Meeting Notes

DRAFT – For Discussion Purposes Only

Meeting Objectives

- Recap the April RPAC meeting and provide status of previous action items.
- Provide regulatory update focused on IRP deadline extension and market report workshop.
- Receive an update on the progress of the 2023 All Source RFP.
- Highlight best practices and trends for planning reserve margin requirements in the West.
- Examine the IRP sensitivities on natural gas and carbon price variability.

Meeting Subject: May RPAC Meeting
Meeting Date: 05/17/2023
Start Time: 09:00am
End Time: 12:00pm
Location: Virtual

Attendees	Organization	Title/Role
Ann Becker	APS	Vice President, Sustainability
Tara Beske	APS	Business Advisor, Resource Management
Keri Copp	APS	Support Technician, Resource Acquisitions
Michael Eugenis	APS	Manager, Resource Planning
Ardyn Feken	APS	State Regulatory Consultant
Jill Freret	APS	Director, Resource Integration & Fuels
Brent Goodrich	APS	Consultant, Stakeholder Communications
Todd Komaromy	APS	Director, Resource Planning
Elizabeth Lawrence	APS	Manager, Product Development & Strategy
David Peterson	APS	Advisor, Corporate Strategy
Rodney Ross	APS	Director, State Regulator
Timothy Rusert	APS	Director, Fuel Procurement and Ops
Michelle Burkeen	APS	Supervisor, Key Accounts
Justin Joiner	APS	Vice President, Resource Management
Evan Lipsitz	1898 & Co.	Consultant
Keaton Clark	1898 & Co.	Analyst
Chase Kilty	1898 & Co.	Consultant
Matthew Lind	1898 & Co.	Director of Resource Planning
Nick Schlag	E3	Partner
Steve Jennings	AARP	Associate State Director
Greg Patterson	Arizona Competitive Power Alliance	Director
Chaunce De Roos	Arizona Corporation Commission	Policy Advisor

Diane Brown	Arizona PIRG	Executive Director
Gary Dirks	ASU	Senior Director
David Millar	Wärtsilä Energy	Principal, Regulatory Policy
Jackie Solares	CalMich Produce	Director, Sales and Business Development
Walter Clemence	Capital Power	Senior Advisor, US Regulatory
Chris Camacho	Greater Phoenix Economic Council	President & CEO
TJ Higgins	Griffith Energy	
Austin Jensen	Holland & Hart	Associate Attorney
Sam Johnston	Interwest Energy Alliance	Policy Manager
Nitin Luhar	Mitsubishi Power	Regional Director
Nicole Hill	Nature Conservancy	AZ Thrives Program Lead
Dugan Marieb	Pine Gate Renewables	Regulatory Associate
Gabriella Tosado	Rocky Mountain Institute	Senior Associate, Carbon Free Electricity
Sandy Bahr	Sierra Club	Chapter Director
Alondra Regalado	Stratagen	Policy Analyst
Caryn Potter	SWEEP	Arizona Representative
Nicole Rodriguez	TE Connectivity	Manager, North American Wildlife Asset Protection
Autumn Johnson	Tierra Strategy	CEO
Kate Bowman	Vote Solar	Regulatory Director
Alex Routhier	Western Resource Advocates	Senior Clean Energy Policy Analyst

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

- Slide 4 – March Meeting Recap
  - APS presented a preview on its 2023 Summer Preparedness. Updates included that it is prepared to serve its projected peak demand plus reserve margin of 9,385 MW.
  - 1898 & Co. explained some of the key themes and takeaways from the first IRP public stakeholder meeting.
  - APS discussed its progress on the 2022 RFP negotiations and the 2023 RFP development. APS emphasized its commitment to maintaining a diverse portfolio of resources.
  - APS provided updates on the Aurora training and details on its Resource Technology Assessment that will be utilized in the IRP.
  - APS summarized adoptions forecasts for solar, storage, and EV adoption that have been developed by Guidehouse.
- Slide 5 – Following Up
  - Action items from previous meetings:
    - Distribute 2022 ASRFP
  - Ongoing Commitments:
    - Distribute meeting materials in a timely fashion (3 business days prior)
    - Transparency and dialogue

Todd Komaromy (APS/) – Regulatory Updates

- Slide 7 – Regulatory Updates
  - APS and TEP filed for an extension of the IRP filing deadline on May 1st.
    - Requested new deadline of November 1st.
    - Stakeholder support included SWEEP, Sierra Club, Arizona PIRG, AriSEIA, and more.
  - The market report workshop was held on May 4th.
    - Agenda included market updates from TEP, UNSE, and APS
    - Open discussion with meeting participants immediately followed.

