PLACE: Dobbs Building
Raleigh, North Carolina
DATE: Thursday, May 23, 2018
DOCKET NO.: E-2, Sub 1159
E-7, Sub 1156
TIME IN SESSION: 1:51 P.M. TO 5:13 P.M.

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding
Commissioner Jerry C. Dockham
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter
Commissioner Charlotte A. Mitchell

IN THE MATTER OF:

TECHNICAL CONFERENCE

Joint Petition of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, for Approval of Competitive Procurement of Renewable Energy Program

Volume 2

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P R O C E E D I N G S

COMMISSIONER BROWN-BLAND: All right. We'll come back on the record now. I want to remind everybody or notify everybody you'll see the court reporter has changed, therefore, you especially need to be sure you state who you are and which party you're with. The questioning is still with the Commission staff, and I'll call on Mr. Patrick Buffkin. You don't have any?

MR. BUFFKIN: No.

COMMISSIONER BROWN-BLAND: He changed his mind? Ms. Jones?

MS. JONES: Nothing on refresh.

COMMISSIONER BROWN-BLAND: Nothing on refresh? So Mr. Dodge, I'll call on you with regard to your request to clarify something.

MR. DODGE: Thank you, Commissioner Brown-Bland. We just wanted to clarify one point on the -- the formula for refresh that was discussed earlier that we'd included in our May 16th comments. We -- that -- our perspective on that refresh was it was limited to the Step 2 evaluation process that that formula would be used, and once you finish the Step 2 evaluation process, that would be the -- the refresh wouldn't or the formula wouldn't apply after that point to increases or overruns in system upgrade costs.

COMMISSIONER BROWN-BLAND: And Commissioners, do you have questions on the bid refresh issue? Commissioner Clodfelter, as long as you don't go over the questions you already asked.

COMMISSIONER CLODFELTER: I will not. So if we -- if we were to change in Tranche 2 and go back to the idea that the developer pays the upgrade cost and so we'd have a bid refresh, you may then recommend and Duke may select winning bidders who are then going to be carrying part of the system upgrade cost. That will become part of the base case for the next round or the next tranche, or we presume it will be, and we -- we have to kind of assume that's going to be part of the base case for the next tranche, right?

MR. JUDD: Yes.

COMMISSIONER CLODFELTER: Yeah. So -- so do we need to then deal with the issue of whether we've got to collect any sort of financial security from the winning bidder --

MR. JUDD: There --

COMMISSIONER CLODFELTER: -- at some point? When, and when?

MR. JUDD: Great question. The structure that we used in Tranche 1 was there was proposal security which went up to when they executed a PPA.

COMMISSIONER CLODFELTER: Right.

MR. JUDD: There is then performance security that is in place to confirm that they -- they reach COD, and that's part of the PPA.

COMMISSIONER CLODFELTER: And so do we need to cha--- I guess the question I'm really asking is do we need to change that, what you did in Tranche 1, do we need to change that if we're now going to also require that the developer include in the bid through the refresh process the upgrade cost?

MR. JUDD: I -- I don't see a reason to.

COMMISSIONER CLODFELTER: Okay.

MR. JUDD: In the RFPs where we've run them where it's all on the developer, we still have a performance security --

COMMISSIONER CLODFELTER: Okay.

MR. JUDD: -- that gets them to in service.

COMMISSIONER CLODFELTER: Just had to ask. Thank you.

MR. JUDD: While I have the microphone, if I might, I committed to have an answer to the question from Commissioner Mitchell, and that was how many late-stage projects were included in the Step 2 analysis. There were three in DEC and one in DEP, and they were all ultimately successful bids.

COMMISSIONER BROWN-BLAND: All right. Mr. Jirak?

MR. JIRAK: Yeah. Just a really quick clarification. If -- if in Tranche 2 the Commission chooses to go to a structure wherein the bidder bears the upgrade cost, then you would -- they would move through the interconnection process -- I mean, that -- that occurs for Tranche 1 as well, but in this scenario you move through the interconnection process, and when payment becomes due in the ordinary course under the current interconnection process, that’s where payment would be due. And currently, that’s -- I think it’s a signed Facility Study Agreement or maybe Facility Study Report received and then payment is due.

COMMISSIONER CLODFELTER: In other words, the answer is you don’t see the need to change that process if we -- if we change the Tranche 2?

MR. JIRAK: Correct. I think -- I think --

COMMISSIONER CLODFELTER: That's fine.

MR. JIRAK: -- it’s handled through the interconnection procedures.

COMMISSIONER BROWN-BLAND: All right. Did anyone hear anything during the bid refresh section that you wanted to make a comment -- a brief comment now?

(No response.)

COMMISSIONER BROWN-BLAND: All right. Good. We're making progress. We're moving on to the second issue, which was the need for more detailed locational guidance and when that guidance should be published to market participants. And I'll start with Commission Staff, Ms. Jones.

MR. JUDD: If I -- if I could, we've arranged for a panel of the -- from the Duke T&D evaluation team and our transmission expert to be available to you as -- as a group to -- in the interest of efficiency. So with your leave, Mr. Layfield will -- we can either move them over here or he'll move over there. Thank you.

MR. JIRAK: Commissioners and Commission Staff, we also have a short presentation on that question. We can give it now or we'll take questions first, whichever -- whatever your preference is.

COMMISSIONER BROWN-BLAND: Let's -- let's go with the presentation, and then we'll come back to Ms. Jones.

MR. JIRAK: We've handed out hard copies, I think, to Commissioners, and I think it'll be up on the screen here. For purpose of introduction, just very briefly, I'll let the -- the Duke personnel introduce themselves and their role with the Company.

MR. QUAINTANCE: Good afternoon, Commissioners, and visitors. My name is Bill Quaintance, and I work in transmission planning for Duke Energy.

MR. BYRD: And my name is Mark Byrd. I'm in transmission planning for Duke -- Duke Energy Progress.

MR. BELL: And my name is Edgar Bell in transmission planning for the Carolinas.

MR. QUAINTANCE: If you're okay, we'll move into the slides.

COMMISSIONER BROWN-BLAND: Yes.

MR. QUAINTANCE: Okay. So we're going to start with a few comments on Tranche 1 and the grid location guidance. And we concur with the Independent Administrator that we felt Tranche 1 went pretty well in this regard. In Tranche 1 we provided a map of the constrained areas, as well as listings of lines and substations that are in those constrained areas. And, in fact, those are on the screen right now.

And we've had -- you know, everyone knows we've had a huge amount of solar interconnections in the state of North Carolina, which is rather unique in the country, and a lot has been connected to the point where certain areas have become constrained. And if -- if everything in the queue today -- you know, we still have a long queue that we have not gotten to, have not studied -- if everything in the queue went forward today, these constrained areas would grow even more so.

These are -- what we put out in Tranche 1 were areas that we're confident are constrained. There is -- they're not really maybes. We've identified them. They -- there have been cost upgrades assigned to specific projects. And those projects, though, may not actually be under construction yet and they're not committed to, but they are firmly identified.

MR. BUFFKIN: Madam Chair? May I ask a question?

COMMISSIONER BROWN-BLAND: Yes.

MR. BUFFKIN: You said those areas grow. Do they grow larger or do they grow more constrained, or both?

MR. QUAINTANCE: It could be both. I was intending it to mean larger, more -- more counties, for example, covered and constrained. But you're right. If we fix one of these zones, it's possible more generation could require more upgrades in the same zone.

And to keep it quick, we can move on. So these are some lessons learned that we -- we drew from Tranche 1. So there were a number of bidders that submitted projects that were clearly within those constrained areas on that map. And, you know, there's no judgment there. I don't understand business cases for various bidders, but I just thought we'd point that out.

There are what we call here a lot of speculative projects in the queue. I -- I don't know that that is -- anyone would disagree with that. And one indication of that is that when we offered some of the bidders the opportunity to move forward in the CPR process, they dropped out, so it's obvious that, you know, many of the projects aren't necessarily ready to go.

And if -- if we were to assume that the entire queue goes forward today, we also feel like that's a completely unrealistic scenario. It would require significant upgrades throughout our systems and -- but, again, we don't feel like that's a realistic scenario.

And then as far as Tranche 2 goes, so between now and -- and the bid close date of Tranche 2, we have no idea how many additional projects will enter the queue, submit interconnection requests.

We also don't know how many projects, which projects will actually bid into Tranche 2. And it's not until all of those things are determined that we even have a potential base case for the Tranche 2 analysis, so it's really impossible to say today what that base case looks like.

And, again, I'll keep it brief, keep moving. So our thoughts on Tranche 2 is to update the map. Yeah. I think we're on the last slide. Our thoughts are to update the map that you saw based on any information we have learned since that map was created, both through interconnection studies and Tranche 1.

And we're open to, you know, considering other options, but, again, we feel like the -- the uncertainties right now are huge in the queue and -- and the bidding process, and so it's really -- if -- if we're asked to say put MW values on how much generation can fit in areas, we don't -- we don't feel like that is something that can really even be determined at this point, there are so many uncertainties.

And those are our initial comments.

COMMISSIONER BROWN-BLAND: All right, now, Ms. Jones.

MS. JONES: If it's okay, I want to circle back to a topic that Larry, I guess, put on the table this morning which had to do with redefining the base case. And if I understood it correctly, it would be to take all the projects that don't have a Facility Impact Study done and set those aside, and they wouldn't be in the base that you study. And shorthand I took from that was that the transmission capacity that was sort of being reserved for those folks in the queue would, instead, be allocated to CPRE bidders, if I get it right.

So -- go ahead, please.

MR. JUDD: Wouldn't necessarily be assigned to CPRE, but would be available in the study, yes, ma'am.

MS. JONES: Yes. Thank you. So I'm curious if we could just take a few minutes and get reactions to that concept from Public Staff, NCCEBA, and the Company.

MR. QUAINTANCE: Can I clarify the topic a little bit? We feel like the red zones -- I'm sorry -- the constrained areas, as shown on the map, are -- are rather firm as they are on that map today. It's possible that it may not grow if we ignore a lot of the queue, but we feel like those areas that you saw on that map are still going to be there. Just a clarification.

MR. DODGE: This is Tim Dodge with the Public

Staff. I can provide a couple brief kind of insights that address Ms. Jones's question. So I -- I think the -- when -- when Mr. Layfield was discussing the base case this morning, there were some -- some statements about the -- the whole base -- I guess all the existing projects in the queue being kind of put in that base case, and -- and I think maybe there were -- there were some categories of projects that were actually maybe not included. I -- I think there were -- maybe some duplicative projects were identified that might have been taken out and some other categories of projects that were eliminated to try to reduce that -- that base case.

I think the idea of looking at the projects that have gotten to a Facility Study Agreement, obviously those projects are -- are more viable and have a much higher likelihood of moving forward and have a higher priority position in the queue and should -- I mean, I think it makes sense to look at -- at that category of projects. Beyond that, I think you do start raising questions about, you know, providing discriminatory treatment to projects for CPRE purposes if you do some other type of analysis that allows CPRE projects to move forward, or evaluate that baseline differently and potentially assign cost to or make assumptions about projects in the queue that aren't part of CPRE.

So I think there are some concerns that would have to be worked out in the interconnection process still.

MS. KEMERAIT: NCCEBA. This is Karen Kemerait. NCCEBA agrees that there are some issues that are going to have to be worked out in the interconnection process, but as far as the specific position of the Independent Administrator and Duke, NCCEBA does not have a position about either of those. We don't have an objection either way.

MR. JIRAK: So, yeah, on behalf Duke, we -- we wholeheartedly agree with the need that's been identified by the IA to -- to figure out a way to make the system baseline study more realistic because we know that 24,000 MW projects are not going to get interconnected in the system. But how you do -- how -- how you slice and dice that to get the right mix of projects, the real projects, is a very difficult question. The proposal put forward by the IA is a reasonable one, understand the intent behind it, but we -- we share their concerns that there's still -- you know, there are projects in the queue that -- that have current LEOs that make them likely viable projects that maybe have not gotten the Facility Study

Agreement, and those projects, if you -- if you don't assume those in your baseline, you run the potential for -- for the wrong -- getting the wrong results.

So wholeheartedly agree with the IA on the intent. Think that's a good starting point to think about, but also open to other ideas on how you get to a realistic system baseline, which is a very difficult question and one, you know, we need to -- we need to solve for.

But any -- any solution that makes assumptions about the baseline could -- those assumptions could turn out to be wrong, and if they're wrong, then your results could potentially be wrong, and that's -- that's the reality. We were fortunate enough in Tranche 1 to find projects that we could be confident in their upgrade cost being accurate even with this unrealistic baseline because of their location, but -- but that's not necessarily guaranteed to be the case in Tranche 2, but it may be, and we may find that we can still find projects that we're confident in in terms of upgrade cost. So that -- that -- that's some of our perspective on this topic.

MS. JONES: Moving on, then, if that's okay. So moving on to a different topic, over in the interconnection procedures docket, which is still pending, but there was conversation there about Duke has started offering interconnection customers mitigation options. You know, if their initial request, say, for 80 MW comes back with a lot of expensive upgrades, Duke is doing a study and saying, well, if you came at 60 or at 50 instead, a smaller project, your upgrade cost would be much, much less.

So my question to you all is, in this time of having a real constrained transmission grid, would it make sense to build into kind of this bid refresh process the possibility for a mitigation piece from Duke back to the bidders to say if you put in a bid for 80 MW, we don't have room at that point of interconnection, but if you lower it to 50 MW, we do have room and give the bidders an opportunity to refresh. And I realize that's a pretty big new idea to throw at you, but I would be interested in your feedback.

MR. JIRAK: If you want to start with us, if you'll give us minute, we'll probably need to just go to internal dialogue on that.

MR. JUDD: While he's taking his moment, I just want to remind you that in Tranche 1 we invited the -- the bidders to identify if they would reduce the size of their project and hold their price by a certain percent, 5 percent, I think it was, 3 percent, something, but as a way of us reaching the goal without having to go over or putting aside a bid, because it -- it didn’t match up. So the concept is very workable. I just wanted to remind you that we had done it already for pricing -- or the size of the projects for reaching the -- the target of the tranche.

MR. O'HARA: This is Brian O’Hara speaking for NCCEBA. Based on conversations we’ve had around bid refresh, I think that concept is not one that NCCEBA would support. I think we’re concerned about the ability for some bidders to refresh while other bidders cannot, and the ability for bidders to come in with an artificially low number, knowing that they’re going to have a refresh option in the future. So we would prefer to keep a level playing field. We think that would tilt things a bit, and we would not support that.

MR. JIRAK: One -- and these guys are going to tell me if I’m wrong, but, I mean, if you think about it in a very abstract sense, you know, there’s a -- you add a bunch of projects to a -- to a circuit or transmission network, there’s one project that in theory is the one that trips the need for an upgrade cost, so there’s a lot of projects that don't trip the need, a lot of projects above that project that definitely need it.

So we think in theory, while we understand the intent behind this, there's only a relatively few number of projects that would fit in that category where like they're right on the line and -- and you can downsize maybe and avoid an upgrade. So given the fact that there's a very small unlikely chance of that happening to more than one or two or three projects out of a big, large procurement, we don't think the complexity of the process warrants trying to -- to solve that problem.

I also just observe as a general matter that mitigation options are a limited procedure that's only applied to distribution projects. We haven't ever used it on the transmission level to date.

MS. JONES: Thank you. I didn't know that.

MR. JIRAK: And there's no plan to do so, either.

MS. JONES: Okay. Then I'm going to move along. Also over in the interconnection docket we were re-reminded of the pre-application process, and wanted to explore whether in this Tranche 1 if the bidders typically avail themselves of the ability to request a pre-application report to hone in on a good interconnection spot, and maybe the same thing applies; this is only a distribution option.

MR. JIRAK: I think -- and, again, you all jump in and tell me where I'm getting off base here, but I think, you know, when you come in with a pre-app, you're getting an assessment based on your position as of the date of your interconnection request, what's available in the system. But for purposes of CPRE Grouping Study, you are -- you are forfeiting that queue position and -- and moving to a later position in the -- in the queue and getting studied based on available capacity at that spot in the interconnection queue process.

So in -- in -- in that spot the -- the available capacity at that spot in the queue is -- is totally contingent on what's in the baseline, so we're kind of back to square one and what do you assume about the baseline is how you would -- if you could even do a pre-app for the CPRE Grouping Position Study queue position, you still don't know what you would be able to tell until you know what the baseline is.

MS. JONES: That's all good. And so then I -- I think I just have one more, which is the locational guidance that -- that you -- you flashed up, both the map and the list of constrained facilities, today, as we sit here today, is that still useful or have you refreshed it? How often would you have to refresh it for it to be accurate? You -- you talked about the fact that it's changing. What's the -- I guess the speed of that change?

MR. QUAINTANCE: I think for Tranche 2 we would update it before the -- the bid window opens. That -- that would be appropriate and as timely as we could for Tranche 2. I mean, we're always learning information as we do our queue studies, and then each tranche we might learn a little more, but for Tranche 2 I would recommend updating it, you know, just before the bid window opens.

MS. KEMERAIT: And can we have an opportunity to speak to that as well?

MR. O'HARA: We talked a little bit over lunch about this, and I think the -- the timing of sharing that locational guidance really matters a lot; the earlier, the better. You know, there's a fair amount of development time and site acquisition that goes into getting a project ready. So from our perspective, I think as soon as the information is available to Duke, we'd like that information to be made available to the rest of the market participants.

And in terms of -- so I think that answers kind of the question on the timing. And then in terms of -- I know we're talking a lot about the -- the base case and what are we assuming. I think whatever we end up choosing is -- to be the right answer there, what would be really helpful from the market participant's standpoint is to see a list of the projects that are assumed to be online that then inform that -- that locational guidance, because at that point bidders can look at the queue, they can look at what -- what's constrained and maybe make some educated guesses about, you know, how constrained this edge is or whatnot.

