PROPOSED ADJUSTMENTS TO SRP'S STANDARD ELECTRIC PRICE PLANS

STAFF INTERVIEWS BY THE PUBLIC

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APPEARANCES

For SRP:

Sarah Glover, Esq.
Kathleen "Katy" Heth, Esq.

For Earthjustice:

David Bender, Esq.

For Southwest Energy Efficiency Project (SWEEP):

Caryn Potter, Esq.

For Arizona Solar Energy Industries Association (AriSEIA):

Autumn Johnson, Esq.

For Steve Neil:

Steve Neil

MS. GLOVER: Good morning, everyone, and welcome. My name is Sarah Glover. I'm an attorney here at SRP.

This is the time set for the interviews of SRP management and the board's consultant as described in the public notice of the price process that was -- that commenced on December 2, 2024.

I'm joined here by my colleague Katy Heth. And we're here to help things run smoothly and support SRP staff in these interview proceedings.

Today we welcome four individuals who requested interviews. We have Autumn Johnson with AriSEIA. Caryn Potter with SWEEP. David Bender with Earthjustice. And Steve Neil, an SRP electric customer. And we appreciate all of you for being here and for providing in advance the topics that you plan to cover and the questions that you might have.

As you can see, we've assembled here a team of SRP representatives who we hope can answer all of your questions today. I'll introduce them briefly. This is Brandon Shoemaker who's our director of pricing, corporate pricing. John Tucker, who's our senior director of financial strategy. And then we have Mark Carroll and Karl Sandstrom, who are each principal predictive pricing analysts.

We also have in attendance by Zoom Bruce Chapman of Christensen Associates, the consultant that the board of directors has retained.

So before we get started with the interviews, I'd like to go over some procedural guidelines that will hopefully help ensure we stay on track and get through everyone's questions today.

First, a few things concerning the schedule and the scope of the proceedings. In advance of today the corporate secretary of SRP provided you with an interview schedule. So just to reiterate that briefly, we will start the interviews with Mr. Chapman, and we expect those to wrap up mid-morning. Interviews with the SRP panel will follow, and we will get a lunch break probably around 11:30. And I believe that the agreed-upon order of questioning is for Mr. Bender to go first, followed by Caryn, then Autumn, and Steve Neil.

And our goal is to wrap up the interviews by the end of the regular business day. To make sure we get through all of the interviews on time and that everyone has a chance to get all of their questions answered, we ask that each interviewer limit your time with Mr. Chapman to about 30 minutes and to the SRP staff to about 60 minutes each.

A reminder that these interviews are

intended to cover your questions related to the SRP pricing proposal and the price process. We therefore ask that you focus your questions on matters that relate to those things. If you have questions that do not pertain to the pricing process or the proposal, we can direct you to the appropriate people at SRP to follow up with you at a later date.

And finally, we anticipate some overlap between the questions that you intend to answer, so we ask that you do your best to minimize the duplication of your questions.

Next, if you have any document or data requests, we ask that you submit those in writing through the SRP website or through other formal channels. That way we can make sure that we can keep track of those requests and make sure that every one becomes part of the public record.

And finally, we have Jennifer Honn with Glennie Court Reporting Services, who will be making a transcript of this proceeding. When the transcript is complete, SRP management will make it available on the SRP website or upon request.

And these proceedings are not being video recorded.

Are there any questions before we get

started?

MS. POTTER: Yes. Thank you so much.

I was hoping as we get a little bit closer into questions from some of the guests today you would give me a little bit of flexibility. I do have a conflict at 1:30. So I'm just hoping we can -- when we get to that point, we can make some adjustments if needed. So I'll just have to step out of the room for about 30 minutes.

MS. GLOVER: Step out briefly for 30 minutes? Okay. I'll take note of that, and we'll see what we can do where we are in the process.

Okay. Anything else?

(No response.)

MS. GLOVER: All right. I believe we're ready for Mr. Bender.

INTERVIEW OF MR. CHAPMAN

BY MR. BENDER:

Q. Good morning, Mr. Chapman.

Can you hear me?

A. I can. Good morning.

Q. Good morning.

Mr. Chapman, are you -- are you in Madison? It looks like you're in Madison from the cold.

A.   I'm in Madison, Wisconsin, yes.
Q.   I left there yesterday, and I'm going to return there when we're done here today.
I'm glad to see it's looking that much warmer outside.
A.   Oh, it's going to be warm for just a day or two, but bring your Wellies because it's going down to about 4 above as a daily high for the next three days.
Q.   I'm looking forward to it.
Mr. Chapman, do you know when Christensen Associates was first hired for your role in this process?
A.   Yes. We went through an RFP process late in the first half of last year, and I think we were hired sometime around June 15, something like that.
Q.   June 15, 2024?
A.   Yes. I don't have the exact dates, but somewhere in June.
Q.   Okay. And then when were you first provided materials for you to review as part of your review and analysis for the board?
A.   Some materials I believe arrived in about September of 2024.
Q.   Okay.
A.   But I don't know exactly. I can check the file dates. I don't know for sure.

Q. Okay. What materials were you provided?
A. I was provided with the materials that you see, which are the reports for the embedded cost of service, the marginal cost of service study, and eventually the rates materials. I also received underlying files that support their calculations.
Q. And were all of those provided at the same time to you in September?
A. No, they were not. For one thing, I received several versions of the same file, of course, as things were developing, but not everything arrived at once.
Q. Were there any changes in drafts from between what you first reviewed and the, I guess, ultimate or the last one you reviewed December 20 -- or December 2, 2022?
A. I can't respond with precision to that.
I think the question that I think you're driving at, which I infer is whether I observed changes in direction between the time I first received materials and the final materials I would say characterize the various things that I received as simply updates and improvements as more information were arrived and as more calculations were completed.
Q. Okay. That wasn't my question, but thank you.
I assume you have your report in front of you?
A. I do.

Q. Okay. I'll mostly talk to you about the marginal cost study piece that you reviewed.
Do you have that in front of you as well? It would be the --
A. Not just yet, but I'll bring it up. One moment, please.
All right. I'm on page 13 of our report, if that helps you.
Q. Okay. One thing I note in your report, so it would be the beginning of your report romanette, so small i, iii, and then on page 14 of your report you refer to marginal energy costs, and on page 14 it's energy-related costs.
Do you see that?
A. Would you like me to share my screen so we can agree on what we're looking at?
Q. That's fine, if that's possible.
A. All right. I'll see if I can do that.
All right. So can you see page 14 here?
Q. I can.
A. All right. So point me in the right direction, if you would.
Q. Sure. Right under 3.2.1, first paragraph.
A. Yes.
Q. Okay. And it's talking about energy-related

marginal costs; right?
A. Yep.
Q. Okay. So you refer here to production costs for an incremental unit of electricity, and the next sentence refers to transmission and distribution.
See that?
A. Yes.
Q. I'm not understanding what transition and distribution costs are included in the marginal energy costs.
A. Well, for each of -- if you look at the rates, you can see that there are energy-related components that are not exclusively generation related. So for each of these pieces there will be components that they've calculated, so I suppose we could go down and get into detail.
I think what you're thinking about perhaps there is that people think in terms of generation costs as being in combination of the main and energy related, but transmission costs I'm thinking of embedded costs now as being almost exclusively demand related, but there is an energy component that's associated with losses in transmission and with distribution, of course.
So I'm not sure if that's what you're honing in on, but essentially that's the source of the energy

component of what we think of as delivery-related cost calculations.

Q. Okay. We're talking about right now. We're not talking about embedded. We're talking about marginal; right?

A. Yes. And I'm speaking specifically of marginal costs because, as I said, with respect to the delivery functions of transmission and distribution, the marginal components of those are associated primarily with losses.

Q. Okay. So the marginal cost study reflects the marginal energy-related costs, and your understanding is that those also include marginal losses for transmission and distribution?

A. Yes. I guess I'm having a little trouble with the taxonomy of what you asked, but I think the answer is yes.

Q. Okay. Any other transmission and distribution-related costs in the marginal energy-related costs?

A. I don't think so. But I'd have to check. In terms of the detail, if I were to scroll lower down, I might investigate further. But what occurred to me was the losses component based on my reading of this a few days ago.

Q. Okay. So putting aside those transmission distribution losses, what other costs or what's the source of the energy costs in the marginal cost study?

A. So if I treat your question literally, the core of marginal energy costs are those associated with generation. So the question, I guess, then is if a customer consumes an extra kilowatt-hour or a megawatt-hour, the higher the costs change, and primarily the cost changes are generation related, and they're reflected in the market value, which varies from time to time, of those generation services.

Q. Mr. Chapman, thank you. You're explaining to me your understanding of what a marginal cost is.

I'm asking what's the source of the cost data used to calculate the marginal energy cost in the marginal cost study?

A. Well, I think that -- is it David who I'm speaking with?

Q. That's correct.

A. So, David, I think that we're starting to stray into questions where you're saying, well, I've got a technical question for you. In terms of the details, the data sources, the right thing to do is to ask the SRP management team.

But my inference from what I recollect from my conversations with them is that the marginal energy costs are derived from the market values that they have acquired over time with respect to the local energy markets. So if we look at the text here, it says SRP participates in the Western Energy Imbalance Market, so they're a source of, for example, hourly or even five-minute data that provides a source for marginal energy costs.

Q. So your understanding is that the data comes from the Western Energy Imbalance Market?

A. That's not quite what I said. What I said was that if you want to ask in detail about the data source or sources that are -- that underpin marginal energy costs, the people to ask are looking at you from across the table.

I'm the board's consultant who was hired to review what was done. And when I reviewed that, of course, I looked at their data sources and pronounced them sane and sound, but I can't recall looking at -- I can't call up for you now the actual individual data sources.

Q. Okay. So you did review the data sources and you pronounced them sound, but you don't recall what the -- what you looked at?

Is that what you're saying today?

A. I don't recall the individual data files, but essentially what's in their report and what's summarized in mine, I guess, is the sources of those data.

But if we go a little further, I might remember what else was related to that. But I don't see a quote other than that. But if you look at the paragraph at the top of this page, the first full paragraph, it says, "SRP's marginal energy costs of generation are based on forward market prices shaped based upon CAISO's historical market prices."

So but did I look at tons of CAISO data? No. I'm just familiar with the CAISO markets, and I know what markets they went to.

Q. I don't have much more.

Can you look at page 21 of your report?

A. Okay. Whereabouts?

Q. The paragraph in the middle. It starts with, "Some may regard."

A. Okay. Can you see that clearly on screen?

Q. I can.

A. Good. Okay.

Q. So this is talking about the customer charge or the fixed charge component of the proposed rates; correct?

A. Yes.

Q. Okay. And you note that in the last sentence there, "Management's move to increase fixed-cost recovery through fixed charges is thus in line with industry practice and embedded cost-based pricing generally."

Do you see that?

A. Yes.

Q. And for residential customers, the proposed rates we're talking about are for single-family 30 or $40 a month; right?

A. Yes. There's a tiered pricing arrangement for the residential customers, as you know.

Q. Right.

What other utilities are you aware of who have a 30 or $40 per month fixed charge for residential customers?

A. From my perspective, I would say that prices in that range are fairly common, as I understand it, among the NRECA electric co-ops, for example. And that's because, of course, those -- those utilities are less dense than the average electric utility jurisdiction in the United States. So they are required of necessity to have higher fixed customer charges in order to cover their higher costs per customer, higher fixed cost per customer.

For more urban areas, large municipals, and investor-owned utilities, the customer charges are lower.

But it's my observation that there's a trend to increase those costs. And we're kind of in the marginal cost area, but, as I think you also may have observed, it's typically the case that embedded cost-based cost of service studies result in customer -- residential customer unit costs in the 30 to $40 area even though the customer charge for residential is often in the 10 to $20 area. It's just an industry fact that the customer charges for residential customers are generally well below the unit costs.

Now, we're speaking here of marginal costs, but I think a similar thing applies because if you ask the marginal costs of adding a customer on the system, it tends to derive from very similar mathematics associated with line extensions. So I'm being a bit prolix, but I think that's the background that I have to offer.

Q. Yes. So my question was if you know of other utilities who have a 30 or $40 per month fixed charge for residential customers. You mentioned --

A. My answer was yes.

Q. And you mentioned rural co-ops. So other than a rural coop, do you know -- can you identify for us today any utility, investor-owned or municipal, with an urban service territory that has that level of fixed charge?

A. My answer is no, but then I would have to research it.

My experience in looking at various costs of service rates and rate designs, though, is that there are such rates in other jurisdictions.

The trend, as I said, is upward, but I also said that the average level in investor-owned utilities is well below that 30 to $40 range.

Q. Do you know what Arizona Public Service fixed charges are for residential customers?

A. No.

MR. BENDER: I don't have any more questions for you today.

Thank you, Mr. Chapman.

MR. CHAPMAN: Thank you.

Just for the record, I didn't hear, was that David?

MR. BENDER: Yes.

MS. GLOVER: Yes.

MR. CHAPMAN: Thank you, David.

MS. GLOVER: Thank you so much.

MS. JOHNSON: Could I just ask a procedural questions?

Are the witnesses not being sworn in?

MS. GLOVER: No.

I think we're moving on to Caryn.

This is -- Bruce, this will be Caryn Potter with SWEEP.

MS. POTTER: Thank you. I actually have no questions for this witness.

MS. GLOVER: Okay. Fair enough.

Then this is Autumn Johnson with AriSEIA.

MS. JOHNSON: And can he -- he can hear us okay?

MS. GLOVER: You can hear okay, right?

MR. CHAPMAN: I can.

MS. GLOVER: All right.

MR. CHAPMAN: So Caryn had no questions, and Autumn is up next?

MS. JOHNSON: Yeah.

MS. GLOVER: Yes.

MS. JOHNSON: With AriSEIA, which is, because no one knows what that means, it's the Arizona Solar Energy Industries Association.

MR. CHAPMAN: Got it. Thank you.

MS. JOHNSON: I have some clarifying questions just about process because this is my first SRP pricing proceeding.

Are we to be asking him just questions that are from the couple of reports? If they're from the proposal, then they're for the panel?

MS. GLOVER: I think that's right, yes. So you'll be asking questions to Bruce regarding his -- his report and what he was engaged to do for the board.

MS. JOHNSON: Okay. And one more question related to that, so there are two other reports from a different consultant. Are we also asking those?

MS. GLOVER: Those are the consultants that management engaged. They will not be here for interviews today, but they will be making presentations at the board meeting.

MS. JOHNSON: So if we have a question about kind of the general concept, we would ask management because it's their consultant.

MS. GLOVER: Correct.

MS. JOHNSON: Okay.

INTERVIEW OF MR. CHAPMAN

BY MS. JOHNSON:

Q. So I just have a couple of, like, I think pretty high-level questions, then -- and it's a little bit weird, sorry, because you're kind of to the side of me, so I'm not meaning to be rude. I actually am not -- there we go. I'm not looking -- even when I look at you, I'm not making eye contact with you obviously, so --

I just wanted to ask so generally what is the scope of your review here? Is it just to make sure that they're kind of engaging with industry practice, or what else were you kind of instructed to do as part of your review?

A.   The scope as described in the RFP as assigned to me by my recollection -- I didn't look at those over the past couple of days in preparation for this meeting -- was to evaluate from the point of view of industry theory and practice the embedded and marginal cost-based cost of service preparation for the rates and then evaluate the rates themselves.

To expand on that a little, when you look at the rates end, SRP has a set of objectives, things like revenue sufficiency, cost relation equity, that sort of thing, so my review of their rates was in reference to that and to the well-known Bonbright principles that are pretty much along those lines for their revenue related, cost related, and practically related, the same sorts of things, avoidance of cross -- cross-subsidy, things like that, price efficiency.

So that was part of the benchmark. If you look backward from rates into costs, then from the point of view of marginal costs, what we looked at was SRP's practices in terms and methodologies in terms of estimating the various types of marginal costs with respect to economic theory and with respect to industry practice.

And then when you get to embedded costs, of course, there are established principles and practices for embedded costs, rules for functionalizing, classifying, and allocating costs from the financial aggregate level to the individual rate cases. So we looked at their methodologies in some degree of detail.

And so I guess our main goal was auditing the individual calculations that went in to the cost of service model or into the marginal cost calculations, but we essentially reviewed their methodology from the point of view of its conformance with industry practice and economic theory.

Q. Okay.

A. Did that answer your question?

Q. Yeah, I think.

And so did you make any recommendations as to the rate design of the individual rates, like, things like the differential between an on and off-peak or the length of TOU periods or anything like that?

A. What we did was we reviewed their plans, their definitions of, for example, time-of-use periods, and their time-of-use periods changed, as you know. And from our point of view the question was did those time-of-use period changes make sense, and did the rates that resulted from that make sense in terms of the various principals, including gradualism that SRP espouses.

And from our point of view the change in the time-of-use periods was entirely sensible given the significant change in the pattern of wholesale energy market prices. And so the rates that they derived based on those new time-of-use periods makes sense as well, and the changes that they made in the interest of gradualism that depart from what you might think of a perfect price efficiency also made sense.

Q. Did you provide any constructive feedback to SRP as to changes that they ought to make or was everything mostly a yes, this is adequate?

A. Well, if you look in our report, then you'll find our suggestions in there in a couple cases. But it wasn't our task to tell them how to redesign their rates. We weren't hired as management's consultant to go into, say, how time-of-use periods ought to be changed or how rates to support solar energy or electric vehicles ought to be changed.

Our role was as support for the board to review whether management's changes made sense.

So from my point of view it wasn't my job or within my power to say here's what you ought to do. What

I do is I speak to the board and say here's the degree to which I think what they have decided to do as management comports with industry theory and practice.

So from my point of view, I didn't advise management on how to design rates, although I had conversations with them about rate design as part of the review process.

Q. Yeah. My understanding is that the board can also make its own recommendations as to changes that should be made during the pricing proceeding, and so are you participating in helping them do that?

A. That wasn't discussed, but from my point of view, I would think the board would only get into the process of making recommendations on its own if it were the case that management had been found to have omitted something that ought to have been reviewed or had undertaken rate changes that the board disapproved of. And from my point of view, I've never encountered anything of that sort in my review of management's plan.

Q. Okay.

A. And I should interrupt by saying I'm sucking on a throat lozenge because I have partially paralyzed vocal chords. And so if I look like a chipmunk and my speech is altered slightly, I'm trying to stave off the collapse of my ability to speak.

Q. Well, that -- I'm sorry to hear that, and we can certainly pause if needed. That sounds fairly significant.

Okay. So I just want to make sure I understand what you just said. So you're saying that in your mind the board who's essentially the -- the only regulator of SRP in this case wouldn't make any of their own proposals absent there being some sort of insufficiency or inadequacy to the management's proposal. So basically if management didn't do anything wrong, then that's what should move forward?

A. I think didn't do anything wrong is sort of a bare minimum type of statement.

Q. Yeah.

A. Because management since the last price process has not stuck with the status quo. They have critically evaluated in my opinion the changes in the market and in their customer base that have taken place over that time period and have proactively undertaken changes to the rates and to their costing methodologies that respond to those changes.

So if, for example, if management had stayed put and had not changed the time-of-use periods, I might have noticed a difference between wholesale and retail market price patterns, right? I would have stepped in and said management has failed to do this, but I didn't see anything like that.

It seems to me in my opinion as an objective reviewer for the board that they responded to the significant changes in the pattern of prices with an appropriate response. Namely, they changed the time of their time of use price pattern.

Notice that they didn't go overboard by totally throwing overboard their time of use price setup. They pretty much stuck with the time periods, made some alterations. But in terms of the price levels, they -- they made -- they moved those in a direction of the wholesale market changes.

Q. And have you presented your findings to the board yet?

A. I've presented my findings to the board in the December 2 report that you have.

Q. Okay. But you have not met with the board?

A. I have not met with the board since then.

Q. And you have not, like, answered -- have a Q and A with the board?

A. No. In fact, your questions sort of embarrasses me because I'm thinking, gee, when did I last see the board. And so I don't have that date in my head. I'd have to go and check my calendar. I apologize.

Q. But you have met with the board at some point?
A. Oh, yes, yes. So I've been to Phoenix and been to board meetings on multiple occasions.
Q. Okay. And then is there going to be a board meeting in which you're going to be present to present the findings and answer questions of the board?
A. Yes. I'm scheduled to make four trips in the next month and a half to Phoenix for board meetings, and all those are in the public domain.
Q. Okay. You mentioned that you have suggestions a couple of times to management regarding -- or to the board regarding management's proposal within the report.
Could you direct me to those pages so that I can look at those again further?
A. Not off the top of my head, but if I go back to looking at the report, then maybe I can dredge them up for you.
I'll go and look at the executive summary first. Let me share my screen once again.
All right. Let's see, can you see my report at this point?
Q. We can see it.
A. All right. Let's see if I can magically produce indications where I made a suggestion or two.
All right. It looks like I'll have to dig a

little deeper. Now, I'm going to -- I'll slide down to the bottom, and I'll see if I can find some nitpicks for you.

Q. I didn't see them. So if they're there, I appreciate them.

A. All right. My recollection is that I had a recommendation about further investigation of pricing alternatives, but I can't remember the detail. I think it might have had to do with E-28, which was one of the rates that serves the distributed energy resources customers. That's the one that comes to mind.

And in that case, that rate -- I think it's that rate. It might be the other one, E-16 -- lacked a demand charge, so it still presented a certain degree of exposure to the other customers of cross-subsidy, but that's the only example I can think of that comes to mind right now.

Essentially, I think you may understand that the basic issue with rates that serve customers, especially net metering rates, is that whenever a customer generates solar power the amount that they -- of the bill goes down by an amount that exceeds the avoided costs of the utility. And so the utility needs some means to recoup from those customers its ongoing fixed costs of delivery. And so a good approach to do that is to use a demand charge, which prices somewhat related to embedded unit cost.

And so there was one rate that did that, but there was another that was an energy only rate, and I think it was E-28. The folks across the table from you can correct me in that regard.

Q. Could you --

A. So I guess I'll stop scrolling up and down here gung ho, but at a certain time I think that was my recollection of one recommendation I had. There may have been others where I said here's something to look up for in the future.

Q. Could you just clarify because my understanding is that the -- because there's the -- there's the E-28 pilot, and then there's the new E-28, and my understanding is that the old E-28 does not include DG customers, but the new E-28 would be DG and nonDG customers.

Which one are you talking about?

A. I'm speaking of the new one.

Q. The new one.

And your concern is that it doesn't have a demand charge like E-16 does?

A. If it's E-28. It was E-28 or E-16.

Q. Okay.

A. The management guys across the table can remind me.

But, anyway, there's one rate that I noted within my report that lacks a demand charge, so in that case what you have -- if you don't recover fixed cost by a demand charge, Autumn, you tend to recover them through an energy charge. So if you're recovering from an energy charge, that means that the energy price is up here, and the avoided costs are down here.

Q. Uh-huh.

A. So anytime that somebody installs a new set of solar panels or uses their existing solar panels that means that there is a potential loss of revenue recovered from that customer, and it has to be made up in a general rate increase.

So our friends at SRP have already taken steps by introducing a demand charge and revising their rates, and I didn't see a big source of controversy when I reviewed this.

And in contrast there are other utilities around the country, of course, that are still dealing with the fact that they have energy only residential rates that support distributed energy resources, and that produces a revenue requirement issue for them.

Q. And your firm, you do this all over the country;

is that right?
A. Yes. We have clients all over the country.
Q. And are your clients always utilities?
A. No.
Q. What are your --
A. Our clients --
Q. Go ahead.
A. Our clients are predominantly utilities, but we've also worked for regulators, and on occasion we have worked for customer interest groups, so other intervenors, shall we say.
Q. And do you find that, well, I guess, in your experience in nationwide, are demand charges for residential customers the norm?
A. Oh, certainly not. But they are being given more serious consideration than they were in the past, and precisely for this reason. You'd like to treat your residential customers equitably, of course. And so if you have two houses side by side, one with solar panels and one without, they likely have quite similar delivery costs, but they have quite dissimilar energy costs in terms of overall level of the electricity delivered and perhaps the time pattern as well.
So but those delivery costs tend to be underrecovered under the traditional net metering rate as

I think you may understand and as most utilities are coming to understand these days.

Q. Do you find that residential customers understand demand charges and how to manage them?

A. My answer is a qualified yes. And the reason it's qualified is, first of all, I don't do surveys or haven't done surveys with residential customers even though I've read the literature, but there certainly are acceptance issues with people who are unfamiliar with them.

But I can think of a couple of prominent cases. And the one that I'll advance to you even though it's a natural gas case, if you look at Atlanta Gas Light, it's a big natural gas distributorship, and it covers Atlanta, Georgia, of course, a couple million customers.

And that utility has a customer charge and demand charges for its customers, but no energy charges or commodity charges. The commodity charges, of course, are charged by the gas commodity folks in a rather more deregulated market than you find in electricity.

But Atlanta Gas Light has had their demand charges in place since 1999, I think. And I've spoken directly with the rates manager of Atlanta Gas Light as part of my research. And he said in our case we find that customers prefer our demand charges to their commodity charges because what it means is that they have relatively little bill variability. They pay the same amount that they always did before, but if you have a period of extreme cold, the bills don't go up because people are billed on the same constant demand charge, and it's a demand charge that's based on what's called the designed day demand, which is a worst-case estimate.

So you take the past 10 years of a gas customer's history, find the most they consumed in a given month, and that's the ongoing basis for billing. So if you have a cold snap in Atlanta, Georgia, the bills barely budge. The commodity side budges, but their delivery side stays put.

So that's People's Exhibit A in my opinion of the virtues of demand charges.

Q.   Okay.

A.   From my own consulting experience otherwise, electric utilities have tried demand charges and are experimenting with them now. Initial experience, as I recall, was not terribly favorable because of the fact that it's a demand charge and what the heck is this. But people continue to look at those as a viable means of equitably billing DER customers and standard residential customers who have no distributed energy resources on their property.

Q. Okay. That's interesting. I have some follow-ups there, but I'm going to move on just for the sake of time.

I wanted to just ask generally a couple of things just about your expertise as far as nationwide whether or not it's a standard.

What do you find is a duration of a TOU period that is actually useable by customers that would modify their behavior?

A. Well, you threw me for a loop because I was expecting what do you expect is a reasonable price differential between time periods that would modify --

Q. You can answer that also. I'm curious about that as well.

A. That's one of those things where somebody's being interviewed and said I'm glad you asked me that and then answer a different question.

I think the issue for customers is not what the time periods are provided those time periods are stable over time.

The issue is the price ratio between an on-peak and off-peak period. So if I'm a customer, to take a recent example, with an electric vehicle, I'm looking for my utility to provide me a period when the utility's marginal costs are low so that I can find a time to charge my electric vehicle.

The central problem, I think, in terms of price ratios these days that utilities confront is that if you look at wholesale prices, the on-peak to off-peak price differentials in wholesale markets, especially in the Eastern Interconnection, tends to be things like two to one and one and a half to one.

And the econometric or statistical analysis that you see in evaluating TOU prices over the past 40 years is that you pretty much have to see a three-to-one on-peak to off-peak price ratio to detect customer -- measurable customer response.

So from the utility's point of view there's a tug-of-war here between representing prices as they are in the wholesale market accurately to customers and representing prices that will cause customers to shift.

Now, speaking wholly for myself here and not for SRP, only for myself, what I tell clients consistently is that a time-of-use price regime is an advisable, a preferable, a desirable set of designs because it takes advantage of available information like most utilities these days. You know, many utilities, not all, have the ability to record the time pattern of people's usage often hourly.

But what you do by offering a time of use rate option is that you get customers to self-select. Regardless of the degree to which they're going to modify their usage, they self-select to an option that meets their needs. And your customers who are strongly peak coincident self-select the flat rate, the customers who are not peak coincident select the TOU rate.

You can -- as a utility you can have mandatory TOU structure. That's okay too. But -- and the basic idea is that with time varying pricing you get an improved match on a customer-by-customer basis and on a class basis between the prices they're being charged and the bills they're paying and the costs to serve the customer.

So it doesn't have to be the case that the TOU prices have to be three to one. It doesn't have to be that you have the exact TOU periods that match wholesale markets. What counts is that as far as -- as well as you can do it that you do your best to match customers' cost to serve with the prices that you're charging.

Now to get to the SRP side of things and stop being a professor for a minute, SRP has seasonal and time-of-day pricing that does a very good job as far as I'm concerned of matching the time periods that you find in the generation services markets with the time periods that they've set up and then also that extends to the prices that they have applied.

Q. It's interesting, though, because most of the, I think, it's maybe, like, I saw two of the rate plans have a pretty substantial differential between an on and off-peak, but, like, the new -- the new plan E-16 doesn't. It's not even close to three to one.

You didn't make any recommendations as to modification of the differential in any of the plans?

A. No, I didn't.

And I think what's in the back of my mind here is that you don't have to necessarily have customer uniformity or price pattern uniformity from rate to rate.

So you can think of customers who tolerate TOU prices well, others who prefer flat rates. So it's not the case that you have to look down through the price portfolio of a utility and say how come this rate differs from that.

And I can think of, I guess, an example in the deregulated market that might supplement that. If you look at any of the Texas generation services providers, Direct Energy is one that I'm familiar with, you'll find a half a dozen rates available to residential customers.

And they're first differentiated by a degree of commitment, three years, two years, one year, month to month, and then they're also differentiated by time periods. Some are flat. Some are strongly TOU. Some are weekday, weekend.

So SRP is doing a good job of mimicking what I see in a wholly deregulated market in that there's a variety of TOU price patterns out there.

Q. I'm surprised to hear you say that you don't think that the duration of a TOU period matters because it would seem to me that that would have a direct impact on the likelihood of modification of behavior or even the ability to modify one's behavior.

So you mentioned before in a parallel to a -- to a winter peaking utility or, you know, worrying about cold snaps you can't precool a home in Arizona for five hours. And so to me a five-hour on-peak period seems like that would dramatically impact the original point of having a TOU period, but you think that that is irrelevant?

A. Oh, okay. I think I struggled with your question when you first asked it because you keep telling me, Bruce, talk to me about time periods. So having wandered all over the map inadvertently in a struggle to answer that question, I'll try to come back to it and answer it a little more directly.

Yes, the time periods matter. And, in fact, we advise clients when they ask us to to in terms of helping to pick time periods. And when we do that, we often depict time periods by looking at the pattern of marginal costs, wholesale prices, and try to create select time periods that create the biggest differential possible between on and off-peak prices.

So from that point of view, we agree wholeheartedly with you that the choice of time period matters.

Now the question is, well, why do we have, say, prices like, say, a three-hour window in some cases and a five-hour window in other cases? And that's sometimes a matter of customer convenience or customer preference. I can think of an example where I think it's Xcel Energy at one point in Minnesota had an on-peak TOU window, but there were three TOU windows. There was 5 to 10, 4 to 9, and 6 to 11.

And what they were doing was they were setting up time periods in this case of equal length in order to have people modify their behavior and smooth the behavior over time so that when the peak period ended not everybody in the world started their applications, their end uses at home.

So there may be some of that going on with SRP, although I didn't inquiz about that, and that hasn't come up. But from the point of view of the utility, there's more at work than just the time pattern that you see in wholesale markets. You have to consider customer preferences and customer capabilities as well.

Q.   Yeah. You mentioned that you thought three to one was appropriate to modify behavior.

What do you think is the correct duration if the goal is to modify behavior?

A.   To me that question doesn't make sense, and I don't mean to insult.

Q.   Insult away.

A.   Right. So let's think about modifying customer behavior.

What I think I said to you before may have seemed a little strange because my attitude was something like, well, you don't necessarily need to worry about getting customers to modify their behavior.

What you need to do as a utility -- this is what we tell our clients when we're hired to consult with management is -- to look at the wholesale market and then set TOU prices and TOU time periods to reflect the pattern of costs that you face and then let customers do what they want.

So from that point of view, you can depart from that you might have a rate design objective that encourages modification of behavior. So if the wholesale price differential is two to one, you might say we're in a transition period, I'd like to offer three to one even though it doesn't mimic the wholesale market exactly.

So from -- from the utilities point of view, the people who are engaged in rate design take as their guidance wholesale market conditions and the circumstances of their customers and then maybe the circumstances of the previous TOU price patterns that they had, timing patterns that they had.

So, for example, you might invoke the principle of gradualism to modify partially to your satisfaction but not wholly the time periods that are available.

So from my point of view, if you say here you go, Bruce, here's the utility who are giving you carte blanche, go and design time periods that please you, I might say, okay, I'm going to say, okay, I'm going to be a hour rate power guy, and I'm going to start by picking time periods that exactly match the wholesale market.

So it looks like the greatest on-peak or off-peak differential is 8 a.m. to 3 p.m. thanks to the influence of California it looks like the off-peak period, and then 4 p.m. to 10 p.m. that's the closest thing I can get to an on-peak period, and then the mid part period is everything else in between, okay, speaking of weekdays now.

But I would then come back and say, well, let's consider your current circumstances, and that might cause me to alter what I recommend. Who are my clients? Are they electric vehicle clients? Well, was there a narrow window between 8 and 3 where my prices are especially low or are the prices pretty much uniform between 8 and 3? Is it uniform between 8 and 3? Okay. Great. If there's a narrower window that's lower priced, okay, let's try to identify that.

Q. But, I mean, you get that we're seeing electricity demand astronomically grow, and the utilities are setting peak after peak almost annually and that SRP itself has a whole bunch of programs to reduce demand, but you don't think trying to modify customer behavior is important?

A. Not quite in the sense that you have in mind.

Q. Okay.

A. What I'd like to do -- if I'm a utility person speaking as me, not SRP, speaking as me, is I'd like to show my customers what the marginal costs are and then have them make decisions.

Now let's do a sub bullet on that. Right now we're seeing rapidly increasing capacity costs. There was a big dustup in PJM a few months ago because the PJM auction had produced capacity changes from here to here with very short notice, okay?

So as an hour rate power economist, I'd like to see those price show up in marginal cost estimates and then show up in rate designs.

But it's -- you know, from my point of view, if I'm a utility person and I'm trying to -- I'm trying to provide service to my customers, I want to tell my customers my prices. Subject to revenue sufficiency I want sufficient prices. I want to respect the principle of gradualism, so I want to make sure that I have costs reflecting prices, you know, energy prices, demand prices, and customer charge prices which reflect my embedded unit of costs.

So from my point of view, I'm not going to necessarily post prices because I want my residential customers to come to my rescue and reduce my peak demands. I want to post prices that tell customers what my marginal cost of demand is. So if I can do that with a certain amount of success, then my customers and I will work together to restrict the growth of demand, and by pricing efficiently we will deliver shared benefits.