Jill Freret (APS/ Director, Resource Integration & Fuels) – 2023 All-Source RFP Update

- Slide 9 – 2023 ASRFP Update
  - APS will hold two ASRFP breakout sessions in June for RPAC members to provide input and feedback on the RFP document and process.
  - Question – RPAC Member: Are those invites already sent? I expressed interest and have not received anything about either of those meetings.
  - Question – RPAC Member: I am also interested in participating in the June meeting.
  - Question – RPAC Member: I am as well, and I have not seen a hold for those dates.
  - Response – Todd Komaromy: We will make sure the invitations are sent out to the interested parties at the close of this meeting.
- Slide 10 – 2022 All-Source RFP Results
  - Contracts Signed Since May RPAC
    - 70 MW PVS – Final Review
  - Battery Storage Project Approval
    - ACC has approved all battery storage projects for including in PSA thus far.
  - Negotiations Still Underway
    - Potential to sign 1,081 MW.
    - Expected to finish negotiations by early June.
  - Remaining Projects Rebid
    - APS expects to see some of the remaining projects rebid into the next ASRFP.
  - Question – RPAC Member: I want to make sure I did not mishear you earlier for the upcoming meetings to discuss the RFP on the 2nd and the 15th. Are you trying to limit the groups who are presenting?
  - Response – Jill Freret: Anyone who may be bidding in or who has the potential to bid into the RFP would not be included in those discussions just for fairness. We don't want to allow any subset of participants to have a sneak preview before the rest of the bidders get access to the document.
- Slide 11 – Important Concepts from the 2022 ASRFP
  - All resources except coal were allowed to bid into the 2022 ASRFP.
  - Demand side resources were allowed to bid into ASRFP.
  - The scoring process remained broad with quantitative & qualitative analysis. ASRFP prioritized low cost and low project delivery risk.

  - Minimum size requirements were 5 MW; Lower bid fee for projects smaller than 25 MW.
  - Question – RPAC Member: I am curious about what you can share about the demand side resources response to the 2022 ASRFP. Often, I think the types of offerings that the demand side resource providers are going to have are different than the offers for supply side resources in an ASRFP. The document might be tailored to larger capacity resources which may have a significant impact on how bidders are going to respond. Is there anything you can share with that and if APS has ever considered conducting a survey of those vendors to see how we can get them to participate more to ensure that the least cost resources are bidding in these solicitations since they are often smaller, local businesses in the state. How are you reacting to that and working on that?
  - Response – Jill Freret: That is something we think about a lot, and I am not sure that we have landed in the perfect spot on that yet. This is something that I think we want to have continued discussions about as a general matter. I can tell you that we have received very little response in the past. Last year we received less than a handful of responses from demand side resources and we ask ourselves, is it because those resources are not meeting our needs the way we have laid them out? Have we made this effort accessible to all providers? Our Customer to Grid Solutions team looks at these resources specifically to provide an additional vehicle to assess demand side potential. We want to encourage that participation and we want to make sure that what we put out in our RFP does encourage those bids and at the same time behave like the other types of resources that we are looking for to fill our needs.
  - Comment - RPAC Member: A big reason why you probably saw that lower response is also driven by the vendor fee that is required to respond. We have had discussions around the fee, and we can continue to discuss it, but that is often going to significantly impact some of the smaller vendors that could offer certain value streams but because they are a local business, they cannot participate in that way. I think that in the smaller subgroups we can discuss how to set up these bids for those types of resources to have a level playing field in terms of how they are competing. Depending on how that is set up, it is going to have a different weight in terms of what resources are going to reply.
  - Question – RPAC Member: If groups who are going to be expected to participate in the upcoming RFP are not going to be in these smaller groups where you are going through the 2022 contract, what would be the avenue you guys would like to see for more global comments on that and potentially requests for increased guidance within that document from those of us who may participate.
  - Response – Jill Freret: Two avenues that I would suggest. One is that you can send any notes or comments and thoughts into the RPAC e-mail address. You can also reach out to me directly. I don't know if the group has my e-mail or phone number, but I am happy to provide that. I think that is a direct route where we do make ourselves available to market participants up to a point. As we get close to the RFP, we cut that off just for optics. We don't want it to appear as if we are having an inside discussion with anyone in the market but that is important information, and we look forward to that feedback regarding market participants and that typically comes directly to me. I would like to continue to invite that over the course of the next couple of weeks.
  - Comment – RPAC Member: You have been extremely responsive to us in the past. I just was not sure if you want to have an open dialogue on that or if it is going to be one on one with APS.
- Slide 12 – 2023 All-Source RFP Key Features
  - There are specific bids that will be identified in the RFP that APS is interested in. Additional information will be included in appendices when the document is released. The bids associated with these opportunities will be treated the same way as all other bids that are received.

