OFFICIAL COPY

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, July 16, 2019

TIME: 2:03 p.m. - 5:34 p.m.

DOCKET NO.: E-100, Sub 158

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

General Electric

Biennial Determination of Avoided Cost

Rates for Electric Utility Purchases

from Qualifying Facilities - 2018

VOLUME: 4

Noteworthy
Reporting Services, LLC

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC, and
DUKE ENERGY PROGRESS, LLC:

Kendrick Fentress, Esq.
Duke Energy Corporation
Associate General Counsel
410 South Wilmington Street
Raleigh, North Carolina 27602

E. Brett Breitschwerdt, Esq.
McGuireWoods LLP
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27601

FOR DOMINION ENERGY NORTH CAROLINA:

Mary Lynne Grigg, Esq.
Nick Dantonio, Esq.
McGuireWoods LLP
434 Fayetteville Street, Suite 2600
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Benjamin Smith, Esq.
Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY:
Lauren Bowen, Esq.
Senior Attorney
Maia Hutt, Esq.
Associate Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

FOR NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE
and ECOPLEXUS, INC.:
Karen M. Kemerait, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR THE NORTH CAROLINA CLEAN ENERGY BUSINESS ALLIANCE:
Steven Levitas, Esq.
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

FOR NORTH CAROLINA SMALL HYDRO GROUP:
Deborah Ross, Esq.
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR CUBE YADKIN GENERATION:
Ben Snowden, Esq.
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION:
Robert F. Page, Esq.
Crisp, Page & Currin, LLP
4010 Barrett Drive, Suite 205
Raleigh, North Carolina 27609

A P P E A R A N C E S Cont'd.:

FOR NC WARN:

Kristen Wills, Esq.
2812 Hillsborough Road
Durham, North Carolina 27705

Matthew D. Quinn, Esq.
Lewis & Roberts, PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

FOR THE USING AND CONSUMING PUBLIC AND ON BEHALF OF THE STATE AND ITS CITIZENS IN THIS MATTER AFFECTING THE PUBLIC INTEREST:

Jennifer T. Harrod, Esq.
Special Deputy Attorney General
Teresa L. Townsend, Esq.
Special Deputy Attorney General
Office of the North Carolina Attorney General
114 West Edenton Street
Raleigh, North Carolina 27603

A P P E A R A N C E S Cont'd:

FOR THE USING AND CONSUMING PUBLIC:

Tim R. Dodge, Esq.

Layla Cummings, Esq.

Lucy E. Edmondson, Esq.

Heather D. Fennell, Esq.

Public Staff - North Carolina Utilities Commission

4326 Mail Service Center

Raleigh, North Carolina 27699-4300

T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

P R O C E E D I N G S

CHAIR MITCHELL:
Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Thank you, Madam Chair. Lunch was really good to you guys, because I've eliminated all but one last question. It was a good lunch break for you guys.

GLEN A. SNIDER, STEVEN B. WHEELER,
and DAVID B. JOHNSON,
having previously been duly sworn, were examined
and continued testifying as follows:

CONTINUED EXAMINATION BY COMMISSIONER CLODFELTER:

Q. So I understand that, Mr. Snider, you were answering the question earlier, so I'll put the question to you, but if the others want to chime in, that you really haven't done any in-depth review or analysis of Dominion's modeling of their proposed redispatch charge? You've looked at it, but you haven't really done any in-depth --

A. (Glen A. Snider.) Correct.

Q. Well -- and I understood your explanation of the different approach that the two Duke affiliates are proposing and that Dominion is proposing, so I want to ask you this question:

Why -- why would you choose -- why do you think it's more important to choose the focus on the intra-hour -- intra-hour variability rather than on the hour-to-hour variability issue? Why is it more important to focus on what you focused on?

A. Yeah.

Q. I'm going to ask them the same questions.

A. Right.

Q. Why they focused on what they did.

A. I think what we were looking at is what is that intra-hour -- that was -- when we look at operating reserves, we've always, as an industry, have accepted the fact that you have to balance minute to minute. Traditionally, you don't have a production cost model, they're at that minute time step, especially in my world when I'm looking out 30 years. So the question we -- as we interpreted it from the Commission in 148 was, how does -- you know, how does this intra-hour -- how does the intermittency -- how does the non-dispatchable intermittent nature affect the Company?

And we went to, well, what does that do to the intra-hour component that we haven't been modeling prior to Sub 158, this proceeding? So we commissioned a study with a consulting firm that did have that intra-hour expertise on the intra-hour model to identify that.

When we started to think about providing the difference in the hourly, it really started to lean more towards a solar-specific energy rate. So the difference of with and without a solar profile, and how much value does that create for the consumer versus how much does a base load resource when it's allocated into the hours.

And our reading of the order in 148 was that the Commission really wasn't looking for us to develop a solar-specific rate, but rather to just look at what is the intermittency causing on the system. I think there was some specific language in that order that said, you know, we're not looking for you to file a solar-specific rate which would take a look at, sort of, those grand -- more of the hourly differences changing the methodology to do the peaker method.

So we elected not to go down that path of filing a solar-specific rate that looked at the hourly differences in an annual profile, an 8760 annual profile of solar; instead we stuck with the historic precedent that we've used before in applying the peaker method of using that base load resource and then simply allocating it to the hours.

And it really gets into some pretty technical differences in terms of, you know, how a system will commit and dispatch its resources. So when you're committing and dispatching resources and you know with certainty for the next 10 years that you've got a base load resource, you're avoiding start costs, you're avoiding other O&M that simply creates a bucket of dollars that which you're going to allocate into these time buckets that is greater than the bucket of dollars you get when you do an intermittent solar shape. But to do the intermittent solar shape really took us down that path of having a solar-only energy rate, and we didn't read 148 as asking for that, so we decided not to go down that path.

And again, I'm not exactly particularly familiar with the exact details of the Dominion approach, but I do know they looked at some of the impacts on more that hourly time step where we were the sub-hourly, but still looking at the energy from a broader prospective.

And I think we responded to a -- I think it was a Public Staff data request where we showed the difference between had we developed these rates using a solar at the hourly level, just with our production cost model before we ever did any of the ancillaries, that we would have filed rates that would have been 10 to 15 percent lower for a solar provider. But we did not do that.

And again, that's just another area where, you know, we're not trying to be as -- you know, perhaps aggressive is the term that was used earlier in testimony. We're not trying to be aggressive. We're trying to balance that, what is fair to the QF and the QF community, recognizing these rates we're filing are still available to any QFs.

But, you know, so I would say that's how we ended up at the sub-hourly look. And that there probably is some, you know, value that we're ascribing to solar that, if we were to look at those hourly time steps, we might have reduced, but we did not in this case.

Q. Thank you for your explanation. That's all I have.

CHAIR MITCHELL: Additional questions from the Commission?

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. All right. I guess lunch was still good, because I whittled away the few I had too.

But I did want to ask you, why did Duke make the decision to go outside with the Astrape consulting in terms of the solar ancillary service study as opposed to doing it in house?

A. (Glen A. Snider.) Yeah. You know, it is something that we likely, over time, you know, will evolve to in house. As I was mentioning in the previous response, this type of statistical modeling is at a granularity that is a set of not -- only is it more granular in the five-minute increments that it looks at, but it's also deploying a stochastic statistical approach that aren't inherent in our existing production cost IRP models at this point.

There are models that we've employed internally that we're now working with to both shrink that time step and also to deploy these statistical approaches that I'm sure you're going to get a great deal of depth on from Mr. Wintermantel in his cross, but it was just the fact that that -- and that's probably the first factor.

The second is, having been the first time deployed, you know, we picked a consultant that has done this type of modeling around the country in multiple jurisdictions. This model has been used before many Commissions. And so, you know, if we were to come forward for the first time doing this, you know, contrary to maybe some of the intervenors' positions, we thought that a third party that has done this in other jurisdictions, using a model that's been vetted in other jurisdictions, would be a better approach than using an internal company model for the first time out on this.

Q. So the -- are you familiar with the models that Dominion used in their IRPs, the PLEXOS and AURORA?

A. I'm generally familiar with those, yes.

Q. Are those tools that Duke has in house or has used?

A. We are looking at those right now. There's three, four, or five industry-accepted models for production cost modeling. We use PROSIM or E7 from ABB, PLEXOS, AURORA, there's a GE model that used to be out there. And then there's -- and all of those models are continually being enhanced to look at different aspects, whether it's getting more granular on a time bucket or more granular geographically, trying to take into account transmission flows.

So those model enhancements are something that we're looking at internally. And, you know, I would also just reiterate the point of it really is important to, sort of, put that in the context of what time horizon are you studying? So this was done to look at a snapshot over a year, and that's a significant amount of analysis for that one-year period.

When we do IRP planning, we're looking out 15 years and beyond. So the feasibility of doing, you know, hundreds upon thousands of sub-hourly simulations over a 30-year time horizon is just not practical with today's computing power that's out there. So you have to use the right model for the right situation.

So if we're looking at a -- sort of the near-term impacts, we use one set of models at a certain time step. If we're looking long term, we might use a different set, all that are, you know, using -- trying the very best to use the same assumptions around the generating fleet, the characteristics of the fleet, what are the gas prices. So we're consistent in our inputs across the models, but the model deployed varies depending upon the analytic question that's trying to be answered.

Q. Are you looking at this enhanced modeling to support integrated systems operations plans?

A. Yes, we are, Commissioner.

Q. All right. And what tools did you use in determining the energy cost component of your avoided cost rates?

A. So the energy costs, which are done at an hourly level and not a sub-hourly -- you really don't have sub-hourly energy costs that are meaningful -- you can do at an hourly level. So we use the same model we use within the IRP framework, which is the PROSIM model. And that's where we take the IRP base case, we did strip out all solar above House Bill 589, and we made that the base case, and then we gave that model a 300 megawatts -- a no-cost-hundred megawatts around the clock and said how much production cost value did that create. And then we allocated that production cost value into the nine energy buckets that were in the stipulation.

Q. Okay. And are the -- is there sophistication to the other type -- to the modeling tools that Dominion used that you need to accurately assess ancillary services?

A. There is -- as I said, I think there are -- ancillary services and integration cost is -- has a sub-hourly component and has an hourly component. And we have -- we used a very sophisticated model to get the sub-hourly. There are other tools to get the hourly difference, and we have those, and we're developing -- further developing those that, you know, we intend to, as we always do, enhance our models and our inputs and bring that forward both in the IRP and avoided cost as we move forward.

Q. And so relative to solar generation, the -- there is intermittency that's related to cloud cover, and that's something that you view as unpredictable, correct?

A. Well, I think the actual key is it's not predictable. So that intermittency that happens on a sub-hourly basis, it's not knowable on a day ahead. You think about how often a weather forecaster gets whether it's going to rain or not right; now I'm going to ask him to tell me what time is a cloud going to pass over this specific XY coordinate on a map? How long is it going to stay there? And how dense is that cloud? Tell me that on a day-ahead basis.

There just is not forecasting methods to allow us to get to that level, so it creates, by its very nature, this intermittent output that, on some days, on a blue-sky day without a cloud, there's very little; and on other days when you have regional haze, or cloudiness, or a host of other factors, you can get, you know, fairly significant intermittency.

And the whole study looks at how do we maintain reliability at an equal level before and after, and how much additional ancillary services do we have to carry to cover that, and what are the costs of carrying those. So what's what Mr. Wintermantel's testimony focuses on.

Q. But as to those things that are not knowable, to use your phrase, don't they sometimes affect both the supply and the demand side of things?

A. And that's the -- what we've shown is, in the study and in my -- where I showed that illustrative graph that we looked at with -- earlier yesterday, is that supply -- or the demand side, there's certainly, you know, people turn on -- industries turn on their chillers or their furnaces, or schools shut down, and you get demand intermittency, you know, before you look at the impact of adding significant amounts of must-take solar to the system.

What the study shows and what my illustrative example -- again, just an illustrative example -- is that that intermittency, that uncertainty rises as a result. So yes, you already have some uncertainty in the normal load profile, that before solar came, if I was to go 10 years ago where we had a nascent amount of solar on the system, we would have intra-hour uncertainty in the load we follow.

Now that we fast forward and we have 3,000 megawatts on the grid, that intra-hour uncertainty went from this to this (indicating). So the natural response is to say that's fine, it's not that we can't manage the system. We just need to reserve more operating reserves that are sitting at the ready to provide for falls or rises than we would have before the solar came onto the system.

So you're correct, it was there in the first place. The addition of 3,000 megawatts of solar has just exacerbated that amount of intermittency.

Q. So the costs associated with intermittent problems on the supply side of that, do we -- do the costs imposed prevent unpredictability or not -- knowability on the demand side?

A. Yeah. That's the point right now, is that right now, those costs are being fully borne by the customer. And the advent of the solar increase the cost. And so we're just trying to ascribe that incremental -- it's important to say it's the incremental increase.

So we're not saying that this solar comes on and now customers should pay for all operating reserves that the utility has to carry. We're just saying an incremental amount of operating reserves are needed. Carrying those incremental operating reserves has a production cost to it, and that incremental amount -- and again, when I say "incremental," I'm going to be careful, because it's the average incremental. We didn't charge just the full incremental amount which would have been a higher number, we just said the average cost for that caused my solar should be paid for by the cost causer. But only that increment.

So, importantly, it's not -- it's not saying there wasn't uncertainty in the first place, it's not saying there's not a cost to dealing with that uncertainty, it's isolating how much additional uncertainty there is and what the cost is to serve that additional uncertainty.

Q. So has that cost assessed when there's unknown effects that cause -- that bring about changes in the demand?

A. Yeah. So how that is looked at is the -- and again, Mr. Wintermantel will answer this in much more detail, but it's looked at as how much can that -- because it's unknowable, what is knowable is the range, right? You have -- we use 36 years of weather data. We have -- that shows the weather, and even changes in weather -- 36 years of load data to show how -- you know, how load moves. But we also have -- you know, and I don't know exactly how many years of irradiance data. And that irradiance data at different spots on the grid, that historical irradiance data has a range around it.

And so that level of uncertainty that you're going to see as a result of uncertain irradiance is quantifiable. So while the exact amount isn't, the range is, and you're positioning yourself to have additional operating reserves, not to deal with the worst case, but to deal with a reasonable expectation of those ranges and say I've got to carry -- and again, in this case -- and Mr. Wintermantel has exact numbers -- but we're talking just, you know, on a system thousands of megawatts, you know, 100-and-something extra megawatts in DEP of operating reserves and less than -- I think it was less than 50 megawatts in DEC of additional operating reserves. And then once you identify how much more you need, you say how much does it cost to reserve that additional amount.

So it's really to cover the range. So you're not trying to plan to any one specific outcome, it's just you know you're going to get a bigger range, a bigger volatility band; and to deal with that bigger volatility band, you'll reserve more resources, and that's the focus of the study.

Q. So when that load -- when the load changes -- if the unknowables affect the loads, you know, are you saying there are penalties imposed?

A. Yeah. Not to the -- what we've separated out is it's only the isolated unknowable to the solar. So the load, and the uncertainty in the load is also in that calculation. And we're saying how much additional uncertainties come from the solar. So if the load was this much, and it's because of the same issues and other issues -- I mean, it's not just cloud cover with load; it's time of day, it's industrial customers that, at their discretion, turn on and off blast furnaces or heating systems, can cause big swings up and down. That's already in there.

And we're saying, before we ever had solar -- we're not asking solar to pay for that, but once we add the solar, those unknowables make the range X amount bigger. And it's only the X amount bigger that we're asking the cost causer, in this case the solar QF, to pay for, not the unknowable that was in here. That's already been quantified in both the base and the change case, and so it's in there. And we're just saying what's the impact of strictly the solar.

Q. So -- but on the other hand, when it's -- when we're talking about unpredictable changes in demand, those costs are just socialized across all customers or --

A. Yeah. Before we ever had any solar, one of the things we have to do on an operations desk is, if we had perfectly knowable load, we wouldn't have to carry operating reserves, and we would have a more efficient dispatch of our fleet. And so they are, to your point, they're socialized as a cost of operating a fleet. In any jurisdiction, they're going to have their set-aside for operating reserves, and so they do get socialized as part of your -- generally, as part of your fuel clause.

Q. All right. Thank you.

EXAMINATION BY CHAIR MITCHELL:

Q. I have a question on avoided T&D costs, and I will ask the panel, and, Mr. Snider, you may be -- may be your question, but I will let y'all decide that.

My recollection is that the P&L study did not address avoided T&D costs, suggested that there may be some as a result of the addition of distributed generation or DERs on the system, but it sort of left that issue to be studied another day. And then that's my understanding that the Astrape studies does the same thing; doesn't address T&D costs, avoided T&D costs.

And you've been asked several questions about that today, Mr. Snider, and I want to make sure I understand what your response has been. Because I think -- I think I heard you say that the Company does not, at this time, see avoided T&D as a benefit provided by the addition of solar on the system; did I understand that correctly?

A. (Glen A. Snider.) Yeah. I think, on a holistic basis, what we're seeing is additional costs.

Q. Okay.

A. What I've said is there's -- I can give you -- and I think I stated, for example, in the technical conference we talked about one of the success of Tranche 1 was all the winning bids tended to be located where there was latent capacity on the transmission system, right? So they didn't require a significant amount of system upgrades.

Well, let's look at how does that really impact customers, okay. So yes, customers did not have to pay for a system upgrade cost as a result of the solar, but but for the solar, that latent capacity -- which by the way, when I say is -- I'm talking transmission capacity, right -- would have been available to sight a dispatchable resource. Now, what's sighted there is a good energy-producing resource, but it has very little capacity. So now when I go to site capacity, whether it's my generation or merchant generation that's getting into the transmission queue, it's getting into the transmission queue with all of the solar, right?

So but for the solar, the transmission cost for these firm dispatchable resources would have been lower. Now we're introducing solar onto the grid, it's consuming that available transmission, and it's accelerating the need for additional transmission upgrades to be able to place dependable dispatchable capacity onto the system.

So again, whether that's a merchant generator trying to get in the queue or Duke trying to put a new generator into the queue, the existence of now I think we're over 10,000 megawatts in the queue, is not making it less expensive for consumers to put that generation, it's making it more expensive. And so we're not trying to quantify that cost at this point. It's a difficult number to do on a system average, sort of a here's a retail rate at this point.

Additionally, I think it's been brought up, maybe in other proceedings, that even if an interconnecting solar customer pays for a system upgrade, right, there's a big new wire that's needed, that wire gets put into service. It's a 30-year asset. That wire is going to require operation and maintenance. That operation and maintenance expense is going to be on behalf and socialized by customers through general ratemaking.

So when we start to look at, you know, independent situations, what are we seeing. And again, it's -- I say when you go to NARUC or when you talk to your peers and you start to look at whether it's solar, whether it's wind, when you get intermittent resources in large quantity, are the transmission and distribution planners saying, boy, I need a smaller budget, or are they saying I need a bigger budget?

And I have yet to find any of my peers that say, boy, we've got all this intermittent generation, we can cut our transmission budget and our distribution budget by 20 percent. I just haven't seen it in practice.

Now, what I've testified to is that we have not tried to quantify that the way we did the integration cost as a cost. But to assume that there's a benefit, I have yet to also see anybody bring forth a credible study that shows how you could actually physically reduce your investment that consumers are paying for in transmission because you're integrating a significant amount of variable energy resource onto the grid.

So my testimony has been it's not that -- it's like you're not studying it to show us the benefits. Well, we don't know how to quantify benefits when what we're seeing is cost. And what we're saying is the cost, while they are case-by-case can be significant, it's hard to come up with an average cost the way we did with an average ancillary service cost.

So we have not asked for a reduction in the avoided costs at this point to account for additional T&D costs that are, you know, by case-by-case basis, being seen on the grid at this point in time. So I, again, have sort of testified that this is another area where we're being conservative, balancing the QF and the customer, recognizing the customer is likely seeing increased T&D costs from having, you know, 3,000 on and over 10,000 in the queue, that they're seeing that, but we're not asking the solar community to pay for that at this time.

But we don't find any basis for a claim that says we should not only not charge them but we should somehow be crediting them for a benefit that we failed to see any study -- credible study that said here's how you calculate that benefit.

Q. Does the Company have plans to analyze transmission distribution costs on a systemwide basis in effort to quantify these costs that you describe? Sort of separate and apart from the interconnection process.

A. Right. It's a separate part to come up with sort an average cost, we have not. Right now, most of our transmission planning and distribution planning resources are pretty heavily engaged in actually doing the interconnection work. And so pulling them aside right now to say we want you to go do this systemwide study is not something that's currently on our radar, but depending on, you know, the magnitude of it, direction from this Commission, et cetera, it's not -- I'm not ruling it out in the future, but I know of no plans in the immediate future to be able to quantify that incremental additional cost to impose upon -- to ascribe, so we're not planning to do that right now.

CHAIR MITCHELL: Any additional questions by the Commission? Questions on Commission's questions?

MR. LEVITAS: Chair Mitchell, just two quick questions following on the line of questions you were just asking.

RECROSS EXAMINATION BY MR. LEVITAS:

Q. Mr. Snider, are you aware that there is a transmission-connected project on the DEP system that's under development that is looking at potentially funding over $200 million in network upgrades? I believe it's called Fresian?

A. (Glen A. Snider.) I'm generally aware of that, yeah.

Q. So is it your testimony that -- well, let me back up for a minute. My understanding, and tell me if I'm wrong, is that, if those upgrades are built and financed by Fresian, that they would have substantial interconnection benefits to other projects seeking to utilize the transmission system in Southeastern North Carolina, potentially including utility-owned projects; is that correct?

A. My general understanding is it's -- you know, the way the queue works is, if they do it, then it alleviates these other solar providers from having to pay for it. If they don't, then those costs fall back to the next solar providers.

But, per my discussion with Commissioner Mitchell, think about $200 million of assets being placed into service. To my knowledge there's nothing in the interconnection process or queue now that says -- those are 40-, 50-, 60-year assets that are going to require maintenance and upgrades and continued operation. All of those continued ongoing O&M will be socialized amongst customers that, but for the solar, would not have needed those upgrades.

So yes, it will have some benefits to future solar projects in the queue. And, potentially, if there was in the region a specific generator in the queue, it could change its interconnection, but at net, net, net, I still believe that there is an additional cost being provided from all of this congestion that's being caused and then solved for that is not being ascribed to the solar community right now. And so yes, I would say that doesn't change my answer at all.

Q. Except that you acknowledge that there is potential benefit by allowing other projects to interconnect that would not otherwise be able to with those costs being absorbed by the initial project; that's a benefit, is it not?

A. To the other solar providers, yes.

Q. And just one more quick question.

With respect to O&M, don't interconnection customers pay, in monthly bills, their pro rata share of their O&M cost?

A. I don't think they pay their incremental amount caused by the incremental. Is there some average O&M cost? I believe there is. But you are adding to -- you're making the bucket bigger.

MR. LEVITAS: That's all I have. Thank you.

MS. FENTRESS: Madam Chair, may I ask a quick question?

CHAIR MITCHELL: Yes.

REDIRECT EXAMINATION BY MS. FENTRESS:

Q. Mr. Wheeler, I think my questions are going to be directed at you, but, of course, Mr. Johnson, Mr. Snider, jump in if you need to. In order to, I think, make this sufficient, I'm going to hand Mr. Wheeler a copy of the Commission rules.

(Pause.)

Q. Mr. Wheeler, I've put in front of you Commission Rule R8-64; is that correct?

A. (Steven B. Wheeler.) Yes, you did.

Q. And would you agree that that rule describes the requirements that QFs must meet in order to obtain a CPCN in North Carolina?

A. Yes. A CPRE program, qualifying co-generator, a small power reducer.

Q. Thank you. And would you agree that the Commission has said in the past, in fact, early on in your experience, that a QF should obtain a CPCN before entering into a PPA; is that correct?

A. That's correct.

Q. And so when the utility enters into a PPA with a facility, the utility knows that that facility has received a CPCN; is that correct?

A. That's correct.

Q. Could you turn the page, and can you look at Section (3)(ii).

A. I have it.

Q. Can you -- and just to give some context, that page lists the requirements of what a QF must show in order to get a CPCN; is that correct?

A. Yes.

Q. Can you read requirement (3)(ii) out loud?

A. "A description of the buildings, structures, and equipment comprising the generating facility and the manner of its operation."

Q. And so when the utility enters into a PPA with a QF that's received a CPCN, that information has been put to the Commission and that information is required for that to be a facility that the utility can then enter a PPA in; is that correct?

A. That's correct.

Q. Okay. If you turn and look at the next rule -- and I'm sorry I don't have it in front of me, but it should be the rule that is R8-65. It's marked. Thank you.

A. Yes.

Q. And that applies to reports of proposed construction; is that correct?

A. Yes, it does.

Q. And that would be a QF that's less -- or 2 megawatts or less would file; is that correct?

A. That's correct.

Q. Thank you. And would you please turn the page and indicate to the Commission if you see similar language in that, a similar requirement with respect to what a QF must show with a report of proposed construction. And I believe you could look at (g)(1)b.

A. Yes. That reads almost identically. "A description on the buildings, structures, and equipment comprising the generating facility and the manner of its operation."

Q. So is it fair to say that, with that information, that is the information that the utility is relying upon when it enters the description of the facility with its PPAs?

MR. LEVITAS: Objection.

MS. FENTRESS: On what grounds?

MR. LEVITAS: I don't know what the basis for that inference is. You're asking about whether the utility relies on that information or not for PPA purposes.

Q. Does the utility have to get -- does the QF have to get a CPCN in before it enters into a PPA?

A. Yes, it does.

Q. So the utility -- the facility has a CPCN; is that correct?

A. That's correct.

Q. Is the CPCN, as described -- does the QF have to put the information described before the Commission in order to get the CPCN?

A. Yes. That's a requirement.

Q. So that is the basis upon which the facility is described with which the utility enters into a PPA with; is that correct?

A. That's correct.

MS. FENTRESS: I have nothing further.

MR. BREITSCHWERDT: Chair Mitchell, just two quick questions for Mr. Snider, if I could.

CHAIR MITCHELL: Okay.

REDIRECT EXAMINATION BY MR. BREITSCHWERDT:

Q. So, Mr. Snider, Chair Mitchell asked you a few questions about quantifying T&D costs. And based on your recollection developing this case, was there not some direction in Sub 148 in the prior avoided cost proceeding where the Commission directed the Company to evaluate whether QFs continued to avoided line losses; not necessarily T&D costs but where there was additional --

A. (Glen A. Snider.) Yes.

Q. -- value, such as distribution-connected QFs?

A. Yes.

Q. And did you undertake such a study?

A. Yes.

Q. And in the nature of your conservative view in balancing the interests of QFs and customers, can you remind myself and the Commission how the Company came out on that study?

A. Yes. So we continue to find it appropriate to pay an incrementally higher energy rate that includes a line loss benefit to the QF. I think we've looked at, at some point, if we get enough QFs on distribution where it's back-feeding onto transmission, it may be appropriate to no longer pay a transmission line loss if the actual distribution-connected QF is consuming the transmission system and not generating a line loss benefit. But in this study, we found it appropriate to continue to ascribe transmission line loss benefits to distribution-connected QFs.

Q. Thank you. And Mr. Levitas asked you a few questions about a Fresian project, which it sounds like you had general familiarity with, and he ascribed the fact that the QF owner would be paying $200 million of upgrade costs associated at that facility; do you recall those questions?

A. I do.

Q. And just so everyone is clear, when that -- if it's a wholesale project that's selling under the Open Access Transmission Tariff and is constructing upgrades under those provisions, will the QF owner who makes that initial investment ultimately be responsible for those costs, or would they be refunded to the generator over -- generator owner over time?

