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Memorandum

TO: Public Service Commission

FROM: Division of Public Utilities
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DATE: August 12, 2015

SUBJECT: **Docket No. 15-035-61** In the Matter of the Application of Rocky Mountain Power for Approval of its Subscriber Solar Program (Schedule 73)

REDACTED COMMENTS FROM DPU

The Division of Public Utilities (Division) has reviewed Rocky Mountain Power's (Company) application for its Subscriber Solar Program Schedule 73. The Division recommends that the Commission approve the Company's application with the following modifications:

- The Company should recalculate the program costs for each participating class in kilo-watt hours (kWh) at the conclusion of the RFP process when the final size and cost per mega-watt (MW) is known. Should the proposed facility's capacity and useful life change, the Company should recalculate the proposed administration, marketing and billing costs. The Company should recalculate the subscription charge based on the new assumptions;

- The Company should bear an equal share of the risk of program undersubscription with other rate payers;
- The Company needs to be clear in its marketing how the program billing will work for each of the participating classes of customers so they are not misled; and
- The Company should be required to report certain metrics to the Commission after six months of program approval and annually after the program begins as described below.

With these modifications, the Division supports the Company's Subscriber Solar Program as being in the public interest.

Background

On June 16, 2015, the Company filed an application requesting approval to implement an optional subscriber solar pilot program under proposed Tariff Schedule No. 73 "Subscriber Solar Program." On June 16, 2015, the Public Service Commission of Utah (Commission) issued an action request to the Division to review the application and make recommendations.

Subsequently, the Commission gave notice of a scheduling conference to be held June 26, 2015 at which time it set out the schedule for this docket.[1] Two technical conferences have been held prior to these comments.

The Commission Order directed parties to submit their comments to the Commission on August 5, 2015. At the request of intervening parties, this deadline was delayed to August 12, 2015. This memorandum represents the Division's comments on the Company's application for its Subscriber Solar Program (Schedule 73).

General Discussion of the Company's Proposed Program

The Division has reviewed the Company's application and found the application to meet the filing requirements pursuant to the Commission's Rule 746-405-1.

As proposed by the Company, the subscriber solar program offers Utah customers the opportunity to purchase kilowatt-hour (kWh) blocks of electricity from a Company solar resource to be built.[2] These 200 kilowatt hour blocks will be offered first-come, first-serve at a

[1] See "In the Matter of the Application of Rocky Mountain Power for Approval of its Subscriber Solar Program (Schedule 73)." http://psc.utah.gov/utilities/electric/elecindx/2015/documents/2671851503561soanoh.pdf.
[2] The final block size will depend on the resource acquired by the Company but is expected to be approximately 200 kWh. The customer's subscription cannot exceed one-hundred percent of their kWh usage for the prior twelve

fixed price for a given contract length of two, five, seven or ten years. The program will be offered through residential Tariffs 1, 2, 3, small non-residential Tariff 23, and large non-residential Tariffs 6, 6A, 6B, 8, 9, and 9A. The current offering of the proposed fifteen mega-watt (MW) facility will be allocated at thirty percent for residential, thirty percent for small non-residential, and forty percent for large non-residential.

The Company's stated intent is that those participating in the program will pay all costs associated with the program. The Company's cost or pricing estimates allow for an initial ramp or subscription period through 2019. Therefore, as long as the program meets the Company's projected ramp rate and remains fully subscribed, the program will be underfunded in the ramp period but overfunded in the later years such that over the life of the program, subscribers will be fully funding the program. However, if the program does not meet the ramp rate or is undersubscribed at any point, the Company proposes that the associated costs of the program be borne by all ratepayers.

The energy blocks are comprised of two cost components. First, the solar block generation charge covers the cost of the solar generation resource and costs associated with the program. Second, the solar block delivery charge covers the delivery related costs such as transmission, distribution and customer services.