- Agave:
  - 150-400 MW ESS
  - 4-hr Duration
  - Must meet APS Safety Standards
  - COD: 2026/2027
- Ironwood:
  - 168 MW Solar + 168 MWs ESS
  - Selected through Green Power Partners
  - COD: 2026/2027
- CCT:
  - Up to 250 MW
  - Competitive renewable generation located on Navajo Nation
  - Third party owned (PPA)
  - COD: May 2027 or 2028
- Cholla:
  - Up to 115 MW
  - New generation on existing site of Cholla Generating Station
  - APS owned or third party owned (PPA)
  - COD: ASAP following Cholla retirement.
- Incremental Gas Generation:
  - Up to 400 MW
  - APS-owned and third party-owned (PPA)
  - COD: ASAP, but no later than March 2027
- Question – RPAC Member: Is it correct to assume the statement "incremental gas generation" is only for peaking generation and does not include new combines-cycle?
- Response – Jill Freret: Yes, that is correct.
- Question – RPAC Member: Is this for summer only or all year?
- Response – Jill Freret: This is for year-round, largely because of the incremental year-round needs that we are seeing with the large customer 24/7 need.
- Comment – RPAC Member: That seems like an awful lot of added gas. Very concerning.
- Response – Jill Freret: Up to 400 megawatts as a percentage of what we believe we are going to be contracting for overall, I think it is relatively small. We showed in the last meeting on the 25 resources that we got, there was a small portion of it that was gas and the lion's share as clean energy resources. As we think about development risk and the reliability needs and keeping resources affordable, these additional gas resources will help to balance that out and provide some diversity.
- Question – RPAC Member: What are you looking for at Cholla?
- Response – Jill Freret: Cholla is open to any resource that can be developed using that site.
- Question – RPAC Member: Would it be a decarbonization transitional generation at Cholla? Natural gas to hydrogen?

- Response – Jill Freret: We talked about clean capabilities and that is going to be a requirement. We touched on this a little bit last time and looked at what it means and what is a blend. Our understanding at this point is that there is a lot of testing going on with the units themselves. Somewhere between 30% and even upwards of 40% hydrogen blend. We also have to look at the deliverability of hydrogen as a fuel and it is something that we are keenly aware of and focused on.
- Question – RPAC Member: My question was prompted by the CCT option, but it applies to Cholla and other resource procurement decisions. It is about the provisions of the Inflation Reduction Act (IRA) that can provide added benefits for resources cited in energy communities. Specifically the Energy Infrastructure Reinvestment Program and then the bonus tax credits that are available to projects that are sited within a certain distance of places where coal plants are retiring. There are big opportunities to reduce the costs of building new energy resources, whether they are replacing a retiring resource or whether they are entirely new energy resources. I'm interested to learn more about how you are thinking about those potential opportunities in the RFP process because there are significant financial benefits. In the case of the loan program, developing a resource that takes advantage of that might have a longer timeline, it might require a more careful partnership between APS and the developer or the community to ensure that you are able to secure those funds. How much are you relying on developers to show that they can go after those provisions and incorporate them into their bids versus more proactively developing an RFP that can solicit and evaluate resources that meet those provisions. Do you see any challenges with evaluating comparable bids where one leverages some complex provisions of the Inflation Reduction Act and is cheaper with those provisions accounted for. How will you evaluate those to make sure that bidders or resource selection is fully taking advantage of all the opportunities.
- Response – Jill Freret: On the evaluation piece, I'm going to pass that in a moment to Todd or Matt. If we look at the financial impacts of those opportunities under the IRA, I think about that in the same way that we have in the past approached either loan guarantee programs or things that could be leveraged to drive down the cost of a project. We invite bidders to explain their strategy and their way of capturing benefits. We want to know what their strategy is around it, because it is an important part of our evaluation. There are more subjective components to that. It is not just the dollars; it is how it might play out in development. What we ultimately want is to create a bid process where we are getting the very best for any given project and getting the optimal way of developing that project. This is a bit tricky, and we don't want to be in the business of providing all the interpretations and the guidance around it. We are still working on where we land on that, and we try to optimize that for each project. I think this would be a good topic for us to discuss a bit further.
- Response – RPAC Member: It would be great to discuss further and given how energy communities have been defined and the maps that have been showing what are considered energy communities eligible for these additional incentives and for the loan program there are substantial opportunities in APS' service territory to leverage those for almost any new generation resource going forward.
- Question – RPAC Member: I would encourage some conversations to look at what SRP is doing over at Copper Crossing with coal or gas and maybe pairing that with onsite solar and storage and seeing what that might do for the resource needs directly on site at that location. If there are opportunities, I think it would be important to see if there is an option like that at the Cholla facility. I also had a separate question on how APS is considering customer side solutions for the 2023 ASRFP and how did APS consider the separate DDSR aggregation tariff RFP that the Commission ordered

APS to put together before the end of this year. How did you all take that RFP requirement into account and some of the resources that will flow from that RFP to create the key features that we are seeing on the slide?