A. I think they will actually be refunded to the generator over -- to the QF over time, is my general understanding of that.

Q. And as a result of that, who will ultimately end up paying those costs?

A. Customers.

Q. Thank you.

MR. LEVITAS: Madam Chair, may I ask one quick follow-up on Mr. Fentress' redirect? Just one question.

MS. FENTRESS: If I could ask a question after Mr. Levitas. We have the burden of proof.

MR. LEVITAS: Just one question.

CHAIR MITCHELL: One. One question, and then Ms. Fentress, you'll have a chance.

RECROSS EXAMINATION BY MR. LEVITAS:

Q. So I guess this is for Mr. Wheeler, but is it the case or isn't it the case that the NCUC generally allows for QFs to amend their CPNs to make material modifications without either providing notice or without losing their legally enforceable obligation?

A. (Steven B. Wheeler.) I'm not familiar with that. Mr. Snider?

A. (Glen A. Snider.) Nor am I, and certainly I don't know -- I, personally, don't know of somebody that's five years into a contract that's come before the Commission. I'm not saying it hasn't happened, but not to my -- it's not my knowledge.

A. (Steven B. Wheeler.) But I would add that we do rely on the CPCN, to some extent, when we negotiate. We know the customer has to verify he has it, like he has to verify he has the QF status, like he has to verify his interconnection agreement executed and enforceable. All of them from -- all those documents provide information on his facility that we rely on for executing a PPA and establishing the terms and the rates under which we'll pay -- compensate back the qualifying facility for its generation.

Q. Well, I understand that you rely on the existence of a CPCN and that's a requirement for LEO formation, but with respect to facility information, you separately require that as the part of the PPA process, and it's formally submitted and reflected in the PPA, itself. It's not in the CPC --

MS. FENTRESS: Objection. I don't hear a question.

Q. Well, I'm asking you, isn't it the case that the information that you rely on for the purpose of contracting with a QF with respect to the facility is the information that you require that facility to provide you as part of the PPA process?

A. Well, most detailed information we have is submitted in the interconnection agreement application. That includes schematics of the site, exact equipment specifications, details for how it's going to be operated; and that has to be in our records before we go and execute a PPA. So we rely on that. We rely on the PPA, which has a summary-level description of the facility. It's only two lines. It's not a huge, detailed, extensive description like it is in the interconnection agreement. We rely on all those documents.

Q. But there's nothing in the standard offer PPA or your negotiated PPAs that makes any reference to the content of the CPN with respect to the facility description, is there?

A. There is a reference that requires that they have to be executed or approved by the Commission. Yes, there is a requirement.

Q. That's not the question I asked you. I understand that you have to have a CPCN.

My question was, there's nothing in the standard offer contract or the negotiated contract that makes any reference to the facility information as presented in the CPCN as opposed to the information that is provided as part of the contract document; isn't that correct?

A. There is a requirement CPCN be issued, and that's a requirement of the PPA.

Q. Okay. I think you may have --

A. -- and the terms and conditions --

MS. FENTRESS: He can finish.

Q. I think you've answered my question. Thank you.

MS. FENTRESS: I will go very fast. I'm going to need to get my rule book back.

REDIRECT EXAMINATION BY MS. FENTRESS:

Q. Mr. Wheeler, I put Commission Rule R8-64 back in front of you.

Would you take a look at that rule and indicate to me if you see any provision in that rule for if there is a change in the information -- a significant change, but a change in the information that has been put forward to the Commission in the application for the CPCN, if that changes, that the applicant is to notify the Commission?

A. Yeah. Under Section D, the certificate, subparagraph 3, it says, "Both before the time construction is completed and after, all certificate holders must advise both the Commission and the utility involved of any plans to sell, transfer, or sign the certificate, or the generating facility, or any significant changes in the information set forth in subsection (b)(1) through (b)(5) of this rule."

Q. Thank you. And would you agree that the description of the facility that you discussed earlier is in Section (b)(1) of the --

A. Yes, that's correct.

Q. Would you accept, subject to check, that similar language exists for R8-65?

A. Yes, subject to check.

Q. Would you agree that, if the Commission's rules indicate that, if there's a change in the information that was submitted to get a CPCN, that it's reason -- that rule is in existence, if you have to come in and notify the Commission and the utility if you're changing the application, information on the facility for a CPCN, that the Company is reasonable in expecting that any change to a facility would be a material alteration?

A. Yes.

Q. Thank you. I have nothing further.

CHAIR MITCHELL: All right. You all have given Commissioner Clodfelter a chance to come up with another question.

COMMISSIONER CLODFELTER: I got to get in on the fun of this.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Wheeler, since you were getting the questions, I'm sorry, it's got to be you. And I'm not going to ask you anything but just one.

Do you know whether or not the Company has taken any position before the Commission on whether or not battery storage equipment even requires a CPCN?

A. (Steven B. Wheeler.) I'm not aware of anything. I know, on our side of the business, we have decided that an interconnection agreement is required for a battery storage installation.

Q. Thank you. That's my only question.

CHAIR MITCHELL: Okay. Gentlemen, I believe that you are -- there is nothing further for you. You may be dismissed. Thank you.

MS. FENTRESS: Madam Chair, we would like to move in our exhibits into evidence as marked, and the testimony and everything else that we have put forth into the record.

CHAIR MITCHELL: Hearing no objections, the motion is allowed.

(Snider Exhibit Number 1 was admitted into evidence.)

MS. FENTRESS: I'm sorry, we still have another witness. We're not stopping now.

CHAIR MITCHELL: Please call your next

witness.

MR. BREITSCHWERDT: Thank you.

Chair Mitchell, the Company calls Mr. Nick Wheeler. Mr. Nick Wintermantel. Mr. Wheeler has now concluded his long day.

CHAIR MITCHELL: For purposes of the record, Mr. Breitschwerdt, just restate your witness' name.

MR. BREITSCHWERDT:

Mr. Nick Wintermantel.

CHAIR MITCHELL: Thank you.

Good afternoon, Mr. Wintermantel. Is there a Bible in front of you?

THE WITNESS: Yes, there is.

CHAIR MITCHELL: Okay.

NICK WINTERMANTEL,
having first been duly sworn, was examined
and testified as follows:

DIRECT EXAMINATION BY MR. BREITSCHWERDT:

Q. Good afternoon, Mr. Wintermantel. Apologies for getting you confused with Mr. Wheeler.

A. That's okay. Good afternoon.

Q. Would you please state your full name and business address for the record?

A. Yes. My name is Nick Wintermantel, and my business address is 1935 Hoover Court, Birmingham, Alabama.

Q. And by whom are you employed and in what capacity?

A. I'm employed by Astrape Consulting, and I'm a principal consultant there.

Q. And you're an expert employee for Duke -- or an expert witness for Duke Energy in this proceeding?

A. Yes, I am.

Q. And did you cause to be prefiled in this docket on May 21st of this year, 33 pages of direct testimony in question and answer form and two exhibits?

A. Yes, I did.

Q. And do you have any changes or corrections to that direct testimony?

A. No, I do not.

Q. If I was to ask you the same questions today that appear in your direct testimony, would your answers be the same?

A. Yes, they would.

Q. And did you also cause to be prefiled in this docket, on July 3rd of this year, 27 pages of rebuttal testimony in question and answer form?

A. Yes.

Q. And do you have any changes or corrections to that rebuttal testimony?

A. I do not.

Q. And if I was to ask you the same questions that are set forth in your rebuttal testimony today, would your answers be the same?

A. Yes, they would.

MR. BREITSCHWERDT: Chair Mitchell, at this time I would move that Mr. Wintermantel's prefiled direct and rebuttal testimony be copied into the record as if given orally from the stand and his two direct testimony exhibits be marked for identification.

CHAIR MITCHELL: Hearing no objection, the motion is allowed.

(Wintermantel Exhibits Numbers 1 and 2 were marked for identification.)

(Whereupon, the prefiled direct testimony and prefiled rebuttal testimony of Nick Wintermantel was copied into the record as if given orally from the stand.)

NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2018	)))))))	**DIRECT TESTIMONY OF NICK WINTERMANTEL ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Nick Wintermantel, and my business address is 1935 Hoover Court, Hoover, AL 35226.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am a Principal Consultant and Partner at Astrapé Consulting. Astrapé is a consulting firm that provides expertise in resource planning and resource adequacy to utilities across the United States and internationally.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I graduated summa cum laude with a Bachelor of Science in Mechanical Engineering from the University of Alabama in 2003. I also obtained a Master's degree in Business Administration from the University of Alabama at Birmingham in 2007.

Q. PLEASE DESCRIBE YOUR CONSULTING BACKGROUND AND EXPERIENCE.

A. I have worked in the utility industry for 18 years. I started at Southern Company where I worked in various roles within Southern Power, the competitive arm, and on the retail side within Southern Company Services. In my various roles, I was responsible for performing production cost simulations, financial modeling on wholesale power contracts, general integrated resource planning, and asset management. In 2009, I joined Astrapé as a Principal Consultant and have been responsible for resource adequacy, resource planning, and renewable integration studies across the U.S. and internationally.

Q. PLEASE SUMMARIZE YOUR TESTIMONY FOR THE COMMISSION.

A. My testimony introduces and summarizes the Solar Ancillary Service Study that Astrapé recently conducted on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "the Companies").

Q. ARE YOU INCLUDING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. Yes. I am including two exhibits with my direct testimony. Wintermantel Exhibit 1 is a copy of my curriculum vitae. Wintermantel Exhibit 2 is the Solar Ancillary Service Study ("Astrapé Study" or "Study").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION")?

A. No, I have not.

Q. BEFORE ADDRESSING YOUR SPECIFIC WORK FOR THE COMPANIES, PLEASE PROVIDE AN OVERVIEW OF YOUR EXPERTISE PERFORMING RESOURCE ADEQUACY AND PLANNING STUDIES.

A. Since joining Astrapé Consulting in 2009, I have managed target reserve margin studies; capacity value studies of wind, solar, and demand response resources; analyzed generation resource selection decisions; as well as managed ancillary service studies assessing cost impacts of integrating renewables. These studies have been performed for utilities and system operators across the U.S. and internationally, principally using Astrapé's Strategic Energy Risk Valuation Model ("SERVM"). I have developed particular expertise conducting ancillary service studies for utilities and other entities across the country that have significant renewable penetration similar to the Companies. Over the last few years, I have worked with our Astrapé team to develop a modeling framework within SERVM to evaluate the impact intermittent resources have on ancillary services.

Q. CAN YOU PLEASE EXPAND ON ASTRAPÉ CONSULTING'S WORK IN THE UTILITY INDUSTRY?

A. Yes. Astrapé is the exclusive licensor of the SERVM model. SERVM is used by utilities, system operators, and regulators to perform resource adequacy and planning studies. In the southeast alone, Astrapé has managed SERVM licenses or performed studies for utilities including Duke Energy Corporation, the North Carolina Electric Membership Corporation, Tennessee Valley Authority, Southern Company, Entergy, Central Louisiana Electric Co-op or CLECO, Georgia System Operations Corporation, Santee Cooper, and Louisville Gas & Electric. Outside of the southeast, Astrapé has used SERVM to perform resource adequacy for large independent operators such as Electric Reliability Council of Texas ("ERCOT"), the Southwest Power Pool ("SPP"), the Midwest Independent

System Operator ("MISO") and Alberta Electric System Operator ("AESO").

Q. PLEASE DESCRIBE YOUR WORK FOR THE COMPANIES THAT IS THE SUBJECT OF YOUR TESTIMONY.

A. Astrapé was retained by the Companies in late 2017 to analyze and quantify the ancillary service impact of integrating existing and future solar generation on both the DEC and DEP systems. I was integrally involved in this work throughout much of 2018 and was primarily responsible for the modeling and development of the Study. Astrapé completed the Study for the Companies in November of 2018.

Q. HAVE YOU PERFORMED CONSULTING SERVICES FOR DUKE ENERGY CORPORATION BEFORE?

A. Yes. I performed reserve margin studies for both DEC and DEP in 2012 and 2016. These studies were reviewed by the North Carolina Utilities Commission—Public Staff and the Commission as part of the 2012 and 2016 biennial integrated resource planning proceedings. In 2018, my team performed a solar capacity value study in parallel with the Solar Ancillary Service Study that is the subject of my testimony. The Companies relied upon the solar capacity value study to determine the capacity contribution of solar generating facilities in their respective 2018 Integrated Resource Plans ("IRPs").

I. BACKGROUND ON ANCILLARY SERVICES IN SYSTEM OPERATIONS AND PLANNING

Q. WHAT ARE ANCILLARY SERVICES?

A. Ancillary services are a set of tools used by utility and independent system operators to keep the system precisely in balance between energy supply and customer demand in real time. While ancillary service product definitions can vary across jurisdictions, ancillary services generally include regulating reserves and contingency reserves comprised of spinning and/or non-spinning reserves. Each of these reserves represents power generation that could be increased or reduced within seconds or minutes to correct any supply and demand imbalance. Regulating reserves must be supplied by generation resources with Automatic Generation Control ("AGC")[1] capabilities while contingency reserves can be met by either online resources with available capacity above their immediate dispatch level or by offline resources with fast startup capability. Regulating reserves and contingency reserves are required in order to maintain compliance with mandatory NERC resource and demand balancing (BAL) reliability standards.[2] The NERC BAL standards are minimum requirements, so additional online reserves (frequently referred to as load following reserves) must also be carried due to net load uncertainty and intra

---

[1] AGC is a control system included on generators that responds to changes in load automatically through frequency response.

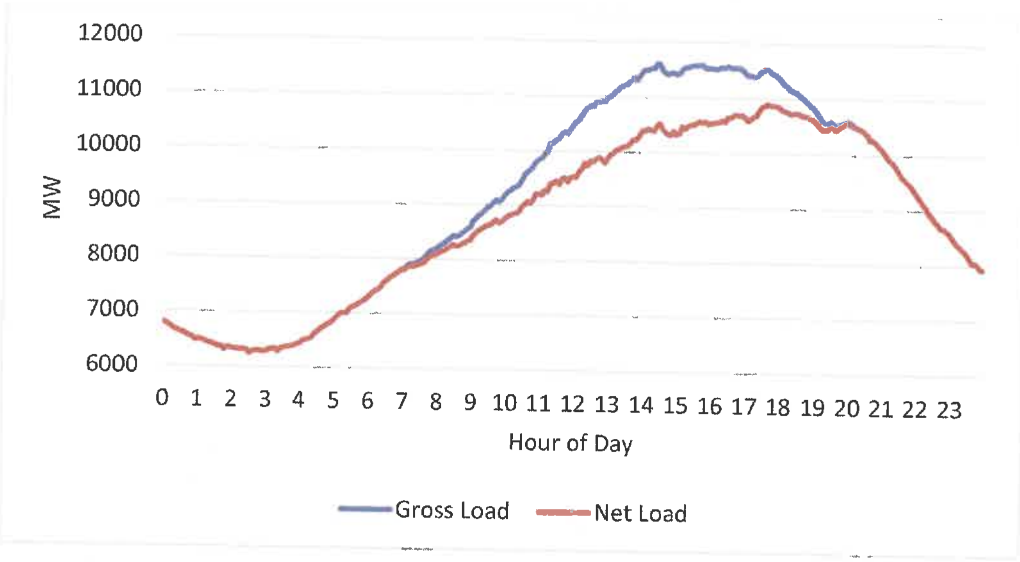
[2] *Reliability Standards,* NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (2017), *available at* https://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx.

hour volatility as well as the need to respond to unplanned generator outages. The more uncertain and volatile net load becomes, the more load following reserves are required to maintain reliability in real time.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY "NET LOAD."

A. Net load is defined as the gross customer demand minus renewable generation. In other words, it is the total load reduced for renewable generation and represents the load that must be served by the conventional fleet. Figure 1 shows an example of gross load compared to net load for a sample summer day.

Figure 1. Net Load Example



Q. HOW DOES ADDING SOLAR GENERATION IMPACT THE NEED FOR ADDITIONAL ANCILLARY SERVICES?

A. Solar is an intermittent resource that is dependent on solar irradiance and is significantly impacted by changes in weather conditions. For example, as cloud cover increases or diminishes over the solar facility, solar output can ramp up or down significantly minute-to-minute, adding significant incremental volatility to the net load of the system. As the size of the solar portfolio injecting energy into a utility's system increases, the magnitude of this unexpected movement increases. In order to offset these large unexpected solar movements, a utility's conventional generator fleet must be able to quickly ramp up and down to compensate for changes in solar output. In order to provide this service from the conventional generator fleet, the level of ancillary services must be increased. Generally, these ancillary services are provided by utility system operators committing additional conventional fleet generating facilities to be online and available in the form of additional "load following reserves."

Q. PLEASE EXPLAIN WHY COMMITTING ADDITIONAL GENERATING FACILITIES TO PROVIDE LOAD FOLLOWING RESERVES WOULD INCREASE COSTS.

A. First, as introduced above, load following reserves are additional online reserves that must be carried to respond to net load uncertainty and intra hour volatility as well as the risk of system disturbances, such as unplanned generator outages. In order to provide additional load following reserves, more generating units must be committed and synched to the grid. This, in turn, forces individual generators to operate further below their max output. When generators operate at levels below their maximum output, efficiency is reduced. Reductions in generator operating efficiency results in increased costs. Also, increasing load following reserves may require generators to start up more frequently, causing additional startup costs and maintenance costs.

Q PLEASE DESCRIBE THE INTEGRATION CHALLENGES UTILITIES EXPERIENCE AS SOLAR PENETRATION INCREASES ON A UTILITY'S SYSTEM.

A. As discussed previously, the uncertainty and intra hour volatility in net load increases as the penetration of solar increases, meaning five-minute deviations in net load can be much more significant in systems with high penetrations of variable and intermittent solar compared to systems with no solar. In order to balance supply and demand in real time, not only are additional ancillary services needed, but additional renewable curtailment practices are also needed. Solar can also ramp up just as fast as it can ramp down, so systems with high penetration will inevitably have periods where the minimum generation level of the generators online is greater than load, requiring solar generation to be curtailed.

II. OVERVIEW OF THE SOLAR ANCILLARY SERVICE STUDY

Q. PLEASE PROVIDE AN OVERVIEW OF THE STUDY THAT ASTRAPÉ COMPLETED FOR THE COMPANIES.

A. The Solar Ancillary Service Study utilized Astrapé's proprietary SERVM Model, which is the same model and framework used for the DEC and DEP 2012 and 2016 resource adequacy studies and 2018 solar capacity value study. The model commits DEC and DEP's resources on week-ahead, day-ahead, and hour-ahead bases and dispatches resources to load on a five-minute time step. For each year simulated, total production costs are calculated and reported as well as the reliability metrics of the system.

For the Study, several solar penetration levels were simulated. For each solar penetration simulated, the amount of additional ancillary services required in order to maintain reliability on the system was determined. Once the ancillary services required were determined, the costs of the ancillary service were also computed.

Q. PLEASE DISCUSS THE SERVM MODEL FRAMEWORK INCLUDING THE STUDY YEAR AND THE WEATHER YEARS UTILIZED.

A. Similar to the previous resource adequacy studies performed for DEC and DEP, the SERVM framework simulates a specific study year and simulates thousands of combinations of weather, economic load forecast error, and generator performance on that single year. In order to calculate accurate reliability metrics, it is important to capture a full distribution of load and generator performance. The Solar Ancillary Service Study models a 2020 study year. The year 2020 was simulated assuming 36 different years of weather (1980 – 2015), which provides reasonable variability in load and solar output. Each weather year was simulated with 5 different load forecast errors, 6 different solar profiles, and 20 generator outage draws providing a full range of potential outcomes that could occur in 2020. Additional details of the SERVM framework and model inputs are provided in Sections I through III of the Study.

An important aspect of the Study is that SERVM is designed to recognize that utility system operators will have imperfect knowledge of day-ahead net load, net load a few hours ahead, and intra hour net load to make generation commitment decisions. This imperfect knowledge is accounted for by incorporating load and solar forecast error, meaning the model commits its conventional generation fleet to a net load that has some level of error and then must adjust accordingly in real time, similar to the way system operators must adjust in real time.

Q. WHAT SOLAR PENETRATION LEVELS WERE ASSUMED IN THE STUDY?

A. Solar penetration levels modeled in the Study begin with a baseline scenario of 0 MW of solar installed on the DEC and DEP systems, respectively. The main purpose of starting with a 0 MW solar scenario in the Study is to set a baseline of targeted system reliability against which to measure solar penetration simulations. The additional solar penetration levels studied include "Existing plus Transition," "Tranche 1," and "+1,500 MW" of solar. The capacity levels of each forecasted solar penetration are presented in Figure 2 and in Table ES-1 in the Study.

Figure 2. DEC and DEP Solar Penetrations Analyzed

Tranche	DEC Incremental MW	DEC Cumulative MW	DEP Incremental MW	DEP Cumulative MW
No Solar	0	0	0	0
Existing plus Transition	840	840	2,950	2,950
Tranche 1	680	1,520	160	3,110
+1,500 MW	1,500	3,020	1,500	4,610

Q. CAN YOU BRIEFLY DISCUSS THE DEVELOPMENT OF THE SOLAR PROFILES USED IN THE STUDY?

A. Yes. Hourly profiles were developed based on data from the public NREL National Solar Radiation Database ("NSRDB") in conjunction with NREL's System Advisory Model ("SAM"). Similar to load, solar profiles were developed for weather years from 1980 – 2015 for fixed and single axis tracking technologies. Additional details regarding the development of the hourly solar profiles are included in Section II.B of the Study.

Q. DISCUSS THE INTRA HOUR VOLATILITY DEVELOPED FOR LOAD AND SOLAR.

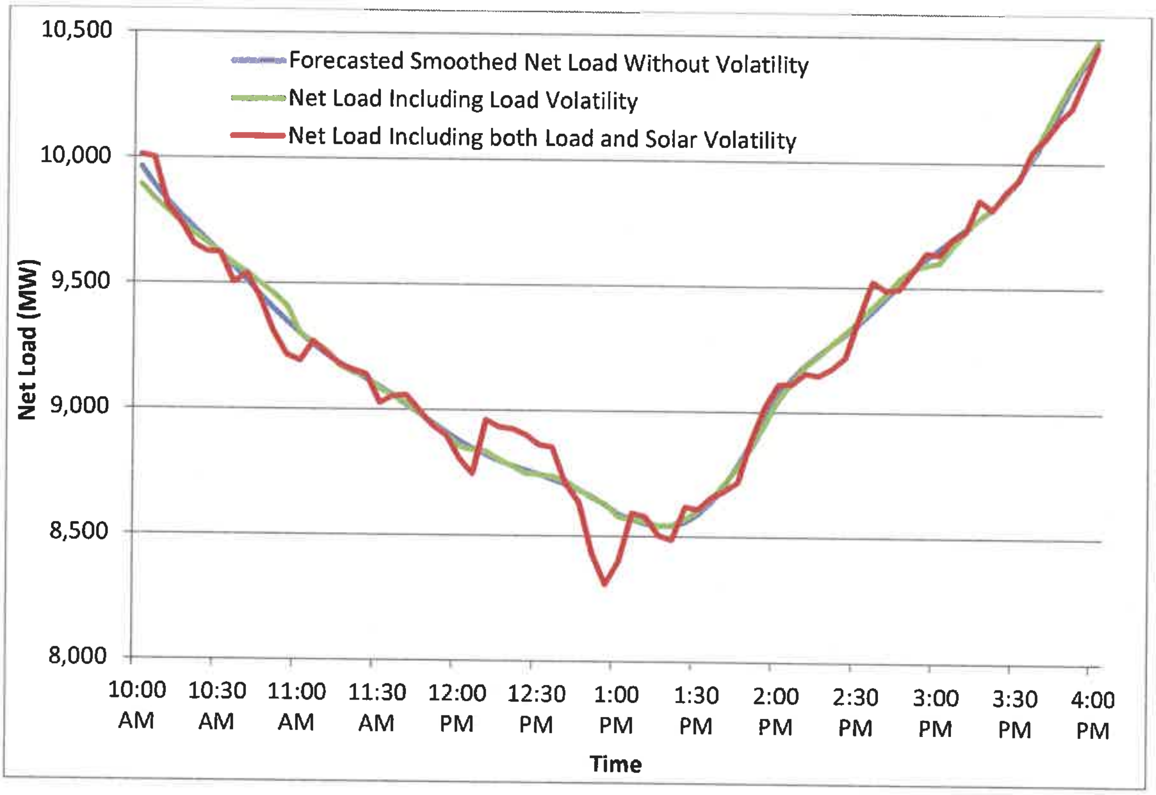
A. In order to mimic the movement of load and solar on a five-minute basis, the SERVM model requires one year of five-minute load and solar data as an input. For both DEC and DEP, the Study uses historical five-minute load and solar data from the 12 month period between October 2016 – September 2017. The five-minute data was scrubbed for reporting anomalies or errors and the volatility embedded in these five-minute profiles was applied to the load and solar for each penetration analyzed. Additional details regarding the load and solar intra hour datasets are included in Section II.C of the Study.

Q. DISCUSS HOW SERVM USES THE INTRA HOUR DATA SETS INTRODUCED ABOVE TO MIMIC VOLATILITY.

A. As discussed above, the Study was designed to mimic the intra hour volatility seen in historical load and solar data sets. SERVM commits resources to meet expected hourly net load and then randomly selects (or draws) from the intra hour historical datasets for load and solar separately based on similar conditions. In other words, to simulate a peak load hour, SERVM randomly selects five-minute volatility data from the set of peak load hours in the historical intra hour load dataset. For solar, if the portfolio is operating at 50% of its nameplate capacity, then SERVM randomly selects five-minute volatility data from a set of hours that show the same amount of solar output (50%) in the historical intra hour solar dataset. The selected five-minute volatility data for that hour is then applied to a perfectly smooth net load profile causing five-minute deviations. The conventional fleet is then forced to serve the net load with volatility in five-minute increments.

Figure 3 below illustrates the net load with and without any five-minute solar and load volatility included. The blue line represents the forecasted net load without solar and load volatility. SERVM takes the hourly load and solar values and creates a smooth profile with minimal ramping. The green line represents the addition of load volatility to the blue line. The green line is very close to the blue line meaning the historical load data selected for this example wasn't extremely volatile. The red line represents the addition of solar volatility to the green line. So, while SERVM schedules its conventional fleet to be able to meet the blue (forecasted and smooth) line, the conventional fleet must actually be dispatched to meet the more volatile red line in five-minute increments.[3] As solar penetration increases, the net load is more volatile, requiring additional ancillary services.

Figure. 3. Net Load With and Without Load and Solar Volatility



[3] This modeling should not be confused with trying to capture the Area Control Error or "ACE" (as further explained below) calculated in system operations. This modeling simply tests whether or not the system can move fast enough to meet a net load value on a five-minute increment.

Q. HOW IS THE AMOUNT OF REQUIRED ANCILLARY SERVICES DETERMINED IN THE STUDY?

A. The premise of the Study is that the reliability of the DEC and DEP systems after incremental solar generation is added should remain the same as the reliability of the systems without solar. When solar is added, ancillary services in the form of load following reserves are increased until the reliability matches what was recorded in the system before solar was added.

Q. WHAT RELIABILITY METRICS ARE USED IN THE STUDY?

A. Loss of Load Expectation ("LOLE") is the primary metric used in the Study and represents the number of days in a year that load plus minimum operating reserves cannot be met by the generation fleet on a five-minute time step[4]. Within SERVM, LOLE is categorized into two metrics: LOLE_{CAP} and $\text{LOLE}_{\text{FLEX}}$.

