Meeting Notes

Meeting Objectives

- Provide recap of October RPAC meeting and provide status of previous action items.
- Provide an update on the ACC regarding community solar, DSM, and transportation electrification
- Provide an overview of APS involvement in Western Market developments
- Discuss timeline of new resource additions in current supply chain environment
- Provide 2023 IRP framework and IRP Base Case Assumptions
- Discuss how APS models gas prices and forecasts them
- Discuss integration cost assumptions and updated market price forecasts

Meeting Subject:	December RPAC Meeting
Meeting Date:	12/14/2022
Start Time:	09:00am
End Time:	12:00pm
Location:	Virtual

Attendees	Organization	Title/Role
Brian Cole	APS	General Manager, Western Market Affairs
Derek Seaman	APS	Manager, Resource Acquisition
Elizabeth Lawrence	APS	Manager, State Regulatory and Compliance
Justin Joiner	APS	Vice President, Resource Management
Michael Eugenis	APS	Manager, Resource Planning
Patrick Bogle	APS	Director, Financial Control
Rodney Ross	APS	Director, State Regulatory
Ross Mohr	APS	Manager, Energy & Revenue
Sadiya Jama	APS	Business Analyst, Resource Management
Tara Beske	APS	Business Advisor, Resource Management
Todd Komaromy	APS	Director, Resource Planning
Yessica Del Rincon	APS	Communications Consultant
Chase Kilty	1898 & Co.	Consultant
Evan Lipsitz	1898 & Co.	Consultant
Keaton Clark	1898 & Co.	Analyst
Matthew Lind	1898 & Co.	Director, Resource Planning
Adrian AU	E3	Consultant
Lakshmi Alagappan	E3	Partner
Nick Schlag	E3	Partner

Steve Jennings	AARP	Associate State Director
Greg Patterson	Arizona Competitive Power Alliance	Director
Daniel Schwiebert	Arizona Corporation Commission	Policy Advisor
Nick Myers	Arizona Corporation Commission	Policy Advisor
Diane Brown	Arizona PIRG	Executive Director
Gary Dirks	ASU	Senior Director
Johnny Key	Freeport-McMoRan	Director
Sam Johnston	Interwest Energy Alliance	Policy Manager
Nicole Hill	Nature Conservancy	AZ Thrives Program Lead
Lisa Hickey	Interwest Energy Alliance	Attorney
Teresa Brown	ACC	
Dugan Merieb	Pine Gate Renewables	Regulatory Associate
Sandy Bahr	Sierra Club	Chapter Director
Justin Brant	Southwest Energy Efficiency Project	Utility Program Director
Nate Blouin	Strategen	Western Policy and Markets Consultant
Kate Bowman	Vote Solar	Regulatory Director
Autumn Johnson	Tierra Strategy	CEO
Alex Routhier	Western Resource Advocates	Senior Clean Energy Policy Analyst
Murphy Bannerman	Western Resource Advocates	AZ Gov. Affairs Manager
Claire Michael	Wildfire	Director

Matt Lind (1898 & Co./Director of Resource Planning) – Introduction / Updated Meeting Guidelines / October RPAC Recap

- Slide 3 – Meeting Guidelines
  - RPAC member engagement is very important. Questions and discussion are welcome throughout the presentation.
  - Meeting minutes will be posted on the public APS website along with questions and items to follow up on.
  - Consistent member attendance encouraged
- Slide 4 – Following Up
  - Ongoing commitments include
    - Distribute meeting materials in a timely manner - 3 business days prior.
    - Transparency and dialogue
- Slide 5 – October Meeting Recap
  - APS effectively managed summer peak demand periods while navigating natural gas delivery challenges.
  - EPRI is developing a climate change scenario analysis study to help APS navigate future uncertainties and risk surrounding climate change. APS requested RPAC member feedback on physical climate conditions that should be considered in the EPRI Study.
  - E3 highlighted new technology risks focusing on outage trends of battery storage resources.
  - 2022 ASRFP contract negotiations are in progress and are expected to be completed in the first half of 2023.

Elizabeth Lawrence (APS/Manager, State Regulatory and Compliance) – ACC Updates

- Slide 7 – Community Solar
  - The last update given on community solar was on September 23rd
  - Updates since the proposal was filed:
    - Staff filed the report towards the end of October.
    - It was recommended that the process goes to an evidentiary hearing. This was heard at the November contingency meeting. This is called a bifurcated process so some issues will be resolved in an evidentiary hearing, and some will be resolved in a policy statement developed by commission staff.
  - An additional docket has been opened on community solar to handle the evidentiary hearing portion.
    - The docket number is 220291.
    - On 12/13/2022 the procedural conference was held. There was a large attendance with many diverse perspectives. Topics such as timeline and public notice were discussed. At the end of the conference Judge Harpring indicated that she was not ready to make any recommendations. A procedural order is anticipated for the near future, this would outline the steps for a testimony and a hearing.
    - January is the deadline included in the order for the policy statement aspect of the bifurcated process.
- Slide 8 – DSM
  - 2022 DSM Plan was approved in November.
    - $78.4M budget, this is a $10.2M increase from the 2021 approved budget.
    - With both existing measures and the approved new measures, the DSM plan targeted 405,000 MWh of energy efficiency savings and 456 MW in peak demand savings.
    - The demand response program was expanded
  - The 2023 DSM plan was filed on November 30
    - This has a budget of $88M
    - The plan includes an energy efficiency savings goal of 1.4% totaling in 421,000 MWhs of energy efficiency savings and 223 MW of dispatchable demand response
    - Includes DDSR Aggregation Tariff consistent with decision Number 78165
- Slide 9 – Transportation Electrification
  - The 2023 Transportation Electrification plan was filed on November 30th. This plan includes:
    - A budget of $5M for Take Charge AZ program
    - In the DSM plan there is a $4.2M request for the managed EV charging pilot that includes programs such as the fleet advisory service and incentives for customers who want to upgrade their charger to a smart charger.
    - Requests approval of a new Commercial Make Ready initiative.
    - Request for approval of revised Residential EV rate.
  - Question – RPAC Member: A lot has been discussed with the RPAC regarding load forecasting and transportation electrification and how the transportation electrification plan will play a big role in the load forecast going forward. The transportation electrification (TE) plan that APS submitted was lackluster to say the least. I do not think it’s innovative enough to catalyze the type of load growth that we have talked about in the RPAC. I’m wondering, is the load forecast

going to change or are there plans to submit a more innovative and aggressive TE plan in the future? How are these two things that are seemingly incongruent going to come together?