- Response – Jill Freret: I don't know if you were on at the very beginning when I was discussing that the demand side resources will play in this space as they have in the past and will continue to discuss whether it is important to revisit the bid fee or other gating items and that is something that we will have more conversation about.
- Response – Elizabeth Lawrence: I'm pretty sure you are referring to the order from a couple meetings ago. To work with LBNL on another RFP for DDSR and the date on that has some flexibility in how we read the order. We are absolutely looking at more DDSR RFPs and figuring out what that could look like but looking at it more holistically. There are October deadlines in that order, but how they are tied together, we are still evaluating and figuring out how it fits into the broader RFP process and strategy.
- Comment – RPAC Member: It sounds like you all might be pursuing a potential extension for that if it is going to be on a separate track from this ASRFP. I would love to discuss how that is being incorporated for the DDSR tariff. There are going to be some differences in the products and how that might be considered here, but I think it is well worth discussing how that might impact how much additional resources you would need to procure from this ASRFP.
- Response – Elizabeth Lawrence: DDSR is also tied up in our DSM plans and some other things there. So, we can continue to discuss that and I'm happy to get your thoughts as we move forward.
- Question – RPAC Member: I missed the last meeting and didn't catch this in the slides. Have you looked at increasing MW in other scenarios, such as CCT, and minimizing gas in the Incremental Gas Generation scenario? Agree with another RPAC Members comment --- that seems like a lot of gas, and from our perspective potentially stranded assets.
- Response – Jill Freret: We are using ranges including Agave and the battery storage addition would need to be at least 150 MW because less than that does not make a lot of sense. If you pair a solar facility with a smaller battery, it does not make as much sense. Aside from that we have ranges. If we got a CCT bid at greater than 250 MW and that looks good in the mix, I think that there is flexibility for other things to flex down. We do have ranges and what we are suggesting here is what we think makes a lot of sense across the entire portfolio.
- Question – RPAC Member: Could you solicit a bid for more to see what you receive in the other scenarios?
- Response – Jill Freret: An effective solicitation is going to provide enough guidance that targets enough that we can get tailored bids and so that is why we do provide ranges, but I guess your point is asking for something greater than that. We can allow bids or focus bidders on ranges but make sure that they are not going to be kicked out if they bid something in excess of that range. I'm giving you an indicative answer because we are still working through the mechanics of this, but I hear your point and that is something that we will continue to talk about.
- Comment – RPAC Member: When I see up to 250 MW, I think that is the ceiling not the floor.

- Slide 13 – Request for Proposal (RFP) Process
  - Four stage screening process is a typical standard and was utilized in the 2022 ASRFP.
  - First screen
    - Review bids for minimum participation criteria
  - Second screen
    - Screen bids using cost and non-cost criteria to create a "shortlist".
  - Third screen
    - Evaluate short list of bids using portfolio analysis.

- Fourth screen
  - Negotiate and execute constricts with one or more resources.
- Slide 14 – Key Attributes for Evaluation
  - Transparent – Open process providing broad participation and ensuring competitive proposals.
  - Flexible – Flexible to accommodate different technologies.
  - Well Documented – Well documented for clear understanding for the evaluation.
  - Aligned – Procurement aligned with IRP.
  - Some recommendations include:
    - Early stakeholder involvement
    - Clear definition of acceptable technologies.
    - Clear identification of information needed.
    - Consistent assumptions established early and "locked down".
    - Evaluation process and criteria need to be established early.
- Slide 15 – 2023 All-Source RFP Timeline
  - Friday, June 30th is the target RFP release date.
  - There are breakout sessions scheduled for June 2nd and June 15th.
  - The RPAC meeting with the entire group is scheduled for June 23rd. This would primarily be informational and would not lead to any substantive changes before the June 30th release.
- Slide 16 – 2023 ASRFP Design: Building on Market Factors
  - Project Deliverability
    - In-service dates
      - Target early in-service dates to mitigate potential delays.
    - Transmission deliverability
      - Provide directional guidance to bidders.
  - Customer Affordability
    - Fixed vs open book pricing
    - Tax credit strategy and utilization of the IRA
    - Interconnection network upgrades
  - Additional Project Risks
    - Increased demand from IRA outpacing supply.
    - Tariff and UFPLA risk still remain.
    - Equipment timelines remain long.
  - Question – RPAC Member: I was wondering if APS has reviewed the recent study that has come out from the Brattle Group regarding the review of virtual power plants and some of the interesting findings as it relates to them. The study shows that virtual power plants can maintain similar reliability of conventional peaking power plants with cost reductions of up to 40% - 60% as an alternative. I was curious if you all have started to review that and how that might be considered as a part of this all-source RFP discussion.

- Response – Jill Freret: Yes, we have started to review that. We are having conversations and that is an important conversation we are having with the Customer to Grid Solutions group that Elizabeth represents. We have not landed on a very specific approach around that or specific targets and strategy around that. That is part of our conversation and thank you for raising that for the whole group.
- Comment – Todd Komaromy: We want to put some real attention to it in the IRP as well and lean in on our customer programs as part of that. We will be seeing more of that as we move along with the RFP process as well.