Q. So I'll just ask one last question just shifting gears a little bit.

One of the other consulting reports mentioned -- and I just want to get your take on this given that you do work nationally, the other report on just sort of utility trends said that electricity rates increases are below inflation, and they had a ten-year average there. And I think that's interesting because, you know, if you go back far enough, you know, the average is always below what you might want it to be.

But for the last five years, according to Lawrence Berkeley National Lab, at least since 2019 electric rate increases are closer to 5 percent, which is above inflation, and do you have any reason to disagree with LBNL?

A. Well, I haven't seen that directly, so I think I would confine my comments to saying elsewhere I have observed something like that, and you're correct in that the choice of the end point matters. If you choose 2000 and -- if the year 2000 is what you choose, you get a different result than if you choose the year 2016.

So you can look back 50 years, if you like, but electricity prices in my recollection, again, right off the top of my head pretty much have tracked inflation, maybe have been slightly below inflation.

One question might be suppose you picked a five-year period like the past five years where they've outpaced inflation, does that give you policy guidance about what ought to be done? And I would be extremely skeptical of any attempt to engage in policy guidance.

Let me give you an example. My own utility here, Madison Gas and Electric, used to tout that their rate increases were well below inflation, and, of course, what had happened was that their rate increases were well below inflation because they hadn't invested in any new generation or transmission capability for 15 years. So as soon as it became necessary to meet their new capacity obligations all of a sudden their rates ramped up and the boasting had to stop.

So from that point of view, you have to be pretty careful about looking at trends two year, five year, ten year when making inferences.

Q. When you say you'd be hesitant to give policy recommendations, do you mean you in your role as the consultant or you mean broadly that you shouldn't give policy recommendations to a utility about their rate design?

A. I guess in my role as a consultant I ought to, you know, not put on too many hats at once.

But if I'm doing -- if I'm looking at somebody's embedded cost of service study, the only thing you can put in there is your legitimate expenses and your contribution -- your rate of return on rate base that's used and useful.

So in the case of Madison Gas and Electric they hadn't built anything in a while so that their rate base kept declining slightly, so the rates couldn't go up. But as soon as they started building new generation and transmission capability, then the rates ramped up in response to that.

So, you know, I had no policy role. I didn't -- first of all, MG&E is not my client. They're just people who gave me the electrons, right? So but from their point of view, there wasn't any -- a consultant advising them would be advising them to recover the costs that you face.

If you were advising them with respect to marginal costs, you might say, well, I know you don't -- you weren't building anything new right now, but go and take a look at the marginal cost of capacity in the MISO market, and if that's high, then you might want to include something like that in your demand charges for large customers, for example.

So that's an illustration of how I might advise a client go about providing for the fact that their rates were currently low but the market was telling them something otherwise.

MS. JOHNSON: I think I can end it there. Thank you so much.

MS. GLOVER: Thank you, Autumn.

MS. POTTER: I actually do have some redirect if that is allowed or some follow-up questions.

MS. GLOVER: Oh, sure. That would be fine.

MS. POTTER: Okay. Great.

INTERVIEW OF MR. CHAPMAN

BY MS. POTTER:

Q. Thank you, Mr. Chapman. I apologize. My name is Caryn Potter. I'm with SWEEP. I just have some follow-up questions after Ms. Johnson's questions.

A. Hi Caryn, I can't see you, but I know you're there.

Q. Good morning. I'm in the background so you can't see me.

A. Yeah.

Q. Just a couple of follow-up questions. Thank you so much.

Mr. Chapman, in your work across the country with other utilities, what price differential for a time of use rate has rendered the highest number of customer adoption in regards to that particular price plan?

Do you have kind of a sense or have you seen something in terms of case studies or your own personal experience?

A. Are you speaking of residential customers only, Caryn?
Q. Correct.
A. Okay. So if you think of residential customers only, regardless of price differentials, historically the rates of adoption where TOU was voluntary have been really quite low, you know, half a percent, 1 percent of the population.
And the key ingredient in that regard has not been time of use price differential, although it helps because people by shifting load if the on-peak or the off-peak differential is high can get greater benefits.
The key thing is the degree to which the utility attempted to make the new TOU rate revenue neutral to the old. So if you had a residential customer paying you on average a hundred bucks a month and you designed a rate so that they would still pay you a hundred bucks a month in the absence of shifting so that the only benefit they got was shifting, then a combination of status quo bias and a mischaracterization of customer cost usually resulted in these tiny rates of participation half a percent and 1 percent.
So technically in order to boost time of use rate participation among residential customers, it wasn't the on-peak to off-peak price differential that you had

to offer. You had to offer them some sort of either cash or noncash benefit. We'll give you free energy audits or help you with your insulation program or we'll just have a straightforward discount.

And those things were well intended but hard to justify. Regulators would rake utilities over the coals about cross-subsidy.

What we learned since then is that they kind of got it wrong, and the reason for that is that when you offer a TOU rate as I was saying earlier, the people who gravitate toward a TOU rate are the people who are less peak coincident in their usage than the other people. The peak coincident customers, they had a flat rate because their bill would go up.

So if you think of introducing a TOU rate, then the people who self-select on that TOU rate are those who have experienced a bill decline. If you try to make the new rate something that's revenue neutral to the old rate, you end up charging customers who have a lower cost to serve the same price as people who have a higher cost to serve.

So in an ideal world a TOU rate has mismatched or different costs to serve but ought to be matched by different pricing. So the theory that people always had that you have to be revenue neutral with your TOU rate option has come to be somewhat discredited. So the way you get TOU -- voluntary TOU participation is you recognize the customer's cost of service to serve relative to the people who are more peak coincident.

Q. Thank you, Mr. Chapman. Let me please rephrase that question. I'm hoping to get more to a specific example that you can demonstrate from your expertise and the work that you have done in terms of an example of high customer adoption of time of use, TOU. So not necessarily looking at the entire population of utility customers, but any specific examples where the subset of those utilities customers did enroll or adopt -- voluntarily adopt a time of use rate, what was that price differential that you saw as that helped to make that more successful?

So is there any -- regardless of what the percentage of conversion to a time of use rate was, can you provide an example of what that price differential was so we can understand in your opinion and from your experience?

A. I apologize. I see now I didn't directly answer your question.

So from my point of view, my experience in this case is looking at the literature. And if I think of a couple of examples like Duke and Xcel, I think there are cases in their various service territories where they've acquired residential customers in goodly numbers for time-of-use prices.

I don't recall what their on-peak to off-peak price differentials were, but I think if you look at Xcel in Colorado, you'll see higher price differentials there.

I realize that's an incomplete answer to your question, but that's the best I can do.

Q. Thank you. I do appreciate that.

And I guess one other follow-up, have you looked at any of the price differentials for time of use rates set by other Arizona utilities as a --

A. I haven't.

Q. Okay.

A. No.

MS. POTTER: Okay. Thank you very much. That's all I have.

MS. GLOVER: Thank you, Caryn.

We are a little over an hour in. Does anyone need a quick break? Should we take five before we start with Steve?

(Recess from 10:47 a.m. to 10:56 a.m.)

MS. GLOVER: We'll pick it up with Steve.

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INTERVIEW OF MR. CHAPMAN

BY MR. NEIL:

Q. Mr. Chapman, my name is Steve Neil. I'm a customer. And this is my fourth pricing process. Though the first one I didn't really do anything but just look around and go what is going on.

So I have some topically arranged questions. And I'll -- based on the previous answers, I think I might be getting too much in the weeds for the -- what you were asked to do, so I'll try to skip some of that.

So you do have some comments in your report about data centers or large customers, so let's talk about that for a little bit.

In page 27 you use the -- you say that the E-67 rate design appears tailored to the provision of cost-effective service to new large customers such as data centers.

And then on page 25, quote, "New E-67 customers are required to pay demand charges that are based on billed demand that are the larger of actual demand or 80 percent of forecasted demand," unquote.

So I'm wondering if you can describe what you observed in the E-67 plan, what -- your analysis of it.

A. I'm not quite sure what you're asking me to do. Are you asking me to expand on what I wrote there?

Q. Yeah. Well, define cost-effective, then.
A. Okay. Well, I think there's no issue with the factual nature of what I put on the page; is that correct?
Q. Right.
A. Okay. So you said I used the word cost-effective that was somewhere on page 25?
Q. 27.
A. 27, okay.
Q. Yes.
A. Let me go and look at page 27 here.
Okay. Okay. So, "As well, the E-67 rate design appears tailored to the provision of cost-effective service..."
So what do I mean by cost-effective is what you're asking; is that right?
Q. Yes.
A. Right. So essentially cost-effective service from my point of view is service where you provide electricity service and bill for it in such a way that you meet the basic criteria for successful rate design and you meet the rate design objectives.
So are you charging the customer their costs to serve? Are you making sure that you avoid cross-subsidy between customers?

Do you have prices that reflect in some sense the notion of efficiency such that the energy prices based to some degree or have some relationship to the marginal costs of generation services, for example.

So from that point of view, cost-effective to me means are you meeting the criteria that you have set for yourself in terms of serving customers generally.

Q. Okay. And you noted that the E-67 plan has provisions for new customers, new large load accounts I think is the terminology SRP uses.

Do you have any -- have you done much work in the data center field?

There's a lot of buzz in the market nowadays about data centers and the rapid growth and the incremental costs of them and things like that, the marginal costs of -- your report didn't speak to that, but I wonder if you could add anything?

A. My straight answer is no in the sense that I have not designed a rate specifically for data center customers. However, I've spent a good chunk of my career designing rates for a broad range of customers, including large customers, many of whom have, say, site generation so they need standby rates, things like that.

So I'm familiar enough with what needs to be done to design rates to serve large customers. And let's face it, data centers aren't the first large customers out there.

Q. Right. Okay. Have you by chance read any of the Concentric Energy Advisors' selected utility trends report?

A. No, I don't -- well, I may have in the past, but I haven't read anything like that.

Q. It was provided to SRP as part of this pricing process, not that one.

You haven't read it? Okay.

A. I may have seen it -- I saw the Concentric Energy Advisors present in front of the board, so I've seen what they were saying.

Q. Okay. All right. I think that will -- some of the things that Concentric says is that -- you know, that -- if I can quote some of their words here, quote, "Financial assurances of cost recovery," unquote. Quote, "Significant infrastructure investments," unquote. Quote, "can lead to higher rates for other customers if not managed properly," unquote.

Quote, "Establish contract terms with minimum service lengths and fees for early termination. Minimum bills and collateral provisions in the form of cash guarantees," unquote.

So those are some of the things that they stated in their report.

What do you -- did you find in your review of the SRP 67 plan along that line?

A. Well, I guess one thing I should say is that sort of question is something I've been working on for some time with one particular utility customer that I have, and they have exactly the sorts of things that are arising in their level of worry right now.

So if you're going to serve a large new customer, then how do you handle a transmission service request from that customer?

What happens when multiple people have transmission service requests, how do you handle those. So I am familiar with those topics to a certain degree.

So let's get back to your question. Why don't you repeat the tail end of the question because that parenthetical thought occurred to me while you were asking it.

Q. Yeah. What -- what did you see of this nature of discussion about new large customers in the SRP proposal?

A. Well, the only thing that I've seen is what's on paper essentially in their report about new large customers. They aren't discussed extensively on how they intend to treat data centers.

Q. Okay. All right. I'm going to take a little aside here and tell you a little something. You were looking for your recommendations. They're on page 18 of your report.
A. Now, which recommendations?
Q. You may --
A. The tail end of my executive --
Q. Yeah, two recommendations in the middle of -- in these two paragraphs here in the middle of the page which you probably can't see under consulting assessment you used the words "we recommend" twice there in those two paragraphs.
A. Well, I'm sure I've used "we recommend" a number of times, yeah. I'm looking at that page now.
Q. Yeah. So that might help whoever asked that question get an answer to that.
Also, there was another aside --
A. Thank you.
Q. -- Autumn asked a question about the differential between prices, and then E-16 plan was discussed, but it was not mentioned that part of the differential of that plan is the demand charge. So it's a two-component differential on E-16 on -- on it's both kW and kWh. So that -- maybe, Autumn, that might help answer your question. So the --

A. Well, when I think about price differentials, I think I was speaking in general without direct reference to E-16 as I recall, but you may recall differently.

Q. Yeah. We spoke about E-28 and E-16.

A. Okay.

Q. All right. So I'd like to talk a little bit about the Bonbright principle of choice that you mention in your report. And so one of the -- I'll go ahead and just make a statement and not ask you any questions that would be difficult to answer.

So the number of plans available to the residential class if this proposal is approved as written will be 13, 13 plans. Eight of those are available to people without solar and without an EV. Nine if they have an EV. And then a separate five plans are available to those with distributed generation and a sixth one if they have an EV.

So all total that -- so the minimum a person could have to choose from or the choice they would make would be five plans, and the maximum would be nine, which these are big numbers in my experience in the electric utility business.

So I just wanted to get your thoughts about choice.

Did you have any discussions with SRP about how

to help customers make this choice?
A. Management wasn't asking me about that question. In other words, nobody said to me, Mr. Chapman, what do you think the best way of going about helping customers choose a rate plan is.
So as you probably know, Steve, there's some utilities that have online devices that help people do that. You know, if you can choose between rate A and B, we'll put your billing determinate at it looks like you can save 2 percent if you go to this other rate.
But I never had discussions with SRP about the mechanics of helping the customer -- helping customers to choose.
I think what's in their report, and they can correct me if I'm wrong, though, is that they're engaging in a certain amount of rate consolidation in this rate application, and so that has two aspects to it. One is that it's simplifying, and the other is it's reducing the range of choice.
But in my view, when I reviewed that, I did ask myself the question are they materially reducing the range of choice, and I eventually concluded that they weren't because what they were doing was they were opening up new designs that are tailored more closely to current circumstances and are perfectly capable of

serving a broad range of customers and closing out rates that either are out of date for one reason or another or just are not well subscribed.

So from my point of view, I concluded that in their evaluation of the question of customer choice versus simplicity that they were using, I think, fairly judicious judgment. And that's redundant, isn't it? They were being judicious in making the rate design choices that they were.

Q. Okay. Yeah, it's true the choices expand upon approval of the price of the proposal, and then they narrow later this year. Late this year the choices narrow greatly. And then people -- and then four years after that, some of those choices go away, and people will be transitioned to one of the three plan -- four plans: E-23, E-24, E-16 and E-28. I'm getting a nod.

Okay. All right. I'd like to move on to pricing study kind of questions.

So you noted in your report that SRP has transitioned away from the traditional 4CP kind of approach to the peak part of the peak and average pricing methodology, and they've moved towards a loss of load probability weighted peak approach.

So do you know of any other utilities using this loss of load probability weighted peak approach to their pricing?

A. Yes. I believe that it's in use for anybody who's in the business of recognizing wholesale pricing because -- because that coincident peak methodology comes from an era where utilities considered themselves to be islands.

So quite properly SRP is saying we're no longer an island. Our links with other jurisdictions are growing. What is the piece of proxy information that will best indicate the degree of cost exposure that we face? So the answer is, yes, there are other utilities who are using some form of market reflecting capacity. You know, capacity cost, LLP, loss of load hours, those things are appearing in cost studies now.

Q. Okay. And just like when I ask my children can you clean your room and they answer yes but don't clean it, I'm wondering if you could also give me the names of some of those utilities?

A. I haven't seen those in the recent cost of service studies that I've done. It's just -- I think it's my impression that I've heard about those. Let's sort of qualify that. I have heard about those in other cost of service studies that you've see in other jurisdictions.

Q. Okay. All right. Did you see -- did you work

on the -- did you study the LOP -- LOLP study?
A. I did not. They provided me with information, but I haven't audited the details of their LOLP calculations.
Q. Okay. All right. I'll skip some questions then.
A. I guess just to supplement that our firm has regularly looked at LOLP and conducted LOLP calculations, so they're not strange to us or new or innovative.
Q. Okay. But, yes, my questions are particular to this process here, so --
A. Sure.
Q. So the current peak pricing hours go to 8 p.m. -- well, I'm going to stop that question. You can erase it, if you like, Jennifer.
All right. So my last question was about the renewable energy credit program. I just wondered if you had heard had any discussion with SRP about their plans to implement a renewable energy credit program?
A. Well, I've reviewed their documentation and discussed it with them, yes.
Q. Oh, okay. So any -- do you think it's appropriate and you think there's -- well, I'd love to hear your thoughts on it.
A. Well, I don't know. It's -- my report, and

especially when I got to the rider section, had something to do with -- had something to say with that with respect to that and how they were using it in the future. I didn't spend a lot of time setting out the details.

But the basic idea is that given the changes in the way renewables are priced these days that I thought that they were sensibly responding with their new renewable energy credit design.

Q. Okay. All right. Well, I just did a Google search for anything related to loss of load probability. There's quite a bit about that, but peak -- I throw in the word peak in there, and I got zero results. Well, I got one result. It was SRP. So I'd just like to state that.

A. My impression in using the web to find cost of service information is that it's always at one removed or very often one removed. You have to go and find somebody else's cost of service study, look at the tables, and read things specifically because the background is usually at a very high level.

Q. Yeah. Well, I'm not looking for an explanation, just a hit, so thank you very much.

MS. JOHNSON: Could I ask a clarifying question on something, which is just --

MS. GLOVER: Sure.

INTERVIEW OF MR. CHAPMAN

BY MS. JOHNSON:

Q. When you were saying that you'd reviewed the REC program, are you talking about the REC program that the pricing proposal says would be forthcoming, or are you talking about the new export rates for solar under the new price plans?

A. Well, this is under the riders section of the report; correct? Was that where we were talking about?

MR. NEIL: There is something there; right? But there's a new something else coming out soon too that's been talked about during this pricing process. It says that management's going to propose it after the price.

MS. GLOVER: Sure. I would suggest we table those questions. And when we have the management panel ready to go, I think they can address those for you.

MR. NEIL: Thank you. Yeah, I can.

MS. JOHNSON: Can he just clarify which one he was talking about?

MS. GLOVER: Sure. Of course.

BY MS. JOHNSON:

Q. Which one were you talking about?

A. I forget the context exactly, but so can you repeat your question. I realize I'm not being helpful, but let's -- let's try to hone in on the question just to make sure.

Q. Well, I was just -- I was asking you about Steve's question.

You said that you'd reviewed the new REC program proposal, and are you talking about the proposal that is forthcoming after the pricing proceeding, or are you talking about changes within the pricing proceeding?

A. Well, what I'm talking about is what appeared as changes in the riders --

Q. Okay.

A. -- as part of a -- as part of the rate design. Okay? So --

MR. NEIL: And I may have thrown you off by using the wrong word. I think I used the word credit instead of certificate.

MR. CHAPMAN: Yeah.

MS. JOHNSON: Okay.

THE WITNESS: So, okay, maybe I don't need to say more, but I was trying to remember what it said in the rider area.

MS. JOHNSON: Could you give us a page number?

MR. CHAPMAN: I think I was thinking --

the -- the report talks about the Carbon Reduction rider and the Energy Attribute Certificate rider, and I believe you're talking about something else; right?

MS. JOHNSON: That's right.

MR. NEIL: Page 28, 29.

MR. CHAPMAN: And my reference to that particularly was on page 29.

So, anyway, I don't know if that answers your question, but anyway that's what I think I was talking about.

MS. GLOVER: Okay. Do you have any more follow-up on that?

MS. JOHNSON: I don't see anything on page 29 related to either of these things.

Are you talking about 29 of your report or your proposal?

MR. CHAPMAN: Of my report on page 29 I mentioned the Carbon Reduction rider and the Energy Attribute Certificate rider.

MS. JOHNSON: Okay.

MR. CHAPMAN: So -- and so, I guess, the question was is that what you had in mind or are you talking about something else?

So because I looked at those -- the documents pertaining to those riders.

MS. JOHNSON: Okay.
MS. GLOVER: Does that clarify it for you?
MS. JOHNSON: Clear as mud. I'm going to leave it there. I don't think we're going to -- I don't think it's going to get better, so I'm going to move on.
MS. GLOVER: Steve, did you have any more questions for Bruce?
MR. NEIL: No.
MS. GLOVER: Are there any other questions for Bruce?
Okay. Thank you very much, Bruce.
MR. CHAPMAN: All set? Thank you very much.
MS. GLOVER: Thank you so much for your time.
(Bruce Chapman left the meeting.)
MS. GLOVER: Okay. So it's a little early, but it seems like now is the time to break for lunch. I think we can have it brought into this room here shortly if that works for everyone.
I would suggest maybe we come back at 12:30. That's about an hour and 15.
Does that sound like a reasonable amount of time?
MS. HETH: Let's go off the record.

(Break from 11:17 a.m. to 12:07 p.m.)

MS. GLOVER: Welcome back from lunch. We're ready to start the afternoon portion of our sessions today, which will be questions of SRP staff. Based on the topics and questions that the interviewers provided in advance, we've gathered the people here that we think are best positioned to answer the questions.

Again, if we have questions that are related to the price process but might require input from others, we take note of those and bring other people in if need be.

A refresher of who's here: Brandon Shoemaker, John Tucker, Mark Carroll, and Karl Sandstrom.

And with introductions done we'll go, at least start in the same order, to David.

MR. BENDER: Thank you.

So I pose a question to the panel, and they answer?

MS. GLOVER: Yes.

PANEL INTERVIEW BY MR. BENDER

MR. BENDER: Okay. To kind of summarize, it's my understanding the price changes here for residential customers will be basically setting fixed charges or customer charges the same across all residential price plans.

MR. TUCKER: Yeah. And to clarify, they are the same already across -- in a sense they're the same across solar or nonsolar customers as to what we're doing. One of the things we're doing is kind of recombining those classes. So all solar nonsolar customers can participate in the same time of use rates.

MR. BENDER: For most, right?

So, like, for example, like, solar customers wouldn't have an option like E-23?

MR. TUCKER: Right. So -- exactly. So they can all participate in the same TOU rates, but, yeah, not a basic -- not the basic price plan.

MR. BENDER: And then they also -- solar customers won't have access to either E-21, E-22 and equivalent, which you're going to phase out, but for the next four years they'll still be --

MR. TUCKER: Well, sorry, so, yeah, those rates are proposed to be frozen, and no one can move on to any of those rates if the proposal's approved and effective November. And then the E-28 price plan is intended to be kind of the E-21, EZ-3-type successor, which, again, all customers can participate in.

MR. BENDER: Okay. And then so then you're closing to new customers and phasing out by November 2029

E-15 and E-27; is that right?

MR. TUCKER: Yes.

MR. BENDER: And there are -- there are also what we'd call legacy solar customers like pre-2014?

MR. TUCKER: Yeah, I'd say pre-2015.

MR. BENDER: Pre-2015. And they have, like, kind of classic net metering?

MR. TUCKER: They do.

MR. BENDER: Right. And they're grandfathered for 20 years?

MR. TUCKER: 20 years from the install date, if I'm not mistaken.

MR. BENDER: Okay. And then what happens to them if their plan is phased out in 2029?

Right, because they're on plans that are not solar-specific plans; right?

MR. TUCKER: Right.

MR. BENDER: Okay. So what happens to them?

How do they retain net metering for the full 20 years if all the price plans that they're on are grandfathered; right?

Because you're -- if I understand the proposal right, you're to transition people on those price plans onto something else?

MR. TUCKER: Yes.

MR. BENDER: Okay. And those something else don't have any net metering provisions explicit in there?

MR. TUCKER: Yes.

MR. BENDER: Right?

So are they -- are those kind of legacy pre-2015 solar customers still going to have net metering if they're kind of moved with the rest of the class?

MR. TUCKER: I think the intent with the grandfathering was to allow them to not require them to go on to these solar price plans that we were requiring strictly for solar customers.

So in my mind now that we've moved away from that or the proposal at least moves away from that world where all customers are on the same price plan, I don't think the intent was to necessarily allow them to stay on their given rate for that 20 years. I think it was more about the structure that was unique to solar customers.

MR. BENDER: Yeah. I think I'm asking something different. I don't think I'm asking it well.

The net metering -- the language in the tariff that allows them to net meter, the legacy customers, right, that's part of the tariff that's being sunset, and the tariff they're moving on to doesn't have anything equivalent; right?

So what's the tariff mechanism that allows them to still net meter once they're transitioned on to the new tariff?

MR. TUCKER: So as I -- as I think about the --

MR. SHOEMAKER: Well, I was just going to try and clarify with Karl that the E-23, right, that is -- I'm sorry. I was just talking about the E-23 confirming with Karl that E-23 does still have that net energy metering provision?

MR. SANDSTROM: Correct. E-23 will remain open, and those customers who are on the renewable net metering rider will take service under E-23 once the rates are fully phased out or frozen or sunset in 2029.

MR. SHOEMAKER: Thanks.

MR. BENDER: So let me make sure I understand that.

But the E-23 is remaining, so that's not an issue?

MR. SANDSTROM: Yeah.

MR. BENDER: All right. So this would be whatever the subset of customers are that are grandfathered net metering customers pre-2015 but are on, what, E-15 and whatever the -- whatever the --

MR. TUCKER: It could be E-21 would be an example.

MR. BENDER: E-21.

MR. TUCKER: As an example.

MR. BENDER: All right. So they'll be transitioned on to E-23?

MR. SANDSTROM: Yeah. So the grandfathering was the structure of the net metering, not necessarily the rates specific. And so they will still be able to take service under E-23 with their net metering rider remaining for them for that grandfathered period.

MR. BENDER: Okay. But is there a way for them to move -- if they're on a time of use now for them to remain on a time of use and net meter?

MR. TUCKER: No.

MR. BENDER: Okay. So they're going to have to move to a flat rate?

MR. TUCKER: Or they could elect the other -- the newer price plans as well. Yeah.

MR. BENDER: Okay.

MR. BUCKER: Thank you for clarifying.

MR. SHOEMAKER: Yeah. Yeah. Yeah, E-23 in the -- this is appendix A for the proposal. Under E-23 it does mention in the applicability section that it's available to those customers with on-site generation which originally installed the onsite generation at a residence on or before December 8, 2014.

MR. BENDER: So sticking with that subset, by our count is, what, 17,000 grandfathered legacy net metering customers, and those are mostly, I think, on E-23 and maybe some on the older time of use plans.

How are those customers treated in the cost of service analysis; right?

Because there's -- you have price plans specific to solar customers, and then there are also references like in Figure 5 in the proposed adjustments, you have on page 30, Figure 5 you have residential and residential solar.

So are those 17,000 customers included in residential solar or is when you refer to residential solar, is that just the solar-specific price plan subclass?

MR. TUCKER: The latter. So that would be just the solar specific.

MR. BENDER: Okay. So those 17,000ish are in -- basically in the residential category for these cost allocation purposes?

MR. TUCKER: Yes.

MR. BENDER: So when you are -- cost allocation at this point -- I guess we'd asked a question written and got a response yesterday or the day before. I think I have -- I think I understand better from that, but to follow up a little bit, do you have your responses to our questions in front of you?

MR. TUCKER: I don't.

MR. BENDER: Okay. That's fine. I'm going to tell you what you said, and you can explain if I have any questions.

So when you're doing -- I understand from the response that when you do your load study or you create the load profile that you use for the cost of service or cost allocation that you net -- or you basically customer exports are included in the load shape or the load data; right?

So a customer who's exporting gets for most cost allocations basically credit or that the load reductions recognize that they're exporting. Okay?

Is that done on a customer basis or on a class basis?

MR. TUCKER: I'd say class. I'll let Mark explain it a little better.

MR. CARROLL: It would be a class basis or more specifically a class or a subclass so for E-13, E-14, E-27, E-13.

MR. BENDER: Okay. So if he and I are both in E-13 with solar and he's importing 3 and I'm exporting 2, in that hour, the class would be -- the class load would show up as 1.

Is that how that works out?

MR. CARROLL: Subject to check, and it might depend on which factor -- which function you're looking at because the channels are read separately. And so if we're using a delivered channel or an export channel or net, then the net would be the difference between them. So for the factors they used the net, it's the combined.

MR. BENDER: So it would be 1 for -- in that scenario?

MR. CARROLL: If we're talking about a function using a net allocator.

MR. BENDER: Okay. Which allocator used both channels and which one used only one channel?

MR. CARROLL: Nothing uses just the export channel. So the generation -- the peak allocators use the net -- the net channel where the energy delivered uses the delivered.

MR. BENDER: Okay. So is energy the only allocator that does not use the net of inflows, outflows for solar customers?

MR. CARROLL: Sorry. Say that --

MR. BENDER: I'm just trying to categorize them. Is energy the only allocator that does not use net of imports and exports to calculate that allocator load?

MR. CARROLL: We could walk through the functions, but for the big ones the generation -- the peak allocator uses a net peak. The transmission uses a net peak. And then for the fuel we're using net either energy or peak.

MR. BENDER: I think we're saying the same thing. So the energy is the only one that's not using the net?

MR. CARROLL: Well, what do you mean by "energy"?

MR. BENDER: All right. So if we go to I think it's in your cost allocation study, so schedule 5 of the allocator factor descriptions.

MR. CARROLL: Yes.

MR. BENDER: Okay. So --

MS. HETH: I'm sorry, what page?

MR. BENDER: It would be 37 in the cost allocation study.

MS. HETH: Thank you.

MR. BENDER: So schedule 5, the allocator factors, row 1 is the 4CP, which is used for transmission allocation; right?

MR. CARROLL: With adjustments is used.

MR. BENDER: Okay. And that uses the net of the inflow and outflow channel for the net metering customers subclass?

MR. CARROLL: It's the most clear if you look on schedule 6.

So schedule 5 calculates all the allocators, and then schedule 6 says each of the functions that we use. It's on page 58.

MR. BENDER: Thank you. I was just trying to find a reference. I think we're talking the same point.

MR. CARROLL: So line number 7 is transmission.

MR. BENDER: Yes.

MR. CARROLL: He's saying it's using the 4CP with adjustments. And the adjustments are for the classes that don't take service at the same voltage level.

MR. BENDER: Okay. But that 4CP allocator used for transmission is the net of inflow and outflow channels for solar customers?

MR. CARROLL: Yes. During the peaks.

MR. BENDER: During those four hours?

MR. CARROLL: Yeah.

MR. BENDER: And then, let's see, ancillary services 1 and 2, same, right, 4CP? That would be the net of two channels.

MR. CARROLL: Correct.

MR. BENDER: And then ancillary services 3 to 6 is the delivered energy at the meter?

MR. CARROLL: Yes.

MR. BENDER: So that one is only using the inflow channel data for solar customers as an allocator.

MR. CARROLL: It's reduced by -- it's allocated based on what SRP delivers to those customers.

MR. BENDER: Which is the same thing as the inflow channel on the metering data.

MR. CARROLL: I -- I want to make sure -- yeah, I believe so, but I just -- subject to jargon differences.

MR. BENDER: Okay. So if customers are -- if solar customers are exporting during the 4CP hours, four different 4CP hours, those exports are not reducing their allocated costs for ancillary services 3 to 6?

MR. CARROLL: Ancillary services 3 to 6 isn't allocated on 4CP at all. It's on the total delivered.

MR. BENDER: All right. Sorry. So if solar customers are exporting, those exports are not reducing the allocated costs to those solar classes for ancillary services?

MR. CARROLL: For 1 through 2 -- 1 and 2 they are. For 3 and 6 they're not.

MR. BENDER: And then for generation, generation's allocated two different ways, if I understand correctly; right?

There's an average and peak allocator; right? So you have a peak allocation on loss of load probability-based allocation.

I mean, do you -- Steve's going to ask a bunch of questions on this I have a feeling, but let me ask a few preliminary so I understand.

Do you do an LOLP value for all hours of the year, 8,760 hours?

MR. CARROLL: The production modeling team takes the loss of load study --

(Reporter clarification.)

MR. CARROLL: Sorry. Thanks for letting me know.

It's our department that does the recent modeling in the loss of load probability study model, and they do an annual load profile iterated tens of thousands of times just for the study. And so all hours are considered in a Monte Carlo simulation many, many times. And then they summarize it for us.

I believe you asked that question for, like, 576 hours. I wouldn't otherwise know that other than I just heard it from you because there's 12 months, 24 hours in each month, and then we're looking at weekday and weekend, so it's summarizing that at that level.

MR. BENDER: Okay. That's helpful.

So for those loads, right, and then those LOLP values are applied to loads to weight them?

MR. CARROLL: To the net load in each of those hours.

MR. BENDER: So it's net?

MR. CARROLL: Yes.

MR. BENDER: So it's inflow and outflow channels netted against each other and then applied to the LOLP?

MR. CARROLL: Correct.

MR. BENDER: Okay. And then the average piece of the generation allocation is -- that's an energy allocator; correct?

MR. CARROLL: Correct.

MR. BENDER: And that's the energy allocator you were referring to before that only uses delivered?

MR. CARROLL: The intent of the peak and average is to both reflect the cost relation piece of the generation side and also the equity. So with the peak it's more focused on the cost relation side. Whereas the average is more reflected in equity of which customers are using SRP's generation fleet. And so we -- delivered more closely aligns with that to reflect how much people are using as base fleet for their -- in its usage.

MR. BENDER: You're one question ahead of me. I was just trying to make sure that I was correctly understanding how, and you explained why.

MR. CARROLL: Okay.

MR. BENDER: Okay. So let's back up. That average energy allocator for allocating generation is based only on delivered load to solar customers; correct?

MR. CARROLL: If it's delivered load, yeah.

MR. BENDER: So as solar customers are exporting electricity to the grid, they are -- their cost allocation for the average piece of generation is not reduced by those exports?

MR. CARROLL: That's correct.

MR. BENDER: Okay. And then you explained why.

Tell me why it is equitable to use only

delivered load for solar customers who are exporting and serving other load at the same time on the distribution.

MR. CARROLL: Sure. The generation function is meant to capture the capacity value, and SRP still needs to invest significant resources for capacity for solar customers.

Kind of an analogy might be if a solar customer if instead of using SRP's grid if SRP were -- provided battery services for a customer to supply their energy capacity needs, it wouldn't make sense to allocate the cost of the battery based off of a net inflows and outflows of the battery because we still have fixed costs associated with the battery that need to be collected to equitably recover costs.

Likewise, SRP's grid can be thought of as a big virtual battery, and so how much they're using that is better reflected by the delivered energy.

MR. BENDER: I get the argument. I don't necessarily agree. I get the argument if we're talking about capacity, but the -- my understanding the point of using a peak and average rather than 1CP or 4CP allocator for generation is to recognize that generation is serving not just the capacity but it's also providing kind of a baseline energy as well. That's two values coming out of the same investment; right?

