM charge. When asked to compare the relative impacts of NEM generation to energy efficiency upgrades, both of which effectively reduce electricity demand from the grid, RMP's witness Joelle R. Steward argued that "[u]nlike a traditional energy efficiency measure where the load and impact on the grid will predictably be reduced by the implementation of the efficiency measure, customers that install distributed generation have the same, or in many cases an increased impact, on the local distribution facilities. Frequently the Company is required to modify the distribution network in order to effectively minimize negative impacts on the grid and accommodate the new flow of electrons from the customer to the grid."[44] Further, Ms. Steward argued that "[e]ven in cases where upgrades are not required, the flow of energy back through transformers and onto the grid causes increased wear on the equipment."[45]

Q Do you agree with this argument?

A No. There is not sufficient information to determine with any certainty whether NEM customers negatively or positively impact the RMP system.

[44] Steward testimony, lines 516–523
[45] Steward testimony, lines 524-526

Q **Do NEM facilities cause wear on RMP grid equipment?**

A In the majority of NEM facilities, the flow through distribution transformers from distributed generation such as solar PV will result in a net reduction of current flow through the transformers. The equipment will therefore operate at a lower temperature, with fewer losses, and useful life will be extended. End of line voltage will be increased resulting in lower energy consumption for end users' equipment as well.

Q **Is it possible that NEM facilities will add costs?**

A If, through poor planning, too much solar PV is added to a feeder, it is possible to overload a transformer, and more voltage control operations from circuit voltage regulators would therefore be necessary. However, the equipment should be designed for this type of operation. The same is true for any capacitor banks on the circuit. With proper engineering, any wear and problems should be minimized.

Q **What are some of the other important considerations for NEM integration with the grid system?**

A There are possible costs, benefits, and technical challenges related to NEM integration that warrant discussion. Since NEM system power integration is done through inverters, they are increasingly important elements of grid operations that require characterization to understand benefits and costs of NEM facilities. In general, the consensus is that modern inverters for rooftop solar systems obviate many of the concerns raised about incurred costs from rooftop solar integration with the grid system.

Voltage regulation is another challenge posed by integrating high levels of grid penetration. Jewell et al. found that at around 15% penetration of distributed solar PV, cloud cover could "cause significant, but solvable power swing issues at the system level."[46] NEM facilities may pose harmonic distortion requirements on the grid system voltage at the point of interconnection, posing power quality problems. While this may have been an issue in decades past, "true sine wave"[47] inverters, such voltage distortions can be minimized. All customer classes, irrespective of whether they are receiving or delivering electricity to the grid have grid system impacts. In one study of this issue, researchers found that the contribution from distributed solar PV to voltage distortion was about 0.2%, far less than the contributions made by many customer loads.[48]

Q What about concerns regarding high levels of NEM penetration as more customers install systems?

A It is a common refrain of electric utilities that high levels of NEM from rooftop solar PV penetration (40% and greater) can cause unacceptable voltage drops when significant amount of distributed solar PV drops off due to cloud cover. Likewise, utilities assert that high levels of distributed solar PV generation during times of low load can lead to reverse power flows that can cause voltage regulators to malfunction. Yet again, there is research that presents findings to the contrary. Thomson and Infield found that "reverse power flows at the sub-transmission-to-distribution substation did not occur even at 50% PV penetration."[49]

The intermittent character of NEM facilities often leads to the claim that increasing levels of NEM facility penetration imposes a need to increase the

[46] Cited in Eltawil, M. & Zhao, Z. 2010. Grid-connected photovoltaic power systems: Technical and potential problems—A review. Renewable and Sustainable Energy Reviews 14, page 121.
[47] A true sine wave inverter is one designed to minimize voltage and current harmonics, which can overheat electrical equipment.
[48] Cyganski, D., Orr, J., Chakravorti, A., Emanuel, A., Gulachenski, E., Root, C. Current and voltage harmonic measurements at the Gardner photovoltaic project. IEEE Transactions on Power Delivery 1989;4(1):800–9.
[49] Thomson M, Infield D. 2007. Impact of widespread photovoltaics generation on distribution systems. *IET Journal of Renewable Power Generation* 1(1): 33–40.

availability of power generators with high ramp rates. While this has been studied for centralized solar PV power plants[50,51] few studies have looked at NEM facilities, which due to their distributed nature are unlikely to resemble centralized power plants. For example, one research team found that solar PV penetration was limited to 1.3% from centralized solar PV power plants, but distributed solar PV penetration could be increased to 36% across a 1,000 km^2 area.[52]

The levels of distributed solar PV penetration can also reduce line losses, although there appears to be a sweet spot where system losses as a function of distributed solar PV penetration are minimized. Quezada et al. found this to be around 5%, with losses increasing at higher levels.[53] However, Thomson and Infield found that at reductions in transformer loads show reduced line losses from base cases as high as 50%.[54]

It is possible that NEM facilities may lead to a phenomenon known as islanding, where parts of the system remain energized. Hence islanding detection becomes very important in the integration of these resources. According to Eltawil and Zhao, serious system impacts can be mitigated with "modern positive feedback-based anti-islanding appears to be effective in eliminating islands."[55] This purportedly would change at different levels of NEM penetration, and these researchers found "[s]ignificant impacts were observed when distributed

