BACKGROUND/PURPOSE: This is a follow up to the 4/13/2021 RMWG Meeting, subject "Community Microgrid Enablement Tariff Discussion with RCEA and PG&E". There was not sufficient time during the discussions to answer all the questions posed by attendees. Below is a written response from our presenters. (Thank you to our presenters again for sharing their expertise!)

Presenters: Dana Boudreau Redwood Coast Energy Authority and Jeremy Donnell of Pacific Gas & Electric

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QUESTION: *For Dana, if RCAM's distribution substation or circuit is shutdown due to PSPS events do the same opportunities present themselves for grid sales/resiliency, given my earlier questions about PG&E-owned grid infrastructure and insurance?* (Tam Hunt tam.hunt@gmail.com)

ANSWER (Dana Boudreau, RCEA): I've lost the context of the earlier questions so this answer may be off the mark. Any islanding will prevent the microgrid from selling into the wholesale market, but during a PSPS event the microgrid shifts priority from energy sales to energizing critical services. The business model needs to take this split benefit into account. The insurance can be structured to address the overall economics of the business model, rather than just blue-sky operations. As climate change continues to escalate, resilience in some circumstances may pay for itself in days or months. For example, a facility offering grid stabilizing services during the recent Texas freeze event would have a dramatically short payback. This is an extreme event that can't be easily forecasted but is occurring more frequently and should be considered during grid transformation.

QUESTION: *To Dana-- Was a utility built microgrid under CMET vs a microgrid built by a microgrid company your first choice or the only choice you had with existing rules?* (Jeff Morris - jeff.morris@se.com)

ANSWER (Dana Boudreau, RCEA): CMET wasn't available when we proposed this pilot, and our grant submission defined a project team with an IOU, a university R&D group, and a community choice aggregator (local government agency). That team is building the microgrid, using existing grid infrastructure with innovations supported by an IOU grid innovation team. The utility will continue to own and operate the distribution grid infrastructure, and the government agency will own and operate the microgrid solar+storage infrastructure. There may have been an option to work with a private entity, but this was the first attempt at an FTM microgrid with PG&E infrastructure, and the project partners had already worked together on related projects, so this was a good fit to explore the next steps in microgrid innovation. With the groundwork being established today, in the future our agency would consider PPAs with private microgrids, but there are ongoing questions around asset control and ownership for critical facilities such as water/wastewater, emergency response, and so on.

QUESTION: *For Dana - what were the three main challenges in working with the CMET from a CCA perspective? In other words, what should other CCAs be considering early on in the process if they want to develop their own projects under the CMET?* (Jana Kopyciok-Lande jkopyciok-lande@mcecleanenergy.org)

ANSWER (Dana Boudreau, RCEA):

a. Evaluate if the project could qualify for socialized costs and could fit within an emerging tariff such as CMEP. This lowers the initial cost barrier since distribution grid upgrades are an expensive burden for the scale of a microgrid. Alternately, the site might qualify for being a remote grid, where the utility determines that it is cheaper to decouple a site from the grid and pay for a microgrid rather than continuing to energize lines through high-risk landscapes.

b. Evaluate the local grid capacity leading to your project site. PG&E can conduct a feasibility study for a fee, understanding that you may not recoup this cost but can at least avoid unrealistic siting. Here's an article to help understand this challenge playing out in the Midcontinent ISO:
https://energynews.us/2020/09/29/grid-congestion-a-growing-barrier-for-wind-solar-developers-in-miso-territory/

c. Carefully examine the energy market opportunities while preparing the interconnection application. CAISO needs to manage an application queue, look at grid capacity projections, consider the grid requirements associated with the proposed project site, and so on. It's a complex and lengthy process, so you'll want to pick your best options in your initial filing. Take into account the lifespan of the project and the possible shifts in market needs, competition, and so on. Note also that different services require different technology so you'll need to consider if the site is suitable for the market participation options. For example, economic dispatch occurs in minutes to hours, but regulation is delivered in seconds to minutes: can your project meet the required conditions and avoid penalties? Here's an introduction to various grid services in the context of wind projects, and a CA roadmap of strategies for integrating DERs onto the grid (thus potential opportunities):
https://www.nrel.gov/docs/fy19osti/72578.pdf
https://ww2.energy.ca.gov/2021publications/CEC-500-2021-010/CEC-500-2021-010.pdf

QUESTION: Allie Detrio verbally asked how RA will be attributed to the RCAM project.

ANSWER (Dana Boudreau, RCEA): As this is our first time through the process it's our best estimate, and we'll know more in a year. From our procurement team, "My understanding is that the facility has to be awarded deliverability from CAISO and qualified with CPUC (to receive an NQC), but that after that the RA is attributed to the project owner who can then sell it to the market."