- Response – Matt Lind: That is a fair question and comment. I don't think there's updated information to share specifically on load forecast today. There are changes and updates coming to the load forecast that needs to be revisited but at this time we are not at a point where we can share in enough detail, but this is a near-term item that will be revisited. EV electrification in the transportation sector is a component affecting what the load forecast might look like for the IRP.
- Response – Todd Komaromy: In the January meeting we're planning on spending a good amount of time on the load forecast. We can make sure that we hit this question head on during that time.
- Question – RPAC Member: I very much appreciate the hard work that went into the DSM plan, and I have been supportive of that plan. Similarly on the TE plan, I am supportive of the TE plan moving forward based on what you have submitted, however as you are looking into future years there's a lot more ramp up that needs to take place to best benefit rate payers overall. I'm wondering, have you had interactions with commission staff to review the plan? Have they come back to you with questions on what you filed? Also, for what you are looking at for the next couple of years, how quickly will that be assessed? Whether that comes up in the TE collaborative or some other venue, I think the notion of having a more robust, comprehensive plan is certainly needed and I think it's what the commission is asking for as well.
- Response – Elizabeth Lawrence: I know there were a lot of questions in that so if I miss any just let me know. As far as having engagement with commission staff on the revised plan, we have not received any discovery requests or anything like that since we filed it. That being said, it was only filed two weeks ago and there was an open meeting in the middle, so it has not been that long. Regarding your question about plans for the future, things are slightly different with what TEP did and what we did. They filed a 3-year plan, and we filed a 1-year plan. We absolutely intend to file a new plan at some point next year. I say at some point because, as I'm sure you all can appreciate, getting some guidance from the commission as far as what's adopted and discussed and asked for during the approval process is crucial for us to be able to put forward a new plan that meets the policy objectives that are laid out in our 2023 plan. The TE collaborative is going to continue, we have committed to quarterly meetings and were very excited about that group. We have received interest from new members recently, so it is definitely going to proceed. We would love to hear your perspectives and what everyone is interested in seeing in new plans.
- Question – RPAC Member: I recognize that a number of these stakeholder meetings have overlap. I appreciate that this group pulls many of the different collaborative groups together and talks about the future. It would be helpful to not just have a 1-year plan moving forward but to have a 3-year plan. TEP did their 3-year plan, but they have also committed to annually revise it as more information comes in.
- Response – Elizabeth Lawrence: I can take that back to the customer to grid teams as we plan for the future.
- Comment – Todd Komaromy: I also want to be cognizant of the different interactions and try to be respectful of everyone's time. There are a number of people who participate in both efforts here, we can certainly have this as a topic that will return to the RPAC at the appropriate time, but we want to make sure we are not duplicating too many efforts.

- Comment – RPAC Member: I would be interested in hearing more about what some of the participants think is missing from the Transportation Electrification plan. This is very actively researched at ASU. How do we get electrification happening at scale, and at pace? I'm curious as to what is missing from that plan.
- Response – RPAC Member: If you look at the docket on this, WRA, SWEEP, and PIRG filed a letter that showed some of the components that are missing. Some of it is what we think could be more robust. Some of it, for PIRG at least, was more of the enablement of public transit and mobility, some of the components that TEP had in their plan were very strong. There is lot is moving forward with infrastructure and funding. The funding levels are low compared to other utilities. If you want people to take up the incentives and get the grid moving in that direction, there are some improvements that need to be made.
- Response – RPAC Member: I think that's a good overview, the other thing we really wanted to see is in the Take Charge Arizona program the elimination of DC fast charging incentives is concerning. In the filing, APS says that they had a large backlog of level 2 chargers and that is what they were going to focus on going forward. If the backlog is that big then why are we not doing more to make sure that people who want chargers and the charging infrastructure can get those. Why is there a waitlist? Along with the previously stated items, the immobility and public transportation are aspects where there are a lot of opportunities for improvement.
- Question – RPAC Member: If I could take you up on the letter can you send it to me, please? I think this is something our own transportation electrification engineering group would be interested in looking at, it might be new to them.
- Comment – RPAC Member: If anyone else wants to see the Arizona PIRG Education Fund, SWEEP, and WRA letter re: the APS TE plan, which we hope is adopted with some tweaks soon, please email Diane Brown at Arizona PIRG.

Brian Cole (APS/General Manager, Western Market Affairs) – Western Markets Evolution

- Slide 11 – Western Markets Evolution (WME) RPAC Update
  - Comment – Brian Cole: I really appreciate the ability to be here to update you all on western markets. My name is Brian Cole, and I am the general manager of Western Markets Affairs at APS. I am responsible for helping APS move forward in markets. I have a background in resource planning, transmission, distribution, regulatory, and marketing so I have a good idea of how things fit together for the bigger picture which is necessary for markets. This is a very exciting time for the integrated resource planning process and overall, for western markets.
- Slide 12 – Goals of WME Effort
  - Reliability
    - Maintain or improve reliability
    - Will be challenged with changing resources
  - Customer cost savings
    - Via utilization of both loads and resource diversity. Western markets can help to provide this.
    - Needed to offset increases in cost
  - Integration of clean energy
    - Can't meet clean energy goals without it moving forward in markets.
  - APS agreed upon these goals 16 to 18 months ago and since then many groups in the west have adopted very similar if not these exact same goals.

  - The continued reliance on reliable electricity and electric service is everywhere in society. Making sure that we are integrated in the west and doing everything to stay reliable is critical. It's not just power, its water, gas, communications, and cars like we just talked about. There is a in that space, and we get that, and we want to do it right.
- Slide 13 – Background & Drivers
  - Previous Efforts
    - RTO discussions have occurred intermittently for over 20 years
  - Current Effort(s)
    - It is different this time
    - Needed for clean energy integration
  - APS Stated Goals
    - Reliability
    - Customer savings
    - Clean energy integration
  - ACC Docket
    - Tracking market efforts
  - APS cannot independently move towards a market. We have to have critical mass to make that work. We have great relationships around the southwest, around the Rockies, and around the northwest. There is very good potential for great load and resource diversity if we can find a way to make the market footprints big enough.
- Slide 14 – Ongoing Efforts
  - These are the four big efforts that APS is currently participating in.
  - Western Resource Adequacy Program (WRAP)
    - A foundational program that sets both resource adequacy and governance starting points. You need to have resource adequacy to make all of these markets work and to make sure that there is equity amongst the markets.
  - CAISO Extended Day-Ahead Market (EDAM)
    - California is taking the next step from the real time market and forming a day ahead market.
  - Southwest Power Pool Markets + Day-Ahead Market (SPP Markets+)
    - Competing market to the EDAM in the west.
  - Western Markets Exploratory Group (WMEG)
    - CEO level group working independently to try to identify what the future market options will look like beyond the day ahead market up to and including the RTO.
  - Sizing
    - WECC load peaks at 160+ GW
    - WRAP footprint 70+ GW
    - CAISO peak load is around 50 GW
    - EIM has about 75 GW
    - WMEG is about 95 GW total if you include all groups that are involved
- Slide 15 – Western Power Pool – WRAP