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[50] Chalmers S, Hitt M, Underhill J, Anderson P, Vogt P, Ingersoll R. The effect of photovoltaic power generation on utility operation. IEEE Transactions on Power Apparatus and Systems 1985; PAS-104(3):524–30.
[51] Patapoff N, Mattijetz D. Utility interconnection experience with an operating central station MW-Sized photovoltaic plant. IEEE Transactions on Power Systems and Apparatus 1985; PAS-104(8):2020–4.
[52] Jewell W, Unruh T. Limits on cloud-induced fluctuation in photovoltaic generation. IEEE Transactions on Energy Conversion 1990;5(1):8–14.
[53] Quezada V, Abbad J, San Roma. 2006. Assessment of energy distribution losses for increasing penetration of distributed generation. IEEE Transactions on Power Systems 2006; 21(2): 533–40.
[54] Thomson and Infield. 2007. Impact of widespread photovoltaics generation on distribution systems. *IET Journal of Renewable Power Generation* 1(1): 33–40.
[55] Eltawil, M. & Zhao, Z. 2010. Grid-connected photovoltaic power systems: Technical and potential problems—A review. Renewable and Sustainable Energy Reviews 14: 112–129.

generation penetration levels were between 10 and 20%."[56] Their study found that, "active anti-islanding, particularly involving positive feedback on frequency has a negative but minor impact on system dynamic behavior."[57] Developing protocols for active versus passive islanding detection might be a best practice if this is determined to be a serious system concern.

Q What is the relative impact of residential NEM customers with rooftop solar installations on the RMP system?

A The relative magnitude of any negative impacts of rooftop solar PV systems on the RMP system will likely be small and limited to isolated cases. To understand this, consider a simplified hypothetical example of how NEM solar PV installations might impact the RMP system. Assume a typical rooftop solar installation on a residence is 6 kW. From a capacity standpoint, assuming a sunny day, each typical solar PV installation will reduce peak demand on a feeder by approximately 6 kW at noon, 5 kW at 3 PM, and 3 kW at 5 PM. Even on partially cloudy days there could still be up to 50% of this production.

The utility system peak demand will vary by geographic region and the type of load being served. For a summer peaking utility, rooftop solar will provide the most benefit during clear summer days. For winter peaking utilities, rooftop solar will provide a smaller or even no capacity benefit but will still reduce energy consumption on a feeder.

A typical 12 kV feeder is rated to serve a maximum load of 400 amps or 8,640 kW. Prudent utility operation would ideally limit the maximum loading on a 12 kV feeder to 300 amps or about 6,500 kW. This is to allow for load transfers between adjacent feeders during emergencies. The average load of a typical

[56] NREL. 2003. Report on distributed generation penetration study. Report NREL/SR-560-34715. August; 2003.
[57] Eltawil, M. & Zhao, Z. 2010.

residential feeder could be 2,600 kW, while the minimum load could be as low as 1,300 kW (actual loading on feeders across the RMP system vary considerably).

According to RMP, there are 2,140 NEM facilities in their service territory. Assuming an average size of 6 kW per installation, and assuming that solar PV production would be uniform across RMP's service territory (unlikely, but for the purpose of illustration we assume it here) this yields an estimated maximum aggregate solar PV peak kW generation of 12,840 kW at noon, 10,700 kW at 3PM, and 6,420 kW at 5PM.

This is equivalent to unloading approximately two 12 kV feeders at noon, 1.6 feeders at 3 PM, and only 1 feeder at 5 PM. Of course, the NEM customers with solar PV installations are actually spread out on many RMP feeders. However, assuming an average feeder load of 2,600 kW, the solar PV on the average could unload the equivalent of 4.1 feeders.

Now assume RMP's 2,140 NEM PV installations are only on ten 12 kV feeders or 214 per feeder, this would mean that under ideal conditions, each feeder's peak load would be reduced by approximately 1,284 kW at noon, 1,070 kW at 3 PM, and 642 kW at 5 PM. Obviously this is not the actual case for the RMP system, but the point here is to illustrate that the relative magnitude of any negative impacts of solar PV on the RMP system should likely be limited to isolated cases. It is difficult to see how current or near term future levels of solar PV installation would pose serious capacity or significant system-wide operating issues to RMP.

Q Can RMP mitigate negative impacts from NEM through planning and operation?

Yes. Good planning, design, and system operations practices should mitigate any negative impacts. The long-term benefits of renewable capacity and energy derived from solar PV are numerous. Experience in Europe has shown that a lack of coordinated distribution planning, transmission planning, and system operation can in some instances lead to overloads and over voltage in integrating high levels of distributed renewable energy. However, with proper planning and engineering, the grid should be able to accommodate reasonably high levels of distributed renewable generation. In European countries such as Denmark, they are successfully integrating 30 % levels of distributed generation. On May 12th, Germany set a record with the highest recorded percentage of renewable energy resources on their grid at nearly 75%.[58] More than 60% of Germany's renewables are distributed solar PV, so ostensibly a large portion of this is from power similar to those integrated like NEM customers are.[59] Thorough coordination of transmission and distribution system expansion, resource planning, and system operation would help integrate even higher levels.

Q What should the Commission consider with regard to integration of NEM facilities?

A To really evaluate the cost/benefits of distributed generation to the electric grid, at the very least, load research should be done by utilities on statistically significant samples of NEM facilities. The best way to do this is install or require smart metering to be installed on the solar PV system as well as on the residential main service. This would allow detailed demand and consumption data on a 15 minute or even on a one-minute basis to be collected and analyzed. This type of analysis also requires that utilities have SCADA or if possible Distribution Management system data available on a coincident interval basis.

[58] Kroh, K. 2014. Germany Sets New Record, Generating 74 Percent Of Power Needs From Renewable Energy. http://thinkprogress.org/climate/2014/05/13/3436923/germany-energy-records/
[59] Trabish, H. 2013. Why Germany's Solar is Distributed. http://www.greentechmedia.com/articles/read/why-germanys-solar-is-distributed

Q What are your overall conclusions regarding NEM integration?

A DG and a smart distribution grid will play a rapidly increasing role in electric utility operations. The days of not knowing what is going on beyond the substation walls/fence are numbered. To really take full advantage of renewable energy will require innovative ways of generating, transmitting and storing energy.

6. FIXED CHARGES DISCOURAGE DISTRIBUTED POWER GENERATION, ENERGY EFFICIENCY, AND CONSERVATION

Q Will the Company's proposed fixed charge impact energy usage or decisions to make energy efficiency investments?

