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BEFORE: Chairman Edward S. Finley, Jr., Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Don M. Bailey

Commissioner Jerry C. Dockham

Commissioner James G. Patterson

Commissioner Lyons Gray

IN THE MATTER OF:

General Electric

Biennial Determination of Avoided Cost Rates

for Electric Utility Purchases from Qualifying

Facilities - 2016

VOLUME 5

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CHAIRMAN FINLEY: All right. Let's come back on the record. Mr. Dodge, I believe the witnesses are with you.

MR. DODGE: Thank you, Chairman Finley.

CONTINUED CROSS EXAMINATION BY MR. DODGE:

Q I just had a couple of last questions on the Performance Adjustment Factor. Mr. Snider, just before lunch we were talking about the question of availability of units and maintenance of those units. Do you think it's reasonable to expect that QFs will have some outages, both forced and unforced?

A (Snider) Yes.

Q And to the extent -- does reliability always -- does a high reliability always factor into a high availability, or what is the relationship between reliability and availability?

A Now, for example, a solar facility could be highly reliable. In other words, it doesn't have issues with its inverters, its panels are working, it's cleaned often so that it's not -- it's not unreliable, but it's not highly available because it's not there at night, it's not there during the early morning hours. So one is, how reliable am I as a physical operating piece of equipment, and availability is am I available when needed throughout the course of the year.

Q Thank you. And so the availability, then, of a generation unit to some extent is dependent on its design, and its maintenance cycles, and fuel utilization?

A Yes.

Q Thank you.

MR. DODGE: I have some additional questions for Mr. Snider for a confidential portion, but that concludes the -- the questions I had for the Duke Panel. Ms. Edmondson does have some additional questions from the Public Staff.

MS. EDMONDSON: Good afternoon. Lucy Edmondson with the Public Staff. My questions are generally for Mr. Freeman.

CROSS EXAMINATION BY MS. EDMONDSON:

Q So Mr. Freeman, would you give us a general description of your responsibilities and involvement with overseeing the interconnection process at Duke?

A (Freeman) Sure. My team is primarily responsible for all the -- what I would call the commercial aspects of the interconnection process. By commercial, I mean the contracting, exchanging of payments, upgrade costs, that kind of thing, executing the Interconnection Agreement, recognizing and reviewing the interconnection request for completeness, that type of thing. My group does not directly support, for example, the system impact study process. Our group does not directly support the facilities process where the, you know, the detailed engineering, construction drawings, work orders, and that kind of thing are done, as well as our group does not directly support the construction process. We do get involved in coordinating all those and making sure those things do get done in -- in a reasonable time frame when and where we can.

Q Are you involved in the negotiation of each Interconnection Agreement?

A Yes.

Q And are --

A Or my team -- my team is, yes.

Q And do you generally sign the Interconnection Agreements on behalf of Duke?

A I sign a lot of them, but I also have at least one other management level person that signs the Interconnection Agreements as well, and that's on the distribution side. And then the transmission side, depends on whether it's DEP or DEC. We may execute those Interconnection Agreements as well or the transmission group will execute and facilitate those Interconnection Agreements.

Q And then in regard to the negotiation of PPAs for Duke, do you have any responsibilities and involvement with that process?

A I do. My team does, yes.

Q And are you involved in the negotiation of each PPA similarly to the Interconnection Agreements?

A Yes. My team is, yes.

Q Okay. Do you sign PPAs on behalf of Duke?

A Yes.

Q And, okay, so just to be clear, your group handles both negotiation of Interconnection Agreements and PPAs?

A Yes.

Q All right. Turning to the updated monthly avoided cost calculations, would you agree that producing those monthly calculations for negotiated PPAs has become routine?

A Yes.

Q To your knowledge, has any qualifying facility contested or disputed the Companies' calculation of these updated monthly avoided cost?

A Not that I'm aware of, no.

Q In your testimony you use the term "legally enforceable commitment." Is that the same thing as a legally enforceable obligation?

A I would -- I'd have to look at the particular place where -- where you're referencing that, but just generally, yes, I would agree that commitment and obligation is similar.

Q Mr. Freeman, do you know of any other states with issues with the interconnection process and a queue that's similar to that faced by Duke, especially by Duke Energy Progress, in North Carolina?

A No.

Q So would you agree that North Carolina has its own unique circumstances as to our interconnection process and the state of QF development?

A Yes.

Q Based on your knowledge and experience with the interconnection and PPA processes, do you know whether QFs generally obtain financing before or after they execute a PPA?

A I can't speak for certain because I'm not involved with the -- the development process, but generally what we believe is that financing does not occur until after contracts are executed, Interconnection

Agreement, Power Purchase Agreement. You know, if you remember two years ago or whenever it was when we revised the interconnection standards, we did include an option for an Interim Interconnection Agreement so that a QF project could at least in theory kind of obtain a commitment for financing, but I think still in general the financing -- I'll call it financial closure I would assume does not take place until you've got an executed Interconnection Agreement and a Power Purchase Agreement.

Q So a QF would subject -- sign and be obligated to liquidated damages before it had obtained financing?

A Yes.

Q Okay. And based on your knowledge and experience with these processes, and I understand that you're not a developer, do you know whether QFs generally begin the interconnection process or -- before or after the PPA process or how they mesh?

A Well, I think, you know, it depends on the -- the developer, but generally the first place that a developer, you know, starts the process is, you know, with the CPCN process, obtaining eligibilities of QF from FERC, submitting an interconnection request. Those are some of the first and pretty critical steps in the process. The Power Purchase Agreement. You know, I think it just depends on the developer as to when that takes place. But keep in mind the current process, you know, of establishing a LEO, going back to your question about the -- what you called the legally enforceable commitment, I mean, we see pretty often that that LEO is established very early in the process as well, much earlier than actually executing a Power Purchase Agreement.

Q Can you give me an estimate on the -- of the average time that you see that a QF -- I know this depends on the size -- that it takes a QF to go from submission of the interconnection request to execution of the PPA?

A I mean, I know we've got a data request that we provided one of the intervenors that -- that describes, you know, size of project and, you know, from interconnection request to completing Interconnection Agreement, so I -- I just don't have that information in front of me, but it depended a lot on size, and it depended a lot on whether it was DEP or DEC.

Q The proposal you have for establishing a LEO differentiates based on the size of the QF?

A (Nods affirmatively).

Q Do you know of any other state that has a similar LEO policy that differentiates based on the size of the QF?

A I'm not familiar on states that differentiate by size, but what we've tried to do with the contracting procedure process is look -- we looked at Oregon, Idaho were two states that have adopted this, you know, this contracting process as part of the process of ultimately, you know, truly making that commitment to sell through the execution of a Power Purchase Agreement.

Q And turning to those contracting procedures, do they generally memorialize Duke's current practices or do they introduce new requirements or practices as well, as I understand it, it would also establish the LEO?

A I mean, some of the process may be similar, but -- but no. Generally, this is a new process that we are proposing and, you know, our thinking is that -- I mean, this is similar to some of the discussion we've had on the interconnection process. It's how can we provide more transparency earlier in the process so developers can, you know, start making informed decisions earlier in the process. You know, so one of the steps in the contracting process is after, you know, certain requirements from the -- from the QF mainly obtaining the CPCN certificate, you know, issuing or submitting an interconnection request, then shortly after that, I mean, our -- at least the way we designed the process is we can -- we will share an indicative pricing. And pricing, you know, is one of the key inputs in determining whether it makes sense for a project to, you know, continue moving forward in the development process.

Q Did Duke seek any input from QFs or other outside parties in developing these contracting procedures?

A Not that I'm aware of, no. But, again, we did look at some other state jurisdictions and felt like that was an appropriate, you know, process to try and use, you know, in North Carolina.

Q Was it only your work group at Duke that was involved in developing and drafting these procedures?

A I mean, our group was involved along with our -- our legal support.

Q In your summary you propose that the Commission direct the Public Staff, Dominion, and other parties to provide input on the proposed contracting procedures which Duke will revise, if needed. After the other parties have provided input, who -- who would decide if revision is needed?

A I mean, our thinking was that, you know, that we would take all the input and we would revise the standards to meet, you know -- hopefully, you know, to satisfy most of the input that's being provided to us, but, I mean, at least that's our -- that was our thinking in proposing that process.

Q And you think this can do -- be done by comments or might work better as a sort of collaborative process?

A I mean, our vision was -- was comments, and I would think clearly working closely with Public Staff, you know, to finalize that process.

Q And you mentioned Dominion providing input. Is it your intent that these procedures would also apply to Dominion?

A That was our intent, yes.

Q Did you seek any -- did you have them review the procedures?

A I personally did not review it with them, no.

Q Do you know if anyone at Duke has done that?

A I don't know that.

MS. EDMONDSON: That's all I have. Thank you.

THE WITNESS: Okay.

CHAIRMAN FINLEY: All right. We're at the point where we need to have cross examination of the confidential information. Is that where we are? All right. Ladies and gentlemen, some of the information that -- that has been filed in this case has been filed under confidentiality, a proprietary designation under the trade secrets statutes. We've been indicated by counsel that they want to cross examine on some of that confidential information, and to the extent that there's anybody in the hearing room that has not signed a confidentiality agreement that would allow them to see that information or listen to it, we're going to have to clear the hearing room temporarily while we ask questions on that part of the testimony. So we will ask you to please leave temporarily, and we'll come and get you once we're finished with that part of the testimony.

And Madame Court Reporter, if you will indicate in the public transcript that from this point forward until I tell you otherwise that the questions and answers that are received will be under a confidential designation, please.

(Because of the proprietary nature of the following testimony found on pages 22 through 41, it was filed under seal.)

CHAIRMAN FINLEY: All right. Cross -- redirect examination on the non-confidential cross.

MS. FENTRESS: Thank you, Mr. Chairman. Thank you all.

REDIRECT EXAMINATION BY MS. FENTRESS:

Q Ms. Bowman, I will start with you. I think, if you recall yesterday, Mr. Ledford was asking you some questions about whether the Commission had established a competitive bid process consistent with the Companies' request to open up a docket to look at that. Do you recall that line of questioning?

A (Bowman) I do.

Q And I think Mr. -- if I remember correctly, Mr. Ledford asked if the Commission should approve the radical changes to PURPA policy proposed by the Companies in this docket if there wasn't a competitive bid process initiated. Do you recall that?

A I do.

Q And so I'd like to talk to you about these so-called radical changes and see just how radical these changes really are.

The first change that the Companies have recommended is that the Commission reduce the 5 megawatt eligibility threshold for the standard offer to 1 megawatt; is that correct?

A That is correct.

Q And what is the minimum threshold that FERC has set for the standard offer contract?

A Minimum is 100 kW.

Q So we have not proposed the minimum threshold, have we?

A No. And there are actually a lot of other jurisdictions in the country that have the 100 kW minimum threshold, so I would say it's not radical.

Q Thank you. And if you turn to your direct testimony on pages 10 through 11. I'll wait for you to get there.

A Okay.

Q And I'm not going to ask you to read through that testimony, but are you in general agreement with me that that testimony outlines instances where the Commission in the past has exercised its expert judgment to balance the encouragement of QF development on the one hand with the protection of customers from the risk of overpayment on the other?

A Yes. It's a balancing.

Q And would you also agree that as -- with respect to the eligibility threshold, that in the early

'80s there was not even an eligibility threshold?

A Yes.

Q The Commission had later imposed one. So the Commission is well within its authority to adjust the eligibility threshold if economic and regulatory circumstances compel it to do so?

A Yes.

Q And does this change in eligibility threshold mean that QFs over 1 megawatt have no place to go to sell their power?

A It does not.

Q And where do those QFs have to go to sell their power?

A They have the ability to do a negotiated contract with us.

Q A bilateral negotiation; is that correct?

A That's correct.

Q And so with respect to the standard offer contract, I'll shift back to that, the Companies are offering a 10-year contract; is that correct?

A That is correct.

Q And I believe you said yesterday in response to a question about whether you were -- whether you had reviewed the QF's ability to finance such contracts, that you had not looked at the QF's ability to finance such contracts in making that determination; is that correct?

A That's correct.

Q Are the QF's finances before the Commission when it gets a CPCN?

A No.

Q Are the QF's finances before the -- do the Companies have the ability to review a QF's finances when negotiating a contract with them?

A No, we do not.

Q And so you responded, I think, instead of reviewing each QF's financial report, that you had looked at other states in the Southeast to determine what a reasonable term for a contract would be under PURPA; is that correct?

A That is correct.

Q And I believe yesterday Mr. Stein asked you specifically about Alabama. Do you recall that line of questioning?

A I do recall that line of questioning.

Q And he showed you SACE Exhibit Number 2?

A Yes.

Q Do you still have that?

A I do somewhere.

Q Okay. If you don't have it in front of you, can I just ask you if you recall SACE Exhibit Number 2 referred to generators of 100 -- of alternative energy of 100 kW and less; is that correct?

A That is correct.

Q And it established that the standard contract for those generators was one year; is that correct?

A That is correct.

Q Okay.

MS. FENTRESS: And now I'd like to pass out an exhibit, and I'll ask Mr. Breitschwerdt to do so. This is a redirect exhibit.

MS. FENTRESS: Mr. Chairman, if I could have this identified as DEC/DEP Bowman Redirect Exhibit Number 1.

CHAIRMAN FINLEY: Let me get it in front of me.

MS. FENTRESS: Certainly.

CHAIRMAN FINLEY: So we will mark for identification this exhibit marked State of Alabama at the top as Duke Bowman Redirect Exhibit Number 1.

MS. FENTRESS: Thank you.

(Whereupon, Duke Bowman Redirect Exhibit Number 1 was marked for identification.)

Q Ms. Bowman, I believe you testified about this Order on pages 37 to 38 of your rebuttal testimony. Can you check that for me?

A Yes, I did.

Q And this is the same Order that you mentioned in the footnote on page 37?

A Yes.

Q I'm sorry. On page 38.

A Thirty-eight (38).

Q Number 46. Thank you. Can you turn to page 8 of this Order?

A Yes.

Q And there is highlighted text. I'm not going to ask you to read the highlighted text in the interest of time, but would you agree that this Order provides that alternative energy generators greater than 100 kW are also entitled to a one-year contract?

A That is correct.

Q And can you look at the back of the Order and let the Commission know when this order was issued?

A This Order was issued on the 7th day of March, 2017.

Q And would you agree that that Order was issued after the FERC's decision in the Windham Solar case?

A Yes.

Q And, in fact, this Order on page 8 cites the Windham Solar case; is that correct?

A Yes, it does.

Q Ms. Bowman, are you aware of any other state in the Southeast that has a longer term contract than 10 years under PURPA?

A No, I am not.

Q So I want to circle back to negotiated contracts because I believe you got some questions about those yesterday from Mr. Ledford and some of the other intervenors. Do you recall those conversations?

A I do.

Q And I believe Mr. Ledford asked you whether the Companies were open to negotiating some of the terms and conditions of their more standardized negotiated contracts. Do you recall that?

A I do.

Q And with respect to what the Companies' obligations are with negotiations with large QFs, what has the Commission said is our overarching obligation? And I don't know that's in your testimony, but it may have --

A I thought it was in my rebuttal.

Q Actually, it could be on pages 23 to 25 of your rebuttal, if that helps. Ms. Bowman, does -- does the Commission impose an obligation to negotiate with large QFs in good faith?

A Yes, it does.

Q And -- okay. And on pages 23 to 25, again, I'm not going to ask that you read these attributes to the Commission, but would you agree with me that the list of issues there, such as the appropriate contract and the party's best work has to avoid a capacity energy credit, service duration, factors such as that would guide the Companies' negotiations with large QFs going forward?

A Yes. I provide a list of -- of factors that the FERC regulations specifically provide, and then I also provide a list of factors that this Commission has provided as well.

Q And would you also agree that with respect to negotiated commiss--- negotiated contracts, I'm sorry, that the Commission issued some guidance in Sub 140 in the Order on Clarification?

A Yes.

Q And I believe that the Commission indicated in the Order of Clarification that if a QF did not agree with the negotiations or -- I'm sorry -- if the QF felt that the negotiations were not proceeding in good faith that it had a remedy?

A That is correct.

Q And what is that remedy?

A That remedy is to come before the Commission.

Q In an arbitration?

A An arbitration proceeding.

Q Or a complaint proceeding?

A Yes.

Q Mr. Ledford also asked if we would submit negotiated contracts for approval. Are you aware that we have been -- that the -- I'm sorry -- that the Companies have been required to file negotiated PURPA contracts at the Commission since, I believe, I'll say early '90s?

A Yes.

Q Okay. So having discussed those changes, Ms. Bowman, is it your opinion that those changes are in any way radical?

A No. They are not radical.

Q Mr. Snider, I'm going to ask you about another one of the changes that the Companies have proposed, and that is the Performance Adjustment Factor.

A (Snider) Yes.

Q Okay. I believe Mr. Dodge and -- and Ms. Bowen as well asked you yesterday -- well, let me back up just a little bit. Sorry about that. Have the Companies proposed to eliminate the Performance Adjustment Factor?

A No, they have not.

Q We're just -- the Companies are just proposing to reduce it; is that correct?

A That is correct.

Q And I believe that Ms. Bowen and Mr. Dodge have both noted to you that the Commission declined to accept the Companies' argument in the last avoided cost proceeding on the Performance Adjustment Factor; is that correct?

A Yes, they did.

Q And can you turn to page 37 of your direct testimony?

A Yes, I can.

Q Thank you. And you let me know when you're there.

A Yes. I'm there.

Q Okay. And I think at the bottom of page 37 and the top of page 38 you discuss the Commission's past order in Sub 140. And, again, I think that's been stipulated into the record. So reviewing your testimony, is it fair to say that the Commission indicated in its past decision that it was not prepared to reduce the Performance Adjustment Factor at that time?

A Yes, they did.

Q And did the Commission further indicate that at that time it saw no adverse impacts to Utility ratepayers resulting from the Performance Adjustment Factor?

A Yes, they did.

Q Mr. Snider, since Sub 140, would you agree that the Companies have experienced, and I'll borrow Public Staff Witness Hinton's word, a tremendous surge in solar QF power in this state?

A Yes. That's been clear.

Q And as a result of that surge, I believe you've testified that customers are exposed to a potential overpayment for PURPA energy and capacity?

A Yes, they are.

Q And what is that overpayment?

A We have put in my testimony extensively that just for the existing, without including the 1,100, that's a billion dollar overpayment and growing.

Q Thanks. And are you aware of any other state in the Southeast that has a comparable Performance Adjustment Factor?

A Other than South Carolina, who has stipulated, or we stipulated in South Caroline to adopt North Carolina between the Utilities so we'd have similar rates, I'm not aware of anyone else that has a PAF.

Q And has the South Carolina Commission imposed the Performance Adjustment Factor on all utilities in South Carolina?

A To my knowledge, it's just Duke.

Q And in your experience, does -- would the existence of a Performance Adjustment Factor in North Carolina attract QF developers to North Carolina as opposed to states that did not have a Performance Adjustment Factor?

A It is a straight multiplier to our capacity rate, so it does add to our rate.

Q I'll continue with you, Mr. Snider. I wanted to talk to you a little bit about the -- our avoided cost per megawatt hour, and I believe you were asked some questions today by Ms. -- by Ms. Harrod, the Attorney General's representative. Do you recall that?

A I do.

Q And if you could turn to page 4 of your rebuttal, that might help guide this line of questioning.

A I'm there.

Q And actually I'm going to back up another day.

I believe Ms. Mitchell was asking you yesterday about the comparison between the $55 to $85 avoided -- I'm sorry -- $55 to 85 per megawatt hour avoided cost rates compared to the Companies' actual system incremental avoided cost rates. Do you recall that line of questioning?

A I do.

Q And the comparison was made that the $55 to $85 rate included capacity value. Do you recall that?

A I do.

Q And in contrast, the $35 was just an energy rate.

A That's correct.

Q And so if we wanted to draw a more apples-to-apples comparison of the -- our actual system energy rates and currently approved avoided cost rates, could you look at your testimony on -- your page 4?

A I'm there.

Q Okay. And I believe it starts on line 16.

A I see that.

Q Just to -- to summarize, would you agree then that your testimony indicates that the energy rates, the avoided energy rates approved in Sub 140, were approximately $43 per megawatt hour for DEC and DEP?

A Just for the energy portion, yes.

Q Just for the energy portion. And then you go on to note that in FERC Form 714, the system marginal cost dropped -- the Companies' system marginal cost dropped from $33 per megawatt hour to $29 per megawatt hour in 2016?

A Yes.

Q And is that an apples-to-apples comparison?

A Yes. We were just looking at history for just that one, and that's not including the 136 which was much higher than the $40 rate in Sub 140. But it just said as an apples to apples to show what's happened over the last couple of years since we signed -- since we did Sub 140, where have the energy costs, marginal energy costs, for the system been relative to the energy costs that were approved under 140, and those were apples to apples.

Q Thank you. I believe also yesterday that Ms. Mitchell asked you some questions about the Western Carolinas Modernization Project --

A Yes.

Q -- and the generating assets associated with that. Do you recall that?

A I do.

Q And I believe as part of that conversation you all got into the theoretical underpinnings of the peaker methodology. Do you recall that?

A I do.

Q I'm going to take you to the real world for this part of the questions. With respect to the Western Carolinas Modernization Project, you have -- we -- the Companies had the opportunity to retire a coal plant; is that correct?

A That is correct.

Q And the Companies propose to replace that retiring coal plant with two combined cycles; is that correct?

A That is correct.

Q And are those combined cycles dispatchable?

A Yes, they are.

Q And are those combined cycles available at peak?

A Yes, they are.

Q And so with -- so with respect to the reality of actually serving our customers, could you replace those combined cycles with a solar facility?

A No. In Western Carolina there would have been no amount of solar we could have added in the western territory to meet our needs for that particular project.

Q I'm going to ask you a couple of brief questions on the fuel forecast. I believe Mr. Culley was asking you questions today about the level of overpayment that you had testified to with respect to the Companies' existing PURPA contracts. Do you recall that line of questioning?

A Yes.

Q And I believe you gave as one of the reasons for the overpayment amount that market prices have dropped and that commodity prices have dropped; is that correct?

A That is correct.

Q And would it be fair to say that another reason that results -- that has caused this overpayment is that the Companies' energy -- avoided energy rates have been set at -- using fundamental fuel forecast prices as opposed to market in the past avoided cost case; is that correct?

A Yes. That is correct.

Q And is that -- is that overpayment as a result of fundamental forecasts lagging behind the market?

A Yes. I've got extensive testimony and discussion on that, that they have lagged for a number of years now significantly.

Q Thank you. And -- but I believe it's also part of that line of questioning that you had indicated that a market -- markets go up and markets go down?

A That is correct.

Q How does the Companies' proposal for the 10-year contract protect customers from the fact that markets go up and markets go down?

A Yeah. I think that was part of the driver. Not part. It was a big -- it was a driver for going to a two-year energy reset. Again, I think I went into extensive detail. It's both fundamentals and the market, the longer you go out, you get that cone shape, right? So the further out in time, the more you're going to be off, either one, from what actually happens at that point in time. So by actually resetting every two years, you never allow yourself to go out to the far ends of that cone. You're resetting and being on the front end of the cone so that that uncertainty never gets as great as it is when you go longer term.

Q And if the Commission accepts the Companies' proposal to do a two-year reset of the energy rate within a 10-year fixed contract with capacity payments fixed over the term of the contract, does this fuel forecast issue -- is it even an issue? Is our fuel forecast even an issue?

A No. There is no debate on fuel forecast at that point.

Q And if the Commission accepts the Companies' alternative proposal to fix the energy rates that we have proposed for the two years for the entire 10 years of the contract, are the fuel forecasts even an issue?

A They are not.

Q Ms. Bowman, I'm going to switch back to you briefly. I believe yesterday you were asked a question about collapsing the BAs, the DEC -- well, I think there are three BAs --

A Uh-huh.

Q -- but collapsing them into one BA, the DEC and the DEP BAs --

A Yes.

Q -- into one BA, and whether that would solve the operational challenges that the Companies are now facing. Do you recall that?

A I do.

Q And I believe you said that collapsing into one BA is probably a fairly complex regulatory procedure, did you not?

A Yes, I did.

Q And I think you also said that it would not address the operational challenges that are faced by the Companies; is that correct?

A That's correct.

Q Would collapsing into one BA do anything to mitigate the risk of overpayments from long-term fixed PURPA contracts that our customers are currently exposed to?

A No. It would have nothing to do with the overpayment risk or actually setting the avoided cost rates.