Q. PLEASE EXPLAIN THE LOLE_{CAP} RELIABILITY METRIC USED IN THE STUDY.

A The LOLE_{CAP} reliability metric measures the number of loss of load events that occur due to capacity shortages, calculated in events per year. A loss of load event occurs when all available resources have been exhausted and generation is still below load plus a minimum operating reserve level. This LOLE metric is traditionally used for IRP purposes to determine target reserve margin and required installed capacity amounts.

[4] Whether the loss of load event lasts five minutes or 10 hours, or has two separate events in the same day, it is considered one day.

Q. PLEASE EXPLAIN THE $LOLE_{FLEX}$ RELIABILITY METRIC USED IN THE STUDY.

A The $LOLE_{FLEX}$ reliability metric is the number of loss of load events due to system flexibility constraints, calculated in events per year. In other words, there was enough capacity installed on the system but not enough flexibility to meet the net load ramps caused by solar generation, or startup times prevented a unit coming online fast enough to meet the unanticipated ramps. Because $LOLE_{FLEX}$ is more related to operational flexibility, five-minute time steps must be simulated compared to $LOLE_{CAP}$ which traditionally has been captured in hourly simulations. Generally, increasing load following reserves will reduce $LOLE_{FLEX}$ events. This metric can be used to measure system flexibility over a range of ancillary service assumptions.

Q. HOW ARE $LOLE_{CAP}$ AND $LOLE_{FLEX}$ USED IN THE STUDY?

A. Consistent with Astrapé's previous reserve margin studies performed for DEC and DEP, $LOLE_{CAP}$ is targeted to 0.1 days per year which is generally known as the "1 day in 10 year" planning standard. The "1 day in 10 year" planning standard is used to ensure a utility has enough capacity installed and available so that only one firm load shed event is forecasted to occur every 10 years. All simulations in the Study were targeted to this level of reliability by adjusting capacity as needed to be consistent with the "1 day in 10 year" planning standard used by the Companies in their resource adequacy planning. Other than this calibration step, $LOLE_{CAP}$ does not have a significant role in the Study. $LOLE_{FLEX}$, as discussed earlier, allows the adequacy of system flexibility to be measured by testing whether the conventional fleet with an assumed amount of ancillary services can meet net load on a five-minute increment. The system without any solar is targeted to have a $LOLE_{FLEX}$ of 0.1 events per year. This is calibrated by adjusting the load following reserves target in the Study. The level of reserves which achieved $LOLE_{FLEX}$ of 0.1 events per year was similar to the average reserves supplied by the total DEC and DEP systems in 2015 prior to significant solar penetration being integrated. As solar is added to the system, the unexpected movement in net load increases and causes $LOLE_{FLEX}$ to increase. In order to lower $LOLE_{FLEX}$ back to 0.1, additional load following reserves are required. This amount of additional load following reserves is the ancillary service impact of the additional solar.

Q. IS $LOLE_{FLEX}$ OF 0.1 A GENERALLY UTILIZED INDUSTRY METRIC OR STANDARD FOR ASSESSING RELIABILITY EVENTS CAUSED BY LACK OF FLEXIBILITY?

A. No. Operational reliability is governed by the NERC Balancing Standards and is measured by different metrics that cannot be easily captured in a production cost model simulated in five-minute intervals. Ultimately, $LOLE_{FLEX}$ as used in SERVM is a measure of the system's ability to satisfy net load obligations assuming the net load is known five minutes before it materializes. While distinct from the NERC Balancing Standards, any $LOLE_{FLEX}$ event should be viewed as a substantial violation of a system's obligation to manage its own load.

Q. COULD LOLE$_{FLEX}$ EVENTS BE MITIGATED BY ALLOWING AREA CONTROL ERROR ("ACE") TO DEVIATE FOR SHORT PERIODS?

A. No. LOLE$_{FLEX}$ events and ACE deviations are not synonymous. While ACE deviations occur frequently, a LOLE$_{FLEX}$ event represents a considerably more extreme violation. Since simulations replicating historically supplied reserves demonstrate approximately 0.1 LOLE$_{FLEX}$, planning to maintain 0.1 LOLE$_{FLEX}$ would not affect the frequency or magnitude of ACE deviations currently experienced. Assuming the volatility caused by additional solar could be absorbed by allowing more frequent imbalances with neighboring utilities would not be appropriate.

Q. HOW ARE THE COSTS OF THE REQUIRED ANCILLARY SERVICES CALCULATED?

A. The SERVM model simulations not only calculate the reliability metrics discussed above, but also calculate total system production costs. These production costs include fuel costs, O&M costs, and startup costs. Once the increase in required load following reserves is calculated, the cost of the required load following reserves is then calculated.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE?

A. Yes. Assume that 500 MW of load following reserves were required in the 0 MW solar case to meet 0.1 LOLE$_{FLEX}$. When 1,000 MW of solar is added to the system while still only assuming 500 MW of load following reserves, then LOLE$_{FLEX}$ increases to 0.2 events per year. In order to reduce the 0.2

events per year to 0.1, an additional 100 MW of load following is required. The costs differential between the 1,000 MW solar cases that included the 500 MW of load following (which produced 0.2 $LOLE_{FLEX}$) and the 600 MW of load following (which was required in the 1,000 MW solar case to return the system to 0.1 $LOLE_{FLEX}$) is the total cost impact of the required ancillary services. This cost increase is then divided by the generation of the 1,000 MW of solar to determine the ancillary service cost impact of the solar in $/MWh.

III. FINDINGS OF THE SOLAR ANCILLARY SERVICE STUDY

Q. PLEASE DESCRIBE THE KEY FINDINGS OF THE SOLAR ANCILLARY SERVICE STUDY.

A. When solar was added to the DEC and DEP systems, net load uncertainty and intra hour volatility increased and $LOLE_{FLEX}$ increased. In order to maintain the same reliability on the system as before the solar was added, load following reserves needed to be increased. Given the level of solar in DEC, the required increase to load following reserves and associated costs for the "Existing plus Transition" and "Tranche 1" penetrations was relatively small. The required increase to load following reserves and associated costs in DEP was more pronounced, given the greater amount of solar already installed and operating on the DEP system. The cost to provide the additional ancillary services for the "Existing plus Transition" and "Tranche 1" for both DEC and DEP was in the $1.00/MWh to $2.75/MWh range. In addition to adding incremental costs to provide ancillary services, the Study also showed an increasing amount of renewable curtailment as solar penetration increased. Looking to the high penetration scenarios, the Study results indicated an exponentially increasing cost of integrating incremental solar with the conventional fleet. At low penetrations, the intrinsic flexibility of the conventional fleet is able to absorb the solar volatility with little operational or economic impact. At higher penetrations of solar, the conventional fleet must be operated very inefficiently to integrate the solar volatility. As the system resource mix changes or as flexible resources are added to the system, the cost of integrating higher penetrations of solar may change.

Q. PLEASE DISCUSS THE ADDITIONAL ANCILLARY SERVICE REQUIREMENTS NEEDED TO MEET AN $LOLE_{FLEX}$ OF 0.1 FOR DEC AT EACH SOLAR PENETRATION LEVEL EVALUATED IN THE STUDY.

A. Figure 4, which is also Table 20 in the Study, shows the ancillary service study impact results for DEC. The results show that 26 additional MW of load following reserves were required to provide the ancillary services needed to meet equivalent system reliability at the "Existing plus Transition" level of solar to the baseline level of system reliability in the 0 MW solar case. After "Tranche 1" was added, 67 MW of additional load following reserves were required compared to the 0 MW solar case. For the "+1,500 MW" of solar, the incremental load following requirements are above 200 MW.

Figure 4. DEC Study Results

	Solar Scenario				
	DEC No Solar	DEC Existing plus Transition	DEC Tranche 1	DEC Add 1,500 MW 75%	DEC Add 1,500 MW
Incremental Solar MW	0	840	680	1,500	1,500
Total Solar MW MW	0	840	1,520	3,020	3,020
LOLE Flex Events Per Year	0.10	0.10	0.10	0.10	0.10
Average Ancillary Service Cost Impact $/MWh	0	1.10	1.37	2.90	9.75
Incremental Ancillary Service Cost Impact $/MWh	0	1.10	1.67	4.38	17.78
Total Load Following Addition MW	0	26	67	243	634
Additional Renewable Curtailment MWh	0	3,268	16,238	114,657	229,475
Renewable Generation MWh	0	1,556,350	2,949,446	6,022,045	6,022,045
% of Renewable Curtailed %	0	0.2%	0.6%	1.9%	3.8%
Solar Volatility Assumption	Base	Base	Base	75% of Base	Base

Q. PLEASE EXPLAIN WHY ASTRAPÉ USED TWO DIFFERENT INTRA HOUR VOLATILITY DATASETS FOR THE +1,500 MW SOLAR PENETRATION SCENARIOS AS SHOWN IN FIGURE 4.

A. The volatility in the "+1,500 MW" high solar penetration scenario is uncertain because this level of potential future solar penetration is speculative at this time. Data representing five-minute volatility for solar portfolios at this high level of penetration on the DEC and DEP systems does not exist. For this reason, two intra hour volatility datasets were simulated representing bookends in the high penetration analysis. One dataset assumed the actual historical data used for the "Existing plus Transition" and "Tranche 1" scenarios, and the other dataset assumed a 25%

reduction in volatility, which would assume there is some geographical diversity within the high penetration solar portfolios. However, in both DEC and DEP today, the majority of the historical data is made up of smaller-sized units while new solar resources are expected to be larger. This means that while it is expected there will be additional diversity within a potential future high penetration solar fleet, the fact that larger units are coming online may dampen the diversity benefit. The uncertainty surrounding future diversity benefit further supports the need to update this Study every two years as laid out in Mr. Snider's testimony.

Q. DISCUSS THE ANCILLARY SERVICE COST IMPACT OF EACH SOLAR PENETRATION LEVEL FOR DEC.

A. As shown in Figure 4, the costs of the 26 MW of required load following to meet the $LOLE_{FLEX}$ requirement of 0.1 events per year in the "Existing plus Transition" solar penetration is \$1.10/MWh. As discussed previously, this cost delta is the difference between two scenarios with the "Existing plus Transition" solar included where only the load following assumption changes. This cost in dollars is then divided by the solar generation included in the "Existing plus Transition" scenario. The average ancillary service cost impact of the "Existing plus Transition" and "Tranche 1" is \$1.37/MWh, which is slightly higher than the cost for the "Existing plus Transition" alone. The "+1,500 MW" values begin to increase exponentially. While the "+1,500 MW 75% volatility" and the "+1,500 MW" values are much more uncertain, these two results represent bookends around the intra hour volatility assumptions for these high penetration scenarios.

Q. PLEASE DISCUSS THE DIFFERENCE BETWEEN THE AVERAGE AND INCREMENTAL ANCILLARY SERVICE COSTS, AS QUANTIFIED IN SECTIONS IV AND V OF THE STUDY.

A. Table 20 of the Study and Figure 4 above present both the "average" and "incremental" cost of adding ancillary services to maintain baseline system reliability as solar penetration increases. The average ancillary service cost represents the cost impacts allocated or "averaged" across the entire solar fleet simulated at each penetration level for DEP and DEC. For example, in the "Tranche 1" analysis for DEC, the $1.37/MWh average value represents the additional ancillary service costs required for the "Existing plus Transition" and "Tranche 1" solar. The incremental ancillary service costs represent the costs allocated only to the 680 "Tranche 1" MW. For DEC the incremental cost of adding "Tranche 1" is $1.67/MWh.

Q. PLEASE ALSO DISCUSS THE RENEWABLE CURTAILMENTS IN THE DEC STUDY.

A. As explained previously, the need to curtail renewable generation also increases as additional load following reserves are added because minimum generation levels of the conventional fleet are higher. Renewable curtailments in the DEC study are less than 1% of the total solar output in the "Existing plus Transition" and "Tranche 1" penetration levels. In the

"+1,500 MW" scenario, the renewable curtailment increases to between 1.9% and 3.8% of the total solar output.

Q. NOW PLEASE DISCUSS THE ADDITIONAL ANCILLARY SERVICE REQUIREMENTS NEEDED TO MEET AN $\mathrm{LOLE}_{\mathrm{FLEX}}$ OF 0.1 FOR DEP AT EACH SOLAR PENETRATION LEVEL STUDIED.

A. Figure 5 below and Table 21 of the Study present the ancillary service study impact results for DEP. The results show that 166 additional MW of load following reserves were required for the "Existing plus Transition" level of solar to meet the system reliability that was represented in the no solar case. After "Tranche 1" was added, a total of 192 MW of load following were required. For the "+1,500 MW" of solar, the load following requirements are above 500 MW.

Figure 5. DEP Study Results

	DEP No Solar	DEP Existing plus Transition	DEP Tranche 1	DEP Add 1,500 MW 75%	DEP Add 1,500 MW
		Solar Scenario			
Incremental Solar MW	0	2,950	160	1,500	1,500
Total Solar MW MW	0	2,950	3,110	4,610	4,610
LOLE Flex Events Per Year	0.107	0.10	0.10	0.10	0.10
Average Ancillary Service Cost Impact $/MWh	0	2.39	2.64	9.72	14.91
Incremental Ancillary Service Cost Impact $/MWh	0	2.39	6.80	23.24	38.34
Total Load Following Addition MW	0	166	192	589	832
Additional Renewable Curtailment MWh	0	188,827	246,582	1,428,797	1,921,068
Renewable Generation MWh	0	5,614,112	5,945,439	9,059,760	9,059,760
% of Renewable Curtailed %	0	3.36%	4.15%	15.77%	21.2%
Solar Volatility Assumption	Base	Base	Base	75% of Base	Base

Q. DISCUSS THE ANCILLARY SERVICE COST IMPACT OF EACH SOLAR PENETRATION LEVEL FOR DEP.

A. A shown in Figure 5, the costs of the 166 MW of required load following to meet the LOLE_{FLEX} requirement of 0.1 events per year in the "Existing plus Transition" solar penetration is $2.39/MWh. The average ancillary service cost impact of the "Existing plus Transition" and "Tranche 1" solar is $2.64/MWh which is slightly higher than the cost for the "Existing plus Transition" alone. Costs for the "+1,500 MW 75% volatility" and "+1,500 MW" penetration levels begin to increase exponentially. Similar to the DEC results, these two results represent bookends around the intra hour volatility assumptions for these high penetration scenarios.

Q. DISCUSS THE AVERAGE VERSUS INCREMENTAL ANCILLARY SERVICE COST RESULTS FOR DEP.

A. As I mentioned above, the average ancillary service cost represents the cost impacts allocated across the entire solar fleet simulated at each penetration level. For example, in the Tranche 1 analysis for DEP, the \$2.64/MWh value represents the additional ancillary service costs required for the "Existing plus Transition" and "Tranche 1" solar. However, given the greater level of existing solar operating in DEP compared to DEC today, the incremental ancillary service cost for Tranche 1 alone is significantly greater at \$6.80/MWh.

Q. DISCUSS THE RENEWABLE CURTAILMENT IN THE DEP STUDY AND WHY IT INCREASES AS SOLAR PENETRATION INCREASES.

A. The renewable curtailments in the DEP study are 3.36% of the total solar for the "Existing plus Transition" solar penetration level and 4.15% when "Tranche 1" is included. The trends show that renewable curtailment ramps up exponentially as additional solar is added to the system. In the "+1,500 MW" level, the percentages jump to greater than 15%. This penetration level includes 4,610 MW of solar on a system with a peak load of approximately 14,000 MW.

Q. PLEASE EXPLAIN WHY IT WAS APPROPRIATE TO TREAT DEC AND DEP AS ISLANDS IN THE STUDY.

A. As discussed extensively in the Companies' reply comments,[5] the DEC and DEP systems were modeled as islands for this Study in order to capture the incremental impact of adding solar generation to each system. Each Company is responsible for meeting NERC requirements within its own BA. I have been advised by the Companies' system operators that while the Joint Dispatch Agreement between DEC and DEP does allow for excess energy transfers of non-firm energy, it does not support the firm capacity that would be required to provide the intra hour ancillary services needed to manage the variability in solar output.

Although DEC and DEP are interconnected with surrounding regions, additional ancillary services are necessary to integrate solar generation, and these services have a cost. Further, it is inappropriate for the Companies to assume that they are able to rely upon surrounding neighbors for this type of service. While the Companies could hypothetically contract for real-time regulation service from designated generating units in other BAs, this alternative would require securing firm transmission service as well as capacity and energy contracts from the neighboring generating facility owners—both of which would come at a cost. For these reasons, it is appropriate that the Study models the Companies as islands.

[5] DEC and DEP Reply Comments, at 86-91 (filed Mar. 27, 2019).

Q. DO THE RESULTS CHANGE SIGNIFICANTLY IF THE UTILITIES ARE COMBINED AND ALLOWED TO SHARE RESOURCES?

A. No, not in my opinion. At the request of the Public Staff, Astrapé performed a sensitivity analysis combining the load and solar volatility assumptions of the two balancing authorities ("BA") and assumed full optimization of resources with no transmission limit between the two BAs. In effect, this combined DEC/DEP BA sensitivity provides an unrealistic "best-case" scenario for integrating the Existing plus Transition solar capacity. Figure 6 shows those results, which provide a modest 15% decrease in the ancillary service costs. Astrapé does not agree with this approach but simply wanted to demonstrate that the results did not change significantly. The DEC average ancillary service cost impact of "Existing plus Transition" capacity shifts from $1.10/MWh to $0.94/MWh while DEP shifts from $2.39/MWh to $2.03/MWh.

Figure 6.

	Solar Capacity (MW)	**Ancillary Service Cost Impacts $/MWh**
DEP Island - Base Case	2,950	2.39
DEC Island - Base Case	840	1.10
Weighted Average of the Island Scenarios	3,790	2.11
DEP – Combined Case	2,950	2.03
DEC – Combined Case	840	0.94
Weighted Average of the Combined Case	3,790	1.80

Q. IS LOLE$_{FLEX}$ OF 0.1 UNREASONABLY STRINGENT WHEN COMPARED TO OTHER STUDIES, AND DOES A LESS STRINGENT METRIC IMPACT THE RESULTS SIGNIFICANTLY?

A. Astrapé spent significant time reviewing the Idaho Integration Study[6] introduced by the Southern Alliance for Clean Energy in their initial comments. In the Idaho Integration Study, a different method was used to determine the amount of additional load following reserves required as solar penetration increased. The Idaho Integration Study determined the additional load following required by analyzing historical five-minute solar data and calculating the 99th percentile difference between the hour ahead average and actual solar output. The study then applied calculated discounts based on diversity benefits of load and wind volatility to calculate the load following requirements.

The Idaho Integration Study highlights that the selected 99% probability metric is "relatively immaterial" because the fact that the system is staying at the same reliability is the most important component.[7] The Astrapé study maintains an LOLE$_{FLEX}$ of 0.1 events per year before and after the solar is added to maintain the same reliability of the system similar to the Idaho Integration Study. The LOLE$_{FLEX}$ of 0.1 does not mean that

---

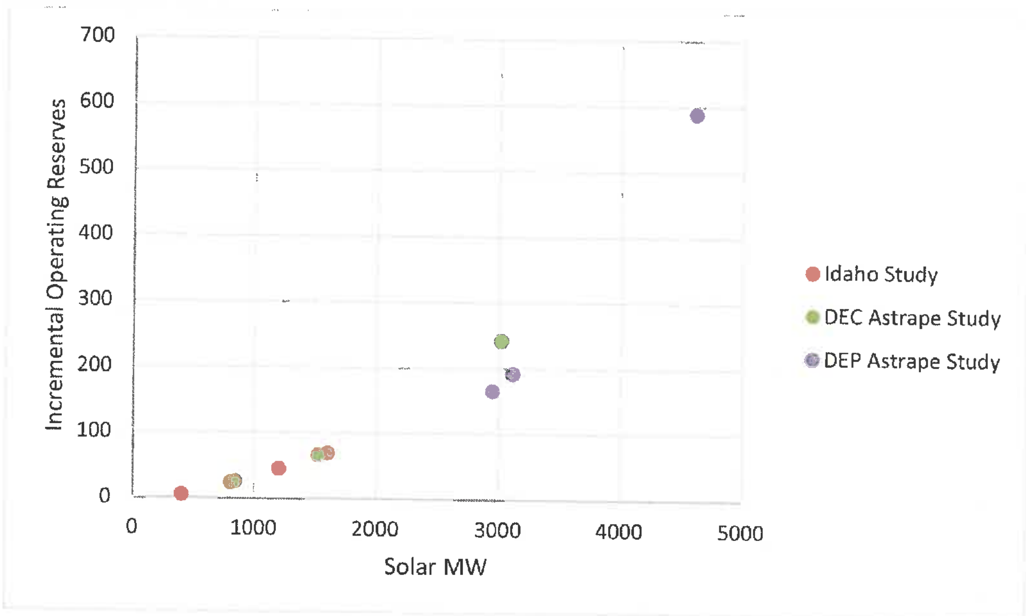
[6] Solar Integration Study Report, Idaho Power, April 2016, http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1611/20160506SOLAR%20INTEGRATION%20STU DY%20REPORT.PDF ("Idaho Integration Study").
[7] Idaho Integration Study, at 8.

the Astrapé Study is adding enough load following reserves to capture all but one five-minute solar deviation in 10 years. If this were the case, the load following increases would reflect the worst five-minute solar deviation reported in the intra hour volatility figures from the Study.[8] Instead, because SERVM is a full production cost model that commits and dispatches generators to load and captures the volatility of load, solar, and generator outages together within the simulations, there are some periods where the pre-existing operating reserves in the base case (no solar case) are able to absorb a significant amount of the intra hour solar volatility modeled in the different solar penetration levels. There are also some hours where the load volatility may offset the solar volatility. Other combinations of factors in the Astrapé Study can occur that make the $LOLE_{FLEX}$ of 0.1 far less stringent than adding reserves to capture all but one five-minute solar deviation in 10 years. If Astrapé had added reserves consistent with the largest five-minute unexpected solar deviation in 10 years for DEC, more than 109 MW of reserves would have been required in the DEC "Existing plus Transition" case rather than the 26 MW that was identified through the SERVM simulations. Similarly, if Astrapé had added reserves consistent with the largest five-minute unexpected solar deviation in 10 years for DEP, more than 354 MW of reserves would have been required in the DEP "Existing plus Transition" case rather than the 166 MW that was identified through the SERVM simulations.

[8] *See* Solar Ancillary Service Study, at Tables 10-17.

While two different methods were utilized, Astrapé compared the studies in the Figure 7 below. The results show that as a function of solar penetration, the additional load following reserves required were similar. For example, the DEC Study and the Idaho Study both have data points at roughly 800 MW of solar and 1,500 MW of solar. For these levels of solar, the incremental load following reserves required is nearly the same between the two studies.

Figure 7.



Based on this review and comparison made to the Idaho Study, Astrapé believes that the LOLE$_{FLEX}$ of 0.1 events per year is reasonable and appropriate.

IV. USE OF THE SOLAR ANCILLARY SERVICE STUDY RESULTS

Q. PLEASE DISCUSS HOW THE COMPANIES HAVE USED THE RESULTS OF THE STUDY TO DETERMINE AN INTEGRATION SERVICES CHARGE TO BE APPLIED TO INTERMITTENT SOLAR GENERATORS.

A. As explained in the testimony of Witness Glen A. Snider, the average ancillary service cost impact for the "Existing plus Transition" solar penetration level was selected to establish the integration services charge to be applied to intermittent solar generators. This represents $1.10/MWh for DEC and $2.39/MWh for DEP.

Q. DO YOU BELIEVE THE COMPANIES HAVE APPROPRIATELY USED THE RESULTS OF YOUR STUDY?

A. Yes.

Q. WERE ANY ADDITIONAL MODEL RUNS COMPLETED TO DETERMINE A POTENTIAL COST CAP?

A. Yes. As directed by the Companies, and as further discussed by Witnesses Snider and Steven B. Wheeler, Astrapé performed additional model simulations to calculate the incremental ancillary service cost impact of the last 100 MW of solar expected to be installed by the end of 2020, based upon DEC's and DEP's IRPs. The DEC IRP forecasts a total solar penetration at the end of 2020 of 1,588 MW while the DEP IRP forecasts 3,061 MW. The incremental ancillary service cost impact of the last 100 MW for each of these solar penetrations was $3.22/MWh for DEC and

$6.70/MWh for DEP. The same modeling framework, inputs, and calculations that were used to calculate the average and incremental results presented in Figures 4 and 5 were used for these additional calculations.

Q. IS THE COMPANIES' RECOMMENDATION TO UPDATE ITS ANALYSIS OF ANCILLARY SERVICE COST IMPACTS EVERY TWO YEARS REASONABLE?

A. Yes. As fuel prices, resource mixes, and solar volatility assumptions change, the changes can be incorporated into future studies. For example, if significant storage is added to the DEC or DEP system, then it would be expected that the ancillary service cost impacts may decrease whereas an increase in gas prices will put upward pressure on the ancillary service cost impacts. Two-year studies also allow the Companies to ensure any prospective diversity benefit among the solar fleet is also captured.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 158

In the Matter of:	)	
	)	**REBUTTAL TESTIMONY OF**
Biennial Determination of Avoided Cost	)	**NICK WINTERMANTEL**
Rates for Electric Utility Purchases from	)	**ON BEHALF OF DUKE ENERGY**
Qualifying Facilities - 2018	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Nick Wintermantel, and my business address is 1935 Hoover Court, Hoover, AL 35226.

Q. HAVE YOU SUBMITTED DIRECT TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I previously filed direct testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke") on May 21, 2019.

Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

A. My rebuttal testimony responds to the direct testimony submitted by the Public Staff, Southern Alliance for Clean Energy ("SACE"), and North Carolina Sustainable Energy Association ("NCSEA") on June 21, 2019 concerning the Astrapé Ancillary Service Study ("Astrapé Study" or "Study") performed on behalf of the Companies.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR REBUTTAL TESTIMONY?

A. No.

I. RESPONSE TO PUBLIC STAFF

Q. PLEASE DESCRIBE YOUR RECENT EFFORTS TO RESOLVE THE PUBLIC STAFF'S CONCERNS REGARDING THE ASTRAPÉ STUDY, WHICH DUKE RELIED UPON TO DEVELOP THE INTEGRATION SERVICES CHARGE.

A. The Companies and Astrapé held several telephone conferences with the Public Staff to demonstrate the validity of the Study and to address the Public Staff's initial comments and concerns. These concerns included (1) modeling DEC and DEP as islands in the Study; (2) justification for the base ("no solar") case leaving out the utility owned solar; (3) the limited amount of 5-minute solar volatility data, especially in projecting future solar penetration levels; (4) the inclusion of load following and the exclusion of other types of ancillary services, and (5) the assertion, based on Mr. Kirby's analysis, that that the reliability standard Duke used was too stringent. Each of the concerns were addressed in detail and, where appropriate, Public Staff requested, and the Companies provided, additional data and sensitivities to help better explain the Study and the impact of specific assumptions.

Q. **WHAT WAS THE RESULT OF THIS COLLABORATION WITH THE PUBLIC STAFF?**

A. As explained by Public Staff Witness Jeffrey Thomas,[1] each of the Public Staff's concerns have been resolved, and the Public Staff has agreed in the Solar Integration Services Charge Stipulation ("SISC Stipulation") to support the methodologies and assumptions underlying the Ancillary Service Study. The Public Staff has also reviewed seven additional renewable integration studies to inform its determination that the Astrapé Study is "generally reasonable and within the range of the studies."[2] As a

---

[1] Public Staff Thomas Direct Testimony, at 14-17.
[2] *Id.* at 9.

result of these collaborative efforts and analyses, Duke and the Public Staff agreed to the SISC Stipulation, as filed with the North Carolina Utilities Commission on May 21, 2019.