Nick Schlag (E3/ Partner) – Planning Reserve Margin Trends in the West

- Slide 20 – Refresher: Best Practices in Resource Adequacy Analysis
  - Develop a representation of the loads and resources of an electric system in a loss of load probability model.
    - LOLP modeling allows a utility to evaluate resource adequacy across all hours of the year under a broad range of weather conditions, producing statistical measures of the risk of loss of load.
  - Identify the amount of perfect capacity needed to achieve the desired level of reliability.
    - Factors that impact the amount of perfect capacity needed include load & weather variability, operating reserve needs.
  - Calculate capacity contributions of different resources using effective load carrying capability.
    - ELCC measures a resource's contribution to the system's needs relative to perfect capacity, accounting for its limitations and constraints.
- Slide 21 – Conceptual Origins of the Planning Reserve Margin
  - Planning reserve margin reflects the amount of capacity above expected peak demand needed to ensure reliability while accounting for:
    - Extreme weather
    - Operating reserve needs
    - Plant outages
- Slide 22 – By 2025, the principal resource adequacy challenge in the southwest is the evening "net peak"
  - With increasing penetration of solar resources, the highest net peak period occurs after sundown.
  - This shift has direct implications for the relative capacity value of different types of resources.
- Slide 23 – Adapting the PRM framework for a high renewable future
  - Historically, utilities have relied upon a planning reserve margin to ensure enough supply is available during peak periods.
  - Introduction of significant quantities of wind, solar, and storage present significant challenges to this accounting framework because:
    - Availability of these resources during peak periods is likely lower than nameplate capacity.
    - Increasing penetrations of renewables & storage will cause reliability needs to shift to other times of day/year.
  - To continue using a PRM, we must revisit how we count capacity to ensure resources are measured based on their contributions across all hours and not just during peak periods.
    - A resource's effective load carrying capability (ELCC) reflects its contribution to reliability considering all hours of the year, across multipole years of load and weather conditions.
- Slide 24 – ELCC Appropriately Accounts for Each Resource's Capabilities and Imperfections

- Applying the ELCC methodology to count resources toward the PRM provides a robust framework for resource adequacy accounting.
- ELCC can account for all factors that can limit availability:
  - Hourly variability in output
  - Duration and/or use limitations.
  - Seasonal temperature derates
  - Temperature-related outage rates
  - Forced outages.
  - Energy availability
  - Fuel availability
  - Correlated outage risk, especially under extreme conditions
- Question – RPAC Member: Will we have access to the ELCC reports APS is using for the modeling? I think E3 has presented it a couple of times.
- Response – Michael Eugenis: As part of the modeling information that we are putting together, that will be released to the RPAC members that are doing their own evaluation. You will be able to see how we have calculated or at least see the net result of those ELCC calculations for the different resources. Astrapé, which is the consulting firm that manages the SERVM software, has developed a multiple dimension lookup table for us so that we can calculate the ELCC values for resources across multiple portfolios. Depending on how the portfolio is structured, you get a more accurate value, and you will be able to see that information in the in the case details.

- Slide 25 – A Transition in PRM Accounting Conventions
  - Historically, it has been common practice for utilities to count firm resources toward the PRM at their full installed capacity.
    - The risk of outages is embedded in the PRM requirement itself.
  - With the application of ELCC to measure variable and energy-limited resources, utilities are increasingly opting to apply ELCC-style derates to firm resources.
    - Moves the risk of outages to the resource accounting side.
  - This change in accounting will result in a lower apparent PRM but does not reflect a change in the underlying system of its reliability needs.
- Slide 26 – Calibrating a PRM requirement based on a statistical reliability standard
  - Loss of load probability modeling can be used to calibrate a PRM requirement consistent with a “one day in ten years” standard.
    - Increasing PRM requirements result in increasingly reliable systems.
  - The relationship between PRM and LOLE is highly nonlinear.
    - Falling short of PRM target quickly leads to frequent reliability issues, exceeding a PRM target results in small improvements in reliability.
    - Nonlinearity has implications for risk and interpretation of modeling error.
- Slide 27 – Planning reserve margin targets vary considerably across Western utilities
  - Reserve margin requirements throughout the Western Interconnection generally vary between 13% and 20%