   - Comment – Brian Cole: I am excited to announce that APS has committed to the next phase of WRAP. The reason there is a several yearlong transition plan before the WRAP becomes binding is because participants are in different situations. Some are resource short, and some are resource long and it's important to give participants a chance to get righted in where they need to be. Ultimately, this is a commitment by western entities for the reliability of the west. The primary purpose of the program is to make sure there is enough steel in the ground. We want to make sure we can reliably serve the western resource adequacy footprint. It levels the playing field and makes sure there is not leaning in between entities. It will also serve as the foundation for the future day ahead market and the development of future markets. This is a really big step. APS and the western entities that are participating have a shared commitment that will provide the foundation of the WRAP.
- Slide 16 – CAISO – WEIM
   - APS has been a member of the CAISO energy imbalance market for seven years.
   - Comment – Brian Cole: No market is perfect. APS wants to get things as close to perfect as possible for its customers. There are some things that APS works with CAISO on regularly to improve such as governance, resource adequacy issues, transmission wheel through issues, and fast start pricing issues. APS believes their customers will receive a better benefit if these issues are resolved. CAISO is a great organization, and we will continue to collaborate with them.
- Slide 17 – SPP WEIS & WPP RA
   - PacifiCorp wants to move ahead into the day ahead market with CAISO. There is a commitment from BC Hydro to join the SPP Markets+ footprint.
   - APS will continue to evaluate their market opportunities to understand what the best opportunity is for its customers.
- Slide 18 – WMEG
   - Western Market Exploratory Group was originally formed together by CEOs from seven companies, including APS. It has now grown to 25 entities.
   - The goal is to explore the pathways to organized markets, all the way up to an RTO.
   - Market footprints are also being studied. Including offerings developments with CAISO and SPP and looking at potential transmission expansion and other power supply solutions consistent with state regulations and policies.
   - The group represents approximately 95GW of load and around 17M customers.
   - In March, Utilicast was hired to help WMEG evaluate the regional market structure and structure possibilities.
      - Utilicast is supporting both as a consultant and as a facilitator to help keep moving forward in a manner that is quicker than some would probably like but this group needs to keep moving forward.
   - The WMEG group and Utilicast contracted E3 to perform a production cost benefit evaluations and studies in the day ahead market as well as additional markets including the RTOs in order to understand where the benefits come from.
   - Comment – Brian Cole: There is a lot going on in the western market space right now and it has been a pleasure to represent APS in this space.
   - Question – RPAC Member: So, WMEG is looking at a non-CA west RTO independent from SPP or CAISO?
   - Response – Brian Cole: WMEG started off with a lot of different thoughts and ideas. WMEG wants to adapt a market that will work for as many participants as possible. Standing up an independent market from SPP and CAISO is unnecessary if western entities can get what they need from SPP or CAISO or both. WMEG is trying to establish what a

good market looks like so it can push the CAISO and SPP markets to get what they need in the west to be successful. The direct answer to the question is no, we are not trying to stand up a third independent market. WMEG continues to work with SPP and CAISO to make those markets as good as possible for western entities.

- Question – RPAC Member: Is it a concern that the west might get split up between SPP and CAISO?
- Response – Brian Cole: The answer really is no. If you think about the RTOs that exist across the rest of the country, they do not have to be giant in size. Some of the RTOs in the Eastern Interconnect are on the order of 20 to 30 GW and they are getting the results that they were hoping for. The WECC is made up of 160 plus GW and the CAISO itself is about 50 GW, so no, I think if you end up with two markets there is plenty of benefits for all across the west if that were to occur.

- Slide 19 – Timelines – High Level
  - WRAP transition period begins on January 1st, 2023.
    - FERC approval needed to move forward.
    - There will be a transition period with a binding and non-binding phase. Entities are allowed to choose their binding timeline. This will take place between 2025-2027.
  - Day-Ahead market evaluation and commitments to be made in 2023/2024
    - Both CAISO and SPP have come out with the high-level options for what the day-ahead markets might look like.
    - Comment – Brian Cole: My belief is that day-ahead market operation will commence sometime in late 2025 or in the summer 2026
  - Future market steps "up to and including RTO" will occur approximately 2026-2030.
  - Question – RPAC Member: The commission is on the front line of all three of the pillars. We receive a lot of input, certainly on affordability. I'm working on behalf of my boss who has spoken in favor of regional markets, he's on the BOSR, and he has received some CAISO sponsored training, so he's engaged on the issue. I can encourage some urgency on APS's part to move forward. The continuation of periodic studies which will site enormous benefits from regional markets as well as CAISO periodically calculating what membership saves. Many see this and scratch our heads when we are asked to approve a lot of PSA increases. We ask why are these savings not being obtained sooner? Anyone is certainly free to comment or respond.
  - Response – Brian Cole: I appreciate your comment and I know there are many members, including APS, who want to continue to move forward as quickly as we can. It is important to make sure we evaluate the markets appropriately. There are a lot of dollars at stake for our customers and we want to get the investment right. It is not easy to change markets once you select a market. This day-ahead step is a big step for us, and we want to make the right decision, and we need to collaborate with the rest of the region to make sure we understand what the benefits can look like. We have to know what the footprint of the group will look like to make sure we can accurately determine the benefits. APS will continue to move forward as quickly as possible.
  - Question – RPAC Member: My question is about the WRAP. There is recent news with the WRAP and its evolving, but can you say some more about what the transition period looks like once that begins and when it comes to participating in the binding portion of the WRAP what that timeline looks like? Also, how will APS be evaluating whether to move forward to the binding portion and what will APS be looking at to evaluate whether it makes sense to move forward to

the binding portion of the WRAP? Are there opportunities for stakeholder education and engagement? This will help the RPAC understand how that's proceeding as you enter the transition period.

- Response – Brian Cole: From the WRAP perspective, I had mentioned the reason for the transition period is because entities are all in different positions and it takes a while to get the right resources in place and make sure that they are meeting their foundational requirements that are required by the program. The non-binding phase allows them time to get the right resources in place and, each season, we do actual measurements and go through the process of what it will look like. There is a forward showing program that looks seven months in advanced for both the winter and the summer where you have to show you have the right resources. If you don't then there are penalties once you're in the binding phase, those penalties are significant, so participants want to make sure they have done everything they can to get the right resource in place. They are measured in a way that is agreed upon and defined in the business practice manual. SPP is the manager of the program behind the scenes. They are doing the measurement and making sure that everyone is doing the right thing. As we go forward and get into the binding phase, the WRAP will allow us to know that other entities will have adequate resources, which is helpful during the resource planning process. This binding phase could have a direct impact on planning reserve margin and how it might change moving forward. This is something that we have an eye on, as an aggregate and as individuals. It helps us build less resources than if we were standing on our own. It will take time to get to that point, but I think it is a very important future state and it will save our customers money. The PSA was mentioned, and it will help in those spaces.
- Question – RPAC Member: As the forward showing events happen, in the transition period some participants will meet them, and some will realize they need to improve resource adequacy or change planning reserve margins. Is that something you will be sharing with this group or through a different forum? What the results of those interim steps are?
- Response – Brian Cole: On an individual company basis, the answer is probably no but what we will be doing and have done in the past as WRAP and WPP is share results at an aggregate level, so people know what is going on with the market. WRAP has also created instructional videos and presentations for those with less of an understanding around what is going on with the market developments. If you want a little more information to form a foundation, I'm happy to put you in contact with them. If you have further questions, I'm happy to reengage and answer even more.
- Question – RPAC Member: One of the questions came up before you answered an RPAC Members question which was how utilities say that the day-ahead markets are a larger commitment to an overall market than EIM or EIS. Can you give a brief overview of why that is and why were not already committed to certain markets through EIS or EIM?
- Response – Brian Cole: I can't give you the granular details of how its calculated up but there is an understanding that if you are in a real time market, you can get 10 to 20 percent of the total achievable benefit of the dispatch through a real time market. The day-ahead market moves the timeframe up and the ability to identify what units will need to be dispatched becomes much more efficient. We believe that we will be able to get closer to 80 percent of the benefits. We use those in terms of what would a full RTO be if you had everything running in that space that will get you 80% of the dispatch benefits. I think it's really important to think about the WRAP consequences and having a foundation of resource adequacy because the resource adequacy allows you to think about what your planning reserve margin can do in this space. The dispatch alone does not help you if you do not have enough resources across the region but if you have a resource adequacy construct, it allows you to build a foundation and determine a planning reserve margin once