Q. PLEASE DISCUSS THE PUBLIC STAFF'S PREVIOUSLY-STATED CONCERNS THAT THE STIPULATING PARTIES WERE ABLE TO RESOLVE.

A. I discuss three specific concerns that both the Public Staff and Mr. Kirby on behalf of SACE have identified and describe how the Companies and Public Staff were able to resolve the concerns.

(1) Regarding modeling DEC and DEP as islands, after detailed discussions with Duke's system operations, the Public Staff confirmed that scheduling for additional load following reserves is undertaken separately and independently for the DEC and DEP Balancing Authorities ("BAs"), and that DEC and DEP are each responsible for their own reserves. Additionally, Mr. Thomas testified that the Public Staff confirmed that although the Joint Dispatch Agreement between DEC and DEP allows for excess energy transfers of non-firm energy, it does not support the firm capacity that would be required to provide the intra-hour ancillary services needed to manage the variability in solar output.[3] Witness Thomas also stated that through the Public Staff's review of the other renewable integration studies, the Public Staff agrees "that modeling utilities as load islands with limited or no ability to rely upon neighboring utilities for real-

[3] Public Staff Thomas Direct Testimony, at 9-10.

time solar and wind output fluctuations is not uncommon." For these reasons, the Public Staff found Astrapé's modeling of the DEC and DEP BAs as islands to be appropriate.

(2) Regarding intra-hour volatility assumptions, the Public Staff's major concerns were the Study's high solar penetration levels. The Public Staff still has concerns with the volatility data associated with the higher penetration solar data, but understands that the Study results are not used to set the ancillary service cost in the avoided cost rates. Therefore, as Mr. Thomas testifies, the Public Staff believes that the high solar penetration intra-hour volatility data will resolve itself as new solar facilities are constructed and additional intra-hour data is collected.[4] As highlighted in the Astrapé Study, Astrapé and Duke have also self-identified that the higher solar penetration ancillary service costs to be experienced farther into the future are more uncertain, which is why Duke has recommended that the study be performed on a biennial basis to allow intra-hour volatility data and other assumptions to be updated.

(3) Last, regarding the $\text{LOLE}_{\text{FLEX}}$ reliability metric being too stringent, Astrapé provided additional calculations that relaxed the constraint by three times and then by 10 times the original metric and demonstrated that the ancillary service costs changed only slightly. As Mr. Thomas explains, "increasing the allowed frequency of events in which load could not be met due to ramping constraints by 10-fold (in the case of 1.0

[4] Astrapé Study, at 53.

LOLE$_{FLEX}$) reduced the average Solar Integration Charge by 6.2% in DEC and 1.9% DEP.... In addition, the quantity of incremental load following reserves appears to be reasonable compared to the capacity of solar resources on the system."[5]

Q. DOES PUBLIC STAFF WITNESS THOMAS MAKE ANY SPECIFIC FINDINGS OR CONCLUSIONS REGARDING THE ASTRAPÉ STUDY METHODOLGY?

A. Mr. Thomas concludes "that the methodology used to quantify the [Integration Services Charge] is reasonable and that assessing this charge on the QFs is appropriate."[6]

II. RESPONSE TO SACE WITNESS KIRBY

Q. SACE WITNESS BRENDAN KIRBY'S TESTIMONY CONTINUES TO DISPUTE THE APPROPRIATENESS OF THE LOLE$_{FLEX}$ METRIC.[7] PLEASE REINTRODUCE THE LOLE$_{FLEX}$ METRIC USED TO QUANTIFY THE NEED FOR ADDITIONAL ANCILLARY SERVICES AS ADDITIONAL SOLAR IS ADDED TO THE SYSTEM.

A. As stated in my direct testimony[8], "[t]he LOLE$_{FLEX}$ reliability metric is the number of loss of load events due to system flexibility constraints, calculated in events per year."

[5] Public Staff Thomas Direct Testimony, at 13-14.
[6] *Id.* at 14.
[7] SACE Kirby Direct Testimony, at 12-18.
[8] Duke Wintermantel Direct Testimony, at 16.

Q. MR. KIRBY CRITICIZES[9] THE FACT THAT THE LOLE$_{FLEX}$ ESSENTIALLY REQUIRES THE SYSTEM TO MAINTAIN ENOUGH RAMPING CAPABILITY TO MATCH 5-MINUTE LOAD RAMPS IN ALL BUT ONE PERIOD EVERY 10 YEARS. DOES THIS MEAN THAT THE SIMULATIONS ARE SOLVING FOR A SYSTEM THAT WILL ONLY HAVE ONE 5-MINUTE BALANCING DEVIATION EVERY 10 YEARS?

A. No. And, this is a critically important distinction that Mr. Kirby continues to ignore, despite the fact that Duke addressed this point in Reply Comments and I re-explained this point in my direct testimony.[10] SERVM models the Duke systems assuming perfect foresight for the next 5-minute time step, meaning net load is frozen and generators are allowed to catch up to load. Given this perfect foresight, SERVM should attempt to carry enough reserves to match the 5-minute ramps in all but one period in 10 years. In reality, operators never have perfect foresight, so many 5-minute balancing deviations are expected every year.

Further, if Astrapé had added reserves consistent with the largest 5-minute unexpected solar deviation in 10 years for DEC, more than 109 MW of load following reserves would have been required in the DEC "Existing plus Transition" case rather than the 26 MW that was identified through the SERVM simulations. If Astrapé had added reserves consistent with the

[9] SACE Kirby Direct Testimony, at 12-13.
[10] *Id.* at 12-15; Duke Reply Comments, at 102-106.

largest 5-minute unexpected solar deviation in 10 years for DEP, more than 354 MW of reserves would have been required in the DEP "Existing plus Transition" case rather than the 166 MW that was identified through the SERVM simulations which utilized the $LOLE_{FLEX}$ metric.

Q. HOW MANY 5-MINUTE BALANCING DEVIATIONS WOULD BE EXPECTED IN A SYSTEM TARGETING 0.1 $LOLE_{FLEX}$?

A. SERVM is not capable of identifying the frequency of 5-minute balancing deviations. However, since the load following reserves held in the no solar case compare well with historical reserves for the Companies before the addition of solar, it is expected that balancing deviations in both the "no solar" and "with solar" cases with the targeted load following identified by SERVM would be similar to what DEC and DEP have experienced historically.

Q. DO THE BALANCING REQUIREMENTS IMPOSED BY THE NERC CONTROL PERFORMANCE STANDARD 1 ("CPS1") AND BALANCING AUTHORITY ACE LIMIT ("BAAL") STANDARDS CONFLICT WITH THE 0.1 $LOLE_{FLEX}$ METRIC TARGETED BY SERVM?

A. No. The balancing requirements imposed by NERC do not conflict with the 0.1 $LOLE_{FLEX}$ metric targeted by SERVM. The operating reserves targeted in SERVM required to meet the 0.1 $LOLE_{FLEX}$ are comparable to historical reserves provided by DEC and DEP, so future compliance with the NERC CPS1 and BAAL standards is expected to be consistent with historical compliance.

Q. IS THE 0.1 $\mathrm{LOLE}_{\mathrm{FLEX}}$ STANDARD MORE STRINGENT THAN THE NERC CPS1 AND BAAL STANDARDS?

A. No. $\mathrm{LOLE}_{\mathrm{FLEX}}$ is not a measure of a system's compliance with NERC CPS1 and BAAL standards. $\mathrm{LOLE}_{\mathrm{FLEX}}$ is intended to measure the ability of a system to carry enough reserves to follow its net load given 5-minute ahead perfect foresight. However, the NERC standards and $\mathrm{LOLE}_{\mathrm{FLEX}}$ should be correlated. If $\mathrm{LOLE}_{\mathrm{FLEX}}$ is allowed to increase substantially, it is expected that NERC CPS1 and BAAL standards would be violated more often.

Q. BASED ON SACE WITNESS KIRBY'S ASSERTION THAT THE $\mathrm{LOLE}_{\mathrm{FLEX}}$ METRIC IS TOO STRINGENT, HOW WOULD THE RESULTS CHANGE IF THE $\mathrm{LOLE}_{\mathrm{FLEX}}$ METRIC WERE RELAXED?

A. The Public Staff raised a similar question and Astrapé performed additional calculations, which demonstrated that if flexibility reliability were measured at 1.0 events per year, the average ancillary service costs used in avoided cost rates would only decrease from \$1.10/MWh to \$1.03/MWh for DEC and \$2.39/MWh to \$2.35/MWh for DEP. This analysis shows the impact in ancillary services costs if the original 0.1 event per year metric is relaxed by 10-fold. Given that the cost differentials are quite small, and that the reserves held in the 0.1 $\mathrm{LOLE}_{\mathrm{FLEX}}$ base case compare well with historical reserves, Astrapé believes a 0.1 $LOLE_{FLEX}$ benchmark is reasonable and appropriate.

Q. IN YOUR OPINION, IS MR. KIRBY'S OBJECTION TO THE SUBJECTIVE NATURE OF THE $LOLE_{FLEX}$ METRIC OVERSTATED?

A. Yes. As Duke pointed out in Reply Comments,[11] the Solar Integration Study Report produced by Idaho Power ("Idaho Integration Study")[12] and favorably cited by Mr. Kirby[13] specifically recognized that the selected reliability level is "relatively immaterial" to the integration cost since both the base case and change case are subject to the same requirement. Additionally, the sensitivity performed for the Public Staff showed that relaxing the $LOLE_{FLEX}$ metric did not have a substantial impact on the results.

Q. IN YOUR OPINION, IS IT FEASIBLE TO MODEL ANCILLARY SERVICES USING THE NERC CPS1 AND BAAL STANDARDS ?

A. No. As stated in the Duke Reply Comments, neither the Companies nor Astrapé are aware of any recently-completed integration studies or currently-available modeling techniques that have attempted to exactly mimic the NERC CPS1 and BAAL standards.[14]

---

[11] Duke Reply Comments, at 101.
[12] Solar Integration Study Report, Idaho Power, April 2016, *accessible at* http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1611/20160506SOLAR%20INTEGRATION%20 STUDY%20REPORT.PDF ("Idaho Integration Study").
[13] SACE Kirby Direct Testimony, at 8.
[14] Duke Reply Comments, at 97-98.

Q. HAS MR. KIRBY EXPRESSED AN OPINION ON WHETHER MODELING ANCILLARY SERVICES USING THE NERC CPS1 AND BAAL STANDARDS IS FEASIBLE?

A. Yes. Mr. Kirby stated in his affidavit that actually modeling the NERC BAAL standards "is currently an infeasible modeling effort."[15] However, his direct testimony now perplexingly discusses the NERC CPS1 and BAAL standards as potential alternative modeling methodologies before again pointing to the Idaho Integration Study as a "feasible way of modeling actual balancing requirement."[16] For the avoidance of doubt, the Idaho Integration Study does not model the NERC reliability standards and, as I explain below, undertakes a statistical estimation of required operating reserve increases similar to that employed in Duke's Study and most other integration cost studies that Astrapé is aware of.

Q. MR. KIRBY CITES THE IDAHO INTEGRATION STUDY AS AN APPROPRIATE STUDY FOR SEVERAL REASONS.[17] PLEASE EXPLAIN HOW THE ASTRAPÉ STUDY COMPARES TO THE METHODOLOGY OF THE IDAHO INTEGRATION STUDY.

A. Mr. Kirby argues that the Idaho Integration Study is reasonable for two reasons. First, he points to the fact that the study "employed production cost modeling with reserve requirements to maintain pre-solar and –wind

---

[15] SACE Initial Comments, at Attachment A, at 10.
[16] SACE Kirby Direct Testimony, at 20.
[17] *Id.* at 35-39.

reliability levels."[18] While Astrapé relied upon the $LOLE_{FLEX}$ metric and more granular SERVM model, the Astrapé Study employs a generally similar methodology, making it comparable to the Idaho Integration Study. Specifically, within the SERVM model, load following requirements were adjusted to maintain the same pre-solar reliability level.

Mr. Kirby then argues that the Idaho Integration Study is appropriate because it employs "targeted reserves sufficient to compensate for 99% of the 5-minute balancing deviations—in other words it allowed a cumulative 90 hours per year of deviations."[19] As to this point, Mr. Kirby suggests that the Idaho Integration Study is much more reasonable because it allows for 90 hours of balancing deviations versus the Astrapé Study's use of the $LOLE_{FLEX}$ standard of 0.1 events in 10 years.[20] While the studies have slightly different approaches to determining the increases in load following reserves, the two studies actually utilize similar overall methodologies but enforce a different reliability metric. Although ignored by Witness Kirby, the Idaho Integration Study clearly states that the reliability level is immaterial as long it is the same in the base case with no solar and the change case with solar.

To explain further, the Idaho Integration Study determines additional operating reserve requirements outside of a production cost model through statistical analysis of 5-minute solar deviations. Through

[18] *Id.* at Kirby Exhibit B, at 11.
[19] *Id.*
[20] *Id.* at 35-39.

that statistical analysis, 90 hours of balancing deviations are targeted representing the 99^{th} percentile (one -half percent at each tail) to determine the operating reserve increase. The Idaho Integration Study next simulates a production cost model with the increase in operating reserves similar to the Astrapé Study to determine the costs of those operating reserves.[21]

Rather than performing statistical analysis outside of the production cost model, the Astrapé Study determines the increase in load following reserves by modeling intra-hour volatility for load and solar within the SERVM simulations. In other words, 5-minute solar volatility data is a direct input into the SERVM model rather than the calculations being performed on the volatility data exterior to the production cost model. The SERVM model then commits and dispatches resources to load on a 5-minute time step testing whether or not the generators can meet net load with the current load following assumptions. If net load on a 5-minute time step cannot be met due to a shortage of load following reserves, then a LOLE$_{FLEX}$ event occurs. Astrapé determines the increase in load following reserves due to incremental solar by ensuring the LOLE$_{FLEX}$ of 0.1 events per year is maintained before and after the solar is added.

To ensure the LOLE$_{FLEX}$ of 0.1 events per year was not too stringent, Astrapé compared modeled operating reserves at 0.1 LOLE$_{FLEX}$ to historical operating reserves and found them comparable. As stated above, Astrapé

[21] Based on Astrapé's review, the Idaho study does not dispatch on an intra-hour time step whereas Astrapé's model simulates on a 5-minute time step.

would expect NERC compliance in these modeled runs since it reflects similar historical operating reserve levels. However, Astrapé would also expect NERC balancing deviations to be greater than 1 event in 10 years. This is because in real time, operators are constantly chasing load on a minute to minute and second by second basis—which is not captured in either the Idaho or Astrapé renewable integration studies. While Astrapé and the Companies believe the 0.1 $LOLE_{FLEX}$ metric is appropriate for this study, the sensitivities relaxing the $LOLE_{FLEX}$ metric by 10-fold further prove that the reliability metric is immaterial, as also indicated in the Idaho Integration Study report.

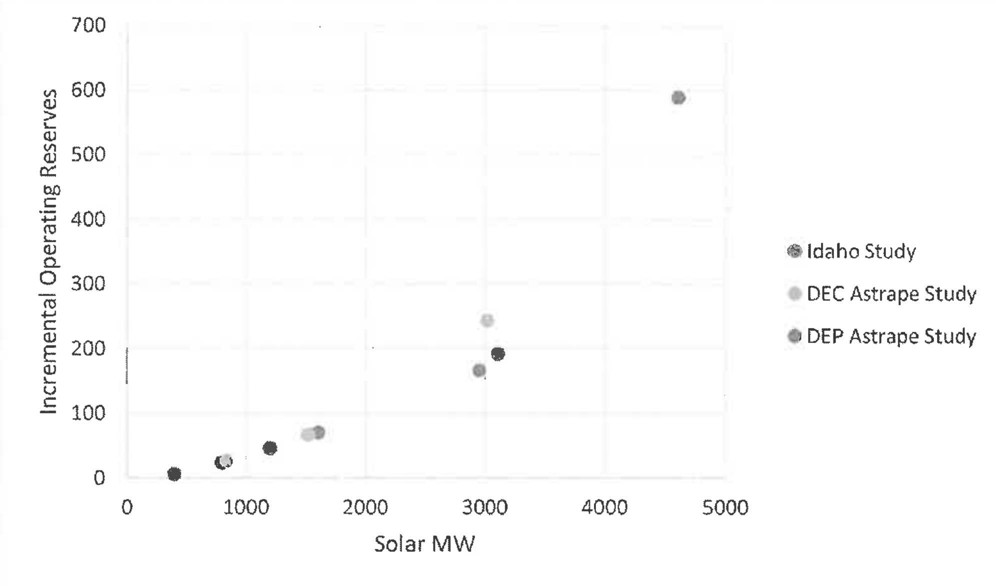
To further compare the Idaho Integration Study approach to the Astrapé Study approach, Astrapé took the 99^{th} percentile of the 5-minute volatility external to the SERVM simulations as is similar to the Idaho Integration Study. The result was that those values suggest a 92 MW load following increase for DEC and a 295 MW following increase for DEP. Thus, these values are much greater than the load following increases determined by SERVM, which were 26 MW for DEC and 166 MW for DEP. Even if Astrapé applied the wind and load diversity discounts identified in the Idaho Integration Study based on solar penetration, the load following determined utilizing that study's approach would be 23 MW for DEC and 188 MW for DEP. While DEC and DEP do not have wind resources, these discounted load following increases are in line with the 26

MW for DEC and 166 MW for DEP values produced by SERVM and the $LOLE_{FLEX}$ metric. .

Q. DO THE RESULTS OF THE ASTRAPÉ STUDY COMPARE TO THE RESULTS OF THE IDAHO INTEGATION STUDY EVEN THOUGH DIFFERENT RELIABILITY METRICS ARE UTILIZED?

A. Yes. While the Idaho Integration Study calculated incremental load following requirements to meet 90 balancing deviations per year, it is notable that the incremental load following as a function of solar capacity added were similar. As shown in my Figure 1 below and in the Duke Reply Comments, the load following reserves produced by the 99% probability metric and the 0.1 $LOLE_{FLEX}$ methodology produced reasonably similar required increases of operating reserves as a function of solar penetration. If Astrapé's $LOLE_{FLEX}$ metric was too stringent, the required reserves would not compare so favorably between the two studies.

Figure 1



Therefore, Mr. Kirby's attempt to frame the Astrapé Study's $LOLE_{FLEX}$ metric as flawed and overly conservative as compared to the Idaho Integration Study should be rejected.

Q. MR. KIRBY THEN COMPARED THE CALCULATED NEED FOR ADDITIONAL OPERATING RESERVES IDENTIFIED IN THE IDAHO INTEGRATION STUDY TO THAT FROM THE ASTRAPÉ STUDY AS A FUNCTION OF SOLAR PENETRATION AS A PERCENTAGE OF SYSTEM LOAD.[22] IS THIS COMPARISON APPROPRIATE?

A. No. The need for increased operating reserves is primarily driven by the changes in solar volatility. Since solar volatility is simply a function of the nominal size of the solar fleet and not at all related to the size of the system

[22] *Id.* at 36-38.

load, it would be entirely inappropriate to compare incremental operating reserves as a function of the renewable penetration percentage of system load. Put another way, regardless of the size of the system, the utility will still be required to manage the volatility imposed by the incremental solar, and larger BAs must still respond to this volatility in the same manner and to an equivalent extent as smaller BAs. Notably, even the cited Idaho Integration Study recognizes this as it bases the load following increases on the actual incremental solar volatility. For these reasons, Mr. Kirby's comparison of operating reserves based on a function of solar penetration is not appropriate and should be ignored.

Q. MR. KIRBY ATTEMPTS TO DRAW CONCLUSIONS BASED UPON MR. SNIDER'S DIRECT TESTIMONY FIGURE 5 DETAILING EXPERIENCED VOLATILITY ON THE DEP SYSTEM DURING MARCH 2019.[23] IN THE PARTICULAR 10-DAY PERIOD REFERENCED, THE NET LOAD VOLATILITY RANGES FROM 7 MW TO 62 MW. WHAT TIME STEP WAS USED IN THIS MEASURE OF VOLATILITY?

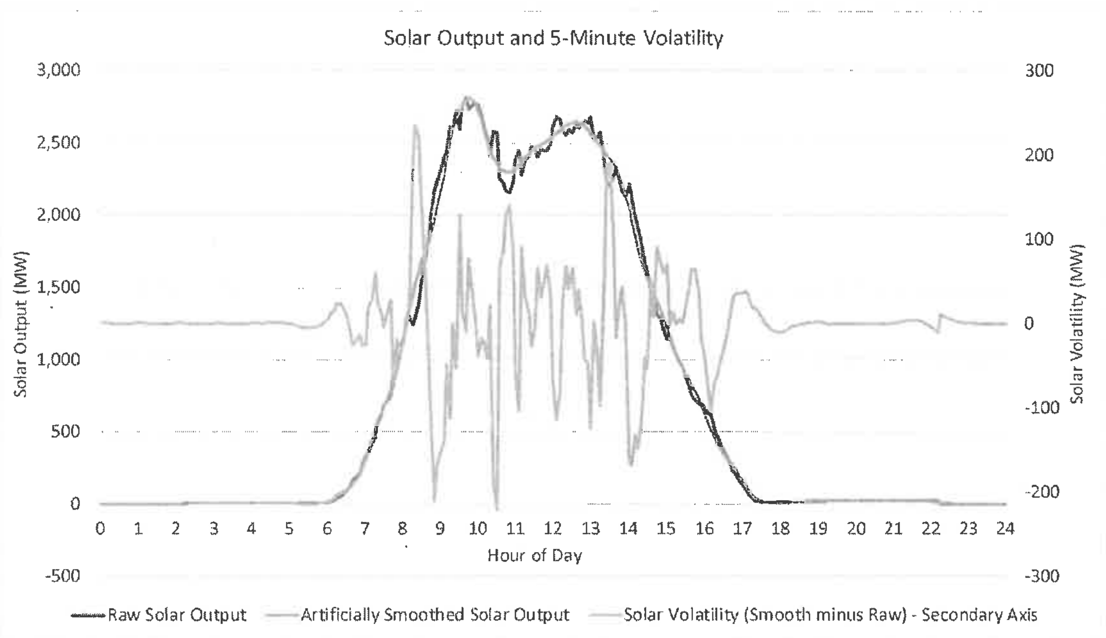
A. The data provided by Mr. Snider was 1-minute data.

Q. IS IT APPROPRIATE TO COMPARE THE NEED FOR LOAD FOLLOWING RESERVES TO 1-MINUTE NET LOAD VOLATILITY?

[23] *Id.* at Kirby Exhibit B, at 12.

A. No. Load following reserves are intended to cover volatility over longer time steps. Using the March 2019 net load data referenced in Mr. Snider's testimony to calculate 5-minute solar volatility demonstrates that solar can move unexpectedly by over 300 MW in a 5-minute time step. The solar output and volatility for March 10th are shown in my Figure 2 below. On this day alone, the 5-minute volatility reached above 230 MW on a 5-minute time step. The blue line represents the raw solar output for that day while the orange line assumes a perfect smooth curve of that day. The gray line (plotted on the secondary axis) is the 5-minute solar volatility and represents the delta between the raw solar output and the perfect smooth curve. This gray line is plotted on the secondary y-axis.

Figure 2



Q. GIVEN THE ANECDOTAL SOLAR VOLATILITY FROM MARCH 2019, ARE THE ADDITIONAL OPERATING RESERVE REQUIREMENTS IDENTIFIED BY THE ASTRAPÉ STUDY APPROPRIATE?

A. Yes. The calculation of additional operating reserves is not as simple as identifying the potential solar volatility range, but it is strongly correlated. Since the max 10-minute volatility in the historical data is much larger than the projected need for additional load following reserves, the results of the Astrapé Study are not inappropriately attempting to address more volatility than should be expected.

Q. IN RESPONSE TO WITNESS KIRBY'S DIRECT TESTIMONY ABOUT MODELING DEC AND DEP AS ISLANDS, DOES MODELING DEC AND DEP AS ISLANDS PRECLUDE THE CONSIDERATION OF THE BENEFITS OF INTERCONNECTED SYSTEMS?

A. No. Astrapé fully recognizes that there are intra-hour benefits of participating in an interconnected system. However, one of the premises of the Astrapé Study is that the Companies should not be assumed to impose a larger burden on other BAs across the Interconnection after adding solar than what was assumed prior to adding solar. To do so would imply that neighboring BAs would bear the costs for Duke's integration of solar. Importantly, SERVM implicitly recognizes the benefits of participating in an interconnected system by modeling reserves in the no-solar case that are comparable to historical reserves.

Q. DO SOLAR INTEGRATION STUDIES IN OTHER JURISDICTIONS ASSUME THAT MORE FREQUENT AND LARGER MAGNITUDE BALANCING DEVIATIONS SHOULD BE ABSORBED BY THEIR RESPECTIVE INTERCONNECTIONS?

A. No. This would be inconsistent with the purpose of the modeling exercise, which is to isolate the impact of adding solar while otherwise holding system reliability constant. For example, the Idaho Integration Study assumes that each BA should have sufficient reserves for all but approximately 90 hours per year.[24] This reserve requirement is imposed in both the base case and change case, so the addition of solar does not relax the respective BA's responsibilities for balancing its own load and generation. Further, there is no indication in the Idaho Integration Study provided by Mr. Kirby that there was reliance on intra-hour assistance from external neighbors.

Q. PLEASE PROVIDE ANY ADDITIONAL REASONS THAT DEC AND DEP WERE MODELED AS ISLANDS.

A. The Companies' Reply Comments[25] extensively discuss several additional reasons explaining why DEC and DEP were modeled as islands. In addition, as stated by Public Staff Witness Thomas,[26] the Public Staff

[24] Idaho Integration Study, at 8.
[25] Duke Reply Comments, at 86-92.
[26] Public Staff Thomas Direct Testimony, at 8-9.

reviewed a number of other renewable integration studies and found "that modeling utilities as load islands with limited or no ability to rely upon neighboring utilities for real-time solar and wind output fluctuations is not uncommon."[27]

Q. SACE WITNESS KIRBY HIGHLIGHTS AN AUTOMATIC GENERATION CONTROL ("AGC") TUNING EFFORT UNDERTAKEN BY DUKE ENERGY'S OPERATIONS STAFF.[28] DOES THE AGC TUNING EFFORT CONFLICT WITH THE ASSUMPTIONS MADE IN THE ASTRAPÉ STUDY?

A. No. As shown in Slide 8 of that presentation,[29] the process and data being discussed surrounds improvement during short term, one-minute deviations and the ability to prevent incorrectly chasing fleeting events. There is no conflict here because the Astrapé Study simply does not penalize solar for one-minute movements since it is conducted on a 5-minute basis with perfect foresight. As discussed previously, and as Mr. Kirby states in his prior affidavit, actually modeling the NERC BAAL standards in real time "is currently an infeasible modeling effort."[30] Again Mr. Kirby attempts to refute the Astrapé Study for not being consistent with NERC BAAL standards even after admitting that it is currently not possible to capture these real time deviations. Further, as the Duke Energy presentation makes

[27] Public Staff Thomas Direct Testimony, at 10.
[28] SACE Kirby Direct Testimony, at 18-19.
[29] Duke Energy Progress presentation to the NERC Operating Committee, June 4-5 2019, "Integration and Monitoring of Distributed Energy Resources in System Operations." SACE Kirby Direct Testimony, at Exhibit D.
[30] SACE Initial Comments, at Attachment A, at 10.

clear, the tuning effort reduces BAAL exceedance minutes by limiting how much the Duke Energy resources respond to sudden, short time duration volatility. This means that the tuning reduces the amount of inappropriate control response occurring as a result of unsustained volt-ampere reactive ("VAR") deviations which cause the Duke Energy resources to make controls changes that are incongruent with the sustained response needs of the system and the intent of the NERC BAAL Standards. The basis of the Astrapé Study is that all reasonable efforts to maintain compliance with NERC BAAL standards will be taken, which is what was demonstrated by the Duke Energy tuning effort.