So just having sort of the same level of information that -- that Duke has in terms of what went into that study I think would be helpful to market participants.

MR. NORRIS: And just on that point and going back to your prior question, I think, about the methodology for determining what's in the baseline, I think what you stated is that, and what I think was confirmed is that it's any project that has executed a Facility Study Agreement does, in fact, go in the baseline, but it was a little unclear to me based on -- on your response, so it would be helpful to just confirm that. Or if there's another standard or methodology being used, then what is that, because I think what would be concerning is if there's some sort of discretionary methodology being used that -- to determine the baseline that we're -- we're all unaware of.

MR. QUAINTANCE: I'll add that in Tranche 1 we assumed everything in the queue was in except for the bidders and except for the late-stage bids, and -- and duplicate bids were not doubled up.

In Tranche 2 I believe the IA has suggested that we look, you know, at changing that to a Facility Study cutoff.

MR. JIRAK: And let me clarify one point. We're talking about two different things. One is what's your system baseline for purposes of the CPRE Grouping Study? That's one issue. Second issue is what is assumed when you issue the grid locational guidance?

So on the first issue, what -- what was assumed in the system baseline for Tranche 1, it was just what Bill just described, and then we're currently discussing what should be assumed for the system baseline for Tranche 2.

For the grid locational guidance for Tranche 1, what was assumed is what Bill explained in the slides, which is just projects through study. So it's a view of what are the current constraints on the system as of the project study today. It doesn't attempt to assess how the -- how the system will become constrained over time as more projects are added. It's the current view. So make sure as we talk about it we recognize there's two different things.

MR. LEVITAS: May I ask a question, Madam Chair?

COMMISSIONER BROWN-BLAND: Yes.

MR. LEVITAS: A very, very quick one.

COMMISSIONER BROWN-BLAND: You may.

MR. LEVITAS: I'm just curious to ask Duke, is the relatively recently approved M-1 payment causing the -- the size of this baseline to be reduced as projects come into Facility Study and either have to put up binding -- binding financial obligation or withdraw from the queue?

MR. JIRAK: We don't know that information off the top of our head. I mean, there certainly are issues we're dealing with right now with -- with projects that are -- have made it to IA or are close to IA and are now attempting to -- when I say tread water, they're looking for creative ways in the procedures to hang out there. So that's an issue we're dealing with as we think about the system baseline, but I'm not aware whether any projects -- how many projects, if any, have -- have withdrawn from the queue due to the -- due to the milestone payment.

MR. BUFFKIN: I have, I think, one question for Mr. Jirak.

COMMISSIONER BROWN-BLAND: Mr. Buffkin.

MR. BUFFKIN: What I understood, your comments on this issue was that essentially there's a Goldilocks principle here. You can get it just right or you can be too specific and cause some problems or -- or too general and -- and the guidance isn't useful; is that fair?

MR. JIRAK: I think in general, yeah. If we're thinking about the system baseline, I -- I think that's right.

MR. BUFFKIN: I'm sorry. I meant about the locational guidance.

MR. JIRAK: Oh. Yeah. I think that's right.

MR. BUFFKIN: And maybe for the other parties, do you all see the same problems with locational guidance, that it's too specific? For example, some of the things we heard about was driving up land -- land lease prices in -- in a specific area and essentially creating too much demand at a specific point on the electric system.

MR. O'HARA: Yeah. I think we -- yes. I think we think the level of detail that’s provided in the locational guidance now is about that right Goldilocks balance.

MR. BUFFKIN: Thank you.

MS. KEMERAIT: And -- and to follow up, if it does become, as -- as Mr. Buffkin mentioned, if the locational guidance becomes too specific, that will be a real issue for solar developers because it could drive up land prices. So we want to have that -- a balance between enough locational guidance, but not something that’s too specific that directs all market participants and solar developers to areas so that the -- the cost of leases will be exorbitant.

MR. DODGE: This is Tim Dodge with the Public Staff. I just wanted to comment on that briefly, too. We indicated in our March 22nd comments that we thought more granular information on locational constraints would be beneficial, and it would hopefully provide better project locations where we could avoid some of these system upgrades. So I think the Public Staff still views more granular location information, to the extent it can be provided, as helpful.

I think also just to -- I think the -- the locational guidance that Duke provided was -- was beneficial. There were -- there was one element that I just wanted to note that Duke pointed out at least in their locational guidance a couple of locations in their system where there were major transmission upgrades required that were known to take multiple years, and earlier today we were talking about the timing of these projects and being able to meet the COD deadlines for Tranche 1 or Tranche 2.

And so to the extent that there are zones where it's a no go, that project just cannot be built, you know, if there are plans for upgrades to be implemented or -- or constructed in that area where projects just aren't feasible to be considered for tranche -- you know, future tranches, it seems to make sense to try to identify those areas. So I just wanted to make that point.

Secondly, and I -- again, this is probably a conversation that will continue as we build towards Tranche 2, to the extent the -- there are areas that Duke can identify where there are right now few constraints -- I mean, right now they've identified these -- these area where there's thermal loading or congestion and constraints, but if there are areas right now where the -- the system is more open where they haven't seen as much development, they could accommodate additional solar and may provide potentially other benefits, system benefits. If those areas, while it might increase activity in those areas, I think to the extent the land cost increase, but larger system upgrade costs are avoided, that would still be a better outcome.

So I think we would be supportive of looking at whether it's called a green zone or something where you could evaluate areas that maybe can accommodate additional development.

COMMISSIONER BROWN-BLAND: Thank you, Mr. Dodge. Anyone else who is a party have comments on the locational guidance?

(No response.)

COMMISSIONER BROWN-BLAND: All right. Let's hear if the Commission has questions. Commissioner Clodfelter.

COMMISSIONER CLODFELTER: I don't know exactly where we are after this discussion, but so let me just start at a random place. You want to react to the green zone idea? Can you do that? Is it useful?

MR. QUAINTANCE: Well, that -- that gets to the topic of, you know, what's the base case --

COMMISSIONER CLODFELTER: Exactly.

MR. QUAINTANCE: -- in determining the green zone, and its -- there's so much uncertainty. We -- in the map you saw, you know, again, the red zones are known constrained areas. We intentionally didn't color the remainder green because it's more of an unknown area.

COMMISSIONER CLODFELTER: Exactly.

MR. QUAINTANCE: And it would be very difficult and -- and -- and not very accurate, I would say, to try to come up with real numbers in any of those areas. I mean, really, it's hard for me to imagine how to do it in a reliable and a useful way.

COMMISSIONER CLODFELTER: Well, let me come back to -- if I may, let me come back, then, to this side of the room. I'm a little lost with what I was hearing over here, so let me ask the question this way. Tell me from this side of the room precisely, very specifically, what do you want Duke to do differently about the guidance they give you in Tranche 2 than what they gave you in Tranche 1, recognizing what we've been hearing about the difficulties that they face?

MR. O'HARA: So we see there's three -- three issues: There's the level of detail, there's the timing of sharing the locational guidance, and there’s the what is the base case.

The first one, the level of detail, we think we’re in the zone of appropriate. That zone is -- has room for movement in the more -- more granular direction, but we’re in the zone of appropriate.

The timing of sharing, we’d like that as early as possible. As soon as Duke has access to it, that’s when we want to see it.

And the -- what’s in the base case, I think the change that we’d like to see there is give us a list of the projects that were assumed to be online when you developed that zone.

COMMISSIONER CLODFELTER: The constrained zone.

MR. O'HARA: Correct.

COMMISSIONER CLODFELTER: What do you say about those three things?

MR. JIRAK: All right. The first one, level of detail, we’re kind of beating around the bush without getting specific. We -- we -- there’s a map. It shows you the -- the physical locations of constraint, and there’s a list of system assets that are constrained. When we hear this suggestion that we become a little more granular, we don’t know what that means. I mean, we think that -- that's -- that's the view right now. We don't know how else to be more granular, so if there's ideas about what that -- when you say you want maybe a little more granularity, we honestly don't know how to do that. So if there's ideas -- at least I don't.

COMMISSIONER BROWN-BLAND: What if he's saying to be as granular as you're able to and be comfortable with it?

MR. JIRAK: I think that's what we -- that is what the good constraint map is. It is the view of the current constraints on the system geographically.

COMMISSIONER BROWN-BLAND: So I think he's -- I interpret that he's saying as your level of comfort with more granular increases --

MR. JIRAK: Yeah.

COMMISSIONER BROWN-BLAND: -- could you be more granular? He likes the zone --

MR. JIRAK: Yeah.

COMMISSIONER BROWN-BLAND: -- but he would like some improvement. That's what I hear from this side of the room.

MR. JIRAK: Yeah. Certainly, if there's -- if there's a way in which we identify to make the map more granular, we would do that, but at this point we're not aware of, without any specific recommendations, a way to do that, so -- but we'll -- we'll keep it on our radar, and if there's a way to do that, we will do so.

Timing, I think it's just we're willing to do it. I think it's just a matter of time to run the study and put it out there. I don't think there's any reason why we couldn't do it sooner rather than later.

You all can speak to that.

MR. BYRD: I mean, the -- the comment was made earlier that we don't really --

COMMISSIONER BROWN-BLAND: State your name again for the --

MR. BYRD: I'm sorry. My name is Mark Byrd, Transmission Planning, for Duke Energy Progress. And one of the issues with what projects are in there is we don't -- it would have to be after we know who bids, because the CPRE bids will be -- not be in the base case.

MR. JIRAK: I think it's about they wanted -- they're asking for the -- what projects are assumed in locational guidance, not in the base case.

MR. BYRD: Well, that's not what I heard, but anyway --

MR. O'HARA: Well, Jack represented my question right.

MR. BYRD: Okay.

MR. JIRAK: So you -- you all want to speak to providing a list of the projects assumed in this -- in the -- in the locational guidance. I -- I think we've already described the criteria that needs to be met. You have to either be interconnected or through the study process and then you're included. Can we provide a list?

MR. QUAINTANCE: I mean, we can -- let us take that back and -- and consider what we can -- some verbiage we could put in there about the assumptions that go into that zone. I think -- let's see what we can add.

MR. JIRAK: Yeah. I think we could explain that. I think once we -- once you understand the criteria, we'll put it in writing for you. You can obviously look at the queue report and see as of right around the date that it's -- the grid locational guidance is issued, you would know then which projects met that criteria and which did not. So I think that would probably be the easiest way to do it.

MS. KEMERAIT: And in response to the -- the question about providing -- this is Karen Kemerait for NCCEBA -- about how to provide a level of more granularity, we support what the Public Staff has said, that if it's possible, we'd like to see green and yellow zones because that would provide some additional information, if that can be done.

COMMISSIONER BROWN-BLAND: And we just -- we just have to hope we don't have a colorblind issue.

MR. QUAINTANCE: At this point I'm -- I'm not sure how to get that granular -- that's, I guess, more of a megawatt availability is maybe what you're asking. And I -- I -- I'm really not sure how to come up with a base case to do that calculation.

COMMISSIONER BROWN-BLAND: So to Duke, just as a follow-up on the timing portion, in Tranche 1, recognizing Tranche 1 was a beta and -- and we're here to try to see if we can improve on it, were there issues with regard to the timing in providing the locational guidance, or why wasn't it provided sooner?

MR. JIRAK: I -- I don't recall the exact date that we provided it. I -- I thought we provided it fairly early in the process and I think well prior to the 60-day kickoff for the comment period, so it -- it felt to us like it was provided relatively early in the process. Certainly understand developers want it earlier, and we'll try to accommodate that as quickly as possible here for Tranche 2.

COMMISSIONER BROWN-BLAND: Mr. Dodge?

MR. DODGE: Commissioner Brown-Bland, I just have one follow-up, too, and this goes back to a question that Ms. Jones raised earlier about the current NCIP proceeding. And I just kind of reiterate some of the points that were made there, that those -- those projects that are still continuing to enter into the interconnection queue that are not CPRE are impacting the baseline for CPRE purposes, so it’s not just a matter of providing better information here; it’s also a matter of providing better information for the NCIP process. So tools like the pre-application report or other information like that hopefully will help projects that are looking to interconnect outside of CPRE to choose better sites or avoid sites or maybe decide not to build if it’s likely that they’re going to be constrained in those locations.

COMMISSIONER BROWN-BLAND: All right. Commissioner Mitchell?

COMMISSIONER MITCHELL: For NCCEBA, the -- my general impression, which is sort of confirmed, I guess, by the information the IA provided this morning in his -- in -- in -- in the report -- I’m specifically looking at page 14 or slide number 14 of their presentation -- suggests that the grid locational guidance provided in

Tranche 1 didn't really -- didn't really -- didn't really eliminate or -- or minimize the number of bids received in what -- what we're calling the red zones. Why?

I mean, it looks like to me that -- I mean, the -- a number of bids were submitted, more -- I mean, 26 for DEC, eight for DEP in the red zone. Why would someone bid in a project in a -- in a constrained area?

MR. NORRIS: I say this not from an informed perspective as a market participant who -- who took that measure, but I -- I could imagine that some market participants that aren't necessarily fully informed about the extent of the network upgrades required in particular areas might assume that there could be interdependent facilities that would share an upgrade under which via the pro rata application of that network upgrade to each facility would be able to compete under the program. And so I assume that that is -- that is what they're hoping will occur, but it may not be based on an informed perspective.

COMMISSIONER MITCHELL: Okay. So if -- if the -- let's -- let's just assume -- let's assume or agree that the goal is to -- to drive or encourage projects to locate away from these constrained areas, thereby presumably avoiding costly updates, how do you -- how do you -- how do you encourage projects to do that? Aside -- I mean, I've heard the green zone and the yellow zone issue, but can you be a little bit more specific, because it's not there?

MR. O'HARA: Yeah. This is Brian O'Hara again. I -- I think this goes back to maybe another idea of what are some other ways to get additional granularity. And so I hear the challenge is -- I heard what Mr. Quaintance said, is the challenge is if I make these -- whatever assumptions I make, there's a level of uncertainty about how accurate that's going to be by the time we get around to -- to actually building.

But if you accept for a moment that there's going to be some inaccuracies, but you make a set of assumptions, we could, I assume, produce a map of the Duke network, where instead of having a binary red or not red by line, you could have sort of what Commissioner Brown-Bland mentioned as sort of a -- or maybe it was Mr. Jirak mentioned -- available MW on this line section and this line section. You have maybe a color-coded map that shows this section of line has significant available, it gets less here, it gets less here, it's constrained here.

So I think the challenge is obviously the accuracy and how dependable that information is, but there are opportunities for getting a lot more information out there and then caveating it, saying here are the assumptions that went into developing that information.

But that level of information, I think, would help inform our participants in a way that doesn't drive everyone to, you know, a very small green zone, then drives up land prices, but gives a very accurate picture of the network map.

COMMISSIONER MITCHELL: One -- one last question. I'll let you -- if you have something to add.

MR. NORRIS: No. I was just going to say, I mean, to the extent that there was any way market participants could be aware of cases where there are interdependent facilities interdependent on a -- on a specific upgrade, that could be valuable because it's not necessarily the case that we want zero network upgrades; it's just that we want a low amount of network upgrades applied to any particular project such that they're still below avoided cost. And if you identified, say, it's a 5 or $10 million network upgrade, but three facilities are shared on it, that may actually be a good deal for ratepayers. So I don't know if there's a way to do that in a -- in a simplified manner, but that's just one idea to -- to put into the mix.

COMMISSIONER MITCHELL: Yes. And Duke, can you -- can you all respond to NCCEBA, please?

MR. JIRAK: I’m not sure I quite follow exactly what the request is, and we’ll give you a second to restate that. But, I mean, the green zone concept, again, you know, we can’t say it enough, what value is it if it -- if you have to make assumptions and those assumptions could just as well be wrong as they are right? What value is it to -- to take the transmission planners who are doing studies for real projects in the queue, have them go spend a bunch of time doing studies that have only very questionable value because you have to make assumptions about 25,000 MW in the queue that we -- of which we know probably less than 50 percent -- probably far less than 50 percent will ever be interconnected? It’s just the -- the combination of the lack of value of the estimate, with the cost and time it would take to do it we just think argues against it. So that’s -- that’s our position.

MS. KEMERAIT: And I think a response to that would be is that it’s very difficult, then, for market participants to provide proposals in areas that will have no or little upgrade cost when there is so much uncertainty about what that is going to be based upon, you know, information that we -- we've been provided. So it's a -- it's very difficult for market participants.

MR. QUAINTANCE: May I add -- I'm sorry. It's more of an anecdote, but after that map came out or maybe even before when maybe the rumor got around about some of those red zones, I can say that recent requests, at least in the DEP area, have been in that non-red area. It has really grown in the northeastern part of DEP. I can assume maybe that folks were taking this map to heart. There are a lot of requests in the queue up there. Not many bid. And, of course, DEP was only looking for 80 MW. But I think there's a lot of opportunity in that zone without being able to quantify it.

MR. JUDD: If I might contribute. The question was asked when these -- the maps were provided. They were released on the website, my office just informed me, on May 10th of 2018. Bidding was in October.

I can also say, going to the question about direction, for what it's worth, in other jurisdictions lightyears away, one of the ways we have dealt with this question was to identify specific POIs, such as substations, and say it's on you to include in your bid the price of getting to that POI, and that was it.

Different situation than here. I'm suggesting this is an issue we deal with most everywhere in the country. Some folks have tried a simplistic approach of simply saying here's a list of substations; all the cost is on you of getting from your project to that point as opposed to here, where the point of interconnection is nondetermined until the bidder presents a bid.

COMMISSIONER BROWN-BLAND: All right. Commissioner Mitchell?