Q Mr. Snider, I'll switch back to you. I believe in discussing the fuel forecast today that Mr. Dodge had a line of questioning about whether the Companies' fuel forecasts had been approved in the latest IRP. Do you recall that line of questioning?

A I do.

Q And I believe that Mr. Dodge was -- was indicating that in order for the Companies to use fuel forecasts in their avoided cost filing, that those fuel forecasts would have to first be approved in a biennial IRP proceeding. Do you recall that?

A I do.

Q You're involved in the biennial avoided -- I mean, the biennial IRP proceedings, are you not?

A I am.

Q Would you say that biennial IRP proceedings are fairly complex proceedings?

A Yes.

Q They have a lot of data requests from the various parties; is that correct?

A That is correct.

Q And they have a comment period for various parties; is that correct?

A That is correct.

Q There is an enormous amount of data produced in the IR--- in a biennial IRP; is that correct?

A That is abundantly correct.

Q And they are highly scrutinized by numerous intervenors; is that correct?

A That is correct.

Q Would you consider the IRP to be a fact gathering procedure as opposed to a -- a rate setting procedure?

A Yes.

Q And when do we file our IRPs in North Carolina, our biennial IRPs?

A September 1st, as long as it's not a holiday or a weekend.

Q And when do we file our biennial avoided cost proceedings?

A In this proceeding it was in November, but generally March -- or I'm not sure. You're looking at me funny. But we file them at different points every two years.

Q And have we generally filed them in November, but occasionally filed them in March?

A Yes.

Q And we would file -- in this year our biennial IRP proceeding, the Companies' biennial IRP proceeding, and the biennial avoided cost proceedings occur in the same year; is that correct?

A Yes.

Q And so do you think that -- do you believe that it was the intent of the Commission in Sub 140 to indicate that an order would be issued approving the IRP that was filed -- filed September 1 prior to the filing of the avoided cost rates on November 1?

A Yeah. And I.-- yes. I believe that we thought we would not be using 2014, that we would be using our 2016 IRP was my -- my thought that the Commission would have thought that at that time, not knowing all the -- that had transpired since then.

Q Well, let me back up just a little bit. I believe in the Sub 140 Order the Commission linked, if I -- if I understand your testimony, the Commission linked the information that was filed in an IRP with the information that we were going to use in the avoided cost proceeding; is that correct?

A That is correct.

Q And with respect to fuel forecast, the Commission indicated you -- if the Commission -- Companies want to change the way they utilize their forecast for avoided cost proceedings, that change must be approved in a biennial IRP proceeding prior to the avoided cost proceeding; is that correct?

A That is correct.

Q And my question to you is we proposed the avoided cost -- that we proposed -- the Companies proposed a fuel forecast in the 2015 IRP; is that correct?

A We did.

Q And were there any comments opposing the Companies' fuel forecast in the 2015 IRP?

A Not to my knowledge.

Q And that fuel forecast was used again in the 2016 IRP; is that correct?

A It was.

Q And that IRP is still -- proceeding is still pending; is that correct?

A That is correct.

Q Would you think it would be unusual, based on your experience, that the Commission would be able to issue an order approving a biennial IRP between September 1 when the IRP is filed and November 1 when the avoided cost proceeding is filed?

A Yes. It's given the procedural had been -- that's not possible in my experience.

Q It's not possible.

A It is not.

Q It would be highly unlikely.

A Highly unlikely.

Q And so taking Mr. Dodge's line of questioning to a logical extension, is it -- is it reasonable for the Companies to hold off on filing their avoided cost case until an IRP with -- or until the Companies' IRP is approved?

A You then make the rates even that much more stale, allowing, you know, old rates, which are well above market to -- to go into place.

Q And so would you agree that the Commission's intention, in your opinion, in the Sub 140 case was to link the Companies' fuel forecasts that are in the IRP to the Companies' avoided cost case?

A That was my understanding and reading of it, yes, it was.

MS. FENTRESS: Can I have one moment, Mr. Chairman? Thank you.

(Off-the-record discussion.)

MS. FENTRESS: Mr. Chairman, I believe I've concluded.

MR. BREITSCHWERDT: Mr. Chairman, very briefly since I sponsored Mr. Freeman. I just have two or three clean-up questions if that's --

REDIRECT EXAMINATION BY MR. BREITSCHWERDT:

Q Mr. Freeman, there was a couple questions from counsel for NCSEA yesterday, and then from counsel for the Attorney General this morning, about the North Carolina connection procedures, and you responded that you are -- I guess from the Public Staff as well, that you are responsible for implementing those; is that correct?

A (Freeman) That's correct.

Q And just -- there was reference to penalties that are imposed by QFs, and in your read of the interconnection procedures, is there any penalties that are imposed?

A Penalties on us or penalties on the developer?

Q Penalties on anyone. Would -- would you agree with me that when the Commission approved the interconnection procedures in 2015, there was significant speculation in the QF marketplace, and so there were a number of changes to those procedures designed to streamline the process and to establish clear deadlines for the interconnection customer to move forward in the process?

A I'm not sure what your question is. Yeah.

Q Does -- does the word "penalties" show up anywhere in the interconnection procedures?

A No.

Q And so when the reference was made to penalties, the point being made was that the qualifying facility interconnection customer is responsible for moving forward through the process in a timely manner; is that correct?

A That's correct.

Q And so the procedures now provide that there will be efficiencies in the interconnection process that weren't there before, based on the manner in which it was approved by the Commission?

A That's correct.

Q Okay. And some questions from Mr. Ledford yesterday, he was referencing the Companies' proposal of the LEO standard, and I just want to make one clarifying point, that your rebuttal testimony, when you proposed the contracting procedures, does not require a qualifying facility to complete a system impact study to submit the notice of intent to negotiate; is that generally the -- can you explain to the Commission what steps the QF needs to take to begin the negotiating process and to move forward to a PPA?

A Sure. You know, first, the whole idea, like I think I said before for the contracting process, was to provide kind of a more efficient process and -- and more transparency in terms of establishing clear milestones in the process for negotiating, you know, with the QF and the Utility. Some of the steps required are, you know, the QF does need to qualify as a QF. They do need to obtain their CPCN or their ROPC certificate depending on what size they are. They do need to file their interconnection request. And then they do need to -- to file kind of a form that we've modified called the Intent to Negotiate form.

Once that's done and we've essentially approved all the submittals, then the -- the project will be eligible for an avoided cost rate from us, and that starts the negotiating process with that QF. And it's completely within their control as to how that process proceeds towards ultimately an execution of a binding Power Purchase Agreement, which we believe is the -- the mechanism to truly bind the QF to a commitment to sell energy to us at a specific date in the future.

Q And one additional clarifying point. So the Public Staff's proposal in this case is that you need to have begun the -- you need a Project A or B to begin system impact study to establish a LEO. Would you agree with me that the Companies' contract and procedures contemplate to begin this negotiation process, that a project only has to be in a Project A or a Project B and begin system impact study similarly to what the Public Staff has proposed?

A Yes.

Q Okay. And one final question. You discussed with Mr. Culley for Cypress Creek this morning liquidated damages and the way the Company calculates their liquidated damages. Would you agree that for the standard offer small QFs under 1 megawatt that there is no provision for liquidated damages in the Companies' contracts with those small generators?

A Yes. I agree.

Q Okay.

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

CHAIRMAN FINLEY: All right. The Commission has some questions of the Panel, and I will start.

EXAMINATION BY CHAIRMAN FINLEY:

Q Ms. Bowman, earlier today you made reference to a non-PURPA QF, I think.

A (Bowman) To a -- a non-PURPA?

Q QF.

A QF.

Q What is that?

A Well, I was just simply saying that, you know, a qualifying facility, that a renewable facility qualifies as a qualifying facility. And you could have a contract with a qualifying facility and it not be under -- under PURPA at an avoided cost rate. It would be outside of the PURPA context.

Q That would be a -- so you would have, for example, a solar facility selling power to Duke to resell to its customers, right?

A It could, yes. You know, I was -- I was referring to -- I was, you know, thinking of the competitive procurement process or similar to Georgia and their RFP process down there. It's not done under the parameters of PURPA and avoided cost. It's done outside of that context.

Q Well, I guess my -- the question that raises with me, how would -- how would the Commission, if it would, have jurisdiction over a sale for resell transaction when we deal with retail matters? In other words, under PURPA we have -- we have jurisdiction to look at these sales for resell, but if it were not under PURPA, would we have any jurisdiction over that?

A Yes, because it would be a purchase that the Utility is making, and you have jurisdiction over the rates that we charge to our retail customers. So in that regard, just like any other Power Purchase Agreement that we enter into to serve our retail customers, you would have jurisdiction over that.

Q Over the sale by this solar facility to the Utility, which would be -- wouldn't that be a wholesale transaction?

A Yes.

Q And how would we have jurisdiction over that piece of it?

A Well, you would have jurisdiction over what we as the Utility can charge to our -- our ratepayers, so you could deem it imprudent, for example.

Q Yeah, but you're looking at the one end. I'm looking at the other end.

A Okay.

Q You see the difference?

A I do.

Q Okay. Mr. Freeman, do you have --

A (Freeman) Well, I was just going to add that at least how we think about PURPA and non-PURPA is that, you know, when we go out for an RFP or when we enter into a contract where we're purchasing the RECs, we -- we internally kind of designate that as a non-PURPA contract, so we call that kind of our Renewable Power Purchase Agreement, so that may be causing some confusion as well, you know. So especially in DEP, historically we've got a lot of what I would call non-PURPA contracts where we're buying the REC.

Q Okay. I understand that. Well, I have some questions about the negotiation of the nonstandard PURPA PPAs and the extent to which that has to do with this issue of financial ability. Mr. Freeman, I heard you to say earlier today that with respect to these negotiated contracts, you sort of like to keep the Commission's oversight out of that process so you have free hands to negotiate with the counterparties. Did I hear you correctly about that?

A Yes, you did. And you need to think about, you know, these negotiated contracts not just being solar contracts. These are, you know, biomass, wind, you know, any number of different kind of technologies. And, you know, at least the -- the technologies, you know, do drive us towards different, you know, different terms and conditions within that contract. And I truly believe that would overburden the Commission with, you know, getting involved in all those negotiations. And, you know, to date we've -- between solar negotiated contracts, I think we saw an exhibit where there were probably 30 plus contracts. You add on top of that the negotiated contracts for all of our animal waste, you know, poultry, swine projects --

Q Let -- I'm not -- I think that's great.

A Okay.

Q I'm not disagreeing with you at all.

A Okay.

Q You know, as long as we don't have to fool with it, I'm happy with that.

A Okay.

Q But on the other hand, I heard Ms. Bowman say, I think she even quoted one of our orders, that to the extent that you do have a disagreement in the negotiated PPA, that you bring the disagreement to the Commission either through arbitration or through complaint, right?

A I think that's -- that's correct. Yes, sir.

Q Okay. And we looked at the exhibits that showed 22 PPAs with negotiated PURPA -- that were PURPA nonstandard contracts that were negotiated, right?

A That -- that's correct.

Q And with a 10-year term?

A That's correct. I think you're referring to that -- the --

Q Yes.

A -- the exhibit that was submitted.

Q Yes.

A Yes.

Q And I also heard you to say earlier today that now for the negotiated contract, Duke is offering not a 10-year term, but a five-year term.

A That's correct.

Q Well, if the length of the term changes, cut in half, won't that mean that the template for other provisions will need to be or potentially be renegotiated?

A I think that's a fair assessment, that we would need to negotiate other terms, yes.

Q All right. Now, we've had some arbitrations on PPAs here, and am I -- well, the statute on that, right? There is. There's a statute on that. And you've got -- both sides have got to agree to an arbitration, right? Right, Ms. Bowman?

A (Bowman) That's correct.

Q And that we have statutes on complaints?

A Yes.

Q And a QF, before it gets to the negotiation stage, would have to have a CPCN, right?

A That is correct.

Q Now, we have two complaint statutes. We have 62-73 and 62-74, and 62-74 is a complaint by a public utility, so we probably fall under that statute to the extent it makes any difference.

A Under the utility?

Q Yes.

A Okay.

Q All right. With respect to the issue of financial ability in the context of the length of the term, a lot of the testimony we hear sort of along the line is I can't get financial ability based on what is being offered, and the other side of it is, oh, yes, you can because other people have done it. I mean, it's -- a lot of it is not digging down too deeply. But if we had a complaint, wouldn't that necessarily involve the financial ability of a particular QF?

A Yes. I believe the complaint would be on a case-by-case basis.

Q All right. And let's take a solar QF just as a generic solar QF, just as an example, and so -- but the rate is paid in part on the capacity cost of a CT, and we've talked about that a lot, right?

A Correct.

Q And that CT is a jet engine that's fueled by natural gas. And the energy part is based to some extent on the cost to the Utility of coal and gas fuel, right?

A Correct.

Q But a solar QF is not a CT, and a solar QF doesn't have any fuel, right?

A That is correct.

Q And so they've got -- so the solar QF, even though it's getting paid under PURPA avoided cost, the costs to build and operate that plant have nothing to do really with a CT or anything that burns coal and gas, right?

A That is correct. And I believe I refer to that in my rebuttal testimony.

Q So an investor who is going to finance in a -- in a solar QF, if it's above -- let's say above -- well, let's say we stay where we are at 5 megawatts, one of the things that that investor is going to want to look at, is he not, is the actual cost of the solar developer, both the capital cost and the O&M cost of that particular facility?

A Yes. That would be one of the components they would look at.

Q All right. And he would look, you know -- a CT, relatively speaking, doesn't take a lot of land space, does it?

A No, it does not.

Q But a solar facility, a 5 megawatt one, takes a substantial amount of land.

A Yes.

A (Freeman) About 40 acres, roughly.

Q Forty acres. So you'd look at the land cost, among other things, if you're going to determine whether or not to finance a specific --

A (Bowman) That --

Q -- solar QF?

A Yes.

Q And you look at the cost of the panels for that particular QF, and you look at the cost of inverters and transformation, and we talked about the upgrade cost, the interconnection cost. You're looking -- if you were an investor trying to look at whether or not to invest in that discrete QF, those are some of the things that you would look at, would you not?

A That seems very reasonable. They would look at all those things.

Q And all those things are different than a combustion turbine?

A They are.

Q And wouldn't the investor want to look at the balance sheet of the owner of this hypothetical solar QF?

A Yes, they would.

Q Yeah. And how much equity the owner of the solar QF was going to put in on its own, what would be the debt/equity ratio. Wouldn't you want to look at that?

A Yes.

Q And whether or not the owner was a LLC or whether it was backed by an owner that was very well financed, for example?

A Yes.

Q And the creditworthiness of whoever owns the --

A Yes.

Q -- the facility? The operations skills, for example? The market rates of interest?

A Yes. All of those.

Q Availability of subsidies and credits?

A Yes.

Q All right. And those -- those types of things are going to -- my assumption is they're going to differ from project to project.

A They will.

Q Okay. Now, when -- and, again, we sort of have jurisdiction over this wholesale transaction, a sale by a generator to you to resell based on PURPA, sort of this --

A Correct.

Q -- sort of this cooperative federalism concept, right, but when DEC and DEP have a dispute with a vendor, whether it be for transformers or poles or cables or computers or office furniture, you don't bring that to us to resolve.

A No, we do not.

Q You go to some other court to do that.

A Yes.

Q And what I'm having trouble with is -- what I'm concerned about is since we may go from a threshold of 5 megawatts to something below that if we're going to have more negotiated contracts and then more disputes with the qualified facilities and the power companies, and so I sort of agree with Mr. Freeman, I certainly don't want to get into the business of resolving all those disputes. And so my question is with respect to the length of the term that you're offering in these negotiated larger QFs, would it be better to have a generic docket, an E-100 docket, to sort of -- to the extent that there are disagreements, and, in fact, I know there are going to be dis--- I know there have been disagreements that have been filed with us, would it be better for us to have a generic docket where we sort of looked at what is the -- what does PURPA require and what is the, for example, the shortest length of time under PURPA that complies with the requirements of PURPA, realizing that the standard is not all that clear and the guidance from FERC is not all that easy to understand versus doing these things on a case-by-case basis?

A Well, certainly if the Commission would like to have a separate docket, we would participate in that docket. I think our belief is that going from the 5 megawatts to the 1 megawatt hopefully will not result in a rash of complaints at the Commission. That is one of the reasons why we're proposing the standard terms and -- and conditions, so that we don't have the rash of complaints at the Commission.

You know, I think we have done a lot of discussing in this docket thus far in terms of what is the appropriate length of contract, and we've talked about other jurisdictions across the country. I just recently talked about Alabama having said one year was sufficient length of term. You have other states that have one year. You have states that have, you know, various years out there. I have not seen a FERC case that has come out and said what is a sufficient length of term for financing of a QF development. I think it could depend upon the type of QF technology.

I think we have agreed to looking in future avoided cost cases at technology specific rates, and I believe we've talked about adding in technology specifics into the negotiated. It's our intent that moving from the 5 down to the 1, and I believe that Public Staff supported moving from the 5 to the 1, hopefully will not result in a flood of complaints in front of the Commission.

A (Freeman) Well, and I'll just add, I mean, I follow your questions, your -- your concerns, but that's why, you know, we're open to the idea of this competitive solicitation process where all the things that you listed, you know, all the investment costs, you know, would drive us towards, you know, what's -- what's the revenue required for a facility to recover all that investment cost and a fair return on that investment. And I would envision that either through the IRP process or through the Commission and its desire to continue some sort of a renewable development going forward, that we -- we utilize this competitive solicitation process to procure the majority of our renewable, you know, generation going forward.

So I think a combination of -- you know, you can't just look at the -- kind of the PURPA piece of this. You need to look at -- I feel we do need to look at this competitive procurement process.

Q Well, that's on, but I think you understand where my concern is. We go through two-days' worth of hearings on a particular QF and say, well, the minimum length of term for this QF to get financing is seven and a half years, five years, 12 and a half years, whatever it happens to be, and then somebody else comes along after that and says, well, you know, my QF, the cost -- the financial ability of my QF is a lot different from that one, and I need a hearing on that for two days, too.

So my request of the Companies and the parties is to think about, among the other things that you're considering doing, helping us out to see if we can address that concern that I've expressed.

A (Bowman) We will.

Q All right.

CHAIRMAN FINLEY: Commissioner Bailey?

EXAMINATION BY COMMISSIONER BAILEY:

Q Well, we'll stay with Mr. Freeman. My -- my questions are going to be sort of around curtailment and somewhat -- I guess I'm somewhat baffled by the fact that I'm sure you had a large amount of nonstandard contracts out there to you, and I'm sure that you likely, and I'm assuming this, that you likely put curtailment in those nonstandard contracts. Am I wrong in that assumption?

A (Freeman) You know, the nonstandard contracts that are still a PURPA contract, you know, they're a negotiated contract, nonstandard negotiated, we kind of use those words interchangeably, we've made a -- we tried to make a -- an adjustment in the curtailment language. It's still -- you know, we still, as long as it's a PURPA contract, can't curtail except in emergency condition situations. So, you know, there is a slight difference in the wording, trying to clarify the definition of emergency in those -- in those nonstandard negotiated contracts. There's no just free curtailment. There are -- wait, let me back up one second because there are a couple of contracts where we have entered into -- have curtailment rights up to a couple hundred hours of curtailment rights, so, you know, that's kind of a first step in terms of including some sort of curtailment rights in them.

Q You could put a ban on, okay, 100 hours, 25 hours, and do a take or pay after that, or some --

A Correct.

Q -- you could say we -- we can curtail you up to 100 hours a year, and after that we'll do a take or pay or whatever.

A Correct. And you're right. We have done that in a -- in a couple of contracts, yes, sir.

Q Yeah. I guess that from a curtailment -- and it sounds like the term "emergency situation" is where we're all hung up here, and it sounds like obviously for legal reasons Duke chose in the recent last six months not to curtail any of these solars or any of your -- I guess you said, hey, let's just don't do that; we'll -- we can transfer it to DEC or to DEP and we can live with the situation, but we've got a problem that we see coming at us pretty hard, and we want to see if we can't take care of that at least through some -- some contractual things in the future.

Obviously, I guess after -- after Chairman Finley's question to you, in the future let's just say we -- we go to a competitive bidding process. Do you still see the standard 1, if we go to a 1 megawatt, or whatever the standard, still staying in place and still seeing solar come in in that direction as well, in addition to your competitive bidding process?

A (Freeman) I think yes. I think that we will still see some smaller projects being developed that are under 1 megawatt, but we would hope that the majority of the projects would be, you know, constructed under this competitive solicitation process where you're kind of moving away from PURPA, and we would have the flexibility to include, you know, other contract terms or requirements in that bidding process to handle dispatchability and curtailment going forward.

Q And I realize Mr. Holeman is not here, and maybe these questions should have been to him yesterday, but I -- I didn't get them out, and I was taken -- I was sort of taken aback when he said the -- the LROL, the -- the Lloyd's liability operating limit is not really a NERC requirement. It is actually a Duke Energy requirement. In other words, you guys sort of set that threshold when you sell, and you start setting limits as you guys start approaching it and obviously to start saying, hey, we got to do -- the operator has got to do something because he sees getting onto that LROL.

A Well, I think what he said was that the definition or the -- the term, the LROL or whatever he calls it, is a Duke term, but every utility has the same challenge. There's a certain amount of generation that you've got to keep online. There's a certain -- I mean, you can only lower it to a certain point. Each generator that's online, that creates your LROL.

Q I misunderstood that totally. So it's -- it's just a term that Duke uses, but it is a NERC requirement; is that correct?

A I don't know if I would call it a NERC requirement, but it's just part of -- of what you need to do on a daily basis to balance your supply and demand. And --

A (Snider) And, again, I -- you know, subject to check with Mr. Holeman because I'm certainly nowhere qualified to do his job as a system operator, but the way I understand it in discussions with him is it's a term they use as part of their procedures to keep them in compliance with those NERC BAL 002, BAL 001. So it's -- you put a procedure in place that references this LROL that then makes -- you know, it's in -- the design of that procedure and the use of that term is to keep you within those NERC -- very specific NERC limits.

Q And that's exactly the way I understood him. That's exactly the way I understood him talking about that. It's just something that you guys use as a tool to make sure you don't exceed -- get into exceeding NERC requirements. And so -- so going forward when you do start talking about in the new -- in the new version anything over -- let's just say it's 1 megawatt or whatever the standard contract ends up to be, you foresee changing that language on curtailment in the future PURPA requirement?

A (Freeman) Again, we are still limited. As long as it's a PURPA contract, we are very limited as to what kind of flexibility we can -- we can include in that contract. I mean, FERC has been very clear, as I understand it, that you can only curtail during these emergency, you know, situations.

Q So the 30 or the -- for the last six months we were talking about 33 occur--- excursions or 17 more on top of that in 2017. Was that considered -- that was not considering an emergency situation at that point in time because you could transfer that power, the excess power to --

A I think that's --

Q -- Duke Energy Carolinas?

A -- that's correct. And then, you know, I'm sure you've -- you've kind of kept up with some of the industry reading. You know, for example, in California there have been several articles recently where, you know, they've solved that excess energy by paying other states to take that generation to keep it, you know, to keep -- keep it online. I mean, that's happening in Germany. I mean, I foresee that happening in the Southeast here before too much longer, that we can't transfer any more between the two balancing authorities. We'll look to the market and see if there's anybody in the market that's willing to take it. Again, we're seeing people not willing to pay, but -- but we potentially would have to pay to take it.

You know, if you look at Georgia, Georgia just added 1,000 megawatts through their competitive solicitation process, so you're going to see more and more solar in all the adjacent states as well, which -- which kind of exacerbates the challenge for all the utilities in the region.

Q So let's just say you get to the point you've got 2,200 plus megawatts of solar in your system. You -- you got no place -- Duke Energy Carolinas is now loaded up with solar in their balancing territory. DEP is now way overloaded. You can't take it to PJM. You can't take it to -- can't take it south to SCANA or Santee Cooper or you got -- or TVA don't want it. You've got no place to take this power. At some point in time you declare an emergency, right?

A I think that's when you would clearly be in an emergency situation, yes, sir.

Q Okay. Now, this is for Ms. Bowman. Yesterday Mr. Holeman was talking about if he had his druthers, he'd like to have situational awareness capability for his operators all the time, and obviously he doesn't have that today, and you likely don't have a lot of information other than just out on your systems and your transmissions that you know exactly what your loads are going on at the point -- at some points on different circuits out in the -- out in the grid. Has Duke -- has Duke Energy done any cost estimating on what it's going to take to try to get the handle to the point where instead of having to call these people, you can just say, hey, we're going to have to take you offline and, boom, you're offline kind of thing? In other words, is that part of the smart grid technology that Duke Energy is talking about, or have they done any other estimating on what this kind of cost is going to be to be able to do this kind of curtailment?