Q. SACE WITNESS KIRBY ALSO MAINTAINS THAT SOLAR INTRA-HOUR VOLATILITY DECLINES ACCORDING TO THE FOLLOWING FORMULA:

$$1 / \sqrt{\frac{\textit{Existing Plus Transition Capacity}}{\textit{Capacity from Historical Dataset}}}$$ [31]

IS THERE EMPIRICAL EVIDENCE FOR THIS RELATIONSHIP?

A. No. Astrapé performed analysis of the diversity benefit of solar projects within Duke's service territory and identified a different relationship as previously discussed in the Duke Reply Comments.[32] While Astrapé calculates a relatively small amount of diversity benefit during the 2016 – 2018 time period, the Companies emphasize that these projections are not guaranteed to materialize and do not incorporate the impact that large solar

[31] *See* SACE Initial Comments, Attachment 1, at 15.

[32] Duke Reply Comments, at 106-108.

projects may have on the volatility when added to the system. It simply extrapolates the diversity benefit seen over the 2016 – 2018 time period. Given the uncertainty in diversity benefit, the Companies believe it is more appropriate to rely on actual historical data to set ancillary service cost rates at the time of the study and perform updates every two years. New data (not available during the study) will continually provide more guidance on solar volatility assumptions.

III. RESPONSE TO NCSEA WITNESS BEACH

Q. TURNING TO NCSEA WITNESS BEACH'S TESTIMONY, DO YOU AGREE WITH HIS STATEMENT THAT "THERE IS NO EVIDENCE THAT THE HIGH PENETRATION OF WIND AND SOLAR RESOURCES THAT THE CAISO SYSTEM HAS INTEGRATED IN RECENT YEARS HAS INCREASED ANCILLARY SERVICE COSTS"[33]?

A. No. CAISO stated in their 2016 Annual Market Performance Report[34] that "[a]ncillary service costs increased to $119 million, nearly doubling from $62 million in 2015." This represents an increase from 0.7% of total wholesale energy costs in 2015 to about 1.6% in 2016. This was primarily driven by the increased regulation requirements to manage variability of renewable resources."

---

[33] NCSEA Beach Direct Testimony, at 12.

[34] Gabe Murtaugh, *2016 Annual Market Performance Report*, California ISO (May 2017), *available at* http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf.

Q. IS IT YOUR OPINION THAT MR. BEACH PROVIDES A FAIR REPRESENTATION OF THE IMPACT OF WIND AND SOLAR ON CAISO'S APPROACH TO PROCURING REGULATION?

A. No. Mr. Beach states that CAISO temporarily "increased the amount of regulation that it purchases, from 300-400 MW to 600 MW (in both directions), due to a concern with increasing amounts of variable wind and solar generation."[35] He goes on to state subsequent to these purchases, CAISO "has been able to return to the use of just 300-400 MW of regulation."[36] While CAISO has made several modifications to its method for procuring regulation due to wind and solar, in October 2016, "the ISO introduced a new methodology for calculating requirements on an hourly basis. After this modification, regulation costs were about 80 percent higher than the same period in 2015."[37]

IV. RESPONSE TO NCSEA WITNESS JOHNSON

Q. NCSEA WITNESS DR. BEN JOHNSON CLAIMS THAT ASTRAPÉ MODELED ONE SITE PER GRID ZONE WHICH MISSES POTENTIAL DIVERSITY ACROSS THE FLEET.[38] PLEASE RESPOND TO THIS CRITIQUE.

A. In regards to the Study, Astrapé was largely concerned with the intra-hour diversity which would not be captured in the hourly solar profiles that were

---

[35] NCSEA Beach Direct Testimony, at 12-13.
[36] *Id.* at 13.
[37] *2016 Annual Market Performance Report,* at 9.
[38] NCSEA Initial Comments, at Attachment 1, at 23-25.

developed with NREL data. So whether one site or ten sites in each of the thirteen grid locations was modeled, it would not have a significant impact on the Study. The general hourly shapes are very similar within each grid zone. Diversity is captured by looking at the volatility across various aggregations of solar projects that were present in the 5-minute historical data. Since the DEC and DEP historical data already had significant installed capacity, Astrapé was able to construct volatility patterns which reflect expected diversity for the entire future potential portfolios modeled. These volatility patterns were then layered onto the modeled hourly profiles to create intra-hour profiles with reasonable volatility characteristics reflective of the solar portfolio size under consideration.

In regards to the Solar Capacity Value Study, the seasonal allocations are driven by general seasonal net load patterns. Given the substantial amount of solar capacity installed in DEC and DEP, the summer net load has decreased compared to the winter net load. Since there is substantial solar output during the summer afternoons and little to no solar output during the morning winter peak hours, the high net load hours have shifted to the winter morning peaks. Having additional diversity in the solar profiles will not alleviate this winter LOLE risk. Thus, while additional sites could always be modeled, it is unlikely the results would have changed the seasonal allocations produced in the Solar Capacity Value Study or the ancillary service costs produced in the Ancillary Service Study.

Q. MR. JOHNSON ALSO ALLEGES THAT ASTRAPÉ INAPPROPRIATLEY FAILED TO CONSIDER POSSIBLE CONFIGURATIONS WHICH MIGHT ALLEVIATE SOME VOLATILITY.[39] DO YOU AGREE?

A. No. Mr. Johnson mentions inverter loading ratios, the mix of fixed and tracking solar plants, and the integration of energy storage as means to manage solar volatility more cost effectively, and suggests developers will experiment with these configurations to find what produces the most favorable economics.[40] However, solar developers are not massaging their configurations to favorably affect the integration costs of solar.

As candidly recognized by NCSEA's other witness, Carson Harkrader, "solar QFs have no financial incentive to minimize the ancillary service requirements that they impose on the grid"[41] Instead, they pick economic inverter loading ratios—fixed or tracking based on which is more cost effective—and only add storage if it improves their project's economics. Each of these items are most appropriately accounted for in the manner utilized in the Astrapé Study, which included using historical or projected installations as the basis for the inputs rather than tuning the configuration to minimize volatility. Moreover, even if a developer was hypothetically willing to uneconomically vary their configurations, the possibilities Witness Johnson mentions largely exacerbate solar volatility.

[39] *Id.* at 18-25.
[40] NCSEA Initial Comments, Attachment 1, at Exhibit A, at 29.
[41] NCSEA Harkrader Direct Testimony, at 13.

Moving to solar tracking results in more hours where changes in solar output produce volatile net load; increasing inverter loading ratios does not help volatility since most solar volatility occurs during unfavorable solar conditions. The net load ramps in these periods would be steeper with higher inverter loading ratios. Adding energy storage without utility control could also exacerbate volatility if developers shape their combined solar + storage output to maximize revenue. This would occur, for example, where developers were to ramp storage facilities from zero to max at the beginning of higher pricing periods. For these reasons, Astrapé believes modeling the solar projects based on historical and projected data is appropriate.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Q. Mr. Wintermantel, do you have a summary of your testimony for the Commission?

A. Yes, I do.

Q. Would you please present it at this time?

A. Yes. My direct testimony introduces Astrape Consulting's experience and expertise performing resource adequacy and planning studies for Duke and other utilities throughout the country, and then provides an overview of the solar ancillary service study that Astrape recently conducted on behalf of Duke Energy Carolinas and Duke Energy Progress, which I will refer to as the Companies or Duke. This study was concluded in fall 2018 and is being relied upon by Duke witnesses Glen Snider and Steve Wheeler to support the integration services charge presented in the Companies' avoided cost filing.

My direct testimony begins with a discussion of why increases in variable and intermittent solar generation require additional ancillary services, and how those additional ancillary services in the form of load following reserves result in an increase in Duke's costs to run its conventional generating fleet. As solar penetration increases, the intermittency of these resources causes an increase in unexpected movement or intra-hour volatility forcing the conventional fleet to either ramp up or down its generation. For example, a solar facility may suddenly experience cloud cover causing the solar facility to significantly decrease its output over a short period of time. This, in turn, forces the conventional generation fleet to ramp up to meet the unexpected decline in solar generation. To manage these intra-hour ramps, additional load following reserves are required on the system which allow generators additional flexibility to meet these unexpected movements in that load. Ultimately, increasing load following reserves results in increase cost because generators are forced to operate less efficiently and operate further from their maximum output capability. Also, generators are forced to start more frequently causing additional startup costs and maintenance costs.

A simple analogy is that operating the conventional generating fleet to meet the increased ramping requirements and volatility caused by intermittent solar is like driving a car on very narrow and increasingly winding city streets. Cars get better gas mileage from smooth and straight highway driving than city driving. Fuel and operating costs increase because you increasingly have to brake to slow down, change direction, and then accelerate again. Similarly, the conventional fleet is being forced to slow, change direction, and then accelerate again, which increases costs.

Next, my testimony summarizing the modeling framework and inputs used in the study which utilized the same framework used in the Companies' 2012 and 2016 resource adequacy studies. This framework takes into account 36 years of weather history, load uncertainty, and unit performance uncertainty, and dispatches DEP and DEC's resources to serve load on a five-minute time step. I further discuss details around the development of solar profiles, the modeling of intra-hour volatility on load and solar, and the solar penetration studied.

Then I summarized the main premise of the ancillary service study, which is to ensure that reliability is the same before and after additional solar is added. My testimony discusses the LOLE FLEX reliability metric which measures the number of loss-of-load events due to system flexibility constraints, calculated in events per year. Ultimately, LOLE FLEX, as used in the SERVM model, is a measure of the system's ability to satisfy net load obligations, assuming the net load is known 5 minutes before it materializes, and provides a means of measuring whether the system has enough load following reserves. The study determines the appropriate amount of load following reserves to add by forcing system reliability back to the original LOLE FLEX metric of 0.1 events per year.

At Duke's request, Astrape analyzed several increasing solar penetrations including a no-solar scenario, the existing plus transition scenario, Tranche 1 solar, and finally an additional 1,500 megawatts of solar per utility above the Tranche 1 level. While higher solar penetration levels were simulated, it is important to appreciate that these are only projections, and that the Companies are only using the current existing plus transition penetration level, which reflects 840 megawatts in DEC and 2,950 megawatts in DEP, to quantify the integration services charge included in their respective avoided cost rates.

The results of the study for DEC, as presented in Figure 4 of my testimony, shows an additional 26 megawatts of load following reserves were required to maintain reliability and to integrate the existing plus transmission solar penetration level for DEC and it's 840 megawatts. The cost of these 26 megawatts of load following translates into an average ancillary service cost impact of $1.10 per megawatt hour. For DEP, the study identified that 166 megawatts of additional load following reserves were required to maintain reliability and to integrate the existing plus transition solar penetration level for DEP, which included 2,950 megawatts of solar. For DEP, this resulted in an average ancillary service cost impact of $2.39 per megawatt hour. This information is presented in my Figure 5.

My direct testimony concludes with the Companies' use of the study results which utilize the average cost of the existing plus transition solar penetrations for each company, with the cap being set by the incremental ancillary service cost impact of the last 100 megawatts of solar expected to be installed by the end of 2020, based upon the DEC and DEP IRPs. The cap was determined to be $3.22 per megawatt hour for DEC and $6.70 per megawatt hour for DEP.

My rebuttal testimony summarizes the effort of Astrape, Duke, and Public Staff to validate the study and to address the Public Staff's initial comments and concerns. Each of the concerns were addressed in detail through additional sensitivities or data requests ultimately resolving the Public Staff's concerns as discussed in Public Staff Witness Thomas' testimony. These now-resolved concerns, included modeling DEC and DEP as islands, solar intra-hour volatility data, and the assertion by SACE Witness Kirby that the LOLE FLEX reliability standard Astrape utilized was too stringent.

Much of my rebuttal testimony responds to direct testimony from SACE Witness Brendan Kirby and addresses the appropriateness of modeling DEC and DEP as islands, the LOLE FLEX metric, and the solar intra-hour volatility used in the study. I refute his claims by explaining three main reasons as to why it is appropriate to model DEC and DEP as islands as first laid out in the Companies' reply comments. First, the DEC and DEP balancing areas are responsible for their own ancillary service requirements in order to meet NERC standards and would need to purchase firm capacity in order to meet those needs. Second, the Joint Dispatch Agreement, the JDA, between the Companies only supports non-firm economic transactions and is not used for firm capacity transactions required to provide operating reserves. Lastly, Mr. Kirby argues that DEC's and DEP's interconnected operations with other utilities should be recognized as inherently lowering DEC's and DEP's regulating reserve requirements to meet NERC frequent and balancing standards. However, implicit in this assertion is an assumption that Duke should rely more heavily on the operational flexibility of neighboring utilities generating fleets as solar is increasingly added to the Duke systems, and allow more area control error deviations in the "with solar" scenario compared to the "no solar" scenario. However, I disagree with Mr. Kirby's assumption, as it violates the premise that system reliability should be the same before and after solar is added.

Notably, the 2016 Idaho Power Integration Study favorably cited by Mr. Kirby addresses the issue of allowing intra-hour assistance from neighbors in order to lower operating reserve requirements. As seen on page 22 of that study, Idaho Power emphasizes that the energy imbalance market is not expected to trade capacity products; i.e., operating reserves, thus, the capability to satisfy all or part of Idaho Power's reserve requirements through EIM participation is not anticipated.

In response to Mr. Kirby's criticism of Astrape's use of the LOLE FLEX metric compared to the methodology used in the Idaho integration study, I demonstrate, on page 31, Figure 7 of my testimony that the Idaho Integration study provides load following increases similar to that of the Astrape study as a function of solar capacity, even though the studies have differences in methodology. For example, the Idaho study integrates 800 megawatts of solar with 24 megawatts of additional operating reserves which is almost identical to the DEC results which integrate 840 megawatts of solar with 26 megawatts of operating reserves.

My rebuttal testimony also briefly responds to NCSEA Witness Johnson's misplaced concerns with the solar intra-hour diversity relied upon in the study and explains that, since the solar volatility is based on aggregated actual historical solar data on the DEC and DEP systems, the intra-hour solar diversity is captured in the study. Finally, I also respond to NCSEA Witness Beach's assertion that the state of California has not seen increased in ancillary service costs due to intermittent solar and wind resources.

I conclude with the fact that Astrape and

Duke have invested substantial time and effort to develop and support the ancillary service study dating back to the fourth quarter of 2017. Based on analysis in this study and in other studies we have reviewed, there is no refuting that integrating additional solar causes an increase in ancillary services and therefore additional costs. The results of the study to incorporate additional load following reserves resulted in the cost of $1.10 per megawatt hour for DEC and $2.39 per megawatt hour for DEP. It is my opinion that these load following additions and costs are reasonable given the current and protected amounts of solar on the DEC and DEP systems. Further, I agree with Public Staff Witness Thomas' testimony on page 8 which states that, "Duke's proposed integration services charge is generally reasonable and within the range of the other studies," as reviewed by Public Staff. Finally, I would highlight the Companies' commitment in the solar integration services charge stipulation to biennially review and update its ancillary solar service cost impacts to appropriately recognize changed in solar volatility and geographic diversity, resource mix, and gas prices to be recognized in quantifying solar penetration costs as solar penetration increases.

This concludes my summary.

MR. BREITSCHWERDT: Thank you, Mr. Wintermantel. The witness is available for cross-examination.

CROSS EXAMINATION BY MR. SMITH:

Q. Good afternoon, Mr. Wintermantel. My name is Ben Smith. I'm regulatory counsel for NCSEA. I'm going to ask you some questions.

A. Sure.

Q. First you said in your testimony summary that y'all have been working on this since, I think, Q4 of 2017.

When did Duke engine Astrape to make this study?

A. It was -- to the best of my knowledge, it was the fourth quarter 2017, as the summary states, yes.

Q. All right. So I guess my first question is you use the verb validate in your summary. I did notice that throughout the study.

Can you explain how you validated your model?

A. Yeah, sure. Somewhat of an open-ended question, but I think there's been a lot of comments from intervenors that have pushed us to validate it further and further bench, which are good things for the study. We ultimately want an accurate study to depict these costs. But I think some of the particulars that we looked at, for instance, is this LOLE FLEX metric of 0.1, and determining whether that was appropriate based on benchmarking back to historical operating reserves, so in the study.

Q. So I guess maybe I'm thinking of validation in a different say.

I'm asking, you have all these outputs from your model; did you confirm they are reasonable or within the range of what is happening in real practice?

A. Yeah. I think they've been -- it's very validated by just comparing against other studies. I mean, if we look at some of the studies brought up by the intervenors in this docket, they compare very well. And that includes if we look at the Idaho study, the operating reserves that are added in that study are very similar to the solar study. When we look at a neighboring SCE&G study performed by Navigant, the costs of that study are -- or actually our costs are actually quite a bit lower than what they're projecting for lower amounts of solar.

I would also say, you know, we have performed these types of studies backing up across the country, and the LOLE FLEX metric has been used in different jurisdictions.

Q. So essentially, backing up. I guess I'm asking did you compare it against past years of Duke's real world statistics? I mean, Duke theoretically gave you inputs to include in your model, so couldn't you have compared it against what you looked at in past years to see, okay, our outcome here matches historical analysis?

A. Yeah. That's exactly what we did when we looked at operating reserves. So we looked at operating reserves before solar was added. Little to no solar was added back in 2015. We compared those operating reserves to our modeling exercise to ensure that our no solar case in our model, the operating reserves were equivalent.

And really what it does is it says that, in 2015, in the real world, we were reliable with this amount of operating reserves. That in our model, when we model the no-solar case, we should have reasonably the same amount of operating reserves. So that comparison validates, kind of, the beginning step of the study.

Q. So you said 2015 you looked back on. Did you look at 2016? 2014? 2013? Any other years?

A. No, we looked at 2015.

Q. Okay. And why didn't you run it against more years for historical data that Duke could provide to you directly?

A. So, obviously, we could look to as many years as we needed, but that validated that, in that year, there was little solar on the system, and we were able to compare that, and that validated it for us. We are not -- we are not modeling some level of reserves that are exponentially above what has been done in history. And so that would be the no-solar case. And so that sets a specific reliability in the model which sets it at this 0.1 FLEX.

Then the next step is to add solar. When we add solar, and we add that intermittent resource to the model, our LOLE FLEX, our reliability gets worse. So our 0.1 would jump, say, to, for example, 0.3. Then we go back to the model, which had the starting operating reserves based on history, and we add incremental operating reserves until we get back to the original reliability metric. That determines the amount of operating reserves we need to increase. And within the model, it also calculates the production cost of those

operating reserves.
Q. So when you built the model, did you know the average cost based on actual Duke Energy historical data without a simulation?
A. Can you repeat that?
Q. When you built the model, did you know the average cost based on actual Duke Energy historical data without a simulation? Or did you just input it into this simulation based on inputs provided by Duke?
A. Yeah. So we just get inputs from Duke. The resources and load, model them in detail, and put that in the model as an input. So we are modeling the future year. We're modeling 2020, so it makes sense to model the system as we expect in 2020.
Q. Sure. But to validate 2020, you would want to look at years 2018, 2017, 2016, 2015, 2014, correct? To make sure it's accurate on a year-by-year basis for what you're saying the model should show.
A. I mean, there's significant changes from '17, '18, '19, and '20. I mean, we're focused on 2020.
Q. The range of outcomes, right?
A. A range of outcomes? So we're -- I mean, help me understand what you mean when you say -- range of outcomes of what?

Q. I'm asking, when you build a model, and you project what it's going to show in 2020, why wouldn't you verify it against past years on a yearly basis?

A. Are you talking about just total cost in the model, or what exactly are you wanting?

Q. I'm talking about whatever the model shows, and whatever the outcome of the model, why wouldn't you look to make sure the model matches the historical data provided to you by Duke?

A. Yeah. And we did that.

Q. On a yearly basis?

A. On 2015.

Q. Got it. Getting to the question of the base case, why did you not include solar in the base case settings of the model?

A. Because you want a starting point that excludes solar. You want to understand what the reliability of the system looks like without solar, and so that was the starting point.

Q. So the presumption would be that there would be no solar on the system, and rather than what the real world actual scenarios where there is solar on the system, correct?

A. That's right. The objective of the study was to analyze the ancillary service cost of different levels of solar penetration.

Q. When you --

A. So you start at zero, and then you increase in different tranches. And we went substantially high, but I think as we said -- as I said in my summary, the ultimate point that was used in the avoided cost rates is the existing plus transition, which is really the first block of solar that got added to the model.

Q. So wouldn't it be more realistic to the base case settings to match the current system rather than a system that doesn't exist?

A. No, because then we would not be able to isolate the impact of the entire block of solar. If we started with what we had right now, then we would just be capturing the incremental from what we have now to 2020 to the existing plus transition level that we're trying to calculate. So, ultimately, if we would have done that, Commission, the incremental cost of going from today to 2020 would be much more expensive for QF projects than allowing the entire block to socialize the cost.

Q. Have you provided the Commission the distribution and costs resulting from all the simulation runs?

A. I'm thinking through all the data requests. We have provided the full results in all the data requests, so I think the answer, yeah, to that is yes, I mean.

Q. Well, the data requests, just so you know -- and you might not know this -- data requests are responsive to the party that asks. They don't necessarily go to the Commission unless a party brings it as an exhibit, for example. So I'm asking, I guess, and what's been presented to the Commission to your knowledge, have you provided costs resulting from all the simulation runs?

A. So we have provided summary tables in the study and my testimony. The more detailed results are -- our part has been provided as part of the data request. So I don't know to the extent the Commission has seen those.

Q. Typically, when you make a model, from my understanding you give a range and an average. A range or a standard deviation and an average. Here I see an average, but I don't see a range or a standard deviation in what was presented in your model.

Why wasn't that presented to the Commission?

A. So I'm not sure I am completely following the question, because the model is a probabilistic model, so inputs -- we're putting in range as an input. The results we're reporting are in weighted average of the range of inputs that we put in. So we're running -- when we run our SERVM model, we're looking at 36 weather years. All those have a component to the final weighted average results.

And so when we're looking across weather years, across different, you know, outage draws, across different load uncertainties in the model, across all the different solar profiles, each of those simulations broken up make up a piece of the total weighted average that gets reported in the results.

Q. Did you do sensitivity analysis around which parameters drove the results in the study?

A. We ran enough analysis to know. You know, I could tell you the major drivers of the study. They are going to be the conventional generation fleet, their ramp rates, and how flexible the resources are, and then how much solar volatility you include in the study.

Q. And what about scenarios run beyond those completed in the report, such as some probability estimate in the model that could skew the results wildly based on a historical estimate that may have some high uncertainty? For example, the polar vortex of 2014.

A. Yeah. So that's included in the model. We have from 1980 through 2018, so we're running every weather year. We did not separately run and pull out specific weather years because they were severe. That kind of takes away from what a resource adequacy study is trying to do. Resource adequacy and loss of load, you're wanting to make sure you cover some of those worst times. If you pull them out, well, then, sure, I can carry a lot less reserves, I can carry a lot less reserve margin. It does not make sense to pull out specific extreme years when they're part of the distribution that we've experienced.

Q. And could you explain, how did you test the sensitivity of the results to different values of solar volatility across the range of reasonable conclusions?

A. So the solar volatility in the model is based on actual history. We're not pulling assumptions out of thin air. So we look at solar volatility historically. And for this study, given that it started the end of 2017, we pulled data for the past year. That's an actual input in the model. So solar volatility, obviously, is a probabilistic metric, in itself. Some days the solar has more volatility than other days, as seen through, I think, some of the examples in Mr. Snider's testimony. So that is an input into the model. The model's probabilistic, so it randomly draws from this set of data based on history.

Q. Wouldn't most modelers typically do a best-case and a worst-case scenario and show a range based on that?

A. Most modelers -- I mean, I think, if the Company requested some more extreme or some more -- less extreme cases, we would have simulated those. But we were simulating what we think is the most accurate of the system. We're trying to model it as it is and get the best accurate answer to be used in these rates.

Q. In your direct, page 27, you stated that, "The DEC and DEP systems are modeled as islands for the study in order to capture the incremental impact of adding solar generation to each system."

And I'm sorry, I apologize if I missed this, but does this include the territories including North Carolina and South Carolina, or is this specific to North Carolina?

A. So it's the entire DEC balancing and area and DEP balancing area.

Q. You state that the -- on page 27 of your direct testimony, that, "While the joint dispatch agreement does allow for excess transfers and non-firm energy, it does not support firm capacity required to provide intra-hour ancillary services needed to manage the variability and solar output."

Can you explain what the difference is between those things? Why did the joint dispatch agreement allow for excess transfers of non-firm energy, but also the joint dispatch agreement does not -- you know what, strike that.

I guess my question is, how can you have one, the transfer of solar, without the other, the ancillary services required to manage solar variability?

A. We're not -- in this statement, we're not talking about transferring solar, we're just talking about transferring excess energy. That can be conventional resources or solar resources. And so the JDA setup does not allow for firm capacity transfers. The BAs are responsible for their own ancillary services to meet NERC requirements, and that requires firm capacity.

And so based on my discussions with the Company operators, the JDA can not be used and is not used to serve operating reserves for each other. So each BA is responsible for their own. And that's the purpose of those two statements, and I think I included those in my summary as well.

Q. You talk about the costs involved in contracting for realtime regulation service and other considerations when, quote, unquote, relying upon surrounding neighbors for solar output give and take.

Have these costs been modeled by Duke or Astrape?

A. Can you point me to where you're reading?

Q. I don't actually have the page, but, subject to check, I have you talking about relying upon surrounding neighbors.

And I guess what I'm just asking is, have the costs been modeled involved in contracting for realtime regulation service and other considerations when relying upon neighbors?

A. No. So the study models them as islands. So all the operating reserves are served inside the BA, so there is no purchases of firm capacity. We didn't speculate on what those would cost and try to model those. We assumed that the individual BAs would serve the operating reserves.

Now, I will add, you know, we performed the 2012 and 2016 resource adequacy study, and it really is a different study here. I think the resource adequacy study is looking at peak periods, peak load periods. And for that, non-firm energy can actually assist in helping peak energy needs. During emergencies, during peak load periods, the Company can go -- go out for purchases for market assistance.

And so that is modeled in the reserve margin study, because we want to reflect that. There is weather diversity across regions, there's unit outage performance, diversity across regions. But for this study, meeting NERC standards for operating reserves, it's firm capacity. And so that's explicitly why we model them as islands.

Q. Just a few more questions. And this is -- I think it's a relatively broad question, but somebody much smarter than me insisted that it made sense.

What are the major assumptions in your model?

A. Major assumptions. So in detail, we model every generator in the fleet, both conventional, hydro, pump storage, solar resources. When you think about a conventional generator, you're modeling all of its details: capacity, minimum capacity, ramp rate, heat rate, minimum up and start --

COURT REPORTER: I'm sorry. Can you slow down a little?

THE WITNESS: Yes. Yes.

COURT REPORTER: Thank you.

THE WITNESS: -- minimum up and down time, start times, and fuel costs for each of those generators.

And so the model is going to dispatch all those generators to load from an economic basis. And the model is set up to do that on a five-minute time step. But in addition to that, the model does not have perfect knowledge of what net load is going to be tomorrow. So the model commits to what it thinks net load is going to be.