everybody is in a market and in a resource adequacy program. I look at those as a joint way to make sure we optimize benefits.

- Response – RPAC Member: I think I understand the value flow of the markets. There seems like there's some apprehension to join a day-ahead market because if you don't get it right, you are stuck with it for a long time. We have been hearing about APS and other utilities listed in your presentation that have been working on EDAM for nearly five years. In this timeline that you put out, we are not even there for another 2 and a half years. I'm trying to understand, what is the apprehension? Is it a significant investment in infrastructure? I thought the CAISO EIM already was. What is the hurdle that causes us to need to be so cautious in selecting a day-ahead market? I think waiting years and years to make the perfect choice when we admit there is no perfect market, are we sort of cutting off our nose. What is the specific thing that makes the day-ahead market decision so much more meaningful that the EIM/EIS decision?
- Response – Brian Cole: I want to address your apprehension comment. I can tell you from APS's viewpoint, there is not an apprehension to join a day-ahead market, there is a desire to make sure we choose the appropriate day-ahead market. We want to make the decisions and move forward but when you commit to a day-ahead market, backing out is a little more complicated than an energy imbalance market. You are right. A lot of the infrastructure, like metering, has been put in place for the real time markets. There is additional infrastructure from a software and integration, standpoint in order to make the day-ahead market work correctly. We want to make sure we make it right, we don't want to slow this down, we want to move forward but we want to make sure we make the right selection. We believe that whichever market we decide to go into will likely set the future for a potential full-RTO evaluation. We are very unlikely to change once we commit to a day-ahead market. Yes, there are customer cost savings, but APS has to think about it in the long term and not just in the short term. APS is trying to make the right decision for the customer.
- Response – RPAC Member: Regarding MOD-030 and APS's recent transition over to flowgate methodology for transmission scheduling, are there more tactical steps that you are working with adjacent utilities to get them in shape for some of these big efficiencies that no one really knows about or sees? There are things that we can do today that don't require us to choose which RTO we go with because either way we're going to need the transition to flowgate transmission system.
- Response – Brian Cole: I appreciate you recognizing that APS is an entity in the west who is moving forward in that space. We have tried to pull others along with us. Importantly, the SPP Markets+ alternative to a day-ahead market will operate the market as close to a flowgate methodology as you could get. It does not require you to go to MOD-030 to do it. That was something that was discussed early on. We believe with tariff changes within each entities tariff we can operate that way in the day-ahead real timeframe without deconstructing the entire OATT process. I think that would get a lot more out of the system which I think is what you are talking about and what your goal is and that's what APS's goal is as well.
- Question – RPAC Member: What is 1898's role in the markets. Is it just because 1898 & Co. is the RPAC administrator or is 1898 & Co. doing something in the market space for APS?
- Response – Brian Cole: Yes, 1898 & Co. is helping with the entire RPAC process which is why it's on the slides. They are a consultant to us as needed but in the western market space we have only been engaged with them at a very high level. This is really an APS presentation but it's on 1898 & Co. slides because they are running our RPAC presentations.

- Response – RPAC Member: I knew the relationship with Utilicast and E3, so I was a little surprised to see these on 1898 & Co slides.
- Response – Matt Lind: I think you covered it well. I would add that as a consulting group we do have expertise and we work with utilities, work with markets directly like an SPP, in this consulting space.
- Question – RPAC Member: In terms of governance, I know some IPPs and utilities have been more excited about the Markets + design. If CAISO sees a legislative change that would change the dynamic from a California-centric governance structure, would that have a major impact on APS's view of the CAISO proposal in general or are there other issues that loom larger over the EDAM proposal?
- Response – Brian Cole: It's a great question and it's a topic that comes up continuously in the west. The CAISO was created for California in the beginning. Its governance was for California and that was perfectly fine when it was done for California and was in California but now that it wants to grow expand and grow to include other states and entities, there needs to be some independence and unfortunately that has not occurred. The desire to change the governance has not been there. They do continue to have those dialogues and to provide a direct answer to your question, if I could snap my fingers and change it into an independent governance, would it make a difference? Yes, it would. I think it is very important but there has not been much change in that space. This was known back when we joined EIM seven years ago. Unfortunately, they have not been able to change anything since. Yes, governance matters. Yes, most of us outside of California do prefer more of an independent governance that I think SPP is on the road for. WRAP has a nice independence governance as well. It will be one of many things that we have to think about as we move forward. Yes, it would make a difference if they could get the governance changed.
- Question – RPAC Member: I keep getting materials about a national HVDC transmission system. Is there anything real about these proposals or are they fantasies?
- Response – Brian Cole: I don't think they are fantasies. I do think there is potential out in the future for a lot of different opportunities including bridging that gap between the western and eastern interconnection. They require a lot of thought, a lot of resources, and a lot of time to figure out how do we best do that. I think that we have to see how the markets play out and what the footprints look like and then understand how to best leverage the setups, either within or outside of the eastern or western boundaries, in order to make an HVDC system work. I do not think an HVDC transmission system is out of the question, but I think we need to think about what we are accomplishing? You don't build transmission just to put wire in the air. I do think there are good opportunities for new transmission in the future. We just need to figure out how to best go about it and get it built so we can keep integrating more clean energy.
- Question – RPAC Member: Does it matter if some AZ utilities go to SPP and some to CAISO? Or having a seam in AZ is not an issue?
- Response – Brian Cole: I think it would be better if regional entities were in the same structure. If there is a seam or a place to separate them that could be allowed, then it allows you to be in two different markets. We are trying to work as closely as we can with Arizona and the southwest entities to stay aligned on what is important to us and where we need to go. I think that is an important concept. Seams are not the end of the world. You can still trade and help each other across seams so there is still a benefit.
- Question – RPAC Member: I wanted to ask you about the cost benefit analysis that you referenced that are happening in the WMEG and I was wondering if there was going to be an opportunity for the public or for this group to see the

results of some of those studies? Either the studies themselves or some distilled versions of the results at some point in the future.