A Yes. Fixed charges cause an "efficiency penalty." Recovering utility costs of service through fixed charges instead of variable per kWh rates discourages distributed power generation, energy efficiency and conservation. This is because customers cannot avoid fixed costs by reducing consumption or installing onsite generation or energy efficient technologies. Applying fixes costs also means that variable per kWh rates are overall slightly lower. This means that customers experience longer payback periods for onsite PV generation and energy efficiency upgrades, and have less of an incentive to conserve electricity since they will save less money by doing so.

Q Did you analyze the impact of the proposed fixed charges on RMP's system?

A Yes. My analysis focused on the impact of proposed fixed charges on distributed power generation and consumption. **Overall, my results show that the proposed fixed charges are the equivalent of reducing the RMP solar incentive program by between $0.19 and $0.34 per watt (or 21-38%) for the customers most likely to install distributed generation.**

Q Are these findings consistent with previous research?

A Yes. Pearse and Harris (2007) were one of the first analysts to model the greenhouse gas emissions and effects on energy conservation (or “efficiency penalty”) due to electric rate structures that employ an unavoidable customer charge based on a nationwide survey of US electric tariffs. An efficiency penalty occurs when “customer charges and other fixed charges are used to subsidize the electricity costs for large consumers at the expense of more energy-efficient users in direct opposition to the public’s best interest.”[60] To estimate the impact of the efficiency penalty on electricity consumption, Pearse and Harris (2007) found an increase of 7.12% in the residential electrical rate would result in a 6.4% reduction in overall electricity consumption, “conserving 73 billion kWh, eliminating 44.3 million metric tons of carbon dioxide.” In their model, reductions in energy consumption came from increased avoidable costs. This had the effect of leveraging an increased rate of return on investments in energy efficiency, energy conservation behavior, distributed energy generation, and fuel choices. My own analysis uses a similar thorough process to understand the impact of proposed fixed charges on distributed generation and consumption.

Q Did you specifically model the penalty to NEM customers associated with the proposed fixed charges?

A Yes. The proposed fixed charges, including the increased monthly customer charge and the monthly NEM charge, increase the simple economic payback period of onsite solar PV generation. Fixed charges discourage distributed power generation by increasing the payback period, and significantly diminish the impact of existing incentives. Fixed charges inherently increase the cost of rooftop solar because the customers who install distributed generation and are not purchasing electricity from RMP would still be required to pay these charges.

[60] Pearse, J and Harris, P. 2007. Reducing greenhouse gas emissions by inducing energy conservation and distributed generation from elimination of electric utility customer charges. Energy Policy. 35: 6514–6525.

Q **You mentioned impacts relative to RMP's solar incentive program. Please explain.**

A Rocky Mountain Power currently offers an incentive program for NEM generators, which is meant to reduce the payback period of onsite PV generation. My analysis shows that the proposed charges negate a large percentage of this incentive.

The following analysis shows that the impact of RMP's proposed fixed charges increase the payback period of onsite solar PV generation by an average of 0.9 to 1.7 years, depending on model assumptions, for the customers most likely to install solar PV. This is equivalent to an increase of $0.19 to $0.34 in the cost per watt of solar, which is equivalent to reducing the existing RMP solar incentive by 21–38%.

Q **Why does the fixed charge reduce payback periods so much?**

A To understand why fixed charges matter so much for the cost-effectiveness of rooftop solar, consider that RMP is proposing a total of $7.25/month of additional fixed charges. Over the 25-year lifespan of a solar PV system, this amounts to $2,175. Under the various assumptions described below, we estimate the range of costs of solar PV systems to be roughly between $5,000 and $30,000, which means that the proposed fixed charges increase the cost of solar PV system by between 7.25% and 43.5%. Given that many customers rely on incentives to make rooftop solar cost effective, the proposed fixed charges will make rooftop solar generation a less attractive investment for most customers.

Q **Please describe the magnitude of these impacts.**

A My analysis concluded that paybacks increase from an estimated 0.9 to 3.2 years for non-Lifeline customers when fixed charges are increased, and 1.3 to 6.1 years for Lifeline customers. To arrive at these conclusions, I developed a straightforward methodology, based on standard assumptions, to determine the simple economic payback period of distributed generation with and without RMP's proposed increased customer charge and proposed NEM charge.

Q What methodology did you use?

A The full methodology is presented in Exhibit SC_DRM-3, and a brief summary is given here. Using data from RMP testimony,[61] I began by constructing revenue neutral alternate proposed rates without fixed charges by converting the forecasted revenue generated by proposed fixed charges in a per kWh rate increase, and adding that to proposed rates. Table 3 shows the calculation made to compute increased per kWh rates, and Table 4 shows all four rates used in the analysis. Based on these rates and consumption information provided by RMP in Sierra Club data request 5.1, I computed tiered usage and annual bills for customers at each increment of 25 kWh of average monthly consumption. I then computed the simple payback period for onsite solar PV generation for each customer usage range based on average solar insolation for the state of Utah (1,399 kWh/kW), a 1% power output degradation rate, federal and state incentives, and a range of costs per installed watt (before incentives) of $3–$6. I explored a range of model assumptions in a sensitivity analysis that shows that modifying these assumptions would not alter our overall conclusions, since these assumptions affect the magnitude, but not the relative impact, of rate scenarios on customer payback period for distributed solar PV.