There's imbedded in the models uncertainty. So just as an operator at the Company would be having to commit its resources tomorrow, it's going to commit those resources based on some error. And as we get closer to that hour, the error decreases. And by the time we get to the five-minute time step, it knows what net load is going to be.

So the whole question of this study is, if I'm right now at noon on a day -- on a Wednesday, and I know what my net load is five minutes from now, can my fleet meet that load given the operating reserves that we've already committed to? So that's ultimately what the study is doing, using the LOLE FLEX metric. So if I can't meet my next five minutes due to some unexpected movement in net load -- say we have a significant decrease in solar in that five-minute movement, and I cannot meet it, and that decrease in solar is based on actual historic volatility, well, that triggers an event in the model.

So as we add more solar, if we maintain that same level of operating reserves, there's uncertainty in the model, we're going to trigger more events. And so what we need to do is we need to increase our operating reserves so we can manage those intermittent events. And so some of the days are -- obviously, most of the days are completely fine, but you end up drawing some of these bad moves in net load, and we need to be prepared for that so the reliability is the same before and after the study.

I think, going back to your question about just details of the modeling, I mean, the big piece of it too is the solar profiles. And so we're modeling 36 weather years of solar and load. They're correlated, if you will, because when we model 2010 load, we're also getting the 2010 irradiance data. So all that's embedded in this model. I think as I spoke earlier, each weather year is given equal probability. So we're getting a wide range of inputs and outputs, and then we're taking the weighted average as the expected case, which is, you know, kind of general probabilistic modeling.

Q. So understanding the major assumptions you outlined at the beginning of your answer, why weren't those major assumptions included in the study as it was filed with the Commission?

A. So are you talking about in the report?

Q. Sure.

A. Yeah, sure. So the report summarizes the study. I mean, as part of this process, we've provided full SERVM data dumps. So all the data is out there and could be requested by anyone, but it doesn't make sense to fill up 400 pages of a report. I think our study report -- I have it right here -- it summarizes all those aspects, but yeah, it doesn't provide the tables and tables of data, because that would just be daunting. But I think the study here is 53 pages. We could provide as much detail as we need, but it doesn't make sense to do that in a summary-level study.

Q. See, I'm going to disagree with that.

Don't you think it's industry standard to include assumptions in reports sent to a regulatory agency? If I went to the FDA and I wanted to get a drug approved, wouldn't I have to include some of the major assumptions that were being included in the model?

A. I think we just have to disagree. I mean, if you look at the massive amounts of data that were translated in the data request, I do not think it would have ever made sense to put that in our study.

Q. Thank you. I have a similar line of questions with what are the limitations of your model?

A. Limitations?

Q. The outline of things that are assumed to make the model run. If you're not familiar with the terminology, I can move on.

A. Yeah. I'm not familiar with where you're going on that question.

Q. Well, I'm not going anywhere, I'm just asking what -- if there are limitations to your model, however those are --

A. So I guess one limitation -- and I think this is brought up by several intervenors -- I think it needs to be cleared up, is that in these integration studies, I think it was SACE's Witness Kirby, saying our study was flawed due to not modeling exact NERC reliability requirements.

So these are NERC standards, BAL-001-2. They are realtime standards that operators have to meet. But if we go and look at any study that's been done, no study is able to capture that. And even Witness Kirby, in his affidavit, states that that's feasibly impossible.

So we are not modeling second-to-second NERC standards, but none of these models or studies have ever been able to do that. So what it takes is a modeler to come up with a metric, which is really what Astrape has done here, and really mimics a lot of what is done in all kinds of study, but we've come up with this LOLE FLEX metric to assess the flexibility of the system. We can't model the entire eastern interconnect on a second-to-second basis, and follow frequency, and capture the real NERC reliability standards.

So if there was a limit to the model, which is a limit, I would say, to all models in this arena who are performing this study, is that those detailed NERC reliability requirements are not being captured.

Q. Okay. And I guess my final question is, then, isn't it industry standard to include a set of limitations in a report sent to a regulatory agency about a model?

A. I'm really not aware of the industry standard for that.

Q. Thank you. That's all for me.

CROSS EXAMINATION BY MS. HUTT:

Q. Good afternoon, Mr. Wintermantel. My name's Maia Hutt. I'm an attorney at the Southern Environmental Law Center, and I'm representing SACE.

So you, along with your colleagues at Astrape Consulting, were responsible for conducting this study, right?

A. That's correct.

Q. And your co- author was Kevin Carden?

A. That's correct.

Q. And the purpose of this study -- correct me if I'm getting this wrong -- was to model the amount of ancillary services required to maintain reliability on the DEC and DEP systems at various levels of solar penetration; is that right?

A. That's correct.

Q. So before I get into my specific questions about the study, I reviewed your CV and I noticed that you have not listed your position with Axion Group.

Are you still currently employed as a consultant at Axion Group?

A. So I am not employed by Axion Group, but I have -- we are a subcontractor of Axion Group, and I worked Axion Group in various jurisdictions. But to be clear, we have not worked in North Carolina with Axion Group.

Q. And your co-author, Kevin Carden, is also employed by Axion Group?

A. He has done subcontract work for Axion Group, yes.

Q. And this is the same Axion Group that functions as the independent administrator for the North Carolina CPRE program, right?

A. That's correct.

Q. And have you and Mr. Carden been screened from involvement with the CPRE --

A. That's correct. There has been very much a line between us and Axion Group with any Axion work for Duke, for DEC or DEP.

Q. Great. Thank you. Okay. So now I would like to ask some questions about your study. And forgive me if some of this seems remedial. I'm trying to get a sense of exactly how this was formulated.

So your study uses the LOLE, or loss-of-load expectation metric; is that right?

A. That's correct.

Q. And my understanding is that the LOLE metric, in general, is traditionally used for utility planning purposes such as IRPs; is my understanding correct?

A. That's correct.

Q. So instead of modeling the long-term capacity that a BA must have in order to ensure that a load-shared event is expected to occur once or less during a 10-year period, your study applies the LOLE one-event-in-10-years metric to DEC and DEP's day-to-day operations; is that right?

A. Yes. The LOLE FLEX metric was set at 0.1, but I think it's important to realize that it is not setting, if you will, NERC balancing deviations to one day in 10 years, because the way the model works is it has perfect knowledge five minutes in advance. We're not -- we're not modeling NERC deviation imbalances, which we would expect in our model, with the level of operating reserves we have in our model, to be much greater than this one event in 10 years.

So the LOLE FLEX metric is -- we would expect a violation that occurred in our model to be much more substantial than, say, just a NERC balancing deviation that, obviously, the NERC standards allow many of those across the year and across days.

Q. Okay. Thank you. So, specifically, your study balances net load and generation every five minutes, and it identifies any five-minute period where generation is not able to meet load and minimum ancillary service requirements; is that right?

A. That's correct.

Q. And then it identifies every five-minute period that is unable to meet load and minimum ancillary service requirements as a reliability violation; is that right?

A. That's right.

Q. And just let me confirm, your study models changes in net load; is that correct?

A. So we model the -- I mean, explicitly in the model, we model gross load and solar generation as a resource, so -- but, ultimately, the conventional fleet has to meet the difference in that, which is the net load, so yeah. And that's what an operator at either of the balancing areas would be determining how their conventional fleet is going to meet that net load, which is the difference between gross and the solar output. Gross load and the solar output.

Q. So just to clarify, the operator doesn't need to meet solar volatility or load due to solar volatility changes; they need to meet net load?

A. They need to meet net load volatility.

Q. Okay.

A. And net load volatility is gross load minus solar, and their embedded volatility is in the model. So we have distributions for load volatility, and we have distributions for solar in the model. And so the model sees the combined effect of both of those volatilities. So there are times in the model where, in an hour or in a time step, the volatility of solar is great, but the load volatility actually offsets that and gives benefit to the solar. So some of that --

that's embedded in the model.

Q. Okay. Thank you. And so I want to go back to what happens when a violation occurs.

A. Sure.

Q. Or what your model quantifies as a violation occurs to a five-minute period where you're unable to meet the requirements.

So your model adds load following reserves sufficient to keep the one year -- one event in 10 years metric in place --

A. Yes.

Q. -- every time it sees a violation?

A. That's right. It keeps this 0.1 metric that it used before solar was added and after solar was added. And so, you know, I think the reliability of metric is somewhat immaterial. What we're really trying to do is make sure that the reliability is the same before and after. And I think further is that, in the no-solar case, because we've calibrated to total operating reserves that we're seeing on the system before a lot of solar was added, and we're in the reasonable realm. The model is producing 0.1 FLEX with historical operating reserves. And that's historical operating reserve world, we know we met NERC balancing standards -- balancing standards, and so we would expect, if we maintain 0.1, based on that calibration effort, that in the future we would still be able to meet NERC balancing standards.

Q. Okay. So if I'm understanding correctly, you're saying that you need to maintain the same level of reliability before and after solar is added; is that correct?

A. That's correct.

Q. What if you overestimated the amount of reliability necessary at the outset?

A. I think, you know, I would probably point to the -- to the Idaho study introduced by Mr. Kirby. Let me see if I can find the page. But ultimately that study, which assumed the reliability metric very similar to our approach, they chose a metric to start with beginning -- although there are significant differences in the study, they chose a reliability metric -- let me see if I can find it here so I can read it, if that works.

Q. They used a 99 percent reliability metric; is that right?

A. Yeah. But I think the statement is clear in the report that says the reliability metric is --

Q. Is relatively immaterial.

A. -- relatively immaterial. Exactly.

Q. Yeah. So --

A. So -- because as long as it's at the beginning and the end of the study that you're getting the same metrics, the reliability metric is fairly immaterial.

Q. Okay. So let's talk about that Idaho study.

So the Idaho study targets loads sufficient to compensate for 99 percent of five-minute balancing deviations; is that correct?

A. That's my understanding. I will say, before I go into extreme detail on the Idaho study, these models and studies are very detailed. I would probably really need half a day with the modelers to really be able to answer clearly 100 percent exactly what they've done in the study. But it does clearly say that they've taken the solar volatility and tried to cover the 99 and a half percentile. It's really a half a percent on each tail of the distribution. And that is my understanding of the study.

Q. Okay. So, subject to check --

A. Yeah.

Q. -- 99 percent reliability, does this

translate, as I understand, for 90 hours of deviation per year used in the Idaho study?

A. That is the starting point for their assumption, yes.

Q. Okay. In comparison, your study allows for a single five-minute deviation per 10 years before clocking reliability violation and adding reserves; is that right?

A. That is correct, but I would argue we have very different methodologies, and I debate on whether to go into the real details here. But when we look at -- let's just start back -- let's look at the results of the two studies.

When Idaho adds 800 megawatts of solar and adds 1,600 megawatts of solar, they're projecting -- let me get to it. So on page 15 of the Idaho study, to increase solar by 800 megawatts, the Idaho clearly states -- and this is something that I can tell is clear -- a lot of the methodology is difficult to translate in these detailed studies, but at 800 megawatts, they're adding 24 megawatts of operating reserves.

At 1,600 megawatts, they say, and this is average over the year, that they're adding 31 plus 39, which is 70 -- if I do my math right, 70 megawatts of operating reserves. So those two figures are very in line with what we're projecting for DEC and DEP.

At 800 megawatts in DEC we're adding 26 megawatts of operating reserves. At 3,000 megawatts in DEP, we're adding 166. At 1,600, which is half of that, they're adding roughly 70.

So my main point here is that the results show similar operating reserve increases as we add solar capacity. Now, I think, you know, it does beg the question, though -- - it's a good question -- why does this study have 90 hours in deviations and produce the same answer as our 0.1 metric? So we dug a little bit, and I'll probably have to speculate, but there are some big differences in the studies.

So the Idaho study determines all those operating reserves initially, almost using just statistics outside of the model. So it's looking at solar volatility as we've been through, they're looking at kind of the 99th percentile, then they're applying some wind and load volatility discounts to that. So they do that separate, outside the model. And then they put that in the production cost model, increased -- based on what they calculated over here, external to the model, they put that in the hourly production cost model. They're not running intra-hour modeling. They're running an hourly production cost model just to determine the operating reserves that I've calculated over here, what are the costs. So SERVM, our approach, we believe, is much more granular. We're doing this all in one single model. We're calculating reliability, we're dispatching resources to load, and we're calculating the costs all in the same model.

And really what that does, in our opinion -- and I will say I'm speculating trying to understand the differences, because it's a valid of question, although the Idaho study does say reliability metric is somewhat immaterial, and we agree with that to some level, but I think the reason we need to go down to 0.1 is because, in our SERVM model, we have, in our no-solar case, when we're meeting operating reserves for peak load, I'm making sure I have enough operating reserves for that peak period so in the off peak, I have excess operating reserves. That's just inherent in operations.

We go to the operations floor and their operating reserves are varying. They have to make sure they commit enough resources to the peak. And in order to do that, it means they're going to probably have some excess in the off peak. So what that does, in our model, is now we go in and we put in the solar volatility, and those excess hours likely absorb some of that solar volatility. We may draw our random five-minute solar draw, that's the most extreme, and it may be coincident where we actually have operating reserves in our no-solar case that were in excess just due to the way we have to commit and dispatch resources. So we absorb some of that.

And I know it's difficult to follow, and it gets into the weeds here, but we've done our best to try to figure out this study that they have brought up. I mean, we're getting the same answer, so there's something in the methodology that we're doing differently that -- not that two wrongs make a right, but it's kind of like that, where we've come to the same conclusion. And both studies are probably very reasonable in the results. And so that's our best way of explaining why the results are the same for the different reliability metrics.

Q. Okay. Two points. So one, I appreciate your clarifying, but can you just confirm for me that the Idaho study does allow for 90 hours of deviation per year, and your study allows for -- or, sorry, 90 hours of deviation per year and your study allows for five minutes of deviation in 10 years?

A. That's correct. But I think --

Q. Okay.

A. -- again, the modeling methods are so different. And if we were -- if we were so stringent in our results, when I think about what our intra-hour volatility is for DEP -- and so we've look at this extensively. So we've got 3,000 megawatts of solar. The five-minute unexpected movement of that, based on historical intra-hour volatility, looks like roughly 350 megawatts. That's just kind of the tail-end risk of what we see for 3,000 megawatts of solar. We're not adding 350 megawatts of operating reserves. We're not covering that as we're kind of trying to paint here one event in 10 years. There's things inside the cost production model that are allowing us to absorb some of these events, which I think bring us back to results that are very much in line with the Idaho study.

Q. Okay. So I would like to follow up on that point. I think you're referring to Figure 7 in your direct testimony when you say that the results of the Idaho study are similar to the results of your study.

And I'd like to talk about that figure for a minute.

A. Okay. I see it.

Q. Okay. So --

COMMISSIONER CLODFELTER: What page is that on?

MS. HUTT: Page 31 of the direct.

Q. Okay. So I would like to ask a couple of questions about this figure.

So on the X axis here you have solar megawatts, right?

A. That's correct.

Q. And that is the size of the nominal fleet, the nominal size of the solar fleet; is that right?

A. That's correct. So that would be the nameplate capacity, yup.

Q. Okay. And then on the Y axis we have incremental operating reserves.

And what's the unit there?

A. That would be megawatts as well.

Q. Okay. Thank you. And so now I'd like to also talk about the direct testimony of Mr. Kirby, page 37, he includes a chart as well. And I know it might be hard to kind of look at both of these charts at the same time, but I'd like for us to compare them if that's possible.

A. Do you have -- I don't have Mr. Kirby's direct.

(Pause.)

Q. Okay. So I'm going from memory right now because I gave you my copy, but I believe that the X axis there is solar penetration; is that right? Or sorry, solar wind?

A. Solar plus wind penetration, yes.

Q. Okay. And then the Y axis is also additional operating reserves?

A. That's correct.

Q. Okay. So if you're looking at these two figures, I can see how, in Figure 7, at low levels of solar megawatts, the Idaho study and your study seem to line up pretty reasonably.

A. Very much so, yes.

Q. However, if you're looking at Mr. Kirby's figure, on page 37 of his direct testimony, we see a big discrepancy.

A. Yes, that's correct. And I've -- I would strongly disagree with the comparison in Mr. Kirby's direct testimony. And we've responded in my rebuttal testimony on that, so I think I will just go to my rebuttal testimony on this.

So what Mr. Kirby's done here is he's mischaracterized the data. So when we think about operating reserves for solar integration, what's driving that is how much solar capacity do we have on the system. It's fairly straightforward that when we add more solar, that variation and uncertainty drives how many operating reserves we need.

And so we address this in my rebuttal, but I think what he has done is he's taken the solar capacity plus wind capacity and divided by the peak load and put in as penetration level. But from our standpoint, we strongly disagree. We believe the right comparison is to compare how much solar have I added and how many operating reserves have I had to add? We're somewhat indifferent to the size of the system. It may be a little bit, a little argument that there's some load deviations that would help the larger system, but I would argue that the wind in the Idaho study would well overcome that.

So they've got significant wind benefit that we don't even have in your study, but all in all, we strongly disagree with Mr. Kirby's comparison here.

Q. Okay. And the reason for that disagreement is that you do not agree that solar penetration, so the amount of solar relative to the total size of the BA, is the relevant metric?

A. That's right. We believe that the amount of load following reserves are much more correlated in the direct function of the solar capacity added than the percentage of solar to load. It's driven by the solar volatility. So as we add more solar, that's the reason we're increasing operating reserves. It's not anything to do with the size of the system.

Q. So why does your study model necessary load following reserves based on various levels penetration on DEC and DEP?

A. The only reason we're changing our load following reserves is to get our reliability back. So we are -- gradually we have our starting point in the zero solar case, and it's X amount of megawatts. We're running simulations over and over, we're just adding operating reserves to the solar cases until we get back to the 0.1 metric. So did I answer your question there, or do you want to repeat it? I may have not answered it correctly.

Q. I guess I'm struggling, because it seems like, when I read your study methodology and when I read your direct testimony, we're talking about solar penetration, which is a percentage of the total. And then when Mr. Kirby produces a figure which models additional operating reserves against renewable penetration, you say no, it's nameplate capacity.

A. That's right. Solar capacity is a part of the equation for solar penetration. So I think we're just talking past each other. I mean, solar penetration is just the solar divided by the peak load in the system. The load following reserves, they're increased because of additional solar, so it's not correct to divide that by the peak load and come up with the penetration level.

Q. Just one last question, and I promise I'll let this go. So if solar penetration isn't the relevant metric, are you saying that the same X amount of megawatts added to a system that has -- a 100 megawatt system will have the same impact as that X amount of megawatts added to a system that's four times bigger?

A. The driver of the amount of operating reserve needed is based on that solar capacity. As we add more solar, that increases the volatility. And so it is a function of the solar capacity we add, yes.

Q. Okay.

CHAIR MITCHELL: Ms. Hutt, how much more do you have for this witness?

MS. HUTT: Several questions.

CHAIR MITCHELL: Okay. We're going to take a break. We'll come back on the record at 4:00.

(At this time, a recess was taken from 3:47 p.m. to 4:02 p.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please.

MS. HUTT: Maia Hutt for SACE.

Q. Okay. Mr. Wintermantel, so I'd like to go back to something we were talking about earlier, which is just how your model works exactly.

So is my understanding correct that each level solar penetration your model determines the level off ancillary services necessary to keep the system at a 0.1 LOLE FLEX or one violation every 10 years, and then adds load following reserves if it has found that violation to have occurred?

A. That's correct. So as we increase solar, if we were to maintain the same operating reserves, that LOLE FLEX number would go above 0.1. So we add operating reserves to get it back to the same reliability that we started with. That's correct.

Q. And then you calculate the proposed solar integration charge based on the level of reserves that you've added at each level of solar penetration?

A. That's right. So in the -- I think just for example purposes in the existing plus transition scenario, we run that case with the solar in it. The existing plus transition solar, we run it in the mode where we had the operating reserves from the no-solar case, our starting point, so operating reserves, which is going to be cheaper scenario, right? And then we're going to increase the operating reserves until we get the reliability back to 0.1. That delta in cost, those operating reserves, with the existing plus transition solar included, is the dollars that are spread across the renewable -- the solar generation to get the dollar per megawatt hour, yes.

Q. Okay. So just to clarify, the LOLE FLEX metric you're using in the study is not a NERC standard?

A. That is correct. And I'm not aware of any integration study that is able to capture the NERC reliability standards. And I would also add that the

0.1 metric in our modeling, as I said this before, we're able to -- we know what the net load is going to be five minutes ahead. I think if you would ask operators if they knew what load was going to be -- net load five minutes ahead, and we're just checking to see if the system that's committed has enough flexibility to meet that, if you ask operators that scenario, that would be a fairly lenient thing they should be able to meet. They should know -- if they know the net load is going to be X in five minutes -- which, in real world operations, they do not know that. They're chasing load every second, every minute, and that's when these NERC balancing ACE deviations, that we call them, occur. You're constantly -- you don't know what net load is going to be 10 seconds from now. But in our model, it's more lenient. We're just checking to see if the operating reserves that are on the system can meet the net load five minutes from now. So it's very less stringent than what I think SACE is trying to paint here, that it's one event in 10 years. Well, it's not one NERC balancing deviation in 10 years.

Q. Just to clarify. So the one event in 10 years is one violation, as defined by you, every 10 years?

A. That's right. By the LOLE FLEX metric, which measures can I meet my net load five minutes from now with the operating reserves I have on my system, my conventional fleet that I've committed, have I committed enough operating reserves to meet that next five-minute time step.

Q. Okay.

MS. HUTT: Madam Chair, may I approach the witness?

CHAIR MITCHELL: You may.

Q. Do you recognize this document?

A. So it looks like it's just a summary of the BAL-001-2, or it is the actual standard.

Q. Yeah. So this is the real power balance and control performance set by NERC.

And do you agree that this document before you sets out the NERC balancing standards that actually govern DEC and DEP's day-to-day operations?

A. Yeah. I assume that's correct.

Q. And the current reliability metrics set by -- sorry, I apologize.

And the current reliability standards set by NERC are the control performance one or CPS1, and balancing authority ACE limit, known as BAAL, which are part of B Sub R2 of this document?

A. That's correct.

Q. And these are the standards that apply to DEC and DEP?

A. That's correct.

Q. Your study, which was published in November 2018, refers to CPS1 and CPS2.

Are you aware that the CPS2 standard was replaced by the BAAL standard in July 2016?

A. I am. And I recognize that, in our study, in that section of the report, we did have an oversight. So I realize CPS2 has been replaced by BAAL. But I would also just note that that section in the study not at all was trying to get the NERC reliability requirements exactly right. What we were actually identifying -- self-identifying in the study is that the LOLE FLEX metric does not capture the NERC standards. And no study that we are aware of can go capture these CSP1 [sic] and BAAL standards listed in this exhibit.

And so while it was an oversight in the write-up of the study, I just want to note that, in that section, we were never -- it actually has no impact on the modeling, because what we were doing in that section of the report is we were self-identifying that the LOLE FLEX metric was not capturing the NERC reliability standard.

Now, we do believe that they are highly correlated. And the reason is, if we increase load following reserves or operating reserves, we're going to better meet our NERC standards, and we're going to better meet LOLE FLEX. If we decrease our operating reserves, then LOLE FLEX is going to increase, and we're going to have a harder time meeting our NERC balancing standards. So the metric, what it's trying to do, is it's trying to capture the NERC standards, but it can't do it accurately. And I think I've said this three or four times, but there's no study out there that is able to calculate the NERC standard, specifically.

Q. So I understand that no study out there has perfectly calculated based on NERC standards, but isn't is it a matter of how close you can get to mirroring the NERC standards, as they're stated in this document?

A. I think that's probably a fair assessment. I would say, in our study in 2015, we feel like we met NERC balancing standards. So we calibrated back to that time when there was little or no solar, and we've hit on that several times. So the calibration in the study is that we started with a level of operating reserves that was seen in history, and within the model, that produces a 0.1 LOLE FLEX. So it makes LOLE FLEX a reasonable threshold.

In addition to making it reasonable, as part of the collaboration with Public Staff, because they had -- they saw some of these questions being asked by SACE and they asked us, well, what happens if we actually relieve that LOLE FLEX constraint a little bit? So we're at 0.1, so we alleviated 10-fold as discussed in my rebuttal testimony. And what that did to the results is it really proved out what the Idaho study says, that the reliability metric is immaterial. The answers changed very small, and I can try to find --

Q. It's relatively immaterial, right?

A. Relatively immaterial, yes. Thanks for that correction. If I look at my rebuttal testimony, if you'll give me just one minute.

(Witness peruses document.)

Q. If you don't mind, I'm going to ask you about the comparison to the Idaho study and the exercise you conducted with the Public Staff in a couple minutes.

A. Yeah, sure. So, in my rebuttal testimony, we do not go into the exact numbers here, but it says, "While Astrape and the Companies believe 0.1 LOLE FLEX metric is appropriate for this study, the sensitivities relaxing the FLEX metric by 10-fold further prove that the reliability metric is immaterial as also indicated in the Idaho integration study report."

Q. Understood. So let's take a look back at that document that I handed to you, which is the actual NERC standards.

A. Okay.

Q. So at the bottom of the first page, under B, requirements, R2, could you please read that paragraph for me?

A. B-R2?

Q. Yes.

A. "Each balancing authority shall operate such that its clock minute hours of reporting ACE does not exceed its clock minute balancing authority ACE limit, BAAL, for more than 30 consecutive clock minutes calculated in accordance with attachment 2, the applicable interconnection in which the balancing authority operates."

Q. Thank you. So am I understanding correctly that a BAAL violation has not occurred until a balancing authority has been out of balance for 30 minutes?

A. That is correct, by the standard. But, again, our LOLE FLEX metric has perfect knowledge going five minutes ahead, so this is not comparable. We cannot compare the LOLE FLEX metric to whether or not we're maintaining these balance standards. It's different. In fact, these BAAL standards are -- as I said, operators are constantly chasing loads, so these deviations are going to occur much more frequently in the NERC standards than they would occur in our model, which has perfect knowledge, can I meet my next five minutes of load given my operating reserves I have on my system?

Q. So when you talk about your model having perfect foresight, that's a limitation of your model, isn't it; that's not the reality of the Duke system?

A. Yeah. I would say that's a constraint of every model, because we can't model second-to-second frequency across the eastern interconnectors, as stated clearly by Mr. Kirby.

Q. Okay. So I'd like to go back to talking about NERC, or the North American Electric Reliability

Corp. And I'm just going to read their mission statement to you. So they're an international regulatory authority whose mission it is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Do you think NERC standards impose unreasonable risk upon utilities?

A. I do not.

Q. Okay. So from what I understand, you acknowledge that your study's use of the LOLE FLEX metric does not follow NERC standards, and that's because NERC standards are hard, if not impossible, to model, and you believe that your metric comes reasonably close; is that fair?

A. Yeah, that's fair. So I think, based on the historical calibration, and knowing that we met our NERC standards in that historical year, and that that year -- or those operating reserves resulted in an LOLE FLEX of 0.1, LOLE FLEX 0.1 is a reasonable starting point, yes.

Q. I believe, on page 11 of the Astrape study, you state that the -- you calibrated the base case model to produce an LOLE FLEX of 0.1.

What does that mean?

A. That's right. So we can adjust the operating reserves to create LOLE FLEX of 0.1. And when we compare those operating reserves that actually did that, they compare well with historical operating reserves for the DEC and DEP combined systems.