COMMISSIONER MITCHELL: Just I want to follow up with Duke. Mr. Dodge recommended some -- some adjustments that could be made to the grid locational guidance to provide some additional granularity. I just want to make sure I'm -- I understand your -- your response or your position on what the Public Staff is recommending here, because ultimately the Commission is interested, or at least one Commissioner is interested in, you know, providing the -- the most guidance, the best guidance that's -- that's possible. So please -- please provide a response.

MR. QUAINTANCE: I mean, I thought Jack kind of said it pretty well, but, you know, if we make an assumption, that -- that would be one of, you know, a thousand possible future states, and we could come up with numbers, and I feel like they would be, you know, unreliable numbers if we went that route.

MR. JIRAK: I -- I mean, I feel like I'm becoming a broken record a bit, but when we hear more granularity, we -- we just are not clear what that would mean. We -- we've talked about showing you what's constrained. We've talked about why we don't think it a makes sense to do all the work required to show you a theoretical view of some future state where maybe these circuits "will be green." So between those two -- those two extremes we don't think the green zone now makes sense. We -- we're doing the red zone view. We're not sure what the -- we -- we have not yet identified a way to make it more granular.

We think the information we provided is reasonable. It seemed to guide some -- some bidders in looking at projects. We recognize it's not perfect, but it's -- it's a function of the size of the queue and the uncertainty that we have to face -- deal with all the time about a problem that we don't have control over.

MR. NORRIS: Can I offer two specific ideas, and then we'll just leave it at that? So -- so one would be there must be a degree to which you can provide guidance on the extent of a network upgrade that would be required. And, you know, the example is a project or -- I think it was one project -- there may have been multiple -- that was selected in the first tranche with a very large bid pool that contained a $5 million network upgrade. And so presumably there -- there are projects that will have network upgrades that will, in fact, be competitive and will be below avoided cost, and perhaps there is some way in which you can integrate the degree of congestion or some notion of, you know, an estimate of how large the upgrade would be. That would be the first one.

The second one would be back to what I mentioned previously, is to the extent that there are interdependent projects on a single upgrade, that could be valuable information from our participants because it is more likely that those projects could compete if they end up sharing the cost of such network upgrade.

Just putting two ideas there.

COMMISSIONER BROWN-BLAND: Mr. Jirak, your response doesn't change. It's still difficult and speculative in your mind?

MR. JIRAK: Yeah. I think that -- that continues to be our concern. And to the first question, I mean, in order for us -- and you all tell me if I'm wrong -- in order to know what those future -- the size of the upgrades, give you a sense of the scale of the upgrades, we're back to the same problem of, well, you only can assess that through a System Impact Study, and a System Impact Study has to assume a baseline, and so we're back to the same question, what do you assume in that system baseline? And do you want the transmission planners going off and doing a bunch of hypothetical studies with baselines that are uncertain, to come up with a potential system upgrade if every assumption in our base case plays out the way we've assumed it? It's questionable -- it's a lot of cost for questionable value.

COMMISSIONER BROWN-BLAND: All right. I think the Commission understands this issue.

MR. JUDD: Pardon me. If I could just correct a misstatement. There was no project that has --

COMMISSIONER BROWN-BLAND: That was 5 million.

MR. JUDD: -- $5 million. That was cumulative of all of the projects that were moved to the PPA stage. Thank you.

COMMISSIONER BROWN-BLAND: So we'll move on to the third issue. We're making good time here. And that's the reasonableness of the energy storage protocol that is a part of the CPRE pro forma PPA. Is that you, Mr. Buffkin?

MR. JIRAK: Commissioners, if you -- if you don’t mind, we have a different set of personnel coming up to present on that topic and --

COMMISSIONER BROWN-BLAND: That’s good. We’ll give you -- we’ll give you a second.

MR. JIRAK: Thank you.

COMMISSIONER BROWN-BLAND: Mr. Layfield, you could have stayed put.

MR. JIRAK: Again, looking to the Commission and the Commission Staff's guidance, if you prefer us to give the presentation.

COMMISSIONER BROWN-BLAND: You have a presentation?

MR. JIRAK: Yes, ma'am.

COMMISSIONER BROWN-BLAND: Okay. We’ll -- we’ll keep the same process.

MR. JIRAK: Okay.

COMMISSIONER BROWN-BLAND: You go with the presentation.

MR. JIRAK: All right. I’ll -- I’ll turn over to Duke colleagues here who will introduce themselves and their role with the Company.

MR. ROBERTS: Okay. Good afternoon, Commissioners. For the record, my name is Sammy Roberts, and I'm the Director of System Operations, Engineering. I have about 20 plus years of system operations experience and another 10 years of utility experience.

MR. JOHNSON: Good afternoon. I'm David Johnson, and I am Manager Director of a group that is responsible for negotiating and executing third-party PPAs, managing those contracts through the life of the -- of the PPA, and also responsible for the REPS and CPRE compliance.

MR. ROBERTS: All right. Thank you. I believe all of you have copies of the presentation, so we'll go ahead and get started. These are just the topics that I want to cover, and I'll try to cover them as briefly as I can to leave time for questions.

But why -- why do we need storage protocols and looking at the Tranche 1 storage protocols which utilize the Sub 148 pricing mechanisms versus the Sub 158 proposed storage protocols and also Tranche 2 storage considerations? So next slide.

So I'll call your attention first to the graph, and this is just a winter load shape, and we see this -- this type load shape in DEC as well as DEP. This just happens to be a DEP curve. And so if you look at the top of the curve, that represents our gross load for winter. And then if you look at the yellow portion, that's -- that's solar output. And then if you look at the -- the blue portion, that's regulating generation. And then the green is -- is base load nuclear generation.

Before I get into the -- more description of the graphic, I will say for Duke Energy in the Carolinas that storage is a relatively new technology for us, and so it's -- it's one that we're having to utilize some -- the little experience we have is associated with things like the Mount Holly microgrid. We are looking at installing some small batteries at Hot Springs and Rock Hill, and so that will give us some more operating experience.

We also read about what other entities that have storage are doing, so we're still trying to learn and gain knowledge about integrating storage onto our system from an operating perspective.

But once again, going back to the need for storage protocols, if you have battery storage and you have uncontrolled charging and discharging on the system, you could -- you could theoretically get it at the worst time, such as during high -- high net demand ramps, during excess energy windows, when you have system peak energy needs and when you have large generator contingency recoveries, et cetera. And I'll explain -- explain that briefly.

You can get it at just the right times. If you have it to cover the peak, then that's a good thing, right? If it can -- if it can help you with charging during excess energy periods, that's -- that's a good thing as well. But looking at this curve, what I primarily need from a system operations perspective is resources across that peak in the early hours, hour ending 7:00, the hour ending 9:00, let's say, and then across the -- going into the evening peak. Going into the evening peak, my solar is ramping out, so I have a high net demand ramp, positive net demand ramp, and so I'm -- I'm going to need some energy as that solar ramps out and going into the evening peak hours.

With respect to excess energy, once again, in that valley when solar is at its max output, that's probably when I don't want to receive discharging from -- from a storage so, thus, the reason for protocols. It helps us with reliable operations. It helps us with giving the customers value where it's needed. And also it helps us with complying with NERC reliability standards. So next slide.

So this is a typical summer load shape. And once again, basically about the same load shape that's seen in DEC that's seen in DEP. This just happens to be a DEP load shape.

What I -- what I want to depict here is once again, you have operational needs, and those operational needs are when the solar is ramping out in the evening hours and you're -- you're going up to your net demand peak. What do I mean by net demand peak? Once again, the gross load is the curve at the top of the shape, including the solar, and then if I take the solar amount, just looking at the top of the blue region, that's net of solar, that's that gross load net of solar. That's what I mean by net demand load.

And so when I'm -- when I'm going into that net demand region where my solar is ramping out and I'm going to the net demand peak in the evening, notice it's not the actual peak that occurs around 1600. That's when I'm going to need discharging from a storage device.

So what about Sub 148 versus Sub 158 pricing windows? Well, Tranche 1 was aligned with Sub 148 pricing windows, and you can see it's fairly wide, it's a fairly broad amount of hours. And so really the system needs are more so toward those evening hours when the solar is ramping out, and so it goes from -- I believe it’s an eight-hour window in Sub 148 to the proposed four-hour window in Sub 158 which is, once again, based on system needs. So next slide.

So this is back to our winter load shape, and here, comparing Sub 148 versus Sub 158 pricing periods, you can see that the winter period for Sub 148, you could be discharging very close to that maximum solar output. And so that -- is that -- I mean, we -- we could manage it, but it’s -- it’s just adding to our excess energy issues that we have to manage. We would prefer that it discharge over that peak, those peak hours. And so Sub 158 establishes a premium peak window, hour ending 7:00 to hour ending 9:00, because we are winter peaking and we’re morning winter peaking. And so -- and then Sub 158 also proposes an evening peak window for four hours as well.

Also, once again, after I start with a heavy net demand ramp after that hour ending 9:00, if I get discharging from storage or in that valley area, that’s really not going to help me with respect to complying with NERC standards and also managing my -- with managing my excess energy. So next slide.

So basically with Sub 158 we streamlined the standard, all of our storage protocol, and the protocol is really looking at being around -- based around the size of the facility. For a standard offer with Sub 158 it’s less than or equal to 1 MW, and so you’re not really projecting a lot of volume of battery capacity with -- under Sub 158. So considering that, with respect to Tranche 2 where you could have a substantial amount of battery capacity, that’s one of the considerations that we’ll need to make with looking at the Tranche 2 protocols.

Also, as shown on the prior slides, you know, you noticed, and as I pointed out, the peak pricing periods are smaller in Sub 148, and I gave you the reasons for those. And so that makes it more predictable as to when you’re going to get charging versus discharging associated with the battery, so discharging over the peak hours and charging during -- during the nonpeak hours.

So this -- this provides the -- or meets the Commission Order with respect to more granular pricing periods in Sub 158, plus, as I told you with the graphics, it basically enhances the reliability that we maintain on the system for our customers, as well as adds to customer value with respect to providing a resource over those peak hours.

Also in that construct we look at levelized facility output, and basically what that means is over that three-hour period your solar plus your battery need to produce a levelized output over that window, and we'll -- we'll propose allowing a ten-minute ramp associated with that as well which really balances the interest of both the developers as well as the customers. It's fewer constraints with respect to the developer, and it also allows the developer to use some control logic and basically levelized that output, maximize the use of batteries and solar for that peak pricing period, and it provides a predictable output for operations with respect to the peak window. Next slide.

Okay. Considerations for Tranche 2 storage protocol. Once again, if we look at the Sub 158 and we adopted something like that for Tranche 2, that would, once again, allow for more predictable storage usage. And we also, you know, thought about having utility control of the storage, however, there are some -- there are some issues there, some reasons that it's not practical at this time, is that we could be controlling the battery in a manner that provides wear and tear. As the developer's asset, we -- we provide control in a manner that provides wear and tear and limits the life of the battery.

Also, if the battery is connected behind the inverter, which in order to ensure that the solar facility is charging the battery, that would need to be the case with respect to House Bill 589. We don't have a good industry ANSI quality revenue meter with respect to metering the battery output. And also if they were -- even if they were available, connecting it to the customer's -- within the customer's boundary would introduce some complexities with respect to installation, ownership, and maintenance, and potential impact to your facility while we're performing that maintenance.

And lastly, we have had some discussions about aggregated battery control systems, but we haven't developed that yet. And so we -- the specs for controls with respect to Carolina system operations do not exist yet. And those control -- that aggregated battery control would -- would be something that would originate from an energy management system, and if it's distribution connected, go through our distribution management system to the controller. If it's transmission connected, it would go directly from the energy management system to the -- the transmission facility. Next slide.

So if we do use the -- or consider to use the Sub 158 peak pricing periods in the Tranche 2 storage protocol, then, you know, that would help with respect to the predictability, as well as the benefit to -- that we see to customers, as well as system reliability. And, also, you know, we -- we could look at considering options with respect to batteries -- controlling batteries at a later date.

So just offering in summary why protocols? Protocols ensure benefit to the customer. Protocols ensure benefit to reliable operations. And once again, Duke is continuing to learn about storage, and also we'll continue to work with or work through the CPRE framework to develop effective protocols to integrate storage.

And that concludes my presentation.

COMMISSIONER BROWN-BLAND: Before we move to Commission Staff, does any of the parties have brief pointed responses to anything you heard in the presentation? Ms. Kemerait.

MS. KEMERAIT: I have a -- Karen Kemerait for NCCEBA. I just have a question for clarification. These considerations for Tranche 2 storage protocol, are they designed to replace the energy storage protocol that's included in Exhibit 10 of the Tranche 1 PPA? Is that Duke's proposal?

MR. ROBERTS: Right. So -- so once again, we had the proposed Sub 158 protocols for 1 MW or less standard offer, and so what we would do is consider looking at those protocols. We would consider adopting those, which are less constraining on the storage facility as compared with the Tranche 1 protocols.

MS. KEMERAIT: So there will be -- so there will be a more specific proposal that you'll be providing than what you're discussing -- than what you've discussed with the considerations for Tranche 2 storage protocol --

MR. ROBERTS: Yes.

MS. KEMERAIT: -- that will be provided later?

MR. ROBERTS: Yes.

MS. KEMERAIT: Okay. But for purposes of this discussion, all of the Exhibit 10 energy storage protocol are considered to be overly restrictive and -- and will not be included in --

MR. ROBERTS: No.

MS. KEMERAIT: -- the Tranche 2 PPA --

MR. ROBERTS: Yeah.

MS. KEMERAIT: -- is that correct?

MR. ROBERTS: I wouldn't say that they are overly restrictive. You had two people bid in that were selected to provide storage in Tranche 1, so I wouldn't say that they're overly restricted. They're just what we considered at the time were needed in order to, once again, ensure that we're maintaining reliable operations, we're maintaining NERC compliant operations, and we're maintaining value for our customers.

MS. KEMERAIT: So not to make an argument about overly restrictive, but these current -- the Exhibit 10 protocol are no longer going to be applicable for the Tranche 2 PPA?

MR. ROBERTS: There's probably going to be flavors of those protocols in the Tranche 2, but, for example, you know, where one of them restricted to 1 percent of ramping, you know, you may see that percentage increase to something more commensurate with other entities.

MS. KEMERAIT: Thank you.

COMMISSIONER BROWN-BLAND: All right. Mr. Buffkin.

MR. BUFFKIN: Thank you, Madam Chair. If you could flip back to slide three, please.

COMMISSIONER BROWN-BLAND: And Mr. Roberts, you pull that mic a little bit closer to you.

MR. BUFFKIN: Could you just briefly refresh our collective recollections about what the LROL is?

MR. ROBERTS: Yeah. So Lowest Reliability Operating Limit is a term established in the 2016 avoided cost rate hearing, and basically that indicates the minimum amount of synchronous generation that you need -- regulating generation that you need to maintain online in order to handle the evening peak, the ramping into the evening peak, as well as the morning peak for the next morning. And so it's a capacity and a regulation requirement.

MR. BUFFKIN: Thank you for that. And that LROL is not depicted in the slides on 4 and 5.

MR. ROBERTS: That's correct.

MR. BUFFKIN: But it would be in the same place, right?

MR. ROBERTS: It -- it changes from day to day based on the -- based on the need for looking at the amount of regulation needed, the amount of evening peak, the amount of the next morning's peak. And also in the summer, you know, you have a load shape, so it changes during the summer as well.

MR. BUFFKIN: Would it be roughly in the same place?

MR. ROBERTS: Yes. I would say it would be roughly in the same place for that size peak.

MR. BUFFKIN: Thank you. Let me stay with Duke, but I think this is probably for Mr. Jirak. I understood your objections and your comments to the basic concept of energy storage devices providing other services, and -- and I understand other service roughly equal to the term ancillary services that would be used in the organized market. And I'll summarize.

I think those objections were four-fold, statutory or lack of statutory authorization, valuation in relation to the cost effectiveness and the difficulties that that presents, and that other services are in some -- some cases incompatible with provision of energy and capacity, and then fourth, that this would require a new contract and some time and effort involved in that. So I'm interested in -- among these factors, were one or more of them more important than the others, or -- or is it -- well, I'll leave it at that. Was one -- one of these factors more important than the other?

MR. JIRAK: Without having them in front of me, hard to -- hard to weight them. I think it depends on, you know, are we -- if the question is can we do it in

CPRE, obviously, the question is about whether it fits within the statutory directives, CPRE is more relevant, but I -- I don't know that I -- without consulting the business folks I could probably -- I could tell you which is more important than others. Certainly, a lot of very complex technical issues there that I can speak to at an extremely high level, but can't get -- get real deep with you.

MR. BUFFKIN: Okay. Well, let me stick with the statutory authorization issue, then. Other parties have suggested that the Commission order a stakeholder process on this energy storage protocol. If -- if your view is that other services not permitted under CPRE statute, what's your view on stakeholder process, then?

MR. JIRAK: Certainly, we're willing to participate in any process the Commission sees fit. I don't know that changes our perspective that paying for things other than energy capacity is, you know, arguably outside the bounds of what HB 589 ruled with respect to CPRE. But at times when I heard discussion, the stakeholder process sounded more broad than just, you know, can we or can we not do this for CPRE. It sounded like there was more of a desire for a general stakeholder initiative generally, but certainly we defer to the

Commission what's the right procedural path forward, and we're not going to object to the process.

MR. BUFFKIN: All right. I think Mr. Johnson may have touched on this, maybe even answered it, but, Duke, you told us in your comments you were still assessing the storage protocols especially with regard to ramping limitations and scheduling. Do you have any updates on -- on progress as you've been assessing that?

MR. ROBERTS: Right. Once again, we're looking at the proposed Sub 158 protocols and also, you know, considering -- considering comments from developers, as well as looking at the system needs from a reliability and customer benefit perspective, but outside of putting pencil to paper, we haven't done that yet.