And so we're talking about the energy piece part of the split allocator; right?

MR. CARROLL: But the part that's pure energy is captured in our FPPAM or fuel and power adjustment mechanism, and those are allocated -- the energy-related portion there is allocated with net.

MR. BENDER: Okay. I understand the argument.

So let's go back.

So those FPM -- FPPAM?

MR. CARROLL: FPPAM.

MR. BENDER: FPPAM. Those are essentially fuel rider components; right? Those -- those can fluctuate between price processes and are based on price-variable fuel costs primarily?

MR. CARROLL: And purchased power agreements.

MR. BENDER: And purchased power agreements.

And those are allocated on, in this price process, is a change on some demand and some energy?

MR. CARROLL: The fuel costs are all in the energy. Some of the purchased power costs are demand related and some of them are fuel related, so it's split.

MR. BENDER: That's what we see on lines 11

and 12 is the distinction?
MR. CARROLL: Correct. On page 58, but you can see what goes into that back on schedule 1.
MR. BENDER: Okay. And those are allocated on LOLP net peak on demand, so that -- that is net flow for solar customers?
MR. CARROLL: Correct.
MR. BENDER: Okay. And then the energy piece is allocated on what basis?
MR. CARROLL: The net energy weighted by the marginal hourly energy costs.
MR. BENDER: Okay. So it's net --
MR. CARROLL: It's net.
MR. BENDER: -- both channels for the solar customers?
What do you mean by weighted marginal energy?
MR. CARROLL: The one thing that's different in this price process than in the past is the way the energy markets have changed. The duck curve has gone significantly steeper, and so there's a significantly more intraday variability in their energy costs.
And so to reflect that more accurately in the cost study, on the cost side we are allocating the

costs weighted by the intraday price differences as reflected in the marginal cost.

On the revenue side, we're not making that change for gradualism purposes.

MR. BENDER: Okay. So you're using -- you're using market energy price differentials by the same 576 hours, or how do you do that calculation?

MR. CARROLL: It's not exactly energy prices. It's SRP's costs, which are obviously heavily influenced by the market prices, but we try to consider holistically what our energy costs are and marginal costs are and then suggested by those same hours summarized by the same by month, by hours.

MR. BENDER: So when you say it's holistic, what are the costs that go into that calculation?

You said market prices is one. And then SRP's own costs you mentioned.

What's included in that?

MR. CARROLL: The way -- so I guess -- sorry, you're asking how the marginal cost study is determining the energy prices or how this cost allocation study's allocating them?

MR. BENDER: What's the relationship between those two?

MR. CARROLL: The cost allocation study

uses those hourly energy prices from the marginal cost study. So in the marginal cost study, they're determined by our, again, our resource team. Our production modelers have a use-forward market prices from SRP quotes that we have as well as some, I believe, the purchase forecast for a gas cost, different fuel costs going forward. And then they compile those down into a forward -- forward price expectations and pricing using the same numbers that the production modelers are using and then weights the -- weights it to have an hourly price based on the three-year average cost of CAISO prices.

MR. BENDER: Let me make sure I'm tracking that.

So your -- your marginal pricing used in the cost of service study, so in the appendix B the marginal cost of service study is using a production cost model output as the marginal price.

MR. CARROLL: I think it's -- I'm not sure if it's an output or an input for the modeling. I don't think it's an output, but I need to check. I think it's an input, though.

MR. BENDER: Backing up it's not just CAISO LMPs. It's something that includes SRP's generation and/or bilateral purchase power?

MR. CARROLL: Yeah, I think we -- yeah, we -- we consider those things when making that price forecast, and I think it's heavily influenced by the buy -- or the market trades -- forward market trades that SRP are to make, but --

MR. BENDER: I'm not sure I'm completely tracking, but I think we'll get to it.

So in the information provided by SRP in response to questions I posed, we got some spreadsheets. I assume you don't have those in front of you. One is called energy and demand prices FY '24 EJ 01, which it looks like a heat map by hour of the day and month for hourly energy prices.

Is that something -- do you know what I'm talking about?

MR. CARROLL: I think so, but --

MR. BENDER: Okay. I can show you my screen.

MR. CARROLL: Okay.

MR. BENDER: Is this the marginal energy pricing?

MR. CARROLL: I believe so, but you may want to double-check.

MR. BENDER: Okay. Fair enough.

So let me ask it this way by way of

comparison.

So the new price plan options that will be available to solar customers have an export credit value that was 3 cents -- a little bit just above 3 cents in early December was revised late December to be 3.4 cents a kilowatt-hour roughly.

And my understanding is that is calculated from CAISO LMP, whatever the node is that SRP transacts at; is that right?

MR. TUCKER: Yeah, it's close. So the ELAP is the representation of, I think, all the nodes that we transact at.

MR. BENDER: Okay. So thank you for that clarification.

And that's -- so 3.4, I mean, I guess with that number we can get --

MR. TUCKER: 3.45.

MR. BENDER: 3.45. That is calculated as, what, an average of what, 8,760 hours?

MR. TUCKER: I don't know the specifics on the calculation.

MR. SANDSTROM: So for that number, it's weighted by the actual export of customers by the price in the 8,760.

MR. BENDER: So you're using an export load curve basically?

MR. SANDSTROM: Correct.

MR. BENDER: Generation is a load generation profile, I guess.

And you're applying that to the 8,760 LMPs?

MR. SANDSTROM: Yes. So the previous three calendar years for that ELAP node.

MR. BENDER: That may explain -- so if I look at your cost of service study appendix B, we have marginal energy prices by price plan and time period. So I'm looking at page 82, for example. We can look at one that's more granular. If we look at, yeah, I guess, 82 to 83, the ones that have a time-of-use period, we have marginal energy cost prices. See that? So it would be lines 7 through 9 or 16 through 18 on 82.

MR. CARROLL: Yes.

MR. BENDER: Okay. And those are all above -- with one exception -- winter off-peak is the only exception from 4. -- 3.45 -- I guess they're all above 3.45; right?

So I'm trying to understand how those two relate to each other. My understanding is they're supposed to reflect the same thing, the marginal cost of energy.

MR. CARROLL: It's not quite right because the footnote 2, little 2 by it, the marginal cost numbers here reflect the value of one kW in each hour cost period. Whereas in the export rate is weighted by the actual exports so it's not one kW of export in each hour of the costing period.

MR. BENDER: Okay. I saw that footnote 2. It didn't make sense.

But so you're saying these aren't weighted. In the marginal cost of service study these are not weighted by load?

MR. CARROLL: Correct.

MR. BENDER: These are just a simple average of each hourly LMP during that time period reflected?

MR. CARROLL: Not necessarily LMP. The market energy numbers.

MR. BENDER: Okay. Two different things?

MR. CARROLL: Yeah.

MR. BENDER: So let's take them in order.

So it's a simple average of each hour equally weighted during that period of the marginal prices?

MR. CARROLL: Correct.

MR. BENDER: Okay. Separately you clarified that it's not just LMP, it's marginal energy cost; right?

MR. CARROLL: Correct.

MR. BENDER: Okay. What's the distinction between LMP and marginal energy costs?

MR. CARROLL: Okay. I think when we're using LMP, we're using it as shorthand for the CAISO ELAP, and I forgot the -- I looked it up once, the ELAP --

MR. SHOEMAKER: External Load Aggregation Point.

MR. BENDER: When I say LMP, that's what I'm referring to.

MR. CARROLL: That's what is used in the -- this price process is export rate calculation. That's not the same as the marginal cost of energy. The marginal cost of energy is what I described earlier the number we use from the resource modelers. It's based off of a combination of the forward energy -- forward fuel prices that we purchase and then with the trades that SRP can make for trades we make. They have a daily price that gets shaped by the CAISO prices, but it's not based off CAISO prices. They're shaped by CAISO prices.

MR. BENDER: So CAISO prices are an input to the projection?

MR. CARROLL: Yes. So instead of using --

if the projection is a daily price, we need to have hourly prices for marginal cost of services, and so the CAISO helps us convert from that daily price to an hourly price.

MR. BENDER: Does SRP incur variable costs of production, fuel, and variable O&M and other variable production costs that exceed the CAISO price for any particular hour?

MR. CARROLL: I don't know.

MR. TUCKER: I don't know either.

MR. BENDER: Okay. If the marginal cost based on your projection of your own fuel costs and other things is coming in higher than the LMPs, the CAISO market prices then does that necessarily have to mean that you're incurring some costs for your own inputs to generation that are higher than LMP?

MR. CARROLL: I think generally if we can buy from the market at a lower cost than we can use our own resources, we're not going to use our resources, we're going to buy from the market, but I don't know --

MR. TUCKER: So that would be our marginal cost is what you're saying; right?

MR. CARROLL: That would be our marginal cost is what we're saying.

MR. BENDER: Do you know that is the case?

MR. CARROLL: I know it's the case generally. I don't know it's the case in every single hour.

MR. BENDER: So if that's the case generally, then your -- your variable costs of production should nearly always be below the CAISO market price; right? That's the way the math would work.

MR. CARROLL: Not necessarily the marginal resource because the marginal resource could be consistent with the CAISO prices.

MR. BENDER: Well, it could be equal to the CAISO prices. Your own marginal generation resource should not be above -- the variable cost of net generation should not be above the CAISO market price?

MR. TUCKER: Like, if we're running it, is that what you're saying?

MR. BENDER: Yeah.

MR. TUCKER: Yeah. Generally speaking, yes, that's the idea.

MR. BENDER: But we don't know what -- it's not where can I find the data, the hourly marginal cost data, that was used to create these values on page 82 of appendix B of the cost allocation study.

MR. CARROLL: I believe they were in the spreadsheet you sent with -- subject to checking that was the same file.

MR. BENDER: So maybe that's the wrong one. Those are -- I'll assume that these are the numbers. Where can I find the inputs to these cells?

Because if I look -- the cells are at some point in the spreadsheet they're imported whole; right? So it's just a pasted value.

Where can I find the source data that was used as the hourly marginal price in there?

And I understood from your comments before somewhere in planning or somewhere else, right, someone's running either a model or a spreadsheet analysis that's generating those?

MR. CARROLL: Someone in pricing, yes.

MR. BENDER: Who?

MR. CARROLL: We can -- I don't recall off the top of my head, so we can --

MR. TUCKER: Would that be something there that we can --

MS. GLOVER: Something that we can -- we can --

MR. BENDER: Yeah.

MR. TUCKER: -- you could submit as a request?

MR. BENDER: I just want to make sure I'm asking for the right thing.

We're looking for the information on marginal energy costs provided to the pricing department.

MR. CARROLL: Okay.

MR. BENDER: All right. And that's coming from somewhere; right?

So if I ask for that, you'll know --

MR. CARROLL: I think so.

MR. BENDER: -- what I'm asking for? Okay. Understood.

So in your response, I think you did it the 14th, to question I submitted number 9, which was asking for how you use net or didn't use net for solar customers for cost allocation, you provided a breakdown by kind of category, and some we already covered. There are a couple of responses that I was unclear about.

So in the response -- so the cost allocated to solar class fully account for exported energy where applicable. All right. So the "where applicable" is obviously unclear. And then you go in and describe elsewhere, and I think we just went through today.

So is that in reference to applying the crediting, the export where applicable, does that mean those categories 4CP, LOLP, we haven't talked about NCP yet, but just not the average part of the peak and average allocator for the generation, is that the only place where it's not applicable?

MR. CARROLL: Well, I want to go through them in order and double-check again that broad of a question. But off the top of my head the -- we already discussed ancillary services 3 through 6, which is also delivered --

MR. BENDER: Okay.

MR. CARROLL: -- and then some of the distribution as well.

MR. BENDER: Yeah, let's talk about those then to make sure we complete that category.

So the distribution is allocated two different ways. There's a facilities and then a demand; is that right?

MR. CARROLL: Correct.

MR. BENDER: Okay. The facilities is allocated -- first, what's included in facilities?

MR. CARROLL: So conceptually the idea is that the stuff is very close to the home, that's dedicated to the home is what's included in facilities. This is typically equipment that is installed often before the home is built when the developer comes and says we're building a subdivision, we put in electricity for these people, we build out that part of the distribution system.

MR. BENDER: So line extension for service connection?

MR. CARROLL: Service connection, the local transformer, the secondary equipment.

MR. BENDER: So 100 percent of transformer, 100 percent of secondary distribution is included in the facility category?

MR. CARROLL: I -- should we go back to the definition to see?

MR. BENDER: Sure. This is schedule 6?

MR. CARROLL: Sorry. The definition is all the way at the beginning. Page 5. So we provided this description for our distribution planning group and asked them to categorize their equipment as either facilities or delivery and then -- this is the description on the top of page 5.

MR. BENDER: So my question is is it 100 percent of each of these?

MR. CARROLL: I'd need to get back to you after discussion with -- though I believe so. This is what we asked them to include in the definition of facility.

MR. BENDER: So to back up, some utilities would allocate on, like, a minimum system or a zero intercept; right?

MR. CARROLL: Yeah.

MR. BENDER: And so you would have some of -- some would be -- some of each of these might be allocated on, like, a customer or some individual max demand-type allocator, and some portion of those same components would be allocated, like, on a demand or load basis? So I'm just trying to clarify it.

I understand at least some, right, of these -- this category and facilities is allocated -- we haven't talked about the allocator yet, but it's a sigma NCP allocator basis, and then distribution is on an NCP basis. And I'm just wondering if there's any components that some of the costs of which are allocated one way and some of the costs are allocated another way.

MR. CARROLL: The intent is for all the equipment that's included in the facilities bucket here, the new business or the distribution business group, cleared all of their jobs for us the last several years and categorized the expenses as meeting this definition of facilities or this definition of delivery.

And then all of those distribution facilities or that percentage was applied to our total distribution dollars. And all of those costs were allocated sigma NCP for the distribution facilities and the NCP way for the distribution delivery with a small exception of there's a few million dollars in distribution-related costs that are directly allocated, but --

MR. BENDER: All right. Okay. Let's talk about those allocators. So the sigma NCP is the sum of every customer's max demand for that regardless of coincidence between customers; correct?

MR. CARROLL: Correct. Other than not wanting to combine residential and nonresidential solar major class and then tier it by multifamily, or the tier 2 up to 225 amps and above 225 amps.

MR. BENDER: So each individual customer you found that customer's max demand during the test year?

MR. CARROLL: Correct. For every customer that was included in a multifamily tier that -- the tier 2 up to 225 amps, what was their average sigma NCP for each of those tiers.

MR. BENDER: Right. So some people call that a sum of individual max demand; right?

MR. CARROLL: It does seem to have different names depending on who's talking.

MR. BENDER: Well, that's the same --

MR. CARROLL: Sum NCP, I believe, are the same concept.

MR. BENDER: Okay. Got it.

For that are you using the net? Are you using just the delivered load channel to find solar customers' individual max demand or are you using their net?

MR. CARROLL: It wouldn't materially -- the -- the way this was done is because this equipment is built often even before the house is there and it doesn't -- so that equipment doesn't change based off of solar or not solar. And so it was done collectively between the solar and the non -- every residential and residential solar account, what was their average sigma NCP for tier 1, tier 2, tier 3, and then that was applied to all the price plans the same. There's no additional or subtraction across the residential and residential solar price plans.

MR. BENDER: Yeah, I don't know if that's responsive.

MR. CARROLL: Those costs don't change with usage --

MR. BENDER: Yeah.

MR. CARROLL: Or by switching price plans.

MR. BENDER: I understand that's a policy argument for why it doesn't matter or why you could use delivered, but the question's just like when you did the calculation here, did you use delivered or did you use net because it -- for each customer's individual NCP or max demand?

MR. SANDSTROM: I would have to check.

MS. GLOVER: Is that something we could check on and find today?

MR. CARROLL: I'd want to double-check that one.

MS. GLOVER: Maybe when we take a break, or do you need a -- is that a more substantial question you need to follow up on?

MR. TUCKER: We'll look into that, yeah, if we can answer it today.

MR. BENDER: Sure. Appreciate that.

So it's going to be the same question for the distribution delivery allocated on a NCP.

So NCP gives -- different people have different meanings, but my understanding is it's the classes coincident to the class peak.

MR. CARROLL: In this case we did a combined residential and residential solar class, and we did measure it off of delivered. Anticipating this question we checked, and it's -- there's no difference between the delivered and the net between the solar customers. There's no material difference between them.

MR. BENDER: So let's take that in steps. So you did a combined, meaning it's the same date and hour load used for every residential subclass?

MR. CARROLL: And residential solar, yeah.

MR. BENDER: And residential solar. I think I found it in here. It's like a July date of, like, hour ending 1800, so like 5 to 6 p.m.

MR. CARROLL: If you found it --

MR. BENDER: Okay.

MR. CARROLL: -- that was probably -- it's in there still.

MR. BENDER: Okay. And then you're saying you only used delivered but you looked and the delivered and the net is the same for that hour?

MR. CARROLL: I believe so. I think the delivery is the appropriate thing to use, again, because this is equipment that is necessary regardless of whether you had solar that was net in that hour.

MR. BENDER: I get the point. I'm asking for now just a math question how it was done and if those numbers are the same.

MR. CARROLL: It's delivered, and I believe they're the same.

MR. BENDER: I think I have one more

question or set of questions. Close to my hour.

MS. GLOVER: Good job.

MR. BENDER: So in the I think the cost of service study or the cost allocation study on page 29 schedule 3 it says -- so the -- are we calling it FPPAM -- the FPPAM includes export credits for E-13 and E-14 price plans? Last line there.

MR. CARROLL: Correct, yeah.

MR. BENDER: What does that mean?

MR. CARROLL: As you know, there's an export credit on those price plans. That would reduce the amount of revenue that they're giving SRP as a credit. And so that was included in the FPPAM function. And so it had a certain amount of revenue that we charged then for FPPAM.

And then that was reduced by their -- their credit. So the number you're seeing here is the -- like, if they had $10 on the FPPAM charge and $5 on an export credit, we're just showing that the net is actually 5.

MR. BENDER: So this is -- the schedule 3 is the revenues?

MR. CARROLL: Yes.

MR. BENDER: You have projected revenues --

MR. CARROLL: Correct.

MR. BENDER: -- for rate-effective year?

MR. CARROLL: And so we also project a credit we're paying for the export.

MR. BENDER: Okay. And then you're reflecting those credits as reductions in the FPPAM revenues?

MR. CARROLL: Yeah.

MR. BENDER: And it doesn't show up in reduction of revenues anywhere else?

MR. CARROLL: I believe it's on the revenue side. It's just in the FPPAM energy.

MR. BENDER: Okay. So then if we look back at Figure 5 in the proposed adjustments on page 30, you show the return with current and proposed prices. And then the residential solar bars in here, that would be -- the revenue value you're using to calculate this is after reducing revenues by the export credits?

MR. CARROLL: Both the revenue side -- so the revenue is reduced by export credits, and the cost is reduced by the cost of the export.

MR. BENDER: For those where you included the export in the load allocation, load used for allocation; right?

MR. CARROLL: Correct. The cost is reduced because of the export.

MR. BENDER: One question, I guess, to

follow up because it seemed different in Christensen's report versus what the spreadsheet seemed to say.

So in metering charges -- so solar customers have two meters generally; right? One's a production meter. We talked about it six years ago.

You -- just you smoothed -- so you basically spread the cost of the second meter across all residential customers this time instead of allocating it just to solar customers; correct?

MR. CARROLL: Correct.

MR. BENDER: But in the cost study you have figures with smoothing and without smoothing, right, where those are either assigned without smoothing it would be all production assigned to solar customers only and with smoothing is spread across all?

MR. CARROLL: I believe on the metering we always use it with smoothing. Every figure should be using with smoothing.

MR. BENDER: Okay. So this figure on page 30, that's with the meter smoothing?

MR. CARROLL: Yeah, it's not allocated just to the residential solar customers. It's spread out between both classes.

MR. BENDER: Okay. But you did not spread customer service costs the same way; right?

MR. CARROLL: Not on the cost side, but, yes, on the revenue side.

MR. BENDER: What do you mean?

MR. CARROLL: So with the costs there's it's not -- it's just one category of cost. But that one category of cost is a little bit higher for solar customers, and on the -- for the -- on like in schedule 6 when we're seeing what did the -- the total operating expenses for the solar customers, we're not smoothing those customer service costs between solar customers and residential customers. We are smoothing the metered costs on that schedule.

MR. BENDER: Okay. You're not -- I'm not sure what you mean not on the revenue side.

MR. CARROLL: So on the revenue side, we're not charging solar customers additional application fees or any connection fees or additional charges in their monthly service charge. They are charged the same as every other residential customer.

MR. BENDER: Okay. But it will show up in this return on, because if they're not paying the extra revenues --

MR. CARROLL: Correct.

MR. BENDER: -- but they are allocated them in the cost allocation so that's going to show up as an under -- it's going to reduce the amount of costs that they're covering with revenue?

MR. CARROLL: Correct.

MR. BENDER: I think that's it. Thank you.

MS. GLOVER: Thank you.

MR. BENDER: Five minutes over.

MS. GLOVER: Perfect. Thank you very much.

Should we take maybe a five-minute --

MS. POTTER: I have -- well, I probably need about 45 minutes for my questions. So I don't know if -- Steve or Autumn, if you want to go next, and I can just be the last one on the list.

MS. GLOVER: Why don't we go to Autumn next. And then if she's about wrapped up by the time you're done with your other meeting, we can go to you, and if not, then we'll go on to Steve.

Does that work.

MS. POTTER: Absolutely.

MS. GLOVER: Okay. Take a five-minute stretch.

(Recess from 1:05 p.m. to 1:16 p.m.)

MS. GLOVER: Let's reconvene here for questions of SRP's panel. With the permission of the interviewees we've switched the order a little bit, so we'll start off now this time with Autumn.

MS. JOHNSON: Okay. Awesome.

PANEL INTERVIEW BY MS. JOHNSON

MS. JOHNSON: I guess for purposes of the record, Autumn Johnson for AriSEIA.

I have some just broad process questions that are just for anyone or just SRP broadly. And then after that, I have them by subject, and I'm going to be focusing on the proposal documents specifically.

So as far as process goes, can SRP provide to the interviewers or to the public broadly an access to a data room that has the other organization's data requests, the responses, and the work papers?

MR. TUCKER: I think all of that is printed out downstairs in the information room.

MS. JOHNSON: I mean, digitally available. I don't know if printed-out spreadsheets are that helpful, but that's what the other utilities all do that.

MS. GLOVER: We do not make all of the spreadsheets available electronically, but if there's one that you're particularly interested in having in an electronic form, you can submit that request.

MS. JOHNSON: Okay. But how do we know what has been provided in response to the other data requests if you don't make those available?

MS. HETH: They're listed in the written responses. The written responses will identify all the documents that have been made available, and you can request them.

MS. JOHNSON: You're talking about on the website where you just say, like, these comments were sent this week, and here's the responses or where on the website?

MS. HETH: Where there's a written request for documents then the response would say here's the list of documents that we're providing, so there would be a list there of the documents that we made available to that requester, and if you'd like them, you can request them. They can be e-mailed to you as well.

MS. JOHNSON: Okay. So you're saying, no, you will not make a data room available, but we can do a data request for the data requests of others?

MS. HETH: The data room is available, and we do make all of the documents available in the info room on paper. For electronic requests we ask that you submit on a document requesting a document or a list of documents, and we'll respond to the requester.

MS. JOHNSON: Okay. So when I say data room, I'm talking about a SharePoint site. I don't think anybody wants to drive to Tempe to look at physical --

like, we don't have an expert that's just, like, you know, residing next door to come pop over here.

So is there a reason why you don't want to do a SharePoint like all the other utilities?

MS. GLOVER: I'm not sure that we can answer that, but this is the process that we have in place.

MS. JOHNSON: Okay. And so, again, if we want to get the data requests of everyone else and all their responses, we have to submit a separate data request?

MS. GLOVER: If there is a particular response that we provided or a spreadsheet or a dataset that we provided to someone else and you would like a copy, submit a request for that, and we will respond.

MS. JOHNSON: Okay. And what's the turnaround time for data requests? Because I'm a little concerned that we only have months to do this whole process, and data requests are taking more than a month to respond to.

MS. GLOVER: Sure. Well, I think it depends on the nature of the request and the extent of them and how many people require to provide input on those requests. So if there's something that can very easily be answered by, for example, this pricing team, those can generally be turned out a little bit more quickly than something where we have to perhaps gather input from other organizations within SRP.

MS. JOHNSON: And so when you say a little more quickly, like, what are we talking about?

MS. GLOVER: Again, it depends on what you're looking for and how extensive the request is. And we have made some effort if it appears that we can answer some questions maybe a little bit more quickly than others to do some partial responses.

And so that can be something that you might -- if you anticipate that some questions might be a little quicker, you can also maybe specify in your data request that you can -- you know, that you prefer a partial response, and we can try to work with that.

MS. JOHNSON: Okay. Well, that's pretty typical.

MS. HETH: If it's a big dataset that we've already produced to another requester, that should not take much time at all.

MS. JOHNSON: Okay. And then can you explain why the pricing proposal process is only two months long and is scheduled over major holidays?

MS. GLOVER: Well, I can tell you that the process is statutory. So we -- we comport with the law in conducting a price process, so there are very particular time lines with respect to once the public notice is issued when we have to hold the initial board meeting and how much time we have to provide people to look at those materials.

And we actually go on the later end of that, so the statute allows the initial board meeting to happen between 30 and 60 days of the public notice, and we actually make every effort to be right on the 60th day or very, very close to it. So I think in this case we are right maybe on the 59th or 60th day I think this time.

MS. JOHNSON: What's the statute you're talking about?

MS. GLOVER: 48-2334.

MS. JOHNSON: 48-2334.

But you're saying that is for the initial board meeting?

Are you saying that the statute restricts when the final vote is?

MS. GLOVER: No.

MS. JOHNSON: Okay.

MS. GLOVER: No, it does not.

MS. JOHNSON: So you could do it over six months, you don't have to do -- from start to finish in two months?

MS. GLOVER: There's -- there's no -- there's no deadline --

MS. JOHNSON: Okay.

MS. GLOVER: -- for when the board is to make its final decision.

MS. JOHNSON: And why does it happen over the holidays when the -- when the rates won't even take effect until 11 months from now?

MS. GLOVER: Well, I'm going to --

MR. TUCKER: Yeah. So I can -- I can tackle that.

Part of it is we're trying to provide a lot of time for customers to understand the proposal and to communicate. As we've discussed, there's a lot of TOU changes as an example. But there's a number of things we're trying to do in the pricing proposal.

So we are providing -- I think the longer period of time I would think is generally a good thing for customers to have -- for us to be able to better communicate what all the price changes entail.

MS. JOHNSON: But two months is not a long time.

MR. TUCKER: Well, the -- I think she addressed two-month amount.

MS. JOHNSON: For the initial meeting, not for the final vote. I thought she said that there was no deadline for the final vote.

MR. TUCKER: Well, the final vote is up to the board's discretion.

MS. JOHNSON: Okay. But it's scheduled for February 27 I thought.

MR. TUCKER: Kind of I think we marked it as tentatively or something to the effect. The board will vote on it when they choose to vote on it.

MS. JOHNSON: Okay. So you're saying there isn't a reason why you have to file it or make it publicly available in December and have a final vote on it in February? That's just at your discretion?

MR. TUCKER: It's up to --

MS. GLOVER: The final vote is in the discretion of the board.

MS. JOHNSON: Okay.

MS. GLOVER: So we worked out a schedule I presume that's reflective of past practices --

MR. TUCKER: Sure.

MS. GLOVER: -- history and --

MR. TUCKER: Yeah, the schedule is very consistent with past practices.

MR. SHOEMAKER: I think to the point of --

of so much time between a tentative decision time line and those rates being implemented that's what John was talking about as far as giving customers as much time as possible from once a decision is made to understand their choices and then be able to make those decisions prior to them being implemented.

MS. JOHNSON: Okay. So that's different than what I thought he was saying.

You're saying that you want to have a lag time in between the decision to change the plans and when they're implemented so that people can decide what plan. And I thought you were saying that the price process is two months because that was a long time for people to weigh in on how the pricing should be changed.

MR. TUCKER: Oh, sorry. Brandon said it better.

MS. JOHNSON: Okay.

MR. TUCKER: That is what I meant. Thank you.

MS. JOHNSON: Because I was like that does not seem like a long time to me, but, I mean, maybe two years at the ACC might be a little too long, two months feels a little too short to me.

How come organizations can't appear remotely to question the witnesses?

MR. TUCKER: As I understand it -- sorry, which witnesses?

MS. JOHNSON: You all.

MR. TUCKER: In here?

MS. JOHNSON: Yeah.

MS. HETH: These are not witnesses. They're interviewees.

MS. JOHNSON: Well, we can call them, sure, whatever you like, interviewees.

MR. TUCKER: I don't know why.

MS. GLOVER: The corporate secretary's office generally runs these processes. These are decisions that have been made, and this is consistent with how we've always done it. I don't know that that was a debated consideration, but I'm certain we're happy to take that request under advisement.

MS. JOHNSON: Okay. And why do we only learn who we're going to be asking questions of the day before?

MR. TUCKER: Well, the intent of the interview is to understand what topics individuals would like to discuss, and then management provides experts that -- and, I guess, I don't understand what relevance that has.

Maybe if we understood better why it was important for you to know in advance maybe that would be different. Maybe we would provide it. It never occurred to me that it would be interesting to know to the interviewers who they were going to talk to as long as they got the information they were looking for.

MS. JOHNSON: Well, I think that the difference is so in a traditional rate case each witness sponsors certain testimony so you know who you're asking questions of, and you may or may not need to question everyone. If you don't know who actually is responsible for the work papers or what information, you don't necessarily know who you're --

MR. TUCKER: Isn't that -- well, okay. But you -- you don't know. Since we don't have the traditional testimony, I guess I don't understand why it's important to know who you're then speaking to in advance.

MS. JOHNSON: Well, like, for instance, since there's nobody from resource planning or consumer services here, presumably those are not questions that are going to be able to be answered.

MR. TUCKER: Well, if they were -- I mean, our intent is to try to answer the questions as best we can and to bring folks in if we need to if the discussion is related to the price process.

MS. JOHNSON: And then last question just in the process sort of category, are you going to allow public comment at all of the board meetings that are advertising on the pricing proceeding or only at some of them?

MR. TUCKER: That's another one that's up to the board's discretion.

MS. JOHNSON: Okay. Do you know when that's going to be decided or communicated?

MR. TUCKER: I don't.

That's also as far as I know up to their discretion.

MS. JOHNSON: Okay. Moving on to just sort of these are general questions related to the pricing proposal.

Can you just speak generally to why the increase for solar customers is higher than the increase both overall and the increase to residential customers?

MR. TUCKER: Sure. The management's proposal page 30 -- we were looking at this earlier. It's conveniently handy. The blue bars represent the current return levels, and that's our measure of interclass equity.

And, as you can see, the residential solar class is the lowest returning class, which means they're paying the lowest portion of their share of costs. Residential, as you can see, is also lower and net negative currently. And then you can see all the other classes.

And we use the rate of return by class to allocate those price increases in line with the principle of equity, and the intent would ultimately over time gradually be to get everybody in this case to like an average return, which is where we proposed 4.7 percent.

So if these classes were closer together today, we would -- we very well may have gotten to a proposal where everyone was to the proposed 4.7.

But -- and from a cost relation and equity standpoint, one could make an argument that's where we should, but gradualism tempered the proposal in terms of how much we moved residential solar and residential prices up.

MS. JOHNSON: Well, one of the mechanics within the rate design that are specifically making it move to 5.5 as opposed to what is it, 3 something for residential generally is it -- because obviously they're all paying the same fixed fee, they're all going to be paying is it a differential between the existing solar plans and the off/on-peak pricing, or what is the mechanic within that rate design that's going to fuel this change to be so significant statistically?

MR. TUCKER: Are you asking how is it that -- like, mathematically how does it turn out that the residential solar class ends up with a higher price increase compared to others?

MS. JOHNSON: When they're all going to be on the same plan, yeah.

MR. TUCKER: So the residential solar class here that's indicated are the existing residential solar price plans. So that's when we're talking about the price increase for that class of customers we're talking about those.

And I think what you might be referring to is the fact that the new proposed rates, the E-28 and E-16, that all customers can participate if those, that's not the residential solar class.

So they all have the same monthly service charge, the existing residential rates and the existing residential solar rates, but they also have energy prices that are differentiated, and that's how we end up allocating that higher percentage increase to the solar class of customers.

MR. SHOEMAKER: And, if I could, for those rates that have demand rates, that's another way that those are differentiated.

MR. TUCKER: Sure.

MS. JOHNSON: So if you're a solar customer and you're on one of the existing rate plans but you decide to move to, say, E-28, do you know what the -- your price percentage difference will be, or is the 5.5 percent only reflective if you're on what is it -- no offense, but I hate the naming of your guys's things. It's so hard to keep track of.

But if you're on, like, E-13 or whatever it is and you stay on E-13, is that when the 5.5 percent is going to apply as opposed to if you're E-13 and you move to E-28?

MR. TUCKER: Yes. Yes.

MS. JOHNSON: Sorry.

MR. TUCKER: The answer is, yes, the 5.5 percent is, say, if you're on E-13 and you stay on E-13, that's what that's getting at.

MS. JOHNSON: Okay. Do you know what the difference is if you're on E-13 versus moving to the new E-28?

MR. TUCKER: So we have -- we can estimate customer bills for those customers that are on any of the rates today on the new rates, but what they'll actually be based on, how they actually consume energy and respond to those price signals, we don't know.

So we can -- we can estimate based on their current behavior, but I don't know how good of an indicator that is of what their real bills will be when they're responding to different TOU hours right there. The TOU hours are different today versus under the proposed new rates.

MS. JOHNSON: There's not anything in this document that's going to help indicate that, that would be kind of a customer bill comparison tool or something if they called, like, the 1-800 number?

MR. TUCKER: Yes. It would be a bill comparison. I don't think we've printed anything to that end.

MS. JOHNSON: Okay. But there is a bill comparison tool where a customer could go online or could call and presumably could do that comparison or rough estimate?

MR. TUCKER: I think it's -- I don't know about online.

MR. SHOEMAKER: No. They would need to call in and request a bill comparison, what would my usage look like on these new price plans.

MS. JOHNSON: Okay.

MR. TUCKER: We also brought that information to the open houses that we had, and customers that came we would give them their estimated bill impact on their existing rate as well as any other rates they might be interested in.