Q. I guess my question is, if you had to calibrate to achieve the 0.1 --

A. That's right.

Q. -- metric, then that seems to imply to me that the original inputs did not inherently fit the 0.1?

A. Right. So the operating reserves are a direct input into the model. It is an input into the model. So we can adjust is -- they are an input to the model, and we adjusted it to what we thought was comparable to historical, which also equates to a 0.1 LOLE FLEX. That's right.

Q. Okay. So this is based on simulations, your base case, it's not based on DEC and DEP's actual operating reserves?

A. So we've got the actuals. We can go calculate those. We got those from actual history dated three or four years ago, 2015. And we could make sure that our model, which has no solar, lines up well with that. And then a result of the model with those operating reserves that compare well to history results in a 0.1 LOLE FLEX. So we know that LOLE FLEX 0.1 is reasonable compared to what's been modeled in the past. Or been actually operated in the past, not modeled in the past.

Q. Okay. Thank you. So now I'd like to go back and talk about something you mentioned earlier, which is your conversations with the Public Staff.

So Mr. Thomas testified that Duke and Astrape's post-processing techniques to estimate where the impact of relaxing your LOLE FLEX one event in 10 years metric would be on the calculated solar integration charge. I assume you were involved with this?

A. That's correct.

Q. And you relax the metric from 0.1 to 0.3 and 1.0; is that right?

A. That's correct.

Q. And so the most you relaxed your metric by is a factor of 10?

A. That's correct.

Q. And the relaxing of that metric yielded a 6.2 percent reduction in the charge in DEP, and a

1.9 reduction in DEC; is that right?

A. That's correct. So it's a very -- relatively small amount which further proves what the Idaho study had said, that the reliability metric should be relatively immaterial.

Q. Sure. So do you know how much you would have to relax your 0.1 metric in order to achieve the same level of stringency as that 99 percent reliability metric used in the Idaho study?

A. No, I do not, because the methods are so different. So our approach to that, we did do something else similar to that to attempt. Because, again, as I said earlier, the Idaho study does statistical analysis on solar external to the production cost model to determining the operating reserve increases. And so what we did was we tried to do that just to prove to ourselves that, hey, we're getting same results, why aren't we getting same results?

So what we did -- we're getting the same results as operating reserves as solar increases, that's the main comparison. And so what we did was we actually took our solar data, historical solar data, we went and pulled the 99 percentile operating reserves, and then we factored in the discounts that the Idaho study does, which they discount for both the wind and the load volatility.

You know, obviously, there's going to be some diversity benefit of having wind and load. Again, DEC and DEP don't have wind, so this would be overstating the discount. But in that analysis -- so we're trying to mimic exactly what Idaho did, come up with how many operating reserves we need to have for our solar.

And so for the DEC case, we -- for the 800 megawatts -- 840 megawatts of solar, we went through the process, and the operating reserve showed very similar, I think it was in the 20s, and it's in my rebuttal testimony. And went through the same process for DEP and actually showed we should be adding 188 megawatts, which is actually higher than the 166 we project.

So using the Idaho method on our data to determine operating reserves, we actually still get very in line with what we have. It would not make sense and we would not be comfortable moving the LOLE FLEX metric to 99 percent or 90 hours a year. And the reason is, to do that, the operating reserves would be well below what we had in history.

So the studies, while I appreciate them trying to paint that 0.1 is very stringent, I think we've gone exhaustively to try to show and benchmark to why it's not. And at the end of the day, when we look at cost, and we compare to other studies, I mean, we're $2 lower than the recent SCE&G study that Navigant produced. We're not -- we're not extreme. And our modeling approach is to try to model as accurate as possible. We're not trying to put thumbs on the scale to move this one way or another. We're doing our best to get the best number for what the ancillary service cost impact is of the solar.

Q. I understand that the Idaho study and your study have several differences.

A. Yes.

Q. But let's just for a second focus on just that reliability metric. So let's do some math here. The Idaho study allowed 90 hours per year of imbalance. That's 900 hours in 10 years. The 0.1 metric you used allows for 5 minutes in 10 years. That's 1/12 of an hour. 12 times 900 is 10,800.

Would you accept that, in order to relax your study's metric to the same level of reliability in the Idaho study, that you would need to relax that 0.1 LOLE

FLEX metric by a factor of 10,800?

A. No, I do not at all. I do not think those metrics are directly comparable. The methods are completely different. Our five-minute known time step within a production cost model, we're getting lots of benefit inside this production cost model. We're redispatching resources.

The Idaho study takes the 99th percentile of just the solar volatility. If we did the 99th percentile of just the solar volatility before any of the wind and load discounts that the Idaho study projects, we would be much higher than the numbers we're showing.

Q. But you were willing, in discussions with the Public Staff, to reduce by a factor of 10?

A. Yeah. We think there's a range that the reliability threshold could potentially -- and so 0.1 to 1 was reasonable, but because -- but we still really would still only support the 0.1 because that's more in line with historical operating reserves. If we go to 90, we're going to be lowering operating reserves -- just because the LOLE FLEX metric is not the same as the Idaho metric, we would be lowering operating reserves well below what we showed in history, and it would not be appropriate. We have to recognize that the methodologies are different. The results produced are very similar.

Q. Just to clarify, the results that the two studies produced are apparently similar at very low levels of solar when your reference point is megawatts of solar; they are completely disparate at higher levels of solar and especially when you consider solar penetration which is what your study models?

A. So I think we're missing terminology. We say solar penetration in our study, but when I say solar penetration, different solar penetrations, I'm talking about 800 megawatts, 1,600 megawatts, 3,000 megawatts. So I think we're maybe talking past each another on the penetrations, but as far as the chart that Mr. Kirby showed, which was a true percentage penetration, completely disagree with that comparison. But if I go back to my figure 7, I think you stated that, even at the high levels, they're not close.

For one, the Idaho study only went up to 1,600 megawatts, so we don't have anything to compare to, but up until that level, the figure -- I mean, they're on top of each other. And, honestly, when you look at the curve, I would think, if they increased to

3,000, they would show similar results.

Q. So your study anticipates exponential growth in the incremental operating reserves, right?

A. So yes, the results show that, and we self-identify in the study that the high penetration levels, they are highly uncertain. We do not know how the intra-hour volatility is going to change as we add more solar; what sizes are we going to add; are we going to add storage? There's lots of unknowns as we go further out. But the block that the Company is focused on, the existing plus transition, is a lot more certain.

So yes, the curve does go exponentially higher. And what that could do out in the future could support, hey, we need more storage to make that operating reserve come down, or there may be more intra-hour diversity across the solar fleet than what we have in the study. We're really uncertain on the high penetration numbers, and I hope we have made that clear, that those numbers are not being used by the Company. But it was a study to test to kind of see. They wanted to understand, in our model, what it showed if we increased solar substantially, so.

Q. I understand that there are levels of uncertainty, but let's just look back at Figure 7. And even if this is the right X axis to be considering these metrics on --

A. Uh-huh.

Q. -- I'm having a hard time seeing how the Idaho studies, the pink dots, justify an exponential growth rate.

A. So, again, yeah, Idaho did not go to the extent -- I think, what is the highest point, is it 1,600 megawatts for Idaho? I don't have the Idaho study. So we really don't have a reference point beyond that.

Q. Yeah, it's 1,600.

A. But if I take my figure -- everybody's got Figure 7 -- and the highest penetration that we're looking at for DEP that actually affects the rates of this docket go up to 2,950. To me, if I draw a curve to that 2,950, we are not extremely higher or out of line. And I think it only makes sense that, as you add more solar, if you don't change your resource mix, that it's going to be more and more difficult for that system to serve additional operating reserves.

Obviously, we're going to -- early on, we're going to use the operating reserves we have, and they're going to be the cheapest. There's this economic dispatch. As we increase the solar penetration, it's going to be more difficult for that same fleet to meet reliability. You're going to have to turn on more expensive, maybe, CTs. Should be more expensive resources that are going to serve those extra operating reserves. So it only makes sense that the curve would be exponential. But I would -- just looking at the figure, in my mind, I still think they are very comparative.

Q. So you mentioned that the charge doesn't consider, kind of, these highest levels of solar, but I'd like to know that you are asking the Commission to sign off on a methodology that does produce those exponential solar integration charges?

A. I think we're asking them -- and I would leave this really to witness Snider and Wheeler -- I think we're asking them to approve the existing plus transition values of the study, and yes, the methodology of that block of solar.

Q. Okay. So let's circle back to something I mentioned earlier, which is the post-processing techniques mentioned in Mr. Thomas' testimony.

How are those different than just rerunning your model with different inputs?

A. Yeah. So we did not rerun. So as part of the study and as part of the -- I think this was submitted as data request, but we show -- we have to take different blocks of load following. We can't run every megawatt of load following. So we can see the LOLE FLEX result, and we have enough levels of load following that we can do some post processing to the results to interpolate what the differences are going to be. So that's what's done.

So around from 0.1 to 1, we have enough results to attempt to interpolate, and that was the post processing. We did not go back and rerun the model for that sensitivity. Public Staff wanted to get comfortable that if we made that LOLE FLEX metric less stringent, to see how the results would change. And so, to the best of our abilities, without having to go rerun the study, that's what we did.

Q. Okay. And are those post-processing techniques included anywhere for the Commission to evaluate? Are they on the record?

A. So I believe -- well, it would be subject to check, but I believe Public Staff testimony may include some of that.

Q. I believe Mr. Thomas' testimony, Exhibit C, has the results. I'm asking about the methodology.

A. Okay. Yeah. To my knowledge, no. But I would further say, we would not support moving from the 0.1 anyway, again, because of the operating reserves compared to the history. That was really just a sensitivity. So we would not support lessening the metric for the study.

Q. Okay. Let's switch gears and talk about another assumption that your study makes, and that's the modeling of DEC and DEP as load islands; that's right?

A. That's correct.

Q. Okay. So their models are separate from one another, and they're modeled as separate from the Eastern Interconnection; is that right?

A. That's correct.

Q. But just in reality, DEC and DEP are part of the Eastern Interconnection?

A. That's correct.

Q. Is it true that an islanded utility would generally have higher balancing reserve requirements than if that same utility was not islanded?

A. Balancing reserve requirements? So, I mean, it's my opinion that the answer to that would be no, because you have to go and get firm capacity, as we have said in our reply comments to the island scenario. Now, when you think about contingency reserves, there are benefits to that of being in a reserve sharing group that allows for benefits.

But from a balancing requirement, it's my understanding, in discussing with DEC and DEP operators, that each balancing area is responsible for their own. And so being interconnected does not lessen that responsibility. And that, to fill that responsibility, they would need firm capacity. So they would need to actually go purchase from a southern company or a TBA firm capacity to be able to meet those balancing standards.

Q. Have you ever operated a power system?

A. I have not.

Q. Thanks. Okay. So modeling DEC and DEP as if they were not part of Eastern Interconnection does not increase their load requirement relative to if they were in the eastern connection; is that what you're saying?

A. Their load requirement. So I think we're saying their operating reserves to meet NERC standards, then they would not.

Q. Aren't NERC standards set based on which interconnection you're a part of?

A. They're set by balancing areas.

Q. I believe that the document that I handed to you includes -- sorry, apologies. I just want to make sure I got the right page on this. So, for example, there are different targeted frequencies for each interconnection. This is on page 5.

I guess I'm trying to make the point that it does matter how a balancing area is connected to the world around it?

A. So I think this page 5, yes, it has different requirements for the Eastern Interconnection, versus ERCOT, versus the Quebec interconnection, but that doesn't change that the responsibility of each BA within those interconnections has to meet their own NERC reliability standards.

Q. I understand that point, and I guess the question I'm trying to get at is not can DEC and DEP rely on the Eastern Interconnection to send them energy or capacity or whatever they need.

My question is, aren't the NERC standards, the ones you're holding, premised on the fact that these utilities are part of the eastern connection? Isn't that built into the standard that they are required to operate to?

A. Yes, I assume so, that these requirements were set based on the understanding of what balancing areas are part of each connection.

Q. Do you acknowledge that being interconnected to neighboring regions can improve resource adequacy?

A. Yes. Resource adequacy. So when we think about setting utilities' target reserve margin and understanding capacity needs, we believe there is market assistance out there available during peak conditions. But not to meet NERC balancing standards, just to meet load in emergency-type situations.

Q. Okay. So the Public Staff, as I understand it, asked Astrape to run a sensitivity analysis that combined DEC and DEP's load and solar volatility assumptions; is that right?

A. That's correct. They were interested in seeing if we combine the two systems, which is not realistic, so no transmission tie. They were actually modeled as one BA, if you will. And we added up their load, their solar, their generator. So if they were one BA, unlimited ties, we modeled that scenario just to understand, you know, kind of extreme market assistance type of world where only -- we're only -- we only have one LOLE FLEX metric for that single combined BA, how do the results change? And yes, so we ran that scenario, which I don't think the Company or I would agree is appropriate, but it was a sensitivity.

Q. Fair enough. And that analysis resulted in a 15 percent reduction in the calculated charge, right?

A. That sounds familiar, yes.

Q. But this reduction was not reflected in proposed solar integration charge?

A. Absolutely not.

Q. Did you perform a sensitivity analysis that modeled DEC and DEP as they are actually operating as part of the Eastern Interconnection?

A. We did not. We modeled them as islands for the reasons I've laid out today. They are responsible for their own NERC balancing standards and the firm capacity to support that.

Q. But you didn't do a sensitivity analysis on that point either?

A. We did not do any more sensitivities other than the combined DEC and DEP as one balance scenario.

Q. Okay. So let's move to the issue of

geographic diversity benefits.

So I believe, in your rebuttal testimony, on page 22, you discuss an analysis of diversity benefits of solar that I think you conducted within Duke's service territory; is that right?

A. Yes. So what we did, we were really just responding to Witness Kirby's calculation of intra-hour diversity, and so we had a data request out to him to provide that data, and he did. And so we took the monthly standard deviations that he calculated, and we curve-fit it to what we thought the diversity was during that time period of that data. And that is in my rebuttal testimony. What page is that?

Q. Page 22. And I believe you said that, after doing this analysis, you calculated what you characterized as a relatively small amount of diversity benefits during 2016 through '18?

A. That's right. And I think it's actually in the reply comments, the actual numbers. Let's see. I think it's roughly 10 percent, but that's --

Q. So the diversity benefit that was calculated is approximately 10 percent, subject to check?

A. Subject to check. It's in the reply comments.

MR. BREITSCHWERDT: Mr. Wintermantel, not to belabor this, but would you like a copy of your reply comments?

THE WITNESS: I have them in front of me, thank you, I'm just struggling to find the page. Too many pages.

(Witness peruses document.)

Yeah. So it's page 107 of the reply comments.

Q. Okay. Thank you.

A. We show, that over that period, from October '16 to 2017, it's -- actually, that's not the right period. 2016 to 2018 we show a 13 percent discount in DEC and 17 percent discount in DEP. Now, that assumes that the exact same type of small solar resources that have been built today from '16 to '18 and even previously, that those are the same types of resources that would get built in the future.

And so the Company has chosen -- and so have we, really, we supported this decision -- is that that future diversity, through the biennial study, we will be able to update this as it materializes. And so with some of the procurements that are going on -- and I'm not an expert on exactly all those procurements -- but they expect larger solar projects. So as you add larger solar projects, this intra-hour volatility diversity could actually -- could actually potentially go the other way, or at least dampen the effects of the diversity that we have here.

So we think a better approach on this intra-hour diversity is to update it with real data every two years when the study is updated. So then you will capture what the true intra-hour diversity. And I would argue that Mr. Kirby, who used similar calculations but found a very different result, instead of the 13 and 17 percent discount that we found for the existing plus transition, he thought it should be a 40 percent discount. So that's why we requested the data and formulated the calculations that we did in our comments.

So while there was diversity during that period, future diversity may not materialize as expected. And so that's why that has not been incorporated in the study.

Q. Okay. So just to clarify, that diversity benefit that you quantified was not incorporated into the study?

A. That we quantified from 2016 to 2018 was not, but we're going from a much -- even a larger level of solar, which we're very uncertain how that's going to materialize.

Q. But your study made a number of assumptions despite uncertainty. For example, your study assumes that the CPRE Tranches would be fully subscribed, but be now know that Tranche 1 was not, in fact, fully subscribed.

So why would your study include that kind of uncertain and indeed inaccurate information but exclude observed quantified diversity benefits?

A. So you mentioned the Tranche 1 solar capacity, and that, in no way, impacts the analysis that we're doing, because we took the existing plus transition, which did not include the Tranche 1 capacity, just to be clear. So our numbers that are being used by the Company for rates is the existing plus transition. It didn't go to the next Tranche 1 block. But I'm not aware of exactly what has been procured.

As part of the study that started in 2017, we have to make assumptions on what solar levels we're going to evaluate. That is our objective is to look at different solar levels. So the fact that Tranche 1 was undersubscribed or oversubscribed doesn't change the analysis of just looking at different blocks of solar.

Q. Fair enough. I have no further questions. Thank you.

MS. BOWEN: If I may, if it would be helpful to the Commission, I know Ms. Hutt had not planned to introduce the NERC standards as an exhibit, but the witness has answered a number of questions. We have enough copies. If it would be helpful to the Commission, we can do that.

CHAIR MITCHELL: Sure. Go ahead.

MS. BOWEN: Okay. I will hand them out, and you can -- yeah, we'll just move to enter the NERC balancing standards that Mr. Wintermantel testified to into the record as the next hearing exhibit.

CHAIR MITCHELL: How would you like that exhibit identified?

MS. BOWEN: Let's identify that as SACE Cross Exhibit 1. And SACE -- SACE Wintermantel Cross Exhibit 1. And I will pass it out and then we could move to the next cross. Thank you.

(SACE Wintermantel Cross Exhibit Number 1 was marked for identification.)

CROSS EXAMINATION BY MR. LEVITAS:

Q. Good afternoon, Mr. Wintermantel. I'm Steven Levitas representing the North Carolina Clean Energy Business Alliance. Nice to see you today.

A. Good afternoon.

Q. I'd like, if -- well, in light of Ms. Hutt's very thorough cross-examination, I'm going to try to keep my questions focused and fairly short. But let me start by talking about this metric issue. That's really the heart of the dispute here.

You've established this LOLE FLEX as the standard to which the volatility performance or the impact of intermittency should be held. And I think you've testified that that is not a regulatory standard that the utilities are required to comply with; is that correct?

A. That is correct. And so, in review of other integration studies, it's clear that there is no standard when it comes to what the reliability threshold should be. We think it's best just to make sure that it calibrates to historical operating reserves, as we've discussed. So there is no defined standard out there, other than the NERC balancing standards, which we've all agreed cannot be captured.

Q. Well, let's -- I appreciate that, but let's separate two different things. There is, in fact, a regulatory standard that the utilities must comply with, which is the NERC standards.

I think you testified that you believe those are sufficient to protect the reliability of the grid and are adequate standards, correct?

A. That's correct.

Q. So the issue is not that there's not a standard, the issue is that it's difficult to conduct an analytical or predictive model against those standards. And I'm not going to get into the reason why that is, but that's the problem, it's not the problem that a standard doesn't exist?

A. That's correct. So modelers, and in my world and across the country, have to come up with ways to understand, do I have enough flexibility on my system, which would ultimately meet those NERC standards.

Q. Sure. Understood. But the dispute in this case is whether, in seeking surrogate in order to try to determine whether the system is sufficiently flexible to meet the regulatory standard that does apply, whether you have chosen a surrogate that is too stringent and it would result in excessive cost.

That's what -- I understand you don't think that, but that's the debate in this proceeding. We got expert witnesses who disagree with you on that, correct?

A. Yeah, I think that's a fair statement.

Q. So a question I have is you have referred to the historical operating reserves, and that you're relying on the LOLE FLEX in part because they're sufficient to achieve those historical operating reserves.

Well, let me ask, is that correct?

A. Well, the historical operating reserves, when modeled, result in a LOLE FLEX of 0.1. So we're basing -- so the historical operating reserves, it's an input into the model, the result is the LOLE FLEX, which is a metric developed by Astrape, but very similar to what was done in the Idaho study from, we have to pick a metric and a threshold before and after solar. But is that clear, though, that the operating reserves are an input. If we put in the historical operating reserves, kind of as a total of the two systems, we get 0.1 FLEX that were reasonable. And that tells us that we're reasonable, because in 2015, we know we managed NERC standards that was operations as they were, and so that was our starting point.

And also what that tells us is that our starting point of operating reserves are not just drastically high, because I would agree with SACE. If we started operating reserves at some extreme level above what we've seen in history, then that isn't a good starting point, and we did not do that.

Q. Well, that's really my question is, are you able to say whether the historical operating reserves that you refer to were -- I understand that they were sufficient to meet NERC standards, but were they necessary? I mean, just theoretically possible that they were twice as large as what was necessary to meet the NERC standards.

A. I mean, that's a difficult thing to answer, but what we did was we took a year that had very little solar, 2015, before all the solar penetration launched, and so that's what we're tying to. So, you know, without looking, I don't think I know any more than that, that that's the best thing we could do at the time.

Q. Well, I understand the limitations of modeling exercises of this sort, but my question really is, if it were the case that Duke were maintaining significantly more operating reserves than were necessary to meet NERC standards, unless the Commission directed them to do that, that would be imposing an excessive cost on ratepayers today; would it not?

A. That's right. If the Companies were operating in a way where they were -- had significantly excess operating reserves, then yeah, that would be an increase in cost.

Q. Right. So similarly, if -- going forward, if they were to maintain more operating reserves than needed to meet NERC requirements, and this charge were to be put in place, the effect would be to overcharge the solar providers who were subjected to that charge, correct?

A. If operating reserves were overstated, then yes, it would increase cost. But to be clear, we feel the study is calibrated well with history and the starting point is not excess.

Q. Well, I'm sorry, what is your basis for saying that the starting point is not excessive?

A. So I think, as I've said a couple of times, we compare the historical operating reserves in scenarios with little solar to what the model, then we put those operating reserves, we compare to what's in the model with the no-solar case. If those are close, comparable, then we believe we're calibrating to how the system is actually running. And then the result of that points to a 0.1 FLEX which is why we deem 0.1 FLEX is reasonable.

Q. But none of that analysis compares to the NERC standard?

A. It does, in that we know we met the NERC standard in 2015.

Q. Right. But to my question, you don't know whether the reserves that you utilized to meet that standard were significantly greater than what would have been required to do so with the minimal amount necessary?

A. Well -- and I'm not an expert on the operations of the NERC standard, but I know it is not NERC's intent for us to push and be very close every month to having a violation. The violations are very expensive to the Company. And so there is no intent by NERC for us to push the limits or for any BA to push the limits.

Q. But to be clear, I wasn't talking about pushing the limits. I was talking about the possibility that you might be significantly long when operating reserves.

A. Fair enough. I just heard you say that the -- you know, the minimum requirement. And we're not -- we want to make sure we're in the NERC standard, and I think that's NERC's intent. I think we're on the same page, yeah.

Q. Let me -- at the risk of asking some overly basic questions, might be helpful -- I know I'm coming last, but just to step back a little bit and be sure we all understand what this model does.

A. Sure.

Q. So I understand there are -- ultimately, you are -- well, you tell me, when I mention a variable, whether you are making a prediction about this parameter or whether you are providing an input based on some historical data assumption.

So one issue is the amount of solar on the system, correct, the amount of solar penetration? And to some extent, I gather you got some historical data, and you're making some assumptions about the amount of solar that will be on the system at various points in the future, correct?

A. Well, not exactly. So we're modeling the 2020 system, and then we are simply just varying the amounts of solar. Because I agree there's uncertainty about what's going to be on there. So we're modeling -- that's really a major variable in the study is we're looking at different solar levels.

Q. Right. But those you don't model; you make an assumption, it could be X, it could be Y; you make an assumption --

A. We make an assumption on the capacity.

Q. On the capacity.

A. For modeling the hourly profiles and the intra-hour volatility and --

Q. We're going to get to that in a minute. Yes. We'll get to that in a minute. So I just want to go step by step. So you've got the amount of solar on the system, and then you've got the issue of load.

And then with respect to load, do you make assumptions or do you model load?

A. So we model load. We have a load forecast for 2020. So we are modeling the Company's load forecast, and then we model 36 synthetic load shapes from 1980 to 2015 that have been developed as part of the 2012, 2016 resource adequacy, and really gives you a variability of what load can look like if we were to have 1980 weather again, 1985 weather again. And we go through the whole 36 years. So we've got these synthetic shapes that are developed based on what the customers' usage patterns are in recent history. So we're not taking load from 1980, don't get me wrong. We're just taking weather from those historical years and we're synthesizing, creating loads, assuming that weather occurs.

Q. Right. So you're doing some analytical modeling for the purposes of predicting what load will be in the test year of 2020; is that --

A. That's right. So we get a full distribution of what load could look like.

Q. And then also you have to model the volatility within that load, correct?

A. That's right. And so based on which -- honestly, from year to year, this probably is one of the least things that's vary. We take one year of historical data, and it's still that same time period, and I think it was October 2016 to September '17. We actually put in the five-minute load data for both DEC and DEP in the model.

Q. Right. So you --

A. That's based on historical --

Q. Fine. That's historical data input; that's not a model function?

A. That's right.

COURT REPORTER: I'm sorry. One at a time.

THE WITNESS: But we would not expect -- we would not expect that to change from year to year, given the size of the system and how load increases from year to year.

Q. And then with respect to solar volatility, do you do the same thing, you just input a single year volatility data, or how do you deal with that?

A. That's right. So we took one year. So it was the best information available at the time. So again, we pulled through the end of roughly third or fourth quarter of 2017 that's in the study. So we got a one-year dataset of what the solar volatility looked like.

And so that was scrubbed in detail to remove any anomalies and five-minute data that would not make sense that we were really just reporting here.

Q. Okay. And then in order to -- you've got all that data in your model.

A. Yeah.

Q. In order to determine whether -- what you're really trying to solve for, the amount of reserves that are needed to meet your target?

A. That's correct.

Q. Do you also have an input, or assumption, or a model with respect to exactly what is going to be done to respond to balancing requirements to follow load? Because they're different -- there are different things that could occur, are there not? That would --

A. That's right. So I think that's -- you bring up -- that's a good point, because I think that's one of the reasons that the Idaho metric and the SERVM metric is difficult to compare. There's a lot of things happening in the SERVM model, because we're testing reliability in an actual production cost model.

So we're able to redispatch units, alleviate these intermittent issues. There's hours where we have excess operating reserves just due to the nature of committing resources to peak load. So I think I hit on this earlier, but that's part of the reason why the 0.1, I think, is different. Now, I'm speculating a little bit, because I'm not -- details on -- I don't know all the details. I haven't sat with modelers on the Idaho study, but I think it needs to be made clear. I think that's one of the reasons that we're different, because we're actually capturing the reliability metric in the model.

So there's things, as you mentioned, that can happen to help avoid violations, and that can be the decision to redispatch if generators go down and, you know, you have quick-start CTs, you have lots of options to avoid some of these five-minute FLEX events.

Q. That's right. And so how do you deal with that parameter? Do you make assumptions, or do you use modeling and run different scenarios of things in that --

A. So those are inputs to the units on the system. So if you've got a CT, you put in exactly how many minutes does it take to start, and that information comes from the Company. So you've got detailed parameters around each generating unit. So the model knows -- and its -- the model's objective is we're going to be reliable first and foremost. So if you have a CT that's available that can start in five minutes, well, then you're going to operate that and be able to avoid an event. So that's inherent in the algorithms of the simulation model.

Q. Okay. So with respect to each of those modeling inputs or components that we've been talking about, is there potential for error, or uncertainty, or variability in each of those elements?

