TASC Data Request 2.2

Joelle Steward Rebuttal Testimony: On lines 166 to 175, Ms. Steward states that net metering customers "are not *similarly situated* to other residential customers, as UCE contends." [emphasis in original, footnote omitted]. Ms. Steward claims that "when the net metering customer's generator operates, the customer has a markedly different load curve and load factor than the average residential customer for whom the residential rate was designed...."

(a) Does the Company have the current capability or the actual data required to determine the load factor of all of its net metering customers?

(b) Has the Company undertaken an analysis of the load factor for its net metering customers? If so, please provide that analysis, any supporting data and any assumptions about the representative net metering customer if estimation and not actual data was used.

(c) Does the Company have the current capability or the actual data required to determine the load curve of each of its net metering customers?

(d) Is Ms. Steward's comment that net metering customers have a "markedly different load curve and load factor" based on the illustrations Diagram A and Diagram B on page 8 of her rebuttal testimony?

i. Did Ms. Steward rely upon any additional analyses, data, documents, studies, or reports as a basis for making this statement? Please provide any additional materials relied upon to make this statement.

Response to TASC Data Request 2.2

(a) No. The Company calculated a load factor for a typical residential solar installation for an average residential customer on the summer peak distribution day, as discussed in Ms. Steward's rebuttal testimony at lines 151 – 158.

(b) Please refer to the Company's response to subpart (a) above.

(c) No. Please refer to the Company's response to subpart (a) above.

(d) Yes. Diagrams A and B are indicative of load curves and load factors for average residential customers that install solar rooftop system in Utah.

i. No.

TASC Data Request 2.9

Douglas L. Marx Rebuttal Testimony: On lines 98-105, Mr. Marx states that "From a customer's viewpoint, the electric grid is the cheapest form of energy storage available. Due to the high cost of energy storage devices such as batteries with corresponding charge controllers and special inverters, nearly all NEM customers refrain from installing energy storage systems. Even the grid-connected customers who do install energy storage systems tend to not use them regularly, preferring instead to use the grid for storage because it is less costly and will extend the life of their batteries".

(a) Please provide the information sources or data that the Company relied upon to assert that the electric grid is the cheapest form of energy storage available.

(b) Please provide any data that the Company has on the number of NEM customers that have installed energy storage systems.

(c) Please provide any evaluations the Company has done on the cost of energy storage devices for customers in their territory.

(d) Please provide data that the Company has on grid-connected customers' usage of any energy storage systems they have, and on these customers' use of the grid for storage vs their use of on-site storage.

(e) What is the Company's basis for comparing the incremental or total costs of using an installed energy storage system with using the grid for storage?

Response to TASC Data Request 2.9

(a) Presently, there is no additional cost for NEM customers to utilize the grid for storage. Even the smallest customer-owned storage system has a price tag.

(b) The Company does not maintain a list of NEM customers with energy storage devices.

(c) The Company does not perform cost-estimation analysis for customers from specific territories or regions.

(d) Please refer to the Company's response to subpart (a) above.

(e) Please refer to the Company's response to subpart (a) above.

TASC Data Request 2.11

Douglas L. Marx Rebuttal Testimony: On lines 137 to 145, Mr. Marx states that "Pacific Power has incurred the cost of replacing distribution system transformers to accommodate the increasing levels of NEM customers in its service territory. The primary reason for the need to replace transformers was the absence of a primary neutral connection on the existing transformers".

(a) Is replacing the transformer with no primary neutral connection required in each of Pacific Power's jurisdictions (Oregon, California, and Washington) prior to operation in parallel by the distributed generation system?

(b) What levels of NEM penetration does Pacific Power have in Oregon, California and Washington (expressed in terms of nameplate capacity of all NEM systems as a percentage of system peak demand)?

(c) If a transformer replacement is required to accommodate interconnection of a NEM system, does the customer or the utility pay the cost of replacing the transformer? Please answer for each of Pacific Power's jurisdictions.

i. Oregon
ii. California
iii. Washington

(d) If a transformer replacement is required to accommodate interconnection of a NEM system to the Company's distribution system, does the customer or the utility pay the cost of replacing the transformer?