MS. JOHNSON: Okay. Just generally why does SRP have more EV customers than they have solar customers given that EVs are much newer technology than solar?

MR. TUCKER: I guess I can't say why customers are making the decisions they're making.

MS. JOHNSON: Why does SRP have approximately 25 percent of the solar customers that APS has with approximately the same size utility in the same geographic area?

MR. TUCKER: We've done some math that indicates -- SRP prices are lower. They start lower. Our bills presolar are lower. So that -- it could be a factor in terms of whether customers see as much value in installing solar when our bills start lower.

MS. JOHNSON: And when you say "a factor," so presumably there would be others?

MR. TUCKER: Well, again, I can't speak to what our -- I can't speak to how our customers make decisions around solar.

MS. JOHNSON: Have you done any analyses as to your different sort of rate designs compared to APS's and how that might impact?

MR. TUCKER: Again, that's exactly what I'm referring to. We looked at -- it's been a while, and I'll welcome Mark to set me straight. But I remember very clearly six, eight years ago we looked at our -- so we took our customer data because that's the data we have. We don't have APS customer data.

We took our customer data, we billed them out on APS rates pre- and post-solar, and we billed them out on our rates pre- and post-solar, and the results were the bills started much higher in APS territory or higher. They started higher in APS territory. And they were almost equivalent post-solar between the two utilities.

So we billed them about the same amount back when we did the math. APS and SRP solar customers were billed about the same amount. APS and SRP nonsolar customers were billed differently. They were billed more by APS, so there was a greater opportunity for savings.

MS. JOHNSON: Do you know when that analysis was done?

MR. TUCKER: I would --

MR. CARROLL: We had presented some of that analysis in the 2019 price process.

MS. JOHNSON: Okay. So that's pretty old, then, presumably, right, because it's been at least six years ago since that pricing process?

MR. TUCKER: Yeah, but our differentials in average rates are very consistent between us and APS for quite some time. So that differential hasn't changed.

MS. JOHNSON: Do you guys look to the other utilities in the state as far as, you know, norms, best practices, any of that kind of stuff?

MR. TUCKER: Well, to some extent we -- yeah, we want to be aware of best practices. But specifically you were asking if we look at bill comparisons. You were trying to ask me why our customers make decisions around solar, so I was -- you asked about other utilities comparisons.

MS. JOHNSON: Well, I think I'm asking you what mechanisms within your rate design would deter people from getting solar.

MR. TUCKER: That our bills are lower. That would be one of them.

MS. JOHNSON: Right. But, like, fixed fees, export rates you don't think -- time-of-use period, you don't think any of those are factors?

MR. TUCKER: I think our prices are better aligned with costs. That could be a factor.

MS. JOHNSON: Okay. In the -- within the

pricing proposal document you make a comment about that there's a new proposal related to RECs from residence solar forthcoming. You mentioned that a little bit this morning.

Does SRP intend for customers to transfer the environmental attributes of all of their solar generation or just exported energy?

MR. TUCKER: So that program is still to be developed, but the idea is that -- that we've heard some solar customers say that, hey, we add value that you don't recognize. And what we realized is that is a value stream. There is value to RECs that our customers could receive.

So if SRP were adding solar to the grid, we actually have programs for customers where we sell RECs to them. So we realized, hey, if a customer -- if a DG customer -- say a residential DG customer is interested in selling their RECs to SRP, that adds value to the rest of our solar -- I mean, to the rest of our customer base.

So the idea is that, again, it's a win-win because there's something of value that's being purchased by SRP, which, of course, means purchased by the rest of our customer base. That's the idea is maybe a REC. But it would be an optional program that the customer would transfer the REC to SRP for some payment.

MS. JOHNSON: But I guess the question is whether they'd be transferring the attribute of all the solar generation or just the exported energy back to the grid?

MR. TUCKER: Are you asking if it's the REC related to the export or all the energy?

MS. JOHNSON: Yeah. Well, I think so. I think that's what I'm asking.

MR. TUCKER: I think it could -- if there was a preference to go one way or the other, we -- I'd be interested to understand that better if our customers had a preference one way or the other.

MS. JOHNSON: Okay. Do you know what the proposed value of the environmental attributes might be?

MR. TUCKER: No. Like I said, that -- the intent is to roll that program out later this calendar year if not at the beginning of next year.

MS. JOHNSON: So there's a lot of comments within the -- oh, can you say it again? I'm sorry, when was the time line for that?

MR. TUCKER: Either later this year or at the beginning of next year.

MS. JOHNSON: Okay. So it could be a full year from now then?

MR. TUCKER: It could be, yeah. Yeah.

But, like I said, it's not developed. Those terms are -- and, like I said, I'd be interested to better understand the customers' preferences. We have time to take that into account.

MS. JOHNSON: Is there going to be a stakeholder process for that or what's the --

MR. TUCKER: An official stakeholder process? That -- that hasn't been discussed that I'm aware of. But at the same time, I think there would be stakeholder input.

MS. JOHNSON: I think -- I mean, my recommendation would be that you should talk to industry, obviously, about -- about the -- you know, the workings of the proposal before you just announce a proposal may be helpful.

MR. TUCKER: That we should talk to industry?

MS. JOHNSON: Yeah.

I'm curious -- I mean, you have a lot of comments in the proposal about expected sales growth. I'm wondering why SRP offers rebates for EVs but not for solar paired with storage.

MR. TUCKER: I am not sure that we still offer EV rebates. Maybe we do.

MS. JOHNSON: You mention them in here.

MR. TUCKER: Oh, well, then maybe.

MR. CARROLL: I think there's a charge here on a rebate.

MR. TUCKER: Oh, okay.

MR. CARROLL: Yeah.

MR. TUCKER: So the EV charger.

MS. JOHNSON: You don't specify that in the proposal.

MR. TUCKER: No. I apologize.

MS. JOHNSON: You just talk about rebates for EVs, but --

MR. TUCKER: I think -- yes, I think the intent was the EV charger.

So, I'm sorry, then what's the question?

MS. JOHNSON: I'm just wondering why you don't offer rebates for solar paired with storage?

MR. TUCKER: Oh, yeah, sorry, I don't do the program design. We've had various incentives over time. One of the concept I think with incentive is to encourage a new technology to be further deployed. I think EVs are a newer technology certainly than solar and storage perhaps. We used to have obviously solar incentives and we had a battery storage incentive that we had in place. It didn't -- as I recall, it didn't have a lot of interest.

MS. JOHNSON: Do you know when the battery storage incentive was?

MR. TUCKER: I think it came out in the 2019 price process. I'm not sure.

MR. SANDSTROM: I guess it was --

MR. TUCKER: I'm not sure.

MR. NEIL: It was doubled.

MR. SANDSTROM: Correct. Yeah. We mention it in the price -- it was not a formal part of the price process in 2019.

MR. TUCKER: Right. Yeah.

MS. JOHNSON: So when did you have battery storage?

I mean, obviously storage technology has changed a lot.

So, sorry, when was there a storage rebate?

MR. TUCKER: I guess I don't know the specific dates.

MS. JOHNSON: Okay.

MR. TUCKER: I guess we -- I'd be happy to respond to it to get you the exact dates.

MS. JOHNSON: Okay. On page 10 of the proposal you talk a lot about the ISP stakeholder process. And I'm just curious you say that there were eight large stakeholder group meetings.

I didn't see the dates of those anymore on the websites. I might have just missed those. But do you know if those occurred before or after the Coolidge vote?

MR. TUCKER: I do not.

MS. JOHNSON: Does anybody else know?

MR. TUCKER: We could certainly get you the dates, if you like.

MS. JOHNSON: Yeah. I'm curious because, you know, you may or may not know that AriSEIA has specifically been denied participation in your advisory counsel related to both ISP and the sustainability group. And so I guess I'm still wondering why that's the case.

And also, you know, when these larger group meetings happened because it would be particularly important to us since we are not allowed to participate in the small groups.

MR. TUCKER: Yeah, again, that wasn't a pricing process, so I'm not -- I wasn't involved in those either, if that helps.

But we can get you the dates of the meetings gladly. Sorry, I don't have them off the top of my head.

MS. JOHNSON: You work here. I feel like not going to a meeting is probably a bonus as opposed to a punishment.

Okay. On page 14 you say that self-developing projects cost less. I believe we're talking about utility-scale here. And I'm wondering why that would be the case, especially when you're using an all-source RFP process.

MR. TUCKER: Sorry. I'm trying to find where we say it. Give me a minute, and I'll find it I'm sure. If you can point me there, I'll take the tip.

Oh, okay. I think maybe I see it. It says, "The self-development aspect of this project as opposed to outsourcing is forecast to save SRP $38 million."

And the question is why is that cheaper?

MS. JOHNSON: Why would it be cheaper to self-develop than to use a developer when you're utilizing an all-source RFP process?

MR. TUCKER: Again, I was not involved in the RFP, but it seems quite possible to me that we may have gotten results of the RFP and said we can do it cheaper.

MS. JOHNSON: I think that you use an independent monitor that is supposed to not allow you to do that. But if you could follow up, that would be great.

I'd also like to know why it would come online faster if it's self-developed versus you're using an outside --

MS. GLOVER: I just want to remind you if there's things that you're looking for follow-up on, it's difficult for us to track those, and we want to make sure we do it properly. So if you have -- you know, keep track of those things that you're looking for extra data or responses on that we can't answer very quickly here and submit requests for those so we can make sure to follow up on all of them.

MS. JOHNSON: I thought you guys were phoning a friend.

MS. GLOVER: No. If it -- like, I said, if there's things that you think we can bring someone in to answer for you, we will certainly do that, but if there's something that you have particular questions that might respond -- or require a more fulsome response, just make sure you submit those.

MS. JOHNSON: I'm worried that you'll have a board vote before I get the responses to these things if I'm being really honest.

Okay. On page 15, you're talking about future gas -- kind of what your plans are regarding some of your gas plants, and I'm wondering does SRP intend to continue obtaining CECs for any new gas projects?

MR. CARROLL: These --

MR. TUCKER: Go ahead.

MR. CARROLL: These aren't -- it's not a price process related question.

MR. TUCKER: I mean, that is a resource planning question; right?

MR. CARROLL: Yeah.

MS. GLOVER: Can you repeat the question?

MS. JOHNSON: All right. My question is does SRP intend to continue obtaining CECs for any new gas projects?

MS. GLOVER: Again, that's outside the scope of these proceedings.

MS. JOHNSON: Is it outside the scope? You're talking about your plans here with gas and the need to continue to build new gas to help offset variable generation, so it seems pretty related to me.

MS. GLOVER: Are you still on page 14?

MS. JOHNSON: Yeah, 14 is where you're talking about the need for flexible natural gas and, like, all of your gas projects.

MR. TUCKER: Yeah, if I can clarify. These -- generally speaking, the -- what we're talking about here are what's happened since the last price process, so if I'm -- so these things are in motion.

And if I understand, I thought you were saying in the future are you planning to issue more CECs, and this isn't -- this isn't necessarily -- this is more focused between the test years.

MS. JOHNSON: I think the ISP is for a much broader time line, but if you want to say that you don't want to answer it because it's not the test year, then you can do that.

MR. TUCKER: No, I think -- I think, yeah, but this isn't the ISP either. The ISP is a broader time line, but what we're talking about in the pricing proposal is what's changed -- generally speaking what's changed since the last price process and then the costs that we've incurred, how have the -- maybe one way to think about it is why are the prices that were approved in 2019 no longer adequate to cover our costs. Well, it's because our costs have increased, and this is sort of what's sort of talking about -- this is the increase of costs in the last six years.

MS. JOHNSON: Yeah, but the sales growth projections you're talking about within this document are forward-looking. But so you're saying that even though you have all of the sales growth data that's forward-looking the cost projections are only backward-looking?

MR. TUCKER: Yeah, generally speaking that's right. The costs are about what's changed in terms of costs. There's -- you're right that there is a forecast in there, but it's kind of providing some color.

MR. CARROLL: The -- the test year -- so the cost using the test year is at 2026. And so it's always the -- it's the forward -- it's still a projection matching the load forecast used.

MS. JOHNSON: And what's you guys's -- when does your -- when do your years begin and end here?

MR. TUCKER: May 1.

MS. JOHNSON: May 1. So this is May 1, '25 to '26?

MR. TUCKER: So, yeah, the test year is from --

MS. JOHNSON: So it's a forward-looking test year, not a historical test year?

MR. TUCKER: That's right.

MS. JOHNSON: Okay. Well, I'm going to ask this, and you guys can just answer or not.

MR. NEIL: I'll answer it for you.

MS. JOHNSON: When does SRP plan to retire Springerville, which you talk about your plans to close Coronado on page 19?

MR. TUCKER: I don't have the Springerville answer, but it's not -- it's not impactful to the test year for whatever that's worth.

MS. JOHNSON: Okay. What percentage of your expected load growth over the next five years is just from data centers?

MR. TUCKER: There's a lot of load growth for data centers in the forecast. I don't have the number off the top of my head.

MS. JOHNSON: Okay. Do you have a general ballpark?

MR. TUCKER: I'm worried I would -- I'm worried I would misspeak. I'm not sure.

MR. SHOEMAKER: Yeah. I'm going to have to say the same.

But you're saying the next five years, so through 2030 is the question --

MS. JOHNSON: Yeah.

MR. SHOEMAKER: -- how much of our load growth?

MR. TUCKER: Which again --

MS. JOHNSON: If you have a broader time line, that's fine too.

MR. TUCKER: -- it could be impactful for future price processes, but load in 2030 isn't really driving the costs for 2026.

MS. JOHNSON: If you want to do it just for '26, then that would also be acceptable.

MR. CARROLL: It would be -- it would be easier for us to answer if you would have asked if the test year was in 2026, but if you can just submit it if you want.

MS. JOHNSON: Okay. So this is a question that I'm sure you're also going to be really excited about.

So despite significant load growth as far as projects in the C&I space, you just changed your master meter requirements that require multifamily housing units to have hundreds of interconnections per project, which will drive up costs and reduce the likelihood that all of the housing necessary to accommodate this growth will have solar.

Do you know if this is going to be corrected?

MR. TUCKER: I honestly am not even quite sure what that meant.

MS. JOHNSON: So now if you want to do a C&I -- so if I say C&I, so do you know what I'm talking about?

MR. TUCKER: Like, business, commercial

industrial?

MS. JOHNSON: Yeah. So if you want to put solar on a multifamily housing unit, instead of just having a couple of interconnections depending on the size of the unit you now have to have an interconnection for every person that lives there, so if, like, it's an apartment complex, it's 250 interconnections. It drives up costs 10 to 20 percent. It's obviously going to reduce the likelihood of putting solar on multifamily housing.

And so this is a new decision that SRP's just made. I'm wondering if that's going to be fixed.

MR. TUCKER: Well, one, I'm not sure that it -- it's broken in a sense, but that wasn't a pricing consideration. It didn't drive the pricing proposal. I'm not familiar with it. But I think that's customer programs if I was to hazard a guess, but I'm not even sure that's true.

MS. JOHNSON: Okay. On page 29, I'm just wondering if you can just say a little bit more about -- I was thrown a little bit by the use of the phrase rate of return when it comes to a non-profit.

MR. TUCKER: Yes.

MS. JOHNSON: So can you just talk a little bit about what you mean and a return to whom?

MR. TUCKER: Sure. Yeah, I agree it is confusing. And it's -- it is very different than in the IOU context. I kind of mentioned it earlier that we use rate of return to measure equity amongst customer classes. And, as I think you're probably more aware than I am, in an IOU setting rate of return is a target IOUs are looking to earn. For us it falls out. There's no target around rate of return.

So there -- yeah. And when we talk about return, it isn't -- your question is fair to whom. It isn't to anyone. All it is doing is covering -- like, there's no stockholders that are taking something out that you might otherwise get a rate of return from an IOU.

All it's doing is covering necessary SRP expenses like our interest payments, which we obviously have to make, the water support that we also have to provide, and the -- and the contributions to future capital, which are obviously required as well.

So it doesn't go to anyone. It actually stays in the SRP bank account and goes to fund operations.

MS. JOHNSON: Okay. So just maybe some follow-on questions for that.

Are you earning a return from a specific subset of customers then?

MR. TUCKER: Again, it's -- I think it is a muddled issue, and I apologize that it's not super clear, but I guess help me understand when you say earning a return what do you mean? To what end perhaps?

MS. JOHNSON: No, I don't know. Like, we don't have enough time to have an expert in this, so this is -- this is our combination of the questions that we could come up in the time frame, so I didn't write this specific -- so I'm asking this question right now.

MR. TUCKER: So I'll take another crack then.

MS. JOHNSON: Okay.

MR. TUCKER: The -- again, the return that's calculated on page 29 what's proposed is 4.7 percent. That return, again, it is money that goes literally to pay interest expense, right? Like interest on a mortgage for your house, that's -- you have to pay that, right, to operate? So for SRP to continue to operate we have to pay our debt.

And, again, SRP has legal obligations to provide support for water operations and the return covers that. And then the return also covers -- whatever's left of -- after those two things whatever's left goes in the bank to pay for capital projects, which, again, I think you want to do because we don't want to borrow 100 percent of our capital expenditures. Like, when you buy a house, you put some money down and you borrow the balance. This is basically that some money down, what's left from the return. So there's no return that goes to anyone. It stays in the SRP system and then is spent to SRP business purposes.

MS. JOHNSON: Okay. Did the company consider evaluating equity between classes by comparing proposed revenue compared to cost of service?

MR. TUCKER: We have looked at something like that. The results are effectively the same thing. But there's a different way. And what we looked at was here's the total cost to serve a customer, which includes the interest expense, the water support, and the future capital contributions, and we looked at how much revenue those customers bring in. It's the same -- effectively it's the same thing. It's the same result, but it's a different way to look at the same issue.

MS. JOHNSON: Okay. And you did that in this process also?

MR. CARROLL: It's not published in here, but we've looked at that as part of this process.

MS. JOHNSON: Okay. But you're saying the results were comparable?

MR. TUCKER: Yes.

MR. CARROLL: Yes.

And if you look at the revenue or the cost on schedule 8 and compare that to the proposed revenues in schedule 9, I think you could see -- you could see where those results are.

MR. TUCKER: The numbers are all there, yeah.

MS. JOHNSON: Is the return SRP proposes to earn from customers above and beyond its actual capital costs?

MR. TUCKER: It is below our weighted average cost of capital, if that's what you're asking.

MS. JOHNSON: Okay. I just want to make sure that data centers and manufacturing facilities, those would fall within the large general service rate class; is that right?

MR. TUCKER: Yeah.

MS. JOHNSON: Okay. And so if we're looking at -- we're on page 31. I just want to make sure that I am reading this correctly. But it looks to me that you're proposing an increase for these large companies that's about one-third of the increase that's applied to residential customers.

Am I reading this correctly?

MR. TUCKER: Yes.

MS. JOHNSON: Or less than that actually. It's more like a quarter. 14 --

MR. TUCKER: Yeah, you're right.

MS. JOHNSON: -- 15 million versus 67 million.

MR. TUCKER: Yes, those are the numbers.

MS. JOHNSON: Okay. And I understand what you were saying before about table 5 and who's underpaying versus overpaying.

But it is, I think, correct that -- you weren't able to answer it, but I'm fairly confident that data centers and manufacturing are a huge driver of the massive load growth.

MR. TUCKER: So, again, I think it might be important to make a -- to distinguish between the load growth that we see in the test year and the load growth that we see like 2030 and beyond.

MS. JOHNSON: Okay.

MR. TUCKER: It is a huge portion of the load growth that we see forecasted for 2030. It's a few hundred megawatts. It's a very small portion of the test year. And, again, the prices that we are proposing here are based on the test year, so they're based on say -- they are based on fiscal '26 load forecast.

MS. JOHNSON: Do you have the test year load growth forecast in this document?

MR. CARROLL: Yes. And you can see the megawatt hours, but it doesn't show the year by year. You can see the megawatt hours for FY 26.

MS. JOHNSON: Okay. What page is that?

MR. CARROLL: It's on schedule 4.

MR. SHOEMAKER: And that's in the cost allocation study.

MS. JOHNSON: Oh, okay. So that's not in the proposal.

MR. SHOEMAKER: Right.

MS. JOHNSON: But it would be in the CAS.

Okay. Okay. Oh, wait, I want to talk a little bit about the transition for existing rate classes.

So, as I understand it, you're freezing the existing rate classes with the exception of what Steve said earlier, so there's going to be E-16, E-23 and 20 -- is it E-23 and E-24 are remaining?

MR. TUCKER: Yes.

MS. JOHNSON: And 24 is essentially a prepaid version of 23?

MR. TUCKER: Yes.

MS. JOHNSON: Okay. And then the new 28.

The other ones are frozen.

MR. CARROLL: Can I just --

MS. JOHNSON: Go ahead.

MR. CARROLL: I just want a clarification. The E-24 essentially becoming E-23 is part of the proposal here.

MS. JOHNSON: Oh, okay.

MR. CARROLL: The existing E-24 prices are a little bit higher than the existing E-23 prices, and part of management's proposal is to bring those in line in particular because a lot of our limited-income customers are on E-24.

MS. JOHNSON: Would E-24 still exist, or it's going to collapse and it will all be called E-23?

MR. TUCKER: Technically E-24 will still exist.

MS. JOHNSON: Okay. But it's the identical to E-23 --

MR. TUCKER: Yes.

MS. JOHNSON: -- except you're prepaying?

MR. TUCKER: Thank you for that clarification, Mark. I agree.

MS. JOHNSON: Okay. So when you froze them -- but they're not really going to be grandfathered. They're going to have a transitionary period of time of four years, and then they're going to be automatically moved to one of the new rate plans; is that correct?

MR. TUCKER: Yes.

MR. SHOEMAKER: Sorry, if I can just jump in there.

Yeah, they'll have -- they'll have a time frame where it will be frozen from new participation, and then before those price plans are eliminated, customers can opt into any of the available rates. And the hope is that they will do that opting in, so there'll be customer outreach before those plans are eliminated, so that they can, you know, again, hopefully pick a plan that they would like to be part of. And then those that haven't yet picked a plan by the time their price plans are eliminated would be moved to one of these rates.

MS. JOHNSON: And are you going to do like affirmative outreach to customers about changing it as opposed to just defaulting them in four years?

MR. SHOEMAKER: Yes.

MR. TUCKER: Yes.

MS. JOHNSON: Okay. Why do you want -- I mean, I think I know the answer, but I just want to confirm why do you want -- instead of grandfathering them on the rate if they want to stay on it, why are they being forced to move?

MR. TUCKER: Because the hours are increasingly out of alignment with costs.

MS. JOHNSON: Okay.

MR. TUCKER: So we're sending -- we're not sending good price signals. And, yeah, one of the -- you already mentioned the ISP. We noted in here that one of the findings in the ISP was that SRP needs to develop new signals to better kind of inform customers when to use energy and not to use energy, so this is part of that.

MS. JOHNSON: Okay.

MR. CARROLL: And it's really designed as a benefit to customers because the alternative would be to just to like on May 1 or November 1 of 2025 change the hours on the existing rates, and then everybody -- you know, we can -- we could easily do that.

MS. JOHNSON: Yeah.

MR. CARROLL: And it's difficult to inform the customers and, you know, have that outreach if everyone's done -- all willing customers have to switch over on a day. This will give customers time to have -- to transition over to the new rates and for us to be able to provide the educational material and things to help make sure that process is smooth.

MS. JOHNSON: So on page 48 you say no later than November 2029.

And does that mean that you might end the old rates sooner, or that's just accounting for the fact that people can opt to leave sooner?

MR. TUCKER: No. We -- yeah, there is a transition plan that's still being developed that, yeah, they may end sooner than November of '29, if that's responsive.

MS. JOHNSON: Okay. So you're saying -- so there isn't necessarily kind of a four-year grace period. You might decide to end them sooner, and they would need to transition faster?

MR. TUCKER: Yeah. So, yeah, correct that there is not a four-year -- you're not guaranteed four years on your existing rate.

MS. JOHNSON: Okay.

MR. TUCKER: The plan is to make the transition after we get on that -- the customer on our new Phoenix -- our new customer information system in place, which should provide at least 18 months before we'd be moving customers en masse.

MS. JOHNSON: Is that kind of like a rate comparison tool that's like a -- is that like an online interface where they can compare them?

MR. TUCKER: I -- well, I'm not sure that would -- no, it's not that necessarily. And that could potentially come sooner. This is more about -- this is more about the back office system.

MS. JOHNSON: Okay. I want to just go back to something when Dave was talking to you earlier that I'm not sure that I totally understood when you were talking about what happens to the grandfathered legacy solar customers, and I want to make this a much higher level conversation because I got a little bit lost in that conversation.

For customers that are legacy net metering customers that are grandfathered for 20 years, that is going to remain regardless of what happens with this price proposal?

MR. TUCKER: So they will have their grandfather status. That will remain. But the rate -- say they're on E-21, but most of them are on E-23.

MS. JOHNSON: Okay.

MR. TUCKER: So but -- and E-23 will persist as we kind of mentioned, so their grandfathered status will continue as the rate will continue.

E-21, that rate will not continue. So if they were -- if -- they would then have the option to go to E-23 or to go to one of the new TOU rates.

MS. JOHNSON: But so, like, at APS if you switched your rate plan, you're not going to keep your net metering, but in this case you'd be switching the rate plan, but the export rate that is the retail rate for electricity would remain the same?

MR. TUCKER: So E-23 would have the net metering.

MS. JOHNSON: Uh-huh.

MR. TUCKER: So that will be the net metering option that remains.

MS. JOHNSON: Okay.

MR. TUCKER: And if you want -- but you could still switch to the new TOU rates, but, yeah, those are not net metering rates.

MS. JOHNSON: So you would lose your net metering, then?

MR. TUCKER: If you went to those TOU rates.

MS. JOHNSON: But if you -- so if you're on E-21 and you go to E-23, you can keep the net metering?

MR. TUCKER: Yes.

MS. JOHNSON: And if you're on E-23, you stay on E-23, you can keep the net metering?

MR. TUCKER: Yes.

MS. JOHNSON: Because I thought that you'd said that E-23 wasn't open to solar customers, but you mean -- you mean new solar customers?

MR. TUCKER: Yes. Exclusive of grandfather.

MR. SHOEMAKER: Yeah. Yeah. E-23, that was what we had -- what we had read earlier. The applicability for E-23 will continue to include those -- those solar customers that -- I don't want to misspeak, but those solar customers that had on-site solar generation installed prior to --

MS. JOHNSON: 2015 or '16?

MR. TUCKER: It was '14.

MS. JOHNSON: Or was it '14?

MR. SHOEMAKER: It was like December 14 of 2014.

MS. JOHNSON: Okay. It was -- I'm glad you clarified because it was a little confusing to me.

MR. SHOEMAKER: It's December 8, 2014.

MS. JOHNSON: 2014. It was a little confusing to me that solar customers doesn't mean solar customers. It means some solar customers.

MR. TUCKER: Yes. Yes. Sorry.

MS. JOHNSON: Okay. Is it true -- so I thought it had recently changed, but is it true that solar customers for APS still have two meters?

MR. TUCKER: For APS?

MS. JOHNSON: I mean for SRP.

MR. TUCKER: They do still have two meters, yes.

MS. JOHNSON: They do? Okay.

MR. NEIL: It changes next week.

MS. JOHNSON: It is next week. So there is a change coming where they're no longer going to have two meters. I feel like I saw an e-mail about that, but --

MR. NEIL: No. You mean three meters. A storage meter is no longer required.

MS. JOHNSON: Oh, okay.

MR. NEIL: So the second meter is always going to be required.

MS. JOHNSON: Okay.

MR. NEIL: Especially if there's REC involved.

MS. JOHNSON: Look at that. He's working for you for free.

MS. GLOVER: I would -- yeah, I would ask that you please allow the SRP folks to answer the questions.

MS. JOHNSON: But it's free work.

Is that correct?

I'll ask you guys just to clarify for purposes of the record is that -- so there is a meter change coming, but it's going from three to two, not two to one?

MR. CARROLL: Any meter changes aren't impacting the pricing charges.

MR. TUCKER: Yeah, honestly -- sorry, yeah, I don't know.

MS. JOHNSON: Okay. It came up in Dave's questions, so I just wanted to ask.

Okay. Can you -- so turning to page 41, can you just describe a little bit about how the Carbon Reduction rider is going to work?

MR. TUCKER: So this -- the Carbon Reduction rider is intended to be like what we currently call the Renewable Energy Credit rider on the prior page. It's --

MS. JOHNSON: Okay.

MR. TUCKER: We're proposing we rename it to Energy Attribute Certificate rider.

But the idea for both of those riders is to provide, in a sense, an umbrella under which SRP can offer programs to customers.

So it may be a corollary is the REC rider as it exists today allows us to offer programs for solar -- for customers to purchase RECs, and we have the sustainable energy offering. We have the -- it's a --

MS. GLOVER: A solar choice?

MR. TUCKER: Thank you. The solar choice, the solar choice select. So we have a small handful of REC programs that we offer under the existing REC rider. The idea was to create a -- this Carbon Reduction rider that might allow us to offer similar -- similar programs around carbon credits if and when something like that was to be of interest to customers and available to us to provide.

MS. JOHNSON: So I just wanted to be clear because I think I got confused with what you were saying. The Carbon Reduction rider is a new rider, but the Energy Attribute Certificate rider is a rename of an existing rider?

MR. TUCKER: Correct.

MS. JOHNSON: Okay.

MR. SHOEMAKER: That's correct.

MS. JOHNSON: Okay. Can you talk a little bit about -- you have a list of riders being eliminated on the same page there, and a whole bunch of them Community Solar related.

Can you explain those to me and why they're frozen?

MR. TUCKER: Yeah. There just hasn't been -- those programs have been replaced by the programs I was mentioning. Basically we have newer programs.

Those are kind of legacy riders that governed programs that haven't had participation for many years.

MS. JOHNSON: And when you say Community Solar, what do you mean?

MR. TUCKER: It was -- so Community Solar for schools as an example was an opportunity for schools to participate to kind of voluntarily to pay more to participate in solar projects on a larger scale.

MS. JOHNSON: Okay. So it was kind of like a green -- I call them green tariffs, but you're essentially paying more to participate in some kind of solar program?

MR. TUCKER: Correct.

MS. JOHNSON: Okay. Which is different than how AriSEIA talks about Community Solar, which is a bill credit for participating --

MR. TUCKER: Oh, yeah.

MS. JOHNSON: -- in a solar array.

MR. TUCKER: Different. Yes. Yes.

MS. JOHNSON: Because I was going to say, wow, SRP, you guys are way ahead of the ball. I didn't know.

Okay. How does the value of solar study that you all produced last summer fit into the pricing proceeding?

MR. TUCKER: So the value of solar study was not an input to our cost of service study.

MS. JOHNSON: Okay. Was it -- just to be clear, was it any other input to the pricing proceeding?

MR. TUCKER: Huh-uh.

MS. JOHNSON: Okay.

MR. TUCKER: No.

MS. JOHNSON: We are shifting to just export rate questions now.

And some of these are not originally drafted by me, so hopefully you know what they mean.

How was the residential solar loss factor determined?

MR. CARROLL: There was a study conducted. This is a study conducted by our engineering groups. It typically happens about once a decade because the energy flows over the system don't change dramatically over year to year.

We updated that study for the -- the -- each of the current price plans. And so we're looking at based on inputs from the engineering groups on what the losses were for like our transmission system at different voltage levels, and then our primary and secondary distribution system at different levels down to the transformer, our losses, and then by hour and then looking at the loads for the classes and weighting the losses by hour by the loads by each hour to get what the average loss it is for each class.

MS. JOHNSON: Okay. And so according to the 2023 state electricity profile from EIA Arizona, line losses are 3.4 percent.

Why didn't SRP include a value for avoided transmission losses and avoided transition costs within the export rate?

MR. CARROLL: So the export credit on E-13 and E-14 captures the losses because we are allocating costs based off of the net kWh adjusted for the losses.

MS. JOHNSON: But what about the on the new -- are they being accounted for in the new rates?

MR. CARROLL: Yeah. On the new rates there's a lost adjustment factor that increases the -- the rate.

MS. JOHNSON: For both E-16 and E-28?

MR. CARROLL: Correct. I believe it's in the equation there.

MR. TUCKER: And so just to clarify, they are adjusted for losses.

MR. CARROLL: Yeah. Yeah.

MS. JOHNSON: For avoided transmission and avoided losses and avoided transition costs?

MR. CARROLL: That's how it's done right now, yes.

MS. JOHNSON: Okay. Did SRP calculate alternative export rates using methods other than the sum of the product of average hourly market energy prices?

MR. TUCKER: So we looked at a couple of different ways that we might, yeah, calculate an export rate. Yeah.

MS. JOHNSON: What were the other ways?

MR. CARROLL: One was the original publication before the errata.

MS. JOHNSON: Okay.

MR. CARROLL: The 3.08.

MR. TUCKER: Yep. We looked at -- so the current --

MS. JOHNSON: That's not still available online, I don't think, is it?

MR. TUCKER: Oh, probably not.

MS. JOHNSON: Okay. Go ahead.

MR. TUCKER: The current export rate is based on solar PPAs, right, or maybe -- anyway, it is based on solar PPAs, so to me there's a couple of different ways you can think about avoided costs. And our focus is that we set that price based on avoided cost because that's what the rest of our customers have to pay for it.

So in 2019 we looked at it in terms of solar PPAs, long-term solar PPAs that we were entering into that because that seems like that's -- that's one way to look at avoided solar costs is, well, you could go buy solar for 20 years. That's one way you could get solar.

Another way you could buy the energy is, well, there's a realtime market that tells you how much energy is worth every hour or less sub-hourly.

So -- so we looked at both of those approaches, and what we proposed this time was to go with the market-based rate rather than a 20-year PPA-type number.

MS. JOHNSON: Okay. And so it says here that SRP's methodology includes overnight hourly market energy prices when solar output is zero, and it's not weighted for either when solar output occurs or when exports occur on their system; is that correct?

MR. TUCKER: Sorry, what was that?

MR. CARROLL: Sorry. Say that again.

MS. JOHNSON: SRP's methodology includes overnight hourly market energy prices when solar output is zero, and it's not weighted for either when solar output occurs or when exports occur on the system?

MR. CARROLL: That's incorrect. It is weighted for when solar --

MS. JOHNSON: It is weighted? Okay.

SRP's marginal energy costs for residential customers as calculated in the pricing proposal are higher than the solar export rate for summer peak and winter periods regardless of service plan.

