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Meeting Minutes

Resource Planning Advisory Council – Virtual Meeting

Date Thursday, July 27, 2023

Time 9:00 AM – 11:00 AM MST

Location Hybrid

TEP HQ

88 E Broadway Blvd,
Tucson, AZ 85701
Conf Rm-HQ-257

Agenda

9:00	**Welcome, Introductions, & Logistics**
9:10	**Updates on WMEG Study Results**
9:40	**Q&A**
9:50	**Update on TEP Portfolio Modeling**
10:40	**Q&A**
10:50	**Break**
11:00	**Next Steps**

Attendees	Organization
Alex Routhier	Western Resource Advocates
Allison Moore	Fresh Produce Association of the Americas
Autumn Johnson	Arizona Solar Energy Industries Association
Caryn Potter	Southwest Energy Efficiency Project
Chaunce De Roos	Arizona Corporation Commission
Claire Michael	Wildfire
Eric Wilson	Pima County
George Hammond	University of Arizona
Kathy Knoop	General Motors
Robert Lamb	Member of the Public at Large
Sarita Morales	IBEW 1116
Seth Wheeler	IBEW 1116
Stephen Jennings	American Association of Retired Persons
Susan Dumon	Sun Corridor Inc.
Bodfield, Rhonda	TEP
Brianna Robles	TEP
Ilse Morales Duarte	TEP
Jenny Crusenberry	TEP
Joe Barrios	TEP
Kansfield, Karen	TEP
Lee Alter	TEP
Medler, Bonnie	TEP
Mike Sheehan	TEP
Nonso Emordi	TEP
Victor Aguirre	TEP

Nonso Emordi (TEP- Lead Supply Side Planner) – Updates on WMEG Study Results

Slide 12

- **Question:** RPAC Member: I want to get a better understanding of why it is cheaper for the whole West to go into one market. Why do specific entities benefit from being separate from CAISO? I'm assuming that means benefits or costs for the utility itself, but that's not taking into consideration the benefits for repairs. Did the E3 study capture that?
    - **Response:** I will address this in the next few slides. There was a specific metric that was being measured, which is the cost savings per utility, and it specifically looked at the costs and revenues generated from participating in the market for each utility.
    - Response: I believe rates were not analyzed as part of the cost benefit analysis.

- **Question:** RPAC Member: What are the costs on the utility side? What are the benefits and costs for rate payers? What are the overall costs for going into a market structure like this in comparison to having to buy separate new supply side resources and to make up what the market would offer instead?
    - **Response:** Well, there was also a BAU case, which modeled each utility as participating in a bilateral market. There was only a bilateral market and the imbalance markets going out through those years.
    - **Response:** So that gives you the comparison of the benefit of no market or no day ahead market at all versus going into one or the other day ahead markets. The market optimizes the scheduling and trading on a daily basis.

- **Question:** RPAC Member: So, you're saying that while it's cheaper for the West to be in CAISO, I guess EDAM versus SPP M+, it might be more expensive for the Arizona utilities. Was that the conclusion?
    - **Response:** These this did not evaluate markets losses. It used EDAM as the one market, so I need to clarify that our base case is the BAU, which is what we're doing now with bilateral trading and the EIM. The first footprint study looked at what would happen if the entire WECC was in one market. The study didn't compare SPP M+ versus EDAM, it just chose EDAM as the one market.

If the entire West was in one market, on average, it is cheaper for WECC on average across the entire interconnection. However, in that same scenario, if you look at the benefits for each individual entity, that was not true. Some had a greater expense on a case-by-case basis, but if you average across all the participants in the study, it was an average net savings.

- **Question:** RPAC Member: If everybody was in EDAM collectively, we would save money, but the individual Arizona utilities may not? Do they have any conclusions as to why that would be the case? Why would it cost the Arizona utilities more if everybody was in one market?
  - **Response:** So, I don't think it's specifically costing the Arizona utilities more than BAU to join the EDAM, but the savings for them are less for other entities in the West. Their costs would go up above their BAU if all the Western entities were in EDAM. So, when you when you sum everyone's cost in EDAM, it's lower than business as usual.

- **Question**: RPAC Member: When you think about all the regulatory agencies involved here, that can either affect the participation in any of these projected market scenarios. I can see a Regulatory agency saying, I'm not going to participate in this for the greater good. Are there any current or anticipated regulatory policy issues that would restrict or inhibit any of these participations?
  - **Response:** Well, I heard about 1 entity who I believe has been mandated to join an RTO, but I can't remember who it is. All these markets that you see are very patchwork and because one utility can join at a time, they're all voluntary, But the program must be federally approved.
  - **Response:** As a result of all these different configurations of markets and RTOs ISOs that are going on across the US, this is the first attempt to do a cost benefit analysis for a group of members asking how it benefits us and at what cost.