MR. BUFFKIN: All right. Same question with regard to the deadline for providing the next-day window for bulk discharge start and end times, and currently it's 4:00 p.m. You've heard some people object to that. Have you made any progress on adjusting that?

MR. ROBERTS: I'm sorry. Could you repeat the question?

MR. BUFFKIN: Sorry. Let me back up. So we've heard from some other parties about the provision in the energy storage protocol that requires Duke to give the next-day discharge start times, and that -- and that current time is 1600, 4:00 in the afternoon, but you also said -- have you -- have you made any progress on adjusting that? What's -- what's your latest thinking?

MR. ROBERTS: Yeah. I'm not aware of any progress on that.

MR. BUFFKIN: So you still think 4:00 p.m. is the right --

MR. ROBERTS: Do -- do I still think it's appropriate with respect to providing those day-ahead times associated with storage discharging? I mean, I think the windows, the time windows, are going to be fairly accurate with respect to the needs for winter load shapes as well as the summer, and so I think we feel the granularity that was requested in the Order by the Commission is met with that.

MR. BUFFKIN: I understand. I understand your view that's the appropriate time. Why -- why not earlier?

MR. ROBERTS: Well, I mean, if -- if -- I guess if you provided a longer duration battery, you could provide for more discharge over the peak, but then you've got to look at the cost associated with that. You've got to look at the cost associated with that versus the other resources.

MR. BUFFKIN: All right. I think I'm back to the lawyers, then, if I -- if I may continue, and I'd be interested in hearing from the other parties, too. Both the Commission in its Orders and -- and the parties in their comments have generally characterized the standard of review for this pro forma PPA as reasonableness or commercial reasonableness, acceptance in the marketplace. What are some of the hallmarks of commercial reasonableness? What -- what are the things the Commission should be looking for?

MR. JIRAK: Yeah. I think certainly it's a relevant factor to consider how other utilities have handled similar issues and looking at PPA structures in other utilities. I think it's also relevant to consider what makes Carolinas unique, and the unique operational and generation factors that influence what's appropriate here as compared with -- with what -- how other utilities have handled it. So I think -- I think you've identified them well, but I think you can't -- in the end it's not a one-size-fits-all solution, and it has to be assessed on a -- you know, given the specifics of our system. I don't know if Sammy has any to add to that.

MR. ROBERTS: I'm sorry. No. You're good, you're good. Yeah.

COMMISSIONER BROWN-BLAND: Any other attorneys want to address the hallmarks of commercial reasonableness?

MS. KEMERAIT: Right. In -- in regard to the energy storage protocol for the Tranche 1 PPA, we've provided information in our comments, and we believe that the -- the restrictions will make the -- a solar plus storage project unfinanceable. Plus, we think that the restrictions are overly restrictive and onerous.

And I did want to point out a clarification to some information that was provided before. It was only the Tranche 1 PPA that was reviewed and approved by the Commission. There are a number of other documents, the asset acquisition documents and the EPC Agreements. And we as an industry provided substantial comments about the asset acquisition documents and the EPC Agreement and provided ways that they could be improved and corrections to that. And only minor changes were made to those agreements and they were never -- and my understanding, that I think Mr. Judd might be able to clarify, but I think even the Independent Administrator did not review or make any changes to those agreements, and then they never came before the Commission for review or approval.

And we have believed that they have been -- that they are all commercially unreasonable documents.

MR. JIRAK: So can I respond to that just briefly? I mean, that's a completely 180 different issue than we're addressing here, but I'm glad to address the acquisition documents if -- if you want to hear those topics.

COMMISSIONER BROWN-BLAND: Well, she tied it to -- came back and tied it to commercial reasonableness, so if that's -- we'll hear from you.

MR. JIRAK: Sure. So, I mean, first of all, this issue was already litigated once. Similar to the market -- post-term market revenues, the Commission has already heard this issue once before and issued a ruling on it, so we think the same basis of facts and -- and logic that led to the Commission's conclusion the first time is appropriate this time.

Secondarily, the marketplace delivered asset acquisition bids that have been successful. The market delivered solar plus storage bids that have been successful. So the premise that they're just fundamentally flawed and unfinanceable is obviously not the case. Certainly understand the perspective that they -- that developers think they should be different, but they're not. The documents are not so unreasonable that -- that bidders refuse to bid in projects. I mean, that's kind of basic facts.

COMMISSIONER BROWN-BLAND: All right. Mr. Levitas.

MR. LEVITAS: Yes. Thank you. I would take issue with the notion that just because a couple of people successfully financed documents, that that makes them commercially reasonable with respect to all of these types of documents. You've got two storage bids. You might have gotten 50 storage bids.

And -- and with respect to the -- the fact that -- with respect to the PPA that's been used here, yes, it's been financed in the past. I've been involved with those financings. I've been involved with negotiating those PPAs. I don't believe the fact that that has occurred necessarily is the definition of commercial reasonableness. It's possible to finance a commercially unreasonable document. You may have to pay more to do it, you may have fewer financing parties who are willing to transact with you, but it still may be possible to get it done at a price or with difficulty. And --

COMMISSIONER BROWN-BLAND: But that some are done is a factor to be considered, correct?

MR. LEVITAS: Pardon me?

COMMISSIONER BROWN-BLAND: That some are financed is a factor to be considered?

MR. LEVITAS: I think it's a relevant fact. I would agree with that. But I actually think Mr. Jirak got closer to the mark when he talked about looking at what's done in other jurisdictions with other utilities and to kind of benchmark for -- for a measure of commercial reasonableness. And I -- I would just -- just to give you one example of that, the -- the PPA that we're dealing with here, which is based on the PURPA PPA that was negotiated, has a section that deals with assignment, and that section on assignment covers lender rights, so these -- these PPAs are collaterally assigned to lenders as part of the security of the financing package. And I will just tell you that those terms in these Duke PPAs do not comport with what we see in most places in the country, and in order to get lenders to accept those, it takes a lot of work.

So I just think the -- the fact that we're able to -- and I've spent a lot of time personally trying to persuade lenders, yes, you should do this deal even though you don't like these terms and this is not what you see in other jurisdictions, so I just think the test is broader than whether some parties manage to succeed in getting challenging terms financed.

COMMISSIONER BROWN-BLAND: So in your view, it's fair to say you might -- with some extra effort you might be able to get the financing, but it's the extra effort that is -- is sort of adverse to the process, I guess?

MR. LEVITAS: That's right. We -- we will find some financing parties who are not willing to participate, given those terms, or they may charge a higher cost for financing as a result of those terms.

COMMISSIONER BROWN-BLAND: All right. Does the IA have something on this point?

MR. JUDD: On commercial reasonableness?

COMMISSIONER BROWN-BLAND: Yes.

MR. JUDD: We -- Commissioner, we feel the --

COMMISSIONER BROWN-BLAND: And the changes that you did or didn't make in Tranche 1.

MR. JUDD: Pardon me?

COMMISSIONER BROWN-BLAND: And the changes you did or didn't make in -- in Tranche 1 based on the parties' contributions.

MR. JUDD: Yeah. We went through the comments of the parties. We found that the final document was commercially reasonable as used elsewhere.

May I offer an observation about storage, since that is the subject that we’re in this segment, or would you like me to come back to that later?

COMMISSIONER BROWN-BLAND: Let me -- let me come back to you. Mr. --

MR. JUDD: Thank you.

COMMISSIONER BROWN-BLAND: -- Buffkin, we’re still with your questions.

MR. BUFFKIN: I think I’m done with that one, but I've got -- I've got just a few more.

COMMISSIONER BROWN-BLAND: Oh. So you're moving on?

MR. BUFFKIN: Yes, ma'am. For Ms. Kemerait, I -- I understood your objections to the ramp rate provisions, and I’m looking for a little help on some details or expanding on your arguments. What exactly is the objection here? You feel that Duke hasn’t met its burden of persuasion to justify these provisions, or -- or is it although they brought sufficient arguments and information, that -- that the Commission should just order a different outcome?

MS. KEMERAIT: Well, I’ll -- Tyler Norris was going to -- is going to talk a little bit about the ramp rate restrictions, but so -- so far, up until today, Duke has provided no justification for the ramp rate restrictions, and so what we have been -- what we have been asking for is justification so that we could have an opportunity to try to find a solution that would allow -- that would be appropriate, that would allow the energy plus storage projects to be able to be bid -- to be -- to be appropriate to be able to be bid into CPRE.

MR. BUFFKIN: So -- so, then, you just think they haven't met their burden of persuasion?

MS. KEMERAIT: Absolutely, uh-huh.

MR. BUFFKIN: I understood that their justification was it's commercially reasonable.

MS. KEMERAIT: Their -- they -- they have not demonstrated that it's necessary for grid reliability, and I think that that is what they need to -- to demonstrate, that a restriction on energy storage must be necessary to protect grid reliability. And we've received -- we -- we have heard some information today, but up -- but it's been very general information, and up until today there's been no justification about why these ramp rate restrictions are necessary for grid reliability. And we've been asking for about a year for that technical justification for these restrictions.

MR. BUFFKIN: All right.

MR. O'HARA: Mr. Buffkin, could I add to that, if I may -- or go ahead, please.

So just as an example here, so one of the ramp rate restrictions is a 1 percent per minute ramp rate restriction while the solar facility is generating. Just as an example, the state of Hawaii, which has a lot of solar and storage on their grid and is a small islanded grid, so presumably less capable of handling variation than a larger grid like this, actually has a 5 percent restriction there. So -- so 1 -- 1 percent in that case, you know, doesn’t seem to make a lot of sense to us, given the differences in those grids, but I think the bigger issue is what -- what we’d like to see is let’s have a definition of the problem that’s -- that we’re trying to solve, and let’s work together to come up with the right solution to solve that.

So what -- what we see is that there’s a -- there’s presumably a problem that’s being solved, and what we see is -- is Duke’s answer to that problem. There’s a lot of expertise in our industry around energy storage as well, and I think if we work together, we may find that there are other less restrictive or contractual or, you know, other solutions to the problems, but we’d like the opportunity to -- to work on those together.

MR. NORRIS: Yeah. And just to expand on maybe some of those opportunities, so on one hand we are hearing a problem definition from the Utility, which is that they have a new capacity need that's, say, a three-hour window on a winter morning. So we're trying to develop solutions to that challenge for the benefit of ratepayers, and the question is, what sort of operational restrictions will best allow that? And what's been proposed in the prior PPA was that a battery could not ramp up to supply that need in less than 20 minutes. So you'd have a 5 percent a minute ramp rate, and that's up and down. So a battery would have to sacrifice the ability to provide that discharge on behalf of ratepayers for a total of 40 minutes, and -- and that's, you know, a two- or three-hour window.

We appreciate that Duke has changed its position and now is -- is talking about a 10 percent ramp rate limitation in that scenario, but even there you're losing 20 minutes of potential output that we're all trying to maximize, again, on behalf of ratepayers, and it's unclear to us why, especially if the battery is, in fact, capable of providing that discharge for a full two- or three-hour window.

Now, the other problem definition I believe that we are starting to hear for the first time is that they are concerned about a resource being able to provide discharge for that full window. They're worried about, say, a cutoff point or an unpredictable cutoff in a period when they're expecting that capacity output. And I think there's a really reasonable solution we can come to, which is simply that we state in the PPA that there will be no ramp rate limitation if you commit to providing discharge for the full period or some -- say, it's a two hour period, but I think we could come to some agreement on that.

But, again, the -- so the -- the issue that we're hearing expressed is a concern about a resource not providing that output for us for a period of time. I think one reasonable solution would be we just say if you do provide discharge for a two- or three-hour window, there's no ramp rate limitation or a substantially lower ramp rate limitation.

So I think that's -- that's the only comment I'll make for now on that issue.

COMMISSIONER BROWN-BLAND: Mr. Buffkin.

MR. BUFFKIN: Let me stay with Ms. Kemerait, if I may. In looking at Protocol Provision Number 9, this is something you've raised objection to in your comment about the operating restrictions in Duke's, in your words, "unfettered right to add additional and undefined operating restrictions." I think I have the latest version in front of me, and it -- it references NERC standards. It references commercially reasonable manner, commercially reasonable demonstration. Are -- are these not limitations on Duke's ability to add new restrictions?

MS. KEMERAIT: So Mr. Buffkin, is your question that our objection to Number 9 would limit Duke's ability to add additional restrictions?

MR. BUFFKIN: No. I understood your objection was it gave them too much ability to add new restrictions. And maybe to say it another way, is where someone would raise objections to these undefined restrictions is, you know, that they're not authorized, but here we have expressly incorporated by reference into this protocol what I understand to be limits on adding new restrictions. For example, if it wasn't necessary to comply with NERC standards, if it wasn't implemented in a commercially reasonable manner, those would be limits on Duke's ability to add new restrictions. Am I -- am I misunderstanding the provisions of the protocol?

MR. NORRIS: So I think this -- this is another example where just the -- the lack of information or technical justification --

COMMISSIONER BROWN-BLAND: Be sure the mic's --

MR. NORRIS: Sorry about that.

COMMISSIONER BROWN-BLAND: -- directionally aimed at you.

MR. NORRIS: It's just -- it's an area where I think maybe we could resolve it if we -- if we sit down and really walk through what a scenario like that would look like. So what -- what is a -- what is a scenario we can imagine where a NERC standard changes that does require an additional operational restriction on the batteries? And if we can really hone those in and define them well and -- and for one, we can then better assess whether they are, in fact, commercially reasonable, but, two, it's the only way that many parties can actually finance such a PPA. Because if we don't know what those scenarios are or how restrictive they could, in fact, be, you're not going to be able to convince a financing party to step into that risk to finance such an asset.

So all we're saying is certainly in that scenario we need to better understand what that scenario is.

MR. ROBERTS: May I answer?

COMMISSIONER BROWN-BLAND: Yes, Mr. Roberts.

MR. ROBERTS: Thank you. So -- so I'll give you a great example. In 2016, NERC changed Standard BAL-001 from something that was looked at on a monthly period, you had a month to dilute your performance to acceptable performance, to a 30-minute window. So now if we exceed what's called our Balancing Authority ACE Limit for 30 minutes, which that steep net demand ramp in the morning and in the evening greatly challenges that, then we've violated a standard. And, of course, the fines are up to a million dollars per day per event, over a million now.

COMMISSIONER BROWN-BLAND: And, Mr. Roberts, did you -- did you have any -- any response to Mr. O'Hara's mentioning of the -- the restriction in Hawaii versus the restriction of Duke?

MR. ROBERTS: Right. So -- so as I mentioned earlier, that is one of the areas we're looking at with respect to Tranche 2 protocols with respect to that 1 percent ramp rate limitation, and so hopefully we can come up with something that's beneficial to all parties.

COMMISSIONER BROWN-BLAND: All right.

MS. KEMERAIT: And can I -- can I just add one more comment? Karen Kemerait. I mean, what we are -- what we are looking for is to have is -- what we've been looking for for the past year is to have a dialogue with Duke, with Public Staff being part of it, so that we can understand what those concerns are and to solve for them so that we can have appropriate energy storage protocol for -- first, we wanted it for Tranche 1, but now for Tranche 2. And then also we think that this is going to be a really critical precedent for PPAs elsewhere, so this is a -- this is a really important issue not just for CPRE, but for all interconnection projects.

And I think that with the stakeholder process that we've asked for, I think that we can come to solutions, and so we, you know, continue to ask for a stakeholder process so that we can better understand what we're trying to solve for, provide solutions, and then as part of the stakeholder process we want the Commission to consider and approve what the -- what the recommendations and solutions would be so that we can have appropriate policies for CPRE and then going forward for other interconnection PPAs.

COMMISSIONER BROWN-BLAND: Thank you. Mr. Buffkin --

MR. BUFFKIN: Well --

COMMISSIONER BROWN-BLAND: -- any more?

MR. BUFFKIN: Just one more for Ms. Kemerait, and then a couple for the Public Staff.

COMMISSIONER BROWN-BLAND: All right.

MR. BUFFKIN: I'll -- I'll be brief. So on -- on that last point, you've all -- you all have had -- at least had the opportunity to attend stakeholder meetings, so dialogue is going on. Have we just reached a point where you all don't agree with each other or -- I'm having trouble understanding you're saying you want dialogue and you haven't had dialogue, but we know stakeholder meetings have happened, so -- so maybe you all just don't agree.

MS. KEMERAIT: I would not characterize it that we just don't agree. I think that we have had no opportunity for that sort of discussion. We did have two stakeholder meetings that we were very appreciative that Mr. Judd and the Accion Group organized and included Duke, market participants, the Public Staff. I mean, they were -- there was quite a bit of interest and they were very well participated in.

However, again, going into both of the stakeholder meetings, we continued to ask for information about the energy storage protocol, we asked for justification, we asked for the dialogue, and we frankly did not receive any justification from Duke. So the energy storage discussion was extremely limited. We did not -- we -- we -- there was no in-depth discussion or analysis. So the discussion that we're having today before the Commission is by far the most in depth and greatest discussion that we've had about energy storage since CPRE has begun.

COMMISSIONER BROWN-BLAND: It's my -- it's my observation that I believe parties on both sides of the room have heard something new out of these discussions today, so we -- that's one of the hopes of the Commission, is that you'll find the proceeding helpful to helping us move along and progress implementation of this program.

Mr. Buffkin, do you have any more?

MR. BUFFKIN: Yes, ma'am, just two more, and I -- I think these are best directed to Public Staff. You recommended the parties take into consideration the study results by the North Carolina Policy Collaborative in approaching the issues in this proceeding related to energy storage. Now, Duke has told us they don't think other services are permitted under the CPRE statute. What's your view on statutory authorization for that kind of compensation under the CPRE program?