Why should solar customers receive less compensation for exported energy than the company's marginal energy costs?

MR. CARROLL: That was a question we answered with David, but the -- the marginal energy costs on schedule B there are assuming 1 kW in each of the hours.

MS. JOHNSON: Uh-huh.

MR. CARROLL: Whereas and the export credit was calculated with the ELAP prices but weighted by when the export happens.

MS. JOHNSON: Okay. Say what ELAP stands for again.

MR. CARROLL: I forgot again.

MR. SHOEMAKER: External Load Aggregation Point. It's a -- it's kind of a weighted average of trading nodes within the CAISO.

MS. JOHNSON: Okay.

MR. SANDSTROM: And that -- just to point out on the cost allocation study, for example, E-32, which is a commercial time of use rate, we do have a marginal energy cost -- this is page 85 of the cost allocation study -- an off-peak kilowatt-hour price of 2.05 cents in summer, 2.35 cents in winter, and a 5.54 cents in the off-peak period.

MS. JOHNSON: Okay.

MR. SANDSTROM: So there are periods where this marginal cost is below that 3.45.

MS. JOHNSON: Is that ever on residential or just on the commercial?

MR. SANDSTROM: Yes. So on E-16 and E-28, both of the new ones, that super off-peak period, there are -- again, during summer and winter the marginal cost of energy is below that 3.45.

MS. JOHNSON: Okay. All right. SRP identifies utility-scale solar project costs as a potential proxy for solar export credit rate but provides no data on their recent or forecasted utility-scale solar projects.

Is that data available?

MR. TUCKER: Well, most of those prices are under NDA, and that's part of why we changed the method here --

MS. JOHNSON: Okay.

MR. TUCKER: -- so that it was more transparent. The -- like they said, the price, the 3.45, is based on those averaged average outputs and the actual CAISO prices, which are publicly available, rather than what I would kind of feel like might be more of a black box with a forward-looking proxy group.

MS. JOHNSON: So it's possible that this question is based on your first --

MR. TUCKER: Yes.

MS. JOHNSON: -- proposal and not your second proposal?

MR. TUCKER: Yes.

MS. JOHNSON: Okay.

MR. TUCKER: Well, first being the existing -- it's possible that it's more reflective of 2019 pricing --

MS. JOHNSON: Okay.

MR. TUCKER: -- today's effective prices as opposed to what we proposed going forward.

MS. JOHNSON: I think, though, I didn't -- I -- I think I -- I'm pretty sure I downloaded the original filing and sent that for feedback and then didn't get the memo that there was a second one that had been forwarded to everyone.

MR. TUCKER: Okay. Just to clarify then, all that changed as it relates to this in the errata is the number itself, so the method of the proposal has not changed.

MS. JOHNSON: Oh, okay. And what is the export rate now, then?

MR. TUCKER: 3 -- 3.45.

MR. SHOEMAKER: We are proposing that to be 3.45 cents.

MS. JOHNSON: And is that the same for that QF-24 thing or that's different?

MR. TUCKER: No. So QF-24 is actually pointing to the realtime market.

MS. JOHNSON: Okay.

MR. TUCKER: So that -- yeah, that 3.45 is a blend of three-year pricing, historic pricing.

MS. JOHNSON: And then it will be locked in for a year?

MR. TUCKER: Yes.

MS. JOHNSON: And the other one would fluctuate?

MR. TUCKER: Yeah, with realtime pricing. Whatever -- whatever you're producing instantaneously --

MS. JOHNSON: Okay.

MR. TUCKER: -- at that -- whatever the

price is at that point in time that's what you'll be paid.

MS. JOHNSON: Okay. Okay. So, well, and I didn't know that this was the next question, but if timely fits into that, I'm just wondering, you know, with the other utilities you have a 10-year lock-in for your export rate.

And so I'm wondering -- you know, yours is just a one-year, so it seems to me that it's going to be extremely hard to evaluate on the front end what the payoff period is of your system when you don't know what the export rate is going to be next year.

And so why -- it's essentially a variable export rate, rates annually variable, and so how do you account for that or can that be changed?

MR. TUCKER: Well, the existing rate is at least -- was -- was a longer term rate; right? And that would potentially be revisited during the price process, and, again, I don't think that rate was super well received. So what -- what we were trying to do is go to something, again, that is more publicly available.

But the export rate that we pay to a customer is -- we, again, means SRP customers, so our customers are just paying that export rate to solar customers. And from my perspective, that is not a fixed value for 10 years. You can't calculate a value today that's reflective of that cost for a whole 10 years.

So I don't think that's -- I understand your point, but at the same time I don't think it's equitable to allow the rest of our customer base or to require the rest of our customer base to be on the hook as those prices may change over time.

MS. JOHNSON: Well, that's also what would happen with the utility-scale project; right? I mean, you would never have the utility scale --

MR. TUCKER: Right.

MS. JOHNSON: -- developer that's going to change what your contract is every year. They have a 20-year PPA or something like that, 30 years.

MR. TUCKER: I kind of feel like that's almost what I'm saying.

MS. JOHNSON: Okay.

MR. TUCKER: We -- when we sign a PPA for 20 years, we know what that number is for 20 years.

MS. JOHNSON: Yeah.

MR. TUCKER: When we pay a customer, we -- that's -- the valuation of that is the market.

MS. JOHNSON: Right.

MR. TUCKER: So that's what -- that's what that's worth to a customer is -- what of it to me, that's what that's worth is what the value of a market, you can -- what the market will bear.

MS. JOHNSON: Okay. I feel like I see what you're saying, but I'm not seeing how it's distinct.

So why is it that a -- if you're a utility-scale solar developer you should know what you're getting paid for 20 years, but if you're me as a developer, I'm basically a tiny developer; right? I'm selling you power, but it's going to change every year.

MR. TUCKER: Well, I think the 20 -- something that's more like a long-term proxy number is like what we're using today.

MS. JOHNSON: Right.

MR. TUCKER: Because under the existing rates, the 2.81 cents was based on a 20-year PPA. So that's in my mind that's one way to do is you base it on a 20-year PPA. That, again, like we said, wasn't super well received. So what we're doing is changing to point to a more realtime market, but that realtime market isn't the market price that's good for 10 or 20 years from now.

MR. CARROLL: And when SRP locks in a 20-year PPA, we also know the production profile, we can evaluate that with alternatives, and SRP can make the decision is this a good value. Whereas then for the export in particular it's a -- it's a when it's available from the customer.

So frequently, like, during July and August, peak times, there isn't export available because the customer's using their solar on their own site, and so the value from the export, it would typically be a lot less than the value from a PPA where we have a pretty good idea of what the profile is and can evaluate that relative to alternatives.

And so the way to be transparently fair is to base it off of what the market price is and when they're exporting.

MS. JOHNSON: What if you did something like -- and I guess I'm just wondering. I mean, like, I guess I don't know that I'm really disputing the idea of reevaluating the rate every year. Obviously all the utilities are changing their rate every year. I guess I'm wondering about the longer period than 12 months for the customer that's doing the install.

Like, is there any wiggle room to do a little bit of a longer period? Maybe it's not a 10-year period but something longer than one year. It just seems like it would be almost impossible to assess the value of it if the export rate could be a dollar in 12 months.

MR. TUCKER: And part of the reason if it's a three-year blended average of pricing is somewhat to that end, that it gives more certainty than -- you know, if it was just the one year, it would be like whatever last year was, and then it's a new year, and it could be --

MS. JOHNSON: It could be more volatile.

MR. TUCKER: -- an entirely different number.

Right. So we are trying to -- we're smoothing those impacts. We are smoothing volatility of a given year.

But, I mean, you certainly I think it's reasonable to propose if you want to propose something like that to the board.

But I -- I feel like the -- what we've put together is kind of as the balance between kind of equity amongst solar customers and the rest of the customers that have to pay for the export. That's the balance we tried to strike.

MS. JOHNSON: Okay. Circling back to QF-24 rider. I just am -- like, want to understand that a little bit better and why like what -- I guess what rate plan would you be on -- would you still be on one of these other rate plans and you would just be electing that as a rider in addition for your export?

MR. SHOEMAKER: Yeah.

MR. TUCKER: It would be an alternative, yes.

MR. SHOEMAKER: Right. Yeah. So for the -- the price plans to which that's applicable it -- it states it in the -- in the price plans. That's going to be in your appendix A.

MS. JOHNSON: Okay.

MR. SHOEMAKER: It will state that that's applicable.

And, yeah, what you'll do is as opposed to receive the 3.45 proposed export rate you would instead then receive your compensation for exports by the QF-24.

MS. JOHNSON: And, like, what kind of customer would that be advantageous for?

MR. SHOEMAKER: This would be for customers who as opposed to wanting that -- that stable known rate for 12 months who might want to take advantage of what they view maybe they could do better on the market. And so that's a more realtime reflection of what prices would be. It's -- it's an option for customers that might want to -- that might want to do that.

MS. JOHNSON: But, I mean, did you guys do any kind of -- like, what kind of customer would want to do that?

It seems like it would be a huge risk.

And, like, two people would actually know enough about how solar export rates actually work for that to make sense.

MR. TUCKER: I think what we were trying to do is to provide it as an option.

But, you know, if a -- if a customer was -- had -- the farther west facing -- the later their solar is producing the -- the -- I think may be the better potential of the QF rate, it works better for them.

MR. CARROLL: More storage customer.

MS. JOHNSON: Storage customer you think? Okay.

MR. CARROLL: Where they have the flexibility to dispatch based off of the marketplace.

MS. JOHNSON: You would have to be a very savvy customer for that to make sense; right?

MR. CARROLL: I think we want to provide the option.

MS. JOHNSON: Okay.

MR. CARROLL: And then let solar and storage providers, they can navigate that better than -- would have those options available.

MS. GLOVER: Excuse me, Autumn. I want to do a quick time check. I think we're coming up on an hour. Do you feel like you are close to wrapping?

MS. JOHNSON: No.

I have some rate design questions, some commercial solar questions, and then just some other broad questions.

MS. GLOVER: I would propose maybe we have you go to 2:30, which is a little extra time.

MS. JOHNSON: Oh, yeah, I don't think -- well, so what happens then if we don't finish?

MS. GLOVER: Well, why don't we make sure we get -- get through everything, answering supplemental questions that are left at the end of the day, and then if we have some time at the end of our day, we can maybe circle back.

MS. JOHNSON: Okay. Okay. Because we still have, you know, two and a half hours, so hopefully -- I mean, Caryn's not even back yet, so she's definitely not going to be ready to go.

Okay. So switching to rate design and talking about the monthly service costs, I'm just wondering why it's so much higher than the other Arizona utilities?

MR. TUCKER: Well, so our pricing is based on our costs. So I'm not an expert on other utilities' costs or their kind of approach to rate design.

But, you know, Bruce talked about our

pricing principles; right? But cost sufficiency, cost relation equity, gradualism, and choice, those are the -- those are the pricing principles as adopted by the board that drive and underlie management's proposal.

So our -- you know, our prices are not based -- our proposal is not based on, you know, other Arizona utilities.

MS. JOHNSON: Why is the cost of the meter going up?

MR. TUCKER: Well, I mean, costs of everything generally speaking go up. So what's proposed in the -- in management's proposal is simply based on the costs of that test year that we used for the pricing proposal.

MS. JOHNSON: Okay. In the MSC, monthly service cost, SRP assigns essentially double the distribution costs to residential customers with 225-plus amp service. It's not clear from their MSCs how exactly they came to this number.

So can you just specify a little bit what this means and who would be impacted by this -- the change from 200 to 225?

MR. TUCKER: So in terms of who's impacted for tiers are we talking about two or three of those customers with 225-amp panels or bigger, I think.

MS. JOHNSON: I'm interested in -- I think you moved -- the current barometer is above and below 200, and now it's above and below 225. And so I'm --

MR. TUCKER: Oh.

MS. JOHNSON: -- just curious why that change.

And then, yeah, who's definitely going to fall into tier 3?

MR. TUCKER: So, yeah, the current is 200. So there are -- we have a few customers, I think, that have up to 225-amp panels, so we were kind of grouping them in the lower cost bucket.

MR. SHOEMAKER: Yeah. When we talked with our -- with our metering group they were -- they were explaining some of the new nuances between and some of the distribution facilities that actually supply up to a 225-amp meter that they were similar to a 200-amp meter and below.

MS. JOHNSON: Okay.

MR. SHOEMAKER: So it's about the same facilities.

And the reality is even though our prior price plans had the cutoff at 200 they were considering that 225-amp class meter as a 200-amp meter. So this is kind of more in line with what we've been -- what we've been doing even in that separation today. We're just now acknowledging, hey, we have these 225-amp meters. Let's -- let's make that line -- make it very clear for customers what that line is.

Also, you mentioned one thing in your question, and maybe you could repeat it, but you mentioned that we're allocating twice as much distribution facilities cost to some of our -- could you restate the earlier part of that question?

MS. JOHNSON: It says SRP assigns essential double the distribution costs to residential customers with 225-plus amp service.

MR. SHOEMAKER: Gotcha. Okay. So I just want to make that distinction. When we look at the actual costs that we're allocating to those customers, that's going to be in the cost allocation study, and the difference isn't as pronounced as what we're reflecting in the price. And part of that difference in the price is we're trying to be, again, looking at balancing all of our cost relations, so it's better cost relation, but it's also there's an equity piece. When you look at the monthly service charge as percentage of total bill, these distinctions, the 20, 30, 40, helps bring those closer in line.

MS. JOHNSON: Okay. And then did SRP look at NCP by residential service tier to assign the distribution costs?

MR. CARROLL: We looked at -- maybe we need to make a distinction between the costs and then -- and then the revenues, the charges.

But for the cost, we looked at the sigma NCP for the distribution facilities by tier, and we used the NCP for the distribution delivery, but the distribution delivery is in the per kWh charge.

MS. JOHNSON: What percentage of residential solar customer are going to fall into tier 3?

MR. CARROLL: It's -- I -- yeah, you can do the math. It's on -- it shows it in schedule 5d, I believe. I can double-check and get you the page number.

MS. JOHNSON: And which document is that?

MR. CARROLL: The cost allocation study.

MS. JOHNSON: Okay.

MR. CARROLL: Yeah, it's schedule 5d, lines number 11, 12, and 13.

MS. JOHNSON: Okay. 11 through 13.

All right. Do you know how that compares to the overall residential customer class?

MR. CARROLL: You can see that on the same lines.

MS. JOHNSON: Okay. Okay. In the new E-16 managed demand rate it adopts a five-hour on-peak period.

Why are you proposing the additional two hours on-peak as opposed to the on-peak period in E-28?

MR. TUCKER: So for a demand rating you'll see it's consistent across all our demand rates. It's a five-hour on-peak period for all the business demand price plans as well, the same five-hour period.

But for demand rate, and that's about reflecting costs of capacity, we wanted to cover all the hours for which we are incurring capacity costs. So that's -- that's why we have those extra two hours compared to the E-28 price plan. It's about best aligning a demand price with the capacity-related cost.

MS. JOHNSON: Okay. Can customers be reasonably expected to manage demand while also managing their on-peak usage over a five-hour period?

MR. TUCKER: I would think so.

MR. CARROLL: Yes. That would be E-27 has been doing it for six hours currently.

MS. JOHNSON: Okay. And you --

MR. TUCKER: It's our most popular solar price plan.

MS. JOHNSON: What are the highest on-peak hours?

Like, we don't have the heat map that you provided to Vote Solar, so what are the hours of the day? Usually it's not five hours. I'm surprised that it's five because I've seen them for the other utilities, and it's usually more of a three to four-hour like your hottest, reddest hours.

MR. CARROLL: For on the -- like, the loss of load probability, the -- where the capacity is most constrained?

MS. JOHNSON: Yeah.

MR. CARROLL: It's 6 -- hours 6 to 7, I believe, is the most constrained, and then 7 to 8 is the next most constrained. I think those two are the top two hours.

MS. JOHNSON: And do you know what the third hour is?

MR. CARROLL: I believe it would be -- it depends -- what do you mean of the year you're looking? I think we're -- if you're looking out to 2030, I believe it's the 8 to 9.

MS. JOHNSON: Okay. So 6 to 9 is your -- I mean, that now makes sense for that plan.

MR. CARROLL: Yeah.

MS. JOHNSON: Okay. So my next question is do you have peak until 10 p.m., and is that year round?

MR. CARROLL: Do you mean on the loss of

load probability are there peak-related costs until 10 p.m. year round or on the price plans are they 5 to 10 p.m. on-peak, is that year round?

MS. JOHNSON: I guess I'm asking -- I don't know if I'm asking either of those.

I guess I'm asking if you're ever hitting peak -- you know, like you set a peak record in August, and obviously when you have peak it's going to drive additional system costs.

Is that really happening at 10 p.m., that late? I mean, that surprises me.

MR. CARROLL: It -- it's -- part of what's been a transition in the industry and in our cost is that it's shifted later --

MS. JOHNSON: Yeah.

MR. CARROLL: -- those loss of load -- the late hours.

And we do have -- once you start getting out to 2030, and especially if you forecast long-term, those hours we believe will be important.

MR. TUCKER: There's also a difference between a system peak and net peak.

MS. JOHNSON: Yeah.

MR. TUCKER: And the generation capacity requirements are based on net peak, not system peak.

MS. JOHNSON: Okay.

MR. TUCKER: And the -- and the net peak is moving to the late hours as Mark was talking about.

MS. JOHNSON: Okay. Because on page 45, you talk about having higher system costs from 6 p.m. to midnight. You know, that's a quarter of the day. And I'm wondering -- well, that's on page 34. I'm sorry.

But it's also interesting -- so I'm wondering what's driving that usage, but I also think it's interesting that you specifically currently have rate plans that incentivize people to start using power at 11 like your EV super off-peak period, so that might be driving that.

MR. TUCKER: Well, it's very much the point of why those TOU hours are not appropriate going forward. That's why we're proposing the new hours because the existing programs really do send some signals that are not aligned with costs.

MS. JOHNSON: And so you mention, you know, you said the E-27 -- what's the on-peak period for E-27 right now?

MR. TUCKER: 2 to 8.

MS. JOHNSON: 2 to 8. And you said that's your most popular plan?

Oh, E-23 --

MR. TUCKER: For solar customers.

MS. JOHNSON: -- was your most popular plan.

MR. SHOEMAKER: That's 2 to 8 in the summer. And then it's in the winter it's going to be 5 a.m. and 5 -- 5 to 9 a.m. and 5 to 9 p.m.

MS. JOHNSON: Okay.

MR. SHOEMAKER: So right now it's going to have seasonal differences in the on-peak.

MS. JOHNSON: Well, we were just -- you know, we were talking about our kids earlier. It just strikes me that a five-hour on-peak period from 5 to 10 p.m., if you really want people to shift their behavior, I'm wondering, like, when are people supposed to eat dinner?

MR. TUCKER: Well, the price plans, they're based on cost, and these are the costs that we're incurring. These are the costs -- these are the hours over which we incur capacity cost.

So what we try to do is send price signals to customers, and, again, E-23 is an option for a lot of customers as well. But what we're trying to do is make sure that our prices are reflective of costs, and then customers can respond as they will.

MS. JOHNSON: But E-23 is not an option for solar customers?

MR. TUCKER: That -- that's true.

MS. JOHNSON: And it's interesting that you say that because I think it's, like, over 65 percent or something of your customers are on E-23, which doesn't help you reduce peak at all because they can use as much as they want whenever.

MR. TUCKER: Well, we do provide choice to customers. They can elect E-23. E-23 does have a higher price because of that. So they're -- they're sort of electing I'll pay this higher average price because I don't want to have to respond to price signals.

But, you know, I'd also -- you mention the five-hour period, but recall there's a three-hour TOU period that solar customers can participate in as well.

MR. CARROLL: Without a demand charge.

MR. TUCKER: Yeah, without a demand charge.

MS. JOHNSON: Yeah, I think that's -- I understand.

MR. TUCKER: Oh, okay.

MS. JOHNSON: Why are you -- I guess this is interesting he brought this up. I mean, I generally think that most people don't understand demand charges, and so I'm wondering why you're keeping that as part of the new residential rate?

MR. TUCKER: Well, one, it's an option. But, two, we've heard candidly we've heard from solar installers that are interested in having it.

MS. JOHNSON: Yeah, but solar installers that preference -- so usually if you have solar and you want to be on a rate that has a demand rate, it makes sense to you if you have storage, but there is no battery that can work for five hours, and so if you have a rate plan that basically incentives the use of pairing solar with storage but you have a TOU period that is beyond the technical feasibility of the battery, what is the point?

MR. TUCKER: Well, I guess I would say solar installers have told us they would like a demand rate. We were happy to design a demand rate that was based on cost.

We -- that was the focus, though. It doesn't about -- that's what it was based on is it is a cost-based rate, and so we designed -- we heard we'd like to have a demand rate still so we can continue to sell more of our product, so we designed a demand base -- a demand rate that's based on cost.

MR. SHOEMAKER: And -- and to that point too, again, the current most popular solar rate that we have is a six-hour period that has demand for that six-hour period as well. So this is one hour shorter than the current six-hour period. So the proposal shortens that on-peak period, not lengthens it.

MS. JOHNSON: But it's 2 to 8; right?

MR. SHOEMAKER: It's 2 to 8.

MS. JOHNSON: So the sun in the summer is shining until 7:30. You know, you're still getting production. In your new plan you're going to have production for not -- you know, a really -- a much shorter amount of that five-hour period.

MR. TUCKER: Well, it's only a couple of hours. If you're getting sun -- if you're getting sun until 7:30, you're only covering two hours, two and a half hours with battery.

MS. JOHNSON: Okay. I'm wondering why does the super off-peak period -- why is it year-round and why does it start at 8 a.m.?

MR. SHOEMAKER: The first reason is it's year round as we've heard. We've heard through customer surveys and market research that customers want consistency in their rates throughout the year.

Having -- having seasonal changes like when do I need to change my thermostats or my behavior to 5 a.m. -- 5 to 9 a.m. to 5 to 9 p.m. and vice versa, that gets confusing for some customers.

So part of the reason to have that all year round is to make sure we have consistency across seasons for those customers.

Is that -- is that part of your question?

MS. JOHNSON: Yeah, I mean, because like, for instance, APS has it in the winter but not in the summer.

Why does it start at 8 a.m.?

MR. SHOEMAKER: It's reflective of the marginal costs that we see.

MS. JOHNSON: Okay. And then, you know, to your point about it being confusing when things are one part of the year but not the other part of the year I think it's interesting and confusing that the rates change three times, including in the middle of summer, right, so the TOU period is the same but the actual costs and, you know, presumably your bill, even if you're adhering to the same TOU period, is going to be wildly different at different times of year, including in the middle of summer.

So is that pretty typical?

Why does SRP do that?

MR. TUCKER: Well, the -- it's reflective of costs. And if we're concerned about reducing capacity requirements and lowering costs and lowering the need to build whatever kind of capacity requirements a utility's going to build, you want to send a price signal that reflects -- that tells customers, hey, it's expensive to use power now. And it's most expensive over two months of the year that had that summer peak season.

MS. JOHNSON: But you think customers understand that?

MR. TUCKER: Yes. We know customers are responsive to price signals.

MS. JOHNSON: But, I mean, does the average customer know that the price per kilowatt is, like, way different in July than it is in June?

MR. TUCKER: I -- I guess I don't know if they know that or not, but I think that what we do know is that they know there's a differential and they're responsive to it.

MS. JOHNSON: Okay.

MS. GLOVER: Do you want to bring yourself to a good stopping point?

MS. JOHNSON: I'm not. And I'll just point out that you guys didn't tell us we only had an hour until yesterday, so I don't feel like that's appropriate.

But I will pick up my questions if there's more time. And if not, I'll be asking for another day of interviews.

MS. GLOVER: Okay. Before we wrap with

you, I took note of a couple of things that it seems like we might be able to get some answers for you maybe from other people.

The first one was concerning load growth impacting the test year. I think you asked about large customer load growth. And then I think you asked about the cost of self-developing the Copper Crossing Energy Research Center.

Are those really the two?

MS. JOHNSON: Oh, you're -- I thought you were telling me that these are the answers you have right now.

MS. GLOVER: Oh, no, because I think we might be able to get a couple people that can get those answered for you.

MS. JOHNSON: Oh, let's see. I circled a whole bunch of ones that you didn't have the answers to.

I did -- are you wanting me to read them back?

Is that what you want me to do?

MS. GLOVER: Well, those are the two that stood out to me that we can probably find some closure to --

MS. JOHNSON: Those are two that I have.

MS. GLOVER: -- that were based on things that were raised in the blue book. So if there were things -- questions or concerns you had -- the blue book, I should say the pricing proposal. If there are questions that you have that were outside of that, we would --

MS. JOHNSON: Well, I don't think any of them were outside of it because they all came up while I was reading the proposal. But, yes, you're right, I did ask about why it's cheaper for -- and faster for SRP to do a self-build, and it was based on that example on page 14.

And then I did ask specifically about the data center -- well, just load -- what the load growth breakdown is over the test year and then the percentage related to data centers.

MS. GLOVER: Oh, okay. So why don't we take 10.

MR. NEIL: How about five? Last time it was 12.

MS. GLOVER: Well, I'd like a few minutes to try to gather up the information that we're looking for and get the right people involved, so that'll take a few minutes. Okay?

So we'll take 10 minutes unless you feel -- okay. And then when we come back, we'll have Caryn.

(Break from 2:35 p.m. to 2:48 p.m.)

MS. GLOVER: Autumn, to wrap up what you were -- to wrap up what we were discussing, we would ask that you submit your question on the load forecasting. We think it would be best if we have a written record of exactly the information that you're looking for so we can get it right and make sure the right people answer that. I'm still looking for -- to see if we can locate the right person to answer the question about the Copper Crossing construction.

So at this time we will invite Caryn.

MS. POTTER: Yep. Thanks so much.

I have just a preview if it helps for planning purposes. I have a few different sections I'll be reviewing and asking questions on today.

I'll be asking questions in relation to your residential rates methodology. We covered some of this a little bit earlier, so some of it might duplicative, but I'll try to eliminate that as much as possible.

I do have some questions as well on residential rates for E-16 and E-28 and specific questions relating to demand charge.

I also have some questions in relation to the large general service rates, specifically E-67, the tiered monthly service charge, and the carbon reduction rider.

But before I get into all of that, just one quick housekeeping question. Can we confirm that the transcripts of these interviews will be made available free of charge next week to the public or to the interviewers participating in this process today?

MS. GLOVER: We will either make it available upon request or put it up on the website.

MS. POTTER: So it will be accessible free of charge?

MS. GLOVER: Or, of course, it will be available in the information room as well.

MS. HETH: I don't know that we can guarantee at this point that it will be available next week. I think that will depend on the turnaround with the court reporter, but as soon as it's available we'll make it available.

MS. POTTER: Okay. Great. Thank you so much.

PANEL INTERVIEW BY MS. POTTER

MS. POTTER: Okay. So going on to residential rates methodology. Some of my questions do refer to certain pages. Some of them are a little more general.

So generally speaking how does Salt River Project develop its residential rates?

Can you just speak to it broadly?

MR. TUCKER: So, yeah, I'll take a crack at that.

So we have a forecast that drives a resource plan. The resource plan feeds into a financial plan that -- and then the forecast also drives revenue estimates. So the revenue and the costs get combined into the financial plan. And then we look at are the revenues sufficient to cover those costs.

So when the answer -- and, you know, between cost cutting, borrowing, and if those two things don't get us there, then it's kind of price process, and that's where we're at now where the last one was 2019.

So then we take from that financial plan, which is a six-year look at our costs, we usually take the second year of the financial plan because that's the first year the prices would be in effect, and that's the source of the information that Mark uses in the cost allocation study.

And then the cost allocation study looks at how customers by class are covering their cost of service. So in this case we said we need 2.4 percent net revenue increase. The cost allocation study looks at how equitably our customers currently are covering their costs.

If everyone had equal returns, we would allocate a 2.4 percent increase to everyone. Because returns vary the rates would be lower returns for the higher increases and vice versa. And then so that then the revenue targets, the revenue requirement, basically comes out of that work, and then the residential rate designer would be told you need to collect this much money from E-24 customers, this much money from E-26 customers and so on.

And then they will build prices based on -- informed by marginal costs like we were talking before to get to a pricing proposal that based on all the customers on a given rate should bring in the revenue that we were targeting.

Is that helpful?

MS. POTTER: Thank you.

For each specific residential rate will SRP use the average load shape to calculate the rate or does it use another load shape generally in order to feed into the appropriate price?

MR. TUCKER: So the -- we use the rate -- the load shapes that are respective to those individual rates. So we don't take an average of all residential customers and look at -- we look at what do your E-21 customers look like, what do E-23 customers look like, what do basic customers look like in terms of load shape and the related costs.

MS. POTTER: Are the load shapes developed from using a flat rate, a time of use rate, or both?

MR. TUCKER: The load shapes are based on actual customers on the given rates. So you have a TOU customer -- a TOU rate. We take the actual TOU load shape from that rate when we look at the costs that we incur to serve them.

MS. POTTER: And what about E-16? So that's a brand-new rate. It's never been used before.

So how was that developed?

Was that developed from a flat rate or a time of use rate?

MR. TUCKER: Do you want to talk to that design, Karl?

MR. SANDSTROM: Yeah. So there is several I would say acceptable ways to get to those numbers. For SRP for this rate design, because the super off-peak hours and the on-peak hours are significantly different than many of the price plans we've offered before, I think for me the key being that super off-peak period being a new part of what rates are.

And so we took E-23 customers, so the flat basic customers, because they're -- they are not responding to any specific hours today. And so we used them to model if these customers were all E-28 or E-16 and they did not do anything different, here's what their load shape looks like and here's what the prices would be to meet that revenue requirement target as mentioned by John.

MS. POTTER: So confirming for clarity, does that mean, then, the E-16 rate, which is a time-of-use rate with a demand charge, was created using a flat rate load shape?

MR. SANDSTROM: Yes.

MR. TUCKER: And to be clear, that -- I think that's a conservative approach. We could have -- because the customer -- to the extent customers modify their behavior on that rate they will lower their bills.

So it's certainly in the realm of the plausibility to model some of that and assume, hey, we're going to have revenue lost because we did not assume customers modifying their behavior. So other utilities do that where they estimate, okay, we think customers will actually behave differently, that will lower our revenue, and then they raise the price up to make sure they get the targeted revenue requirement.

So that our approach is conservative and could result in slightly less money than we're trying to bring in.

MS. POTTER: Yeah. And the reason for the question is to better understand for a new -- for a new rate like this, which will be considered a significant rate for -- since everything's going to be collapsed by 2029, I wanted to better understand a rate that has availability that is a time of use rate and how -- what data was constructing that rate and if it was being appropriated in terms of the signals and the timing, so thank you for that.

I wanted to refer now actually to page 2 of the customer allocation study. I have a couple of questions on loss of load.

So on page 2 SRP's proposing to move, of course, to the LOLP methodology when calculating the peak contribution generation resources. I believe it was mentioned earlier, but just for clarity so I can make sure I have this information, can you provide again the hours that the LOLP methodology will be looked at in determining the peak load contribution?

MR. CARROLL: It looks at all hours. And then it summarizes them based on the 12 months, 24 hours for each month -- sorry for the court reporter. I'll stop using hand gestures -- and then splits it into weekdays and weekends. I believe there's 576 hours that it summarizes, and then we summarize the load in the same way.

MS. POTTER: And confirming, though, for -- for all hours, though, on-peak, off-peak, and super off-peak -- or, sorry, on on-peak and, yeah, super off-peak, and that's for any of the time-varying plans; correct?

MR. TUCKER: The loss of load probability is a -- a system calculation, and then each of the -- each of the price plans has their own load shapes that's unique to that price plan to apply to.

MS. POTTER: So are you sure that the loss of load is the same calculation spread amongst the classes, and then from there you're using your variation to decide what is the appropriate on-peak, off-peak windows relative to that demand profile essentially?

MR. CARROLL: If I -- if I followed you, I think the answer is yes. We used the individual load profiles from each price plan applied to the same systemwide loss of load probability numbers to calculate each price plan surge classes' share of the weighted loss of load probability megawatts.

MS. POTTER: Thank you.

And you may have already answered this, but feel free if I can refer to this -- the transcript later.

But how exactly does SRP determine the LOLP hours?

I think you already talked about it a little bit in your stance earlier, so I just want to make sure.

MR. CARROLL: We did talk about it a little bit earlier, but just to be clear that our load production modelers do a Monte Carlo simulation. They do tens of thousands of iterations and with different weather years, different outage simulations, and then they summarize that for us as I previously mentioned.

MS. POTTER: How does SRP consider energy efficiency and demand response or demand site management in the modeling of LOLP hours?

MR. CARROLL: I believe that would -- the energy efficiency load reduction would have -- would be part of a different forecast that are inputs to the model, but if you have specific details, you could submit those.

MS. POTTER: Okay. Yeah, we'll submit to just to confirm.

Okay. I do have a couple of questions kind of related to some of the solar stuff. It's more for I'm more interested in kind of the broader impact as well for all residential customers.

So would you agree, then, that all else being equal, moving to the -- the new methodology that you're proposing from the 4CP will lead to more costs than for residential customer class compared with the commercial rate class?

MR. CARROLL: The -- relative to the commercial class, the loss of load probability weighted peak is relatively higher for residential than commercial?

I don't -- I don't have any -- I'd want to -- I'd want to check that.

MS. POTTER: Maybe that's something we can table for follow-up.

MR. CARROLL: Yeah.

MS. POTTER: And then this might be another follow-up question, but would you also, then, agree that this is an increase in cost is -- being borne by residential solar customers?

You may have asked this earlier, but I just wanted to confirm -- or this may have been answered earlier.

MR. TUCKER: Well, to be clear, the way I think about that, the costs are what they are, and we're trying to allocate them accurately to customer classes. So, I mean, that's my number one, I think, the most important criterion is that system costs are what they are, and what the cost allocation study does is it tries to allocate those costs as accurately as possible to all of our customer classes. It's agnostic to who's getting those costs. It's just trying to accurately allocate those costs to the customers that cause us to incur them.

MR. CARROLL: Okay. Management's revenue targets -- okay. Management considers the cost allocation study when setting the revenue targets, but then it's heavily -- with heavy deference to gradualism. And so the results of the cost study aren't directly -- the prices that the residential customers will pay management considers gradualism as well.

MS. POTTER: I want to go back to the moment for the load shaping and the use of a flat rate versus the time of use rate for the development of E-16 -- or, sorry, for the LOLP.