- Response – Brian Cole: Appreciate the question and I should have mentioned that. We have every intention to put a study out once we are to that point where we have everything put together. We do want to make that public so yes you will see that.

Nick Schlag (E3/Partner) - Timeline of New Resource Additions

- Slide 22 – New resource procurement is a multi-year process
  - The Request for Information (RFI) is used to collect information and market intelligence from potential bidders.
    - This can take anywhere from 3-6 months to perform
  - The Request for Proposal (RFP) is used to solicit competitive bids to meet an identified resource need. The evaluation is based on relative costs, benefits, and other factors.
    - This can take anywhere from 3-15 months to perform
  - The actual construction can vary depending on a number of factors, but this can take anywhere from 1-3 years.
  - Many tests are run on a new facility, and this can take 1-2 months before the generator is synched with the grid.
- Slide 23 – Current RFPs are targeting resources online in 2024-2026
  - Most current active RFPs focus on procurement resources that can come online between 2024-2026
    - Reflects a 2-4 year timeline for procurement and development that begins when a utility issues an RFP
    - Many include procurement targets for multiple years, which naturally increases RFP evaluation complexity
  - All all-source RFP including bid evaluation and negotiation can require up to 15 months to complete and is just the first step in new resource development.
  - The figure shown represents generally what is happening in the west with regards to RFPs
- Slide 24 – Multiple years are typically needed for resource development once a utility executes a contract
  - A historical look at the solar PV resources that came online in AZ, CA, and NV between 2016-2021
  - The average time it took from contract execution to online date was 2.4 years.
  - Once a utility has decided to move forward with a project (either utility owned or PPA) multiple concurrent processes are required to turn that project into a reality
    - Permitting
    - Regulatory approval
    - Financing
    - Transmission
    - Engineering, procurement, and construction
  - In total, these processes typically take years to complete which underscores the importance of proactive, forward-looking planning process.
  - Question – RPAC Member: Do you have any similar information on storage projects yet?
  - Response – Nick Schlag: I wanted to have it for this presentation but no we have not been able to compile a similar set of data for storage projects. This timeline for the solar PV ends with projects that were roughly signed in the 2020 to 2021 time. 2020 to 2021 is right around the time that we started to see contracts for energy storage be signed, so no we have not had a change to compile that data yet, I would be really interested to see it myself.

- Question – RPAC Member: Did you look closer at causes for delays for longer term projects? Supply chains, permits, etc.?
- Response – Nick Schlag: In the context of this specific figure, we did not drill into any of the longer timelines and specific causes for them. This timeframe that we are talking about in this particular slide, you'll notice it ends in 2021 which I think predates a lot of the current supply challenges that we have seen in the market for the past year or two. I would not expect that to be a major driving factor in the timelines that we have seen here. I will talk a little bit about all the supply chain issues that have been popping up.

- Slide 25 – Example timelines for new resource development (wind and solar)
  - The development of a new wind power plant is a multistep process that can take years to complete.
  - The development process can take up to 5 years.
  - The timeline for a utility scale solar power plant (250 MW) can take over 6 years.
  - The timelines can vary greatly depending on the resource
- Slide 26 – Recent supply chain issues continue to stretch development timelines
  - Continued supply chain pressures have resulted in construction delays for new power projects, particularly solar and energy storage.
    - Delays have typically pushed back project online dates by months – or in some cases, years
  - Prospect of continued disruptions in upstream industries and further delays increase importance of building enough time into planning process
    - Particularly important when replacing retiring resources, where large amounts of new capacity is needed over short periods of time to enable a successful retirement.
  - There were many delays around planned utility scale solar projects between January and June 2022.
    - 20 percent of plants were delayed
  - Question – RPAC Member: US strategic disengagement with China continues to progress. Do you have any plans to look at supply chain risk if Chinese materials and systems are discouraged or banned?
  - Response – This is a continuing area of concern. I don't have any specific plans to examine the impact of strategic disengagement but it's certainly something we will be watching closely as these international, geopolitical dynamics continue to play out. To the extent that it does occur and puts even more pressure on the supply chains, I think it only further underscores the importance of making sure there is enough time allotted for planning and procurement processes.
  - Question – RPAC Member: Have these risks affected the way that you are evaluating RFP's and the contractual structures? I know we had some discussion around build transfers vs PPAs and these development timelines and the way that APS is doing RFP's now. These risks may force you to change where your headed or compared to the beginning of the RFP process that was started in March. Can you comment on that?
  - Response – Derek Seaman: We definitely have taken a different approach to our RFPs. The approach was setup in a way to allow for flexibility during the negotiation phase to account for changes in pricing. It's tough to navigate these times and figure out what is going to be a perfect approach and I don't think there is going to be one perfect silver bullet. What our approach does allow is the availability to be flexible in our negotiations and we are seeing success in that space. We are offering flexibility to counterparties and I think its keeping things moving forward in a nice way.

Another aspect is that we are looking to procure as soon as possible to make sure that we hit these longer timelines. Does that answer your question? Or is there anything else I can elaborate on?

- Response – RPAC Member: I think that's the vein that I was looking for. I don't really know how to articulate it perfectly. All of this is meaningful to customers and the whole southwest is in a pinch between bringing new capacity online and experiencing inflationary pressures across all commodities, supply chain issues, and project delays. There would be a massive number of failures in the contracts that were signed in 2019 and 2020 and potentially 2021 because once they got beyond the execution of the PPA, the projects never even came online, and were delayed indefinitely. I'm trying to think, how does all this trickle down to how a customer should be thinking.
- Response – Derek Seaman: It is a good topic. If you think about RFPs of past, the methodology was to find a fixed price and hold the counterparty to that fixed price no matter what. In a sea of rising cost, these counterparties quickly found themselves underwater. Once they are underwater it is not a good business environment to be in. We want them to have their level of success. Obviously, we need to the project to be a success and hit its COD. It's important to know where these costs are coming from. If it's isolated to one developer, you can't have that. If they are running up costs on you, it's not good for customers and it's not good for APS. We want to make sure we have the transparency with these developers. If their costs are rising and everyone's costs are rising, then you can feel safe that what you are contracting for to keep the contract in line is lock step with the rest of the market. The index pricing was one mechanism to say, "if your prices are going up, we need to understand what the lever looks like". The other approach that we use from time to time is more of an open book approach. Making sure we have a quote ahead of time for some of the major components and if those prices move for whatever reason we need to be able to see what they move to, but then also give ourselves the opportunity to say, "if costs get out of control, we might have to pull the trigger and step away from the agreement and look at other opportunities." It's a tight supply chain out there so we are putting reliability first and foremost and we are trying to find as much flexibility in these agreements as possible.