MR. DODGE: So the -- excuse me -- this is going to carry forward into our discussion on the dispatchable PPA, I think, a little bit this afternoon, but we -- I think we recognize the -- the CPRE's purpose is to procure energy capacity and environmental attributes, but in terms of the -- the cost cap that's used for determining cost effectiveness, that's based on avoided cost. And you -- as long as you're below that, if they're providing the most cost effective resources to -- that provide energy capacity and environmental attributes, but also provide other services to benefit customers, then we think that those can be recognized or should be recognized as values.

I think in our March 22nd comments we talked a little bit about the transparency of the evaluation process and the net benefit to the grid as well, and that to the extent that that, I think, is more -- after Tranche 1 parties are able to evaluate that a bit more fully and understand that that that may be -- we may see more -- more innovative bids or bids that may -- may try to target those that net system or net benefit to the grid determination, and maybe -- that maybe help incentivize additional storage.

MR. BUFFKIN: Thank you for that. And my final question, again, I think for the Public Staff, so House Bill 589 directed that that energy study by the collaborative be delivered to the General Assembly, the Joint Legislative Commission on Energy Policy and the State’s Energy Policy Council, and to my knowledge. neither has acted on that study. To what extent is it premature for the Commission to do so based on the results of that study in the absence of any other legislative direction to take action?

MR. DODGE: That’s -- that’s a good question. No. I mean, it’s hard to avoid storage right now. It seems to be coming up in IRPs and avoided cost and CPRE. It’s a -- it’s a theme that we keep coming back to, interconnection, so it’s -- it seems to be something that a lot of work went into to developing that collaboratory report and some of the -- the potential benefits. We -- we also recognize that it was a report to the General Assembly and whether some action would be taken there first. But to the extent that there are values identified in that report and that the Utilities are also looking at in IRPs and -- and some of their other modernization plans, I think we -- we think it’s appropriate for the Commission to look on a larger scale at the energy storage protocol.

We've -- we've recommended a stakeholder process for -- or not energy storage protocol, but energy storage that would also include whether the energy storage protocol could be modified in a way, whether it's -- I mean, certainly, when Mr. Roberts attends these meetings and provides information on how -- you know, how reliability is key in making sure that the -- the storage is integrated in a meaningful way, it's helpful, but we also want to make sure that we're not overly conservative in that application and that some of those other benefits could be captured, if possible.

MS. CUMMINGS: Jeff Thomas here, our engineer, has pointed out to me -- he spent quite a bit of time with the study -- that there are specific recommendations in the study that are for the General Assembly to act on or -- or are more appropriate for the Commission to act on, like changes to interconnection standards, so that may be relevant in thinking about recommendations of the study.

I would also point out from my time at the Legislature, the Legislature will not hesitate to tell you if you've gone too far, so...

COMMISSIONER BROWN-BLAND: All right. Let me --

COMMISSIONER CLODFELTER: But until they do, we can go as far as we want.

COMMISSIONER BROWN-BLAND: So I want to come back to Mr. Judd.

MR. JUDD: Thank you.

COMMISSIONER BROWN-BLAND: He asked to make comments about this general storage protocol issue.

MR. JUDD: Yeah. I'll be very brief. I just wanted to, if I could, put this in context. Neither the CPRE rules nor the underlying legislation expressly states that storage should be part of this. And as I opened my remarks this morning, I spoke of Tranche 1 as being a beta test. Duke agreed to include the storage opportunity so that we could prompt this sort of discussion. What does the market need to participate? How could we make it work in North Carolina?

I'll also note that the first time my group, our group, has been involved in storage was a dozen years ago, and it was brought in as an experiment by another jurisdiction, another commission, saying let's give it a try. And it was a small part of a much larger, much larger conventional RFP.

Also, we have done quite a bit of work with --

in Hawaii as an independent evaluator. And, in fact, it's not an island, sir; it's four separate island systems, which you would think would make it easier to bring in storage, but it didn't. And the first time we had conversations with them about how can we incorporate it was easily six years ago. So my point being that this takes time. We walk before we run. The fact that HECO -- strike that; I'm sorry -- Duke agreed to bring in storage as a starting point in Tranche 1 and introduce it into CPRE to see where it could go was, we thought, a very good thing. And we obviously encourage that. We're encouraging expansion of it.

And I just wanted to, if I could, put it in context. They were -- it was not like they're putting up ways -- a roadblock. We said let's put it out there and see what the market will bring us and then let's find out what we need, because each jurisdiction is unique. Thank you.

COMMISSIONER BROWN-BLAND: All right. Thank you. Commissioner Clodfelter, any questions on storage?

COMMISSIONER CLODFELTER: It's kind of a halfway observation and a halfway question, so you can take it both ways. When we teed this up this afternoon, we -- we thought we were going to be talking about issues that are right for the Commission to have to express some viewpoint. And based on what I've heard, it sounds as if there are going to be some significant new proposals for the storage protocols in Tranche 2 that they haven't fully formulated and you haven't seen at all. So my question about this afternoon is, is it really even useful for us to continue with this until there has been a chance for Duke to talk to you about the new proposals, for you to react to the new proposals? I think they've heard you. We've clearly heard you, that it needs to be a very robust discussion and exchange, and I think they've heard that. And we'll probably repeat that several times ourselves.

Is there anything useful, more useful, we can do? Is there any issue that you know is not going to get resolved even if you sit down and discuss a whole new set of storage protocols? That's the real question. Is -- is there something that's just not going to get resolved regardless for Tranche 2? Yeah.

MS. KEMERAIT: Yeah. So Commissioner Clodfelter, Karen Kemerait with NCCEBA. We know of no issue that won't be able to be resolved. We are -- as -- as I've mentioned, we're very hopeful that with a dialogue and a stakeholder process, that we can work together to find solutions for Duke’s concerns about grid reliability. And then, of course, if we -- if we can’t reach agreement, we’ll be asking the Commission to -- to make a determination.

COMMISSIONER CLODFELTER: Well, we’ll see the new PPA for Tranche 2 and the proposed new protocols and it will be teed up then, so...

MS. KEMERAIT: And I -- it’s difficult for us to really respond because --

COMMISSIONER CLODFELTER: We’re not -- I’m not suggesting you do so.

MS. KEMERAIT: Right.

COMMISSIONER CLODFELTER: The very point of my question is that it’s not right for this afternoon.

MS. KEMERAIT: Right. We came -- it’s not right because we came prepared for the current Tranche 1 and --

COMMISSIONER CLODFELTER: I -- I respect that. I understand that. I think what I’ve heard from this side of the room is they’re not going to do a repeat.

MR. O'HARA: Commissioner, what I think is right for this afternoon --

COMMISSIONER CLODFELTER: Okay.

MR. O'HARA: -- and what you’ve heard from -- I think from us and from Public Staff is for the Commission to direct these parties to engage in a stakeholder process more broadly around storage, so not limited to just CPRE, with -- with some level of Commission oversight on that process.

COMMISSIONER CLODFELTER: Yeah. Well, that's -- that's -- we heard you on that. That's something, though, right now we're trying to get Tranche 2 out the door, and we -- we know that that's a pending suggestion, proposal, from several parties that's broader than that, and we understand.

I want to make one other observation and only because of the dialogue that occurred in the last series of questions, and I'm speaking only as one lawyer and one Commissioner, but, you know, it's an interesting statute in so many ways. The -- the way I read the statute, and I think it's pretty -- pretty clear to me, at least, is that the compensation structure for the CPRE program contemplates payments for energy and capacity, but that operationally the statute contemplates that Duke has -- is entitled to receive every other value stream from -- from these facilities that exists.

Now, maybe, for the reasons that they've articulated, as a practical matter they can't realize on those value streams right now, today, but legally the law says you're entitled to get dispatch, operation, and control in the same manner as if you owned it. So the way I read the statute, you're entitled to those services any time you're able to get them. That's one law review.

COMMISSIONER BROWN-BLAND: Commissioner Mitchell.

COMMISSIONER MITCHELL: Duke, just a few for -- for you first. Mr. Roberts, just a very practical question. For those instances in which the Companies -- either of the Companies has dispatch down rights through existing PPAs, how do you execute on those -- how do you provide those instructions and then make sure they're -- that the operator follows through?

MR. ROBERTS: Yeah. So we have filed the curtailment protocols and --

COMMISSIONER MITCHELL: Not -- not a -- so -- so this would be sort of a negotiated contract where you've got the right to -- and I --

MR. ROBERTS: Okay.

COMMISSIONER MITCHELL: -- and I'm sorry to interrupt you. You may be going down that --

MR. ROBERTS: Sorry.

COMMISSIONER MITCHELL: -- path --

MR. ROBERTS: Yeah. So --

COMMISSIONER MITCHELL: -- but I just want to make sure we’re talking about the same thing.

MR. ROBERTS: Yeah. So in third-party negotiated contracts, if that’s what you’re referring to --

COMMISSIONER MITCHELL: Yes, sir.

MR. ROBERTS: -- we've had 10 percent operational issue dispatch down rights, and the way we execute those currently is through a phone call. And so we will -- we’ll call up that third-party control site. I won’t name names of vendors, but, you know, anyway. We’ll call up that third-party site, and we’ll request them to dispatch down to a minimum level, and then we’ll explain to them that we’ll call them back and tell them when they can bring their facility back up.

COMMISSIONER MITCHELL: Okay. And I assume that there are electronic controls between your -- your operations facility and the solar -- solar generating facility that allow you to be certain that that facility has --

MR. ROBERTS: So -- so we can -- we have monitoring of the output of that site --

COMMISSIONER MITCHELL: Okay.

MR. ROBERTS: -- so, yes, we can -- we can visually see the reduction in output from --

COMMISSIONER MITCHELL: Okay.

MR. ROBERTS: -- that site.

COMMISSIONER MITCHELL: Okay. Okay. And so at this point in time it’s just by -- through telephone instruction?

MR. ROBERTS: That’s correct.

COMMISSIONER MITCHELL: Okay.

MR. ROBERTS: For third-party negotiated, yes.

COMMISSIONER MITCHELL: Okay. One of the -- one of the points made on your slides as a potential adjustment for Tranche 2 protocol is that you would consider -- the Company would consider the option to negotiate terms for Duke control of batteries at a later date after control capabilities have been developed and tested or --

MR. ROBERTS: Right.

COMMISSIONER MITCHELL: -- or -- how -- can you -- can you talk a little bit more about that? How far away are you from that, and what have you done, you know, towards that end?

MR. ROBERTS: Right. So basically towards that end we've just had discussion so far. We -- we have discussed the technical aspects of what would need to be -- take place with the EMS coding with infrastructure with respect to communication protocol between EMS and DMS for cybersecurity reasons. EMS is Energy Management System; DMS is Distribution Management System. To go to distribution connected batteries, and then for transmission connected batteries it would be directly from the Energy Management System to the transmission connected facility.

And so it -- is it feasible? Yes. Have we laid out the entire engineering design? No. We still have a little ways to go on that.

COMMISSIONER MITCHELL: And -- and so can you give me a sense of how much time, like what, you know --

MR. ROBERTS: Yeah. So --

COMMISSIONER MITCHELL: -- how far away are you from that?

MR. ROBERTS: So one of the things we are discussing putting in place is getting some operating experience through sending a signal from the Energy Management System through the DMS that's supposed to go live sometime later this year to the -- I believe it's the Rock Hill site, and just get some operating experience with controlling that battery once it's installed.

COMMISSIONER MITCHELL: And the Rock Hill site, that is a -- is that a Company site?

MR. ROBERTS: Yes.

COMMISSIONER MITCHELL: Okay.

MR. ROBERTS: Yeah. That's correct.

COMMISSIONER MITCHELL: Okay. Are there any third-party batteries or energy storage facilities operating on either of your systems at this point in time?

MR. ROBERTS: There may be on a --

COMMISSIONER MITCHELL: I'm sorry. Utility scale. I'll be more specific.

MR. ROBERTS: Yeah. Utility scale? No. Once again, there -- there -- there may be some connected to some wholesale PODs that I'm not aware of, but...

COMMISSIONER MITCHELL: Okay. But you're not aware of any solar plus storage facilities --

MR. ROBERTS: No.

COMMISSIONER MITCHELL: -- at this time?

MR. ROBERTS: No.

COMMISSIONER MITCHELL: Okay. Okay. And do you know -- you may not know this information, but if -- but if anyone on the Duke side knows this information, please -- please answer the question. But do you know if any solar plus storage facility has been -- has been -- has made it through the interconnection study process and will be interconnected at some point in the future from outside of the CPRE process?

MR. ROBERTS: I'm not aware. I guess Bill Quaintance could probably --

MR. QUAINTANCE: No, none that are as far along -- none that are into IA.

COMMISSIONER MITCHELL: Okay. Okay.

MR. JOHNSON: I would say -- I would add --

COMMISSIONER BROWN-BLAND: Madam court reporter, could you get that?

MR. JOHNSON: Oh, I'm sorry.

COURT REPORTER: I did. Thank you.

COMMISSIONER BROWN-BLAND: All right.

MR. JOHNSON: Dave Johnson here. I -- I'd add that we know of at least one large PPA, negotiated PPA, where there is storage included.

COMMISSIONER MITCHELL: But that project is not yet online?

MR. JOHNSON: It's not online, no.

COMMISSIONER MITCHELL: Okay. And that would be a project that is not involved in the CPRE process?

MR. JOHNSON: That’s correct. It’s a -- it’s a solar plus storage.

COMMISSIONER MITCHELL: Okay. I have a few questions for the IA. So in this Tranche 1 you all received four bids that included an energy storage facility. Three of those were selected as successful or winning bids. Can you -- can you sort of describe how you perceive that? Was that -- is that a success or do you -- did -- did that -- did that fall short of your expectations? Help us understand sort of the relative significance of that number.

MR. BALL: There were four in one --

MR. JUDD: Go ahead. Go ahead.

MR. BALL: Excuse me. Yes. The -- there were four bids submitted with storage. One of them dropped out, and then so there were just three that were left for evaluation, and two of those were selected.

COMMISSIONER MITCHELL: Okay. I’m sorry. So I stand corrected. Okay.

MR. JUDD: Permit me to answer it this way. In other jurisdictions, other RFPs, we’ve gotten a more robust response. In fact, we have run solicitations that are strictly for storage for a specific purpose, such as in the LA Basin we do it to avoid new transmission.

The response rate and the success rate is not out of line with some other jurisdictions. And I’m being circumspect simply because some information that -- we’re -- we’re still working through some RFPs elsewhere that that information is not public. At the same time, we completed one in Colorado last year. It had a very robust response with storage. But there were different criteria, including, and I think this is an important one I want to share with you, because we are bringing in storage to CPRE where it must be for a 20-year term a renewable resource, which would mean the storage must be recharged from the renewable asset. In other jurisdictions we permit the storage after a term of years to be recharged from the grid. Typically, it’s five years because the developer captures all of the ITC value, then we have a different product when you can charge it from the grid. You know, they can charge at 2:00 in the morning and deliver it peak time in the afternoon, by way of example.

So we have constraints here in CPRE that should be recognized as may have had a factor in determining the -- the response.

COMMISSIONER MITCHELL: Well, we -- we would appreciate your helping us understand what those constraints are, so thank you for -- for that information.

MR. JUDD: And we can provide more if -- in fact, we did provide some as part of the stakeholder process that was referenced earlier, where we had a list of all the ways we have used storage in other jurisdictions. I'll make sure that your staff gets that.

COMMISSIONER MITCHELL: Okay. One last question for the -- for the IA. You indicated that you -- you all perceive Tranche 1 as a beta for the CPRE process in general. And you -- you -- you suggested that, you know, you -- storage is kind of part of that; you wanted to see what you would get, including storage in the -- in the process. And I -- and I think I heard you say that you're encouraging the expansion of -- of storage. Can you -- can you explain what you mean by that or --

MR. JUDD: We're -- thank you. If -- I may not have been clear enough in trying to be brief in my remarks. We are encouraging Duke to revise the protocols. We were hoping in the comment period that preceded Tranche 1 that we would have gotten more direction from the marketplace as specifics that they would like changed in the protocols. From what I've heard today, I'm hopeful that we will get some of that. It's more helpful to have specific -- you know, the ramp rate, we'd like it to be 10 percent instead of 1 percent, as opposed to we don't like the ramp rate. And I understand. It was all rather vague, and it came in in the process, but with more of that we think that we can help refine the protocols, and with that we are hopeful that we can get more expansion of offers for storage.

I -- the point I made just a moment ago about the recharge of storage, we have been -- I will share with you, we have been exploring whether there's a way to at some point bifurcate, if you will, the storage to make it so it could be separated from the renewable process. We don't see a way to do that in CPRE and stay within the confines of the legislation. That's a -- that's a huge one in other jurisdictions. I -- I will share that with you. But we are looking for ways.

We have found, in all candor, Duke and the parties in interest to be interested in working together to come up with revisions. We have more time now. When we rolled out storage before, I think it caught some folks a bit by surprise. It was new. We gave it a try. We're going to do better.

COMMISSIONER MITCHELL: Okay. Thank you. For

-- let's see. For the Public Staff -- actually, I'm going to ask NCCEBA a few and then I'll come back to the Public Staff.

Can you give us -- can -- can NCCEBA provide its -- its explanation or its position on for the relative significance of the storage numbers from Tranche 1? Let me -- let me be a little bit clearer with my question. Under what circumstances could the response have been more robust?

MS. KEMERAIT: So this is Karen Kemerait on behalf of NCCEBA. Our opinion is, is that the energy storage response was not robust at all. There were four projects that were bid in out of 78. And I did want to share that Mike Wallace with Ecoplexus, Ecoplexus had the two winning storage plus -- excuse me -- solar plus storage projects. And he wanted to be here, and I mentioned he was ill, because he wanted to convey to the Commission that even though Ecoplexus did bid in projects to CPRE and did have the two winning projects, that Ecoplexus has very significant concerns about the energy storage protocol.