A. So I think we attempt to tie these inputs to historical data and to calibrate as well as we can, but yeah, I would be lying if we're not modeling. There's a model aspect to this. We can't predict the future. I mean, we've already discussed extensively about gas forecasts. Obviously, gas forecast is a portion of this integration cost. So yeah, there's uncertainties that a planner has to make in any model.

Q. So, for example, with respect to the load volatility, which you indicated was based on, I believe, a single year of historical data, if that year, in fact, was not representative of future years, then you would have the potential for some deviation of the model results, correct?

A. I just happen to think that exact example is probably a bad one, because if you've got 125,000 five-minute intervals in 8760, you're going to get a pretty good representation across that year, even from year to year. When you increase load, you're not going to change that volatility distribution that much.

Q. Well, with respect to all of these elements, and these elements combined that roll up into these results, to what extent have you done sensitivity analyses to look at how the model output or the model results would vary as these various inputs might vary or prove to be inaccurate?

A. Can you -- I mean, is there a specific assumption? Because there's a lot of assumptions in this study that would really have little to no impact on the results. I mean, there's specific inputs that would drive the results, so I don't know if you could help me.

Q. Well, let me give you an example. On the solar volatility, for example, I believe you projected a linear increase -- escalating increase in solar volatility, whereas Mr. Kirby takes issue with that and believes that solar volatility does not increase in a linear fashion with solar penetration, for example.

A. Yeah. So, yeah, solar volatility, I think, kind of discussed my stance and the Company's stance on this, is that we took one year of historical data, and that was the best available data at the time. To assume that there was some significant weather diversity going forward to get to the existing plus transition tranche, we did not believe was appropriate given that the next set of solar projects that could come online would be much larger than the amount sitting on the system today. Small amounts of solar that actually, in various places, improves the volatility distribution. But if we add large projects, say we add 100 megawatt project here and here, cloud cover hits those individual projects, it could actually dampen any diversity.

So the analysis that Mr. Kirby did did not have any of these larger projects that we expect. And so while that's 2016 to 2018 period that he analyzed, we would agree there is some diversity during that period, because lots of smaller solar projects are coming online. We just aren't -- we were not in a position to where we could believe that, going forward, giving what we know is coming on. And then I think the approach of updating this every two years is substantial.

But yeah, certainly, if you change the -- I think where you're going, if you change the intra-hour volatility substantially, then you're going to see a little bit different result. But I think we modeled it in a way that projects what we believe is the intra-hour volatility of the system today and is appropriate.

Q. Have you done any statistical analysis that would lead you to derive a confidence level in the result of your model?

A. I have not done any additional statistical analysis, but as I stated earlier, the model is already probabilistic, so we're already taking into account 36 years of weather, all these different assumptions, and rolling into an expected case. So it's not like we're letting one assumption drive the results. We've got lots of variability already in the model.

So you throw all these potentials -- because I agree, there is uncertainty around what solar is going to do in one year. So what's why we have 36 weather years to help weight that, produce an expected case. So in that sense, we really have -- within the simulations in the model, have taken into account some kind of confidence intervals. I mean, we could go and pull the -- we have weighted average results. We could pull what the 90th percentile-type look is.

Q. Right. And then that would be interesting to know, wouldn't it, whether the accuracy of these results is to a confidence level of, say, 90 percent versus 99 percent?

A. Yeah. I mean, I think we would always still propose that you're going to take the expected case out of these results, which is what we've done.

Q. Well, you indicated several times that your goal was for this result to be as accurate as possible, correct?

A. That's correct. We have no bias in the study we performed. We're trying to understand and produce a product that is accurate.

Q. And isn't it the case that the kind of sensitivity analysis that I'm referring to is a fairly common tool in the modeling world in order to validate and determine the confidence level the decision-makers can have in a model of this sort?

A. I mean, I just feel like, as part of this process, we've hit on some of the major sensitivities already with Public Staff external. You know, looking at what happens on the island scenario, we've kind of shown those results, we've shown what happens if we alleviate the LOLE FLEX metric. So I feel like we've, for the most part, covered our bases.

Q. Well, one of the things that you did, I don't think we've talked about, is that you -- if I understand what you did in your -- it's Exhibits, I believe, 4 and 5 to your direct testimony, pages 21 and

25. I'm sorry, I had a handout the other day with those. But you have what you call a 75 percent volatility case; is that correct?

A. Yeah, that's correct. On the most extreme solar penetration level, we felt, at that level, we needed to understand that if we reduced the volatility distribution and added some additional diversity. But again, those results are not being used by the Company. It's just a point in the study.

Q. Just to be sure we all understand what you did there, did you assume that the volatility -- the solar volatility was 75 percent less than your base case scenario; is that correct?

A. So it's --

Q. I'm sorry, 25 percent less.

A. That's right, 25 percent.

Q. And isn't it the case that, when you did that, that the solar integration chart that you derived was significantly lower than at the 100 percent volatility scenario?

A. Yeah. They decreased when you decreased the volatility assumption, yes.

Q. And how is the Commission to know whether that 75 percent number is a better number than the

100 percent number?

A. That is a difficult thing for the extreme solar penetration level. We self-identified that in the study, that those high penetration levels, we -- they're highly uncertain. And so that has been the stance of the Company through this whole process is, this needs to be updated every two years. We're getting changes on the system that will affect these results.

But we are much more confident in the results as you move down that solar penetration level. When you look at the existing plus transition level, which is the first block we looked at, we're highly confident in those results. The volatility distribution, as you go further out, we're just going to have to see how it materializes.

Q. Have you used this model at this point to -- or have you calibrated this model against any future years? I guess we're in the middle of the year right now. I think the model's been developed over the last year. Are you in the process of trying to calibrate this model against 2019 performance to see how well it matches up to actual experience?

A. I mean, that would be subject to Duke requesting it. So no, we are not -- there's nothing on the horizon for us to be doing that right now. I mean, I will say, though -- and I think it's probably to the benefit of the Commission -- that the SERVM model is not a new model. It was developed by a southern company in the early '80s. It's been a resource adequacy and production cost model ever since Astrape took control of it in 2005 and has commercialized the model since then. And we have done studies and even used the LOLE FLEX metric in various jurisdictions.

So some of them are public studies, some are private. I would bring to light one in California that was done in kind of the '15, '16 time period called the CES-21 project. It's the California Energy Systems Project. So Astrape was actually selected -- the SERVM model which uses the LOLE FLEX metric was selected to assess the flexibility of the California system. We know they're number one in renewables.

So as part of that -- and I know we discussed kind of peer reviews yesterday, and Mr. Snider obviously doesn't have the knowledge of the model as I do, but as part of that '15 and '16 study, the CES-21 study, the peer review, the advisory group to that was EPRI, was Lawrence Livermore National Lab, all three

IOUs in California, so that would be Pacific Gas and Electric, Southern Cal Edison, and San Diego Gas and Electric, plus the Cal ISO, plus the CPUC, the regulatory commission.

So as part of that, the calibration that you speak of, your questions are going down, the model is well vetted. It's been calibrated in many jurisdictions. It's been used in results. And the LOLE FLEX metric, while not 35 years old, the LOLE FLEX metric, obviously, has been developed over the last five to 10 years in order to accommodate the renewables that are coming on the system, these modeling techniques, but that has been used in several jurisdictions. In fact, we just filed a report -- public report, and have I testimony in New Mexico regarding a study we just performed for them which includes the FLEX metric.

So I just want to be clear that this is not a new model. It's been vetted. And that's all I'll say. So the calibration of the model has been tested in lots and lots of different jurisdictions.

Q. In other applications, as opposed to this application?

A. No, no. And integration-type analysis.

Q. I'm sorry. My question wasn't clear. I meant with respect to its utilization for this purpose in this proceeding.

A. Okay, yeah.

Q. And isn't the sort of technical review committee or the sort of peer review process that you were just talking about and that I asked about earlier, isn't that best practice with respect to this kind of work and --

A. We perform a lot of studies for investor on utilities that do not have -- this was a DOE sponsored -- more of a research project in California that sponsored the advisory group. So, honestly, I would agree with Mr. Snider yesterday that most of the work we do, which are practical studies that get approved by commissions by investor-run utilities, do not go out and hire four different -- three or four different academic firms to confirm the study.

I recognize the Idaho study, I don't know who sponsored that, did have a larger technical group, but in our experiences, not -- it's not common for us to have that type of an advisory group. Now, I will say, as part of this study, there were lots of experts involved.

I feel like Astrape Consulting and the model is state of the art when it comes to this type of analysis. The Duke employees who have years and years of experience had their hands in this model. And, honestly, from our perspective, the Company doesn't really have a reason to be biased here. This is moving costs that are going to be paid by customers to decide who gets paid. So it's not -- I agree that there's not a huge bias, but -- and then Public Staff spent substantial time validating and hearing concerns from SACE and other experts, and we did our best to validate that. So I would not say it's always the case where there's this significant peer review for a study like this.

Q. Well, let me talk about what happened here. You were talking about the number of people involved in the model, and I don't think you mentioned anyone who is not an employee or a contractor of Duke Energy, correct?

A. Public Staff.

Q. Before you got to the Public Staff. I'm talking about the development of the model and producing the study?

A. Yeah. I mean, I think that's fair. They hired us, they felt the burden to prove this, so they hired Astrape to perform the study. They kind of wanted third-party unbiased opinion.

Q. Okay. And you obviously didn't feel the need to consult with any independent third parties to obtain their input with respect to the models --

A. I feel like we've gotten that third-party input over various jurisdictions over the last 10 years.

Q. Okay. Now, as you present -- following your presentation of this model, there were a number of experts who took issue with your methodology and your results, including Mr. Kirby.

Now, would you agree that Mr. Kirby is an extremely experienced and well-qualified expert in the area of intermittency, and integration, and balancing issues?

A. I have not met Mr. Kirby up until this docket and still haven't met him, but based on a résumé, yeah, he seems like he has great credentials.

Q. And have you had any personal interaction with him in an attempt to talk through his issues and see if you could reach a mutual resolution of the concerns he's expressed?

A. We have not.

Q. And having -- I understand what you described as a normal process, or what you believe was kind of standard operating procedure, but having been presented by a recognized expert with serious objections to your methodology and results, did it, at that point, occur to you that it might be helpful to involve a neutral third party to see if you might achieve come resolution of that dispute?

A. No. I mean, I think, as a subcontractor to Duke, it was our responsibility to respond and reply comments. We did the best we could to address every issue that Mr. Kirby addressed. We did not leave anything hanging out. We responded in reply comments with what we thought was correct, and so we still stand by those comments that we believe the study is appropriate and was conducted correctly.

We do not see the critiques that Mr. Kirby has represented as being flaws in the study, so there was really no reason to reach out further to him when we completely disagree on items.

Q. I just have one more line of questioning.

A. Sure.

Q. I want to talk to you some about the cap.

I'm sorry, one quick question before I go to that.

Energy imbalance markets. Some of the experts on this side of the room have suggested that there's the potential for significant cost reductions with respect to integration charges or integration costs through the formation of energy imbalance market or other similar kind of regional cooperative mechanisms; do you agree with that?

A. So my experience, I do not have a significant experience with EIM. My -- really, it's been part of this project, I've understood Idaho's stance on the EIM, which was not surprising, because it lines up with the Company's stance. But basically, when I read that quote earlier -- did you hear my quote earlier from my summary -- that they basically said in their study, which is favorably sided by your experts, that the EIM, they do not anticipate that to lower their operating reserves, because that is a non-firm exchange of energy on the intra-hour exchange of energy.

So it's interesting that that's their take. I'm not an expert on that, but taking their quote and hearing what DEC and DEP have told me in regards to this islanding issue, I would lean towards that is the correct approach.

Q. I'm glad you raised that because it reminded me of one other thing that I wanted to ask you about --

A. Yeah.

Q. -- which is the difference between the cost of having operating reserves -- required operating reserves in place and the cost of actually utilizing them to follow load. So I thought about it. I'm not sure I had much success with my analogy yesterday, but I'm going to try another one.

There's a regulatory requirement with respect to fire code in this building. You see these sprinklers around the room? And they're, I imagine, fairly expensive, and if you ever had to operate them, that would be very expensive, because the room would be flooded and you'd have to deal with all that sort of remediation. If we had a little fire over here in the corner of the room and Mr. Dodge was be able to stamp it out, the actual cost of dealing with that problem and complying with the fire code would be substantially less than if you had to sort of bring in the heavy artillery and use the most expensive solution.

And so what I'm wondering about with respect to these issues of following load, I understand there are costs associated with maintaining the operating reserves that you believe are necessary, but in the moment when the operator is actually having to take the steps necessary to follow load, you have potential variability in cost.

So, for example, even though they may not be able to rely on neighboring utilities, if they are, in fact, able to import energy to achieve balance, then they may not incur a more expensive cost that would be reflected in your model either; am I right about that?

A. I mean, to the extent that there is this vast difference in the cost of energy across the interconnection, and you could bring in those chief resources and firm up your capacity, I guess there is a chance there's some savings there.

Q. Okay.

A. But they're still responsible for their operating reserve requirements.

Q. Understood. But those are the capital costs, if you will, or the fixed costs of maintaining the reserves as opposed to the operating costs of -- so, for example, of having to ramp up a unit. If it turned out you didn't need it, then you wouldn't -- there's some portion of that cost that you wouldn't incur, correct?

A. I'm not sure I completely follow your example. I mean, we're still needing to meet operating reserves. We're still going to have to back down our generators, which are going to make them more inefficient. Basically we're paying for energy at a -- let's just say a A-type heat rate, which is kind of a generic price, I just don't see the savings you're talking about.

You're still going to have to back down generators. You still have to serve that operating reserve. You still have to back down your generation and make it more inefficient. It's just now I'm maybe purchasing energy from somewhere else, just because it's slightly cheaper than what my next resource -- energy resource is. There's still the inefficiency of serving that level of megawatts of operating service, so I think I disagree.

Q. Let's talk about the cap. And I apologize, but I find it very difficult to follow, and this may just be me, so I may need a little explanation and ask some questions to be sure I understand how it works.

I believe the proposal is that, during the contractual term of a solar facility, it would -- one that would be subject to the cap, it would initially be subject to the average charge, correct? And then it would have been set, for example, in this proceeding, and then in a subsequent biennial proceeding, there would be a new average charge determined?

A. So let me just stop you for a second, because my testimony calculates the cap, the mechanics of the cap. As far as how the cap is applied to PPAs and rates, that's not my testimony. But I will be happy to talk about how that cap was calculated.

Q. Okay.

A. But --

MR. BREITSCHWERDT: I think Mr. Wheeler's testimony addressed the mechanics of the cap.

Q. Okay. Well, all right. Let me, then, deal with how it was calculated.

So the -- as I understand it, the cap is based on your calculation or your modeling of the incremental cost of the integration charge. And I believe it's for the last hundred megawatts of the vintage of the contract; is that correct?

A. So based on the -- and it's in my summary. Let me just get to my summary real quick. So in my summary -- you're right, it's the incremental of the last 100 megawatts to be expected to be installed by the end of 2020 based on the Company's IRP. So that's the level solar there. And looking at that last 100 megawatts and calculating the incremental cost of the 100 megawatts. Very similar to the other tranches, it's just now we're looking at the 100 megawatt increments. So we run it before and after that 100 megawatts and determine what the cost of that last hundred megawatts is.

Q. Well, I'm having trouble following the logic of that, because let's imagine a five-year PPA that's entered into today. And under this proposal, the charge is going to be adjusted every two years, as I understand it, subject to a cap.

A. Yeah. Well, again, you're beyond my scope. Ratemaking piece of this --

MR. BREITSCHWERDT: Objection.

THE WITNESS: I'm not familiar with exactly --

MR. LEVITAS: Well, if I may, Mr. Breitschwerdt, I'm not going to ask this witness to testify to anything he doesn't know, but I don't know how I can get to the question about what he does know without just -- we can stipulate and you can tell me if I've got it wrong, but I need to ask him a question about how this cap is calculated, which he said is within his area of testimony.

MR. BREITSCHWERDT: He said how the cap is calculated. So nothing to do with a five-year PPA. And I would submit that Mr. Wheeler's testimony for the Company addressed that, and I also replied that the Public Staff was a party to that stipulation. And I think Mr. Thomas is well qualified to answer the question that you might have. So please answer if you are able to.

MR. LEVITAS: Well, let me try to get the question on the table and see if he can answer it.

Q. What I'm trying to understand is the basis for charging -- for potentially charging a PPA over the life of a five-year term a cap that is based on the incremental charge.

What is the logic in using that incremental charge when that solar facility is only going to pay an average charge over the life of its PPA?

A. And I --

Q. Let me -- I'll try to rephrase the question.

The problem that I'm trying to ask you about is that you've proposed caps that are roughly three times the average -- the initial average cost; is that right?

MR. BREITSCHWERDT: Objection. Mr. Wintermantel did not propose a cap. Mr. Wintermantel quantified the cost -- the incremental cost of those load file reserves for that amount of penetration. The Company proposed a cap. And I would reiterate that that was in Mr. Wheeler's testimony and a witness for the Public staff who is also a party to the stipulation that purported the cap will be available later in this proceeding. I'd also note that NCCEBA had five minutes to cross that was reserved, and we're now an hour and 20 minutes in. So it seems like, if it's beyond the scope of this witness' testimony, we should leave it at that.

MR. LEVITAS: Well, we'll be happy to take that up with the Public Staff witness at this point. I have nothing further, thank you. Thank you, Mr. Wintermantel.

Ms. Hutt: Madam Chair, if we may, we would like to now move SACE Wintermantel cross Exhibit 1 into the record.

CHAIR MITCHELL: Without objection, that motion is allowed.

(SACE Wintermantel Cross Exhibit Number 1 was admitted into evidence.)

CHAIR MITCHELL: Redirect?

MR. BREITSCHWERDT: Just one topic very briefly.

REDIRECT EXAMINATION BY MR. BREITSCHWERDT:

Q. So, counsel for SACE asked you a few questions, Ms. Hutt, about Figure 7 on page 31 of your testimony, and then Mr. Kirby's figure on page 37, and the differences between the two, in terms of solar penetration versus the actual nominal solar that was being set on the system.

Can you just take a minute and explain to the Commission what is the relevant consideration and why you think Mr. Kirby's analysis is inappropriate?

A. Yeah. So again, my Figure 7, it's a comparison between our study and the Idaho study. And it's simply comparing the operating reserve increase as a function of the solar capacity. So when you look at our study, you look at the Idaho study, the operating reserve increases are driven by the actual nominal amount of solar capacity. I mean, that is what's driving the additional operating reserves.

What I think Mr. Kirby has done is somewhat confused the situation is try to tie the solar divided by the load which is a percentage penetration. Yeah, sure, Idaho has a higher solar penetration, but not more solar capacity. And so the solar capacity is the right comparison.

When I add 100 megawatts in DEC and I add 100 megawatts in Idaho, the volatility -- let's say they're the exact same solar projects -- we realize they're different jurisdictions, but the volatility on those would be exactly the same. So you have to address the same amount of volatility. So the increase in operating reserves on those 100 megawatts is what should be compared. It should be compared based on the 100 megawatts, not the solar penetration which takes that solar 100 megawatts divided by the load and really starts to distort the figure.

MR. BREITSCHWERDT: That's all I have.

CHAIR MITCHELL: Questions from the Commission? I do have one question for you.

EXAMINATION BY CHAIR MITCHELL:

Q. I understand from your testimony that the model, in accounting for the blocks of solar, or including the blocks of solar, did not include any storage with those blocks of solar; is that correct?

A. That's correct. So at the time, yeah, that's correct.

Q. And I heard your -- you also explained that, you know, that's sort of one of the unknowns or uncertainties at this point in time is how much solar, if any, will actually come online and when will it come online; is that -- did I understand that correctly?

A. Yeah, that's fair. I think projections of solar out in the future and how much storage is going to come online is an unknown, so we model kind of the system and projections as we expected when we started the study as best we could do.

Q. And so were you all to rerun the model or update the model every two years, update your results every two years, as you suggested would be appropriate, is the model capable, at this point, of taking storage into account? And if the answer is yes, can you explain how? Does it look at storage as a smoothing device, or does it look at storage as an energy shifting device? I mean, how would it consider storage?

A. So, traditionally, if you just put the battery in by itself, it's going to optimize energy and ancillary services. But the majority of that with what we would see is that it would be more of a shifting resource. But we would have the ability that, if we knew -- whoever was the developer had the battery and the solar, and we knew they were going to smooth it, and we saw that, and that was -- we could accommodate that in the modeling and allow that to smooth, which would ultimately lower the intra-hour volatility.

So if we knew, based on operations or some contractual that they were going to meet some level of smoothing, we could incorporate that in the model which would reduce some of the solar that is causing volatility, that would actually be modeled as smooth. And you'd see a little bit of a decrease. Now, I don't know how much, I mean, commensurately, whatever -- whatever the change was, you'd see some differences. But we still would need to kind of know the use of it. And there's -- in general, the model would try to shift.

CHAIR MITCHELL: All right. Thank you.

Commissioner Brown-Bland.

EXAMINATION BY MR. COMMISSIONER BROWN-BLAND:

Q. Mr. Wintermantel, can you define operating reserves, you know, in a basic, simplistic way that we can all understand?

A. So think about -- so when I think of operating reserves, you've got your conventional resources, the ones that we would call dispatchable. They can go -- increase up and down. So they have minimum and max capacities. They also have startup times. But let's just assume you've got three or -- let's just make it -- so you've got 200 megawatt units, and one is operating at 100 megawatts, one is operating at 70 megawatts, and it can ramp -- in 60 minutes, it can ramp 30 megawatts up. So what that would be -- that system, that 200-megawatt units, one operating at 70, would be basically producing 30 megawatts of operating reserves.

It sits there, and if it's needed, it can ramp up in a certain time constraint. And so what we're doing, when we think about operating reserves and increasing them, is we have more of those units that are operating below that 100 megawatts. Those are coming down. Unfortunately, there's a cost to that. The heat rate curve on these units is less efficient. And so by having to do that, that's really what we're calculating, those additional operating reserves.

Units being below their maximum output and further below the maximum output. Does that help?

Q. I think so. I appreciate that. Now, in your rebuttal testimony, I think you indicate that Duke provided the historical operating reserves?

A. They --

Q. For DEP and DEC?

A. That's right.

Q. Is that -- is that already in the record somewhere?

MR. BREITSCHWERDT: I don't believe it is.

THE WITNESS: I'm not sure it is.

Q. Could we get that in the late-filed exhibit?

A. Yes.

MR. BREITSCHWERDT: And just specifically so we're getting the right thing, the operating reserves for 2015 that Mr. Wintermantel relied on?

COMMISSIONER BROWN-BLAND: Those historical reserves that he was talking about on his rebuttal, page 8.

MR. BREITSCHWERDT: Okay. Thank you.

COMMISSIONER BROWN-BLAND: I will revise

that from 2014 to current, if you have it.

MR. BREITSCHWERDT: Noted.

COMMISSIONER BROWN-BLAND: All right. Thank you.

CHAIR MITCHELL: Questions on the Commission's questions?

MR. SMITH: I just have a couple very briefly. Two questions.

RECROSS EXAMINATION BY MR. SMITH:

Q. Mr. Wintermantel, would you say that only having 2015 data and not data over multiple years is a limitation of your model?

A. I would not. I would expect, giving load increases going from '14, '15, '16, '17 being relatively small as a percentage, that the operating reserves, on average, which is kind of what we were calibrating to would not being that varying across that set of data, the operating reserves that were realized on the system, I would not expect them to be that different.

Now, to the extent solar was added to the systems, I'm sure the operators have accommodated that and there has been an increase. But remember, we're trying to benchmark to a no-solar case or little-solar case so we can be comparable with our starting point.

Q. So to that point, then, would you say that only having 2015 data rather than a number of years, or if it's limited to one year, a more recent year is a limitation of your model?

A. I don't think -- I mean, can you restate it again, because I don't really feel like it's a limitation to the model. The model -- we're looking at just some data outside of the model, some actual data, so that's not a limitation to my model.

Q. Sure. Understood. I guess my question is just that it seems to me that you started Q4 2017 working for Duke, and so theoretically there would be at least the 2016 data as more recent. And theoretically, if you want to do 2018, then the 2017 historical data from Duke. And so I just don't understand why you didn't use more than just a single year.

A. We were looking for a year that had the least solar, and so that's kind of how far back we had to go. We had to go back further. We were looking for periods where there was not a lot of solar on the system to compare.

Q. But in order to validate what your model says, in terms of the flexibility issues, doesn't it make sense to look at an average of a number of years rather than just a single year?

A. I mean, I would expect a -- I just don't know, so -- but I would expect, as solar has increased, the companies have seen operating reserves increase. So you start at 2015, my expectation would be that the operating reserves would be increasing as solar has been added.

MR. SMITH: Nothing further for me.

MR. LEVITAS: One quick question for me, if I may.

CHAIR MITCHELL: We are past 5:30 at this point, so I'll give you one question.

MR. LEVITAS: One question.

CHAIR MITCHELL: Please keep it brief.

RECROSS EXAMINATION BY MR. LEVITAS:

Q. In your example to -- in response to Commissioner Brown-Bland about these two hypothetical operating units, and you talked about having to back one down and there's a cost associated with that, before you get to the issue of operating reserves, wouldn't there be some reduction in the operation of those facilities because you now had a source of solar energy on the system? So prior to solar, you would be operating at some level.

A. Yeah.

Q. Solar comes onto the system. Forget about volatility for a minute --

A. So you're talking about the energy value --

Q. That's right.

A. -- which is in the avoided -- I mean, I'm not an expert in what's going on in the docket and the rates, but that would be the avoided cost energy that you're getting paid, so --

Q. Well, I'm not asking what they're getting paid, but there would be some reduction in the operation of that unit because of the fact that there was a new generation source on the system, correct?

A. That would be the avoided energy cost, yes.

Q. So my question is, now that that unit is already operating less, do you account for that in your -- do you qualify that as an operating reserve which -- because it's already operating at a lower capacity?

A. So we're calculating -- when we calculate the increase in cost, the same amount of solar is in the case between -- we're going back to -- the no solar case gives us the operating reserve, right? But when we're looking at the existing plus transition case, the solar is in both cases, so my change case has solar in both cases.

So we're not capturing the energy value of the solar. That's done separately, as explained by Mr. Snider and Mr. Wheeler. It's a separate component, so this is incremental to that.

MR. LEVITAS: And thank you for indulging my questions.

CHAIR MITCHELL: Okay. I believe that you're finished with your witness. You may be excused.

MR. BREITSCHWERDT: Thank you.

CHAIR MITCHELL: With that, we will return --

MR. BREITSCHWERDT: Chair Mitchell, just briefly, I think Mr. Wintermantel had two exhibits with his direct testimony. If we could move those into the record, that would be appreciated.

CHAIR MITCHELL: Identified as marketed in the prefiling?

MR. BREITSCHWERDT: Yes, ma'am.

CHAIR MITCHELL: All right. Without

objection, that motion will be allowed.

(Wintermantel Exhibit Numbers 1 and 2 were admitted into evidence.)

CHAIR MITCHELL: We will return at 9:00 in the morning. And we are adjourned. Thank you.

(The hearing was adjourned at 5:34 p.m. and set to reconvene at 9:00 a.m. on Wednesday, July 17, 2019.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was taken, do hereby certify that the witnesses whose testimony appears in the foregoing hearing were duly sworn; that the testimony of said witnesses was taken by me to the best of my ability and thereafter reduced to typewriting under my direction; that I am neither counsel for, related to, nor employed by any of the parties to this; and further, that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 24th day of July, 2019.

JOANN BUNZE, RPR
Notary Public #200707300112