Can you explain the justification or your reasoning for using a flat rate and not a time-differentiated rate for calculating rates for your new -- your new plans, obviously E-16, E-28, given that both of these rate plans are time differentiated?

I just want to go back to that for a moment because I think that's -- depending on how that information is utilized, that could have a significant impact in terms of how these costs are borne out amongst all of the customer classes because the methodology is so important to setting up all of the other load profiles and all the other price plans.

MR. TUCKER: So I'll ask these guys to chime in as well, but the costs are what they are. The prices and the price -- underlying price plan are based on the costs that we incur. The assumptions I think in terms of a flat -- in terms of the customer load profile where we use the shape of a customer who does not respond to time of use, again, I think that was a conservative approach because we could have tried to model what customer responses would actually look like, and that likely would have resulted in us bringing in more revenue.

So that, again, I think that's a conservative approach the way we modelled the assumed load behavior, but the pricing is based on cost.

MS. POTTER: Okay. Do you generally see customers on existing time-varying rates able to shift to system load out-of-peak periods as of today on SRP's system?

MR. TUCKER: Help me understand that a little bit better.

What do you mean by shifting to out-of-peak loads?

MS. POTTER: Yeah, I can rephrase that.

So are you seeing right now that customers that are on time of use plans today, are they having an impact, or are they helping SRP to avoid more power being utilized during on-peak periods of the day?

Is it having an active impact on demand reduction?

MR. TUCKER: Can I try it two ways?

One I would say we do see customer -- customers responding on TOU rates. The challenge is, though, the hours that they're responding because that's what we ask them to do in the rates, so it's, you know, no fault of their own. They're changing their load like we ask them to based on the price signal, but that isn't very much in line with our costs anymore.

So I'd say the answer to your question is ultimately they are not responding all that well to help us reduce our costs, but that's our fault for the TOU hours, not their fault for not responding to the price signal, and that's why we have the new proposed hours.

MR. CARROLL: Thinking about like EZ-3 in particular, that period of 6 time period, we see customers reduce their -- their usage along from 3 to 6, and that was appropriate, and we gave them a bill savings because it gave us a cost savings historically, but in the last three years that 3 to 6 hours is not important from a generation capacity. Especially going forward 6 to 9 will be the most important hours from a cost standpoint. And so that's why the proposal -- it's important to get the time of use hours aligned correctly.

MS. POTTER: How much capacity of megawatts were shifted or avoided entirely due to time of use price plans during the test year?

MR. CARROLL: We can get you that if you submit it.

MS. POTTER: That would be great. Thank you.

Okay. Let's go on. We're going to talk a little bit -- I'm going to -- we're going to talk about primarily E-16 and E-28 in this section. I might be going back and forth between those two options.

So generally speaking, what are Salt River Project's primary goals for proposing the new time of use price plans E-16 and E-28?

What's the goals or the objectives for the plans?

MR. TUCKER: I think they're probably in line with our five pricing principles. So they need to be sufficient. They need to bring in enough revenue to maintain the health of the operation. They need to be based on costs, and that's why we have, again, these two new TOU programs that are a lot different than our existing programs. There's a couple options, so there's choice.

Equity is about being based on costs and making sure customers aren't cost shifting. And then gradualism, I don't know if that applies as much, but beyond the fact that there will be some time to help customers, you know, for us to work with the customers to help them understand new options.

MS. POTTER: Are there any other secondary goals, then, anything like grid management, any savings for customers or anything else that you were thinking about when you were putting these plans together?

MR. TUCKER: Yeah, certainly. And I appreciate you asking that because there's a lot of underlying things that I just didn't think to say. So, for example, when I say cost relation, yeah, I want to -- I want to send a signal to customers at the right time for them to reduce their load to lower our costs, and then we pass that savings on to customers. So, yeah, we want to -- we want to help customers lower their energy expense if they're willing to participate with us in a time of use rate as an example.

MR. CARROLL: We were also very cognizant that the super off-peak price aligned very well with our low carbon hours.

MR. TUCKER: Absolutely.

MR. CARROLL: And we believe that it will help increase or decrease our carbon density and increase our sustainability by offering really half-priced power when it's green resources that are providing that power.

MS. POTTER: So when would you say that one of the objectives for proposing new time of use rates is to -- one, to set send a signal to help to decrease maybe more -- maybe decrease the use of, like, fossil fuels during your on-peak periods of the day or to help to avoid capacity during your most expensive times of the day in terms of your marginal costs?

MR. TUCKER: So that if I -- I think you were asking does -- are the price -- the proposed price plans intended to reduce our peak costs? Yes, absolutely.

And then what was -- was there more to it than that?

MS. POTTER: Yeah, in terms of sometimes

some utilities have also additional decarbonization or sustainability goals when it comes to time-varying rates, so is that one of SRP's goals as well when it comes to the E-16 and E-28 price plan to utilize these plans as a means of avoiding more -- maybe more costly capacity but also capacity that is probably more dirty when it comes to a carbon emissions perspective?

MR. TUCKER: Yeah. In particular the way I thought of it was more along -- in terms of the carbon emissions, I thought it more along the lines of what Mark said where we have this large chunk of time in the middle of the day where we have a lot of nonemitting resources available to us, and to the extent that we can encourage customers to shift their consumption into that period of time, I think that's a huge win both from a cost perspective and from an emissions perspective.

MS. POTTER: Thank you.

So now I'd like to refer to looking at the different price plans. I'd like to refer to E-15. So specifically Table 12 I want to review for a moment the customer characteristics table. This is a similar table that has been provided for some of the other price plans, but specifically I wanted to talk about why this particular analysis for customer characteristics that explains the average bill impacts for customers by stratum, why this analysis was not included for all of the price plans, and in particular E-16 and E-28, which, you know, SWEEP would argue based on your proposal is one of -- is two of the most significant residential price plans that you want customers to move to in the future, so why wouldn't a similar customer impact analysis be provided for those price -- for those price plans?

MR. SHOEMAKER: Yeah. These -- these impact tables -- and feel free to correct me if I'm wrong, but these impact tables are generated with regard to the customers that are on the plan, what are the stratums of customers that are on the existing plan.

And so for 16 being a new rate, E-28, we have it in pilot, but this is a new rate. We don't really have the customers on it to be able to break those down by stratum.

MS. POTTER: Would SRP be able to provide some let's say some assumptions or estimates for what those stratums would look like in order to provide new customers kind of a sense of what their impact would look like?

Is that a possibility for customers?

MR. TUCKER: It sounds like are you talking about maybe a bill comp?

So I'm not -- or what I think I hear you saying is can we create a table like this for the new rates so customers can understand their potential bill better?

MS. POTTER: Yes. Is one of the challenges with -- you know, it's always helpful to look at the -- you know, the impact of rates relative to the revenue adjustment or the impact for SRP, but it's challenge -- it's going to be challenging for customers looking at this to really understand how these two rates are actually going to on average potentially impact them.

So I'm wondering if there's an opportunity -- you know, even if it's an estimation utilizing the average monthly summer energy consumption rate, if there's some kind of estimation that you can provide to give people a sense of where they may land if they're interested in these price plans.

MR. CARROLL: I think what we did for the pilot on E-28 we provided a lot of information for customers with different estimates. You know, there's no one on the rate now, but if -- if you move your air conditioning or put your precool on on these hours, this is what the cost savings could be. If you do your laundry on --

(Reporter clarification.)

MR. CARROLL: I'm sorry. If you do your

laundry on -- oops, hand gestures again.

Sorry. If you do your laundry -- if you move the laundry from the off-peak hours to the super off-peak hours, here's the savings and what savings might look like. And I -- and we will offer things like that as part of the -- the education materials to customers when we're moving customers to those rates.

MS. POTTER: Does that mean that it's not possible to create even an estimated customer characteristics table like this for Table 12 for the new E-16 and E-28 price plans?

Is that not a possibility or not an option to create?

MR. TUCKER: I guess I'm not sure how we would accurately -- how I could get comfortable with the way we model the load behavior to -- I mean, that's my only -- you know, that's what gives me pause about the concept.

It's not that I don't want to share the information with people. I'd like to give them as much as we can to help them make an informed decision. I'm just not sure that the -- I'm not sure -- we -- so for, one, as I think I mentioned earlier, we have customers, we can provide them a bill estimate based on their current usage, which, again, isn't responding to the price signals, so I recognize it has limitations, but we can -- if nothing else, we have that right now.

And Mark said we had -- we had worked to try to communicate how behavior changes could impact your bill when we put the E-28 pilot together, and those are the sort of things that we'd want to communicate, but that's just my concern about that idea.

MS. POTTER: That's fair. But I guess I'm bringing this up because, you know, SWEEP believes that it would -- it's concerning for customers to walk into this, especially with all the price plans collapsing and not really having a clear sense of what this is going to mean for them, so I think that should be something SRP should consider. And maybe we -- I would heavily encourage that we would do that in this pricing process for creating some kind of understanding of what people should be expecting.

MR. TUCKER: Okay.

MS. POTTER: Thank you.

Okay. So moving on, is SRP planning for the E-28 time of use price plan to become the default rate for residential customers?

MR. SHOEMAKER: Yeah. Yeah, as far as default -- default rate, we don't have, and this sounds similar, we've been working on your data request as well, so some of these sound pretty similar, Caryn.

But as far as a default rate, we don't -- we don't really have a default rate that -- that we're aware of from customer operations that they -- they put a customer on. They -- they typically will talk, you know, what, agents are familiar with and comfortable talking about, you know, price plans with customers.

You know, today if a customer -- you know, they'll maybe hear a time of use option. Maybe -- maybe they'll hear up to a second depending, but if they want to turn on service, they can -- they can put them on, you know, the basic rate today and then allow them some time to further research and make a decision.

So, you know, I don't -- in conversations with customer, are you guys aware of any kind of default that they're -- that they're going to do? I'm not aware that there's a default rate. We can circle back with customer service and --

MR. SANDSTROM: Yeah, we don't -- no, we don't have any form of an opt-out use like some other utilities may have.

But I would anticipate if someone called, you know, December 2025, you know, if approved and they ask to take service, I believe the first option would be offered would be 28. So in that sense that -- so not quite a default in that, you know, if you call us up we will put you in that rate, you know, and that's it, but I think that will be a primary option offered along with the existing.

MS. POTTER: So, if I may for a moment, so if I could put a scenario together. So, like, let's say I'm a customer setting up service for the first time and I'm talking with customer service going through the process. You know, I'm trying to initiate service.

As I'm, you know, I'm talking to the customer service agent, and, you know, we come to the point where I have to select a plan, what is SRP's, you know, communications protocol for, you know, how they're asking customers for what plan they want to put -- that they -- you know, that they want to be placed on; right?

So is there -- do you just say you can start with just the basic price plan just to get you started, or is there some kind of education for what plan that you move customers towards?

MR. SHOEMAKER: Yes. To be able to respond to that really well and not give you inaccurate information, we probably need to double-check with our customer contact operations folks to get, you know, how they -- how they walk -- how they're trained to walk customers through those options, so that can be something we can follow up.

MS. POTTER: All right. That would be really helpful. Thank you.

But it does sound like at least for now it -- it sounds like the intent at the moment -- and please correct me if I'm wrong -- that, you know, through the conversation that the E-28 plan at least will be, you know, encouraged or shown to the customers as an option, and that is a good starting point, if you will.

Is that fair?

MR. SHOEMAKER: I think they do tend to lead with a time of use option to help customers understand it, and, again, we'll confirm, and then kind of a fallback, if you will, is basic. So --

MS. POTTER: Thank you.

Okay. Just one moment, please.

So for both the E-16 and E-28 price plans, did SRP use the E-26 standard rate price plan load shape in developing the rate?

Is that -- I think I believe that's what I read or I just want to make sure I understand that correctly.

MR. SHOEMAKER: I thought it -- and so and then I misunderstand the question because it sounds similar to a question you asked just earlier. Could you repeat that?

MS. POTTER: Yeah. So we were talking a little bit earlier about an LOLP section about the use of either time of use load shape just generally or a flat rate, but I believe I read and I unfortunately don't remember the page, so I do apologize for that, but is the E-16 rate and the E-28 rates, were the creation of those rate plans utilizing the E-26 standard rate plan load shape that was developed for that plan to develop the new proposal that you have set forward, or was that just created entirely -- you know, entirely new?

MR. TUCKER: So, again, I think it goes back to that -- tell me if I'm -- if I'm missing the question. I think it goes back to that same discussion where the pricing was based on the -- our cost or costs, but the -- so the load shape that we assumed drives revenue assumptions, how much revenue we think we'll collect from customers based on their on, off-peak and super off-peak usage. And for that purpose what we used was the standard -- the shape of a standard price plan E-23 where they're not responding to any price signal yet because, again, I think that's a little more conservative approach.

MS. POTTER: Okay. Gotcha. I just wanted to make sure. Thank you.

MR. TUCKER: Okay. Sure.

MS. POTTER: One moment.

Okay. Could you explain the reasoning then -- and this is going to be familiar from the data request, but I just want to talk about it a little bit today.

Could you explain the reasoning behind the minimal changes? And I'm looking and referring to the E-28 price plan.

I want to talk about the minimal changes and the price differential between the three pricing seasons and the on-peak and off-peak periods for E-28.

You know, was that -- would that be a specific decision in terms of essentially combining rates, the summer and winters rates, into a similar price. You know, when we're looking at the, you know, the price per kilowatt-hour for each of those pricing seasons, they're very similar for summer and winter, and so similar that the pricing signal may not be as responsive as my -- as you originally desired, right, in the creation of the plan. That's one of our concerns.

So I guess I just want to better understand the decision-making behind that or if that was an intentional choice.

MR. SHOEMAKER: Sure. And can I -- can I

just -- just for clarity if we look at maybe page 92 we're talking about the differences, then, between which of those time-of-use periods, the on-peak between summer, summer peak and winter?

MS. POTTER: The difference between the summer pricing season and the winter pricing season for --

MR. SHOEMAKER: Okay.

MS. POTTER: -- on-peak and super off-peak.

MR. SHOEMAKER: Okay. Okay. So independent of summer peak you're talking about the differences between summer --

MS. POTTER: Yes.

MR. SHOEMAKER: -- and winter.

MS. POTTER: Yeah. Okay.

MR. SHOEMAKER: Okay. Okay. That is -- that is helpful.

MR. TUCKER: So in my mind there's a couple thoughts there. One, when it comes to the capacity cost reduction concept, the capacity costs are incurred in July and August. So that's why you see a very large relatively speaking on-peak price in the summer peak season, just those two months.

So we're not incurring a lot of capacity cost in the winter and summer seasons. The bulk of our capacity costs are incurred in the summer peak season. That's why you see such a marked differential in the on-peak price and the other prices in summer peak.

But in terms of the other idea that we talked about, encouraging customers to shift as much load as they can into that super off-peak period, there is still a pretty hardy differential, I think, between super off-peak and the other two prices for both the summer and the winter season.

So it's not as critical that we're not -- we don't -- but the costs don't suggest that we send a price signal in the on-peak period for winter and summer like we need to send one in the summer peak season.

MS. POTTER: So then it sounds like the main focus for both E-16 -- or, sorry, E-28 it -- when it comes to the price differential your -- your intended focus is to really ensure that you're having maybe a larger price differential for that summer peak season to send that; correct?

MR. TUCKER: That's -- that's right because that's where the costs are. That's where we -- the costs come from that season, so we send the higher signal in that season.

MS. POTTER: Okay. So then going to the proposed adjustment document on page 91 and 93. Let me pull that up. So for that, yeah. I'm just going to review that price plan a little bit more. I guess I wanted to -- and we went into this a little bit with Mr. Chapman on the price differential.

In our calculations it looks like the differential is closer to a four to one specifically for the winter on-peak and off-peak rates and also the summer as well. And typically, you know, based on consumer preferences and consumer adoption of time of use rates, usually a three to one is more of a desired approach.

So can you provide any SRP's perspective on that when it comes to price differential and your thoughts on that decision-making?

MR. SHOEMAKER: I think, again, we -- we focused on our costs and trying to align these with -- with costs. So I don't think we looked at an optimal -- Karl, feel free to kick me under the table and correct me, but I don't think we looked at an optimal, you know, differential.

Again, we're trying to reflect costs. The best way for us to communicate to customers how we could kind of mutually save money, right, SRP and that customer, is through proper alignment of prices to costs. And so that's -- that was the focus of those costs.

MR. CARROLL: And, again, I'm just -- I'm just looking at this, and part of the approach I think that's very beneficial to customers for E-28 and E-16 is instead of the stick of an on-peak, it's kind of a carrot to the super off-peak and the significant bill saving opportunities by having a lower price when the costs are lower.

And that is -- that does look like in the summer or the winter season it is about a three-to-one ratio between the off-peak or the on-peak and the super off-peak.

MS. POTTER: Yeah. Thank you for that.

I guess the reason I bring this up too is, I guess from SRP's perspective this goes back to the goals a little bit as well because from SWEEP's perspective time of use -- time of use is -- it's a bit of art and science when it comes to studying the not only a price that is going to reflect costs for the system but also a price that is going to promote and to encourage as many customers to adopt the price plan as possible.

So has SRP done any analysis when proposing either of these -- well, E-28, but this could also apply to E-16. Have you conducted any analysis to see what is the sweet spot for a price differential that SRP customers would feel comfortable with paying in order to actually enroll in the plan itself?

MR. SHOEMAKER: So I'm not aware of price differential. Karl, feel free to jump in. But I know we have -- our marketing research group has done a study to find out the approximate annual bill savings that would motivate them to be able to change and try a time of use plan.

I believe that number -- do you remember that number, Karl? I don't want to misspeak on the number, but it's a number, you know, in excess of a hundred dollars a year that -- I think I'm safe in saying that number at least. But that they would want to say, hey, these are your potential savings to be able to go and try this price plan, which may require some -- you know, some change in your behavior and how you utilize electricity.

So I know that that -- that kind of study. I'm not aware of a survey or study that's been done with regard to an optimal differential within SRP.

MR. SANDSTROM: There's -- there's a vast amount of literature out there from consultants particularly who have, you know, this ratio graph of how high the on-peak/off-peak ratio is to see a load reduction. I know Brattle has published that in the past.

I mean, we -- you know, we currently

have -- you know, three to one is kind of the ratio that a lot of people throw around as the optimal ratio for whatever that means. I mean, we currently have that very close to that on E-21 and E-26 a little weaker.

I think to John and Brandon's point, you know, as a rate designer what I want customers to do in each of these seasons -- you know, summer, winter, on-peak and off-peak, the cost difference is so close there it's really not a material difference but really the super out-of-peak period.

And so for those seasons we're saying, oh, yes, you know, use as much as you can super off-peak. It's low cost and low carbon. And it kind of absorbs a lot of the energy transfer that customers can do.

But then in summer peak it really becomes I really want to encourage customers to not use on-peak if they can avoid it, and so that's why that ratio is significantly higher during that period.

MS. POTTER: Thank you. That's helpful.

So then, I guess, to -- related but in a little bit of a different direction, has SRP conducted any evaluation or provided their own studies on the effectiveness of time of use rates in reducing peak demand both coincident and noncoincident for your system?

MR. CARROLL: I think -- did we send her

the SWEEP response?

MR. SHOEMAKER: Not yet.

MR. CARROLL: Maybe if -- maybe while we're sitting here hopefully.

MS. POTTER: Okay. Yeah. Thank you.

MR. CARROLL: Well, who knows. It's I compiled part of that answer, and I included -- we did a price -- a different study for the E-28 pilot to look at the E-28 participants compared to a matched full customer that stayed on one of the three existing.

(Reporter clarification.)

MR. CARROLL: Sorry.

We -- we matched the E-28 participants with a control customer with similar pretreatment usage on one of the various price plans and then looked at the impact on that on loads. And you see a similar response to the end of the 6 to 9 off-peak window as we see with, like, the current E-21 customers on the 3 to 6. But then we also see an increase in load on the super off-peak period as I think you would kind of expect. So we have looked at that, and it should be beneficial to assist them once we've transitioned to those new load shapes.

MS. POTTER: Thank you. I look forward to seeing that.

So then I guess generally speaking to wrap up this section, would you agree that surveying SRP's peak demand is -- and reducing peak demand is driving management's resource acquisition decision-making?

MR. TUCKER: That serving peak demand is driving our resource acquisitions?

MS. POTTER: You know, or being able to regardless of where demand is at your peak times and, you know, your coincident peak for your system, that making sure you have the power you need to serve that peak at all times is a -- is a primary driver goal of your resource acquisition process?

MR. CARROLL: Making sure that we're differentiating here between, one, the load peaks, which tends to be earlier in the day, we have a lot of solar available earlier in the day, and so those -- the system planners aren't very concerned about the actual load peak anymore.

They're much more concerned about the peak after the solar resources have started to shut off. The solar shuts off much quicker than the load decreases. And so those net peak hours, the load might only be a small amount lower than what it is a few hours earlier is the system peak, but the resources available are much less because we have -- they go off the solar going offline, and so those later hours -- just to be clear that when we say critical hours we're referring to those hours.

MR. TUCKER: It is a net peak hours that drive resource acquisitions, not the system peak hours.

MS. POTTER: Okay. Thank you.

Okay. A little bit in the same vein of broader kind of time of use studies and evaluation.

It sounds like you've already done this based on your previous response, but I just want to clarify have you also done any customer group surveys, focus groups, or pilots for understanding a customer's ability to learn and understand and respond to a demand charge?

So any focus groups, any customer surveys to understand how much your customers understand about demand charges, their knowledge of it?

MR. TUCKER: Yeah. Offhand --

MR. CARROLL: I don't recall -- yeah, I don't recall direct customer -- like, customer surveys other than looking at the load shapes and are the customers on demand reflected in E-27 in particular.

We've done a study -- I have a -- it's publicly available if you Google for it. The E-27 customers are responding to the demand signals even though there's a very small price difference between the on-peak and off-peak off because of the demand charge you still have a very large load reduction.

MR. SANDSTROM: Okay. In -- in 2015, as part of the price plan -- E-27, which was the singular solar rate available at the time, in response to I think significant customer feedback -- whether that was a formal study or not I can't speak to that, but in 2019 we did expand the option including the two nondemand E-13, E-14, again, I would say directly in response to the customer and installer feedback.

MS. POTTER: Thank you.

MR. TUCKER: And to follow up on that point, interesting to me is E-27 continues to be the most popular solar price plan.

So, again, I'm not positive how much direct research we've done on customers' understanding of demand rates, but they do seem to select the rate --

MR. CARROLL: And then they --

MR. TUCKER: -- when given the option.

MR. CARROLL: And then they -- their usage reflects the numbers.

MR. TUCKER: And then they respond to signal.

MR. CARROLL: Yes. So I don't know if they -- if we were to survey those customer if they could explain in an engineering term what demand is and what energy is, but their usage indicates that they are understanding it just as well as the behavior changes necessary to comply just as much as, you know, a nonpeak energy charge.

MS. POTTER: So then maybe the customers that are on where you just mentioned the rate, you know, what the demand charge is it's very popular are those customers that have always stayed on that price plan or are those customers that opted into that plan after being on another price plan?

MR. TUCKER: My understanding is it was as solar installers are selling to customers they sign up on E-27 is generally how I think it's working as opposed to the other options they have available at the time.

MS. POTTER: Okay. So with E-16, that's a proposal for a demand charge for solar but also nonsolar customers as well.

So can you talk a little bit about your -- your kind of customer marketing or customer educational plan for addressing customer confusion or resistance to demand charges and making sure they understand what their options are?

MR. TUCKER: Well, some of the -- some of the communications still have yet to be rolled out, of course, because it's not even, you know, approved. I guess I'm not totally tracking what the issue of resistance to demand charge in that they're not required to go on it, if you know what I mean.

MS. POTTER: So then maybe resistance is the wrong word. Maybe we can just say confusion or maybe let's say for customers because there has been a long history for other Arizona utilities for unfortunately for some demand charges a lot of customers not understanding how they worked and, you know, got a -- got a bill that they did not -- was not planning to be as high as it was in the middle of the summer; right?

So maybe resistance isn't the right word or maybe confusion or frustration about how a demand charge works when maybe they felt like they didn't get all the information that they needed.

So maybe what's your plan to combat that risk, right, for customers that are going to be on this plan?

MR. TUCKER: So I would say there is still material and such to be created to that end. One of the things, though, that I think differentiates E-16 from E-27, E-16 has an average demand rate, so to your point, because we've heard -- we've heard those sorts of stories where, you know, they were surprised by a high demand --

a high demand charge, E-16 with the average demand rate looks at every individual day's demand, so usually the stories that I've heard from customers shall be along the lines of, you know, I have one bad day in my month, and that set -- you know, I had one day where I had people over or whatever happened, and that caused me to kind of, you know, maybe a spike in my bill or something. And with an average demand you have about 22 on-peak days where you would set your on-peak demand so you won't have one instance, which I think -- which was deliberate, and I think that's hopefully helpful to customer.

MR. SANDSTROM: And we've had extensive education on demand ever since the 2014/2015 price process. We've had I think a 10-year-old video on YouTube about how on-demand charge works for E-27 customers back then. We have a whole website.

The customer reps on the DG side are trained in demand as well when customers call, and, again, part of the education is, you know, provided by installers as well if they choose to go on E-27.

MR. TUCKER: Maybe one other thing I'd throw out, too, is -- you might not have been here when I said earlier, and I apologize if you were -- was that part of the reason we have E-16 is because we've had discussions with solar installers and they were interested in us having a demand rate. So, in my mind, I would imagine E-28 will be the more popular time of use price plan.

And the intent, though, with E-16 is, one, to provide options, but, two, we heard interest from solar installers in particular that wanted to continue to have a demand charge. Not -- not all of them, of course, but some said this is the way we like to do business, so it's an option that we provide.

MS. POTTER: So when -- and maybe there might be some nuance to this because I usually don't work on solar issues as much, so I just want to make sure I understand what you mean by that.

So when you "solar installers," do you mean the companies that are installing the solar on people's roofs or customers that are interested and intend to install solar on their home?

MR. TUCKER: I mean the companies.

MS. POTTER: Okay. I think that's important because at the end of the day even though -- even though the installers are interested in a demand charge and want to put those customers on a plan with a demand charge, it's the customers that are paying the demand charge not the installer; right?

In some ways it's not as important what the installers think. It's what the customers are able to pay and they're comfortable with; right?

MR. TUCKER: Well, what I would say is that the -- it's usually, if not exclusively, solar and storage installers that like the demand charge, and what they find is they're able to save customers the most money by pairing those products with a demand rate, if that makes sense.

MR. CARROLL: We've actually found over the years a large chunk -- not a majority but a large chunk of our E-27 customers do better on E-27 than they would on one of the grandfathered price plans, and that's because the savings opportunity on E-27 is higher than on a demand rate in general. It's higher than on nondemand rates because you have -- you have more control over exactly how much capacity costs you're paying.

And so the solar installers have used that to help them with demand management systems and battery storage to help customers be able to have that capability to have those cost savings and bill savings.

MS. POTTER: Okay. Thank you.

So -- and you may have already addressed this earlier and I do apologize if I missed this.

MR. TUCKER: That's okay.

MS. POTTER: So the target audience for the

E-16 price plan, is that solar customers?

MR. TUCKER: No, I wouldn't say that's necessarily the target audience.

To Mark's point, it is absolutely true that if you want to aggressively manage your consumption, a demand rate is the best way to lower your bill. So, again, I really like it from an options standpoint for customers.

And when we were developing new pricing options, we got input that in my mind encouraged us to consider a demand rate.

So I guess I can't say whether or not there would be an E-16 without that input from solar customers -- or from solar installers I should say, but it isn't exclusively for them. I'm on E-27.

MS. POTTER: Okay. Fair enough.

MR. TUCKER: E-27P. I'm on E-27P. I elected to be on that price plan.

MS. POTTER: Okay. So with that in mind then because I guess -- from SWEEP's perspective the best way to manage energy is to conserve energy as much as possible and to conduct energy efficiency and to help us set up a volumetric rate in a way that helps to align with signals to reduce energy as much as possible.

With that in mind, what are you doing to ensure that customers that are on the economy price plan, for example, if one of them enrolls for this plan, how do we ensure that we're not disproportionately burdening vulnerable populations with a rate that they may not be able to manage if, you know, they're not given the right information?

And, well, just generally how can we protect those customers or how are you intending to protect those customers?

MR. TUCKER: Well, like I said, some of that material in that plan has yet to be developed because, you know, as you know, it's not yet approved.

But if there -- you know, one of the things we do is we engage with our community partners, and if -- if there was concern with -- amongst our community partners that a demand charge was a particularly risky rate, then, you know, option for limited-income customers, I think that's -- I guess I hadn't heard that myself that it's necessarily more risky for one customer than another, but I'd be very interested to know that.

And if community partners such as yourself and others felt like you should think about this as you develop -- when this plan rolls out, think about how you communicate this to the EPP customers when they sign up or when they take service on EPP you might be mindful. I mean, I think that would be a good idea for us to keep that in mind and build that into our training materials for our reps and that sort of thing.

MS. POTTER: I think that would be great because for one, from our perspective, you know, we're concerned that if this proceeds and this is not at the front end of this discussion, you know, really -- you know, these customers maybe, like, they should not even be steered toward this kind of price plan at all honestly because, you know, there's a lot of consideration for these customers that should be held in the very beginning of a pricing conversation before the final plan is approved versus after.

And if there's not enough time to have those conversations beforehand, I would -- I would like to see when it comes to, like, the marketing, and this could be more, like, on the customer service side talking through that -- the education materials and the phone scripts and the information you all are using for those particular customers to ensure that they're not being steered into a plan that they're not 100 percent prepared to take on.

MR. TUCKER: I guess, but I would note that we have a demand rate right now, and I don't think we have -- I -- we could certainly look it up how many EPP customers are on E-27P, but I don't think there's an issue where we're steering EPP customers in droves to a demand rate and they're having disastrous results.

So I understand your point and that I don't want to put those customers on the wrong rate either. I also don't think there's a huge risk of that because we already have a demand rate, and we're not -- that's not, in a sense, the default or primary rate for EPP customers today. We have a basic rate and other TOU options that are where those customers tend to fall. And that's -- I would expect that to be the case going forward.

MS. POTTER: So then are -- most EPP customers, are they on the basic price plan or M-Power today essentially?

MR. CARROLL: Yes, I think that's --

MR. TUCKER: I don't know those figures, Karl.

MR. SANDSTROM: It's -- you know, so roughly 25 percent of customers are on some kind of time of use give or take a few percent there. EPP is similar. It's not like, you know, 2 percent and 98 percent on the other ones, but it's --

MR. CARROLL: The majority are on E-23 and 24.

MR. SANDSTROM: Correct. Yes.

MR. TUCKER: Yes, that is true.

MR. SANDSTROM: Yeah.

MS. POTTER: Okay. I think maybe that can be a follow-up for us to look at the numbers of EPP customers on either a basic price plan but also price plans with the demand charge today --

MR. TUCKER: Sure. We can --

MS. POTTER: -- to better understand concerns.

MR. SANDSTROM: We can give you the numbers.

MS. GLOVER: If you would just supplement your data request and make sure that we have --

MR. SANDSTROM: And when we -- for the E-28 pilot we did send out e-mails to a lot of customers, and we had customers who were on EPP were twice as likely to, you know, click through to the end in terms of us, you know, gauging the interest of customers on EPP.

So I do think that that super off-peak period is I think enticing for many customers who have maybe limited income, whether they're home more or they're retired. For example, the 8 a.m. and the 3 p.m. could be I think result in material savings for them.

As well as in this proposal an important part too is that, you know, limited-income customers are more likely to be on tier 1 as well than other customers, and so that also includes that lower monthly surcharge.

So I do think there is many things in here that are very favorable for customers. And we'll continue to have the consumer protection of the 90-day bill guarantee. So if a customer does switch, if they're on EPP or not EPP, switch to E-16 or E-28, they end up having a higher bill than they would on basic, they can request or call us up, and we'll put the them back on basic and refund the difference if they did pay more on those rates.

MS. POTTER: Okay. That's helpful to know.

And I imagine that particular point is something that's made -- they're made aware of as they're signing up for the EPP discount?

MR. SANDSTROM: Yes. Or, in addition, if they sign up for any form of time of use plan it's stated on that page or over the phone --

MS. POTTER: Okay.

MR. SANDSTROM: -- so they can have the guarantee.

MS. POTTER: Thank you.

I'd like to switch now to the E-23 price plan because I noticed some -- more kind of a clarification on a few points on this plan in looking at

Table 19, the E-23 customer characteristics.

Is it correct that 45 percent of SRP's residential customers are on this price plan today, or is it -- correct me if I'm wrong.

MR. TUCKER: Do you have that in the green book?

MR. SANDSTROM: It will be in green book, yeah.

MR. SHOEMAKER: Well, is it not page 72?

MR. TUCKER: Oh, yeah, so on page 72 --

MR. SHOEMAKER: It says approximately 45 percent of SRP residential customers. Yeah. Page 72, top of page 72.

MS. POTTER: Okay. Thank you.

So I wanted to just point out for the record Table 19, that first stratum, is showing for these customers that the change or the increase to their average annual bill is approximately 13.1 percent in that first stratum.

So I guess pointing that out, can you all explain why the customers that are using, in essence, the least amount of energy on the most common residential price plan are forecasting to experience such a great percentage in terms of an annual average bill impact?

Just because this caught my attention

because I've never -- I usually don't see stratums outlined in this way.

MR. TUCKER: Karl, can you talk a little bit about what our stratum 1 customers look like?

MR. SANDSTROM: Yeah. So stratum refers to the amount of usage they use between the months of June and September, so really kind of that, you know, peak hot season of the year. And so stratum 1 would be customers falling under 400 kilowatt hours on average by month. Extremely hard to do that in Arizona if you're in a home and you're there present, you know, to use less than 400 kilowatt hours. On your AC alone you can use quite a bit more than that.

And so generally we see stratum 1 specifically for many customers who are simply, you know, it might be a second home or a vacation home for them, and they're simply not here or less present during summer.

If they're in tier 2?

MR. TUCKER: Yeah, so 2 -- so the tier 2 I think, Karl, you're saying the tier 2 with the $10 monthly service charge increase --

MR. SANDSTROM: Yes.

MR. TUCKER: -- is driving the 13 percent change.