A (Freeman) We've done a lot of work recently to provide additional transparency to -- to Sam's organization. You know, we do have -- we do require projects over 250 kW to include -- I mean, we require them to pay for an electronic recloser where we have a SCADA --

Q So you have SCADA?

A -- control mechanism, so we can curtail through -- through the electronic recloser today.

Some of the larger projects we are requiring developers to include capability to dispatch them because curtailment, you know, is essentially on or off, where dispatchability would -- would create more flexibility for us going forward. So we are working with developers, working internally on creating better transparency and better means to control or curtail.

But, again, you know, I keep going back to PURPA. We're so -- we're very limited as to what we can do with these facilities under PURPA. That's why we think it makes sense to start transitioning the market to, you know, this more sustainable I'll call it control. I think we use the word control the market where, you know, bid projects out and put these, you know, requirements in place, you know, outside of PURPA.

Q Back to the states again. I mean, obviously we're -- we're talking about the California duck curve and -- other than being able to just sell the power or give the power away or have, you know, pay people to take the power, what else -- do you know anything else they're doing in California to try to handle that heavy ramp in three hours that they're talking about?

A Well, I do know that, you know, California has -- has mandated utilities to, you know, start moving towards, you know, batteries. I think they do have a mandate to contract for and bring battery storage online here at some point to help manage that.

But let me kind of add one other point. Keep in mind when -- when you're selling to some -- Sam would kind of drill into us, you know, when you're selling, you know, this excess energy, say, to a, you know, to an adjacent state or whatever, I mean, that's very non-firm energy and subject to curtailment by the purchasing entity on a -- on an almost minute-by-minute basis, so it is not a -- what I would call a sustainable solution. I mean, it's kind of a -- you know, kind of Band-Aid on, you know, what the -- what the more reliable fix will be.

Q And I -- and it's my understanding that one of those fixes may be transmission, may be intrastate transmission to be able to transfer back and forth in a more firm basis rather than a non-firm, just if we can, we can, if we can't, we can't.

A Well, I don't think -- I mean, especially with -- with an intermittent resource like solar, I don't you're ever going to, you know, be able to kind of firm that transfer up. That's always going to be done on a, you know, kind of a non-firm kind of economic basis.

COMMISSIONER BAILEY: That's all I have. Thank you, sir.

CHAIRMAN FINLEY: Let's -- if it's all right with you, Commissioner Brown-Bland, we'll take our break and come back at 4:00. Is that okay? 4:00.

(Recess taken from 3:43 p.m. to 4:00 p.m.)

CHAIRMAN FINLEY: I think everybody is in place, so we will go back on the record, and Commissioner Brown-Bland has some questions.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q Mr. Freeman, just to be sure I got this right from yesterday, so in terms of the long-term contracts, the negotiated long-term contracts, nonstandard as you say, the term in terms of the period is currently five years, had been 10 years, currently five years, correct?

A (Freeman) That's correct.

Q But the Company is always looking forward and adjusting to meet present circumstances, so I understood you to say you're considering -- presently considering or looking at two years?

A We've talked about two years, but the present thinking is five years.

Q All right. And -- and you might, even under the Alabama position, one day consider one year as a long-term contract; is that right? Or perhaps?

A Perhaps, yes.

Q All right. So -- and this will probably, I guess, go to Mr. Snider, but Ms. Bowman can handle it, too, I suppose. But help me just in a general way with the peaker method itself. That isn't really a real-world application. Isn't it -- isn't it just a construct that has been developed over time to find a way to develop a fair and reasonable way to determine what the avoided cost is at -- at a given point in time?

A (Snider) Yes. I think that's a fair interpretation you had right there. It's what's the value of your avoided energy and capacity, and it's a construct to calculate that.

Q And so the FERC has a stated premise that the risk of overpayment by the customers when avoided cost rates are used would generally balance out with the risk of underpayment over -- over time; is that correct?

A Yes. I think what the FERC was referring to was if you have a very updated avoided cost on a regular basis, and you have QFs over the long run coming in at different points in time, that when you look back in arrears, some will be above market, some will be below, and that they will over time balance out, but that would require that you update your avoided cost very often and that you had QFs coming in across time. And if that happened, I think that's what FERC was referring to, that then those under/overpayment risks would balance out.

When you don't update your avoided cost regularly or when you have these -- the conditions we have here today, those under and overpayments do not balance out. They tend to be systematic towards overpayment.

Q Have you seen any statements from the FERC, public statements, indicating that they were referring to this kind of updating?

A That's my understanding just in my reading of that statement and what FERC was referring to there.

Q So my question, then, is right from the beginning, FERC is recognizing through that statement about the balancing out of over and underpayment that that avoided cost determination at that point in time and here in North Carolina, it's -- it's biennial, is not a perfect market price, and that's known from the -- the one thing you know at the outset is the price may not be exactly right; is that correct?

A That is correct.

Q And so is the FERC in that premise about the over and underpayments looking at over the long run the Utility, and that's some theoretical long-run period, I suppose, but the Utility's customers will, as long as the Commission in setting the avoided cost rates does so, set those rates as just and reasonable -- and once we set them, I believe they're deemed just and reasonable -- as long we do that over time, it will balance out for the Utility's customers regardless of whether QFs or -- or a given set of QFs perhaps do receive overpayment?

A Yeah. And, again, I would just -- you know, just in the real world playing it forward, if they're not updated very frequently, what happens -- and this is why we think updating on a monthly basis is very important -- is you create this free option that I spoke about where all the -- if the rate is stale, and the longer it is, the more stale it can become, the more overpayment risk you have, that a significant number of QFs can rush in, take the higher of the stale rate or the new rate at any point in time and systematically across time you're not going to have this balancing out that FERC was speaking of. You're going to have a systematic bias towards an overpayment. And that's why it's critical to do just and reasonable rates on a -- on a very regular basis, which in our negotiated rates we attempt to do.

Q And using that peaker method, there are all kinds of inputs that go into that. So different inputs we could get a little bit high, some a little bit low. All those contribute to it not being perfect, correct?

A Yes. I think it's --

Q All of those different inputs. So by the same token, all those different inputs are the things that FERC perhaps was referring to when it talks about eventually balancing out over time?

A Yeah. It's market prices change, cost of, you know, technology changes, the fuel.

Q Not just -- not just one. Not just --

A Not just one --

Q -- fuel or --

A -- right.

Q It's the whole combination --

A Peakers can get more expensive, less expensive. Not just peakers. Any generation can get more or less expensive. The technology. What we've noticed, for example, is the technology is getting more and more efficient, so the heat rates are getting better, so it takes less gas to make the same amount of power, so that changes across time, which will affect your avoided cost value. So, yes, as you point out, you know, updating those on a -- on a more frequent basis rather than less frequent avoids that systemic risk of systemic overpayment.

Q And with regard to PURPA implementation in North Carolina, accepting that those rates the way it's been implemented here is a driver in the traction of QF business here, accepting that, haven't there been other factors like the tax credits, the state tax credits as well as federal tax credits?

A Yes. I think clearly for the Sub 136, when the state tax credits were in effect, that was a -- a big contributing driver on top of the Sub 136 rates, so yes.

Q Have you been able to -- since the state credit expired, which has only been a short time ago so I don't know if you're able to, but have we been able to -- are you able to give any quantification or -- or attribution as to the impact on that credit going away versus -- so that we can see how much is PURPA driven, how much was tax driven? Are we able to see?

A (Freeman) You -- we can't quantify it, but we really haven't seen any real slowdown in project proposals and project development. I mean, we're seeing projects still being constructed today. When we've talked to developers, you know, they, you know, recognize that the -- the cost of panels, the cost of construction has come down significantly, and I think more sophisticated developers have kind of planned all along for -- to drive costs out to where they could continue to develop with or without those -- those tax credits.

Q Well, is it fair to say that that same level or maybe even a little bit increased level of construction has to do with the applications that were made prior to the expiration of a credit?

A (Freeman) I think it -- it did. If you remember, up through 2016, you know, they were eligible for, you know, kind of that -- I forget what you call it -- the Safe Harbor, but even today, you know, we -- I think as of a month ago we already had 60 megawatts of projects come online and be constructed in 2017, and we've got roughly -- I think the number is 700 megawatts under construction here in 2017. So I'm not a good forecaster, but I think we're well on our way towards seeing a very similar amount of construction in 2017 that we've seen in '14, '15, and '16.

Q How's -- how much is the current federal tax credit?

A It's still 30 percent.

Q And we expect to see that go away?

A Yeah. It -- go ahead.

A (Bowman) Well, I don't know the precise, but it

-- it goes down over a period of years, so it'll drop down to 20 percent, then it'll drop down to 10 percent. Is that -- is that --

A (Freeman) Well, it stays 30 percent, I think, for several more years, and then drops down to 10 percent and stays at 10 percent.

Q All right. So going back to Mr. Snider and the billion dollars overpayment that you see was based on the rates that you proposed in this docket, I had a question, if, say, seven years ago you had to go out and acquire that same 1,600 megawatts that you were looking at both capacity and energy, if that's what you were having to pay for, but we were in a PURPA free world, would the cost have been significantly less than that $2.9 million existing obligation or do you have any way to know?

A (Snider) I'm sorry, Commissioner. I want to make sure I'm answering the right question. If we were seven or eight years ago when commodity prices are higher, what were you asking me to compare that to?

Q If we were in a PURPA free world and you had to go out and acquire 16 megawatts of capacity and energy and that's what you were paying for in the market, and it -- and it wasn't just energy, but it also included capacity, is it significantly different from the 2.9

million that you see remaining on the contracts now?

A Yeah. I mean, I think had we secured fixed price power PURPA, non-PURPA, pre-shale gas, for example, I think the fundamentals -- and, again, I keep coming back to the risk of using a market, at the time the fundamentals where gas was going to be $10 for just about forever, because we were running out of gas at that time and the fundamental forecast believed you would be at double-digit gas prices, so had we entered into fixed price obligations that were long dated back in 2008, 2007 that were 10 or 15 years at $10 gas, we would have had significantly greater losses than we have today.

Q So how does that relate to the 2.9?

A Well, I think same amount, 1,600 for 1,600, it would be, you know, $10, the current market is 3, 6 to 3, so, you know, maybe double as a real quick, and I violated my rule of doing math on the stand, but...

Q So at that point in time, that avoided cost wasn't unreasonable?

A I think if set appropriately using the market, if there was a liquid market, I'm -- I don't think pre-fracking of gas you could have gone out 10 years, but if -- you know, I do think, you know, back then if you set the markets, you would have -- you would have had greater losses at a reasonable -- I mean, it would have been reasonable to assume greater losses. Again, if you use fundamentals, those losses would have been even greater.

Q And just circling back to where I started, FERC -- there was anticipation that the price inputs and -- that there would be changes from where the set price is at a given point in time to a future price five years, 10 years down the road?

A Yes. I think, you know, if you looked at the commodity environment we've been in, like I said, over the last almost, you know, seven, eight, nine years now, the more PURPA you have done, the more losses you would have because the commodity prices have systematically fallen for six, seven, eight years now, and so the more you enter into these long-term obligations further back when those prices are higher, just the greater your losses would have been. So clearly over the last seven, eight years there would be no balancing out. You know, any long-term obligation that was entered into seven years ago is going to have bigger losses than five years ago, which is going to have bigger losses than three years ago.

Q And in this case we know that primarily is driven is by one cost, which is the fuel cost?

A That is the biggest driver, yes.

Q Okay. So the Company is, in its proposal, and I believe at least -- at least in both your testimony and Ms. Bowman's, have -- you've indicated that the proposal is based on the current situation that we face that didn't exist in prior dockets, correct?

A That is correct.

Q So if your proposal in this docket is adopted and then down the road we see that the QFs have kind of all but gone away from North Carolina and the queue -- and the queue is clear, the interconnection queue is clear, would you agree that those new circumstances at that time would necessitate a change in how we implement PURPA?

A I think the Commission is always free to reassess the market conditions, absolutely free to reassess how the market condition looks moving forward through time.

Q And I know that you proposed a separate docket to look at the competitive bid process, but -- and I don't know that we necessarily linked those, but if the Commission were to decide that it would like to see how that would -- what that would look like and how that would operate before making changes in this docket, would

-- would it be your view that that would be an inappropriate thing to do?

A (Bowman) Well, I think what we have presented in this -- in this docket now is that we feel like we are at a point in time where we need to make a change to the implementation of PURPA in North Carolina. I think we've -- we've spent several days here talking about some of the challenges and potential cost risks to our customers, so I think we feel we need -- we need to make a change at this point in time. But clearly we're happy to move forward and share details on a proposed competitive procurement process.

Q Is it presumed under the competitive bid process that there would not be any regular solicitation, but it would be solicitation based on the need as reflected in the IRP?

A So I believe what -- what we proposed is kind of a transition, so going from -- you know, PURPA will still be there, but trying to transition away from kind of that PURPA put to the more managed, smarter, sustainable and kind of a competitive procurement, you know, to get a process underway, and then potentially moving forward in the future to it all being based upon needs of the IRP.

A (Snider) And as -- as I said, I think it's -- you know, we've got to recognize that it's the needs relative to the energy. So here, you know, we can buy the commodity forward or we can buy the power forward, but that the IRP is not showing a need for solar capacity, so I want to be clear to delineate between capacity and energy in that -- that it does provide energy, and so to the extent on a cost-based RFP it could come in as a prudent and reasonable way to procure that energy by just buying the solar output in megawatt hours, then that would be a cost-based as opposed to a rate-based approach.

Q All right. Mr. Freeman, in your view, does -- does the proposal that you put forward regarding the legally enforceable obligation, does that require actions that are completely in the control of the QF in terms of establishing that LEO, as we call it, and that none of those actions are subject to responses or actions by the Company that could stymie the QF's ability to establish that LEO when it -- when it's able and ready to come forth?

A (Freeman) I believe that's correct, yes.

Q Okay. Could you envision changes to the interconnection procedure alone, just changes to that procedure alone, that would help to narrow -- not necessarily eliminate, but narrow the period between the LEO date and the operational date of a QF facility to lessen the stale pricing impact concerns with -- without the need to execute the PPA?

A Well, I think, you know, we'll look at the interconnection, you know, standards here again shortly as requested by the Commission. But, again, I mean, we've got so many projects in the queue, and the, you know, the cost to interconnect any particular project is continuing to go up, so, you know, the construction time, the -- you know, the engineering time, you know, the system impact study time continues to go up for us on a project-by-project basis.

So, I mean, I think we'll look at that, but I'm not sure that there's going to be a clear way to kind of shorten that -- that process, especially with the volume of projects that we still have in the queue and the number of projects that are interdependent on another project, which, you know, kind of relates to, you know, action of one project halts or stymies, you know, the next project in line.

In fact, we've got, you know, some projects, you know, some circuits and substations where we've got six and eight projects kind of stacked one on top of the other, so it could be still years potentially before we get to those -- those later projects. So that's the challenge that we have with dealing with the amount of projects that we have in the queue.

But I think it's a fair question that we'll -- you know, we'll explore. I think one of the things that we're -- that I'm personally hoping to accomplish is this transparency thing, providing more transparency earlier on in the process so that developers can make -- make more informed decisions as they go through the process rather than waiting so long before they get any first indication from us as to whether it's even feasible to interconnect the project.

You know, we all agreed two years ago to eliminate the feasibility study concept. Well, I believe we need to -- we need to put that back in place in some manner and provide some screening kind of solutions to help the process.

Q So with the current -- under the current interconnection procedure, the Company, at least with regard to that feasibility that you mentioned, found that maybe it didn't work as well as anticipated going into it; is that a fair statement?

A I think that's a fair statement. Now, we eliminated the feasibility study process at the request of developers. You know, the focus there was trying to eliminate as many steps in the process we could to kind of speed the process up, but I think in hindsight when we look back, providing that more transparency would have been a better -- a better solution.

Q So when I hear that, to me it's sort of a work in process and we haven't --

A Yeah.

Q -- quite hit the bulls-eye yet, and --

A We use the term we're in a -- I call it a living laboratory, you know, where we've got more 5 megawatt distribution connected utility scale projects than anywhere in the country, and I mean, that's -- that's the living lab concept that we, you know, that we're just learning every day.

Q Right. So I like to think of us as, you know, can-do people and when possible, but it's not always possible, but I guess that's where my question goes. Can you envision that it would be useful for the community and those stakeholders to come back together and examine these issues and perhaps find a way forward to lessen that gap between the -- the operation and the LEO --

operational date and LEO so that those prices -- cut back significantly on the staleness of the prices?

A Well, I think you're -- I don't know. I feel like you're kind of mixing the LEO concept with the interconnection process. I think when we look at the interconnection standards, we'll look at, you know, are there ways to provide more information to developers to make decisions earlier on to either stay or, you know, cancel their project. That's a completely separate process from the LEO.

But even with that said, you know, I feel like for developers to truly make that commitment to sell and execute a Power Purchase Agreement, you know, they need information from the interconnection process. So that's why originally -- you know, our original proposal was, you know, we felt like you really can't make that firm commitment to sell till you've got a much clearer idea of what all your costs are. And like I shared with you earlier, one of the biggest costs the developer has is the interconnection cost.

Q Right. So I appreciate that they're separate -- separate parts of this --

A Right.

Q -- this animal, but I think the Panel testified that the stale pricing is really one of the biggest issues that you're trying to address. And I see -- granted, early in the process we can have the LEO established, and you're -- you're wanting to push that forward, but I see one of the reasons for doing that is to shorten -- and that the interconnection piece only helps exacerbate and pushes out the operational date from the QF, because they do need this information and different inputs to know whether they're going to forward, so that's why I sort of connected them, that if we could get that period, not eliminating the staleness altogether, but reducing that length of time.

A Well, I think -- I think you're right. I think that does help with reducing that time. But, you know, our proposal is to, you know, one, the LEO -- I mean, I think we even saw it in some of the exhibit proposals, that, you know, a lot of projects move to a point and they withdraw. In fact, I think we've seen where roughly 30 percent or more of the projects withdraw at some point, so does it really make sense for them to establish a LEO so early on in the process when they really are not making any kind of a commitment to sell.

So that's what our proposal is, is move it to a contracting process, put the -- essentially the responsibility on the developer to decide when it makes sense for them to truly make that commitment to us -- or to us, to our ratepayers, because it's our -- you know, it's -- it's our -- it's the obligation of our ratepayers to accept and pay for that energy that's being delivered to us.

Q And that reminds me. So what's -- what is the harm to the Utility's customers if the Company has not moved forward to the point where it was planning and counting on that capacity and it never comes to fruition, and the customers, I presume, don't pay because it didn't come to fruition?

A Yeah. I touched a little bit on that question earlier, and I -- I reflected on the capacity component, but, you know, thinking about that even more, you know, if we've got 1,000 or 2,000 megawatts of, say, LEO commitments that were made today and they're not coming online for three or four years, I mean, we've still got from our trading floor, energy procurement perspective, gas hedging program, I mean, we struggle to really make the decisions we need to make to optimize the, you know, the fuel purchasing, you know, component. I really feel like that's even a bigger part of the uncertainty that establishing that LEO so far ahead of time, you know,

makes it a challenge to us, and uncertainty leads to --
Q Uncertainty of knowing what's going to be available?
A Right, right.
Q Or what's going to be coming on?
A Because, you know, a solar project coming online, you know, reduces our obligation to purchase, you know, gas or coal, and -- and we do try and look, you know, several years out at making those decisions. So, you know, tightening up that commitment to a point as close as reasonable towards when they're actually going to deliver that energy so we can plan is what we're trying to accomplish.
Q Okay. And Mr. Snider, the -- the 1.05 PAF sought here in this docket, that's the same that was sought in the 2014 biennial proceedings, correct?
A (Snider) Yes, it is.
Q And you and I back then engaged in a long conversation and you explained about capacity factors and capacity value and availability and all that stuff. Has -- those were your arguments in support of the 1.05 back then in 2014. Have -- do you now have -- has something changed where you now have additional arguments in support or basically we're looking at the same arguments?

A No. I appreciate that question, and I think what's different is when we reviewed the Finding of Facts in Sub 140, I think we were advancing that we were saying the CT is available. We got into a long debate on what's availability versus capacity factors and had a pretty robust discussion. The Findings of Facts said, no, we think it's more important to look at the utility system as a whole, that the peaker method is a proxy for any generator.

And so what we've done in this case, and we've agreed with Public Staff that looking at a set of baseload generators, a -- a set of those, and saying what is the availability factor is the right way to look at it, with the exception of the fact that the QF is not held to an availability to earn its capacity during all 8,760 hours of the year. The QF can operate during only the on-peak hours and get the whole annual value.

So we said if the QF only has to operate in less than 25 percent of the hours that are deemed peak under Schedule B, then the equivalent metric, now that we're looking at the utility system, is how do those same utility generators that were envisioned in Sub 140, how do they operate during those same set of hours, during those on-peak hours, so that while we're allowing the QF adequate -- 75 percent of the hours of the year to be offline for whatever purpose and still -- and still achieve their whole capacity payment, what's the equivalent utility measure to look at when developing a path. And what we've said is that the on-peak availability that we strive to maintain within the Utility, as demonstrated through our availability metrics, when you narrow that to on-peak, then the 1.05 is an -- is an equivalent that puts you on an apples-to-apples.

So I think what's changed is we've gone away from saying, no, you're right, it's not just the peaker. We can look at those baseload units as well, as envisioned in 140, and if you hold them on an equivalent basis to the QF so that you do get this but for principle that I'm -- look at that the same way -- the QF the same way I'm going to look at the traditional generator, as you apply that to the PAF concept within this broader concept with the peaker method, the 1.05 is what's mathematically correct.

Q All right. And in Sub 140 and in other Commission orders, the Commission spoke of the PAF being -- being incorporated into the peaker method as a way of saying that the QF is operating reasonably if it's -- if it's coming in at that level, whatever level we end up with.

A Yes. And I -- you know, I think we -- we've said that in the past, those circumstances, you know, have evolved, and one of the reasons that we see a overpayment risk is what are we doing differently that no other state in the Southeast is doing with respect to our implementation of PURPA. And, you know, to my knowledge, as I stated earlier, I don't know anyone else that pays a pure multiplier. We recognize that a 1.05 is fair and appropriate, but given the unprecedented surge in solar QFs, you sort of look across and say what -- what are we doing differently that has caused this, and is it just and reasonable, is it apples to apples.

So what we've filed here says we're looking at it differently, we're trying to make it very apples to apples, and we think that this is a -- a fair and reasonable adjustment to the capacity payment relative to the QF. And, again, so I say that multiplier is -- is appropriately set at 1.05.

Q And so was your -- between last time and this time your calculation that leads to 1.05 was the same?

A I think this time what we've done is say -- last time we said just based on the peaker start avail---

which we did advance again in this proceeding and said if you look at it from the peaker perspective, a 1.05 is justified; however, in rebuttal and in agreement with Public Staff we said if you look at a broader set of units, which we didn't do in 140, and -- and take the appropriate metric, so this is a new calculation that we did not advance in 140, we say that, yes, the 1.05, even when you look at the broader set of the Utility assets, is a more appropriate apples to apples with the QF. So it is a different calculation from 140.

Q All right. We're becoming old friends on this topic.

A Yes, we are.

Q And then I may have missed this because I know Ms. Fentress started her redirect asking about an exhibit, so I wanted to -- I don't know if it was, but I wanted to follow up on just the NCSEA Duke Panel Confidential Cross Exhibit Number 5. I'm not going to ask you about anything on it, other than to say to the extent that there was that category there that Ms. Bowman wasn't quite clear on, if she could bring that information forward just so that we understand what we're looking at and what -- and what that represents.

A (Bowman) Yes. We can do that.

Q Maybe in a late-filed exhibit or --
MS. FENTRESS: Yes.
Q -- if you would do that.
MS. FENTRESS: Yes.
COMMISSIONER BROWN-BLAND: That's all.
CHAIRMAN FINLEY: Other questions by the Commission?
EXAMINATION BY COMMISSIONER BAILEY:
Q I apologize. Someone -- Commissioner Brown-Bland brought me -- brought me back around to it. This is a question for Mr. Freeman again. If -- instead of trying to make the LEO or the date for the LEO very complicated, if we tried to come up with a very simple system saying, okay, if a QF comes in and does a LEO right at the same time they do a CPCN at the Commission and it takes two or three years to get this thing built and obligated and committed power to the Utilities, what if you just had a fine based on maybe whatever the megawatts or the kilowatts that this -- this QF was putting in, and if they decide at some point in time, if they do it before get their interconnection, that's their -- that's their call, but at some point in time they say we're punching out, we're not doing this, but they had a LEO that the Company was already making plans for, what

would you think would be a magnitude fine that would be worth that? Is that in the thousands, the tens of thousands, hundred thousands, and the millions? What -- where would you categorize that?