So our view is, is that the vast majority of the solar developers did not even bid any storage projects into CPRE, even though there is a substantial amount of interest in solar plus storage projects among the market participants. So I think that if we can fix the energy storage protocol and, you know, work together with Duke to find good solutions, my expectation is, is that for Tranches 2 and 3 there will be much more substantial participation with storage projects.

MR. NORRIS: I’ll just add a couple of comments. Part of the inherent challenge is that the avoided cost rate structure is not particularly valuable for storage resources. And as -- as Duke has accurately sort of portrayed, this is a relatively emerging technology, it's still nascent, and the rate structure is not very supportive.

Now, the Sub 158 proposed rate structure in DEP, it is more supportive and especially in those winter morning periods. Of course, the challenge is that the CPRE procurement on DEP is extremely minimal, and so we’re unlikely to see a whole -- a whole lot of DEP storage capacity in Tranche 2 or ever.

And the DEC rate structure, while being a slight improvement of Sub 148 and Sub 158, may not be enough to -- to support this if we’re only valuing energy and capacity. And, hence, the -- the question, I think, that was asked previously, would it be appropriate to consider the possibility of -- of valuing other value streams, I would just submit to the Commission that the South Carolina Legislature just required all utilities in that state to submit a revised avoided cost methodology that does account for ancillary services, and so I believe that filing will be forthcoming soon from Duke and may be worth taking a look at it, and there may be an opportunity to take advantage of some of those other -- those other value streams in a way that could make storage more creative.

And just one final point is because the rate structure is -- is not quite supportive, all of these little aspects, they matter a lot because it’s very much on edge. And so a difference of a ramp rate of 5 percent or 10 percent really does make a difference overall on whether those resources can be cost effective.

COMMISSIONER MITCHELL: So just so I understand, Mr. Norris, I mean, are you -- because, you know, we -- we were talking about the operational limitations and parameters that are set forth in the protocols, and you’ve discussed the rate design that’s now at issue in the avoided cost docket. So is the rate design more conducive to pairing storage with the solar or -- I mean, what’s more important, to the extent one is more important than the other?

MR. NORRIS: I think it's difficult to say. Certainly, the -- the fundamental rate structure, I suppose you could argue, is the most important on a marginal basis. And so, for example, the difference certainly between the Sub 148 and Sub 158 capacity value, and especially for those winter mornings, that -- that is accretive, and so I think, you know, if you did see a substantial amount of CPRE procurement in DEP, you probably would see more storage bids in Tranche 2, but, again, especially in DEC because it's so on edge everything adds up, and I would say those -- those ramp rate restrictions certainly do factor in.

COMMISSIONER MITCHELL: Okay. Okay. Thank you. Just for the Public Staff, just very quickly. Will you summarize the Public Staff's position on -- on energy storage at this point? I mean, you -- you all have recommended now for -- for some time in this docket in particular that the Commission order the parties to engage in discussion or workshopping. I mean, is that still your recommendation? Can you just provide me the -- the specifics?

MR. DODGE: Sure. I'd be happy to. I mean, I think the -- the dialogue today kind of exemplifies there's a lot of learning still going on in this, and I think we're hearing information that's been shared from the Utilities today about some further evaluation that they're making of how the energy storage protocol may be applied in -- in the future.

I think in general, we -- we don't have the expertise necessarily to comment on the reasonableness of the ramp rates or the discharge window specifically. I think we've tried to, through other dockets such as the avoided cost docket, to find ways such as targeting specific hours where the -- we're providing better price signals that might incentivize storage or make those -- those other more attractive.

So I think we have tried to work, and -- and whether it's in interconnection or avoided cost, to find ways to, to the extent storage can add value and provide additional benefits to customers, to make that possible.

We -- I think with regard to the stakeholder process, I think we did recommend that last fall initially for energy storage when energy storage protocol was first being considered, and we did repeat that recommendation in our March 22nd comments. I think there's -- there's still a lot of, again, a lot of learning going on and a lot of information that can be shared.

For Tranche 2, I think, again, there may be -- if things are moving on a time frame that provides time for further discussions to take place on a Tranche 2 energy storage protocol and maybe some further information sharing, it may be appropriate to limit it to that purpose, but I think at some point it -- it makes sense for this -- the questions of energy storage and the value proposition that it provides to be more broadly considered by the Commission.

That wasn't quick. I'm sorry.

COMMISSIONER BROWN-BLAND: All right. We've worked our way through three issues. We have one left. I'm going to take a break here in a minute. Before we do that, hearing no objection, we will -- the Commission will allow Commissioner Patterson to read in the rest of this technical conference that he was unavoidably not able to be here for the afternoon session. And I think we will now take a brief break until 4:05, and then we'll take up the final issue on the dispatchable PPA. And Mr. Judd, if -- if the other two gentlemen -- if you don't need them by your side, they're free to sit a little more relaxed in the back, but I don't think we're ready to let you leave yet.

(Recess taken from 3:56 p.m. to 4:06 p.m.)

COMMISSIONER BROWN-BLAND: We are so close, we do not anticipate coming back tomorrow. We still want to end this by 5:30, if at all possible. Everybody bear -- or sooner -- and everybody please bear that in mind.

So we're down to the fourth issue, which is the reasonableness of the dispatchable PPA proposed by First Solar for the purposes of the CPRE program. And a little bit different in this section. We're going to start with First Solar, and I believe they have a presentation for us.

MR. BREDDER: All right. Thank you very much. Roger Bredder from First Solar. And as the Commissioner indicated, I'm going to talk about the issue of curtailment. I'm actually not going to go through the slides in light of where we are in the day. I want to just hit a few points and let's get into a discussion because I think it's a fairly, you know, meaty topic.

And, also, I think it fits really well with having just gone through the storage issue, because the way I really think about curtailment and flexible solar is it's a great intermediate step before you even need storage. If you're operating these -- these assets in a more flexible way, it allows to resolve some of the issues that Mr. Roberts was talking about in terms of thinking about solar as being this very inflexible asset that I've got to manage around instead of the way we like to flip it around and look at solar as saying it's the most flexible asset you have on your system because it can ramp, it can load follow, it can dispatch up and down faster than in any other asset, and so it's all these capabilities, but if it's under a must take contract construct, you lose all those -- all those benefits.

And so what we're proposing is -- is basically moving to a structure where you're looking at a capacity payment rather than, you know, having a, you know, even a limited curtailment, which is what we have on -- on Tranche 1. So when you have a 5 and a 10 percent curtailment rate, there's kind of two things that happen with that. One is, from a developer perspective, we price in assuming that full right is going to be utilized. So if Duke doesn't end up needing 5 percent or 10 percent in the case of DEP, they essentially have overpaid for something they didn't end up using to have that option.

Conversely, it's a 20-year contract, so was 5 and 10 percent the right numbers? I mean, it's -- you know, people took a stab at what they thought they needed in flexibility, but it might be right or wrong 10 years from now, right? So it doesn't have enough flexibility in our mind.

When you move to a capacity base structure, what that introduces is the ability to manage your system much more robustly, get, from a Duke perspective, the complete ability to act like that asset is their own and decide when they need to -- to ramp it. It allows them to ramp down certain gas assets that otherwise they have to keep on min load. So from an emissions perspective, you're going to have lower emissions.

And, you know, the interesting thing -- and this is a study folks haven't -- aren't familiar with it. We did a study with Tampa Electric where we took their system and looked at if they operated it with solar as a must take, all the way down to a situation where it's completely flexible like we're, you know, indicating here like it's as a capacity payment, and what came out of that was the system cost actually went down, not up, in having that completely flexible system that -- that they could -- they could operate in -- in the best mode.

So from a developer's perspective, what that does for us and why we're advocates of it, because it -- from a pure contracting perspective, as I mentioned, you know, we can handle the 5 or 10 percent, we just have to gross up for it, so we can -- we can work around that. But what we're after is in the long term if the Duke system, everybody's system is going to be able to support more solar in their system, having it in a flexible, fully dispatchable way about doubles the amount of solar that you can support in the system before you, you know, you've -- you've run into any curtailment issues, and that's even before having even to think about battery storage.

So there's certainly, you know, an important place that batteries and storage play in the system, but we think coupling that with this, you know, kind of intermediate step on the contracts of -- of having a more flexible contracting format in place, you can forestall when you need batteries or limit the amount you need. And, obviously, batteries are getting cheaper every year, so if you can push back a few years when you need to introduce those, then, you know, they become a better long-term solution as you start to look down the road.

So that's -- that's basically the, you know, the key points I just wanted to open up with to get the conversation going.

COMMISSIONER BROWN-BLAND: All right. Thank you. Did Duke have a presentation on this issue?

MR. JOHNSON: We do.

COMMISSIONER BROWN-BLAND: All right. We'll hear that at this time. He needs his mic back.

MR. BREDDER: Yeah. Sorry.

MR. JOHNSON: My name is David Johnson, again. And so what I want to start with on the First Solar proposal, the First Solar proposal, as compared to the Tranche 1 PPA, there's two main differences. One is pricing, the pricing structure and, two, the dispatchability.

So for the Tranche 1 PPA structure, Duke has a dollar per MWh rate, and that's paid to the seller based on the energy delivered, so that's a very important fact. Under the First Solar proposal, it's a fixed price, so you pay $1.00 per MW month or kW month. It's a fixed price. You know the capacity, so you know the megawatts, so you -- it's a fixed payment. And, of course, you -- they do have a -- the ability to apply a performance standard and adjust the price or create a penalty if they don't deliver in accordance with a theoretical calculated value.

The Tranche 1 PPA that we have, we have built in there what we call dispatch down curtailment, and we've built in there percentages based on analysis that we've done in house, taking into account how many megawatts of solar that we have currently operating, how much we are expecting to be operating in the future, including CPRE, and we've run sensitivities on that. And so we came up -- we had logic behind the 5 and 10 percent dispatch down, and that's, of course, 5 and 10 percent of the total estimated annual energy production.

MR. JUDD: Your slide is off.

MR. JOHNSON: I'm sorry. Okay. The other point I was going to make on Tranche 1 -- the Tranche 1 PPA is we've built in controls so that we can actually send a signal. Based on the language in the PPA, we can send a signal to the facility remotely from the operating center, and it's different from what Sammy mentioned earlier. So under the previous larger negotiated agreements we have to make a phone call. Well, under this we decided let's put the control language in the PPA. So now we can -- you know, when the time comes in 2021 or so, we can hopefully push a button and dispatch that unit down, and when we need to move it back up, we simply give that instruction.

And the last point I'll make about Tranche 1 is we felt like, as the IA has talked about, we felt like that Tranche 1 was successful in awarding approximately 600 bids, 600 MW of bids, well under the AC avoided cost cap.

So some of the concerns we have with the First Solar proposal, the fixed price payment structure, that -- we see that as shifting the risk from -- from the developer, from the seller to the Duke customer because of the fixed priced nature, and you're -- and you're using a theoretical value of energy to adjust the -- the price. For instance, the risk of sun availability, that's all going to be borne by the Duke customer instead of by the seller. Under -- again, under the Tranche 1 PPA we pay based on what's delivered, so the seller has that risk. Other items, equipment degradation, that gets locked in when you're talking about a fixed price as far as performance measures, and then facility configuration. So there's a number of issues that the risk shifts from the seller to Duke customers.

PPA performance measures, I mentioned that just a little bit ago. Those would require continuous monitoring. You'd be using theoretical calculations that are, you know, complex. They create cost, administrative -- more administrative burden, and because you're using these theoretical values, it's going to create more disputes than I think what we have today under the PPA.

The potential value of additional control or dispatchability proposed by First Solar above the Tranche 1 levels that we have, that value, we think, is uncertain. We think -- we question whether it’s necessary.

The dispatch down levels, as I mentioned before, in Tranche 1 are based on analysis that we’ve done and the needs that we've projected. And also the control of the third-party facility for dispatch down is allowed in Tranche 1 so, effectively, we can control the facility. The only difference is we don’t put it on automated generation control where it’s automatically swinging. What slide am I on here? Thank you.

The risk of fixed price. From a recovery standpoint we do have some risk in South Carolina in wholesale. Presumably, in North Carolina if we went forward, we would get approval to include a fixed price structure, but we do have other jurisdictions we’d have to recover.

We’re not -- we’re not clear at this point of how we would apply the avoided cost cap for a fixed price bid as -- which is required under House Bill 589. I think I heard Roger mention earlier that storage was not considered under -- under this proposal, and one of the comments we were going to make is we could not tell, but if you did have storage, you'd have to have separate measures. It would have to be separate, really, from the solar facility.

And then lastly, our concern with full control, I mentioned AGC or automated generation control, it's very difficult with a solar facility. We typically use coal -- coal units or combined cycle or simple cycle CT gas units, and it's very predictable swinging up or down, versus if you have a solar on automated generation control, you may be able to predict it swinging down at a certain point, but the swinging back up is unpredictable because of sun. So we just think as compared to what we currently use that would be uncertain, more uncertain.

So in conclusion, I would say our -- our positions are the Tranche 1 PPA is tried and true. It's a tried and true method for procuring from solar resources. It provides us with what we need for dispatch curtailment, as we've analyzed. It allows for control to dispatch down. We've built in the controls in the PPA. The Tranche 1 results, as I mentioned, as well as historical use of the same -- similar PPA, proves viability of the PPA structure. And as I mentioned before, the PPA price structure under the first solar proposal shifts the risk from the developer to the Duke customer.

And then the last point is we just think it's not advisable to test this completely new PPA structure for a 600 MW competitive procurement in Tranche 2.

That's all my comments. Thanks.

COMMISSIONER BROWN-BLAND: Mr. Johnson, could -- outside of this CPRE could you ever foresee the dispatchable PPA structure or the ability to test it, see if it can be proven? Can you -- can you see a scenario like that? Or does the overall, you know, summary of -- of your presentation mean you -- you never see that in the future?

MR. JOHNSON: Yeah. That's -- that's a good question. The TECO study that First Solar provided as part of their proposal, that had four different modes of dispatchability. The fourth one was -- the fourth being the most flexible, the automated generation control. The third was a dispatch down option, which is what we have. And that paper actually talks about levels of -- of solar generation being on the order, I think, of mid to high 20 percent range, and I believe right now we're at somewhere around 4 percent, I think I heard.

So if we got, you know, out -- out in time to those kind of levels, then I would think we would consider, but I just don't think we're there yet.

COMMISSIONER BROWN-BLAND: All right. Mr. McDowell?

MR. MCDOWELL: Yes. Hi. Steve McDowell with Operations. Most of my questions are going to be directed to First Solar, and then I know Mr. Buffkin has some in addition to this.

First Solar has made a case for the value of flexible solar. Would you agree that some of that value proposition is already provided for in the development of avoided cost? The fact that solar production has zero fuel cost and can provide capacity value is included in the avoided cost methodology; is that correct?

MR. BREDDER: Yeah. I -- I think, you know, our agreements are so much around, you know, that part of the value system; it's more geared around the operation and the robustness of how the solar asset can be used in the system.

MR. MCDOWELL: Right. However, some of that value stream that you've just mentioned and discussed and offer insights from certain studies is not presently accounted for in the avoided cost calculation; is that your position?

MR. BREDDER: Yeah. That's correct.

MR. MCDOWELL: Such as emissions reductions, ancillary services, frequency voltage, those are not accounted for in avoided cost, and that is your position, then, correct?

MR. BREDDER: Yeah. Those are incremental values that aren't fully captured unless you really can, you know, fully operate the, you know, the plan at its full capability.

MR. MCDOWELL: So First Solar's proposal, this capacity based PPA structure, possibly relies on the rates to be developed to properly represent all these value streams; is that correct?

MR. BREDDER: You know, I don't -- I don't think that's necessary to -- I mean, certainly, it's inherent to -- to kind of what values, but we're not looking for some increase to avoided cost to make this a viable concept at all. It's -- the only thing I would say is, and what we're doing right now with the 5 and 10 percent dispatch, right, we're putting that in, and inherently everybody is pricing up and artificially making their price 5 or 10 percent higher, and they shouldn't be burdened with that in comparing it to the avoided cost.

MR. MCDOWELL: Okay. Thank you. So as a developer, does the proposal that First Solar has put forth, does that proposal work for you if Duke were to develop fixed rates without attempting to value these things like emissions reductions and ancillary services? Does it work for First Solar as a developer?

MR. BREDDER: It does.

MR. MCDOWELL: Okay. Are you familiar with Duke's proposed integration service charge in the avoided cost docket, E-100, Sub 158?

MR. BREDDER: I'm not personally. I don't know if others are.

MR. WHITE: I have familiarity with it.

MR. MCDOWELL: Okay.

COMMISSIONER BROWN-BLAND: Wait a minute. You need the mic. Could you repeat?

MR. WHITE: Yes. Some --

COMMISSIONER GRAY: Please pull the mic to you, sir.

MR. WHITE: Yes. This is Andy White with First Solar. I have some familiarity. Thank you.

MR. MCDOWELL: So are you also aware that the Public Staff and Duke filed earlier this week a

Stipulation of Partial Settlement regarding solar integration service charge?

MR. WHITE: Yes. I was aware.

MR. MCDOWELL: So let me read from page 6 of the Settlement, as filed, “The Stipulating Parties agree that it is appropriate to consider the ancillary services cost of adding incremental solar and the potential applicability of the integration services charged to solar generations solicited in CPRE Tranche 2 and other future CPRE tranches.” Do you accept that as an appropriate statement of what was in the Settlement?

MR. WHITE: I’ll -- I’ll take your word for it. I don’t have the Settlement in front of me. Thank you.

MR. MCDOWELL: At a high level, I guess the parties recognize that there is a real cost for integrating distributed generation. In other words, nonflexible distributed generation creates additional cost and system operation space. You accept that?