[61] Exhibit RMP_(JRS-5)

Table 3. Values used to calculate per kWh cost of increased customer and NEM charges

Non-Lifeline total expected revenue from increased customer charge (1 phase)	$	25,196,331
Non-Lifeline total expected revenue from increased customer charge (3 phase)	$	84,564
Lifeline total expected revenue from increased customer charge (1 phase)	$	1,108,371
Lifeline total expected revenue from increased customer charge (3 phase)	$	1,542
Total expected revenue from increased customer charge	$	26,390,808
Total expected revenue from NEM charge	$	101,711
Non-lifeline total forecasted kWh		5,991,705,796
Lifeline forecasted total kWh		208,454,662
Cost/kWh of increase customer charge	$	0.4256472
Cost/kWh of NEM charge	$	0.0016975

Table 4. RMP proposed and alternate proposed rates used in analysis

	RMP Proposed Rates	No Increase in Customer Charge	No NEM Charge	No Increase Customer or NEM Charge
Tier 1 Summer	0.08941	0.09367	0.08943	0.09369
Tier 2 Summer	0.11662	0.12088	0.11664	0.12089
Tier 3 Summer	0.14600	0.15026	0.14602	0.15027
Tier 1 Winter	0.08941	0.09367	0.08943	0.09369
Tier 2 Winter	0.09993	0.10419	0.09995	0.10421
Customer Charge	8.0	5.0	8.0	5.0
NEM Charge	4.25	4.25	0	0
Minimum Charge	15.0	15.0	15.0	15.0
Lifeline Credit	12.6	12.6	12.6	12.6

Q **What did you find in you analysis of payback periods?**

A The series of graphs below (Figure 7–10) show the payback period for an average customer at each 25 kWh increment of monthly usage (from 25 to 1300 kWh/month) for each of the four rate structures described above, for Non-Lifeline and Lifeline customers separately.

Q **Why did you include multiple graphs?**

A Each graph shows this information at a different assumed cost per installed watt. I do not show information for any average customer with a payback of over 40 years, since this investment is highly unlikely, and for some scenarios, I limited the range of payback periods to make graphs more legible.

Q What do these graphs show?

A The Y-axis is payback period, and the X-axis is the average monthly usage. So if you pick one spot on the X-axis, you can see the difference in payback periods charted by each line. For example, looking at Figure 7, if a non-Lifeline customer's average monthly use is 325 kWh, the payback period of about 14 years under current rates increases to about 18 years under RMP's proposed increase in fixed rates. The dotted lines show the effect from imposing only the NEM facilities charge or only the customer fixed charge, respectively.

The difference in payback periods between the rates diminishes with higher consumption because the customer charge is a smaller percentage of the overall bill, and results in a smaller percent increase in the total cost of solar (system plus fixed charges). The sharp rise in payback period notable in each graph at roughly 475 kWh of average monthly usage is a result of the smaller RMP solar incentive for solar PV systems over 4 kW.

Figure 7. Simple solar PV payback period for customers of increasing average monthly consumption, under various rate structures, for non-Lifeline and Lifeline customers, at $3 per watt.

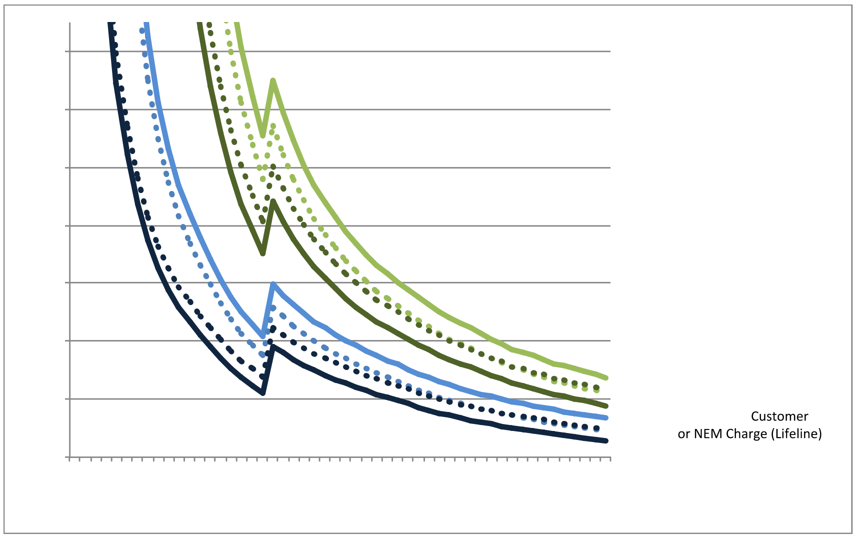


Figure 8. Simple solar PV payback period for customers of increasing average monthly consumption, under various rate structures, for non-Lifeline and Lifeline customers, at $4 per watt.

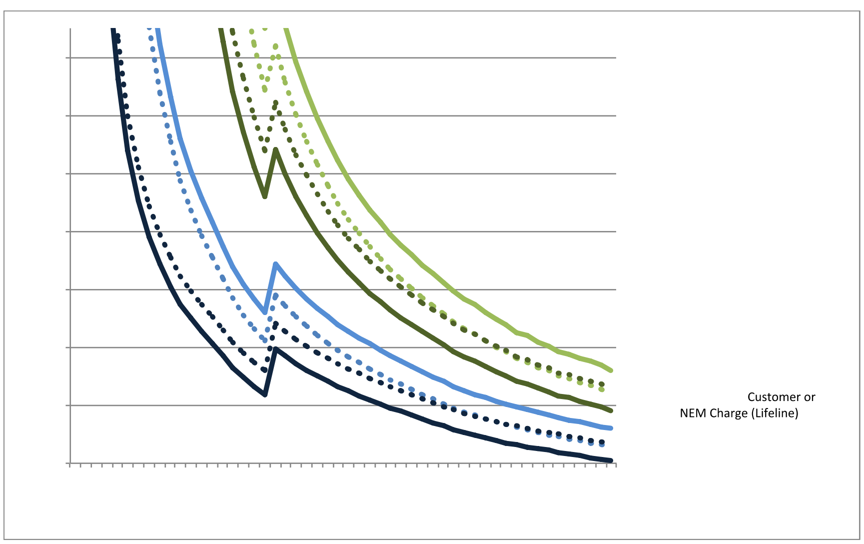


Figure 9. Simple solar PV payback period for customers of increasing average monthly consumption, under various rate structures, for non-Lifeline and Lifeline customers, at $5 per watt.