MR. SANDSTROM: Right.
MR. TUCKER: And his point is these are extremely low users who often tend to be winter visitors, folks with second homes. So they are wildly underpaying their cost of service. These are not EPP customers generally speaking.
MS. POTTER: Okay. Thank you.
So -- so it sounds like, then, the primary driver of this asymmetry is the monthly service charge in terms of how you tiered it that's impacting this particular stratum.
MR. TUCKER: Yeah. So they have almost no use, and their -- so their bill is going from something -- yeah. That's the answer, yes.
MS. POTTER: Thank you.
Well, since we're -- well, since I started talking about monthly service charge, why don't we just stay there for a moment.
MR. TUCKER: Sure.
MS. POTTER: So we're not moving around here.
So does SRP anticipate all residential customers are fitting into one of these three tiered monthly service charge categories?
Are there any residential customers that

wouldn't be in the tier?

MR. SHOEMAKER: It will be 100 percent of residential customers that will be in either tier 1, 2, or 3. Yes.

MS. POTTER: Okay. Thank you.

So in looking at -- this is, I think, broadly. I apologize. I don't have a specific number in the customer allocation study, but it appears that the metering costs are having a big impact on driving the tiered monthly service charge increase or that they increase broadly for fixed charges.

So would you agree that for residential rate classes for metering costs that increasing it significantly from the $2 to $5 per month is a significant cost?

And that's our understanding of it just based on the calculation.

MR. TUCKER: So --

MR. SHOEMAKER: You're saying the price, is that what you're saying, the portion of the monthly service charge that is -- that is for the metering?

Is that what you're saying?

MR. TUCKER: So it's I think -- correct me if I'm wrong, but what I think you're looking at is the current charge for metering is about $2 and the proposed is about 5.

MS. POTTER: Yes.

MR. TUCKER: I guess I wouldn't say that's a huge driver, though. The bulk of these costs is not meter costs. It's distribution facilities costs, and customer and billing costs.

Right. So of a -- anywhere between 20 and $40, any of those monthly service charges the meter is only $5 of that, so it is -- it's the smallest portion of those costs.

MS. POTTER: All right. I guess for in terms of costs just for metering a $2 to a $5 jump is fairly significant if we're just looking at that line item of costs.

So is there -- what's really driving that for this -- you know, for this particular pricing process?

Normally jumps like this just for metering could maybe indicate significant, like, metering infrastructure updates or something bigger happening.

MR. CARROLL: It's probably more along those lines from the cost study that the accounting -- the way -- the way things are classified in the accounting systems either changed or some of those new IT systems are hitting it more, but we can follow up if you submit it.

MS. POTTER: That would be helpful. Thank you.

Similar -- a similar line here. And you mentioned this, John, that the distribution facility costs are pretty significant. It looks like here based on what we calculated I could be -- we could be incorrect, though, so please correct me if I'm wrong. It looks like the current E-23 customer pays approximately $0.36 per month and no volumetric rate towards that class of costs.

So it looks like it's significant. That could have been an error, so I'm happy to look at that again, but it just seems, like, broadly for distribution, though, it's pretty significant.

MR. TUCKER: Yeah. So to clarify, I think you're saying in the monthly service charge the distribution facilities today is 36 cents.

MS. POTTER: Yeah.

MR. TUCKER: And the proposal is different than that --

MS. POTTER: Yeah.

MR. TUCKER: -- up to 20 bucks.

That's true. So the distribution facilities charges today in excess of the 36 cents that you see in the monthly service charge are collected down in the distribution delivery line item.

MS. POTTER: Would you say that this increase -- this significant of a change for distribution costs is happening maybe because of a change of methodology in the cost of service or some other new costs that are added to that category?

MR. CARROLL: It's -- it's mostly in the previous study anything that wasn't collected or the previous price plans anything that -- the -- the label could have been improved.

MR. TUCKER: It's a labeling issue.

MR. CARROLL: It's a labeling issue.

MS. POTTER: Okay.

MR. CARROLL: So and if it was in the monthly service charge in the price plans, they just put it in the distribution facilities bucket, and if it was in the -- they put it in the delivery bucket even though the cost study did not have it allocated that way.

MS. POTTER: So if you were to relabel that and reidentify what those -- where those costs should line up, maybe that would be named something differently if you did it again?

MR. CARROLL: And that's what we did then with the proposed prices, yeah, we corrected the label.

MS. POTTER: Okay.

MR. TUCKER: So if -- yeah, if you look on, say, page 73 where we got the current and the proposed side by side, you can see there is a distribution facilities line item in the per kilowatt-hour charge under the proposal while that's not there in the current. And then -- I'll let you get there.

MS. POTTER: Sorry. My fingers are not --

MR. TUCKER: No problem.

So, yeah, like, just as an example, if you look at the summer, the per kilowatt-hour charges. Distribution facilities are zero in the current and .37 cents under the proposal. So we've created that line item for better labeling.

And then you can also see the distribution delivery number in the current is much higher than it is in the proposal because we've -- we've moved those costs up to the distribution facilities and the monthly service charge and to the distribution facilities and energy charge, so it was really just the labeling issue.

MR. CARROLL: And to be fair to the rate designer in 2019, there was a footnote saying that the costs could be collected in either, but --

MS. POTTER: I should have looked at that footnote.

MR. CARROLL: Yeah, yeah, but --

MS. POTTER: Thank you.

MS. CARROLL: -- we think it's more clearer the current way.

MS. GLOVER: Caryn, time check. Do you think another few minutes will suffice?

MS. POTTER: I will probably be another 10 minutes.

MS. GLOVER: You'll be done in an hour hopefully?

MS. POTTER: Hopefully, yeah. That's an estimate.

Let me see just where I'm at really quickly here. Yeah, that should be sufficient.

Okay. One more price plan section, and then we're going to go to riders.

I'd like to look at the E-67 price plan for large general service customers.

MR. TUCKER: 155.

MS. POTTER: All right. You've got this thing memorized.

Okay. How does SRP assess the potential impact of increased customer load from this particular price plan on grid stability and reliability for existing customers?

MR. TUCKER: Sorry. Just thinking about how to answer that maybe.

So the way I think of it is we talked about that we get a load forecast. We create a load forecast every year, and that includes -- increasingly includes large customers. And the resource planners run that load forecast through the resource planning model, and then that helps us understand do we have enough resources to provide the level of reliability that we want to provide or does it require that we build more resources.

I'm not sure that's entirely responsive, but I want to start there.

MS. POTTER: Yeah, I think that's fair.

MR. TUCKER: Okay.

MS. POTTER: And when you say resources in this broad definition just for this conversation, would you consider that transmission resources, distribution resources, power generation resources broadly?

MR. TUCKER: Yes. Well, yeah, all of it.

MS. POTTER: What type of customers typically enroll in the E-67 price plan?

MR. TUCKER: So today there's a bit of change in how the proposal has a bit of a change in what the rate is intended to do. Today it's -- requires a high load factor. It requires 20 megawatts of load and a

90 percent load factor.

So are you asking about today or the future? Maybe I should just clarify it.

MS. POTTER: Today is good, but then what are you proposing if there are changes to that?

MR. TUCKER: Okay. So today it tends to be -- well, 90 percent load factor customers, they're -- they have to run 24/7 operations basically, and we probably have half a dozen customers on the rate today.

The intent going forward, though, is -- is to -- in order to better -- in order to protect our customers, the rest of our customer base, from being exposed to costs that these very large customers could cause us to incur.

So the biggest change in the way the rate works is we've introduced this minimum demand concept where customers on this rate will give us a load forecast. If they're in excess of 20 megawatts, they would go on this rate. They would be required to give us a load forecast because what -- basically what happens is a customer says, hey, I'm going to be X megawatts, let's call it a hundred megawatts, and they expect us to go out and build the hundred megawatts of resources to serve them.

And the risk is that we have a number of these customers saying -- they're coming to us and telling us that, and many of them are far bigger, and many of them are over a thousand megawatts, and the risk is that we go out and build those resources and then the load doesn't materialize like they tell us.

So the intended change here is to make sure that those customers if we go out and procure and build resources for them, they're going to pay for 80 percent of that cost whether they show up or not or whether that load materializes or not.

And so that's the pretty consequential change that we're proposing for this price plan.

MS. POTTER: So in terms of the types of customers or types of new accounts that would enroll in the new proposed plan is that -- is it safe to say that that's advanced manufacturing customers, data centers, semiconductors? Help me out here.

MR. TUCKER: Generally speaking I think it would be all of those, but from a cost perspective, we're agnostic in terms of what the customer does. It's more about how much -- how big are they. So if their load is expected to be -- if they tell us they need 20 megawatts or more of capacity, that's when we tell them, okay, E-67 is the price plan you're going to be served on, and the way that works is you pay us based on your forecast because we're building resources based on your forecast.

MS. POTTER: Okay. Thank you.

Would you say that -- in terms of looking at your interconnection request queue pipeline today, would you say that those interconnection requests are being largely driven by customers that would end up on a E-67 price plan?

MR. TUCKER: That's my sense. I haven't looked explicitly at the interconnection requests, but I know there's a lot of -- well, I guess -- sorry, to -- just to make I understood, are you saying the customers that are largely looking to interconnect with us are they -- do they tend to be this large?

MS. POTTER: Uh-huh.

MR. TUCKER: That would be my sense.

MS. POTTER: Okay. Thank you.

So then this might be a resource planning team question, but I'll just say it for the record. Do you know the projected load growth from new customer accounts that would enroll on the E-67 price plan in total megawatts as a fraction of, you know, the current peak demand, so, like, what percent of maybe those customers or, you know, that type of load is impacting your total peak demand, if that makes sense?

MR. TUCKER: So I'm thinking about -- so

the test year -- I'm trying to think how I can respond.

The test year has a few hundred megawatts of data center load in it. However, that is not all new load, so some of those accounts are already turned on.

MS. POTTER: Sure.

MR. TUCKER: So offhand I don't know how many of those accounts for the test year -- or how much of that load is new accounts. We could certainly get that, but in total for what it's worth, a few hundred megawatts of load in terms of our entire portfolio is not hugely consequential.

I think part of what -- so for the test year I don't think it's all that consequential, these large load customers, but what we're trying to do -- we know that they're coming, so what we're trying to -- or they tell us they're coming anyway. So what we're trying to do is make sure that we have a tool in place to protect the rest of our customers.

MS. POTTER: Gotcha. Thank you.

How do you then plan to ensure that costs associated with infrastructure enhancements for these types of customer data centers, advanced manufacturing, what have you, are not unfairly transferring to residential customers?

MR. TUCKER: I think we've got a couple of pretty strong tools in place, and then we have this.

So the existing tools are that when these customers come to us and tell us they want to interconnect, they're responsible for 100 percent of the dedicated facilities required to serve them, so substation, switchyard, transmission interconnection, they have to pay 100 percent of that up front even. So even if they don't show up at all, they've already paid that cost so there's no risk to the rest of our customers from that cost.

And then if they require system upgrades to the transmission system, so not just the line that's dedicated to them but an upgrade to the system somewhere else, to the extent that there's no benefit for the rest of our customers there they pay for all of that system upgrade too even though it's not dedicated to them but they're causing us to incur that cost. And if they don't pay it, somebody else does. So that's -- we have that protection built in already.

So we have a pretty robust CIAC policy. And then when I think -- what we're trying to address here then is the generation capacity, so there isn't really a corollary on the CIAC side for a generation capacity, and that's what we're trying to address here.

So I feel like once this piece is in place we've put really solid protections in place for the rest of our customer base.

MS. POTTER: So speaking of customer protections and benefits from these types of customers, though, can we talk a little bit about demand side management relative to a customer that would be on E-67 or, you know, similar types of accounts.

Are there plans today to implement or expand demand response initiatives targeting E-67 customers or new E-67 customer accounts to manage peak lows and to enhance grid stability?

MR. TUCKER: So we do -- I'll share a couple of things and tell me if it's not responsive.

One thing, our -- our customer programs team and our strategic energy management or key accounts team, they do go work with our individual customers to see if they would participate in a demand-side management program.

We did also change the demand charge on the E-67 price plan to be an on-peak demand charge rather than around-the-clock demand charge.

So that hopefully sends a much stronger price signal to customers who are able to shift load because the existing rate does not provide that kind of incentive, so that's -- it's a pretty marked change I guess that I didn't mention.

MS. POTTER: So then has SRP had conversations with customers on this price plan to, you know, talk about opportunities for demand response?

And, you know, with customers like this that are -- have such significant load requirements it seems very appropriate to have some kind of demand or load management requirement as a part of the tariff or as a part of a price plan like this.

MR. SHOEMAKER: Yeah, we have a business demand response program that's managed through our customer programs group, and I know they're actively working with strategic energy management and those dedicated energy managers that work with those large customers to understand how -- you know, ways to save, ways that they can, again, right, we can mutually save where they can reduce their costs as SRP reduces its cost, and the business demand response is one of those programs I know that is actively marketed to those large customers.

MR. TUCKER: And we do have some of our largest customers that have signed up for that program.

MS. POTTER: And is that the same also in the energy efficiency side when it comes to reducing, you know, waste and energy sources at facilities?

Would that be the same in terms of participation and is that also a focus for the business solutions team?

MR. SHOEMAKER: Yeah, they definitely talk. They definitely talk with them about ways that they can take advantage of energy efficiency and whether they're taking advantage of those energy efficiencies. All of our customers are a part of paying for energy efficiency programs.

MS. POTTER: Does SRP require customers enrolled in the E-67 price plan or new customers that want to enroll on it to participate in demand response and energy efficiency programs?

MR. SHOEMAKER: So they will be paying for energy efficiency programs through their -- through their rates, but beyond that we don't require that they participate in those. We make those programs available and educate them about the programs that are available, but they're not required to.

MS. POTTER: Is there a reason why you wouldn't require them to do that given their, you know, system requirements and, you know, requirements they need in terms of, you know, also the community as well?

MR. TUCKER: So say that again.

MS. POTTER: Is there a reason why you

wouldn't require it or have some type of requirement -- you know, these -- these are big customers, and, you know, it may not have an impact for the test year this time but it will for the next one, and it's a question of community, it's a question of ensuring not just, you know, growth paying for growth, but it's growth also investing in the community where growth has to happen and also helping to ensure that that new growth coming online is not, you know, forcing such significant, you know, transmission investments, power generation investments, or distribution investments that it's going to impact other important corporate goals that SRP has; right?

MR. TUCKER: So help me understand what would it look like to force a customer to be on a demand response program?

MS. POTTER: I think there are a couple of different examples that I've seen started to come forward. For example, you know, there is -- I've seen some agreements where, you know, large, large users, let's say data centers for this, for example, in order to guarantee the capacity benefits that they need and to get their energy supply agreements underway, they can agree to a certain amount of the energy efficiencies that they invest in for other customer segments as a means of showing good faith for the community and also showing their support to minimizing the impact of the additional load that their facilities demand.

MR. TUCKER: So energy efficiency more than demand response you're saying?

MS. POTTER: That's just one example. I would say both really. I mean, we need the demand response as well, but in terms of requirements that could be I think you would have to create a specific demand response event or demand -- a demand responsive program for all those different types of businesses, right, or industries, but also something that -- a requirement that you can include as a part of potentially this price plan or as an additional tariff to help to minimize that capacity impact because energy efficiency as a capacity resource has a significant impact for reducing peak demand and it is the lowest cost resource that we have available. Why would we not have some minimum requirements for these big users to help ease this burden through providing relief in the form of demand-side management to other customers?

MR. TUCKER: I guess we don't -- we don't have anything -- I guess -- but I'm -- I'm struggling a little bit. So we have an on-peak demand charge that sends a price signal, but --

MR. CARROLL: And they also contribute to the energy efficiency programs.

MR. TUCKER: Yeah. And they -- yeah, they pay into that bucket, but it seems like if I think of a demand response beyond a price that encourages them to conserve, it sounds like they're saying we cut their load every now and again.

So if they can't -- it's like a 24/7 operations, think of a semiconductor manufacturer, they can't reduce their load with -- so I don't know quite how a required demand-response program works in that situation.

MS. POTTER: And perhaps a demand response would be more challenging for data centers for that particular example, but maybe that's more available for other types of industrial customers on this price plan.

But I have seen other examples of customers that would be on this price plan that would invest in energy efficiency weatherization services or whether it's energy efficiency measures that can be used for capacity reduction over time in other customer segments to help the system overall to loosen the pressure that it's putting on the total net peak.

MR. TUCKER: And these customers, well, like all customers in fairness they all are required to pay in to energy efficiency programs whether they use them or not.

But I guess to answer your -- if you're asking do you specifically have a requirement in excess of the standard payments, the EE program support, for these customers, we do not have one specifically just for these customers.

MS. GLOVER: And I think we need to wrap there so we have enough time to give Steve his hour.

MS. POTTER: Okay. I do have some others on that carbon reduction rider. I can also submit these -- if Ms. Johnson is doing a follow-up, I can just send that as well.

MS. GLOVER: Okay. Anything we don't get to today you're welcome to submit either as a comment or a request for completion.

MS. POTTER: Thank you.

MS. GLOVER: Let's take five minutes, and then that'll put us ending just a little after 5 today.

(Break from 4:06 p.m. to 4:13 p.m.)

MS. GLOVER: Back on the record. Here we'll start with questioning from Steve Neil.

PANEL INTERVIEW BY MR. NEIL

MR. NEIL: Okay. All right. Let's talk some rate design first.

So earlier this year somebody showed me E-28, and I thought it was, like, something from hell. And I described it as this is awesome. This has a lot of nice features in it like super off-peak aligning with solar production, shorter hours for peak pricing but with a wince for how late they were in the day.

And I told them the price points of E-28 would take a lot more analysis, which I really haven't swallowed up entirely yet.

And then on E-16 people said, oh, they're still pushing demand rates, and I said, well, that -- well, was just when the price analysis came out in December. And I said, well, no, it's important to have a demand rate because it fills out the Bonbright choice buckets in today's market, you know, and so I think those things are great.

And we'll talk more about other points of them, but that's just to address those two.

So while I'm on the topic of rate design, I guess which wasn't in my original notes, but a couple points. The -- stated in the management's proposal is a goal to simplify our pricing or another way of saying that would be our rate structures, I think. And so I do have some concerns about two different peak pricing periods, 5 to 10 on E-16, 6 to 9 p.m. on E-28.

And so I just wondered if, you know, what was the rationale that we needed more hours on 5 to 10 with the demand plan?

MR. TUCKER: I think -- like I noted earlier, the demand charge -- the demand rates, the commercial rates as well are that same five-hour window. Our demand -- our current demand rates for business customers are a five-hour window. You don't build capacity for just a few hours. So we're building capacity for a bigger period of time. If you want a capacity-related charge, a charge like that is five hours. To me the anomaly is probably more of a three-hour window when we're providing E-28.

MR. NEIL: So you were trying to continue with the tradition of EZ-3 I think I heard you say earlier with that. Okay. So that makes sense.

So 5 to 10 would be your desire, but you compromised to 6 to 9.

Okay. And, John, you and I have talked the 60-minute demand period, which is used to be a 60-minute rolling window back in the old days or a 30-minute rolling window or a 15-minute rolling window. Then it switched to -- with more advanced meters it switched to clock quarter-hours, clock half-hours, and clock hours, and I believe SRP is using the clock half-hour approach.

MR. TUCKER: I do believe.

MR. SHOEMAKER: Yes.

MR. NEIL: Yeah. So, you know, what are the thoughts? Any input you can give -- and the reason I ask these questions is because, you know, I feel like these questions move the needle a little bit. Six years ago we were in here talking about that extra solar meter and that it wasn't the customer's meter, it wasn't there for safety, it wasn't there for billing. It was there for data for SRP that is valuable to the customer too, but most valuable to SRP, and it would be really available if you start doing SRECs and things like that. So that's the reason I talk about these kind of design principles.

And so, yeah, what about a 60-minute clock-hour demand measuring period?

MR. SHOEMAKER: It's definitely something that we've talked with and are in discussions with our metering -- our metering group as far as meter programs. So I don't think -- it's not something fundamentally that pricing is against a 60-minute window. If that were something that were, you know, proposed, I think we'd be open to that. Again, we'd need to redesign rates based on that.

But right now we have those -- those

30-minute windows for residential price plans. Changing -- changing that and meter programs creates some -- some issues with implementation if they need to reprogram that in zeroing out demand reads and things like that, so it can cause some issues with -- with customers.

So given the state of our customer system, you know, that's -- that's in the process of being modernized, that that's more likely something that with additional system capability we could -- we could entertain with less, you know, customer system impact.

MR. NEIL: Okay. And you already went through that meter reprogramming with APS in 2019, and it carried over into 2020. It took many months to effect it. I don't know, they had a fleet of a number of different vendors which really complicated things, meter vendors, so I would hope that could be handled fairly easily.

You're all aware that TEP and APS use the 60-minute clock-hour measurement?

Yes? Okay. That's a nod over there.

MR. TUCKER: That's a, yes, at least aware that APS does it.

MR. NEIL: Well, I checked just recently, and TEP does it also, at least on residential. There still may be legacy stuff going on in commercial with shorter periods.

Okay. My notes are all jumbled here. I guess I'll jump back in. Let's see, let me jump from the bottom. I started from the bottom up. This ought to be confusing.

So also I've noted in your proposal and I imagine you guys were probably responsible for this -- for all the details in this appendix A book, but I noticed basically what I see, like, three -- when this is implemented, if it's approved as proposed, you'll end up with three different export rates? Or let me call -- let me call a grandfathered one an annual excess rate. So you'll have an annual excess rate for grandfathered.

MR. CARROLL: So you mean customers grandfathered on the net meter and rider before 2015? I think we called that an annual settlement credit.

Karl, is that correct?

MR. SANDSTROM: Yeah.

MR. NEIL: And that would be one of the rates of compensation, and the other one would be the new E-16 and E-28 three-year rolling average. And then all the plans to be frozen and sunseted, and we won't go into the numbers with the export rates, they would have a -- one that was frozen and wouldn't change. So I just wondered what the logic was behind that.

MR. TUCKER: I think the net metering is sort of its own animal.

MR. NEIL: Right.

MR. TUCKER: And so to the extent that customers generate more than they need, they get a true-up. At some point we need to true-up there, I think. So that's -- so I think that one kind of stands on its own. The --

MR. NEIL: And there's still almost 10 years to go on that 20-year grandfathering.

MR. TUCKER: For those, yes, that installed toward the end of the window. Yep.

For the new rates we talked through that a little bit, but the intent was to have that be a market-based avoided cost. To have it true-up you said -- like you noted, it will adjust every year. For the rates that will be sunset, the -- they're only going to be around a few more years, and honestly the way the current rates are set up is that that number would be available for a few years. You know, between price processes it was fixed, so we were comfortable just allowing that rate to remain fixed until the sun -- until the rate goes away, that export rate to be fixed until the price plan goes away.

MR. NEIL: Okay. It just creates three -- you know, three separate measurements. Maybe you can get down to two is all I'm saying.

MR. TUCKER: Well, we would certainly if -- we'd be -- we would not object to updating the one for the frozen price plans either if that was somehow preferable for customers.

MR. NEIL: Yeah, we'll see what the board thinks about the idea.

MR. TUCKER: Yeah.

MR. SANDSTROM: I mean, we will be at two in 2029 when those customers are on a different rate, so it would just be the annual credit and the market adjusted one.

MR. NEIL: So speaking of 2029, one of the submissions I made I got a reply back that the -- see if I can find the wording here, 2029 was not set in stone basically, November 2029, that it could be later than that even though in this book over and over it says no later than November '29.

So any feedback on that?

MR. SHOEMAKER: Yeah, I think we talked a little bit with Mr. Bender. That is a -- that is a -- by that time they will all be gone, but there will be I think John mentioned roughly at least 18 months between when price plans are implemented and we would start the plan to eliminate those frozen price plans probably focusing on those most misaligned with, you know, TOU hours that we're seeing and we're moving to or we're proposing I should say.

MR. NEIL: Yeah. This just was struck by -- I've heard all about your information systems upgrade, and that seems to be the main driver for the date, the November 2029 date.

MR. SHOEMAKER: It is certainly a factor.

MR. NEIL: Okay.

MR. SHOEMAKER: Yes.

MR. NEIL: All right. So I have a whole bunch of questions here about customer cost comparison or, you know, price plan customer cost comparison, and I have in my hands one that you sent out to one of my neighbors who shared it with me, of course. I didn't raid his e-mail box.

And, you know, I'm very familiar with customer price plan, customer cost comparison. And I was very involved at APS with it, and, you know, so it was more of a debacle than it was a pleasurable experience.

But this is very little information, what you're giving to customers as part of this price process, and I would point out that you have asterisks on here, one to say that the average monthly bill is not really the average. It's probably overstated a little bit because you're using November 2024 prices.

So -- and, you know, we all understand that it's based on past usage. This is a rebilling, you know, which can never predict the future, so no problem there.

But, you know, what -- so I was hoping to meet with customer service staff, people who were involved with pricing. You used to have a tool up. So, you know, you've -- Caryn asked a whole bunch of questions of how customers are going to make this choice.

So just tell me more. I mean, I'm just literally in a vacuum here as to how customers are going to choose between these five to nine plans they have to choose from between approval and for the same time.

MR. TUCKER: Well, to clarify, one, assuming -- so if and when the prices are approved, the proposal is they go effective November 1. At that point in time the options are four; right?

MR. NEIL: Plus one for an EV, yes.

MR. TUCKER: No. The options -- no, no. Effective November 1 as proposed.

MR. NEIL: Or if they haven't moved already; right?

MR. TUCKER: All right. The only options

you have available to you effective November 1 under the proposal are E-23 the basic rate, E-24 M-Power, E-28, and E-16.

MR. NEIL: Right.

MR. TUCKER: So --

MR. NEIL: No. It's the transition period I'm speaking of.

MR. TUCKER: All those rates?

MR. NEIL: Between approval and frozen time.

MR. TUCKER: Well, so between -- so let's say approval, like, board vote February 27 as an example, is that what you're saying?

MR. NEIL: Sure. Yeah.

MR. TUCKER: Between then and November 1?

MR. NEIL: November billing cycle, yes.

MR. TUCKER: So -- yeah, so between those two dates it's the existing price plans and not the new ones, right, because they're not effective yet?

MR. NEIL: And they may want to switch to one of those.

MR. TUCKER: To one of the existing price plans?

MR. NEIL: Yes.

MR. TUCKER: Well, yeah. So --

MR. NEIL: That may be their most -- are you familiar with the term most economical plan?

That's what we use down at the Corporation Commission.

MR. TUCKER: Yeah, I can imagine.

MR. NEIL: It's easy to understand.

MR. TUCKER: Yeah, I can imagine what it means.

MR. NEIL: No finance degrees necessary.

So, yeah, they -- they have an opportunity to switch between plans. They could also decide to switch to first thing right out of the go to E-16 or 28. You know, sign me up. I'll sign up during my October billing cycle so that when my November one hits I'll be on one of those new plans or some other plan.

MR. TUCKER: Yeah. So but the options until -- again, we're talking about assuming board approval. The options until November are the existing options, and we have current -- I would imagine that the existing vehicles for sharing rate comps between estimates we print on bills and customers calling in I don't imagine that those will necessarily change a lot for the existing price plans that will be frozen.

MR. NEIL: Okay.

MR. TUCKER: And then so -- and then in

November we would have the new rates available.

MR. NEIL: Right. Okay. I'm not going to spend much time on this topic because it's not your -- not your team's expertise as, you know, working with customers on this and that type of thing.

And to the legal department, I'll put up my objection that I asked for experts in this matter, and they're not here.

MS. GLOVER: Noted.

MR. NEIL: Okay.

MS. HETH: We do have someone standing by from customer operations if you have questions that are pertinent to the price process that we can bring down to answer some of these questions.

MR. NEIL: They're pertinent to what was -- what would this -- what would this plan cost, what would these proposed costs -- these proposed plans cost. That's very pertinent to the price process.

MS. HETH: Okay.

MR. TUCKER: But I would just note that we don't have the communication plans put together. The rates are not approved. So I'm just saying if we bring in somebody else, nobody else can -- that answer has not been finalized.

MR. NEIL: Well, you've -- you've been a

utility for a long time. You should know what cost comparison is and how to do it.

MR. TUCKER: We just have -- we have until -- yeah, we provided it there. And we -- the rates aren't approved and then --

MR. NEIL: That's the poorest cost comparison I've ever seen.

All right. So let's talk about LOLP weighted peak.

All right. So you stated earlier that the loss of load probability study was done by the resource modeling group?

MR. CARROLL: Correct. I believe so, yes. I might be mixing up group names, but --

MR. NEIL: Okay. So next question, you know, in the Concentric advisors' report they put up a CAISO duck curve, a net load duck curve. It didn't say that on the diagram, but -- so -- and it shows that -- it shows that the peak demand in California curves around 8 p.m.; correct?

MR. TUCKER: Yes. If we're talking about page 6.

MR. NEIL: Yeah.

MR. TUCKER: That's what it looks like.

MR. NEIL: So what does that duck curve

look like for SRP?

MR. TUCKER: I'm not looking at ours at the moment, but I believe it looks like a lot like this one. Well, it doesn't necessarily go as deep.

MR. NEIL: Right. But does it -- that's -- the pertinent point is when does it peak the top of the head?

MR. TUCKER: Given our loss of load work, the costs that we see for on-peak hours, it looks like it's in the same world.

MR. NEIL: So -- so do you have a diagram like this if I was to request it?

MR. CARROLL: I don't know of an existing diagram just like that for SRP load data.

MR. NEIL: Okay. All right. So I already asked that question.

So 4CP, back in past -- let's just talk about the price process 2019. Did you massage or adjust the 4CP numbers for the classes at all?

MR. CARROLL: Are you --

MR. NEIL: The 4CP peak demand.

MR. CARROLL: Are you -- are you referencing in the transition allocation where we make an adjustment to --

MR. NEIL: No. When you're doing a peak

and average to get the peak -- the classes' peak contribution was it massaged at all or was it just simple math?

MR. CARROLL: Right. My recollection is it would have just been the average of the four CP numbers for the average of June, July, August, September to the classes.

MR. NEIL: So just straight math on that one, nothing -- no adjustments really. Okay?

So how did you -- so for loss of load probability -- I'll just cut right to the chase. Let's go to the green book to page -- schedule -- class characteristics. Is that 4?

MR. CARROLL: Schedule 4?

MR. NEIL: 4, so page 35, 36.

All right. I can make a suggestion for you, whoever is producing these books, since you're using flow-over tables you could say this place intentionally left blank to make sure all the flow-over tables are viewable when open like this. It's mostly that way but not always.

If I look at line 8 on page 35, 4CP, you know, I see some numbers there. And I understand what the noncoincident peak is on line 9 and I understand what number 10 is.

But then if I look at your LOLP weighted peak, which is your new -- that's going to flow into LOLP weighted net peak later; right?

MR. CARROLL: Yes.

MR. NEIL: Mark? Okay. Thank you.

So I see that the LOLP net peak is generally between the 4CP and the NCP. It's either -- it's either below it or in the range of the 4CP to NCP for all of the nonsolar rates.

So if you look at -- take, for example, column A, 721 to 857 would be that range there, and the LOLP weighted peak is 747. It's in between them. And then you move over to the next one, and it's below the bottom of 4CP. It's below the 64. And so on and so forth.

Do you see how those numbers fall in those ranges?

And then if you move to the solar rates only, G-27 is in the range, and the rest of them are at or above the high end of those two ranges, that range of numbers.

So I was wondering if you could help me understand what's going on here.

MR. CARROLL: What's the specific question?

MR. NEIL: Why the three solar plans are

outside the range of the between 4CP and NCP. Why all the other rates, commercial and residential, are inside the range or below the range.

MR. CARROLL: I think that's the way the math worked when we looked at the data for what the loads were during the hours.

MR. NEIL: Okay. So what kind of data do I need to ask for to see how this happens, how -- what resulted in these numbers?

MR. CARROLL: You could ask for that spreadsheet.

MR. NEIL: The study results spreadsheet?

MR. CARROLL: I think you asked for the study results spreadsheet.

MR. NEIL: That's the one that came broken, the one that made me want to log into Microsoft.com?

MS. HETH: Let's try to resend that.

MR. NEIL: Okay.

MR. CARROLL: We probably need to break all the links.

MR. NEIL: The other one said -- the other one said broken links in it.

MR. CARROLL: Some people don't want the links broken, and so I try to send it intact when possible. In this case if it's causing problems for you --

MR. NEIL: Are these integrated spreadsheets or are they referencing other workbooks?

MR. CARROLL: Most of them have references to other workbooks because that's probably what's breaking for you.

MR. NEIL: Can you send a set so they don't break?

MR. CARROLL: They would probably still break because the path would break. The path wouldn't be consistent.

MR. NEIL: The paths are to -- not to an online repository that can be shared like SharePoint's been offered earlier?

MR. CARROLL: It's not.

MR. NEIL: Not there yet? Okay.

Okay. What's the alternative to broken links and incomplete data?

MR. CARROLL: The data's complete. I think you would need to figure out how to store that on your --

MR. NEIL: Part of the data is the formulas and the links and the references.

MR. CARROLL: Okay. The formulas were intact when we sent them. So you would need to work on your side to make sure that you're not auto updating to the link that you don't have available or I can break the links.

MR. NEIL: Okay. It seems like an impractical solution. It seems like I'm going to end up with something that's not very useful without an integrated working product.

Is SRP willing to -- okay. Next -- so LOLP -- I'm going to call it lollipop. Lollipop study results seems to indicate there was a lollipop study.

MR. CARROLL: Yes. We discussed that study.

MR. NEIL: Yeah. Is it separate -- it's separate from the spreadsheets?

MR. CARROLL: The -- the results were summarized to us and sent to pricing, and those were the first several tabs of the spreadsheet we sent you.

MR. NEIL: Those are the results are the first several tabs.

What about was there a narrative like there is in these books to describe the process and the logic?

MR. CARROLL: No, not that I'm aware of.

MR. NEIL: And how was this communicated to you that -- so you could validate their work?

MR. CARROLL: I can speak to the analysts who did the work.

MR. NEIL: Okay. Any e-mails that would help?

MR. CARROLL: Not that I know of. I'd have to check.

MR. NEIL: Wow. Wow. So this is a key -- John, I'll ask this question to you.

Am I incorrect in saying that this LOLP weighted peak is a primary contributor to rate calculation, to price calculation?

MR. TUCKER: It's one of the cost drivers.

MR. CARROLL: And, again, be careful to distinguish between a cost and the rates, the prices, the --

MR. NEIL: Yeah.

MR. CARROLL: It's a significant portion in the cost allocation. It's a much less significant portion of the revenue and charges.

MR. NEIL: Because it's only part of many pieces of -- okay.