A (Freeman) Yeah. The way I've been kind of thinking about the, you know, the liquidated damage component or the way we've been calculating it so far is roughly taking the capacity commitment and looking at one year's worth of capacity. So for a 5 megawatt project, that number is in the 2, $250,000 range, roughly.

Q Okay. That's what I was looking for. One question -- I don't want Mr. Snider to feel left out here -- and this is really more of a curiosity question for me. If you had decided when you bought this 10-year forward gas contract that you just had, if you had done that for 500 megawatts versus the 50 megawatts, would the price have been a lot lower or would it have been about the same?

A (Snider) It's the same, sir. It's not quantity specific.

Q Okay.

CHAIRMAN FINLEY: All right. Any intervenor questions based on the Commission's questions? Mr. Stein?

MR. STEIN: One question.

EXAMINATION BY MR. STEIN:

Q Ms. Bowman, in response to a -- a question by Chairman -- Ms. Bowman, in response to question by Chairman Finley, you mentioned an Alabama Power tariff; is that correct?

A (Bowman) Yes.

Q Okay.

A Not -- I don't know that it was in response to Chairman Finley's question.

MS. FENTRESS: I don't believe Chairman Finley asked about the Alabama tariff. That was -- that was me.

MR. STEIN: But Ms. Bowman did reference the Alabama tariff in her response to Chairman Finley.

MS. FENTRESS: Okay.

A (Bowman) Okay.

Q Just one simple question. Are you aware that the state of Alabama has only approximately 100 megawatts of total installed solar capacity?

A I am not familiar with how much installed solar capacity Alabama has.

Q Okay. Would you be willing to accept that, subject to check?

A Subject to check.

Q Okay.

MR. STEIN: Thank you.

EXAMINATION BY MR. JOSEY:

Q Mr. Freeman, referring back to Commissioner Bailey's questions, I just wanted to get some clarification on the differences between dispatch down language and the negotiated contracts versus the curtailment for system emergencies. In the negotiated contracts there's a limit to the amount of hours Duke can instruct a facility to dispatch down before they have a payment for the energy the facility would have produced but for the dispatch down instruction, correct?

A (Freeman) Subject to check. I haven't looked at the contract in -- you know, recently, but I think you're right, yes.

Q Okay. And -- but Duke does not compensate the facility if the facility is curtailed due to a system emergency or force majeure?

A That's correct.

Q Okay. And Duke does not count the outage hours due to the system emergencies or force majeures towards that limit of dispatch down before having to pay them?

A I'd have to look at the language again to see how we're counting, you know, counting that dispatch down.

Q Thank you very much.

EXAMINATION BY MS. MITCHELL:

Q Mr. Snider, just one question for you. Do you recall the question that Commissioner Bailey just asked you about the 10-year gas purchase we've talked about today?

A (Snider) Yes.

Q And at the amount that Commissioner Bailey referenced, how much would Duke have had to pay for that purchase?

A Zero.

Q Thank you.

MS. MITCHELL: Nothing further.

CHAIRMAN FINLEY: Questions by Duke?

MS. FENTRESS: Thank you.

EXAMINATION BY MS. FENTRESS:

Q Ms. Bowman, Chairman Finley asked you about the eligibility threshold proposal from the Companies. Do you recall that?

A (Bowman) Yes.

Q And in discussing reducing the eligibility threshold from 5 megawatts to 1 megawatt, is it fair to say one of the goals of the Companies in doing so was to discourage the disaggregation of larger QFs into multiple 5 megawatt facilities?

A That's correct.

Q And one of the reasons for that would be that a larger facility could enjoy cost of -- enjoy --

A Economies of scale.

Q -- economies of scale. Thank you. And so with -- so in that respect, instead of having ten 5 megawatt facilities, the Companies would instead be interconnecting and purchasing power from one 50 megawatt facility; is that correct?

A That's correct.

Q And in that situation there would be one PPA to negotiate instead of 10 PPAs to negotiate?

A Correct.

Q And as a result of the reduction in number of PPAs, was it likewise a goal of the Company that that would reduce complaints and arbitrations to the Commission?

A Yes, it was.

Q Thank you. And I'm going to ask you to turn to page 26 of your rebuttal testimony.

A Okay. I'm there.

Q Okay. On line 14 your Q is, "Would the

Companies oppose the Commission establishing a new proceeding to evaluate the manner in which the Companies determine their avoided cost for QFs?" Do you -- do you see that?

A Yes, I do.

Q And I believe responsive to Chairman Finley's question, you agreed that such a proceeding would be -- would be appropriate if the Commission determined it needed one?

A That's correct.

Q And I believe in your rebuttal testimony you indicate that it would be beneficial. Do you still agree that a proceeding would be -- could be -- could be beneficial to level set expectations for participants in the PURPA solar market in North Carolina?

A Yes.

MR. BREITSCHWERDT: Just briefly, two questions for Mr. Freeman.

EXAMINATION BY MR. BREITSCHWERDT:

Q First, there was a question from Commissioner Bailey about the terms and conditions of the negotiated PPAs, and Mr. Josey asked you a similar question a moment ago about dispatch down rights in that contract, and you had responded that you are generally familiar with the contract and the way the Company negotiates the contract and drafts those kind of detailed terms to be consistent with PURPA. Would you agree with me that your statements earlier were as -- in your role as a business executive of the Company that oversees this process, but it's normally managed by the folks that work for you as well as the attorneys who ensure those contracts are consistent with the provisions of PURPA?

A (Freeman) Yes. That's correct.

Q Thank you. And just one question responding to a question Commissioner Brown-Bland asked about the expiration of the renewable energy tax credit in North Carolina and the amount of development. You have a chart you present on page 9 of your rebuttal testimony that identifies the quarter-by-quarter development of QF solar utility scale above 1 megawatt going back to the first quarter of 2014. And so I think the discussion earlier was that the renewable energy tax credit expired at the end of 2015, so based on that chart, would you characterize the continued development since the tax credit expired as robust?

A Yes.

Q And just for one point of clarification, these are new interconnection requests, so these are projects just beginning the process similar to the certificates that are requested from the Utilities Commission?

A That's correct.

Q Thank you.

CHAIRMAN FINLEY: All right. Let's deal with the exhibits here quickly. By my count we have Freeman Direct Exhibit 1, Rebuttal Exhibits 1 and 2. Without objection we will move those into evidence.

MS. FENTRESS: Thank you, Your Honor.

(Whereupon Freeman Direct Exhibit 1 and Freeman Rebuttal Exhibits 1 and 2 were admitted into evidence.)

CHAIRMAN FINLEY: We have NCSEA Duke Panel Cross Examination Exhibits 1, 2, 3, 4, and 5 Confidential. Without objection we'll move those into evidence.

(Whereupon, NCSEA Duke Panel Cross Examination Exhibits 1, 2, 3, 4, and Confidential 5 were admitted into evidence. Because of the proprietary nature of NCSEA Confidential Duke Panel Exhibit 5, it was filed under seal.)

CHAIRMAN FINLEY: We have SACE Duke Panel Cross Examination Exhibits 1, which is Confidential, 2, 3, 4, and 5, which without objection we will receive into evidence.

(Whereupon, SACE Duke Panel Confidential Cross Examination Exhibit 1 and 5, and SACE Duke Panel Cross Examination Exhibits 2, 3, and 4 were admitted into evidence. Because of the proprietary nature of SACE Duke Panel Confidential Cross Examination Exhibit Number 1 and 5, it was filed under seal.)

CHAIRMAN FINLEY: We have Public Staff Snider Cross Examination Exhibits 1, 2, 3, 4 which is Confidential, 5 which is Confidential, and 6 which is Confidential. Without -- and without objection we will receive those into evidence.

(Whereupon, Public Staff Snider Cross Examination Exhibits 1, 2, 3, Confidential 4, 5, and 6 were admitted into evidence. Because

(of the proprietary nature of Public Staff Snider Confidential Exhibit Numbers 4, 5, and 6, they were filed under seal.)

CHAIRMAN FINLEY: And we have Duke Bowman Redirect Exhibit Number 1, which without objection we will receive into evidence.

(Whereupon, Duke Bowman Redirect Exhibit Number 1 was admitted into evidence.)

MS. FENTRESS: That's correct. Mr. Chairman, we would also like to move the Company's Joint Initial Statement, filed November 15th, 2016, in this docket into evidence.

CHAIRMAN FINLEY: All right. Without objection we will move that statement -- receive it into evidence.

(Whereupon, the Joint Initial Statement and Proposed Standard Avoided Cost Rate Tariffs of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC was admitted into evidence.)

CHAIRMAN FINLEY: All right. Unless you'd rather all sit around a while longer, you may be excused.

MS. FENTRESS: Thank you, Mr. Chairman.

CHAIRMAN FINLEY: And let's -- Dominion is next. Let's bring the Dominion witness up here and swear him in and get him started, if we can, in a few minutes. Give us a second to rearrange the microphone.

MS. KELLS: Dominion calls Mr. Scott Gaskill and Mr. Bruce Petrie.

BRUCE E. PETRIE; Being first duly sworn, testified as follows:

J. SCOTT GASKILL: Being first duly sworn, testified as follows:

MS. KELLS: I'm going to start with Mr. Gaskill.

DIRECT EXAMINATION BY MS. KELLS:

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

A (Gaskill) Yeah. My name is James Scott Gaskill, 5000 Dominion Boulevard, Glen Allen, Virginia, 23060.

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

A Dominion North Carolina Power. I am the Director of Power Contracts and Origination.

Q And did you cause to be prefiled in this docket on February 21st of this year 38 pages of direct testimony and an Appendix A and one exhibit?

A Yes, I did.

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

A Yes. I have one correction. And on page 33, line 6 -- so page 33, line 6, the words "six, i.e., 50 percent" should be replaced with the word "five."

Q Thank you. With that correction, if I were to ask you the same questions that appear in your direct testimony today, would your answers be the same?

A Yes.

MS. KELLS: Mr. Chairman, at this time I move that the direct testimony and Appendix A of Mr. Gaskill be copied into the record as if given orally from the stand, and his one direct exhibit be marked for identification as prefiled.

CHAIRMAN FINLEY: Mr. Gaskill's direct prefiled testimony, filed on February 21, 2017, of 38 pages and his one appendix are copied into the record as if given orally from the stand, and his exhibit is marked for identification as premarked in the filing.

MS. KELLS: Thank you.

(Whereupon, the prefiled direct testimony of J. Scott Gaskill, as corrected, was copied into the record as if given orally from the stand.)

**DIRECT TESTIMONY
OF
J. SCOTT GASKILL
ON BEHALF OF
DOMINION NORTH CAROLINA POWER
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100 SUB 148**

Q. Please state your name, business address, and position of employment.

A. My name is J. Scott Gaskill, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. My current position is Director of Power Contracts and Origination for Dominion North Carolina Power ("DNCP" or the "Company"). My responsibilities include the negotiation and administration of the Company's non-utility generation power purchase contracts, including those signed under DNCP's North Carolina standard avoided cost rate schedules, Schedule 19-FP and Schedule 19-LMP. A statement of my background and qualifications is attached as Appendix A.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to present DNCP's rationale and support for each of the Company's proposed changes to the calculation of avoided cost payments and to its standard avoided cost contract terms and conditions, as contained in the Company's November 15, 2016 Initial Comments filed in this proceeding. In addition to providing specific support for each of these proposals, I will also more broadly describe the tremendous and unprecedented growth in North Carolina solar qualifying facility ("QF") development that has occurred in the past two years and the resulting need for modifications to the rates and terms that were approved by the Commission in the previous avoided cost proceeding, Docket No. E-100, Sub 140 (the "2014 Avoided Cost Case").

Company Witness Bruce Petrie also presents direct testimony, which addresses the disparity between DNCP's forecasted payments to North Carolina QFs and the expected value of North Carolina QF generation resources, and supports the detailed calculations of the Company's current avoided costs and resulting proposed rates.

Introduction & Overview

Q. What is your understanding of the purpose of these biennial proceedings conducted by the Commission?

A. My understanding is that, as required by the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the purpose of the Commission's biennial avoided cost proceedings is to determine each individual utility's avoided cost. Through the biennial proceedings, the Commission meets its obligation under the Federal Energy Regulatory Commission's ("FERC") regulations to establish standard rates for "small" QFs, which under FERC's rules are those with capacity of 100 kW or less.

Q. What are avoided costs?

A. FERC's rules implementing PURPA define avoided costs as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from a QF, the utility would generate itself or purchase from another source. Both PURPA and FERC's rules require that these rates be just and reasonable to the electric utility's customers, in the public interest, and non-discriminatory to QFs.

Q. Do PURPA or FERC's regulations implementing PURPA require a utility to pay QFs more than its avoided cost in order to encourage QF development?

A. No. It is my understanding that under PURPA a utility is not required to pay a rate for purchases from QFs that exceeds the utility's incremental cost. FERC's regulations specifically provide that an electric utility is not required to pay more than the avoided costs for purchases from QFs.

Q. What is the result of a utility being obligated to pay rates to QFs that exceed its avoided costs?

A. The result is that the utility's customers bear the burden of shouldering costs that exceed what is required under PURPA.

Q. Which avoided cost rates and contract terms are currently effective for DNCP?

A. The Company's avoided cost rates and standard contract terms and conditions that were effective for a QF that established a legally enforceable obligation ("LEO") prior to November 15, 2016, were filed on February 2, 2016, as revised on February 26, 2016, in compliance with the Commission's December 31, 2014 *Order Setting Avoided Cost Parameters* ("2014 Phase 1 Order") and its December 17, 2015 *Order Establishing Standard Rates and*

Contract Terms for Qualifying Facilities ("2014 Phase 2 Order"), both issued in the 2014 Avoided Cost Case. In those orders, the Commission addressed the methods used to calculate avoided cost payments as well as proposals by DNCP, Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC to revise the applicability of standard avoided cost rates and terms and the content of those standard contract terms. A QF that establishes a LEO on or after November 15, 2016, will receive the standard avoided cost rates and terms that DNCP has proposed in this proceeding, subject to true-up based on the Commission's final order or orders in this case.

Q. Is the Company filing the same standard rate schedules and contracts that it did in the 2014 Avoided Cost Case?

A. Yes, with the modifications that I discuss below. As in the 2014 Avoided Cost Case, on November 15, 2016, the Company filed two standard avoided cost rate schedules, Schedule 19-FP and Schedule 19-LMP. As provided in Section I of our proposed rate schedules, they are available to any eligible QF that (a) obtained a certificate of public convenience and necessity ("CPCN") for its facility from the Commission or filed a report of proposed construction according to Commission Rule R8-65, as applicable; (b) is a QF; and (c) submitted to DNCP an executed "Notice of Commitment to Sell the Output of a Qualifying Facility to Dominion North Carolina Power Company" (the "LEO Form"), no later than the date on which the Company files proposed rates in the next biennial proceeding after this Docket No. E-100, Sub 148. DNCP also filed the Schedule 19-FP and Schedule 19-LMP standard contracts and terms and conditions that were approved in the previous case, with the modifications discussed in the Initial Filing and in this testimony.

Q. As you state, the Company has proposed several modifications to its standard offer rate schedules and contracts in this proceeding. Some of these modifications are similar to issues that the Commission addressed in previous avoided cost proceedings. Why is it appropriate that the Commission reevaluate its previous decisions on these topics at this time?

A. The Commission recently made clear, in its Order Denying Motion issued in this proceeding on January 18, 2017, that it "has always established avoided cost rates and implemented PURPA in *light of the then prevailing economic conditions facing public utilities and QFs and whether changed conditions justify changes in avoided cost rates and/or PURPA implementation.*"

It is true that several proposals similar to those that the Company has proposed in this proceeding were not accepted by the Commission in the 2014 Avoided Cost Case. However, as I will explain further in this testimony, since the 2014 Avoided Cost Case, the landscape of QF development in the Company's North Carolina service area has changed significantly. Given these changes, the Company believes that it is imperative that the Commission reconsider these issues on a prospective basis for new solar QF development, and evaluate the Company's proposed revisions to its standard avoided cost rate schedules and contracts to adapt to those changing circumstances as discussed in both my testimony and that of Company Witness Petrie.

Q. Can you provide more detail as to how the landscape for solar QF development in North Carolina has significantly changed even since the 2014 Avoided Cost Case?

A. Yes. When the Commission issued its *Order Establishing Biennial Proceeding and Scheduling Hearing* on February 25, 2014, which established "Phase One" of the 2014 Avoided Cost Case, the Company had only seven power purchase agreements ("PPAs") executed for approximately 58 MW of solar QF capacity in its North Carolina territory. Only one of these seven PPAs was for a project that had actually completed the development process and was operating at the time. Due to the high number of CPCN applications that were being filed and approvals being issued at that time, both the Company and the Commission were aware of the increased solar QF development activity, but it was still difficult to predict the speed and magnitude of solar development that would occur in the ensuing years.

In fact, the actual speed and magnitude of development that has occurred since that case exceeded all expectations.

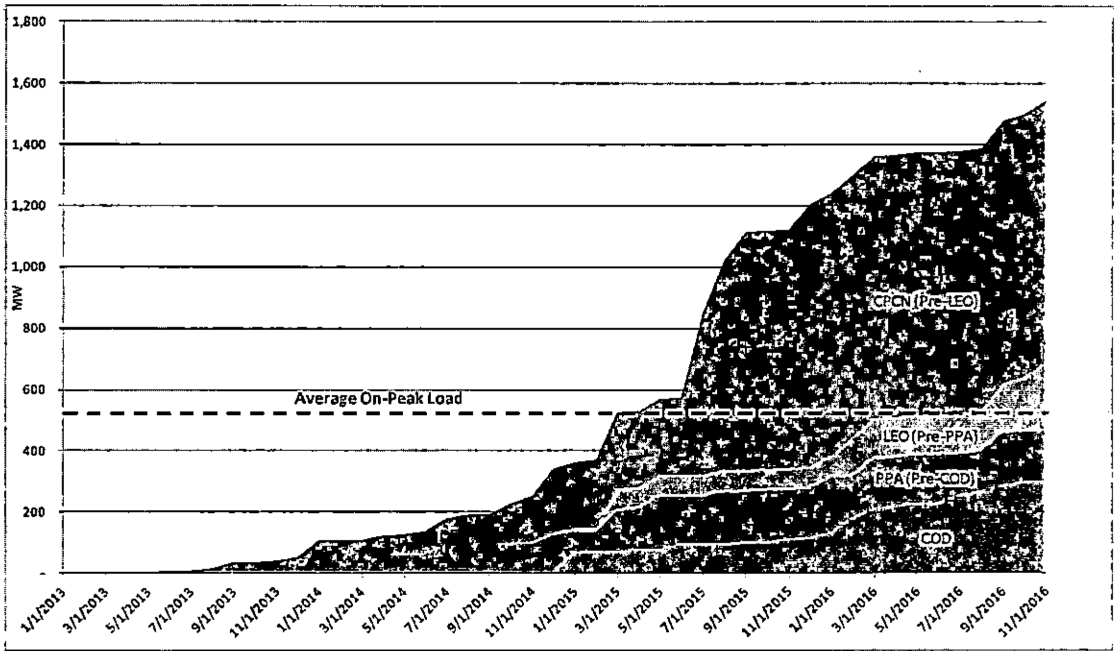
As detailed on pages 3-4 of the Company's Initial Comments, solar costs have continued to decline rapidly over the past several years, including since the 2014 Avoided Cost Case. DNCP believes that this cost decline, along with the extension of the 30% federal Investment Tax Credit ("ITC") through 2020, has made the financing and construction of solar projects achievable at lower avoided cost rates.

The influx of distributed solar generation onto DNCP's North Carolina system is now adversely impacting our system operations in this State and is causing DNCP and its customers to pay far in excess of the Company's avoided costs for QF output. DNCP believes that the revisions to its standard offer rate schedules and contracts it has proposed in this case will mitigate these impacts while remaining consistent with the requirements of PURPA and FERC's rules.

Q. How much distribution-level solar has been developed in DNCP's North Carolina service territory?

A. The chart below shows the rapid increase in distributed solar generation ("Solar DG") since the beginning of the 2014 Avoided Cost Case up until when the Company filed its Initial Comments in this case in November 2016.

Figure 1: QF Solar Development in DNCP's North Carolina Territory



As an update to this data, as of February 1, 2017, DNCP has 72 effective PPAs for approximately 500 MW of solar QF capacity in North Carolina. (The Company has executed 9 PPAs totaling 45 MW even since the Initial Comments were filed just three months ago.) Of these 500 MW, approximately 350 MW have already commenced commercial operation, while the remaining 150 MW is under various stages of development. This is a mere three years since February 2014, when the Company had only 58 MW of distributed solar capacity under contract, with one project operational.

Viewed from the perspective of the interconnection process, as shown in Figure 2 below, there are approximately 1,000 MW in various stages of the North Carolina distribution queue.[1]

Figure 2: Interconnection view of Solar DG in DNCP NC queue

	NC Distribution Queue	
	No. of Projects	Capacity (MW)
Operational	59	435
Under Construction	19	174
Study Phase	64	363
Total	**142**	**972**

Q. How does this amount compare to the Company's actual load needs?

A. DNCP's North Carolina service territory had a 2015 average on-peak load of approximately 518 MW. Thus, the amount of distributed solar generation that is either already operational or under construction when viewed from the interconnection perspective, or under contract as viewed from the PPA perspective, already exceeds or equals the Company's average on-peak load requirements in North Carolina. As Figure 1 demonstrates, when QFs that have established LEOs but not yet executed PPAs are included, the total capacity of distributed solar planned for the Company's North Carolina system rises to approximately 680 MW, which exceeds DNCP's average on-peak load requirements by approximately 160 MW. Even more striking, when the capacity of those projects that have received CPCNs is accounted

[1] In addition to the distribution-level interconnections, there are approximately 1,800 MW of active solar projects in the PJM interconnection queue for North Carolina at transmission level. Therefore, in total there are approximately 2,800 MW of total active solar projects either operating or in development in the Company's North Carolina service territory.

for, the total increases dramatically to over 1,500 MW, almost three times the size of the Company's on-peak need in North Carolina.

Q. What are the impacts to DNCP's North Carolina system that result from distributed generation exceeding the Company's load needs?

A. The Company has reached a point of Solar DG saturation where the majority of circuits on which Solar DG is interconnected in North Carolina are backflowing onto the transmission grid. This means that the generation from the distributed solar exceeds the load requirements of the circuit on which it is connected. The generation that exceeds the load on the circuit therefore flows back onto the transmission system to reach load elsewhere on the system.

Q. How is DNCP's avoided cost affected when Solar DG exceeds load and energy is flowing back onto the transmission system?

A. When the amount of distributed generation reaches the point where it exceeds the load on its respective circuit, many benefits (and therefore avoided costs) attributed to the distributed nature of the generation are lost.

Previous avoided cost proceedings before the Commission have considered the potential benefits of Solar DG that can be realized when this type of generation is deployed correctly. Two such interrelated benefits are that Solar DG is a scalable resource that can be located at or near the Company's load. These benefits can in turn result in added benefits such as reduced congestion, mitigated line losses, and, in some cases, improved local reliability over centrally-located generation. In particular for Solar DG, geographic diversity reduces the effect of intermittent cloud cover over any single location. Spreading Solar DG across the Company's service territory therefore improves reliability and minimizes integration costs (such as increased operating reserves and load imbalance charges) and operational challenges, in turn reducing costs for customers.

Because of the backflow that is occurring on the Company's system, which will only increase as additional distributed solar is added to the system, the benefits of Solar DG – scalability, mobility – are no longer being realized. This is especially true when additional Solar DG is added in a narrowly distributed geographic and electrically-connected location with little load growth, which is the case with the state of solar development in the Company's service area in this state.

In this proceeding, the Company has specifically identified three areas of avoided costs that are impacted by Solar DG exceeding load: (1) distribution line losses are not avoided by incremental Solar DG; (2) locational marginal prices ("LMPs") in the Company's North Carolina service territory are lower; and (3) incremental QF generation is unable to avoid future capacity costs because there is no longer load to offset. In addition, when Solar DG is not geographically dispersed, it leads to increased operational challenges, although the Company has not proposed to include any integration costs in this proceeding.