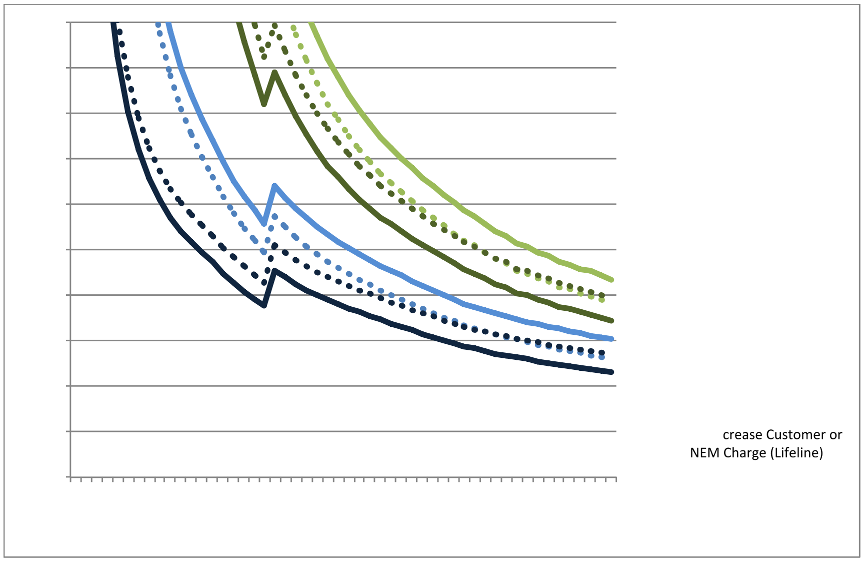
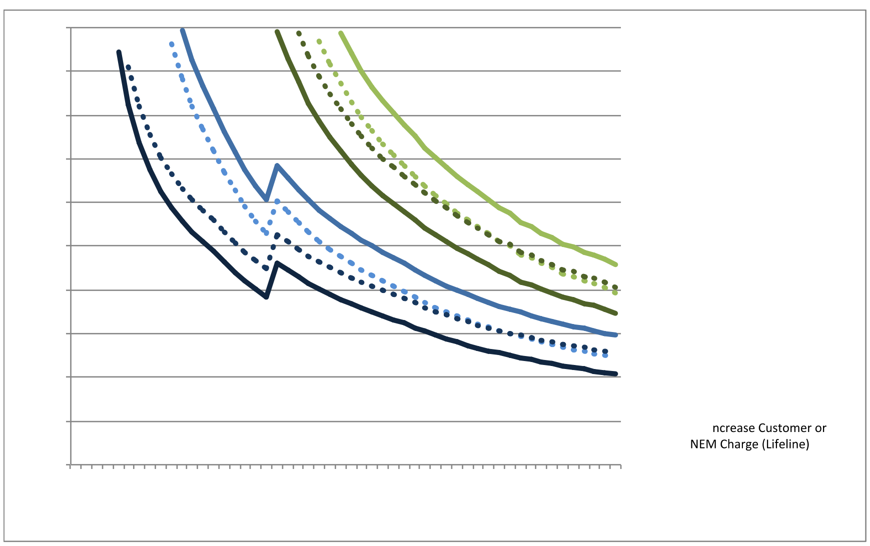


Figure 10. Simple solar PV payback period for customers of increasing average monthly consumption, under various rate structures, for non-Lifeline and Lifeline customers, at $6 per watt.



Q What do you conclude from these results?

A Our results show that payback periods for NEM installations increase as a result of proposed customer charges in all scenarios. For non-Lifeline rates, the RMP proposed rate consistently has the highest payback periods. The impact is most drastic for low usage customers, which is logical because they would require a smaller solar PV system and therefore customer charges would increase the cost of the system by a relatively higher percentage.

Q Did you calculate how the fixed charge impact specific customers?

A Yes. To understand how much the proposed fixed charge will impact RMP customers, I computed the average weighted payback period by multiplying the payback period at each customer usage bin by the number of customers in the bin, and dividing the sum of these products by the total number of customers. Because customers with the shortest payback periods are the most likely to install solar, I did this analysis for each quintile of customers (ordered by payback period) separately. This allowed me to isolate the impact on customers with lower payback periods.

Q How much will the fixed charge impact customers?

A Table 5 shows results for the top three quintiles, since payback periods become unreasonably long for the bottom two quintiles. This shows that average weighted paybacks increase from 0.9 to 3.2 years for non-Lifeline customers when fixed charges are increased, and 1.3 to 6.1 years for Lifeline customers. Focusing on the top quintile of customers (80%-100%), which are customers with the highest usage and therefore the shortest payback period and the most likely to install solar PV, the payback period increase ranges between 0.9 and 1.7 years, depending on the assumed cost per watt of solar PV.

Table 5. Change in simple payback period for the top three quintiles of average monthly usage

Quintile of customers by average montly usage	Cost / Watt Installed	Simple Payback Period: RMP Proposed Rates (yrs)	Simple Payback Period: No Increase Customer or NEM Charge (yrs)	Difference in Payback With and Without Charges (yrs)
Non Lifeline				
40-60%	$3	15.0	13.2	1.8
	$4	20.8	18.3	2.5
	$5	26.5	23.3	3.2
60-80%	$3	13.4	12.1	1.3
	$4	18.8	17.0	1.8
	$5	24.2	21.8	2.3
80-100%	$3	12.0	11.1	0.9
	$4	17.0	15.7	1.3
	$5	22.1	20.4	1.7
Lifeline				
40-60%	$3	20.8	17.4	3.4
	$4	28.9	24.1	4.8
	$5	36.9	30.8	6.1
60-80%	$3	17.0	14.9	2.1
	$4	23.8	20.9	2.9
	$5	30.6	26.8	3.7
80-100%	$3	14.2	12.9	1.3
	$4	20.2	18.3	1.9
	$5	26.1	23.7	2.4

Q Are these increases in payback period significant?