The first component, the solar block generation charge, is comprised of three parts: first, the solar generation is the per-kWh cost of the resource dedicated to the program. The Company's application assumes a solar resource cost of [redacted] per mega-watt hour (MWh) or [redacted] cents per kWh. Different actual costs per kWh would change this part of the solar block generation charge accordingly. Second, the cost per-kWh of any utility generation resource needed to provide service to the participating customer above the purchased blocks, which is currently [redacted] cents per kWh. Third, program costs including administration, marketing and billing. This charge is different for residential, small non-residential and large non-residential; [redacted] cents, [redacted] cents, and [redacted] cents, per kWh, respectively. Combined, the generation charge for residential, small non-residential and large non-residential customers is [redacted] cents per kWh, [redacted] cents per kWh, and [redacted] cents per kWh, respectively.[3]

months. Large non-residential customers cannot exceed the lower of one-hundred percent of their prior twelve months or two megawatts.

[3] See Company direct testimony of Paul H. Clements at p. 18.

The second component, the delivery charge, applies only to residential and small non-residential customers. This charge relates to transmission, distribution and customer charges as prescribed in their respective approved tariff schedules. This component of the program would change with the tariffs as the Commission approves normal changes. Currently, this charge is [redacted] cents per kWh for residential Schedules 1, 2 and 3 and [redacted] cents per kWh for Schedule 23. The total block charge is the sum of the solar block charge and the delivery charge per kWh. All other charges in the respective tariffs would remain the same and subject to rate making proceedings.

The Energy Balancing Account (EBA) surcharge would be included normally for the first year. This is necessary because the EBA adjustment is for the prior year of operations. After the first year in the program, the EBA charge would drop off the participating customer's bill for the portion of the bill covered by a solar block.

PacifiCorp will retain the Renewable Energy Credits (RECs) and retire them. In addition, the Company will retain all other environmental attributes and retire them on behalf of subscribers.

Subscribers can bank excess kWh not used over the year. However, the Company proposes that any unused excess kWh will be cleared after the first full year of participation and donated to the Low Income Program.

Customers can opt out of the program within thirty days of signing up. However, if customers cancel outside of the thirty day period but before the term of their agreement ends, the Company proposes a cancellation fee equal to six months of the solar block charge times the number of blocks subscribed times 200 kWh.

<u>Division's Specific Responses to the Program</u>

While the Division is generally supportive of the Company's proposed program, the Division has several concerns.

First, as the value or avoided cost of solar changes over time, ratepayers potentially face a pricing risk under the proposed program. The Company's proposal in essence allows participating ratepayers to purchase a renewable resource at a fixed price, which the Company then sells to all ratepayers at a variable cost. As long as the two values are equal, ratepayers should be indifferent to the exchange. If, however, the two values differ, there would be an impact on the Company's revenue requirement. Whether the impact is beneficial or not depends on the value of the solar resource relative to the fixed price. If the value, as captured in net power costs declines over time, ratepayers will pay a premium over the fixed price. Alternatively, if the value increases, ratepayers would receive a windfall. This potential difference is illustrated in Tables 1 and 2 for a PPA arrangement.

Table 1: Illustrative Pricing—Zero Net Revenue Requirement Impact

Utah Allocated Embedded Costs		**Net Power Costs**	
-6.2	Generation	-5.0	Solar PPA Costs
-4.0	Delivery	4.5	Solar Value (GRID Avoided Costs)
-10.2	Total	-0.5	Total
Solar Subscription Program Pricing			
5.0	PPA Price		
4.0	Delivery Price		
1.6	Incremental Generation Price		
10.6	Total		
0.4	Net Impact on Class COS	-0.4	Net Impact at 70% Sharing Band
		0.0	Net Revenue Requirement Impact

Table 1 illustrates the Company's proposal with a net zero impact on revenue requirement. In this scenario, the Utah allocated embedded costs total 10.2 cents (per kWh) and the net power cost impact, measured at the 70% sharing band, is 0.4 cents. As proposed by the Company, the solar program pricing would recover an amount equal to the embedded costs plus the net power cost (NPC) impact, or 10.6 cents. The total pricing, or 10.6 cents, includes the allocated delivery cost, which will vary from rate case to rate case; the power purchase agreement (PPA) cost, which is fixed over the life of the asset; and an incremental generation cost, which also will be fixed at the initial approval of the program. Thus, as proposed, the cost of service impact, 0.4 cents, just offsets the net power cost impact.