Q. **How many Sub 136 and Sub 140 PPAs is the Company party to and for how much capacity?**

A. The table below shows the number and capacity of the Sub 136, Sub 140, and negotiated QF contracts that DNCP has executed to-date. Since the negotiated contracts were signed within the same timeframe as the Sub 136 and Sub 140 contracts, they have similar avoided cost pricing.

Figure 3: Effective NC Solar QF PPAs

	# of PPAs	Capacity (MW)
Sub-136	53	253
Sub-140	7	33
Negotiated QFs	12	214
Total	72	500

As noted earlier, the Company is also obligated to execute contracts with additional projects that have already established LEOs. The vast majority of these outstanding projects would qualify for the Sub 140 standard contract or negotiated avoided costs based on their specific LEO date.

Q. **How have the rates paid to QFs under the rate schedules approved in the Sub 136 or Sub 140 cases, or negotiated rates reached prior to the Company's filing in this case, compared to the Company's actual avoided costs?**

A. As Company Witness Petrie further details, DNCP's customers are now committed to hundreds of millions of dollars of above-market QF payments for the next 15 or more years. As Witness Petrie shows, given the significant decrease in gas and power prices over the past several years, these contracts' prices significantly exceed – by 46% – the Company's actual avoided cost for energy and capacity when compared to the current market value of these contracts. It is therefore clear that the Company has been, and will continue to, pay well above its actual avoided costs for the hundreds of megawatts of contracts procured under the previous two avoided cost proceedings.

Q. How does the Company recommend that the Commission address this issue going forward?

A. The Commission has in numerous avoided cost cases recognized the balance that must be struck between the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other. Given the unprecedented level of QF development in the state as a whole and in the DNCP North Carolina territory specifically, it is clear that the prior avoided cost rates approved by the Commission have succeeded in encouraging QF development. It is also clear, however, that this encouragement has come at a cost that has burdened, and given the long terms of these contracts will continue to burden, customers with above-market long-term contracts. In light of this, the Company believes it is time to reconsider several of the issues evaluated in the 2012 and 2014 avoided cost cases, or else the Company will be forced to continue to over-pay for new QF output in contravention of the intention of PURPA.

<u>Proposed Changes to Standard Rates and Terms</u>

Q. Please summarize the changes that the Company is proposing to its standard offer avoided cost contracts and rate schedules in this proceeding.

A. In its November 15, 2016 filing, the Company proposed five major changes or adjustments to its standard offer contracts and rate schedules. These changes are summarized below and supported in detail later in my testimony. In sum, the Company proposes to:

1. Reduce the threshold at which a QF qualifies for the standard rates and contract terms from 5 MW to 1 MW. While the Company retains the obligation to purchase the output of QFs 20 MW or less, this adjustment will allow DNCP to better match avoided cost pricing with the QF's LEO and to customize the avoided cost rates for each QF's specific size relative to the load on the relevant circuit and specific location.

2. Eliminate the 3% line loss adder from DNCP's proposed avoided energy cost rates. Due to the saturation of distribution-level QFs relative to load, line losses are not in fact avoided for most new QFs.

3. Adjust the avoided cost energy rates to reflect the locational energy value of the Company's North Carolina service area as opposed to the entire DOM Zone. Since the QFs in question in this proceeding are all located in North Carolina, this adjustment better ensures that avoided energy rates for these QFs reflect the Company's actual avoided cost for their output.

4. Set the avoided capacity rate to zero to reflect the fact that additional Solar DG in North Carolina will not enable the Company to avoid additional capacity costs either in North Carolina or elsewhere on DNCP's system.

5. Reduce the maximum standard QF contract term from 15 years to 10 years.

My testimony below provides additional rationale and support for each of these five proposed modifications. Company Witness Petrie then addresses the disparity between DNCP's forecasted payments to North Carolina QFs and the expected value of these resources, and supports the Company's current avoided costs and resulting proposed rates incorporating these proposals.

I. <u>Reduction of Threshold from 5 MW to 1 MW</u>

Q. **You mentioned earlier that the purpose of these proceedings is to determine avoided cost rates and terms for "small" QFs. How does the Commission define "small" QFs?**

A. As I noted above, FERC requires the Commission to determine avoided cost rates for QFs of 100 kW capacity or less. FERC's rules also allow the Commission to determine avoided cost rates for larger facilities. In recent avoided cost proceedings, including the 2014 Avoided Cost Case, the Commission has concluded that standard avoided cost rates should be determined for QFs that produce energy from renewable sources of power with capacity of 5 MW or less and for other QFs of 3 MW or less.

Q. In your opinion, is it still appropriate for the Commission to define "small" QFs this way?

A. No. For several reasons, the Company believes that at this time standard rates and contracts for all QFs should be limited to projects with 1,000 kW (AC), or 1 MW (AC), or less of nameplate capacity. This would allow more QFs to enter into negotiated contracts instead of standard contracts, which would have three primary benefits: (1) avoided costs will better align with the QF's LEO; (2) rates and terms can be customized to the specific project and location; and (3) additional customer protections can be included in the negotiated contracts.

Q. Please explain how making this change will allow avoided costs to align with the LEO of each individual QF.

A. Under current practice, standard avoided cost rates are updated biennially. Generally speaking, any QF eligible for the standard contract that establishes an LEO within this two-year period receives the standard rates. The effect of this framework is that projects that establish an LEO late in the two-year window receive rates based on avoided cost determinations that are often up to four or five years old by the time those projects commence commercial operations. This disparity is amplified by the long-term nature of these contracts, which can extend under Sub 136 and Sub 140 rates up to 15 years in length.

In contrast, the Company calculates the projected avoided costs for QFs that do not qualify for standard offer rates, which instead receive negotiated contracts, based on data that is available at the time the QF established an LEO. This approach allows the rates customers pay the QF to better align with current market conditions and take into account, for example, significant changes in gas and power market prices. Such timely updates also help mitigate the compounding impact of any differences between the actual market prices and the contract prices over the long terms of these contracts.

The Company believes that, given the influx of distributed solar projects in its North Carolina service area, it is appropriate to extend this negotiated, more precise approach to determining avoided costs to all projects of sizes greater than 1 MW. In effect, lowering the standard offer size threshold still provides the opportunity for non-negotiated contracts for the truly small projects, but helps ensure that payments to the larger projects more closely align with ratepayers' actual avoided costs.

Additionally, lowering the size threshold for standard contracts helps to mitigate any disparity between forecasted avoided costs and realized market value over the long term of these contracts as I mentioned above.

Q. What other benefits arise when rates and terms are customized for each specific project and location?

A. One of the key limitations with the current manner in which PURPA is implemented in North Carolina is the Company's inability to incentivize QFs to locate in one location over another. This is because all QFs under 5 MW, regardless of location, are eligible for the same standard contract and rates.

The result is a heavy concentration of distributed solar on a few substations. As noted in the Company's Initial Comments, approximately 80% of the interconnected Solar DG in DNCP's North Carolina service area has been located on only 15 substations out of a total of 42. This is because developers only have an incentive to locate where they can develop the project at the least expense – not where it has the most value to customers.

With more negotiated contracts, the Company would have the ability to incentivize projects to be located in areas or on circuits that have a need for new generation. For example, the Company could pay for avoided line losses and capacity costs where a QF locates on a distribution circuit with excess load to offset, but not for a QF supplying generation on a circuit that already exceeds load, as discussed further below. This should be advantageous to both the Company and the QFs as it would provide the opportunity to increase the avoided cost payments for more projects located in more valuable locations.

Q. What customer protections can be included in negotiated contracts that are not included in the current standard contract?

A. Negotiated contracts can include provisions that benefit customers but are not permitted in the standard contract. For example, negotiated contracts can apply non-levelized rates instead of the levelized calculations used for standard contracts. The Company has recently (within the past year) successfully negotiated contracts that provided for non-levelized payments. As I discuss further below, a non-levelized rate ensures that the PPA rates better match the Company's actual avoided costs throughout the life of the contract and protects against overpayment if the QF fails to perform later in its project life.

Q. Are there any other considerations in favor of DNCP's proposal to reduce standard offer eligibility to 1 MW?

A. Yes. In addition to the scale and scope of QF solar development in DNCP's North Carolina service territory changing significantly over the past two years, in most instances, the five MW projects that are located in DNCP's North Carolina service area are developed by large, national developers with broad portfolios of renewable generation, access to complex financing, and experienced in PPA negotiations. Nearly all of these projects are developed or owned by companies that also develop large projects or multiple small projects, and not by small unsophisticated developers. Of the Company's North Carolina QF contracts, approximately 83% (60 of 72) of the PPAs are for standard contracts sized 5 MW and below. Furthermore, 55 of these 60 PPAs were developed by only seven different developers. Though I do not claim to know the developers' motivations, it seems rational to conclude that these large developers develop multiple 5 MW projects in order to take advantage of the two-year-old standard avoided cost rates. Reducing the eligibility threshold to 1 MW will save the standard rates and terms for those fewer truly small scale projects that need them, as well as protect our customers from excessive overpayments as I discuss above.

II. <u>Elimination of the line loss adder for standard contracts</u>

Q. Please explain the rationale for including a 3% line loss adder to the energy payment provided in previously approved standard avoided cost rate schedules.

A. When deployed effectively and efficiently, one benefit of Solar DG is the avoidance of line losses. When load on a particular circuit exceeds the generation interconnected to that circuit, Solar DG or other generation at that location can often directly serve the load on that circuit and avoid transmission and transformer losses that would otherwise be associated with serving that load. The avoided energy cost rates reflected in DNCP's previous standard avoided cost rate schedules, including those approved in the Sub 140 proceeding, included a 3% loss adder for QFs connected at the distribution level to compensate those QFs for this added avoided line loss benefit. The 3% energy loss adder was established in previous avoided cost proceedings under the assumption that distributed generation from QFs would be less than load on interconnected circuits, thereby permitting the Company to reduce or eliminate losses arising from centrally-located generation.

Q. Why does the Company believe a line loss adder is no longer appropriate for standard contracts?

A. Losses are generally only avoided when the substation load exceeds the local distributed generation on a substation bus. Otherwise, excess generation must "backflow" onto the transmission grid to be transmitted to serve load on a different circuit. In such circumstances, there may actually be an *increase* in system line losses, as the distributed generation then has to pass through two transformers (distribution to transmission to distribution) in order to reach load. As I discussed earlier, due to the volume of Solar DG on the North Carolina portion of DNCP's system compared to the typical load in the DNCP territory, the point where generation does or will soon exceed load on most circuits has been reached. When this occurs, power flows the "wrong" way up through the transformer and through transmission lines to load, and no line losses are avoided.

Reverse flow already occurs most of the time on some of DNCP's North Carolina substations and part of the time on other substations. Exhibit JSG-1[2] shows the hourly load flow for the period of September 2015 through September 2016 on the 33 DNCP distribution transformers in North Carolina that have Solar DG facilities currently connected. Of the 33 transformers, 11 show a predominantly constant backflow of power, indicating that the energy delivered from the distributed generation connected at these substations exceeds the load. Of the remaining 22 substations, 18 are "neutral," meaning that they either have a mix of forward and reverse flows or that there is only a small amount of excess load remaining. The interconnection of additional Solar DG to these "neutral" circuits will tip the scales, lead to backflow of power, and will not result in any additional line loss savings at those locations. Only 4 of the 33 circuits still show a clear margin of load over currently interconnected Solar DG and the ability to host additional Solar DG.

[2] This data was provided as Exhibit DNCP-7 in the Company's Initial Comments.

However, it should be noted that just one or two new projects at 5 MW each will eliminate this margin. Additionally, it should be noted that this data was collected over the 12-month period from September 2015 through September 2016, and does not include Solar DG that only recently commenced operations, nor the remaining 600 MW of Solar DG already in the interconnection queue that has not yet commenced operations. When this generation is connected, the backflow will increase substantially.

To account for the effect of the geographic saturation of Solar DG, the Company proposes to eliminate the 3% line loss adder to the avoided energy cost rate offered for future standard QFs. Otherwise, customers will be paying for losses that are not actually avoided. As the data shows, in many cases customers are already paying for a loss adder under the Sub 136 or Sub 140 contracts where no actual losses are avoided. While those QFs are certainly entitled to keep receiving the loss adder specified in their contract, future QFs should not be paid for losses that are not in fact avoided. For QFs that are not eligible for the standard avoided cost rate schedules (i.e. between 1 MW and 20 MW), the Company may calculate a project specific loss percentage, either positive or negative, depending on each project's specific interconnection location.

III. <u>Adjustment to avoided energy rates to reflect locational energy value</u>

Q. Please describe the Company's proposal to include a locational component in the avoided energy rates to more accurately reflect the Company's actual avoided cost.

A. PJM calculates the locational marginal price or LMP that reflects the value of energy at each specific node on the grid. Areas in which generation is needed to meet load will realize higher LMPs in order to incentivize generation to locate in that place. Conversely, locations where generation is not as valuable due to congestion and/or losses will realize lower LMPs. As Company Witness Petrie further details, LMPs in the Company's North Carolina service territory have been consistently lower than the prices for the DOM Zone as a whole.

Lower LMPs mean that additional generation in this area is less valuable than generation in other areas of the DOM Zone. The discounted value of generation in this location must therefore be incorporated into the forecasted avoided energy price because that is the *actual* value that PJM gives to this generation. If this adjustment is not made, customers will pay rates that exceed the marginal energy costs that are actually avoided.

Q. Since the Commission has always viewed DNCP's cost of energy on a system level for ratemaking and in its approval of DNCP joining PJM, please explain how the lower value of power in North Carolina locations justifies the proposed reduction of the Company's marginal cost of energy.

A. It is true that the Company's fuel rates are based on the total system cost of energy, but the system cost of energy is fundamentally derived from the LMPs where the load and generation are located. The Dominion Load Serving Entity ("DOM LSE") buys load from PJM at a rate that is based on the load-weighted average LMP across the DOM Zone. The Company's generation ("DOM GEN") receives an energy payment based on each generator's output times the LMP at its respective node. The net of the cost of load and generator energy revenue and cost is the total system cost:

Load Cost ($) = Load (MWh) x LMP ($/MWh)
Gen Revenue ($) = Generation (MWh) x LMP ($/MWh) (at each specific generator location)
Gen Cost ($) = Cost of operating generator (i.e. fuel, etc.)
Net System Costs ($) = Load Cost ($) – Gen Revenue ($) + Gen Cost ($)

Therefore, if additional generation is being added (or load is being reduced) in a location with low LMPs, it has less effect on lowering Net System Costs than if the generation were added in a location with high LMPs.

Q. Can you provide an illustration that shows how the LMPs at specific locations affect the total system costs that customers pay?

A. Yes. The following illustration may be helpful in understanding how LMPs affect the Company's total system cost.

Assume a system where there are three buses (Bus A, B, and C) and their LMPs in a given hour are \$25/MWh, \$50/MWh, and \$75/MWh, respectively, and the net load (load minus generation) on each bus is an equal 100 MW.

Figure 4: LMP Example Base Case

Base Case			
Bus	**Load (MW)**	**LMP (\$/MWh)**	**System Cost (\$)**
A	100	25	2,500
B	100	50	5,000
C	100	75	7,500
Total System	300		15,000
Zone LMP (\$/MWh):	50.00		

As shown, the total system load cost is \$15,000, derived from multiplying the load at each bus times its respective LMP and summing the total cost of all the load.

In this example, the Zone LMP is \$50/MWh, which represents the load-weighted average of all the buses in the zone. This is calculated by multiplying the net load times the LMP at each node and then dividing by the total load.

Next, assume that 5 MW of generation is added at Bus A reducing its net load from 100 MW to 95 MW.

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Figure 5: Generation added to Bus A

Load Reduced by 5 MW at Bus A			
Bus	Load (MW)	LMP ($/MWh)	System Cost ($)
A	95	25	2,375
B	100	50	5,000
C	100	75	7,500
Total System	295		14,875
Zone LMP ($/MWh):	50.42		
Avoided Cost ($/MWh):	25.00		
Avoided Cost ($)			$ (125)

The system cost has been reduced from $15,000 to $14,875 ($125 of avoided cost) by adding 5 MW of generation at Bus A. This implies that the avoided cost is $25/MWh or $125/5 MW, equal to the LMP at Bus A where the load was reduced. Furthermore, the Zone LMP has *increased* to $50.42/MWh because there is less load at the lower-priced bus, thus causing the load-weighted average of the zone to increase.

Conversely, assume that 5 MW of generation is added at Bus C (instead of the lower-priced Bus A) reducing its net load from 100 MW to 95 MW.

Figure 6: Generation added to Bus C

Load Reduced by 5 MW at Bus C			
Bus	Load (MW)	LMP ($/MWh)	System Cost ($)
A	100	25	2,500
B	100	50	5,000
C	95	75	7,125
Total System	295		14,625
Zone LMP ($/MWh):	49.58		
Avoided Cost ($/MWh):	75.00		
Avoided Cost ($)			$ (375)

The system cost has been reduced from $15,000 to $14,625 ($375 of avoided cost) by adding 5 MW of generation at Bus C. This implies that the avoided cost is $75/MWh or $375/5 MW, equal to the LMP at Bus C where the load was reduced. Furthermore, the Zone LMP has *decreased* to $49.58/MWh because there is less load at the higher-priced bus, thus causing the load-weighted average of the zone to decrease.

Therefore, the avoided cost of added generation or load reduction is equal to the LMP at the bus where the generation or load reduction is located.

Q. Is the proposed LMP adjustment consistent with the peaker method?

A. Yes. The underlying theory behind the peaker method is that the long-run avoided energy cost is equal to the *marginal* costs of the utility's system in each hour. As demonstrated above, the LMP where the generation is located directly translates into the marginal cost avoided for the utility system.

IV. Avoided capacity rate of zero

Q. Please explain the Company's proposal to set the avoided capacity rate to zero.

A. Simply stated, the Company does not have a near-term need for additional generation capacity and, even if it did, additional Solar DG in North Carolina beyond what is already under contract would not defer future capacity needs.

Q. Please elaborate.

A. FERC has clearly stated that an avoided cost rate is not required to include capacity costs where a QF does not allow the purchasing utility to avoid building or buying future capacity. FERC has explained that even though utilities may have an obligation under PURPA to purchase from a QF, that obligation does not require a utility to pay for capacity that it does not need. Put simply, FERC has concluded that when a utility's demand for capacity is zero, the cost for capacity may also be zero.

In the 2014 Phase 1 Order, the Commission acknowledged FERC's determination that avoided cost rates are not required to include the cost for capacity when the utility's need for capacity is zero. The Commission interpreted FERC's decisions as meaning that the time period over which the need for capacity should be considered is the planning horizon, but it also agreed that "[i]f … poor economic conditions, *combined with a large influx of QFs*, eliminated the need for utility fossil generation capacity, there would be no future capacity to offset or avoid." The Commission stated that, "under these circumstances, the payment of avoided capacity could be inconsistent with PURPA." 2014 Phase 1 Order at 35-36. Certainly, the Company has realized a large influx of QFs in only a short few years.

As Company Witness Petrie further explains, the Company's preliminary updated load forecast does not currently reflect an avoidable capacity need until 2024 at the earliest. Using the most recent PJM load forecast, a capacity need does not arise until after 2026.[3] Even if such a capacity need were to arise, adding additional Solar DG in North Carolina would not allow DNCP to avoid future capacity expansions. There is therefore no need for additional distributed solar in the Company's North Carolina service territory.

Because DNCP will not avoid capacity costs due to incremental distributed solar North Carolina QF generation, a zero capacity payment accurately reflects the Company's actual avoided costs for QF contracts signed today.

V. <u>Reduction of standard term from 15 years to 10 years</u>

Q. Please explain the rationale for reducing the maximum contract term from 15 years to 10 years.

A. The Company proposes to reduce the maximum term of a standard avoided cost contract from 15 years to 10 years, such that QFs that qualify for a standard avoided cost contract may enter a PPA with either a 5-year or a 10-year term. The intent of this change is to mitigate the Company's customers'

[3] *See* https://www.pjm.com/~/media/documents/reports/2016-load-report.ashx.

exposure to the significant above-market payments for QF output that are resulting under 15-year contracts. As discussed below, this proposed change does not compromise QFs' rights under PURPA, since the Company will remain obligated at the end of each PPA term to purchase QF output.

Q. How do shorter contract terms mitigate customers' risk of paying more than avoided cost?

A. By necessity, the fixed long-term prices provided in PURPA contracts are based on projections of future costs for electricity. It is therefore unavoidable that due to such factors as technology advances, declining equipment costs, and new fuel supply sources, the rates the Company pays for QF output under a standard PURPA contract will not exactly match its actual avoided cost in any given year of that contract. For example, for combustion turbines ("CTs"), construction and operating costs have decreased, performance has improved, and fuel costs have fallen, leading to greater capacity factors and energy benefits that impact future avoided cost calculations. The result of this mismatch between market energy costs and locked-in avoided cost contract rates is that DNCP and its customers currently pay more under these contracts than the Company's true avoided cost for QF output. As discussed above, currently, given the decline in fuel and thus power prices that has occurred since the 2014 Avoided Cost Case, and especially since the 2012 avoided cost case (Docket No. E-100, Sub 136), the Company is significantly overpaying QFs that have executed PPAs under those two sets of rates. For example, the Company's on- and off-peak prices for Option B under Sub 136 for a 10-year term are $56.75/MWh and $45.49/MWh respectively. There was a reduction in the on- and off-peak Option B prices in the Sub 140 docket to $48.02/MWh and $40.85/MWh respectively, and a further reduction in the Company's proposed on- and off-peak avoided cost prices in this proceeding to $33.94/MWH and $28.72/MWH respectively. The trajectory of these prices indicates an approximate 10% *annualized* drop in avoided costs between Sub 136 (2012) and Sub 148 (2016).

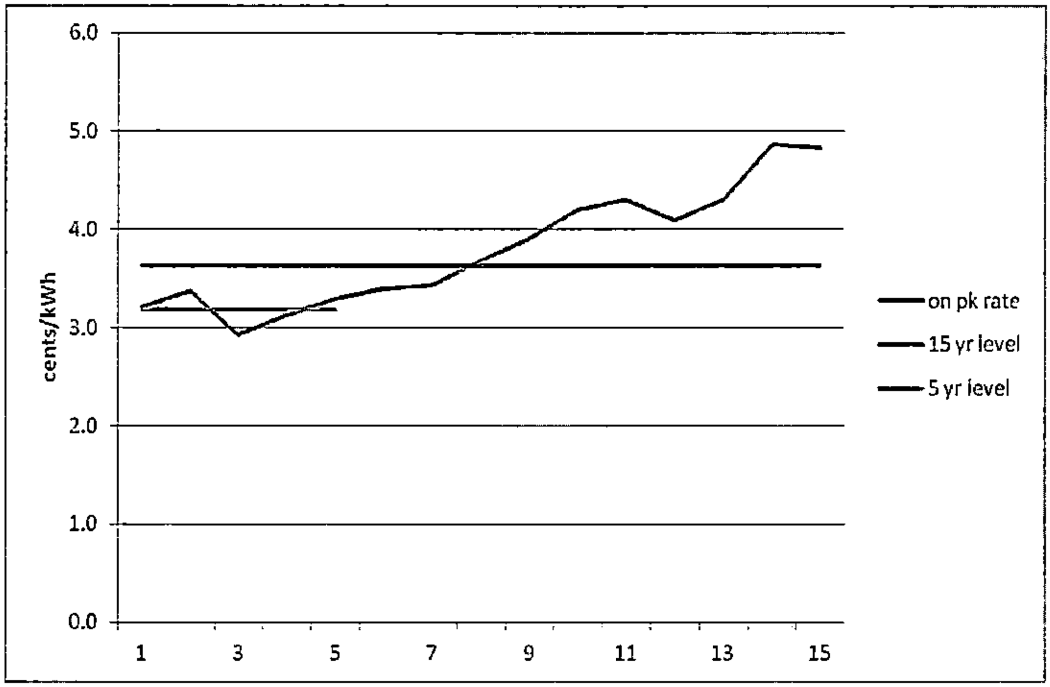
The longer the contract term, the more severe this mismatch becomes. A 15-year term therefore exacerbates the problem, because as renewable development and other power production costs continue to decline as discussed above and in DNCP's Initial Filing, the delta between those costs and the rate DNCP is contracted to pay QFs increases. Reducing the contract term from a maximum of 15 years to 10 years will better align the fixed prices provided by these contracts with the Company's actual avoided costs over the contract term and, as a result, reduce the risk of overpayment by the Company's ratepayers.