A Yes. To understand how significant these increases in payback period are, I estimated an equivalency between the increased fixed charges and an increased cost per watt of solar. Focusing on only the top quintile of average monthly usage, I decreased the cost of solar in our assumptions to generate a curve with the RMP proposed fix costs that was similar to the payback periods of proposed rates with no fixed charges. In other words, I am testing how much the cost per watt of installed solar would have to decrease in order to find similar paybacks without fixed costs. Thus, I solved for a cost per watt of solar that yielded the same payback period under RMP proposed rates as when using the rate without additional charges at assumed costs per watt of $3, $4, and $5 (Figures 11–13).

Figure 11. Simple payback period for under three rate and cost per watt scenarios, for the top two thirds of average monthly electricity usage, with $3/watt as the baseline cost per watt.

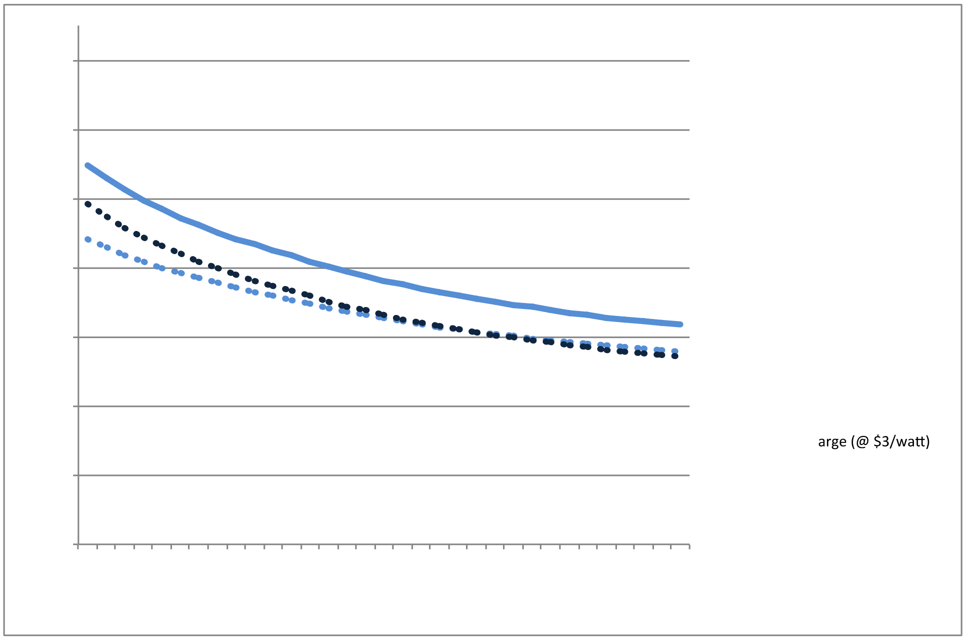


Figure 12. Simple payback period for under three rate and cost per watt scenarios, for the top two thirds of average monthly electricity usage, with $4/watt as the baseline cost per watt.

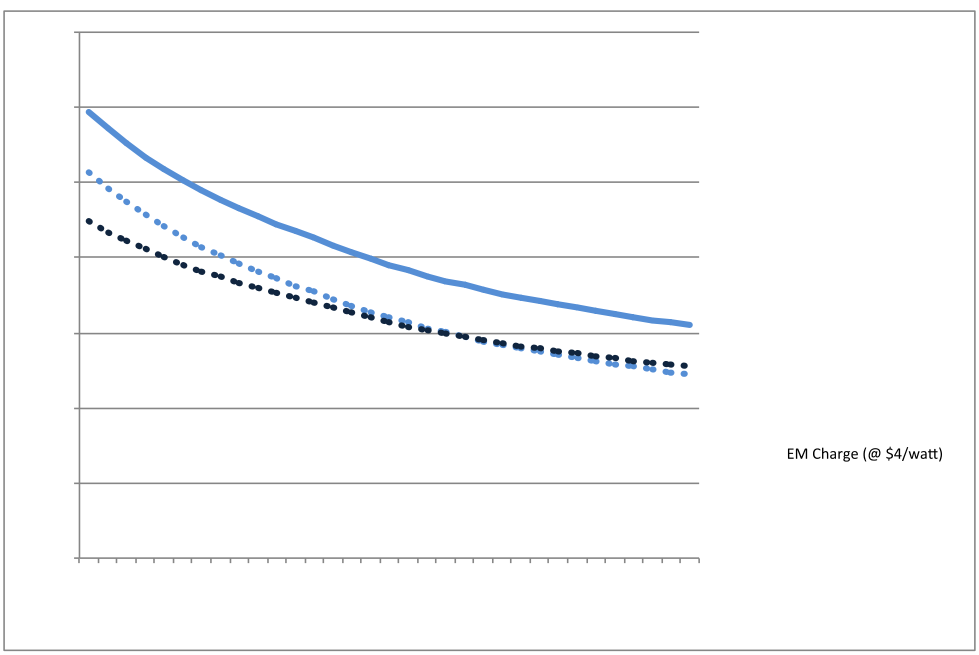
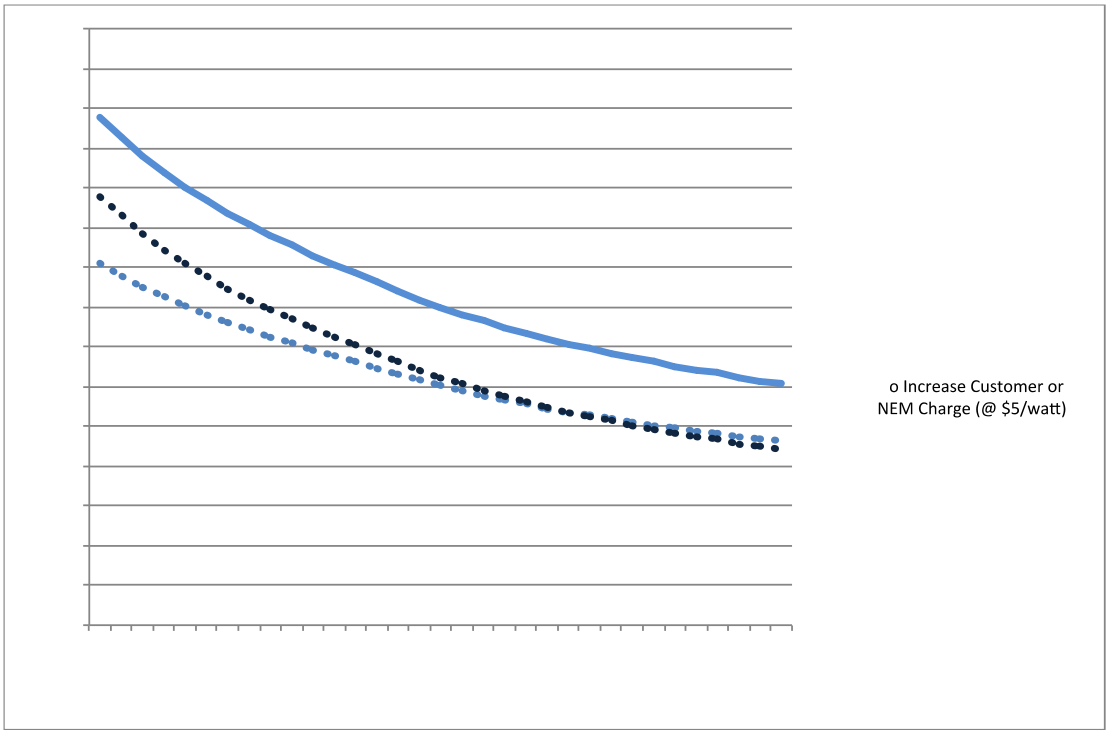