If, however, after the initial pricing where the PPA and incremental generation prices are fixed, the value or avoided cost of the solar resource changes, the net cost of service (COS) impact will not offset the NPC impact. This scenario is illustrated in Table 2 where the avoided cost is less than initially assumed.

Table 2: Illustrative Pricing—Net Revenue Requirement Impact

Utah Allocated Embedded Costs		**Net Power Costs**	
-6.2	Generation	-5.0	Solar PPA Costs
-4.0	Delivery	**3.5**	Solar Value (GRID Avoided Costs)
-10.2	Total	-1.5	Total
Solar Subscription Program Pricing			
5.0	PPA Price		
4.0	Delivery Price		
1.6	Incremental Generation Price		
10.6	Total		
0.4	Net Impact on Class COS	-1.1	Net Impact at 70% Sharing Band
		-0.7	Net Revenue Requirement Impact

For example, suppose the value or avoided cost of the solar resource falls to 3.5 cents. In this scenario the COS impact does not offset the NPC impact and rate payers would pay an incremental 0.7 cents per kWh for the solar resource. The opposite could also be true: avoided cost could have increased relative to the PPA cost and rate payers would have paid less per kWh for the solar resource. Note, the revenue requirement impact in the second scenario is partially offset by two factors: by the 70% sharing band as applied through the energy balancing account and by the net COS impact. Thus, at this time the Division is not proposing additional mitigation for the pricing risk.

Second, while the Company intends that the program be fully funded by participating subscribers, there is always a potential risk that the program will go undersubscribed for one reason or another. For example, the Company's marketing efforts could be unfruitful or economic downturn or simple attrition could cause participants to cancel or not subscribe as kWh blocks become available. Furthermore, according to the Company's 2015 IRP, the preferred portfolio indicates that capacity resources are not needed until 2028.[4]

The Division acknowledges that the Company is responding to perceived customer demand for access to renewable resources. The Company's witness, Mr. Paul Clements,

[4] See 2015 Integrated Resource Plan, Volume 1, at p. 2. Note that the 7 MW Blackrock Solar project dedicated to Oregon customers is schedule for 2016. The IRP considers 816 MW of renewable PPA's scheduled to be online by 2016.

discusses the results of two surveys conducted by the Company. These surveys concluded that there is considerable interest in this type of program. Exhibit RMP_ (PHC-1) of Mr. Clement's testimony showed that opinion leaders prefer the subscriber solar option for obtaining renewable energy over other options. Additionally, community leaders support an optional program and would be willing to solicit support for a subscriber solar program within their communities. The second survey was conducted in 2014 by Market Strategies International (MSI). Mr. Clement's Exhibit RMP_ (PHC-2) summarizes MSI's study. The findings in this study were similar to the opinion leader study. However MSI found that although most customers surveyed recognize and value the environmental benefits of solar and other renewable power, the appeal of home roof-top and community solar drops considerably as the marginal costs of participating in such a program increases the customer's pre-participation power costs.

The Division notes that there is risk to non-participating customers if the program is not fully subscribed by 2019. However in the event the program is not fully subscribed, the Company would utilize the extra capacity as part of its supply side renewable generation resources. At the proposed [redacted] per MWh or [redacted] per kWh, the NPC of the facility would be comparable to other renewable generators either owned by the Company or through PPAs. Rates would not be adversely impacted by NPC as a result.