MR. WHITE: Could you repeat the question one more time, please?

MR. MCDOWELL: So at a high level, I guess the parties recognize that there is a real cost for integrating distributed generation. In other words, nonflexible distributed generation creates additional cost and system operations space.

MR. WHITE: Nonflexible resources that you indicate, yes, there would be additional cost, although what we are proposing is to --

MR. MCDOWELL: Understand.

MR. WHITE: -- increase the flexibility of those types of systems served.

MR. MCDOWELL: Yes. And so First Solar's proposal that promotes fully dispatchable assets will provide system operations additional tools needed to minimize this impact; is that a fair statement?

MR. WHITE: I wouldn't necessarily characterize it as minimizing, but creating additional value streams that -- that create -- enhance value, not necessarily just to -- to mitigate some of the -- the challenges that you outline.

MR. MCDOWELL: So this is a -- this is a value, then, that Duke should recognize in developing fixed cost rates required for First Solar's proposal?

MR. WHITE: That's why we're here today, is to consider that very -- that very proposition.

MR. MCDOWELL: But you also said that those additional value streams didn't have to be recognized for this to make sense for First Solar. Your proposal works with or without those; is that correct?

MR. WHITE: That’s correct, yes.

MR. MCDOWELL: Okay. First Solar’s position, as stated on page 6 of your comments, is that "Dispatching utility-scale solar can provide measurable system cost savings." Is the dispatch that you’re referring to -- and this may have been addressed in the comments from Duke earlier. Is the dispatch that you are referring to different than that provided for in the PPAs associated with CPRE Tranche 1 projects?

MR. WHITE: I’m sorry. I’m going to have to ask you to ask that question one more time --

MR. MCDOWELL: Okay.

MR. WHITE: -- because I was referencing page 6.

MR. MCDOWELL: So page 6 --

MR. WHITE: Thank you. Uh-huh.

MR. MCDOWELL: -- it says, and I quote, “Dispatching utility-scale solar can provide measurable system cost savings.”

MR. WHITE: Great. So I was reading -- reading the previous statement, so now that I’ve found my place --

MR. MCDOWELL: Okay.

MR. WHITE: -- if I could have you reframe the question, please.

MR. MCDOWELL: So then the question is, is the dispatch that you're referring to different than that provided for in the PPAs associated with CPRE Tranche 1 projects?

MR. WHITE: The -- the dispatch is -- is different than what's provided for in -- in the Tranche 1, correct.

MR. MCDOWELL: Can you speak to that, and especially if it reinforces what comments were made earlier by Duke?

MR. WHITE: Sure. Roger, do you want to address that?

MR. BREDDER: Yeah. It's just, you know, what we're advocating is a -- a fully dispatchable approach where you're not -- have a hard stop at 5 percent. If Duke had a particular window where they needed 7 percent, they could go to 7 percent because it -- it optimized, you know, the cost of the system, because we're really looking at the overall reduction of the cost of the system rather than a single plan because that's ultimately the goal.

MR. MCDOWELL: So let me probe that just a little bit further relative to the actual hardware and software. First Solar states on page 5 of its comments that “Dispatchable contracting structures for utility-scale solar facilities are possible due to advances in technical capabilities of utility-scale solar control technology.” And then it goes on to say “Utility-scale solar developers are increasingly including these technologies in their projects today.” Are you with me there?

MR. BREDDER: Correct.

MR. MCDOWELL: Okay. So in that the PPAs associated with Tranche 1 include provisions for -- for the projects to immediately and fully comply with all system operator instructions, does this suggest that the technologies you are referring to are already necessary to the CPRE Tranche 1 projects?

MR. BREDDER: Yeah. I can’t speak to how various developers are going to achieve that requirement. I can tell you from a First Solar perspective even without those requirements, every plant that we build, you know, has a -- a SCADA and a plant controller that provide that whole robust capability that you’d have on any thermal asset in the -- in the system.

MR. MCDOWELL: Does Duke understand there to be something additional to support what First Solar was proposing in terms of its dispatchability different than is required in CPRE Tranche 1?

MR. JOHNSON: Our understanding is that the First Solar proposal includes a full, flexible AGC, automated generation control, where you would simply put the unit on automation and it would follow your load. And we do that currently with our coal units and gas units. And -- and my point before was that's very reliable, whereas if you do it with a solar facility, you don't know if you're going to be able to swing because you don't know when the sun from moment to moment is going to be out or in.

MR. MCDOWELL: Do you have that capability with the projects that will be developed, the winning projects from CPRE Tranche 1?

MR. JOHNSON: No. We were -- we were not -- our plan is not to put those projects on AGC. It's simply to, as Roger mentioned, to use the plant controller, and we have requirements built into the PPA where we can actually control the facilities through the plant controller from our operating center and send messages, send orders to dispatch down. And what I -- what I mean by that, you can -- you can reduce about 10 percent, 20 percent, you know, whatever you want to do, or you can go all the way down, turn it all the way off. Currently, that’s our mode, is on or off, but under CPRE we can turn it down with this logic, but you've got to give the order. You've got to give an order to go down, then you've got to give an order to go up remotely.

MR. MCDOWELL: So do you require something additional at your plants if you’re a winning bid under your proposal than Tranche 1?

MR. BREDDER: No. Absolutely not. And we've got a -- a study that we did with NREL that speaks, you know, quite a lot to this point, where they asked us to load follow and showed how a solar plant could precisely follow much more accurately than any thermal plant could a load dispatch profile, frequency control, same thing. You know, our plant actually in California had the capability, and the Utility said don’t need you to do that, so we sat back with the full capability.

And then they had a system of instability because one of their nuclear plants -- because they said we’ve got this big nuclear plant on the line, we don’t need you guys, they actually called us up and said turn it on, we need you to do this, and we were able to completely stabilize the line for them. So it’s -- it’s an interesting study. If you haven't gotten hold of it, I'm happy to provide it for everybody.

MR. MCDOWELL: I think it's attached to your attached to your -- to your filing, yes. To enable the proposal offered by First Solar, Duke will have to determine the components of fixed rate, including energy, capacity, and any other value streams you can agree to?

MR. BREDDER: Well, I think, yeah. I think from a CPRE 2 process they would simply value based on the -- on the bid price and compare it to avoided cost.

MR. MCDOWELL: So in Duke defining what that fixed rate would have to be to establish that, the Utility would have to make some assumptions relative to the energy output, how they would actually dispatch it, how many megawatt hours there would be associated with that plant? Otherwise, somebody gets too much or somebody gets too little, right?

MR. BREDDER: Well, I think you'd -- you'd look at it as fully, you know, the full output of the plant, just like when you're putting a, you know, a gas plant or some other asset in rate base.

MR. MCDOWELL: But to -- to determine the fixed rate that you're asking for, they wouldn't necessarily calculate a fixed rate and be paying for, say, energy that wasn't being provided for.

MR. BREDDER: Well, they'd be -- they'd be making a capacity payment. That would be just a fixed capacity payment, and then it would be subject to adjustment, to the extent that the plant either failed to perform as it was supposed to in terms of dispatch or just didn't have the capability that it said it -- it had. So if it had a, you know, 100 MW capacity and you ran a test and it didn't have that capacity, then there would be a -- a discounting to the -- to the capacity payment. So it would work from kind of deducts --

MR. MCDOWELL: Okay.

MR. BREDDER: -- rather than --

MR. MCDOWELL: Right. Thank you. Let me get Duke to respond to the same question about calculating of fixed cost based on this proposal. Do you think that you have to somehow assume model a certain dispatch of those units in order to get a proper assessment of what fixed rate should be?

MR. SNIDER: Glen Snider. I'm Director of Resource Planning and Analytics, heavily involved in our avoided cost IRPs. Yeah. You would absolutely -- I mean, what you're really looking at is if you're not going to get full energy output for various reasons, it could be, you know, soilage, degradation, snow cover, cloud cover, you need to use it to curtail because you start getting a lot of solar on the system and you have these LROL issues.

If you're paying a fixed capacity payment on one hand that assumes you're getting full output as though it's capacity, but then only getting, let's say, 70 or 80 percent of that in the energy that was used to derive the fix capacity payment, you're, in essence, overpaying the avoided cost value that you assumed when you established that fixed payment. So for 20 years you live with that fixed payment, irrespective of the output, and how the output of that unit performs is subject to so many factors that were listed in these presentations, that you're then going to have to sit and try and litigate for the next 20 years as to was this a natural occurrence that the customer should bear or was this the market participants' issue that they should bear. And so you can spend the next 20 years litigating that or you can just pay for the megawatt hours you get.

And, you know, I think it's important to note that that's -- the structure in Tranche 1 does that, and I think Tranche 2 it's the way we're providing as well. We're also going to even more granular avoided cost. If you think about the direction I heard this morning from the previous Order out of the Commission, it’s let’s get more granular. Let’s not have three price buckets. Let’s have more granular price buckets. Now we’re going to go backwards. We’re going to have a single price bucket, and it’s not even a price bucket per megawatt hour. It’s just pay me $1.00 per month whether I deliver or not.

That just, as Dave pointed out, pushes all that risk to the consumers for a two-decade period. We just don’t think that that’s a good risk/reward balance or the direction that, you know, the Commission established in 148 that the parties talked to today about getting more granular.

MR. MCDOWELL: I think that’s all the questions I have.

MR. BREDDER: Speak to that last -- last point. Just to -- to be clear, we’re not saying you get paid no matter what you do. There's adjustments that occur, so that -- and this is done, you know -- you know, across the board. I mean, if you look at every thermal plant, how it’s contracted historically, you have an energy payment and a capacity payment. Solar is actually the outlier that we move to this pure energy payment structure, and that's just simply because there's no fuel cost, so it -- it moved that direction.

But, you know, what we're suggesting here is no different than any PPA that utilities all over the country have been executing for many, many years with a capacity and energy payment. And then obviously, you know, criteria that holds you, that you've got the capability to do what you said you were going to do.

MR. WHITE: And, again, this is Andy White with First Solar. And I would also kind of redirect or -- or sort of recharacterize or -- or correct the characterization of -- of the PPA structure that was before by -- by Mr. Snider, where, you know, if there are certain -- certain circumstances that cause the facility to -- to degrade as -- as not expected or -- or there are certain -- certain soilage, et cetera, that's where we're proposing to shift from an energy only model to that where -- where the accuracy of the output and the availability is key here and measuring the -- the availability of the facility. And we've included a number of -- number of metrics to make sure that -- that the pure measure of the -- of the facility is not its ability just to -- to put energy on the system, but its -- but its true capacity.

And so there is -- there is both a measure of the theoretical energy output of the facility and also a mechanism by which the Utility can true that up on the Utility’s demand at certain points, I think, with two or three days’ notice as called for in the PPA. So I -- I would take -- I would kind of recharacterize how you -- how you put forward the -- the PPA as -- as having these -- these certain scenarios that would result in a lesser degree of output from the facility that would then be, you know, imputed upon the -- the consumer. We -- we have included those provisions to account for -- prep for that and allow for the Utility to -- to call on the IPP to be able to -- to make sure that, you know, we’re delivering as required by the contract.

MR. SNIDER: So, you know, we’ve structured deals like this for, you know, a lot of years with gas, but you’re not trying to differentiate there. It’s -- it’s the same issue that -- that we talked about earlier. It’s a known quantity, and so you measure commercial availability based on 200 -- let’s say a 200 MW CT, they guarantee you 200 MW 24/7, with a small window for maintenance outages. You then measure commercial availability and say did you earn that capacity payment. You’re not trying to delineate with that CT, well, how much of the CT wasn't there due to cloud cover versus maintenance, how much was soilage versus maintenance, how much was degradation, how much was this, was that? It is simply you're commercially available and dispatchable with a known quantity. That's why it's called a capacity payment, because you're there with a known quantity.

No matter how many controls you put on a solar facility, it's still an intermittent facility. We'll see one day 500 MW on the system, the next day 2,000. That's not capacity. That's non-firm energy. And it has value. I mean, non-firm energy, that's why we have an avoided cost that specifies the value of non-firm energy, but it is not a capacity dispatchable resource that you can depend upon for AGC because if I need 2,000 MW tomorrow and it's going to be cloudy, I'm only going to get 500 MW, and so that's very different than 2,000 MW of CT where I'm paying a fixed price because they're guaranteeing me 2,000.

So what this contract does do is it says, yeah, if we don't -- if our panels break or something, we'll fix them, and that outage is on us. But you're having to delineate was it -- did you have, you know, 30 of your panels out or was it just cloudy, and then we're going to do a theoretical calculation to try and figure out what was panel performance versus what was cloud cover to see what portion of that fixed payment you got, and we're going to do that for 20 years. That's a -- you know, I structured deals for 10 years prior to being in the IRP, you know, group, and I've never seen a non-firm energy product in my 10 years of doing that receive a fixed monthly capacity payment. So to say this is standard is comparing apples and oranges.

COMMISSIONER BROWN-BLAND: What -- what do you say, Mr. Snider, to the, you know, the must take versus the flexibility? Is it -- is there not a savings or a benefit?

MR. SNIDER: No. I think what's really important for the Commission to understand when you start looking at the studies, I'll take a little dispute with it actually provides more value. All these high levels of penetration is what causes the need for the additional ancillaries. So if I didn't first have the need, I wouldn't need the AGC to help control it. So what we're saying is at high, high, high levels, 15, 20 percent, you're going to need to have active control just to be able to have a stable system. But it would have been cheaper, from a systems operations perspective, not to have all that intermittency in the first place, so you are helping to mitigate the intermittency?

It's not a solution that is better -- you know, even though they can respond faster, you're creating the issue in the first place that you then have to solve. And, yes, it does mitigate it. And it's important to note that we can do it today. We're not limited to 5 or 10 percent in these contracts. I want to be very clear. It's just we have to pay customers, if we go to 12 percent, have to pay for that extra 2 percent. Well, in this example they're paying for it -- whether you use it or not, you're paying a fixed capacity payment that would include a value stream for that. We can do that today under the existing contracts. We can curtail 15 percent of the time. We just compensate the extra 5 percent. That gets you to the same place you are with the fixed energy payment without all of these theoretical calculations for 20 years.

And it also sends, you know, these much more discrete price signals to say here's when, you know, capacity and energy have different price values. And we're going to get a lot into that, I'm sure, in the -- in the 158 proceeding, but we've gone from three price periods to nine under the Stipulation to -- to provide, you know, a very specific, more granular price signal.

This is two big steps in the opposite direction where it doesn’t matter when in the day you produce because you’re just getting a fixed payment.

So if we have nine price buckets and you say you’re going to produce in the most high period hours because you’re going to figure some way, well, now I've got to contractually figure out how to guarantee not only total energy, but you need this much in this bucket, this much in this, and this much in this, whereas, if we just price avoided cost that way, you’re delivering those hours, you get paid high dollars in the high hours, less dollars in the lower value hours, and you’re right at your, you know, your avoided cost. And now we’re going to try and contractually, you know, engineer that in, you know, hundreds of pages of contract that you've got to live with for 20 years. It just does not seem -- I’ve never seen it on a non-firm energy resource be a successful way to contract.

COMMISSIONER BROWN-BLAND: All right. Does Commission Staff have questions?

MR. BUFFKIN: I do.

COMMISSIONER BROWN-BLAND: Be mindful of the time, please.

MR. BUFFKIN: Yes, ma'am. So you all, First

Solar, were in the room earlier when we were talking about the energy storage protocol and I asked for the folks here to offer some views on what exactly the hallmarks are of commercial reasonableness, and you all argue that your PPA is reasonable and complies with House Bill 589 so you didn't weigh in at that time. Do you have any thoughts on what -- what the Commission should look for to determine whether a proposal is reasonable?

MR. BREDDER: Reasonable with respect to storage or...

MR. BUFFKIN: No. Whether it ought to be approved. We heard things like -- like Duke suggested do other utilities do it, is it accepted in the marketplace, was it successful in -- was it accepted in Tranche 1? These were some of the factors that these folks suggested that the Commission weigh in determining whether or not this is a reasonable proposal. Did they leave anything out? Do you agree? What's -- what's the standard we should be applying here?

MR. BREDDER: For overall just reasonableness of contract. I'm sorry.

MR. BUFFKIN: Uh-huh. That's right.

MR. BREDDER: Yeah. I think you -- you know, there's obviously -- you've got to look at the whole set of facts of -- of, you know, is it producing the lowest cost result for the -- for the consumer, you know, the environmental aspects of is it, you know, providing, you know, benefits on -- on that end? You know, I think those are...

MR. BUFFKIN: Okay. Those in addition to the other things we discussed earlier?

MR. BREDDER: Yes.

MR. BUFFKIN: Thank you. I understood your argument about the dispatchable PPA being consistent with 62-110.8(b), the provision that requires providing the Utility the right to dispatch and control the facility. What about the other goals of the CPRE statute, for example, cost effectiveness, diversification of the location and distributed resources, and reliably meeting the needs of the electric consumers?

MR. BREDDER: Yeah. I think, you know, locationally it should not, you know, really change what happens. That’s kind of a neutral. But, you know, with the other aspects I think it has a positive, you know, impact on -- on those.

MR. BUFFKIN: All right. And might there be periods of time -- under this dispatchable PPA, might there be periods of time when the Utility has to pay you all a pay -- excuse me -- pay the renewable generator in the absence of any energy being delivered to the Utility?

MR. BREDDER: Yeah. I mean, that's the whole point of making it dispatchable. Now, the reality is solar is the cheapest resource on the system, so a lot of this is theoretical, that you really shouldn't be needing to curtail. Really, kind of the irony of the -- the -- the TECO study is by having the flexibility, you actually use it less. It's just inherently knowing that you've got that capability that you use it.