Slide 13

- **Question:** RPAC Member: I'm wondering how this affects the IRP?

- **Response**: Updating on our participation in market firms was required by the order. From the last IRP we wanted to let you know what was going on with the different market forums and it does factor into long term planning. We wanted to make sure you understood some of the issues we are considering when we have these conversations across WECC.

- **Question**: RPAC Member: Can we get access to the study and some of the methodology? I'm curious to look at some of the differences in the assumptions here versus the state-lead market study conducted by energy strategies.
  - **Response**: My understanding at this point is that the results are confidential for all Members, and the utility does have the discretion as to what level of detail they would share. Also, some of these results have prompted additional studies. The plan is to update the Commission when the studies are completed towards the end of the submission of the IRP. If that changes, we will let our RPAC know, but that is the state of things as we know it for now.

Lee Alter (TEP- Lead Supply Side Planner) – Update on TEP Portfolio Modeling

Slide 3

- **Question**: RPAC Member: It does seem that there's some concern about the transparency of the data that APS has provided versus what TEP is provided.
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  - **Response:** All the data we use is now included. APS may have more in their data because they will be running Capacity Expansion Models which identify new resources or performance or cost assumptions. So, there's going to be more in their database because they're using the model more comprehensively than we are at this point.

- **Comment:** RPAC Member: We have been working on data validation and have started running some of our own scenarios. I expect to start getting results from some of our own scenarios today.

Slide 4

- **Question:** RPAC Member: APS also did a PRM study and they determined that they needed something closer to 20% by 2026. This is almost a 4% difference between TEP and APS. Do you think you'll have an additional margin in the in the coming couple of years or is it correct that you just have a 4% discrepancy between what APS needs for reserve margin and what you need?
    - **Response**: It all depends on the load profile, the type of resources, as well as a regional component. The other thing to understand about PRMs is that they can, and perhaps should, vary by year because they are dependent on the resource mix and load shapes. Ideally there have be a change in the planning reserve margin every three years and whenever there is a significant change in resources.

- **Question**: RPAC Member: I'm looking at the operating reserves, they are only based on requirements and best practices, but that's based on the current balance of dispatchable versus non dispatchable resources, right? Which is going to change going forward?
    - **Response:** Well, as far as actual operating, we don't count anything as reserves that's not dispatchable.

- **Question**: RPAC Member: I think PRM is kind of an archaic measure that does not do a very good job of capturing the reliability concerns that we have for the system. So, I'm curious what other metrics you're using reliability-wise to back into what your PR needs to be. Are you looking at LOLE or something else to ensure that your PR is high enough?
    - **Response:** I know that that leads us right into subsequent slides, so I'll move on, I guess, and let me know if I don't answer your question. (Slides 5-6)

Slide 7

- **Question**: RPAC Member: How confident are you in your energy efficiency numbers?

- **Response:** They do have a significant contribution and they are measured on paper. As we have dispatchable DSM programs right now, we cannot conclude a confident number.

- **Question**: RPAC Member: I'm noticing that there's some variability in the energy efficiency. I'm wondering where that noise is coming from in the modeling because it seems to be that every point where you're running into your shortfalls, there's a shortfall in your energy efficiency at the same time. It is interesting how the model is simulating whatever that resource is.
  - **Response**: This might be because of lighting programs, and this could be because of pool pumps and rebates.

Slide 8-10

- **Question**: RPAC Member: Can we do a new resource cost assumption for energy efficiency and look at it in the model? Is that an opportunity that you think is feasible? Are we at the point right now where we're hitting marginal tradeoffs on energy efficiency investments in the community or are we at the point where there's work that we could do that would help us have more available?
  - **Response:** In the last IRP we did assume the continuation of largely the same shape, if you will, and an expansion of the savings. We included some dollar per MWh savings. We can certainly look at a couple of different scenarios.

- **Question**: RPAC Member: I noticed in slide 7 there's no demand response modeled in here. I'm wondering what flexible load levers you have to pull and how that's captured in the modeling?
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  - **Response:** I know that most of the energy savings in here are not driven by demand response. Time of use rates are included in this I think, and they will shift things around. We just launched the Smart Rewards pilot and I think at this point it is only a few MWs. I guess there's a philosophical discussion to be had on whether you want to include that in a stack like this. Coming from operations as something that you dispatch in contingency or when you are

expecting issues on your system. Rather than relying on it for every day that you forecast some shortfall, especially because you know or at least with the smart Rewards program, it's based on the thermostats, people can opt out at any time.