Figure 13. Simple payback period for under three rate and cost per watt scenarios, for the top two thirds of average monthly electricity usage, with $5/watt as the baseline cost per watt.



Q What does this analysis show?

A In all scenarios, I found that the cost per watt of solar would have to be lower for RMP proposed rates to offer similar payback periods as a proposed rate without increased fixed costs. At a baseline cost of $5/watt, I found that RMP's proposed rates would offer the same payback as rates without proposed fixed charges only if the cost of solar were $4.66, or $0.34 lower. This means that adding the proposed fixed charges is the equivalent of increasing the cost per watt of solar by $0.34 per watt. Table 6 summarizes results at $3, $4, and $5 per watt. **In sum, the RMP proposed rates create a penalty of between $0.19 and $0.34 per watt to own solar for non-Lifeline customers.** The penalty is even greater for Lifeline customers, at between $0.22 and $0.40 per watt.

Table 6. Cost per watt penalty to install PV under proposed fixed charges, by baseline costs per watt

Baseline assumed cost per watt	Non Lifeline		Lifeline	
	Required $/watt for equivalent payback	Difference	Required $/watt for equivalent payback	Difference
$3.00	$2.81	**$0.19**	$2.78	$0.22
$4.00	$3.73	**$0.27**	$3.68	$0.32
$5.00	$4.66	**$0.34**	$4.60	$0.40

Q Is the penalty for solar installations consistent with other Utah Public Service Commission policies?

A No. In 2015, the RMP solar incentive program will offer an incentive of between $0.70 and $1.15 per watt installed (Table 7). For the all customers in the top quintile of average monthly usage, I calculated solar PV system to be between 4 and 25 kW, which means that they would be eligible for an incentive of $0.90 per watt installed. **Therefore, RMP's proposed fixed charges are the equivalent of reducing the existing state incentive by 21-38%,** depending on the assumed cost per watt of solar.

Table 7. RMP Solar PV Incentive Program.

Program Year	**Residential Systems (≤ 4kW)**	**Small Non-Residential Systems (≤ 25kW)**	**Large Non-Residential Systems (> 25 kW- ≤ 1,000 kW)**
2012/2013	$1.25/Watt (AC)	$1.00/Watt (AC)	$0.80/Watt (AC)
2014	$1.20/Watt (AC)	$0.95/Watt (AC)	$0.75/Watt (AC)
2015	$1.15/Watt (AC)	$0.90/Watt (AC)	$0.70/Watt (AC)
2016	$1.10/Watt (AC)	$0.85/Watt (AC)	$0.65/Watt (AC)
2017	$1.05/Watt (AC)	$0.80/Watt (AC)	$0.60/Watt (AC)

7. FIXED CHARGES INCREASE ELECTRICITY CONSUMPTION AND GREENHOUSE GAS EMISSIONS

Q Do fixed charges have an impact on electricity consumption?

A Yes. I found an increase in electricity consumption of 52,749 MWh from RMP's proposed charges.

Q Does this increase in electricity consumption have an impact on greenhouse gas (GHG) emissions?

A Yes. Based on an average carbon intensity value for the regional electricity (WECC, Northwest, all generation), this amounts to 21,729 MT of GHGs annually.

Q How did you reach those conclusions?