Q. Do the levelized rates provided by the standard contracts exacerbate the overpayments to QFs?

A. Yes. Under the rate schedules and contracts approved in the 2014 Avoided Cost Case, a QF could enter into a standard contract with levelized rates for a 5-year, 10-year, or 15-year term. As discussed in that case, when rates are levelized it creates an additional discrepancy between the payment to the QF and the utility's avoided cost in any particular year. This is because, in the early years of the contract, the QF receives rates that exceed the Company's actual avoided cost, and in the later years the QF receives rates that are less than the actual avoided cost. For shorter term contracts (3-5 years), this overpayment is usually not large. For longer periods, especially those in excess of 10 years, this overpayment increases.

Figure 7 illustrates levelized rates versus non-levelized avoided costs for both a 5-year and 15-year term. The longer the contract, the more disparity exists between actual annual avoided costs and the over/under payment created by the levelization. While in theory the over payment in the early years of the contract will be negated by the underpayment in the later years, this disparity creates a significant risk for customers that the QF will not perform during the later "underpayment" portion of the contract. It is the Company's belief that for most QFs, non-levelized pricing is advantageous for customers because it better aligns payments with costs that are being avoided throughout the life of the contract.

Figure 7: Illustrative Levelized Rates Example



Q. **Is a 10-year term consistent with PURPA?**

A. Yes. DNCP's proposal to reduce the maximum contract term to 10 years is consistent with PURPA and FERC's implementing rules and precedent. A 10-year contract still provides a basis for long-term financing of the project, as demonstrated by the fact that six, i.e., 50 percent, of the non-standard contracts that the Company has entered into with solar QFs ranging from 12 MW to 20 MW have contained 10-year terms. These projects have been able to achieve financing and continue development, with several having either already commenced commercial operations or reached late-stage development.

Moreover, even with a reduced maximum term, DNCP still retains the PURPA obligation to purchase the QF's output at the end of the contract period. The shorter term simply allows the prices the Company must pay to be closer aligned with its actual avoided costs.

Other Standard Contract Proposals

Q. In addition to the proposals you have already discussed, is the Company proposing any other changes to its standard avoided cost contracts?

A. Yes. DNCP has proposed other minor modifications to the standard contracts with the intent of simplifying and clarifying certain items. First, the Company has removed the map requirement from Exhibit D of the standard PPAs, as this information is already incorporated into the QF's CPCN application and is therefore duplicative. Additionally, the Company has inserted a provision to Article 1 of the Schedule 19-FP standard contract for the QF to choose the Option A or Option B rate schedule. Since the previous PPA does not provide for such a clear election, this change will clarify precisely which option the QF wishes to select.

Conclusion

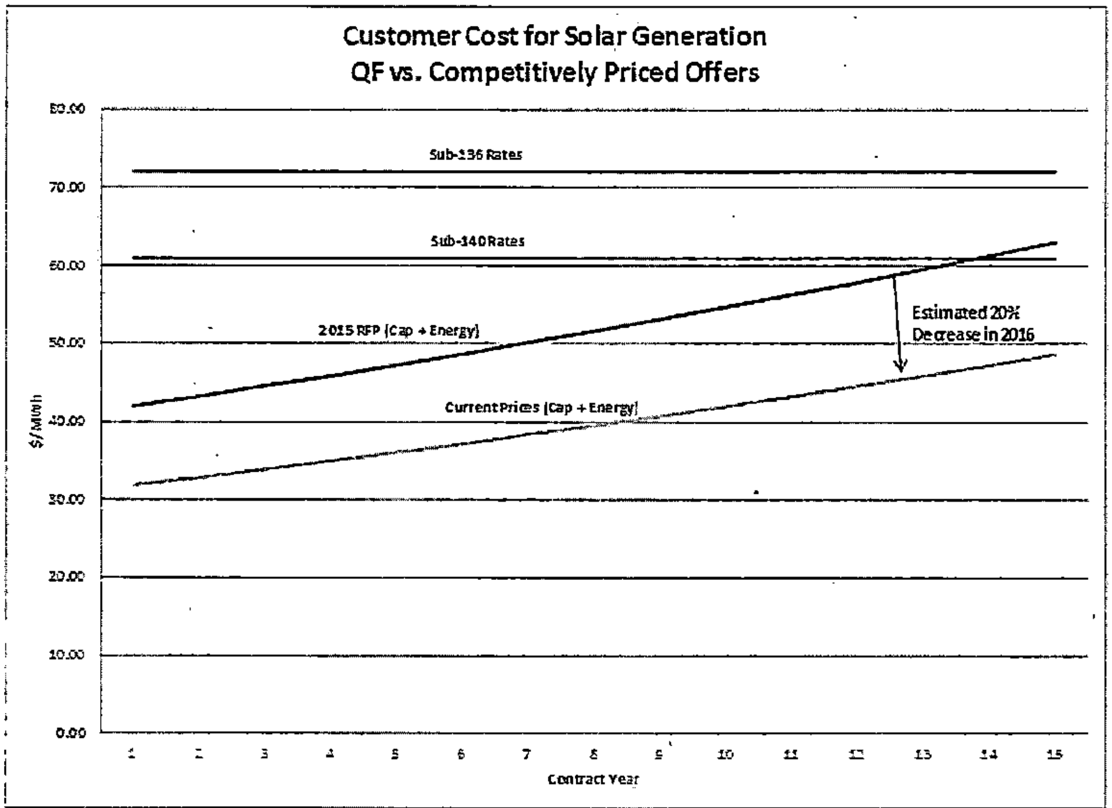
Q. In the Company's Initial Comments, you discuss the benefits of a Request for Proposal ("RFP") process as a more efficient means to procure solar generation. Please explain.

A. DNCP continues to recognize the many potential benefits of adding solar generation to its system. However, the Company's goal is to incorporate solar in a manner that better increases the benefits and reduces the cost to customers of these resources. By procuring solar generation outside of the PURPA context, the Company can take advantage of the declining cost of solar as well as encourage future solar generation projects to locate where they would be most beneficial to DNCP customers.

An RFP process is one such way to more efficiently deploy Solar DG across the Company's system. Through an RFP process, DNCP's ratepayers benefit from competitively-priced solar generation, stronger contract provisions, and geographically diverse project locations. In addition, an RFP can include not only the output of the facility, but also the renewable energy credits to ensure anticipated future compliance with the Clean Power Plan or other future carbon regulation. In short, customers can receive a better product for lower costs and are able to realize the benefits of declining solar costs and extended tax credits.

For example, the Company recently solicited offers for new solar generation projects located within its Virginia service territory. The result of that RFP was that the Company was able to build or purchase approximately 76 MW of new Solar DG at a lower cost with more benefits to customers than it could achieve through the North Carolina PURPA contracts. Figure 8 below demonstrates the degree to which the costs associated with solar PPAs in the Company's service territory exceed energy and capacity costs of competitively-priced offers, and how much can be saved by deploying solar generation outside of the PURPA context.

Figure 8: Customer cost vs. competitive prices



Through this RFP process, DNCP's ratepayers benefitted from lower-priced procurement of solar generation, stronger contract protections, and geographically diverse project locations. In addition, the Company obtained not only the output of the facility but also the renewable energy credits to ensure anticipated future compliance with the Clean Power Plan or other future environmental regulations. In short, customers receive a better product for lower costs and are able to realize the benefits of declining solar costs and extended tax credits.

The Company acknowledges that it would still retain the obligation under PURPA to purchase at its avoided costs the output from QFs that did not participate in, or were not awarded a contract through, an RFP. The Company envisions, however, that an RFP process could be used in conjunction with its PURPA obligations, with the proposed changes to the avoided cost rates and terms proposed here.

In sum, the changes the Company is proposing in this case for its standard avoided cost contracts would permit the payments that DNCP and its customers make to QFs under these agreements to more accurately reflect the Company's avoided costs for typical QFs and limit the risk to customers of overpayments. A parallel RFP process would offer solar developers the opportunity for longer-term contracts at competitive prices, and would allow the Company to use factors such as geographic diversity in its selection of projects to ensure that the full benefits of distributed solar are realized.

Q. Please summarize your testimony.

A. Since the 2014 Avoided Cost Case, DNCP's North Carolina service territory has experienced unprecedented growth in distributed solar generation QFs. In just a few short years, the Company has become obligated under numerous PPAs to purchase solar capacity that exceeds its average on-peak load in the region. The Company has therefore proposed revisions to its standard contract rates and terms that it believes will better align these rates and terms with DNCP's actual avoided costs and generation needs to limit the risk to our customers of continuing to pay PURPA rates in excess of the Company's actual avoided costs.

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Q. Does this conclude your testimony?

A. Yes.

APPENDIX A

BACKGROUND AND QUALIFICATIONS OF J. SCOTT GASKILL

J. Scott Gaskill joined the Company in 2007 as a Senior Financial Analysis Specialist in the Generation System Planning department. In 2012, Mr. Gaskill was promoted to Manager of Generation System Planning. In June 2015, he was promoted to his current position as Director of Power Contracts. In his current role, Mr. Gaskill is responsible for the negotiation, origination, and day-to-day administration of the Company's NUG power contracts.

Prior to joining Dominion Virginia Power, Mr. Gaskill worked for Ventyx as a Senior Consultant specializing in the areas of resource planning, market price forecasting, and unit valuation. Additionally, he assisted multiple utilities, including Dominion Virginia Power, in their implementation and use of the PROMOD and Strategist production cost planning models.

Mr. Gaskill graduated from the Georgia Institute of Technology in 2003 with a Bachelor of Science degree in Industrial and Systems Engineering. While working for the Company, he also received a Master of Business Administration degree from Virginia Polytechnic Institute and State University in 2011.

Mr. Gaskill has previously presented testimony before the State Corporation Commission of Virginia and the North Carolina Utilities Commission.

(Whereupon, Exhibit JSG-1 was identified as premarked.)

Q Mr. Gaskill, did you also cause to be prefiled in this docket on April 10th of this year 34 pages of rebuttal testimony and one exhibit?

A Yes.

Q Do you have any changes or corrections to that rebuttal testimony?

A Yes. Similar to my direct, on page 13, line 3, the word "six, i.e., 50%" should be replaced with the word "five."

Q And with that correction, if I were to ask you the same questions that appear in your rebuttal testimony today, would your answers be the same?

A Yes.

MS. KELLS: Mr. Chairman, I move that Mr. Gaskill's rebuttal testimony be copied into the record as if given orally from the stand, and his one rebuttal exhibit be marked as prefiled.

CHAIRMAN FINLEY: Mr. Gaskill's rebuttal testimony filed April 10, 2017, consisting of 34 pages, is copied into the record as though given orally from the stand, and his one rebuttal exhibit is marked for identification as premarked in the filing.

MS. KELLS: Thank you.

(Whereupon, the prefiled rebuttal testimony, as corrected, of J. Scott Gaskill was copied into the record as if given orally from the stand.)

REBUTTAL TESTIMONY
OF
J. SCOTT GASKILL
ON BEHALF OF
DOMINION NORTH CAROLINA POWER
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100 SUB 148

Q. Please state your name, business address, and position of employment.

A. My name is J. Scott Gaskill, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. My current position is Director of Power Contracts and Origination for Dominion North Carolina Power ("DNCP" or the "Company").

Q. Are you the same J. Scott Gaskill who filed direct testimony in this proceeding with the North Carolina Utilities Commission (the "Commission" or "NCUC") on February 21, 2017?

A. Yes.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of my testimony is to respond to the March 28, 2017 comments and testimony filed on behalf of the Public Staff, the North Carolina Sustainable Energy Association ("NCSEA"), Southern Alliance for Clean Energy ("SACE"), Cypress Creek Renewables ("CCR"), and other intervenors in this proceeding. My testimony will further support the Company's proposed modifications to its avoided cost calculations and standard contract terms, while addressing the various concerns raised by the intervenors.

Additionally, Company Witness Bruce E. Petrie addresses the significant above-market payments that DNCP customers are committed to under current Purchased Power Agreements ("PPAs"), and provides support for the Company's avoided cost calculations and proposal to set the avoided capacity rate to zero in the standard contract.

Q. Please summarize the issues your testimony will address.

A. As explained in the Company's Initial Comments and direct testimony filed in this proceeding, DNCP has proposed a number of modifications to its calculation of avoided cost payments and its standard avoided cost contract in response to the unprecedented growth in North Carolina solar qualifying facility ("QF") development. With this growth, the Company and its customers are already committed to hundreds of millions of dollars in QF PPA payments over the next 15 years. The risk of overpayments from customers is real and significant, warranting DNCP's proposed modifications to the standard contract offer at this time.

The Public Staff also appears to recognize this unprecedented growth and the need it presents for certain modifications in how the Public Utility Regulatory Policies Act ("PURPA") is implemented in North Carolina. As Public Staff Witness John R. Hinton summarizes:

> This significant growth of facilities from which the utilities are obligated to purchase energy and capacity has increased the risk of potential overpayments by ratepayers. In addition to exceeding load growth experienced by the utilities, the higher penetration of resources pose operational and technical

> challenges for the utilities in meeting their obligation to provide safe, reliable, and economic service to ratepayers.

(Hinton at 7.)

To address these concerns, the Company has proposed five major changes to its standard offer avoided cost contracts. My testimony will address the intervenor comments on each of these proposals as well as proposed improvements to the process by which QFs establish a Legally Enforceable Obligation ("LEO").

I. REDUCTION OF STANDARD OFFER ELIGIBILITY THRESHOLD FROM 5 MW TO 1 MW

Q. Please briefly summarize the Company's proposal with respect to eligibility for the standard Schedule 19 contract.

A. The Company believes that at this time the standard avoided cost rates and contracts should be limited to QFs with 1,000 kW (AC), or 1 MW (AC), or less of nameplate capacity. A 1 MW size threshold both preserves the standard contract eligibility for truly small QF developers, and allows the rates paid to the larger QFs to more closely align with their actual avoided costs.

Q. What is Public Staff's position on reducing the size threshold from 5 MW?

A. Public Staff Witness Hinton states that "the Public Staff believes it is appropriate for the Commission to consider modifications to the standard offer threshold." (Hinton at 41.)

While Mr. Hinton provides reasoning to reduce the threshold to either 1 MW or 2 MW, he ultimately concludes that:

> it appears that the 1-MW limit may have more practical significance. As indicated by [Duke] witness Bowman and DNCP witness Gaskill, the reduced threshold will allow the avoided cost rates offered to more QFs to be based on more timely information, including updated capacity needs, fuel costs, and other factors that may reduce the exposure of ratepayers to potential overpayments due to the changing market conditions.

(Hinton at 44.)

In addition, Mr. Hinton notes on page 43 of his testimony that the 1 MW threshold is consistent with other regulatory contexts, including North Carolina's maximum size for net metering and the Federal Energy Regulatory Commission's ("FERC") current requirement that only those QFs with 1 MW or more of capacity must self-certify.

Q. **NCSEA Witnesses Kurt G. Strunk (Strunk at 13) and Carson Harkrader (Harkrader at 15), and CCR Witness Patrick McConnell (McConnell at 8) expressed concern that lowering the capacity threshold for QFs to use a standard contract from 5 MW to 1 MW will impact QFs' ability to finance some projects. Please respond.**

A. Though the Company is not in a position to know the financing ability for every potential QF, QF developers in North Carolina tend to be large solar developers with large portfolios of generation projects in this State and elsewhere around the country. They are well capitalized with access to financing resources that afford them the ability to negotiate a PPA.

Furthermore, based on my observations, these developers are breaking up their large portfolios of projects into multiple 5 MW projects in order to qualify for the standard offer, including the standard avoided cost rates that can be two years old by the time a QF establishes an LEO.

As I discussed on page 19 of my direct testimony, 83% (60 out of 72) of the QF PPAs the Company had signed at the time that testimony was filed are for projects sized 5 MW and below. Furthermore, 55 of these 60 standard contracts were developed by only seven different developers.

I found it quite instructive to read the testimonies of the intervenors with solar development experience, in particular NCSEA Witness Strunk and CCR Witness McConnell. Both witnesses discuss the fact that they group together multiple small projects in order to improve the financing terms of a larger portfolio.

For example, Mr. Strunk states that "one sometimes observes pools of small projects being financed together as a group." (Strunk at 13.)

Similarly, Mr. McConnell admits that "[t]he only way to make most financings work with a 5 MW threshold was to group them into portfolios to create critical mass for debt and tax equity investors." (McConnell at 8.)

Q. Do these large solar developers require the standard contract in order to develop their QF projects?

A. No. Based on my experience, these larger developers clearly have the resources and sophistication to negotiate contracts, and the market would be better served by removing the incentive to break up the projects into small increments.

For example, Mr. McConnell's company, Cypress Creek Renewables, claims on its website that "With well over $1.5 billion raised and invested and over 4 gigawatts of local solar farms deployed or in development … Cypress Creek Renewables is the largest and fastest-growing dedicated provider of local solar farms"[1] It simply defies logic that large, sophisticated developers like Mr. McConnell's company require a standard offer in order to successfully finance and complete solar projects in North Carolina.

The Company believes the intent of the standard offer contract is to provide simplified and standard market access for the truly small developers – it is not intended as a means for a large developer to break up large solar deployments into small individual projects simply to get higher pricing and better financing terms, which in my opinion is occurring now in North Carolina.

Q. SACE Witness Thomas Vitolo expresses concern that the lower size threshold will have other negative consequences. Do you agree?

A. No. Dr. Vitolo states that the reduction from 5 MW to 1 MW will have "negative consequences relate[d] to the lengthy, resource-intensive, power imbalanced bilateral negotiation process, the significant loss of economies of scale, and the ramifications of a significant increase of interconnection

[1] https://ccrenew.com/who-we-are/ (last visited Apr. 10, 2017).

requests or bilateral negotiations." (Vitolo at 8.) On the contrary, I believe the standard offer size reduction will ultimately realize a positive benefit to developers, utilities, and customers alike in all of the areas identified by Dr. Vitolo.

First, Dr. Vitolo states that negotiated contracts require a more "resource intensive" negotiation process than standard contracts. (Vitolo at 8.) While it may be true that in some cases a negotiated PPA may take some additional time up front, over the life of the contract it actually requires significantly less resources to administer a single 20 MW contract instead of multiple small projects. An executed contract, regardless of whether it is standard or negotiated, requires approximately the same number of man-hours to administer, including labor-intensive tasks such as performing monthly meter readings, settlement, invoicing and billing, and payments. The Company's proposal is intended to encourage developers to build fewer, but larger, projects instead of breaking up their projects into multiple 5 MW pieces, greatly reducing the number of resources required to originate and administer the volume of QF contracts under consideration.

Second, while Dr. Vitolo does not specify what he means when he speaks of the "power imbalanced bilateral negotiation process" (Vitolo at 8), I assume he intends to imply that the utilities have more power than the QFs in the negotiating process. However, it is important to recognize that it is the utility that retains the obligation under PURPA to purchase the output from QFs with no ability to walk away from a negotiation. Furthermore, the procedures for establishing avoided cost rates and the vast majority of the terms and conditions of negotiated contracts have been pretty well established at this point. In fact, rarely do the negotiations of large contracts include much negotiation or dispute on the contract rates themselves, as they are calculated based on avoided costs as of the LEO for each contract. With few exceptions, the utilities and developers have essentially established a template for negotiated contracts that supports efficient and successful negotiations. As noted on page 12 of my direct testimony, the Company has successfully executed negotiated contracts with 12 QFs totaling 214 MW.

Finally, Dr. Vitolo expresses concerns about the loss of economies of scale and the increase in the interconnection queue. (Vitolo at 8.) Again, the Company believes its proposal will encourage developers to seek larger projects, as it removes the incentive to divide up a portfolio of projects into 5 MW increments. This change will in fact increase economies of scale and reduce the number of projects in the interconnection queue over time, while at the same time preserving the benefit of the standard offer contract for the truly small projects.

Q. Dr. Vitolo also notes that the Commission rejected a similar proposal by the utilities to reduce the size of the project eligible for the standard contract in the Sub 140 proceeding. (Vitolo at 11-12.) Why do you believe this change is necessary at this time?

A. As I stated in my direct testimony, the landscape of QF development has changed significantly since the Sub 140 proceeding. Furthermore, this proceeding will decide issues on a prospective basis, meaning the Commission must decide on the appropriate standard offer for QFs that are developed in the future. What may have been appropriate two years ago must be adapted to the circumstances the Company faces today and anticipates it will face over the next two years.

I note in particular that the Public Staff, who supported a 5 MW threshold in the Sub 140 proceeding, now believes it is appropriate to modify this standard size threshold. Mr. Hinton notes on pages 40-41 of his testimony that it is this change in circumstances that has led him to the conclusion that the reduction in size threshold merits reconsideration.

Q. Do you have any final comments regarding the reduction of size threshold for the standard offer to 1 MW?

A. Yes. As stated in my direct testimony, reducing the size threshold of the standard contract will allow more QFs to enter into negotiated contracts. This helps to ensure that the avoided cost rates customers are paying better align with the QFs' LEOs and commercial operations. Additionally, rates and terms can be customized to the specific project and location. In short, negotiated contracts provide important protection for customers to reduce the risk of overpayments to a large portfolio of QF projects.

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II. REDUCTION OF STANDARD CONTRACT TERM FROM 15 YEARS TO 10 YEARS

Q. The Company has proposed to eliminate the 15-year term option from its standard contract. Please summarize the need for this change.

A. As detailed in the Company's Initial Comments and Direct Testimony, the Commission has in numerous avoided cost proceedings recognized a balance that must be struck between the need to encourage QF development, on the one hand, and the risks of overpayments and stranded costs, on the other.

The Company's proposed change provides the QF a contract of sufficient length to obtain financing while also mitigating customers' risk and exposure to the significant above-market payments that have resulted from 15-year contracts. In light of the fact that the Company still retains the obligation under PURPA to continue purchasing the output at the end of the term at then-avoided cost, the Company believes that a 10-year contract will still allow the QFs to obtain financing and successfully complete their projects.

Q. What is the Public Staff's position on this issue?

A. Public Staff Witness Hinton discusses both the advantages and disadvantages of eliminating the 15-year term option. (Hinton at 49-57.) Ultimately, however, he concludes that "[d]ue to the continued rapid pace of QF development in North Carolina, the Public Staff believes it is appropriate at this time for the Commission to consider a shorter-term structure for avoided cost rates. This would serve to reduce the risk borne by ratepayers for overpayments over a longer term. The Public Staff believes that the utilities' proposal to limit the standard offer term to ten-year fixed PPAs is reasonable." (Hinton at 56.)

Mr. Hinton then goes on to note numerous examples of solar QFs obtaining financing with a 10-year contract term.

Q. SACE Witness Vitolo notes that the Company has only signed 10-year contracts with QFs that are greater than 5 MW. Please comment.

A. Dr. Vitolo states that "[d]ata responses from [both DNCP and Duke] show that at least some solar QFs 10 MW and larger have been built with 10-year contracts as well. However, this does not suggest that projects under 5 MW or over 10 MW will be financeable in the future with contracts of that duration." (Vitolo at 13.)

First, it should be noted that the Company does not have any 10-year contracts for QFs under 5 MW to date simply because QFs of this size have previously been eligible for the 15-year term. In an environment of declining avoided cost rates, QFs eligible for the standard contract would certainly opt for locking in above-market rates for the longest possible duration. Of course, it is the ratepayers that ultimately pay for these above-market rates.

Second, as I have previously stated, there is very little distinction between the developers of QFs under 5 MW and greater than 5 MW. Large developers simply have broken up their project portfolios into smaller increments in order to qualify for the standard offer rates. If they can obtain financing with a 10-

year term on a large MW project, it stands to reason that small projects could do the same since, as NCSEA Witness Strunk testifies, "pools of small projects [are] financed together as a group." (Strunk at 13.)

Q. Other intervenors have expressed concern about the ability to obtain financing with a 10-year contract term. Can you please respond?

A. Yes. Several of the intervenor witnesses expressed concern with the reduced term of the standard contract, primarily because they claim it increases their financing costs. CCR Witness McConnell states that limiting contracts to 10 years would require additional equity investment and increase the cost of debt, therefore reducing the rate of return the developer realizes on the project. (McConnell at 6-7.) NCSEA Witness Strunk similarly states that reducing the PPA term will increase the cost of capital for investors and short-term cash requirements. (Strunk at 8.)

While I have no reason to question Mr. McConnell's or Mr. Strunk's claims that a shorter term, all else being equal, will change financing requirements, I do not find that to be a compelling reason to expose customers to the risk that comes with 15-year fixed price contracts at avoided cost. The goal of PURPA is to encourage QF development, but I am unaware of any regulation, or of PURPA itself, stating that QF developers are entitled to rates that ensure a particular rate of return or that guarantees any particular project (or class of projects) is able to achieve financing.