Ratepayers who can neither control the Company's administration of the program nor future economic circumstances, should not bear the risk of the program being undersubscribed. The Company should share the risk with ratepayers. Sharing the risk incentivizes the Company to act prudently and recognizes the lack of control customers have over future circumstances. Customers may share in the risk because the apparent demand for renewable resources arises from them. Therefore, the Division recommends that the Company and ratepayers bear equally the risk of undersubscription.

Third, the Division is concerned that some customers may falsely perceive that their rates will remain constant over the life of the program if marketing is not carefully crafted. The program is based on the price per MWh of the resource facility. While the subscription charge will remain fixed over the life of the program, other charges such as the delivery and utility generation charge will vary as general rates vary. As the price per MWh changes, the break-even kWh for all schedules participating in the program would also change. For example, for residential Schedule 1 with the Company's proposed pricing, the kWh break-even point would be higher than the average 742 kWh per month. Residential customers may only see a benefit during the summer months[5] or if the customer has banked kWh's that can be used over the course of the year. The small non-residential customers are on a declining rate schedule and may benefit during both seasons depending on their usage and whether they have additional power charges. The Division recommends that the Commission caution the Company to ensure their marketing campaign is clear about how the program billing works and how various charges might change so participating customers are not surprised with changing circumstances.

Fourth, the program's administrative, marketing, and billing costs appear, in the Division's view to be excessive. These costs total approximately [redacted] million dollars over the proposed life of the program. Of this amount, marketing costs total [redacted] million dollars or [redacted]% of the general costs. The Division suggests that the Company take a careful look at these costs before filing reply comments and determine if there is room for efficiency improvements.

For example, the Company plans to spend [redacted] initially on marketing to start the program, [redacted] during the uptake, and then [redacted] thereafter escalated at inflation. Given the Company's implied assurances through its witness Mr. Clements that the two previously mentioned surveys indicate a robust interest in the program, the intensity of the marketing and its costs over the life of the program would appear unnecessary. In a recent DSM Steering Committee meeting, for example, participants discussed the Home Energy Report and the impact of intermittent efforts of reporting on program savings. Anecdotally, it was reported that similar reporting programs in other utilities' areas had little or no effect on the achieved savings. Similarly, once the program is fully subscribed, it may be possible to scale back the marketing in the later years of the program to maintain full subscription.

Although the program costs are designed to support the program without impacting non-participating customers or revenue requirement, these costs should be reasonable. Therefore, the Division recommends the Company trim its estimated administrative, marketing, and billing costs before final approval of the program.

Finally, the Division is cautious about unintended consequences that such a program might have on the need for added infrastructure or other system upgrades, or the Company's DSM programs. The Company does not believe this to be a problem because the resource

[5] Summer months are considered to be May through September and the winter months are from October through April.

capacity proposed is relatively small. However, this could change depending on the popularity of the program, whether the program is expanded or similar program initiatives are undertaken, and actual load growth or reduction.

Conclusion

The Division believes there is sufficient demand for the proposed small program and supports the Subscriber Solar Program as modified by these comments. However, the Company's proposal contains many figures that remain estimates at least until the final project RFP is approved. If approved, the Division will monitor these estimates and their effects as the program proceeds. Additional risk is added if the program is not fully subscribed. The Division recommends the Company should share the undersubscription risk with other non-participating customers. The Division cautions the Company to be clear in how the program is marketed. The billing process is complex for all the participating classes and must be clearly explained. The administrative, marketing and billing cost projections appear excessive. The Company should re-evaluate them during this regulatory proceeding and once a final RFP is accepted.

The Commission should require the Company to report certain information, to be determined by the parties, six months after program approval and annually after the pilot program begins. These reports should include subscriber uptake information broken out by classes of service, number of customers in queue by class, revenues, cost by category, facility generating capacity, and renewable energy credits retired.

CC Paul H. Clements, RMP
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Service List