A To quantify the efficiency penalty on electricity consumption resulting from RMP's proposed fixed charges, I evaluated the impact on consumption for RMP residential customers. Using recent estimates of consumer-level price-elasticities in the western United States, I predict that the proposed changes to the rate schedule will increase total energy consumption by at least 52,740 MWh, or 0.85%, under our assumptions. This increase occurs because adding a fixed charge reduces the amount of revenue generated from variable charges, and thus brings down the portion of a customer's bill that can be avoided through conservation. This increased consumption corresponds to an additional release of 21,740 Metric Tons of GHGs, which is equivalent to the emissions of roughly 5,540 homes in Utah.[62]

[62] Based on the EIA average monthly consumption in Utah of 793 kWh. Ito, K. 2010. "How do consumers respond to nonlinear pricing? Evidence from Household Electricity Demand", Energy Institute at Haas Working Paper 210, University of California Berkeley.

Q How did you model the impacts of fixed charges on electricity consumption and GHGs?

A To evaluate the impact of the changes to the RMP residential rate schedule, I constructed a simple simulation model and ran the simulation over a variety of elasticity assumptions. I took the same RMP proposed rates and the alternate rate without the increased customer charge used in the previous section on distributed generation payback period. I chose to model results using a rate without the increased customer charge only (rather than without the NEM charge as well), because removing the NEM charge has a negligible effect in rates for non-NEM customers.

I modeled the impact of the increased customer charge based on its effects on the *average* price of electricity, as opposed to using marginal or expected marginal prices. This is motivated by Ito[63], who shows that consumers of electricity tend to respond to average prices rather than marginal price tiers. Further, Borenstein[64] evaluates the effects of average, expected marginal, and marginal prices and finds that only the first two prices have a consistently negative effect on consumption (when compared with marginal prices). As expected marginal prices are only useful for consumer level data (which we do not have), I use the average price and evaluate the effects of changes to the average price on average consumption.[65]

To summarize the changes to rates schedules, and the effects of these changes on the modeling inputs, Table 8 reports RMP forecasted energy usage, proposed pricing changes, estimated pricing changes if the customer charge were not

[63] Ito, K. 2014. "Do consumers respond to marginal or average price? Evidence from nonlinear electricity pricing," American Economic Review 104(2), 537-63.
[64] Borenstein, S. 2009. "To What Electricity Price Do Consumers Respond? Residential Demand Elasticity Under Increasing-Block Pricing," seminar paper, Yale Department of Economics. http://www.econ.yale.edu/seminars/apmicro/am09/borenstein-090514.pdf
[65] Average prices for our purposes are calculated by multiplying the price of each tier by the relative share of consumption in each tier. Expected marginal prices assume that consumers set a target level of consumption, but may miss the mark according to some randomly distributed noise. The expected marginal price is hence the expected price around the consumption target (including the noise).

applied, and the average price for RMP residential customers. I chose to combine the analysis for Lifeline and non-Lifeline customers, since Lifeline customers represent a small percentage of overall usage, and any differences in elasticities between high and low income customers would have negligible impacts on results. This approach does not assume any concomitant price change, which is a strong assumption. However, absent billing data from RMP at the level of the consumer to estimate an empirical distribution function directly (along with demand), this is the best possible approach.

Table 8. RMP proposed and alternate tiered and average rates.

			Tiered Rates		Average Rates	
	Forecasted Consumption (kWh) (from Exhibit RMP___(JRS-5))	**kWh Seasonal Share**	RMP Proposed Rates	Proposed Rates, No Customer Charge Increase	RMP Proposed Rates	Proposed Rates, No Customer Charge Increase
Non-Lifeline						
Tier 1 (May-Sept)	1,322,071,859	47.8%	0.08941	0.09367	0.1075	0.1118
Tier 2 (May-Sept)	1,072,363,320	38.8%	0.11662	0.12088		
Tier 3 (May-Sept)	369,079,646	13.4%	0.14600	0.15026		
	0					
Tier 1 (Oct-Apr)	1,677,692,653	48.8%	0.08941	0.09367	0.0948	0.0991
Tier 2 (Oct-Apr)	1,758,952,980	51.2%	0.09993	0.10419		

Q What was the impact you found on electricity consumption?

A Using this information, I simulated the total effects of the proposed rate changes over a variety of elasticity assumptions for RMP residential customers (Table 9). For all elasticity assumptions, the proposed changes will increase consumption relative to the current rate structure. As a base case, we assume price elasticities of -0.2 for all customers. These reflect the most recent estimates from Ito using consumer level billing data. Other studies that use more aggregated data (Reiss and White) find elasticities that tend to be larger (between -0.3 and -0.5)[66], and using these estimates would magnify results.

[66] Reiss, P. and White, M. 2005. “Household Electricity Demand, Revisited”, *Review of Economic Studies*, 72: 853-883, Table 4, Page 871.

Table 9. Changes in consumption resulting from proposed increase to customer charge under different constant elasticities

	Summer			Winter			Annual	
Consant Elasticity		Change in Consumption			Change in Consumption		Change in Consumption	
	Total MWh	MWh	%	Total MWH	MWh	%	MWh	%
0.00	2,763,515	0	0.00%	3,436,646	0	0.00%	0	0.00%
-0.10		10,939	0.40%		15,431	0.45%	26,370	0.43%
-0.20		**21,879**	**0.79%**		**30,862**	**0.90%**	**52,740**	**0.85%**
-0.30		32,818	1.19%		46,292	1.35%	79,110	1.28%
-0.40		43,757	1.58%		61,723	1.80%	105,480	1.70%
-0.50		54,697	1.98%		77,154	2.25%	131,851	2.13%

Q Please summarize your conclusions.

A Overall, under the assumptions I modeled, RMP's proposed fixed charge rate increases result in an increase in energy consumption of 52,740 MWh, or 0.85%, relative to a revenue neutral rate schedule without the increased customer charge. With assumptions of higher price elasticities, consumption could increase by as much as 131,851 MWh, or 2.13%. Overall, using this straightforward simulation approach, we judge the most likely outcome of this program to be negative for efforts of energy conservation.

Q Does this conclude your testimony?

A Yes.