It is the Company's experience that a 10-year contract is of sufficient length for many QFs to obtain financing and complete projects. In fact, as I noted in my direct testimony, six – that is, 50% – of the non-standard contracts that the Company has entered into with solar QFs have contained 10-year terms, including all but one of the non-standard contracts signed within the past two years. (Direct at 33.) A 10-year term also strikes an appropriate balance in protecting ratepayers from overpayments resulting from changes in market conditions over time.

Q. SACE Witness Vitolo describes on page 15 of his testimony a concern that QF solar projects are treated differently than utility projects since utility-sponsored projects depreciate capital over their lives. Please respond.

A. By their nature, rate regulated utilities and QFs differ in terms of how they are organized, regulated, financed, obtain cost recovery, and, in the case of utilities, their obligation to serve customers. Dr. Vitolo ignores these fundamental differences.

In particular, Dr. Vitolo ignores the fact that a utility must operate under cost-of-service rate recovery, which differs significantly from how independent power producers, like QFs, recover their costs. First and foremost, when a utility builds a plant and places it in rate base, it does not receive avoided cost for energy and capacity like the QFs, but instead only earns a return on the capital investment required to meet its obligation to serve. For example, when DNCP builds a new solar facility and places it in rate base, all of the benefits, including fuel savings, revenue from renewable energy credits ("RECs"), and

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investment tax credits ("ITC") generated by that plant are passed on to customers. In other words, the utility earns a return on its investment, but all of the benefits are passed directly to customers via lower fuel or base rates. In contrast, QFs are paid marginal (i.e. highest) costs for both capacity and energy *and* retain all of the other revenue streams such as from RECs and ITCs.

Additionally, under a cost-of-service recovery mechanism, the Company is limited to earning only what the Commission approves. The cost of debt and equity, as well as the overall capital structure, is determined by the Commission in a rate case after receiving evidence and undertaking considerable deliberations. In contrast, a QF has no limit on the amount of debt it may use for financing, the return on equity, or overall rate of return it may earn on a particular investment.

Finally, it is important to recognize that a utility faces a much higher burden to obtain a Certificate of Public Convenience and Necessity ("CPCN") and cost recovery for a new project, which usually requires that the utility demonstrate that the investment can be used to meet customer energy and capacity needs at a cost that is *below* avoided costs. For example, in the CPCN proceeding for the three solar facilities Dr. Vitolo alludes to on page 15 of his testimony, the Company provided evidence to the Virginia State Corporation Commission ("VSCC") that it would save customers an estimated

$32 million net present value below projected market prices.[2] The VSCC would typically only approve a project if it is shown to be favorable for customers relative to other options.

Q. Dr. Vitolo also states that "a longer depreciation schedule [for utility rate-based assets] allows for a reduced near-term rate impact, therefore making the investment more attractive." (Vitolo at 15.) Please respond.

A. Dr. Vitolo is correct that longer depreciation lives for utility rate-based assets lower the near-term rate impact for utility projects. This is because the lower annual depreciation costs are passed directly to customers via a lower revenue requirement. For QFs being paid avoided costs, however, there is no near-term rate reduction for providing longer contracts. The savings from the longer depreciation and lower financing costs are entirely kept by the QF, and customer risk is therefore increased with no offsetting cost benefit.

As demonstrated by all of these considerations, Dr. Vitolo's recommendation on page 17 of his testimony that "[t]he Commission should consider requiring the utilities to offer solar QFs fixed contracts at lengths that match the recovery period of the respective utility's own assets" should be rejected.

Q. Do FERC regulations support the use of a 10-year term?

A. Yes. Public Staff Witness Hinton notes that FERC regulations require utilities to make available data "from which avoided costs may be derived." (Hinton at 56 n. 38, citing 18 C.F.R. § 292.302(b).) FERC promulgated this regulation

[2] Case No. PUE-2015-00104.

because it believed that, "in order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate with reasonable certainty, the expected return on a potential investment before construction of a facility." Order 69, 45 Fed. Reg. 12,214, 12,218 (Feb. 25, 1980). The maximum financial feasibility period FERC incorporated in its regulation was 10 years. *See* 18 C.F.R. § 292.302(b)(2) (2016).

Q. In summary, does the Company continue to support a 10-year term as reasonable?

A. Yes. The Company agrees with Public Staff that a 10-year term is reasonable for the standard contract at this time. (Hinton at 57.) A 10-year term strikes an appropriate balance between the need to encourage QF development while also protecting ratepayers from the risk of overpayment through the contract term. The Company, of course, still remains obligated by PURPA at the end of the 10-year term to purchase the output from the QF, but the shorter term reduces the risk to customers that rates throughout the life of the project misalign with actual avoided costs.

While the purpose of PURPA is to encourage QF development, PURPA's express requirements that rates paid to QFs be just and reasonable to utility customers and not exceed the utility's avoided costs show that that purpose is clearly not intended to put customers at a disadvantage or to force them to pay more than their actual avoided costs. Furthermore, nothing in PURPA states that the rates a utility provides should guarantee financing on particular terms for any particular QF, nor does PURPA dictate any particular minimum term. Reducing the maximum standard contract term to 10 years will help to ensure that rates paid to QFs better align with actual avoided costs throughout the life of the project, while at the same time continuing to encourage QF development in North Carolina.

III. ELIMINATION OF LINE LOSS ADDER

Q. The Company has proposed to eliminate the 3% line loss adder in the standard contract. Please summarize the reasoning behind this proposal.

A. The Company has proposed to eliminate the 3% line loss adder in its avoided cost rates because the level of QF development in DNCP's North Carolina service area has reached the point where generation either already has or soon will exceed load on most circuits. When this occurs, backflow occurs and the distributed generation is no longer being used to serve the load on the interconnected circuit, but instead must use the distribution and transmission lines to meet load elsewhere. In this case, no line losses are avoided and, in certain instances, additional line losses will occur.

Q. Does the Public Staff agree with the Company's proposal to eliminate the line loss adder?

A. Yes. As Public Staff Witness Dustin Metz explains on pages 20-21 of his testimony:

> At a system level, DNCP has demonstrated that its North Carolina electric grid is experiencing reverse power flows onto its transmission system from DG. DNCP has shown that

> several of its substations are already experiencing reverse power flows, with some distribution substations impacted more than others. In the next few years as more DG is interconnected to the DNCP grid, those loss reductions will continue. It is no longer appropriate to include a line loss adder in the avoided cost rate schedules when line losses will continue to diminish as more DG is interconnected.

(Metz at 20-21.)

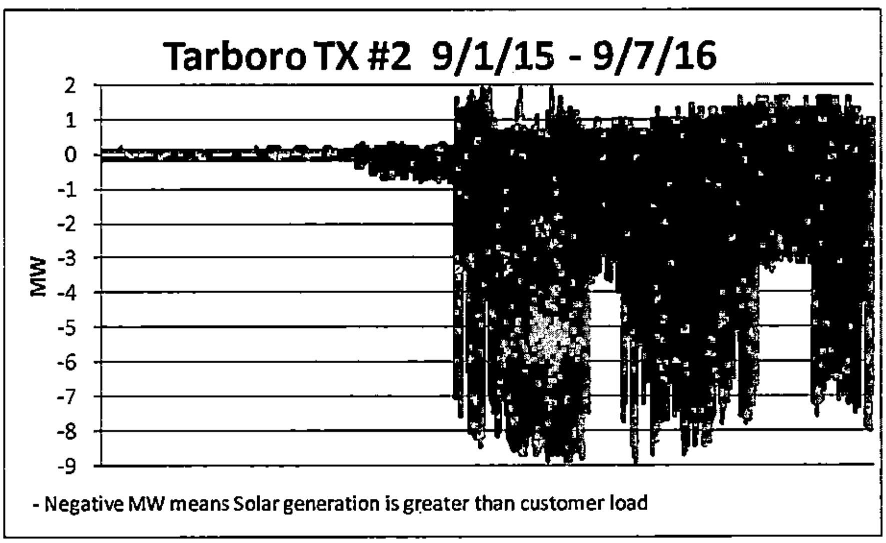
What is particularly important about Mr. Metz's statement is that he correctly recognizes that this is a forward-looking proceeding. While many substations today already realize significant reverse flow, any such avoided line loss will continue to diminish in the future as additional DG is interconnected. Therefore, it is inappropriate to continue to pay for avoided line losses when it is clear that the typical QF that signs contracts under this Sub 148 standard contract will be unlikely to actually avoid any line losses.

Q. SACE Witness Vitolo questions the Company's assertion that the majority of the circuits have reverse flow and therefore concludes that line losses can still be avoided. (Vitolo at 39-42.) Please respond.

A. Dr. Vitolo states that he disagrees with my assessment that 11 of the 33 circuits show a predominately constant backflow of power. He conducts his own analysis of the data and concludes that only Whitakers TX#2 has a majority of backflow.

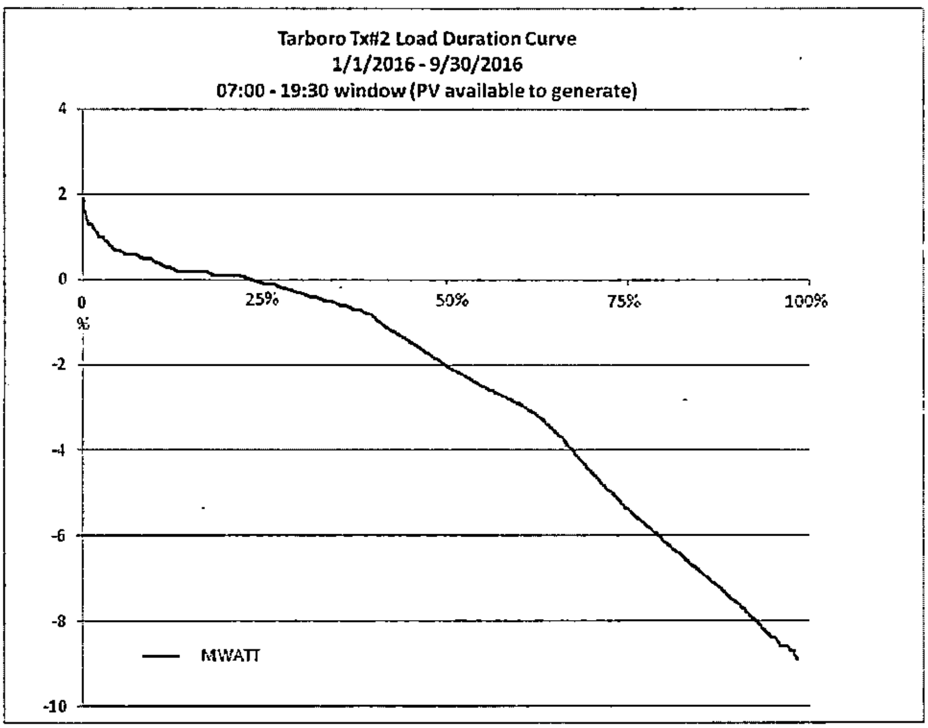
Based on his workpaper provided through discovery, it appears that he included hours where there would be no solar QF generation (like nighttime hours) and did not account for the fact that QF generation was incrementally added over the course of the year. That is, the data would show more hours with backflow late in the year than early in the year, but what is important is the state of the flow as they exist today. To be fair to Dr. Vitolo, he would have no way of knowing the in-service dates of QFs within the dataset, but nonetheless this information should be considered in making a determination as to whether or not a circuit is currently experiencing high levels of reverse flow.

For example, the table below is presented on page 17 of Exhibit JSG-1 in my direct testimony, showing the chronological 30-minute load flows on the Tarboro TX#2 transformer from September 1, 2015, to September 7, 2016.



It is clear by observing the data throughout the year that reverse flow increased as more QF generation was added. By the end of the period, nearly all daylight hours resulted in reverse flow on the transformer.

To look at this data another way, the graph below shows the same energy flow on Tarboro TX#2, but only for daylight hours (7:00 am through 7:30 pm) from January 1, 2016, to September 30, 2016. I have excluded the hours prior to January 1, 2016, because the first QF generator interconnected on this transformer completed construction at the end of 2015. The 30-minute load flows are then resorted from highest to lowest (instead of chronologically) to produce a load duration curve. The percentages across the x-axis therefore indicate the percentage of time that the load flow was above the amount indicated on the y-axis.



As the graph shows, this transformer experiences positive flow only 25% of the daytime hours, or conversely experiences reverse flow approximately 75% of the daytime hours. A similar analysis for the other transformers identified as "negative" in Exhibit JSG-1 would show a similar result. Dr. Vitolo is simply incorrect when he states that "only Whitakers TX#2 had a majority of its half-hours presenting backflow." (Vitolo at 41.)

Significantly, Dr. Vitolo also ignores the fact that line flows presented in my direct testimony as Exhibit JSG-1 only accounted for the distributed generation that was already operational at the time, which included only 293 MW of solar QF generation as of September 1, 2016. However, as shown by Figure 1 in my direct testimony, the Company already has PPAs or LEOs in excess of 600 MW of QF solar generators, meaning the load flows presented in Exhibit JSG-1 included only approximately half of the QF generation that has already committed to sell output to DNCP. Many of the transformers identified as "neutral" and "positive" will also soon experience predominately reverse flow as these remaining QFs commence operations. While reverse flows existed in the data presented, the issue will only be exacerbated as more QFs commence commercial operations.

In this proceeding, the Company is proposing rates for the standard contract for all small QFs across its North Carolina service territory. Therefore, we must derive a rate that applies to the "average" QF. Given that the amount of QF generation committed to the Company already exceeds average on-peak load, the data shows that the average QF from this point forward will not be avoiding additional line losses and, in some cases, will be adding to system losses.

Finally, the avoided costs set in this proceeding are forward-looking, as they will be the rates customers pay for prospective QFs that sign PPAs in the next two years. It is absolutely clear from the data that most of the QFs subject to this proceeding will not be avoiding additional line losses.

Q. NCSEA Witness Ben Johnson also comments on the reduced avoidance of line losses as reverse flow occurs. Please respond.

A. Mr. Johnson acknowledges that "[o]n DNCP's system, in cases where backflow is occurring, some of these potential savings (and the costs that could be potentially avoided) are not being avoided. From society's perspective, this is unfortunate – costs that could be avoided are not being avoided." (Johnson at 164.) However, he goes on to state his belief that the QF rates have historically not included all of the avoided costs of distributed solar. (Johnson at 164.)

The Company has in fact incorporated avoided costs that are reasonably known and quantifiable – such as for avoided energy, capacity, line losses, and congestion. As QF generation has exceeded load, these benefits are reduced or eliminated and it is only now in the absence of these benefits that the Company is proposing to reduce or eliminate these from its standard avoided cost rates.

It should also be noted that the Company has not proposed to include any integration costs into its avoided cost rate at this time. As Public Staff Witness Hinton notes with respect to Duke Energy Progress, LLC, he has a growing concern that "the added uncertainty associated with additional integration costs that are not yet fully quantified, may lead to higher utility rates." (Hinton at 8.) The Company shares this concern and is studying the issue, but has not yet quantified the costs with enough specificity to include them in the avoided cost rates at this time.

IV. ADJUSTMENT TO AVOIDED ENERGY RATES TO REFLECT LOCATIONAL ENERGY VALUE

Q. The Company has proposed to include a locational component in its avoided energy rate to more accurately reflect DNCP's actual avoided cost. Please summarize this proposal.

A. The Company has proposed to base its avoided energy price on the locational marginal price ("LMP") of our North Carolina service territory as opposed the DOM Zone average price. As explained in detail on pages 23-27 of my direct testimony, the LMPs in North Carolina more accurately reflect the avoided system costs of North Carolina QFs, which are the subject of this proceeding.

Q. Does Public Staff also support this proposal?

A. Yes. Public Staff Witness Hinton states that he thinks the Company's "proposal is reasonable" and that the Company "provided support showing that the locational marginal prices (LMPs) for North Carolina nodes have been consistently lower than the DOM Zone average LMP. Its PROMOD model, however, does not currently allow for calculation of energy rates at the nodal level. As such, it is reasonable for DNCP to amend its avoided energy costs to reflect the lower LMPs than the DOM Zone average." (Hinton at 61.)

Q. Only one other intervenor, NCSEA Witness Johnson, comments on the LMP proposal. Please summarize and respond to Dr. Johnson's position.

A. Dr. Johnson states that "[o]n a purely conceptual level, I have no objection to using LMP data to help refine the QF rates. LMPs may [have] potential relevance to the problem of how best to improve QF price signals, in order to encourage QF power to be generated where it is most valuable." (Johnson at 177.) However, he goes on to opine that further investigation is required before such LMP data is included in the avoided cost rate. (Johnson at 177-178.)

The Company, however, has already provided evidence in direct testimony and discovery to address most, if not all, of Dr. Johnson's concerns. For example, Company Witness Petrie shows on page 10 of his direct testimony that LMPs in North Carolina have been consistently lower than the DOM Zone over the past three years and that this discrepancy has remained relatively stable. LMPs are a reflection of the underlying supply and demand across the system, including local congestion and marginal losses. As more generation is added relative to load, this will have the likely result of widening the gap between the LMPs at the North Carolina nodes and those in the DOM Zone as a whole. This means, as I explain on pages 25-27 of my direct testimony through Figures 4, 5, and 6, that if additional generation is being added (or load is being reduced) in a location with already low LMPs (like North Carolina), it has less effect of lowering Net System Costs than if the generation were added in a location with high LMPs. These are the costs that customers actually avoid due to North Carolina QF generation.

Q. **Dr. Johnson further questions whether pricing signals, including the LMP adjustment, should be done on a more granular basis instead of having a single price apply to all standard QFs in the state. (Johnson at 177-78.) Do you agree?**

A. Yes, at least in part. The ability to provide more granular pricing signals and more timely avoided cost rates is a significant reason the Company is making the proposals it has in this proceeding. By necessity, the standard contract offers a single price and contract that is available for all "small" power producers. Therefore, the Company must average LMPs and line losses across the North Carolina service territory to arrive at an appropriate cost for an average QF. To derive an average rate, the Company averaged the LMPs of six different nodes geographically dispersed across its North Carolina service territory. It is the difference between these average LMPs and the DOM Zone that is the basis for the projected avoided energy costs in the Company's filing.

Conversely, negotiated contracts give the Company the ability to look at the avoided line losses and LMPs at the specific circuit and location in which the QF is interconnected at a much more granular level. Because DNCP is proposing that QFs above 1 MW will enter into negotiated contracts, this will allow for more projects, and the larger projects in particular, to have individualized evaluation of LMPs that is not available under the standard contract. The Company's proposals in this proceeding, in aggregate, therefore go a long way toward achieving Dr. Johnson's desired outcome of more precise price signals for individual QFs.

Q. Dr. Johnson also states that the Commission should understand the underlying factors that are causing this differential. (Johnson at 178.) What causes LMPs to be different in one location versus another and what does this mean in terms of costs to customers?

A. There are two factors that cause LMPs to be different from one location to another: congestion and marginal losses. LMPs are fundamentally a function of supply and demand at each location – generally speaking, as supply increases, LMPs decrease; if demand increases, LMPs increase. As more generation is added in a location where it is not needed, the cost of congestion and marginal losses increases, reflecting the re-dispatch cost to enable this generation to "flow" to locations on the transmission grid where it is needed to serve load.

The fact that the LMPs are lower in North Carolina than the DOM Zone as a whole is a reflection of the fact that congestion and losses exist between the North Carolina nodes and the DOM Zone as a whole. Rebuttal Exhibit JSG-1 is a discovery response provided by the Company to the Public Staff in this proceeding, which shows the congestion and marginal loss components of the North Carolina nodes and the DOM Zone. For example, the on-peak congestion between the two locations in 2016 was $1.84/MWh.

This has real costs for customers. Given that there are approximately 500 MW of solar QF generation under contract, and assuming a 25% capacity factor, this congestion equates to approximately $2 million per year in congestion cost attributed to these QF generators, as illustrated below:

500 MW x 8760 hours x .25 capacity factor x $1.84/MWh = $2,014,800

This illustrates the importance of using the LMPs associated with the locations where the QFs are generating to correctly price the avoided cost rates.

Q. Do you continue to believe the LMP adjustment, combined with the other standard contract modifications proposed in the Company's initial filing, is reasonable and appropriate?

A. Yes. The LMPs of the node at which a QF is interconnected will equate to the Company's actual avoided energy cost as a result of additional energy at that location. Since QFs that are subject to this proceeding and want to sell to DNCP will be interconnecting to nodes in the Company's North Carolina service territory, our proposal simply aligns this QF generation with the market energy prices it is expected to avoid.

This proposal, when combined with our other proposed changes, can also be beneficial to the QF, as it gives non-standard contracts a better price signal as they choose where to locate their projects. As with the Company's other proposals, the LMP adjustment is a means to lower the risk that customers pay rates in excess of their actual avoided costs.

V. ADJUSTMENTS TO THE AVOIDED CAPACITY RATES

Q. The Company has proposed to set the avoided capacity rate to zero. Please summarize the reasons for this proposal.

A. The Company has proposed to set the avoided capacity rate to zero to reflect the fact that additional distributed solar generation in North Carolina will not enable the Company to avoid capacity costs either in North Carolina or elsewhere on DNCP's system.

Q. This proposal was not supported by the Public Staff or the other intervenors. Please respond.

A. As Company Witness Petrie explains in his direct and rebuttal testimonies, the Company's preliminary updated load forecast does not currently reflect an avoidable capacity need until 2024 at the earliest. Even if such a capacity need were to arise, adding additional distributed solar generation in North Carolina would not allow DNCP to avoid future capacity expansions. As I noted in my direct testimony, FERC's rules implementing PURPA define avoided costs as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from a QF, the utility would generate itself or purchase from another source. (Direct at 2-3.) The "but for" language in that definition is important in the context of this issue of capacity payments, because it is not the case that, but for the distributed solar QFs on its North Carolina system, DNCP would be purchasing or self-providing capacity.

That is because, as Mr. Petrie and I discussed in our direct testimonies, while previously QFs interconnecting at the distribution level acted as load reducers and, by reducing the Company's load obligation, deferred the need for new capacity, that is no longer the case because distributed solar has reached the point where it exceeds the load in our North Carolina service area. For the same reason, adding more distributed solar to our service area in this state will not improve overall system reliability, especially as it relates to meeting winter-time peak demands. For these reasons and those discussed further in Mr. Petrie's direct testimony, there is no need for additional distributed solar in the Company's North Carolina service territory. Because DNCP will not avoid capacity costs due to incremental distributed solar North Carolina QF generation, a zero capacity payment accurately reflects the Company's actual avoided costs for QF contracts signed today. Company Witness Petrie addresses the comments of the Public Staff and other intervenors on this topic in more detail in his rebuttal testimony.

Q. Are utilities required to provide avoided capacity costs to QFs?

A. FERC has clearly stated that an avoided cost rate is not required to include capacity costs where a QF does not allow the purchasing utility to avoid building or buying future capacity. FERC has explained that even though utilities may have an obligation under PURPA to purchase from a QF, that obligation does not require a utility to pay for capacity that it does not need. Put simply, FERC has concluded that when a utility's demand for capacity is zero, the cost for capacity may also be zero.

VI. MODIFICATIONS TO THE LEO REQUIREMENTS

Q. DNCP did not propose any modifications to the current requirements for a QF to establish a LEO. What are those current requirements?

A. As determined by the Sub 140 orders, in order to establish a LEO, a QF must receive a CPCN or file a Report of Proposed Construction, if applicable, be a QF, and submit to the Company a "Notice of Commitment" form (which DNCP calls the LEO Form).

Q. In their direct testimonies, Duke Witnesses Bowman and Freeman recommended improvements to the process by which QFs establish a LEO. Do you share the same concerns with the current LEO process as Duke?

A. Yes. While the Company did not specifically recommend changes to the LEO Form in its initial filing and subsequent direct testimony, I do share many of the same concerns that Ms. Bowman and Mr. Freeman present. The current LEO process, while improved in the Sub 140 proceeding with the determination of a uniform LEO Form and the addition of the QF status requirement, still allows the QF to establish an LEO before it is in a position to truly commit to develop the project and deliver power in a timely manner. In practice, the LEO Form has been used by North Carolina QFs as a means to establish a put option price, but it has not obligated the QF to actually deliver power to the utility.

This has two significant implications, both of which unjustly harm customers. First, it impairs adequate utility system planning because we do not know how much QF power will ultimately be constructed and delivered. The Company simply cannot count on the energy and capacity to be available based on an LEO. The Company, with an obligation to meet customer energy and capacity requirements, must secure short- and long-term capacity without the QFs, thus, reducing or eliminating any avoided capacity costs. Second, the current process has created a situation where the LEO, and thus avoided cost prices, are significantly outdated by the time the QF actually completes construction and begins delivering output. The result is that customers are paying rates to QFs that established LEOs and therefore qualified for avoided cost rates that in many cases were calculated years prior to the QF actually coming online.