Michael Eugenis (APS/Manager, Resource Planning) - 2023 IRP Framework

- Slide 30 – IRP Objectives and Evaluation Framework
  - There are 4 major categories that are addressed from an analytical and qualitative perspective.
  - APS is interested in a generation mix that is most resilient to changing conditions in the future.
  - Reliability
    - Reserve margin
    - Diverse generation mix
  - Affordability
    - NPV-RR
  - Sustainability
    - Clean target
    - Renewable target
    - Emissions
    - Water consumption
  - Risk
    - Price exposure
    - Technology risk

- Permitting and licensing

- Slide 31 – Managing Risk and Uncertainty
  - Identifying key drivers of uncertainty
  - Identify scenario themes
  - Identify qualitative risk factors
  - Identify quantitative risk factors
  - Key case inputs
    - Load growth
    - Fuel price
    - CO2 price
    - New Resource Capital Cost
    - Energy efficiency and demand response
  - Comment – RPAC Member: For risk, should we be talking about risk, given we have seen attacks on energy infrastructure in several states recently? I think there were incidences in WA or OR too.
  - Response – Michael Eugenis: This is a very timely question given the impacts of the recent events on the east coast as well as a string of events on the west coast, specifically in the pacific northwest including vandalism of specific substation equipment. Moving forward, I think it is key to determine how we can build a more resilient grid and I think physical security is a portion of that resiliency. There are a lot of different ways that you can think about that going forward. How is something more reliable from a resource adequacy perspective? How is something more reliable from an operational flexibility perspective? The ability to withstand a physical attack is a piece of that. Cyber security is another issue that is thought about a lot in the utility realm, especially years ago with the cyber security attack that happened in Ukraine. A lot of what we focus on as a utility is maintaining reliable and affordable service for our customers. Specific to the IRP, I don't know if we are going to have a physical section, but we can take the feedback and think about it internally and see if it is something we want to address specifically. I appreciate you bringing up that topic.
- Slide 32 – APS Proposed Scenarios
  - Reference
    - The reference scenario is a future scenario using base forecast assumptions.
    - Utilized current expectations for load growth, fuel prices, technology development, and environmental regulation.
  - Rapid technology development
    - Technology cost reductions for renewable, storage, DSM, and EE.
    - Carbon price and fundamental drivers remain consistent with the reference scenario
  - Enhanced environmental regulations
    - Fuel and CO2 prices are increased to reflect accelerated environmental regulations.
    - Technology costs remain consistent with the reference scenario.
  - Accelerated electrification
    - Technology development and federal incentives.
    - Higher load growth

  - Technology cost reductions for renewables, storage, DSM, and EE.
- Slide 33 – Scenario Overview
  - This table shows information on how APS is thinking about different scenarios. This is not a complete list of all the different cases.
  - The last two scenarios show the Base scenario, but they are not the exact same. The cases are going to be subject to other changes that are not highlighted in the chart.
  - Question – RPAC Member: Building on the earlier conversation around the development of markets, I think there should be a scenario within the context of the IRP that looks at enhanced and expanded regional markets. Different aspects related to commodity price, load growth, and capital cost could all be directly impacted by a regional market scenario. Would you be willing to consider that? Since day-ahead markets are already in the plan, is there any combination for that in the reference case that is acknowledging that business change?
  - Response – Michael Eugenis: APS is thinking a lot about market development and how it relates to the IRP. As we are going through this phase, we are still very much exploring what the markets will look like in the future but as the governance continues to get ironed out in those markets, there is a modeling risk around assuming what the markets will look like when finalized. It is something that is very much on our radar. I don't know if we have all the information needed for APS to model a market ourselves. It dove tales into a second thing. For regional markets, the cost benefit analysis of the market is very much a WECC wide study case, and a much broader footprint must be considered. The IRP is traditionally focused on the utility itself. I appreciate the comment and I think it is something that we are going to continue to discuss further. APS is evaluating what it should do in the future from a portfolio perspective on modeling a market. APS will have to think about some of the realities of data acquisition and modeling for 8760 simulations of such a broad footprint. APS also has to determine if we can leverage existing study work that may be out there. All of those considerations are very much on our radar.
  - Question – RPAC Member: I'm not following it closely, but are you tracking the EPA pending new CPP or ACE rule? Seems like that might have an impact in emissions regulation.
  - Response – Michael Eugenis: I don't have a lot of information on the CPP or ACE rule right now. That's something we can follow up on either in a future meeting or as we get more information. Thank you for the flag.
  - Question – RPAC Member: As part of your risk management, not necessarily IRP, are you looking at prolonged disruption in the energy system lasting over years?
  - Response – Michael Eugenis: That is an interesting study case, I would be interested in your thoughts of what that would look like if you would like to provide more context.
  - Response – RPAC Member: There's two things that I think are concerning from an energy systems standpoint. One is the war in Ukraine and the way that the west, the NATO alliance, is handling Russia and Russian energy supplies. They are increasingly putting pressure on minimizing them in the global markets. That looks to me like something that will continue well into the future. The way in which Europe is responding is to look to other parts of the world to find those supplies. They might make it through this winter but next winter is looking really tough. Strategic disengagement from China is looking very real. It is impacting semiconductors, chip manufacturing, and things of that nature first. I expect that unless there is some real accommodation between the Biden administration and Xi Jinping, which doesn't look probable at the moment, we are going to see pressure on strategic materials and on the amount of energy systems that we're buying from China that are being supplied by Chinese companies. These are not things that are going to

resolve in six months, they might not even resolve in two or three years, they could well last for five years or more and get progressively worse along the way. That is what I have in mind, it is a little bit out of mainstream of this conversation but not completely unrelated.

- Response – Michael Eugenis: What I heard there is an interest in a future scenario that utilizes high capital costs for renewable resources going forward paired with high fuel costs as LNG exports increase from the Permian over to Europe.
- Response – RPAC Member: I think it is a very high probability that you are going to see exactly that. Price pressure from the supply chain on renewables and at best extreme volatility in the hydrocarbon market, quite possibly high prices over long periods of time.
- Response – Michael Eugenis: It is fortunate that we have both of those, the renewable costs or new resource costs as a potential sensitivity that we can perform. The next slide talks about that a little bit more as well as fuel prices as something that we can look at further.

- Slide 34 – Risk/Sensitivity Analysis
  - Qualitative risk analysis
    - Power supply
    - Market volatility
    - Siting and permitting
    - State and federal policy
  - Quantitative risk analysis
    - Fuel price
    - Load
    - CO2 price
    - Capital cost
    - Intermittent renewable resource profiles
    - Plant forced outages
  - Comment – Mike Eugenis: There are correlations between qualitative risks and quantitative impacts that can be modeled in the IRP process and allows for the modeling of sensitivities.
  - Question – RPAC Member: Is there a data set or report with the specific assumptions for each scenario in the group? For example, what is meant by enhanced regulation? Is that driven by federal regulation? What drives the higher price for commodities or CO2? Overall, looks like a great list.
  - Response – Michael Eugenis: We have not performed a deep dive into each of these to do a comprehensive list of the specific pieces of legislation or other impacts that would affect these different scenarios. I think there is some value to the ambiguity because it is really difficult to tell what is going to happen in the future and there could be legislation that is passed tomorrow that is being drafted today that we do not know about. Some of these we have treated on a more high-level basis, and we may not have a specific bill to point to, but there may be something in the future that creates a carbon emission cost associated with it. I want to look at what those potential impacts would be. As we go through this process and as we add more detail to these scenarios that could be something that we put together. I like having a little bit of flexibility too, both are valuable.