(e) Please identify the total number of transformers replaced by Pacific Power in all jurisdictions based on NEM penetration concerns.

Response to TASC Data Request 2.11

(a) Yes.

(b) Please refer to the table below:

State	Net Metering MW_{DC} Nameplate Capacity (June 5, 2014)	System Peak Demand 2013 (MW)	Percentage
Oregon	30.5	2,408.3	1.3%
California	2.9	155.6	1.9%
Washington	1.4	797.4	0.2%

(c) Please refer to the responses to (i), (ii) and (iii) provided below:

i. Oregon - The customer pays for the transformer upgrade.
ii. California - The customer pays for the transformer upgrade.
iii. Washington - The customer pays for the transformer upgrade.

(d) The customer pays the cost of upgrading the transformer.

(e) Pacific Power does not identify transformer replacements by the issue that necessitated the replacement, so we are unable to provide this information.

TASC Data Request 2.12

Douglas L. Marx Rebuttal Testimony: On lines 146 to 157, Mr. Marx states that "Pacific Power also found that two solar customer generation units in Oregon with installed capacities of 500 kilowatts ("kW") and 363 kW each were having issues with line protection devices. This led to rapid voltage fluctuation of 5.3 percent every 15 seconds. These two projects are interconnected to Pacific Power's 12.5 kilovolt distribution circuit serving a total of 1760 customers. The voltage fluctuations triggered by these solar projects propagated into Pacific Power's distribution system, causing operational issues to not only the distribution circuit they were connected to, but also the adjacent circuit. A total of 2515 customers were affected by this event, several of whom complained about voltage fluctuation and light flicker. On investigation, we determined that the customer generation reclosing device was operating incorrectly and was the root cause of the problem. Further, a significant amount of time, effort and money was spent by the Company to identify and mitigate the problem".

(a) Has RMP or its parent company experienced comparable voltage fluctuation issues with residential rooftop solar installations (or aggregations thereof)? If so, please provide any study, conclusions, actions taken to mitigate the issues and costs associated.

(b) Absent the incorrect operation of the customer generation reclosing device, has the Company experience voltage fluctuation issues on the circuit serving the two solar generation units in Oregon? If so, what were the determined causes and who bore mitigation costs?

(c) Did Pacific Power calculate the costs incurred to identify and mitigate the problem experienced on the circuit serving the two solar units in Oregon? If so, please provide.

(d) Please provide a count, broken down by month, of customer complaints regarding voltage fluctuation and/or light flicker in RMP's Utah territory. Please also provide an identification of whether these customers were on circuits that also contained distributed solar, if available, and whether the complaints were attributable to events caused directly or indirectly by these solar installations, if available.

Response to TASC Data Request 2.12

(a) Rocky Mountain Power (RMP) does not have a large penetration of rooftop solar and, to the best of its knowledge, neither does its parent company.

(b) The Company has experienced two other recent voltage issues on the circuit serving the two solar generation units. One issue was high voltage when reverse power flow was sensed at the substation regulator. The correction was

a change in the regulator control settings and the cost was borne by the Company. The other issue was voltage imbalance at the solar generation units. The correction was the repair of an open jumper on the tap to the solar generation units and the cost was borne by the Company.

(c) A total cost of $7,569.25 was spent to identify and mitigate the problem experienced on the circuit.

(d) Please refer to the table below:

Month	Power Quality Complaints	Systems on the Circuit	Capacity (kW) on the Circuit	Caused by Solar Installations
Jan-13				
Feb-13				
Mar-13				
Apr-13				
May-13				
Jun-13	1	2	22.58	Unknown
Jul-13				
Aug-13				
Sep-13				
Oct-13				
Nov-13				
Dec-13	1	8	38.07	Unknown
Jan-14				
Feb-14				
Mar-14				
Apr-14	1	2	7.1	Unknown
May-14				
Jun-14	1	0	0	No
Total	**4**			

TASC Data Request 2.15

Douglas L. Marx Rebuttal Testimony: On lines 231 to 234, Mr. Marx states that "When the distributed generation exceeds the load on the circuit and events occur that require RMP's protective equipment to isolate that circuit, the delay in the inverters to disconnect from the system will create an overvoltage condition."