In terms of operationally, I think what the TECO study showed is these solar assets were, in fact, not getting curtailed, so, you know, a lot of the concerns around all these calculations, you know, those are really on the margin that they need to -- need to happen. The most part of the energy is just going to be called on, you know, whenever it's available.

MR. BUFFKIN: Okay. So I think you said, yes, there's time periods when the Utility is going to pay the renewable generator even though energy isn't delivered.

MR. BREDDER: Right, which would be --

MR. BUFFKIN: Is that consistent with House Bill 589?

MR. BREDDER: You know, I -- I -- what I'd say is it's consistent with any other asset that gets rate based, right, that -- that, you know, when a plant gets added to the system, you have a peaker. The peaker probably is only going to, you know, see, depending on the, you know, the -- the load scenario, maybe 40 or 50 percent load.

MR. WHITE: And, also, to -- to add -- again, this is Andy White with First Solar. One of the -- you know, not -- not to lose sight of -- of one of the key elements of what I would contend of -- of 589's legislative directive was that the -- that the renewable assets could be operated as though they were owned by -- by the Utility themselves and to the highest degree of operational flexibility that could be afforded to the Utility, and -- and that's specifically called out in the legislation. I think that that's a key component of -- of sort of evaluating the -- the effectiveness of -- of the -- of a PPA, as you suggest, you know, some of the various metrics.

I would also include, because it goes back to your prior question as well, where it's -- evaluating where it's also deployed, I would -- would recognize we did point out some examples as to where this type of contracting model is in place elsewhere in the US, so this would not be a wholly new concept overall in terms of US energy policy here. We have -- we have seen it -- this deployed in Hawaii, for example, as well to a different, but a similar -- similar means in Nevada as well.

MR. BUFFKIN: So let's talk about that a little bit. Are there practical differences with how the electric system is operated in Hawaii and -- and in some of those other places that were in organized markets that the Commission should -- should the Commission take that into consideration in reviewing this dispatchable PPA?

MR. BREDDER: Each -- each market has to be analyzed, you know, given its distinct characteristics. You know, Hawaii has obviously an island or several islands, as -- as was pointed out, has some unique challenges to it. I think what we can do is we can learn from some of the jurisdictions, you know, like California, that have had much higher levels of solar penetration in trying to get ready for what's going to happen next because, you know, to the point of you can say, okay, let's wait until we get to that point when we've got, you know, 15 or 20 percent energy, you know, penetration of -- of renewables on our system before, then we've got to do something. It's really hard to play catchup.

It’s -- it’s much better to jump in early on and lay the foundation so you have a robust flexibility that, you know, as you move up to those levels, which inherently I think we will, whether through the flexible solar storage getting added, our system is moving directionally, that it’s going to be 25, it’s going to be 50 percent renewable, a lot of the challenges I know you guys are going to have to deal with, you’re pointing up, you know, are the reality of -- of where the economics are going to drive utility systems over the next, you know, 10, 15 years.

MR. BUFFKIN: Okay. So Duke says it’s unclear if First Solar’s proposal addresses solar plus storage. Can you help me clarify that? Does -- this dispatchable PPA could be used in the absence of storage with a solar PV facility only, or with solar PV plus storage only, or both?

MR. BREDDER: Yeah. You can -- you can work in the same concepts that -- in the -- in the mark-up we provided it was really just marking up the PV only contract, but the same concepts, and to some extent more so, work with storage where we’ve seen a number of jurisdictions go to a capacity payment for storage, because inherently on storage, once again, over the next 20, 30 years where that peak load moves and all that, it’s going to change around.

If it’s a capacity payment, the Utility can use that asset and that storage capability to precisely match what they need as opposed to in Arizona they went with an approach that was a targeted payment structure. You got paid a bunch more money if you provided power in certain periods of time. And, you know, it’s an elegant solution because it -- it tells people exactly what problem they’re trying to solve, but the problem they’re trying to solve today might be a different problem 10 years from now, and the system has been designed so that it only prices up power in certain periods when the Utility may be saying, oh, that’s not the right period I’m solving for anymore. They've got to go renegotiate that contract if that happens.

MR. BUFFKIN: Okay. Now, I’ve -- I’ve got your mark-up here in front of me, and it looks like you did not update Exhibit 10, the energy storage protocol.

MR. BREDDER: We did not. We really wanted to use this to get the conversation going on this topic and, you know, given, you know, given the complexity of -- of introducing, we thought that the first place to start was to just mark up the, you know, the contract itself and -- and kind of show what sorts of changes would be needed to be made.

MR. BUFFKIN: That being the case, if the Commission wanted to approve this contract, could it do that since it’s essentially incomplete?

MR. BREDDER: I -- I think there would need to be some, you know, review and discussion among the parties and, you know, it’s -- it’s -- it’s basically, you know, it’s -- it’s -- it’s a beta in terms of, you know, introducing the concept of what it would look like. And I would think that folks would want to, as you say, include storage and -- and -- and give it a similar, you know, treatment.

MR. BUFFKIN: Final question, do you agree with the characterization that the dispatchable PPA shifts risk from the independent power producer to the Utility’s customers?

MR. BREDDER: No. You know, I think it comes down to putting the right checks and balances in the contract structure so that the, you know, owner/operator is being held to the same, you know, level standard that you -- you’d expect to perform or be able to perform. We do all these things inherently in our plants because we need to model 8760s. We need to know how much energy we have. We need to understand degradation. All these things, we have plant models and systems that -- that we already do.

So, you know, is it complex? I take the point, absolutely, there's -- there's more complexity, but in our view, the long-term benefits of doing it outweigh taking on the brain damage right now to -- to put those provisions in place that create the right checks and balances.

MR. BUFFKIN: Thank you.

COMMISSIONER BROWN-BLAND: Commissioner Mitchell?

COMMISSIONER MITCHELL: Has the Public Staff had an opportunity to review this proposal and develop a position or any recommendations?

MR. DODGE: Yes. Thank you, Commissioner Mitchell. So I think we -- we have just had a few discussions about this. We haven't looked deeply. We have met with First Solar on one occasion and walked through this presentation, and they answered some questions as well, and it's -- it's been a helpful discussion. I think we do agree that the dispatchable PPA approach proposed by First Solar is arguably more consistent with the language in House 589 in that it does seek to allow the Utility the right to dispatch, own, and control the facility in the same manner as the Utility's own generating resources.

It's not just comparing it to the Utility's own solar generating resources, but the Utility's other resources, maybe, you know, peaker plants or other things that the -- the Utility would be receiving certain types of benefits from. And so I think we think that that aspect of it has merit.

It does require a high level of coordination, though, between the Utilities. We've heard about some of the -- the coordination, both -- some technical challenges that -- that may need to be addressed. I know there have been some discussions maybe of -- recently of some attempts to put solar facilities in North Carolina on some type of automatic control system that have maybe not been as successful as hoped, so I think there's some -- I'm not sure if Mr. Roberts or maybe Mr. Metz from -- Mr. Metz, if you want to address that.

MR. METZ: Good day. Dustin Metz of the Public Staff. As we're meeting with the Company as they host the TRSG meetings, the Technical Review Standards Group, there was general conversations brought in the last TRSG meeting where their company is trying to roll out and incorporate AGC like controls. I wouldn't go as far as AGC. They're more looking at putting on a plant computer on the front-end component and looking at more of an automation system to do dispatch down without the need of picking up the telephone call.

Some of the conversations that were at least echoed through the TRSG meeting, that the Utility, even though it's in its infant stage, are having some difficulties in incorporating that technology. Most notably, I think one of them was dealing with multiple inverters. As we roll forward, as you have a communication protocol going to different inverters, well, the Utility has to have -- maintain their cybersecurity, so they have to go through their buffer programs, but when you look at deployed across the fleet, well, every plant controller has to talk to a different inverter manufacturer. Some of them are just different communication protocols. And that creates unique challenges.

MR. ROBERTS: May I make a statement?

COMMISSIONER BROWN-BLAND: Just a minute. Mr. Metz, what kind of meeting was that you were saying? Could you spell it out?

MR. METZ: Technical -- Technical Review Standards Group, as we talked about in the NCIP proceeding. I believe Mr. Williamson had testified on that, that basically it's a stakeholder group that Duke Energy hosts about every quarter, and we bring up general topics at it at an engineering level. No lawyers allowed.

COMMISSIONER BROWN-BLAND: All right.

MR. METZ: Just trying to work through the system.

COMMISSIONER BROWN-BLAND: Mr. Dodge, were you complete with -- with that answer to Commissioner Mitchell's question?

MR. DODGE: I -- I had a few other points, but I didn't know if Mr. -- if you wanted to let Mr. Roberts address the question of these recent discussion or...

COMMISSIONER BROWN-BLAND: Mr. Roberts, you want to go now or you want to hear the rest of what Mr. Dodge has to say?

MR. ROBERTS: I'll go ahead and make a statement for the record.

COMMISSIONER BROWN-BLAND: All right. Go ahead.

MR. ROBERTS: Sammy Roberts, Duke Energy. So I just wanted to make a statement that we haven't seen the need to put DEP on solar on a AGC-like control, so -- I mean, one thing that concerns me from an operational perspective is if you issue automated dispatch down, and then you want to -- you need it to come back up to full power or cloud cover has come over, you're not -- it's not truly a dispatchable resource, so just wanted to make that statement for the record.

COMMISSIONER BROWN-BLAND: All right. Mr. Dodge.

MR. DODGE: And -- and I would just agree with Mr. Roberts in that it's not what I would consider a -- a dispatchable resource. I -- I think part of this model is kind of just maintaining it in some steady kind of strategic curtailment, whether -- and building in some foot room or head room that allows the -- the system to operate in a more flexible fashion. It certainly does, I think, have the potential to provide flexibility.

From a consumer protection perspective, I think we wanted to also make a point that, you know, there's talk about shifting risk because it provides rate certainty, revenue certainty to the project developer, but it -- and may shift some of that to customers, so we certainly have an interest in ensuring that the system, once -- if the Utilities and the project developer were to agree to a dispatchable PPA along these lines, that the system does then end up operating in the most cost effective fashion and that it's operating in the way that it was designed to when it was selected through the process.

So there are some -- you know, there may be some incentive for the -- reduced incentive for that system to operate as efficiently as might be provided through a -- kind of a must-take PPA paid on a per megawatt hour basis. And so while there are performance metrics that are included in there, going back and doing some of that analysis from the, you know, theoretical output to the actual production does require a lot of coordination.

So I think there’s a lot of -- I mean, it has some merit, but there’s some -- some aspects of it that I think need to be further evaluated and fleshed out, you know, where in terms of if the Commission were to consider moving forward with something along the lines of a dispatchable PPA model like this, maybe -- it may make sense to do it on a more limited scale. So whether that’s through some kind of pilot or some smaller carve-out or something from the CPRE process to allocate some portion and -- and take a look at how that performs relative to a must-take PPA.

I know -- we spoke to the Independent Administrator about this model as well, and there may be, you know, may -- it's hard -- it may be harder to compare different kinds of models or different kinds of PPAs. You know, if you start having multiple pro forma PPAs, that you -- you're not -- you're not providing quite as simple a process.

So those are our main -- main points that we wanted to address.

COMMISSIONER BROWN-BLAND: Limited in scale and limited in length of the contract?

MR. DODGE: Well, if it's -- if it's under CPRE, it would be a 20 -- 20-year term, so if it's under that purpose. If it's under some other than -- you know, outside of CPRE, then a different term may be evaluated.

COMMISSIONER BROWN-BLAND: All right. Commissioner Mitchell? No more? Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Thank you. Mr. Dodge's comments and remarks saved me a lot of Q and A, so thank you for that. So I just have a couple -- couple things in there. Because of your helpful comments, most of what I got are comments rather than questions, but I -- I want to ask the First Solar folks, it strikes me that -- and I understand you, that you think this is -- the value proposition works here for solar without storage, but it strikes me that an awful lot of the system benefits value comes if this is applied to solar plus storage, that the value proposition is much, much greater on a system basis. Would you agree with that?

MR. BREDDER: Yeah. I think our -- our view is there is value --

COMMISSIONER CLODFELTER: It -- it works without storage, but -- but would you agree with me that if -- if this is applied, this concept is applied to solar plus storage, the value -- system values are much, much greater?

MR. BREDDER: That ultimately it -- I guess the way I'd phrase it is I think it -- it -- first of all, forestalls when you need storage --

COMMISSIONER CLODFELTER: Right.

MR. BREDDER: -- but ultimately when you get to storage --

COMMISSIONER CLODFELTER: Right.

MR. BREDDER: -- it absolutely becomes a -- a much better solution than without having a capacity based alternative.

COMMISSIONER CLODFELTER: All right. The last thing is a couple of observations, and -- and just really, I'm not sure that for some of the practical reasons that the parties have discussed we're quite ready for full rollout of this or full adoption of this. Maybe what Mr. Dodge suggests is -- is something the Commission can discuss and consider. But -- but I want to make a couple of observations.

The CPRE statute is a capacity procurement program. It is not an energy purchase program. There are some compensation structures in here that are keyed off of the amount of energy delivered, but it is not a program for the purchase of must-take energy. It is a purchase of capacity. So what First Solar is proposing here is a compensation structure that recognizes that that's what you're buying. That's exactly what you are buying. That's what the Legislature has directed you to buy is to buy capacity, and they've given you three ways to buy.

They've said you can buy it from -- the facility for somebody -- from somebody else. If you do that, you've got an all-in total acquisition cost. And then you allocate that out, you see how much per megawatt it costs you to acquire the capacity you've bought. That's essentially the concept here. That's functionally the concept here. The difference is you won't own the facility under their models; a third party owns it.

Now, I -- I hear you about the complexities that creates about the owner of the asset is not you, and that does create some complexity. But conceptually what they're talking about is exactly what's provided in (b)(1). You build -- you buy your own -- you buy a facility that somebody else has built, and then you have all the same risks about the energy output from that facility that you have in your own facility. That -- that strikes me as -- as not an -- not an issue here.

Same is true with the second methodology, is you can build your own facility, then you own it and operate it and you've got the same risks about energy availability. What's the energy output of that facility going to be? And you've got to manage it. It's the same concept as exactly what they're talking about. And so it strikes me that, conceptually, what these guys are talking about may be a closer fit to 589 than an energy-based PPA product.

Now, we've got energy-based PPA products in here. That's allowed. That's the third option, right?

I get it. But it's -- one of the things in listening to this discussion that struck me as really curious is that if you go out and build the solar facility, own it and operate it, there is no cost cap in the statute. Isn't that interesting? If you buy the facility from somebody else, there is no cost cap in the statute. The only cost cap that applies -- the only time avoided cost comes in is if you're buying the energy and capacity from a third-party owner, the third branch.

So, you know, I want to come back and put some context on this, is I think what these guys are -- are suggesting here really is worth exploring because it actually fits the statute a lot better. It fits the statute a lot better.

Now, practically, I don't think you can -- I -- I don't think -- I mean, we're probably not there practically to do what they'd say, you know, across the board, but they're not so far off. They're not so far off. That's -- that's my observations.

COMMISSIONER BROWN-BLAND: The Commissioner made a -- made a comment and gave his view. Does -- does Duke want to respond at this time?

COMMISSIONER CLODFELTER: Something to think about.

MR. JIRAK: Yeah. Interesting -- interesting thoughts, and getting the perspective, I think a couple of points I make is the projected avoided costs we use have a capacity value in the years in which there's a capacity need, and we purchase under the -- under the -- the Power -- the PPA we are purchasing all of the energy and the capacity; it's just priced on an energy basis. So I -- I -- it's sort of -- it's sort of nomenclature in some respects, but we -- we are acquiring all the capacity to the CPRE resources, but the way in which payment is tied to is it includ--- the avoided cost includes the capacity value --

COMMISSIONER CLODFELTER: Absolutely.

MR. JIRAK: -- where we have a capacity need.

COMMISSIONER CLODFELTER: Absolutely. And so if you -- if you did what these guys are suggesting, you'd take that capacity that you bought and you'd pay it out over a 20-year period in fixed monthly installments, but you'd aggregate it and you'd derive a present value for what -- the capacity you bought. You'd do the same thing if you built the facility. You'd take your all-in cost and you sort of calculate what's the per megawatt cost to us of that. So it -- it's really not functionally very different, not -- not at all.

MR. JIRAK: Yeah. Yeah. I understand the perspective.

COMMISSIONER BROWN-BLAND: All right. If I don't hear anything else, I think we've come towards the end. All right. I -- I apologize that we had to take shorter breaks and shorter lunch than we normally do, but we had a goal. Seems like we've met it. I was a little apprehensive about this proceeding, but I found it very helpful, and I hope you have, too. Everyone is still learning. You know, we started out with a beta. We're still trying to develop this, but -- and perhaps that is the reason folks have been a little reticent to come out with absolute statements or -- or deal with each other, but the Commission would encourage you to be open in your communications with each other. I think we witnessed some of that here today, and I think that it's made a difference.

In the beginning, in particular, there were a number of requests for information or volunteer to follow up. Looking for my note here. I would ask that you follow up and make filings with that additional information within seven days of today, if you're able to. If not, let us know, but I think that will be a reasonable time frame.

One of the reasons we had this proceeding and -- and organized it as we did was to eliminate the -- the -- to reduce the time frame and eliminate the need for comments, responses, replies, and that sort of thing. And so when you make those filings, I would ask that you not make additional comments, but just respond to and provide the precise information that has been requested.

I want to thank everybody for hanging in here with me. Everybody really did contribute, and it was a good thing, from my perspective, to see. I particularly want to thank our Staff for hanging in here, not only the ones who participated, but the ones I see sitting out in the -- in the audience.

And if there's nothing else, we'll be adjourned. Thank you.

(The hearing was adjourned.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket Nos. E-2, Sub 1159 and E-7, Sub 1156, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 9th day of June, 2019.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150