MR. TUCKER: Well, more than that.

MR. CARROLL: No.

MR. TUCKER: No, that's not --

MR. CARROLL: Because of the gradualism reasons management didn't propose that we adjust the prices according to the results of the cost studies that said what the costs are for each class.

MR. NEIL: Okay.

MR. CARROLL: And -- and --

MR. TUCKER: So if the prices were equal to the cost study results --

MR. NEIL: Yeah.

MR. TUCKER: -- returns would be equalized, and there would be much different price changes.

MR. NEIL: So do you call that smoothing or what do you call that?

MR. TUCKER: No. It's --

MR. CARROLL: I think it's called management's proposal.

MR. TUCKER: Yeah. It's -- it's gradualism; right? The principle of gradualism is what -- why we don't go directly with the cost study results as our pricing targets.

MR. CARROLL: But it's -- a very good description in schedule 9. It talks a little bit about that.

MR. NEIL: Yeah, I saw that.

So what does the word "weighted" mean on weighted peak?

MR. CARROLL: The loss of load probability study. We interpret it such as 100 percent probability if you add up all the different hours. So we normalize it in that way. And then those probabilities are applied to the loads in each hour, the net loads in each hour.

MR. NEIL: Okay. Do you know of any other utilities -- I asked the consultant the same question.

Do you know of any other utilities using a loss of load probability-based peak in their calculations, in their pricing calculations?

MR. CARROLL: I focus on what our costs are and what our costs are --

MR. NEIL: John.

MR. TUCKER: We haven't done a survey on that.

MR. NEIL: Okay. All right. Thanks.

What is -- you also used the term in here normalized LOLP study. How do you distinguish that from other uses of the term of the word LO --

MR. CARROLL: The results of the study indicate what hours there could be outages under different simulation conditions, and those don't add up to a meaningful number, and so we normalize them to 100 percent.

MR. NEIL: Okay. So is the formula for LOLP weighted peak stated anywhere in your report or in any of this paperwork that you made publicly available?

MR. CARROLL: It's in the spreadsheets we've provided to you.

MR. NEIL: Okay. The one that's called LOLP study results?

MR. CARROLL: I believe so, yes.

MR. NEIL: Okay. All right. So it seems as though there's nothing in the paperwork that really describes how it works even though it's a primary driver.

MR. CARROLL: I think it does describe it in the description, doesn't it?

MR. NEIL: A little bit.

Let's see what it says. So it says the loss of load probability weighted net peak use is dated from the LOLP study to weight each class' hourly usage by the normalized LOLP study. That's one of the few things it says, I think.

So explain the net adjustment for system losses that's covered on schedule 5A, page 42 of the study. We could probably talk all day about it.

So which line 20 is the new adjusted weighted peak?

MR. CARROLL: Yes. So we're measuring usage at the meter, but the -- the cost savings happens at the generator because we -- we have to build less capacity at the generator, and so there's line losses between the generator and the meter.

MR. NEIL: Okay.

MR. CARROLL: And the line losses differ a little bit by class, and so the loss estimate is intended to accurately reflect the cost differences between the classes due to differences in the line losses.

MR. NEIL: So I mentioned earlier that I couldn't get the math to work on one of the final pages in this book, so how would you like to receive a request to understand, you know, so that we can both come to an understanding on this? Let me find -- I'm having to flip through until I see my notes. I think I might have gone too far. No. No, I'm still going. For some reason I forgot to write down the number it was.

Dang it. Dang it. Dang it. Oh, well, I'll have to come back to that one while I'm flipping here.

Do you know which -- where the one that does the peak and average and all that?

MR. CARROLL: 5G.

MR. NEIL: Yeah. Oh, there we go. Exactly. Impressive.

So I -- you see I filled in some values here trying to go to down here and other things to get them. Divide by a thousand, took out -- and I came up with these wildly different numbers following these formulas, including the parenthetical notations.

So how could we work together to understand this?

MR. CARROLL: You can request the spreadsheet, but I'm not a calculator, so I can't -- I'm sorry, I can't do that live.

MR. NEIL: So this -- all these are available as a spreadsheet?

MR. CARROLL: Yeah. Yes.

MR. NEIL: What's it called?

MR. CARROLL: The cost allocation study.

MR. NEIL: Oh, how simple is that? All right.

So I understand the dynamics you're talking about with market prices, and certainly SRP should model the market when you're figuring the value of things. But I'm trying to figure out how customer rooftop solar somehow ends up showing like it needs a weighted peak that's outside the range that I talked about earlier.

It's not in the -- it's not -- it's above NCP or equal to it and it's not below it. And whereas every other class or subclass, whatever you want to call them, is showing in the range or below the range.

So can you come up with any ideas how that happened?

You mentioned earlier that it came from you -- from the other group.

MR. CARROLL: Well --

MR. NEIL: It was in the spreadsheet?

MR. CARROLL: -- I'm not -- you can follow the calculation in the spreadsheets.

MR. NEIL: You don't have any idea how that -- how the formulas would come up with that number?

MR. TUCKER: I'm not aware of why they shouldn't be. Well, should they be as you're expecting them to be? I guess I just don't know that.

MR. NEIL: I just don't know why they're different than all the rest. Nobody has ever caught that?

MR. CARROLL: I don't like speculating on -- I'll give one small speculation, though, obviously subject to check. The residential and residential solar classes were combined for the NCP calculation on what hour determined their NCP, and so if we would have used solar as their own class, they probably would have had a higher NCP every hour. I'm speculating there, so we need to check that, but that could be one -- it might have shown a lower NCP number for the solar classes.

MR. NEIL: Okay.

MR. CARROLL: But, again, if you submit the questions, we can -- we can --

MR. NEIL: All right. So I'm not going to ask about renewable energy certificates. I think we covered that pretty well today. And I'm not going to ask anything more about price cost comparison.

I would like to yield some time to Autumn, if possible.

MS. GLOVER: That's perfect. And, yeah, why don't we do a time check here.

Autumn, how much time do you think you need for the remainder of your questions?

MS. JOHNSON: Yeah, I think that maybe 10 or 15 minutes given that Caryn touched on a lot of these subjects.

MS. GLOVER: Yeah, 10 or 15 minutes would be perfect.

And then I have a follow-up response that I'm happy to share about the Copper Crossing development if I can do that.

MS. JOHNSON: Sure. Go ahead.

MS. GLOVER: Yeah, the -- the expert out of major projects is in a remote location, so I said, come on down to the conference room and couldn't do that.

So what he shared about -- so the question, if you recall, was how SRP was forecasted to save $38 million in development costs on phase 2 of the Copper Crossing Energy Research Center. And the answer was that self-performing enables SRP to purchase the required material at competitive prices without contractor markups. The schedule was improved by ordering material well in advance of bringing on a construction contractor. And all specialty work that would require the contractor to hire a sub was also competitively bid. That enables good prices with no contractor markup.

PANEL INTERVIEW BY MS. JOHNSON

MS. JOHNSON: Okay. So I left off in the middle of my rate design questions, but I'm going to skip ahead to some of my commercial questions just because we're running low on time.

So I want to just talk a little bit about E-32. Why was the TOU period changed for that rate plan?

MR. TUCKER: So consistent with the discussion we had around the residential side, these TOU hours for both E-32 and all the E-60 series price plans, the E-60s are time of use based, same challenges in that they are no longer well aligned with pricing -- I'm sorry, the prices are no longer aligned with costs.

So we just -- we were comfortable making the change to these hours for all the business customers feeling that they're more sophisticated and can respond to the new price plans or to the new hours, I should say.

MS. JOHNSON: I mean, so kind of along with the comment I made earlier, and it's interesting that you are saying that -- my -- my understanding is that you think E-16 is something installers want, because the feedback I got on both the commercial rates and the new residential rates at least for E-16 is that it seems like you're trying to set up the price differentials in a way that preferences distributed generation paired with storage but not enough so that there's actually a reason to invest in storage.

And so the feeling on E-32 is that this is actually marginally worse than before the rate design, and there isn't any way that a project with storage would actually pencil, and so I'm wondering was that considered or do you know that?

MR. TUCKER: The design of the price plans is not about solar and storage. The design is about our costs. So we are trying to make sure that our prices are reflective of costs so that customers pay the costs that they cause us to incur.

MS. JOHNSON: But there's a capacity benefit to customers that have on-site generation with storage, no?

MR. TUCKER: I would say there's -- are you asking if there's a capacity benefit that the rate provides to customers with storage?

MS. JOHNSON: No, not that the rate provides. I'm asking if the customers are pairing their on-site generation with storage when you're seeing increasing load growth is a value.

MR. TUCKER: It depends entirely on when they use the storage. If they use it at 3 in the morning, no.

MS. JOHNSON: Well, presumably the rate is designed so that they use their storage at a time it's most economic.

MR. TUCKER: Yes, that's right. The pricing does provide the customer with a capacity benefit if they respond to the price signals whether it's with storage or load controllers or just behavior modification.

MS. JOHNSON: Well, but I think what I'm saying is that because of the additional costs of the battery the offset and the way you designed it won't actually do that.

So I'm saying that I think you have a rate that could do that if it was modified, but the way it's currently designed actually won't.

MR. TUCKER: Well, I guess I'd be curious what the modification would have to look like to -- you know, if the rate's supposed to be based on cost, if there was a modification that was somehow based on cost and equitable to everybody and did that.

MS. JOHNSON: Well, we'll see if we can propose such a thing. I'm not a modeler, but I will -- I'll make the request.

On E-36, I'm wondering why do you continue to use a declining block rate design because presumably you would want -- I guess why would you want prices to get cheaper the more power you use when we're seeing such significant load growth. It seems like you'd want to incentivize the opposite behavior.

MR. TUCKER: So the E-36 price plan is a load factor rate. It's just kind of by definition what this kind of rate is. It rewards customers because based on cost the more efficiently a customer uses the system, which is to say the higher load factor customer has a lower cost, so this sort of price plan just reflects that reality.

MS. JOHNSON: So it's more efficient for them to use more power?

MR. TUCKER: It's more efficient for them to use more power relative to their peak.

MS. JOHNSON: Okay.

MR. TUCKER: So if -- if that makes sense.

MS. JOHNSON: I mean --

MR. TUCKER: It is a -- it is a lower -- it's lower average -- the customer has a lower average cost with a flatter load than with a really peaky load.

MS. JOHNSON: Okay.

MR. TUCKER: And what this rate does is it reflects that fact.

MS. JOHNSON: Okay. All right. Switching back to the -- my rate design questions, and I'm going to try to skip ones that I think you addressed with Caryn. But there were some things that came up with Caryn that I -- I'm not sure that I understood correctly, and I want to make sure that I heard them correctly.

MR. TUCKER: Sure.

MS. JOHNSON: Okay. So one of the comments I was just making about commercial rates and the design versus the actual impact on the usage of storage applies to residential too, but I'm not going to belabor that.

You had this conversation with Caryn about the default rate, and it kind of sounded like you said there wasn't a default rate but then also maybe the E-23 was the default rate. And so can you just clarify?

MR. SHOEMAKER: Yeah. I think that was one where we said we can -- we can circle back with -- with how customer service representatives are trained on walking customers through that want to sign up for a new rate, walking them through their different options.

MS. JOHNSON: Okay.

MR. SHOEMAKER: So that -- that can be something we can follow up with.

MS. JOHNSON: So it kind of sounds like in that rate -- that means that to me that you're saying that there really isn't a default rate if it is based on the conversation that they're having. It's not like if you become a new customer, this is standard unless you opt out. You have to basically opt in to a plan.

MR. SHOEMAKER: Right.

MS. JOHNSON: Okay.

MR. SHOEMAKER: Yes, that is true.

MS. JOHNSON: And -- and that's true what -- if you're a new customer regardless of whether you become a new customer today or after November, that process would be the same?

MR. SHOEMAKER: Yeah, that's -- that's -- yeah.

MS. JOHNSON: Okay.

MR. SHOEMAKER: That's currently in place.

MS. JOHNSON: I'm wondering why would TOU -- why would you not want to have it set up so that TOU was the default?

MR. CARROLL: I think -- correct me if I'm wrong, Brandon or John, this is something that's changed over time. Many years ago people always defaulted to basic.

As our TOU rates developed more, I think the move to the TOU, especially EZ-3.

MS. GLOVER: If you don't mind, I just want to interject. So we do have Glen Traasdahl coming down to answer --

MR. CARROLL: Okay. Great.

MS. GLOVER: -- some of these questions from customer service, and I think he'll be able to address these questions.

MS. JOHNSON: Okay. And I guess just so when he comes in because you guys pointed to a different page for the E-23 rates, I would just direct everyone to page 45, which I actually think is a little bit more helpful as far as the percentage of people and what rates.

And my understanding of this is at least 64 percent of SRP customers are not on a TOU rate, at least for residential customers. I think that that's what Table 4 is reflecting in the accounts percent of class.

MR. TUCKER: So Table 4 is both E-23 and M-Power, which I think is to your point.

MS. JOHNSON: Oh, they're both -- those are -- neither one of those --

MR. TUCKER: That's right.

MS. JOHNSON: -- is a TOU rate?

MR. TUCKER: Right. Yeah.

MS. JOHNSON: Okay. So I'll -- we can put a pin in that then.

I am concerned about kind of half of the current solar customers just automatically getting bumped to E-16 if they don't change. Maybe more in line with Caryn and contrary to Steve, I'm really not excited about E-16. I don't think that that is a great rate design because of the TOU period, not because I necessarily -- I agree with you comment about for storage customers demand charges might make sense.

I'm concerned about the five-hour on-peak given that batteries are good for four hours essentially.

Is there a reason why you have to default them to E-16 as opposed to some kind of affirmative outreach to make sure they're on their most economic plan?

MR. SHOEMAKER: Yeah. So this is going to be, again, only the default if -- if they don't select, there will be -- there will be active marketing and outreach to those customers to help them understand what will be most economical to them and be able to guide them to the rate that they're going to -- that's going to work best for them.

So this is, again, kind of an if they haven't selected or they haven't engaged even with a lot of outreach --

MS. JOHNSON: Okay.

MR. SHOEMAKER: -- this is where they'd go.

If there's another recommendation as to which they should be defaulted to, I think we're absolutely open to that.

MS. JOHNSON: I mean, I would suggest that they -- that solar customers be defaulted to E-28 unless they affirmatively select otherwise. I just think it's a better rate design.

MR. SHOEMAKER: Okay.

MS. JOHNSON: I like the differential better and the on-peak period better. Though, I do understand that for storage -- customers with storage, which is not the majority of solar customers, that the demand charge might be attractive.

I was going to ask why you would default E-21 and E-22 to E-23. It seems weird to move existing TOU customers to a nonTOU rate as opposed to defaulting them to E-28.

MR. SHOEMAKER: Yeah. And that's really just a function of the -- the misalignment of those TOU hours. If you get an EZ-3 customer that's -- that's responding to that and they start using energy at 6 and they haven't engaged with this, if you move them now to a 6 to 9 p.m. on-peak, for example, that could be now some of their peak usage that's within that peak window.

And so, again, we would -- we would try to guide them again towards, hey, you're on the EZ-3 rate. We've got another price plan that's going to be very similar with a three-hour on-peak; let's move you there. But this would be if -- if they haven't engaged with -- with the outreach and they're unaware, moving them to the basic I think we viewed that as kind of least punitive.

MS. JOHNSON: Okay. I mean, I was thinking it's a three-hour period to a different three-hour period, so you're just explaining that, like, hey --

MR. SHOEMAKER: So -- so that's -- yeah.

MS. JOHNSON: Yeah.

MR. SHOEMAKER: That's exactly where we'll encourage them to go.

MS. JOHNSON: Yeah. Okay.

MR. SHOEMAKER: This, again, is only those who haven't opted into a new rate that we would be moving them over.

MS. JOHNSON: And then I think I really only have two -- I think a couple of other ones, and I'll just say what they are, and then you guys can decide if he's better for them or you are.

I'm curious about the -- I realize that you said that the reason for the lack of a differential between an on and off-peak for things like E-16 is because you're looking at actually the super off-peak versus the on-peak.

I still really think we should be driving people away from the on-peak period, not just towards the off-peak period, because for people who aren't home during the day I think that's going to be kind of hard to use. I would just suggest we spend a little more time thinking about that.

MR. TUCKER: May I put in one comment?

MS. JOHNSON: Yes, go ahead.

MR. TUCKER: Recall too that on E-16 part of the on-peak cost is in the demand charge, so it's not just about the on-peak energy charge.

MS. JOHNSON: Yeah.

MR. TUCKER: There's also a pretty healthy signal on the demand charge as well.

MS. JOHNSON: Okay. That's helpful.

But that's also true, though, I looked at the differentials for all of the rates, and most of them are not even close to three to one, even the existing rates that are getting updated even if they don't have demand charges.

So I think that's helpful clarification, but I still think you should consider that differential for on-peak versus off-peak.

And then I think we already touched on the -- I think it's confusing that there are different -- three different plans as opposed to two, but as far as three different time periods and that June and September and October are different summer than July and August.

But I just wonder could you just briefly explain to me how -- is there a difference in how the demand charge for E-16 is calculated versus how existing demand charges on the rate plans that are going to be frozen are calculated?

MR. SHOEMAKER: It's going to be calculated the same as it is on E-15.

MS. JOHNSON: Okay.

MR. CARROLL: With a slightly different

on-peak period.

MS. JOHNSON: Okay. Yeah.

MR. SHOEMAKER: Correct. Yes, the on-peak period, but the methodology for the calculation is the same.

MS. JOHNSON: Okay.

MR. SHOEMAKER: Thank you.

MS. JOHNSON: All right.

MS. GLOVER: Are you ready for --

MS. JOHNSON: Sure.

MS. GLOVER: Glen Traasdahl from -- your title.

MR. TRAASDAHL: Senior director of customer services.

(Reporter clarification.)

MR. TRAASDAHL: Glen Traasdahl, senior director of customer services.

MS. GLOVER: And we were able to bring Glen in to answer some of the questions mostly pertaining to how customers might be guided to choose a price plan, determine which price plan might be best for them, and any other questions you have that might be best answered by someone in the customer services organization.

I'll leave it up to you two to decide who'd like to go first.

MS. JOHNSON: You gave me time, so I think you should go.

MR. NEIL: Oh, okay. All right. Fair enough. Oh, five o'clock on the nose.

PANEL INTERVIEW BY MR. NEIL

MR. NEIL: My name is Steve Neil.

MR. TRAASDAHL: Hi, Steve.

MR. NEIL: I'm just a customer.

Oh, boy, I'll see if I can get myself recalibrated here.

So the tool -- you used to have a tool online that people could use, and it was taken down in August.

MR. TRAASDAHL: Yes.

MR. NEIL: What was the reason for that?

MR. TRAASDAHL: There was an IT conversion to the back-end database where we had all of the reads that we could use to compare the -- make the comparisons from. They went from one technology to another technology, and then that introduced the need to do a conversion that would be -- you know, take several months and cost some money.

MR. NEIL: Wow.

MR. TRAASDAHL: At the same time, we were getting word from our customer modernization team -- are you familiar with the customer modernization program?

MR. NEIL: Is that SAP?

MR. TRAASDAHL: SAP, yeah.

We were being told by SAP and the partner that we're using from SEW to build out our My Account, that they don't have the native capability to do a price compare. So that what we were looking at is inevitably that price compare tool was going to come down when we implemented, so we made the decision because we have so many people working on customer modernization they're freezing -- doing a code freeze --

You're familiar with that concept; right?

MR. NEIL: Too familiar.

MR. TRAASDAHL: Okay -- saying because we're in flight we don't want too many interruptions to the program as we're developing it.

So that's why it made sense to -- we got to take it down -- we're going to take it down now rather than invest in a conversion that then would be up for maybe a month or two or three and then have to be taken down.

And so what we are going to work through is post-customer mod is how to reintroduce it. We liked it very much too. It's a good tool. It helps customers.

And we want to figure out a way to reintroduce it in the new customer modernization program, but it's not going to be included with customer mod because they don't have a native facility to do that, so we'll have to figure out some other way to do that.

MR. NEIL: Is there a contemplated time frame for reintroducing?

MR. TRAASDAHL: We -- we haven't. I mean, it's going to be one of the things that's going to be noted as -- we know we want it. There's only a handful of things that we know we want right now as sort of the fast followers. That is one of them.

MR. NEIL: Okay. So as you're aware, these big books here, the price process increases the number of choices for people for let's say a six-month period or eight-month period where they'll have more choices than ever before to choose a price plan before some plans are frozen.

So, I mean, what's -- what's the talk in customer service about addressing this need? People are going to be either locked out or locked in to something almost. I would say locked out would be more accurate, right, of choosing a plan after their November billing cycle this year.

MR. TRAASDAHL: I'm not sure I understand.

It's my understanding that we're having less choices.

MR. NEIL: You're going to go from now to more to less.

MR. TUCKER: Just for clarity, Glen, I don't agree with the way Steve says it.

You will never have more choices than you have today.

MR. NEIL: Okay.

MR. TUCKER: So just I feel like that's --

MR. NEIL: You could pre -- you could prechoose that I'm going to choose one of these new choices, so you -- you're looking at all of them so you do have more choices.

MR. TUCKER: You can't select it, but you could think, oh, in six months I could be on this other rate, if that's your point.

MR. NEIL: Yes.

MR. TUCKER: I agree.

MR. NEIL: So you could say -- because you -- you do have a limitation if you don't like people changing more than once a year; right?

MR. TRAASDAHL: We don't as a general rule, but I don't know if you've called our call center. We have good discussions with our customers.

MR. NEIL: But it's not a hard-and-fast

rule.

MR. TRAASDAHL: It's not a hard-and-fast rule.

MR. NEIL: Okay.

MR. TRAASDAHL: A customer who, you know, is insistent they made a mistake, they didn't understand it, those kinds of things, we make those exceptions all the time.

MR. NEIL: Okay. Now, I talked to some of your customer service reps in concert with my neighbors and stuff to help them get on their most economical plans, and they've -- they've intimated to me that they have some sort of spreadsheet or something that they pulled data from the customer accounts and they're able to massage and look, and they kind of have a general feel, but they didn't give me the impression that it was a completely push-a-button, programmatic way of doing things, so if you could describe what they do now to try to help people.

MR. TRAASDAHL: Let me make sure I'm clear.

MR. NEIL: Customer service reps, the general line at 888.

MR. TRAASDAHL: So, yeah, they can -- you're asking what they can look at to help customers?

MR. NEIL: Yes, even without the tool.

MR. TRAASDAHL: For the most part what they do is have very general conversations with the customers because most customers are -- are not -- they're not looking for a very difficult conversation. They're looking for, hey, what's -- what are your -- I'll give you an example of the conversation.

A new customer calls up and they say what plans do you have? And we say, well, we have some time of use plans and we have a basic plan in general, and we have a prepaid plan.

And in our -- in our time of use rates, they're differentiated. You pay a higher rate during an on-peak period and this is if you pay a lower rate. And what do you think would work best for you and your lifestyle?

Those are the types of conversations we have --

MR. NEIL: Okay.

MR. TRAASDAHL: -- because there's not going to be -- typically a new customer, we don't have their usage patterns, we don't know what they did, so we don't have that available to pull that up. They're a new customer.

MR. NEIL: Oh, new customer?

MR. TRAASDAHL: Yeah.

MR. NEIL: How about an existing customer?

MR. TRAASDAHL: Well, an existing customer we do have access to that, but we could talk to them about what, well, what were you on before, did that seem to work for you? And so we can have that same conversation.

MR. NEIL: But you don't have any tools or spreadsheets to do a programmatic analysis?

MR. TRAASDAHL: We have a basic system where we can do a time of use comparison -- if we have the data in our system a time of use comparison to a basic. So you pick one of our time of use rates and we can do a compare there. That's the basic tool that they have.

We frankly don't have lots of those conversations because most customers just don't have that interest and that level of patience to kind of work through all of that.

MR. NEIL: Okay. Well, that -- that answers my questions.

I'd like to just read a statement to the group from the Arizona Attorney General Mark Brnovich in the case with APS where they -- about their people not being on their most economical plan.

And the statement by the attorney general was, "APS does not inform customers adequately regarding the benefits of switching to their most economical plan."

And that resulted in $25 million in credits that went to customers plus attorneys' fees.

So I guess I would like to emphasize to everyone that this is a very important topic, and it's in -- not in a great state at SRP. You know, it's just really you have a lot of choices. You're going to narrow those choices, but that won't come until later this year.

And then there will be people wishing they were probably on another plan even if they're on a frozen plan. And then they'll still need to know should I jump to one of the new plans, E-16 or E-28 or E-23 possibly if -- you know, if I'm allowed to jump, which is most customers except for some caveats for solar.

So it's just a really important topic and really beneficial. I'm on an APS consumer stakeholder group, and we meet every month, and we've seen people on their most economic plan go from 30 percent to 65 in the past four years.

So it's been really -- and a lot more customer satisfaction. J.D. Power ratings. APS's J.D. Power ratings are -- you know, they can see your dust trail now.

And so this could -- you know, as

frustration builds up -- I mean, if you've seen the comments in the public comments, there's just so much angst about paying a dollar more a month, and I'm sure you hear it every day.

MR. TRAASDAHL: Yeah.

MR. NEIL: So anything you can do, which this is a thing you can do, and I know you guys know the complexity of it better than most people in the company. And I know the complexity of it because I've modeled every hour of every rate of yours in a spreadsheet, but I haven't done it, you know, for multiple years. And it gets -- it just gets monstrous.

And it's -- and so it's -- but it would be really valuable, and I'd like to encourage it, and that's the last words I'm going to say. Thank you.

MR. TRAASDAHL: Thank you, Steve.

MS. GLOVER: Autumn, do you have any questions?

PANEL INTERVIEW BY MS. JOHNSON

MS. JOHNSON: I guess I'll just make a comment to you since this is your department sort of similar to what they made.

And I will say APS does tell you every single bill if you're not on your most economic plan. So

I'm an APS customer, and they tell you what it should be and how much you would save if you switched. So they are very aggressive about it now, but I refuse to be on a demand charge, so I don't change.

MR. NEIL: Well, that's -- the Bonbright principles talk about --

MS. JOHNSON: Choice. I know you said that earlier.

MR. NEIL: -- personal preferences.

MS. JOHNSON: I just think they're too complicated without a battery.

So, okay, I just want to just flag two things that I had brought up that I am concerned about I think.

I agree with Steve that for existing customers being able to know what your most economic plan is is very important. I think it should be a TOU plan. And if it's not a TOU plan with a rare exception, then maybe there's a design problem because I think we want to be shifting people out of those high-demand hours.

But the other thing I was going to say is I really think there's a lot a social science research on the power of opting in versus opting out, and so I really think you should consider a default TOU plan for new customers since you won't have that historical data to do a -- the most economic plan.

And if it's between E-16 and E-28, I just think -- I say this as a customer, not as an energy person. If this was a customer and a mom of little kids, I just feel like E-28 is going to be a lot easier for people to manage than E-16. I don't know how I would feed my kids if I had a five-hour on-peak period. I just, like, don't know how that would work, and so I would just consider -- I would recommend you just think about that.

MS. HETH: Do you want to ask your question to Glen about whether we have a default rate currently or how we have plans to have a default rate after E-21 is no longer available?

MS. JOHNSON: I thought he said you don't or I thought you guys already said you don't, but, sure, I'll ask the same question to you.

Is there a default rate now? And if so, what is it?

MR. TRAASDAHL: Yeah, there's a technical answer. When we get a meter from the factory, there's a default rate that's put into the meter, and we -- so we just pick a rate. It almost doesn't matter what the default rate is because we just ignore it. It has to be a rate in the meter.

So what we do in practice is when a customer calls and they say I want to turn on, it's like the discussion I just had with Steve is, we talk to them about the rates. We say we have a basic rate and we have time of use rates. And we describe the time of use rates a little bit and our prepaid rate.

And so we don't have in any situation a rate we're pushing or we're defaulting to say -- the conversation is almost never like would you like us to choose your rate and we'll put you on it or here's the one that we recommend.

We recommend it based on a conversation we have with them based on, you know, if they're able to shift and they talk like they want to shift and they want to economize, we will really push the time of use rate that is best for what they just talked about.

Does that make sense?

MS. JOHNSON: Do you have a script as far as what order you talk about the plans in because I also --

MR. TRAASDAHL: No.

MS. JOHNSON: -- think that makes a big difference.

MR. TRAASDAHL: No, we don't.

MS. JOHNSON: Okay.

MR. TRAASDAHL: It's -- it's we do rely on our reps to let that conversation move as it needs to in their conversation with the customer.

MS. JOHNSON: And maybe it will be different as you have fewer choices and the names are a little less confusing, but I'm just thinking if I'm a layperson and you say we have this basic plan or we have these, like, more complicated sounding plans, I would just pick that one as a layperson.

MR. TRAASDAHL: Yeah.

MS. JOHNSON: Which is maybe why you have 64 percent of people on a nonTOU rate.

MR. TRAASDAHL: Yeah, I can -- I can see that point. The path of least resistance for a lot of people is I don't want to think about it and I don't want to worry about it.

MS. JOHNSON: But for the grid that may not be the best option.

MR. TRAASDAHL: I don't disagree with that.

MR. NEIL: I'm sorry, if I could jump in on that point. At the Corporation Commission when you're sitting around the table, people get to jump in.

MS. JOHNSON: I'm done, so you're not even jumping in.

MR. NEIL: I went through the same process at APS where they wanted to simplify. They had rates that were called --

MS. JOHNSON: They were horrible.

MR. NEIL: -- what was it called -- Saver Choice, Saver Choice Plus, Saver Choice Max. They didn't tell you anything.

MS. JOHNSON: They were horrible.

MR. NEIL: And I got on Saver Choice Max, and my bill went up.

And so you're doing the same thing here. You've gone to descriptive names to the plans, so I don't know that helps as well. I don't know if Karl has anything to do with that, probably not, marketing.

MR. SHOEMAKER: Marketing.

MS. HETH: Do you have any more questions for Glen?

MR. NEIL: I don't think so.

MS. GLOVER: Okay. That's fine.

MR. NEIL: Thank you.

MS. GLOVER: And, Autumn, I just want to confirm. I know you said you're done. We have some more time. We have the people. Do you have any more questions before we leave --

MS. JOHNSON: I got through my list of the ones I think you're willing to answer, so, no, I don't have any more. No.

MR. NEIL: I have come across a couple of notes I forgot to refer to.

Springerville. You asked about Springerville?

MS. JOHNSON: I did, and they didn't want to answer.

MR. NEIL: 2031. I said 2032.

MS. JOHNSON: That's -- oh, I think you're talking about Coronado.

Springerville is the TEP rate.

MR. NEIL: I e-mailed you about the battery program when it started and when it ended. And there was a lot of talk about, you know, what choices people have, grandfathered solar choices they have. I think they came from you, the questions. Well, it came from David first and then from you.

So grandfathered people will still have the choice of pretty much everything through until the -- these plans are sunseted. They can get on any of the EZ-3 plans according to my reading of the appendix, E-21 E-22, E-23, E-26. They can be on any of those. They all have the same language.

MS. GLOVER: Did you want anyone to confirm that?

MR. NEIL: Yeah.

MS. GLOVER: And do you want to ask a question --

MR. NEIL: I had talked to Brandon about it --

MS. GLOVER: -- and make sure we have a correct answer?

MR. NEIL: Yeah. Did you guys verify that in the appendix?

MR. TUCKER: Yeah. So if I'm not mistaken, I don't think that the proposal as written lets grandfathered net metering customers move around between those rates once they're frozen, but that is something that certainly could be proposed.

MR. NEIL: So there's some new language for frozen?

MS. HETH: Oh, I think he's talking about the period between adoption and when they freeze. So between now and November any customer could move their rate; right?

MR. NEIL: Right. I'm talking afterwards too.

MS. HETH: Okay.

MR. NEIL: Because as adopted they all have the same language in them.

MS. GLOVER: They say frozen from new participation, and so I think the interpretation would be that if you are not on that plan now, you would therefore be a new customer on that plan or new participant.

MR. NEIL: I might be making -- so now I'll take a minute here.

MS. JOHNSON: I thought John had said that you could only move to E-23.

MR. TUCKER: I did say that.

MS. JOHNSON: Okay.

MR. NEIL: So new participation. Okay. So that's what you're meaning there even though all the wording down here is wouldn't be allowed to switch to one of those because of the wording the word frozen up here?

MR. TUCKER: Yes. The word frozen from the new participation that's what that's getting at.

MR. NEIL: But if it said down here the frozen part doesn't apply to these, that could work also, so --

MR. TUCKER: I guess I need to look at it.

MR. NEIL: Page 27, E-21.

MR. TUCKER: Oh, I think this is the prior applicability language talking about the fact that, like, today customers who are grandfathered can be on E-21.

MR. NEIL: Yeah.

MR. TUCKER: But I do think -- I think that's today. And then when we -- the availability piece saying it's frozen from new participation I think precludes anybody from participating at that point in time. If you're a grandfathered customer today, you can be on E-21 still.

MR. NEIL: Yeah.

MR. TUCKER: But if approved as proposed, effective November you couldn't move into it.

MR. NEIL: Right. Okay. So -- all right. So all the more need for cost comparison between the different plans so people would know -- there's a lot of people -- when you start freezing things, you take away choice, and so it would be great to -- for them to be able to know what they're getting into ahead of time, but --

MS. HETH: Autumn, there was a question you asked earlier about whether we have any rebates available to our solar customers.

MS. JOHNSON: Yeah.

MS. HETH: And I was able to get an answer to that. And we do have a $250 rebate available for demand management systems for new solar customers.

MS. JOHNSON: What's a demand management system for a solar customer?

Do you have an example of that?

MS. HETH: It's a system that allows them to manage their demand that they're on, a demand rate. It allows them to --

MR. NEIL: Braden Energy here in Tempe makes one of those devices.

MR. TUCKER: Like a load controller?

MR. NEIL: Yes.

MS. HETH: Yes.

MS. JOHNSON: Okay. So it would be an additional device that you would install with your solar.

Is that what you're saying?

MS. HETH: Correct.

MR. NEIL: Yeah. But it's very expensive. 250 might pay the tax.

MS. JOHNSON: Okay.

MS. GLOVER: Okay. It sounds like we've concluded the questioning, so I'd like to thank you both for your very valuable participation and wish you all the best.

MR. NEIL: A lot of fun.

MS. GLOVER: Thank you so much.

(Proceedings concluded at 5:21 p.m.)

STATE OF ARIZONA)
)
COUNTY OF MARICOPA)

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