    - Comment – RPAC Member: That would be some very efficient lawmaking! I agree I would like to see more detail on the scenarios.
    - Response – RPAC Member: Would you see any of these being somewhat equivalent to a high renewable or no new gas scenario we see elsewhere? Would you consider that scenario?
    - Response – Michael Eugenis: I think there are some here that get close to that, rapid technology advancements being one. If we were to alleviate the supply chain concerns that we see today with renewable developments, if the cost curves come down precipitously, and if there are less and less failures with the renewable and clean technologies from an operational standpoint, then I think there is a scenario that looks very much like that in the future. The rapid technology case looks similar to that scenario considering it includes lower renewable capital costs and low energy efficiency and demand response program costs in the future.
- Slide 36 – IRP Base Case Assumptions/Reference Case Assumptions
    - For modeling we are looking at a 15-to-20-year period so some of the assumptions are averaged out over a period of time.
    - Inflation
        - Base assumption = 2.5%
    - Compliance with standards
        - Meet RES/EE Standard
    - Discount rate
        - WACC is currently 6.30%
- Slide 37 – Load Forecast
    - Load forecast update imminent
        - Large customer growth
        - Recession risk
        - Impact of DSM & DE
    - The market is in a really unique position. Inflation is very high and there is potential for a recession in the future.
- Slide 38 – Carbon Cost
    - Carbon costs seek to represent future emissions costs that would be realized if a carbon tariff would be enacted from a state or federal level.
    - Modeled based on a range between the cap-and-trade and auction programs administered in CA and WA. APS takes results from most recent auction results in CA and WA and applies an escalation rate to the price into the future.
- Slide 39 – Future Resource Capital Costs
    - The curves on the graph show the predicted capital cost for different technologies that APS is interested in.
    - The sensitivities are based off high, medium, and low scenarios
    - Utilizes pricing from the 2022 APS All-Source RFP
    - The NREL Annual Technology Baseline cost curves are applied to APS's 2022 ASRFP baseline.
    - Forecasts assume that the supply chain complications will dissipate.
- Slide 40 – Planning Reserve Margin Requirements
    - Maintain 1-in-10 LOLE

- SERVM: Planning Reserve Margin Study
  - Improve understanding of resource adequacy risks.
  - Identify additional cost-effective solutions to meet given resource adequacy standards.
  - Clarify the link between economically efficient planning reserve margins and physical reliability standards such as the 1-in-10 LOLE standard.

Patrick Bogle (APS/Director, Financial Control) - Gas Price Modeling and Forecasting

- Slide 43 – Gas Markets Overview
  - Henry Hub – Primary trading location for natural gas in the U.S.
  - Basins – Location where gas physically flows to APS. Prices are provided as basis from Henry Hub.
    - San Juan (SJ)
    - Permian (PE)
  - Price Construction
    - San Juan = Henry Hub + SJ Basis
    - Permian = Henry Hub + PE Basis
- Slide 44 – Pricing Process
  - Forward price curves are received from independent pricing brokers.
  - Broker prices are selected based on granularity to create primary curve.
    - Henry Hub, San Juan Basis, Permian Basis
  - Primary curves are combined to create secondary curve.
    - San Juan = Henry Hub + San Juan basis
  - Secondary curves are shaped and escalated into a compiled curve.
  - Compiled curve is reviewed for reasonableness based on market conditions.
- Slide 45 – Shaping and Escalation Factors
  - Shaping – Process of taking multi-month quotes and approximating monthly prices.
  - Escalation – Process of creating outer year forward prices where broker quotes are unavailable. The escalation factors applied to forecasts are based on analysis of historical price data.
- Slide 46 – Control Processes
  - Pricing function is independent of forecasting and planning teams. Primary purpose is for financial reporting and all controls are built to ensure prices are complete and accurate for forecasts.
  - Shaping factors are reviewed monthly.
  - Escalation factors are reviewed monthly.
  - Broker quotes are reviewed quarterly to ensure pricing data is not stale.
  - Margining process gives comfort our prices are reasonable to peers.
  - SOX-controlled process
    - Valuation
    - Financial reporting
    - IT system

- Question – RPAC Member: I think TEP showed the RPAC an actual versus projected gas costs curve and, obviously, there was a dramatic difference. Can you comment further on how you account for the wild increases we have seen in the last year? How does that impact action plans? Does it just impact sensitivities? Is this a new normal?
- Response – Michael Eugenis: We utilize the gas curves that Patrick's group puts together for all of our modeling, and you are right, there is significant volatility in the market and its incredibly difficult to predict what that volatility is going to look like in the future. As I think of gas prices, I think about a lot of the resources that are running for reliability purpose than in the past. During the daytime we have a prodigious number of solar resources on our system, we are continuing to invest in solar resources, and there is going to be more on APS' system. Gas is becoming the backstop for when the solar resources are not available. There are nighttime load demand needs and there are periods when there is more cloud cover, so it becomes less of an economics decision and more of a decision around what dispatchable generation is available on the grid when we need it? As we think about that going forward, I think there is implication of our coal fleet there as well. It is something that is important for us to look at.
- Comment – RPAC Member: There are non-fuel options at night too.
- Response – Patrick Bogle: Speaking to the last question, "is this the new normal?" I will say we are absolutely looking at whether we need to make changes to how we hedge our gas needs going into the future because of the last few years' volatility. So yes, we start to see the impacts in the forward curves. The Texas freeze offs have caused prices to spike in February and March going forward. The events that happen are changing how the curves get shaped going forward.

Nick Schlag (E3/Partner) - Integration Cost and Market Price Update

- Slide 49 – Planned Updates to Renewable Integration Cost Assumptions
  - Renewable integration costs refer to costs associated with balancing the subhourly variability and forecast uncertainty of renewable resources
    - Higher levels of variability and uncertainty require increased operating reserves
    - Higher operating reserve requirements result in less efficient dispatch of the entire generation fleet
  - Integration cost study for APS' 2020 IRP calculated costs on the order of $1-3/MWh for solar and wind
  - Using industry-standard production cost modeling, E3 will update integration cost analysis for 2023 IRP will account for:
    - Updates to natural gas prices
    - Anticipated changes to composition of APS' portfolio since 2020 (Including impacts of energy storage)
    - Improved understanding of required increases in operating reserve needs
  - Question – RPAC Member: Is it safe to assume these costs will be higher than the 2020 results?
  - Response – Nick Schlag: No, I don't think it is necessarily safe to assume that. There are multiple things that I can think of off the top of my head that might act in different directions in terms of their impact on renewable integration cost. Generally speaking, natural gas prices would tend to put upward pressure on the cost of renewable integration, but the increased penetration of energy storage would tend to relieve the burden and might push costs in the opposite direction. I would not necessarily expect or plan for an increase in these costs. It is hard to say without having done the analysis which direction they are going to move at this point. I do not expect them to change in terms of order of magnitude.
  - Question – RPAC Member: Admittedly it's been a few years. Did we do this in the 2020 IRP? I don't remember talking about this.