- Variations between utilities are driven by several factors:
  - Different system characteristics
  - Different accounting conventions
  - Different methodologies
  - Different assumptions regarding market support
- Most utilities rely on loss-of-load-probability modeling as the basis for establishing a PRM requirement, but some are stipulated based on rules of thumb.
- Question – RPAC Member: I'm a little bit dismayed by the range and I'm wondering is there no best practice? Is there any analysis as to the sufficiency of these? The reserve margin versus outages that utilities have seen. How do we know if 15% is right for Arizona, given the fact that the range is what most utilities are using?
- Response – Nick Schlag: I would say there are absolutely best practices when it comes to the planning reserve margin, but those best practices may not lead each utility to the same number. This gets back to each utility system being a little bit different, but essentially what we would emphasize as best practices is the idea of starting with the loss of load probability model, where a utility would look at the characteristics of its own load profile, which depends on the weather that that is present in its own system, as well as the characteristics of all the resources that are on its system. When you build that model in a loss of load probability model and sweep out that curve that I showed just a couple of slides ago, you might find a different number for each system. My response to your question is there are best practices when it comes to arriving at these numbers, but there is not a best practice as far as what exactly this number should be. I would say it is a feature rather than a bug that there are different answers to this question for different utilities. The second part of your question, how do we know what the right number for Arizona would be? I know that the folks from Astrapé are working with the APS team and maybe Mike can talk a little more about what might come out of that study. Those are the types of studies that I personally would drill into. Looking at an individual utility study or system to try to understand, does this requirement make sense for this utility?
- Response – RPAC Member: We talked a lot about California and Texas outages and the California percentage is significantly larger than ours. Do you know what the Texas Reserve margin is?
- Response – Nick Schlag: Texas does not have a formal planning reserve margin. They are an energy only market, which means that they don't have a forward planning process to ensure that enough capacity is present on the system to meet the given reliability standard. They rely instead on the pricing signals that exist within that energy market to try to induce the right amount of capacity onto the system, so Texas is a hard jurisdiction to compare against all of these others that maintain the forward planning requirement. I will say in the California example, there has been a lot of effort to look back at what that number should be for California and a big part of what is driving that increase is a much better understanding of what the risk of extreme weather might look like and how that drives the need for capacity.
- Question – RPAC Member: If you had a column here for loss of load expectation (LOLE) or loss of load hours, would there be more alignment? Are they all mostly trying to do one day in 10 years or is California trying to do much lower?
- Response - Nick Schlag: As far as I know, and I have looked back at most of these recently, most utilities on here are targeting that one day in 10-year standard. There are likely a couple of exceptions, but I think you would see most of these utilities are targeting that one day and 10 years.
- Question – RPAC Member: Would it be fair to say that geographic diversity on their systems is a strong factor in and how these PRM's differ across the region?

- Response – Nick Schlag: The answer to that is generally yes. You might think of it as a bit of an indirect impact. A utility whose system is spread over a larger geographic area will experience more variability in weather conditions at any specific moment in time compared to a system whose loads and resources are all concentrated within one very specific area where you might imagine everybody turning on their air conditioner at the same time. I would say that is probably a factor that plays into these. We have not made any effort to quantify exactly what that diversity effect looks like, but I think in principle it makes a lot of sense that would be embedded there, and in fact, when you see larger pools of resource adequacy programs, those tend to be able to capitalize on that geographic diversity to achieve lower reserve requirements.
- Question – RPAC Member: I'm curious how conversations related to resiliency of the grid are playing into an updated framework related to PRM. I think as we are trying to look through and make sure that the PRM's are set up to capture what the grid is going to need in the future, the older methods had some significant assumptions related to historic weather trends, which will obviously not be sufficient for the future. I'm curious how E3 is looking at resiliency and ensuring that the grid is stronger even in the face of potential brownouts or blackouts. How is resiliency and an updated review over what resiliency means in this new paradigm going to impact APS' ability to meet these planning reserve margin targets in the future.
- Response – Nick Schlag: One of the challenges when it comes to resiliency is the fact that the models that we use for planning reserve margin require us to be able to specify the probability of certain types of events happening and how frequently we expect the system to be in those types of conditions. In contrast to that, the greatest examples of resiliency failures that we have seen have been events that are often unprecedented in their historical relevance. One that I recently heard was that when we experience these resiliency failures, it is not necessarily a failure of the models, it is a failure of our imagination in the sense that in order to plan for the unknowns, we have to be able to imagine what the worst possible scenario that could occur across many different dimensions may look like and try to tie that back to how it relates to the planning reserve margin and the direction that we are going in our own work. As we think about resiliency, it requires a complementary analysis alongside a traditional loss of load probability planning reserve margin study just in the sense that it does not fit that well into a probabilistic planning framework. That might look like imagining several different types of stress scenarios that could be plausible bookends for those Black Swan events that you want to plan your system where you might test what happens under those most extreme conditions. Those might be events that are so improbable or whose probability is so unlikely that they would be difficult to build into the planning reserve margin framework intrinsically.
- Comment – RPAC Member: I think it is a fair answer and an interesting question and I think, for me personally, leads to a conclusion that likely the way we are looking at historic extreme 100-year events is likely going to have to change in terms of how often they come up and how that is assessed in the model and how they are properly weighted. It also seems like this secondary assessment that you are discussing will have to be created and will have to happen in coordination with any PRM models that also move forward. It sounds like those two will have to move together and we will have to decide in terms of how resources are selected in the future.

- Slide 28 – Multiple trends driving recent increases in capacity requirements
  - Improvements in representation of extreme weather in reliability modeling – coupled with effects of climate change.

        - As extreme events become more frequent and more severe, utilities capacity needs to preserve reliability will increase.
    - Tightened conditions across Western markets.
        - Load growth and resource retirements have led to tighter conditions in wholesale markets – a trend that, exacerbated by supply chain delays, is expected to continue.
        - Utilities that have previously counted on "market support" to fulfill a portion of their needs have reduced their reliance on the market to meet reliability needs.