(a) What other events beyond distributed generation exceeding load on a circuit are necessary to trigger response by protective equipment?

(b) To the best of its knowledge, is RMP aware of distributed generation exceeding load on a circuit on its system?

(c) Was this exceedence, if experienced, sufficient to trigger response by its protective equipment?

(d) If a response was triggered, what was the delay in disconnection and was this delay in line with design specifications?

(e) Regardless of the answers to (c) and (d), were any customers affected by these events?

Response to TASC Data Request 2.15

(a) Events are triggered by abnormal conditions on the circuit, not distributed generation. Abnormal conditions might arise due to a variety of events including but not limited to animals, winds, trees, lightning, and equipment failure.

(b) No.

(c) Not applicable. Please refer to the Company's response to subpart (b) above.

(d) Not applicable. Please refer to the Company's response to subpart (b) above.

(e) Not applicable. Please refer to the Company's response to subpart (b) above.

TASC Data Request 2.18

Gregory N. Duvall Rebuttal Testimony: On lines 99-104, Mr. Duvall states that the Commission recently addressed the value of solar in Docket No. 12-035-100. Mr. Duvall asserts that "there is no reason to apply different standards to rooftop solar versus a QF with regard to energy value, capacity value, integration costs or the imputation of environmental costs or other adders. These were all decided in Docket No. 12-035-100".

(a) Has the Company completed a solar integration study?

(b) If so, does the Company' solar integration study conclude that there is "no reason" to draw a distinction between the integration costs of large-scale solar installations (i.e., 320 MW solar farms) and rooftop solar PV systems?

(c) Is the Company aware of any other jurisdiction imposing solar integration costs on NEM systems?

(d) Is it Mr. Duvall's contention that there is no difference, in terms of energy value, line losses, generation capacity value, and transmission and distribution value, between large-scale solar farms and rooftop systems that serve onsite load and are often located close to load centers?

(e) If so, please identify the basis for this contention.

Response to TASC Data Request 2.18

(a) No.

(b) Please refer to the Company's response to subpart (a) above.

(c) No.

(d) No.

(e) Please refer to the Company's response to subpart (d) above.

TASC Data Request 2.19

Gregory N. Duvall Rebuttal Testimony (lines 39-41): "The benefit of the freed-up power in 2015 is about $30/MWh.[1] This value reflects an energy only value, since the Company does not need new capacity until 2027 based on the 2013 Integrated Resource Plan ("IRP") Update".

(a) Please provide the values which the Company believes is appropriate to consider when evaluating distributed generation (DG) avoided costs for all available years beyond 2015, including, where applicable, avoided costs beyond energy-only.

(b) On slide 10 of the presentation "Schedule 37 Technical Conference Presentation" in the referenced docket, PacifiCorp identified a transmission constraint known as Huntington / Sigurd cutplane, and highlighted the fact that the "GRID model [used to calculate avoided costs] has been updated to model Utah as three bubbles: Utah North, Clover, and Utah South". Please identify, by number of installations and total installed rating, the DG of NEM customers north and south, respectively, of this transmission constraint. Please also identify, by number of installations and total installed rating, the DG of NEM customers in each of the three "bubbles".

(c) Has the Company calculated locationally-differentiated avoided costs? If so, please identify whether the value of $30/MWh, or 3 cents/kWh, remains applicable to assessing the costs avoided by all distributed generation in 2015, or whether a different value may be more appropriate based on the location of DG.

Response to TASC Data Request 2.19

(a) The values are reflected in the Company's proposed avoided cost filing for solar qualifying facilities (QFs) which is publicly available on the website of the Public Service Commission of Utah (UPSC) under Docket No. 14-035-T04, and can be accessed by utilizing the following website link:

http://www.psc.utah.gov/utilities/electric/elecindx/2014/14035T04indx.html

(b) Please refer to Confidential Attachment TASC 2.19. Note: Utah North (NU) and Clover (C) are north of the transmission constraint, and Utah South (SU) is south of the transmission constraint. Confidential information is provided subject to Utah PSC Rule 746-100-16.

[1] See Docket No. 14-035-T04, In the Matter of Rocky Mountain Power's Proposed Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities.

(c) No.