- Response – Nick Schlag: There was an assumption in the 2020 IRP for what these costs were but I may not have the full history as to exactly what went into the analysis.
- Response – Michael Eugenis: We performed this for the 2020 IRP. Energy Exemplar, the consultant that maintains our Aurora software that APS utilizes for IRP modeling, performed a study to determine integration costs.
- Question – RPAC Member: E3 has been super helpful in the past with providing some comparisons for what other utilities are doing. Is there a slide next time that you could do to demonstrate the aggregation of what other utilities are doing regarding their renewable integration cost assumptions?
- Response – Nick Schlag: If it would be helpful, we could pull together a couple other data points in terms of what these costs look like. I can say that not every analysis is apples to apples in terms of the methodology or level of detail. Considering that, most of the numbers that we have seen have been anywhere from $0.50/MWh to $5/MWh. That's the general range that I have seen. There could be examples that are beyond that but if it would be helpful we can pull together some of those examples concretely.
- Question – RPAC Member: That seems like a big range to me. Do you think that's a big range or not really in the grand scheme of things?
- Response – Nick Schlag: It can vary significantly from one utility system to another as a function of A, what type of renewables we are looking at, and B, what resources are available to integrate those renewables. At two extreme ends of the spectrum, I would expect the renewable integration costs to look much higher on a system whose generators are predominantly inflexible coal resources. It would be much higher on that system where the cost of ramping and recommitting those units is pretty high than it would be on a system where your predominate resource is a flexible hydroelectric dam whose output can ramp very quickly without much cost in terms of how that impacts the systems operations. I don't think APS is in either of those positions, but that is just meant to illustrate two bookends. It really does not surprise me that the ranges are that wide.
- Question – RPAC Member: In Arizona, renewables are a lot broader than just solar and wind but are you only applying integration costs to solar and wind? Second part of the question, I'm intrigued with what you said about coal versus having more gas on the system and how nuclear might factor in the range of expected costs.
- Response – Nick Schlag: The reason these studies traditionally focus on wind and solar as far as renewable integration costs is mainly because those two resources are fairly unique in their intermittency and their forecast error. In general, other renewable resource options like geothermal, small hydro, or biomass don't typically come along with the same sorts of forecast errors and uncertainty and in a lot of cases they are controllable or dispatchable. In the same sense that a natural gas plant doesn't have an integration cost associated with it, a lot of those other renewable resources would not either. With respect to your second question, I can't speculate without having done the analysis. APS' portfolio has some inflexible resources in Palo Verde and a number of others that are flexible in natural gas and storage so it is hard to say at this point what affect those will have in concert.

- Slide 50 – Updated Wholesale Market Price Forecasts
  - E3 uses a fundamentals-based approach to project how changing energy supply mix will propagate throughout Western electricity markets
    - Prevailing historical patterns of electricity trade will shift with increasing scales of renewable deployment
    - Heuristics for market price forecasting tied to natural gas prices will break down as other resources increasingly set marginal price

- To simulate these dynamics, E3 uses AURORAxmp, a production simulation model of the Western electricity system
  - Provides a fundamentals-based method to evaluate future market prices as the electricity system evolves
  - Enables scenario analysis of possible alternative futures
- Question – RPAC Member: From the last IRP cycle in the report, it was mentioned that AURORA has a difficult time in modeling the intermittency of renewables properly. If I'm not mistaken, I think AURORA uses sampling days instead of 8760 for its modeling. I'm just wondering what type of stuff you guys are doing to adjust for that to make sure that the model outputs are accurate.
- Response – Nick Schlag: AURORA is one of those models where it comes populated with a default set of assumptions and you can always go in and change those assumptions when it comes to hourly profiles. Our team has spent a lot of time trying to improve upon the base AURORA dataset with improvements in those hourly profiles to capture the full range of conditions you would expect to see across an 8760 and our price forecast generally reflects that. When it comes to variability and intermittency within AURORA, a model like this is run at an hourly time step to produce hourly market prices, for this purpose specifically, any limitations that AURORA may have in terms of how it deals with the sub hourly variability, does not have a very significant direct first order impact on those hourly market prices. I think we feel comfortable with the forecasts especially having done some benchmarking against price trends in the west. We are doing an okay job at capturing how those changes in hourly dynamics will translate into market prices.
- Question – RPAC Member: Knowing that APS is in the EIM and that it is a real time 5- and 15-minute market, price signals are coming much faster than hourly. I think a lot of the value that comes from storage resources is exemplified in those short time periods rather than in the hour time periods. What are you guys doing to make sure you are capturing the full value of both renewables but particularly storage like batteries, pumped hydro, or any other storage. Do you make sure that you are capturing the full value that APS' system is getting from those?
- Response – Mike Eugenis: It is interesting to think about the different sources of values that we see from energy storage on our system. Broadly, I think about it as a capacity value during peak times. There is an energy arbitration value where you can charge them during low price periods and discharge during high price periods even outside of periods where you need the capacity explicitly. There is also the potential to provide ancillary services to the grid. You can use storage to smooth out those inter-hour fluctuations on the grid, and it may even help integrate renewables. This can be seen a little bit in the Southwest Resource Adequacy Study that the E3 team put together. There is a correlation between batteries and solar when it comes to the capacity value gained between the two of them. Some of the things we think about when it comes to battery values too is how much of each of these tranches do we need on the system? Are we going to have to operate different sets of batteries on our system differently? Are there batteries that we need to hold back and reserve potentially and not carry ancillary services? Do we need to hold back batteries to ensure they are available for capacity on certain days for the system? Are there going to be constraints on charging and discharging batteries due to contracting terms and conditions? There is a lot of uncertainty around how we optimize value streams when it comes to storage. As we continue to invest in it, and we have a lot of storage in our plans today, we plan to better refine our processes.

Matt Lind (1898 & Co./Director of Resource Planning) - Next Steps

- Slide 53 - Looking Ahead… January 2023
  - EPRI Climate Change Scenario Analysis Update
  - Load forecast update

- Question - RPAC Member: Are we going to be able to provide updates through the RPAC or do we expect everyone to be closely reviewing those filings?
- Response – Todd Komaromy: We try to bring regulatory updated through this forum and I think it's an appropriate one. To the extent that we have updates we can use this as a place to bring that forward.
- Reminder: APS has limited Aurora licenses for stakeholder use; access will be provided to interested stakeholders that have responded via email
- Next meeting is January 18th at 9:00am

New Action Items:

- APS will address Aurora licenses for RPAC members in first quarter of 2023. Communication will be managed directly through email.