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

- Slide 31 – APS has developed natural gas sensitivities to evaluate in various IRP cases based on internal and public sources.
    - Base forecast comes from APS annual average of monthly weighted delivered natural gas prices through 2035. Prices are escalated annually at 2.39% from 2036 on.
    - Low & High forecasts come from EIA's 2023 Annual Energy Outlook Henry Hub prices. Prices are adjusted to account for APS natural gas hedge. Henry Hub is the hedging point that APS utilizes.
    - Question – RPAC Member: I have a question about your hedging strategies. When you show these natural gas prices, does it include the cost of the hedging contract because the natural gas companies don't give that away for free. You must sign a contract with them so how do we see the cost of those hedging contracts and how is that accounted for in your natural gas price.
    - Response – Michael Eugenis: Regarding the contract itself and the cost associated with the contract, I cannot definitively say if we include that in the pricing. We do include all our relevant costs when it comes to contracts in our total revenue requirements process. A lot of these we have phases in our analysis, and we focus on the relevant pieces of data for each of those phases and then at the end that revenue requirements is putting our arms around every cost associated with doing business for these assets and recognizing those costs in the overall portfolio. I am confident that we include that in the revenue requirements, but I do not think that it is included on a $/MMBtu basis within the forecast.
    - Comment – RPAC Member: I am struggling to wrap my brain around this because all the utilities that we have talked to have talked about hedging for natural gas like it is a magic bullet that solves all the problems in the natural gas markets, but the natural gas markets would not offer hedging contracts if they were not making money on their end. If they were losing money by doing this, then they would only sell gas on the open market. If every utility is saying that they are saving money by hedging, then what is the incentive for natural gas companies to sell hedging contracts? I am trying to get a better understanding of the price signals that are being sent by the natural gas companies and APS.
    - Response – Michael Eugenis: It is an insurance product and as everybody knows, there are very large firms that sell insurance for all kinds of things, and they exist in perpetuity. It is very helpful for us because it smooths volatility, and it eliminates that immediate price pressure on our customers when there are high-prices.
    - Comment RPAC Member: Does APS have any proof that the reduced volatility reduces the cost of natural gas overall?
    - Response – Michael Eugenis: I could not speak to the deeper analysis on hedging but that is something that I think we could take back and have a discussion with the team that manages the hedge as well as the risk analysis team and that might be something interesting for them.
    - Question – RPAC Member: I am curious to what extent the hedging, or the different sensitivities here play in or are evaluated based on real time prices you see over time? We have seen the fuel adjuster increases and those accounts

have large balances that must be made up. Does that factor in here at all? Are you comparing to the dockets or are they separate from each other.

- Response – Michael Eugenis: That harkens back to our conversation that we had in December on the development of these price forecasts into the future. The broker quotes that are utilized represent pricing for executable contracts into the future. We utilize those broker quotes to develop these forecasts, so in that way we have an executable product as the baseline. Whenever you forecast a commodity out into the future, you are going to see smoothing effects and it is impossible to determine how big some of those price spikes that we have seen in real time are going to be into the future.
- Comment – Todd Komaromy: I don't want you to get ahead of yourself here when you start describing the high and low forecasts, but the hedge has an impact on both of those as well. It is both positive and negative.
- Question – RPAC Member: These are the EIA curves, and I am not as familiar with what the fundamental story behind these curves is. Why does it go up to 8 dollars for the high forecast and drop down to 2 dollars for the low. If you are familiar with those, can you talk about that a bit and what is the probability associated with the likelihood that we get $8 gas? I just want to confirm, but you correlate the gas price with the power price so the green power price associated with this gas price would be higher, correct?
- Response – Michael Eugenis: That is correct, we correlate natural gas pricing with our power price forward curves because there is a heavy dependence on what gas prices are, especially during some hours of the day where you primarily have more thermal units online. As far as the probability of the scenarios that the EIA put together, I'm not prepared to speak to it in much depth. That's something that I could return, or we could follow up with you. When we were doing our evaluation of this, the thing that really stood out to me was the fact that this was a public source and a government source. Since we must study the impacts of different gas prices on our system, I felt like this was one of the most robust places that we could get this information without us developing our own scenario or forecast internally, which would be off our own assumptions.
- Comment – RPAC Member: That sounds great. I would recommend that there must be a good analytical reason to do scenarios and a good understanding of how they drive decision making at the end. It would be critical to have good understanding of what the drivers would be to create a world in which this high or low natural gas prices actually happen.

- Slide 32 – EPA Proposed Carbon Pollution Standards
  - Existing coal and new/existing natural gas impacted.
  - Relies heavily on developing technologies.
  - APS will continue to monitor developments and include the implications in IRP analysis as more clarity is provided.
  - A carbon price is being utilized in the 2023 IRP as a proxy for new EPA standards that will continue to get fleshed out into the future.
- Slide 33 – APS has developed carbon price sensitivities based on programs active in neighboring regions
  - CO_2 emission costs are from California Cap-And-Trade Program
  - CO_2 is updated based on the May 2023 reserve price and escalated at 2.5% starting in 2028 for base price. Escalated at 7.5% annually for high price.
  - Question – RPAC Member: I appreciate you including this, especially the recent EPA proposed rules. I mean, probably you are all and many of us remember all of the saga that was the Clean Power Plan, and I don't envy you trying to have

to do 15-year plans with what seems like constantly changing policy scenarios. You said that you did not expect this to have an impact in the near term, but potentially in the long term and obviously these are long term plans. Could you elaborate on that a little bit more? Can you say a little bit more if you know the timeline and what we are expecting for these EPA rules? I'm assuming that they will also end up in litigation, much like the Clean Power Plan, and I know there has been a bit of talk about exempting some CT's. Could you say a little more about the details and a little more about how the rulemaking itself factors into the planning.

- Response – Michael Eugenis: In the near term, I want to recognize the fact that today we do not have a carbon price or carbon tax within Arizona. There is nothing that states that there is a real cost that we are incurring associated with carbon specifically. APS does not have a carbon regulation specific to it right now and that is the reason that it is not included in the near-term action plan. The assumption is that we would be considering the carbon tax out into the future. So hopefully that answers your first question. To answer your second question about considering the rulemaking and the potential litigation in the future, the best that we can do is consider all of the regulatory requirements that we have at the moment. As we learn more about these different buckets such as emission reductions and what the costs are going to be associated with those, we will include that in our modeling and know that in the future this may change. We try to plan based off what we anticipate the future will be and if it ends up changing that is the purpose of some of these sensitivities. This allows us to look at how uncertain assumptions are going to change the resources that we are going to pick. If we have a specific scenario or a specific case that we run that omits that carbon price, you can see how the portfolio of resources is going to change. That helps us measure the durability of decisions into the future.
- Question – RPAC Member: That made me think of another question. In the 2020 IRP's, TEP provided their RPAC with different dashboards for all the different portfolios and they did include a societal cost of carbon. Since you brought that up, can you mention if APS is considering that at all? Is there a way to consider that within the modeling or to show those comparisons in whatever output that we are all going to see when we discuss the preferred portfolio?
- Response – Michael Eugenis: We had an RPAC discussion about them not long ago, and it prompted me to reach out to TEP and dive into those a little bit more. I think that there is something that we can do on our side, it may not look the same as what they pulled together, but it should be helpful in visualizing how these portfolios are different and what the input assumption is and then what the end result is of the optimal portfolio that is built for each case. To the societal cost of carbon, I feel like this carbon price that we use and this carbon tax assumption that we use is the best benchmark that we have for that into the future. It recognizes the fact that we anticipate that there is going to be some regulatory changes that that are not present today.
- Question – RPAC Member: Does the ACC have any PRM requirements?
- Response – Todd Komaromy: I think there is an expectation that APS will plan its system prudently, but I don't know that there is any specific standard around PRM's at the ACC. I will look into that and get back to you.

Matt Lind (1898 & Co./Director of Resource Planning) – Next Steps & Open Discussion

- Slide 36 – IRP Timeline
  - Market report is planned for early June
  - The June RPAC is going to be on 6/23/2023
  - Public stakeholder meeting #2 on 6/27/2023
  - July RPAC meeting on 7/19/2023

- IRP filing on 8/01/2023
- Public stakeholder meeting #2 and the IRP filing dates are subject to change if the IRP extension is approved by the ACC.
- Question – RPAC Member: Can you just comment on when the Aurora training is going to happen? Do we know that yet?
- Response – Todd Komaromy: The public stakeholder meeting could get pushed out if the date for the filing is extended as requested. We have had requests from stakeholders that the training occur closer in time to when the information on the inputs is available, and we anticipate that to be available to the RPAC stakeholders in the second week of June. That would likely be the best time to have those trainings from Aurora. From what I understand, they have several tutorials that are available to folks that they will step through and then the APS team is certainly hoping for more personalized Q&A sessions and helping to facilitate that.
- Question – RPAC Member: Is the training in June intended to be a full day event? Do we have a proposed day or anything like that?
- Response – Todd Komaromy: I don't think it will be a full day. It is intended to be a few hours, but it will be based on the needs of the participants. It is being hosted by Energy Exemplar and those that put the tool together and they have given us a couple of different options and we had to push them to get the RPAC a more robust training. If more time is needed, we can follow up with them. So far, we do not have a day specified for the training.
- Question – RPAC Member: On our all-source RFP small breakout groups, are you going to send out information for those who have requested to participate in those?
- Response – Todd Komaromy: Yes, we will send that out today and if you if you don't see that, please follow up with us. We are intending to audit our list of those that have requested to be included and make sure we have that complete list of parties and make sure that they have those folds and invites on their calendars.
- Question – RPAC Member: Who should we contact if we want to be included in the list?
- Response – Matthew Lind: Please reach out through the e-mail address arpac@aps.com Express an interest there.

Action Items:

- APS to confirm ACC requirements on planning reserve margins in IRP analysis.