Q. Do you agree with Duke's recommended improvements to the LEO process?

A. Yes. Duke's proposed LEO process would better align a QF's commitment to the point in time at which it can be reasonably sure whether it will or will not proceed with the project.

For QFs with a capacity of 1 MW or less, Duke has recommended that, as an additional condition to establishing an LEO, a QF should complete an Interconnection Request. The Company agrees that for small QFs, this is a reasonable step to ensure that the QF is in fact progressing in its development.

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Public Staff Witness Jay Lucas states in his testimony that the Public Staff also agrees with this recommendation. (Lucas at 7.)

For QFs larger than 1 MW, Duke proposed that the LEO be established after the QF executed and returned a Facilities Study Agreement. Duke Witness Freeman also proposed in his direct testimony that an LEO could be tied to the negotiated PPA process. The Company agrees that either of these proposals would be an improvement over the current process because, again, it better aligns the LEO with the point in time at which the QF has enough information to actually commit to developing the project. At either of these points, it can be reasonably concluded that the QF is likely to move forward and an estimated timeline of construction can be established.

Q. What is the Company's position on Public Staff Witness Lucas' alternative recommendation with regard to the LEO?

A. Mr. Lucas supported Duke's recommended changes with respect to the LEO for QFs that are eligible for the standard contract. (Lucas at 7.) As such, DNCP agrees with Mr. Lucas' position for these QFs.

For QFs larger than 1 MW, Mr. Lucas recommended (Lucas at 7-8) that a LEO be established in the same way as with the small QFs, but with two additional requirements, as follows:

1) The QF must be a Project A or B in the interconnection queue, as described in Section1.8 of the NCIP.

2) The LEO would not be established until the earlier of the QF's receipt of the utility's System Impact Study for the QF project or

3) 105 days after the QF submits a completed interconnection request to the Company.

While I believe Mr. Lucas' proposal for non-standard QFs still allows these QFs to establish a LEO before they have made any material financial commitments (beyond the interconnection request fee) and, thus, before they have made an actual commitment to deliver output to the utility, the Company does not object to the Public Staff's recommendation and considers it to be an improvement over the current process. This position is predicated on our assumption that obtaining a CPCN or filing a Report of Proposed Construction would continue to be a requirement in order to establish an LEO, as we feel that is an important prong of the LEO test currently in place.

Q. Have you provided a modified Notice of Commitment form in this proceeding?

A. No, not at this time. It is our belief, however, that the requirements to establish a LEO should be uniform for all QFs in the state, regardless of the utility to which a QF is committing to sell its output. Therefore, once the Commission determines any changes to the requirements for a LEO in this proceeding, the Company will work with the Public Staff, Duke, and other stakeholders on the appropriate modifications to the LEO Form to implement the Commission's requirements.

Q. The Company proposed other minor modifications to its standard contract. Were there any objections to these changes?

A. No. The other minor modifications to the standard contracts, as discussed on page 34 of my direct testimony, were made with the intent of simplifying and clarifying certain items. No one appears to oppose these changes.

Q. Please summarize your testimony.

A. In this proceeding, the Company has proposed several modifications to its standard Schedule 19 rates and terms, most of which—reducing the standard eligibility threshold to 1 MW, reducing the maximum standard contract term to 10 years, and adjusting DNCP's avoided energy rates to remove the line loss adder and to reflect the locational value of new solar QFs in our North Carolina service area—are supported by the Public Staff. In addition, the Company continues to support setting the standard avoided capacity rate to zero, and supports the modifications to the LEO standard discussed above. Given the unprecedented growth of QF development and the real and observed risk of overpayments, these changes are a reasonable step toward striking an appropriate balance between encouraging QF development while also protecting customers from the risks associated with future QF contracts.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

(Whereupon, Rebuttal Exhibit JSG-1 was identified as premarked.)

Q Mr. Gaskill, do you have a summary of your direct and rebuttal testimonies?

A Yes, I do.

Q Would you please present that now for the Commission?

A Sure. Good afternoon. My name is Scott Gaskill. I'm the Director of Power Contracts and Origination for Dominion North Carolina Power. My direct testimony describes the tremendous and unprecedented growth in solar QF development that has taken place in Dominion's North Carolina service area during the past several years, particularly in the three -- three years since the 2014 biennial proceeding.

Three years ago Dominion had 58 megawatts of distributed solar QF capacity under seven contracts. We currently have almost 10 times more distributed solar QF capacity; approximately 521 megawatts under 76 effective PPAs. When QFs with legally enforceable obligations, or LEOs, are included, the total capacity of distributed solar either in place or planned for in our North Carolina service area rises to approximately 680 megawatts.

In contrast, our average on-peak load in this area is approximately 518 megawatts. So Dominion has, therefore, reached the point where distributed solar generation exceeds the load on our system in this area. Equally important, the vast majority of this generation is located on a narrow segment of our North Carolina service area.

So taken together, this tremendous influx of solar onto our system, combined with a narrow distribution of this generation in an area with recent load growth, has several important implications for our avoided cost.

Most importantly, given the significant decrease in gas and power prices over the past several years, the contracts signed during the previous biennial avoided cost periods have resulted in significant above-market payments as compared to the value that customers are actually receiving from that solar generation. Given the significant overpayments the Company is making under current contracts, it is clear that the encouragement of QF development in North Carolina is no longer being balanced with protecting customers.

To address these issues moving forward and to restrike that balance, Dominion has proposed five major modifications to its North Carolina standard QF offer. First, reducing the threshold for a QF to qualify for the standard offer from 5 megawatts to 1 megawatts -- from 1 megawatt to 1 (sic) megawatt -- excuse me -- will allow us to better match avoided cost pricing with more QF LEOs and customize avoided cost rates to QF's specific locations and characteristics.

Second, reducing the maximum PPA term from 15 years to 10 years will mitigate customers' exposure to the risk of significant future above-market payments as we are currently making under the existing standard offer contracts.

Third, eliminating the 3 percent line loss adder from our avoided energy rates will appropriately reflect the fact that prospectively, line losses are no longer being avoided for most QFs due to the saturation of distribution level QFs relative to the load on Dominion's system.

Fourth, adjusting avoided energy rates to reflect a locational value of this generation in Dominion's North Carolina service area will allow these rates to better reflect the Company's actual avoided system energy cost.

Finally, setting the avoided capacity rate to zero for the term of the PPA will reflect the fact that there is no short-term need for capacity, and additional distributed solar generation in North Carolina will not enable Dominion to avoid additional capacity cost here or elsewhere on our system.

My rebuttal testimony responds to comments filed by intervenors and the Public Staff on each of these proposals. I also recognize the concerns raised by Duke with regard to the LEO and support the proposed modifications to the LEO standard offer -- proposed -- the modifications to the LEO offered by Duke and the Public Staff.

Dominion's testimony in this case shows that the Company is currently obligated to purchase solar capacity that exceeds our average on-peak load in North Carolina, and that our customers are bearing a real and observed risk of overpayments to QFs. The standard offer modification that Dominion has proposed will better align standard avoided cost rates and terms where there are actual avoided costs and generation needs. As a result, these changes will help maintain customer indifference as to the QF purchases as required by PURPA.

They will also limit the risk to customers of overpayments under future QF contracts and, therefore, achieve a better balance between customer protection and QF encouragement consistent with PURPA and this Commission's goals in these proceedings.

That concludes my summary. Thank you.

Q Thank you. And now Mr. Petrie, would you please state your name and business address for the record?

A (Petrie) Yes. Bruce Petrie. The -- my address is 5000 Dominion Boulevard, Glen Allen, Virginia.

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

A Dominion North Carolina Power. I'm the Manager of Generation System Planning.

Q And did you cause to be prefiled in this docket on February 21st of this year 24 pages of direct testimony and Appendix A and two exhibits, a portion of the first of which contains confidential information?

A I did.

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

A No.

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

A Yes.

MS. KELLS: Mr. Chairman, at this time I move the direct testimony and Appendix A of Mr. Petrie be copied into the record as if given orally from the stand, and that his two direct exhibits be marked as prefiled, with the first of those containing confidential information as marked.

CHAIRMAN FINLEY: Mr. Petrie's direct prefiled testimony filed February 21, 2017, consisting of 24 pages and Appendix A, is copied into the record as though given orally from the stand, and his two exhibits are premarked as -- are marked for identification as premarked in the filing, the first of which containing confidential information, and it shall be designated as such.

(Whereupon, the prefiled direct testimony of Bruce E. Petrie was copied into the record as if given orally from the stand.)

DIRECT TESTIMONY
OF
BRUCE E. PETRIE
ON BEHALF OF
DOMINION NORTH CAROLINA POWER
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100 SUB 148

Q. Please state your name, business address, and position of employment.

A. My name is Bruce E. Petrie, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am the Manager of Generation System Planning for Dominion North Carolina Power ("DNCP" or the "Company"). My responsibilities include forecasting total system fuel and purchased power expenses, and forecasting the Company's long-term avoided costs. A statement of my background and qualifications is attached as Appendix A.

Q. What is the purpose of your direct testimony in this proceeding?

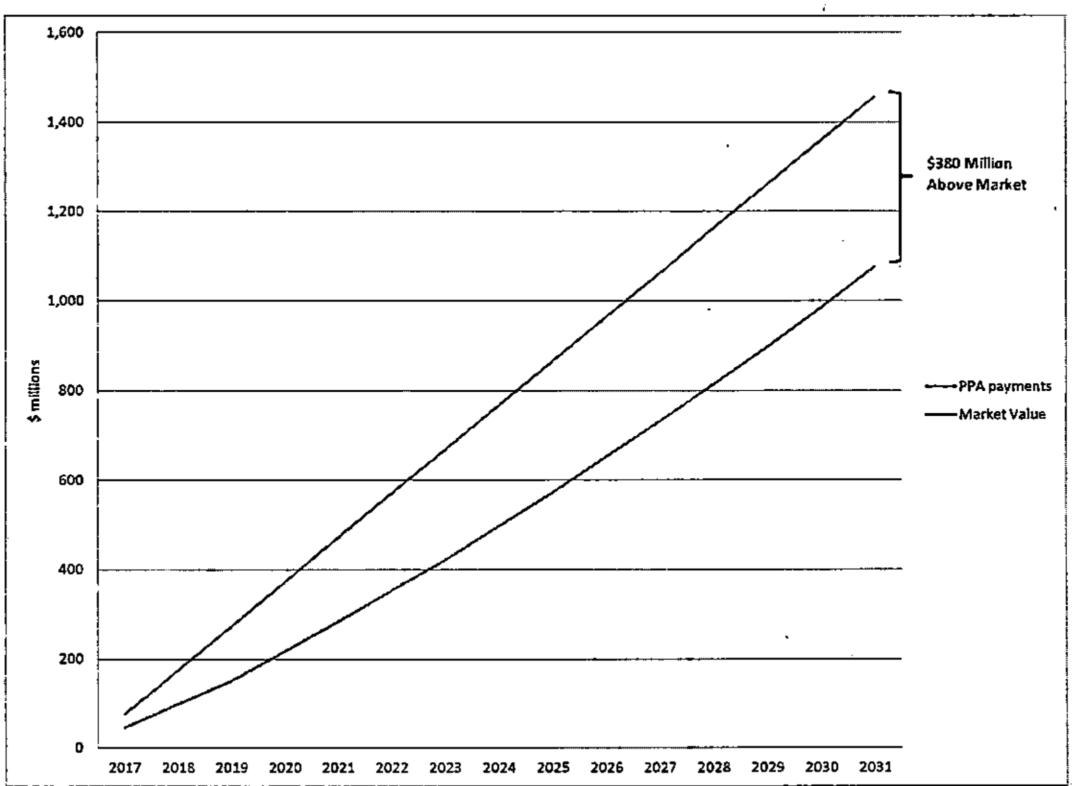
A. The purpose of my testimony is to discuss the significant disparity between the forecasted payments to qualifying facilities ("QFs") under previously approved rates and terms in North Carolina versus the current expected value of these QF contracts in terms of the Company's current avoided costs, and to explain the calculation of the Company's proposed avoided energy and capacity rates.

Q. Please describe the disparity between the Company's forecasted payments to North Carolina QFs versus the expected value of the QF contracts committed to by DNCP during the last two avoided cost cases, in terms of avoided costs.

A. In the orders it has issued in these biennial avoided cost cases, the Commission has stated that it attempts in these proceedings to strike a balance between the need to encourage QF development and the risks to the utilities and their customers of overpayments and stranded costs. As discussed in DNCP's Initial Filing and in Company Witness J. Scott Gaskill's direct testimony, the influx of distributed solar generation onto the Company's North Carolina system, particularly since the 2014 Avoided Cost Case (Docket No. E-100, Sub 140), shows that the Commission has successfully encouraged the development of QF resources in this state and in DNCP's service area in particular. This encouragement is no longer, however, balanced with the risk of overpayment associated with this development, because the Company's customers are now burdened with hundreds of millions of dollars of above-market QF payments for the next 15 or more years through long-term contracts.

For the approximately 650 MW of solar QFs that established a legally enforceable obligation ("LEO") since 2012 (i.e., under the standard rates and terms authorized in Docket No. E-100, Sub 136 or Sub 140, or pursuant to negotiated rates within the same time period) the Company is committed to approximately $100 million per year of PPA payments for the next 15 years, totaling an estimated $1.4 billion. As shown on Figure 1 below, this amount significantly exceeds the current and projected market value of these contracts by approximately $381 million, which means that DNCP and its customers are paying $381 million more under these contracts than the Company's actual avoided costs for energy and capacity in relation to these QFs. Put another way, the prices contained in these contracts are on average approximately 46% above the Company's actual avoided costs, creating hundreds of millions of dollars in above-market payments over the lifetime of these PPAs.

Figure 1: NC Solar QFs – cumulative committed payments vs. current market value



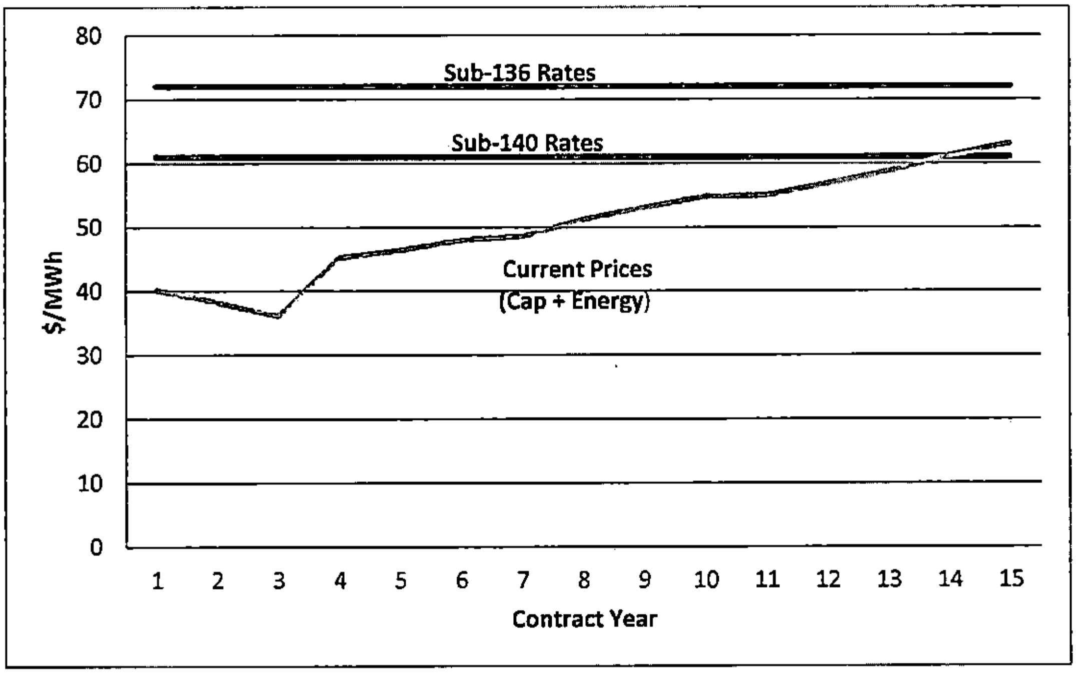
Q. What do you mean by "current and projected market value" and "actual avoided costs for energy and capacity in relation to these QFs" in your previous answer?

A. The red line (Market Value) in Figure 1 reflects the current estimated value of energy and capacity in the future, based on forward energy prices from the consulting firm ICF International, Inc. ("ICF") as of October 2016, and on the most recent PJM Interconnection, LLC ("PJM") capacity market clearing price (from the 2016 Base Residual Auction for the 2019/2020 Delivery Year). The blue line represents the forecasted payments for North Carolina PURPA contracts signed during the 2013-2016 time period, including standard contracts entered into under Sub 136 and Sub 140 rates as well as negotiated contracts from this time frame, based on expected production volumes for those QFs.

Q. Why are the committed payments to QFs higher than the current forecast of avoided costs?

A. The forward prices of fuel and power have dropped substantially over the last several years, causing the current payments to QFs under these contracts to be uneconomic. As shown in Figure 2 below, the current estimate of avoided costs, based on the same ICF and PJM data as discussed above, is substantially below the contractual rates paid to small QFs that signed agreements under the two prior avoided cost dockets.

Figure 2: Customer cost of rates paid to small Solar QFs under NC PURPA contracts vs. current forecast of avoided cost



Q. How were the avoided cost rates DNCP has proposed in this proceeding calculated?

A. The avoided cost energy rates DNCP has proposed in this case for Schedule 19-FP were calculated using the peaker method. (As in previous proceedings, avoided energy rates under proposed Rate Schedule 19-LMP are based on the hourly PJM Dominion Zone ("DOM Zone") Day Ahead Locational Marginal Price ("DA LMP") expressed as $/MWh.)

Q. Please describe the peaker method.

A. The peaker method as applied in North Carolina, which the Company adopted in the 2012 Biennial Avoided Cost Case (Docket No. E-100, Sub 136), determines avoided energy costs based on the forecasted marginal energy costs of the system in each hour, and determines avoided capacity costs based on the total fixed costs of a hypothetical new combustion turbine ("CT") peaking facility.

Q. Can you provide an overview of how the avoided energy cost rates are calculated based on the peaker method for Schedule 19-FP?

A. Yes. DNCP uses the production cost model PROMOD to derive avoided energy cost rates for Schedule 19-FP. These energy rates are composed of the following two components:

(1) avoided energy rates + (2) fuel hedging benefit.

First, the DOM Zone avoided cost energy rates are derived using the PROMOD model, and then adjusted to reflect the locational value of energy in the North Carolina service area where the QF projects are situated. Next, a fuel hedging benefit is added to the locational marginal price ("LMP")-adjusted energy rates to determine the final energy rates for Schedule 19-FP.

Q. Please describe in more detail how the model is used to calculate the avoided cost energy rates.

A. PROMOD is a utility production costing model leased from ABB/Ventyx that DNCP uses to calculate its avoided energy costs and then derive the avoided energy rates contained in Schedule 19-FP. The starting point for the analysis is the PROMOD base case, which includes the generation expansion plan "A" from the Company's most recent Integrated Resource Plan ("IRP"). The new units in the generation expansion plan are listed in the attached Exhibit BEP-

1.[1] This first simulation is referred to as the "without QF" case. A second PROMOD case, referred to as the "with QF" case, was run with an additional QF resource. The additional QF resource was modeled with the following operating parameters: 100-MW unit; must-run; 85% availability; and zero energy cost. All other assumptions from the base case remained the same. The difference in the annual system production costs between the "with QF" and "without QF" cases represent the Company's forecasted avoided energy costs. DNCP then used the resulting output from PROMOD to calculate the levelized on-peak and off-peak long-term fixed energy rates for the various contract durations under Schedule 19-FP. Exhibit BEP-2[2] provides details of the Company's development of the fixed long-term levelized avoided cost energy prices for QFs under Schedule 19-FP.

Q. What input assumptions does the Company use for its PROMOD calculations?

A. DNCP includes three major categories of input assumptions in this modeling process. The first category includes PJM power price assumptions, the price of emergency energy purchases, and the cost of non-utility generation sources. The second category includes assumptions regarding generating unit operating characteristics. The third category reflects the variable (or dispatch) costs of the generating units (including fuel, variable O&M, and emission and start-up

[1] This information was included as Exhibit DNCP-5 in the Company's November 15, 2016 Initial Comments.
[2] This information was also included with the Initial Comments as Exhibit DNCP-6.

costs). In order to calculate the unit dispatch costs, the Company relied on ICF to provide an independent forecast of commodity prices, including gas, coal, oil, power, capacity, and emissions. Summary information on these input assumptions is provided in the attached Exhibit BEP-1.[3]

Q. Why are the model results adjusted for the locational value of energy deliveries in the North Carolina area?

A. The PROMOD model used by the Company is zonal, meaning that the power price inputs and outputs are expressed at the DOM Zone level, and not at the nodal level. The DOM Zone is an aggregate pricing point in the PJM energy market, and represents the average of the LMPs of all the nodes within the zone.

PJM calculates LMPs that reflect the value of energy at specific locations on the grid. Areas in which additional generation is needed to meet load will realize higher LMPs in order to incentivize generation to locate in that place. Conversely, areas where generation is not as valuable due to congestion and/or losses will realize lower LMPs. Because the LMPs for the nodes located in the North Carolina portion of the DOM Zone are consistently lower than the DOM Zone average LMPs, the model results should be adjusted to reflect the locational value of energy for QF deliveries in the North Carolina

[3] This information was also included with the Initial Comments at Exhibit DNCP-5.

service area in order to ensure that the avoided energy rates DNCP and its customers pay are as accurate as possible.

Q. How does the Company propose to adjust the energy rates to account for the locational value of energy?

A. The adjustment to the avoided cost energy rates is based on the historical energy price differences between the DOM Zone and the North Carolina service area. The Company based its calculated value of energy in the North Carolina area on the average day-ahead LMPs at six locations, which were selected because they are geographically dispersed, and because they are known to have QF development at or near those locations. Historical price data from 2014-2016 shows that the LMPs in the DNCP North Carolina service area are lower than the LMPs for the DOM Zone as a whole, which is typical for locations on the grid with an oversupply of generation relative to the customer demand. See the table of historical LMPs and price differences below (Figure 3).

Figure 3 – History of LMP differences DOM Zone vs. NC locations

			Option B hrs		
			On peak	Off peak	All hrs
Jan-Dec 2014	Dom zone	$/MWh	70.19	49.07	53.68
	NC locations	$/MWh	67.71	47.00	51.53
	Difference	$/MWh	(2.48)	(2.06)	(2.16)
	% Difference		**-3.5%**	**-4.2%**	-4.0%
			On peak	Off peak	All hrs
Jan-Dec 2015	Dom zone	$/MWh	50.16	35.46	38.67
	NC locations	$/MWh	47.88	33.54	36.68
	Difference	$/MWh	(2.28)	(1.92)	(2.00)
	% Difference		**-4.5%**	**-5.4%**	-5.2%
Jan-Sep 2016	Dom zone	$/MWh	41.56	27.73	30.80
	NC locations	$/MWh	39.40	26.42	29.30
	Difference	$/MWh	(2.16)	(1.31)	(1.50)
	% Difference		**-5.2%**	**-4.7%**	-4.9%
	2014-2016 avg	%Diff	**-4.4%**	**-4.8%**	-4.7%
	Ratio NC/Dom		95.6%	95.2%	

This historical price data shows that the LMPs in the Company's North Carolina service area are consistently lower than the prices for the DOM Zone as a whole. The energy prices for Option B were 4.4% lower than the DOM Zone prices during the on-peak periods and 4.8% lower during the off-peak periods during these years.[4] All things being equal, the LMPs in the North Carolina area are likely to be even lower in the future as more solar distributed generation ("Solar DG") is added to the Company's system.

In order to more accurately reflect the lower LMPs associated with the North Carolina service area in the Company's avoided energy cost rates, DNCP

[4] For Option A energy rates, using the same methodology, the energy prices were 4.7% lower than the DOM Zone during both the on-peak and off-peak periods.

therefore proposes to reduce the Option B rates by 4.4% for the on-peak period and 4.8% for the off peak period[5] to reflect the actual value of QFs delivering power in the North Carolina portion of the DOM Zone.

Q. Why are the benefits related to fuel hedging included in the avoided energy rates?

A. In Phase 1 of the 2014 Avoided Cost Case, the Commission decided that it is appropriate to recognize fuel price hedging costs that are avoided as a result of energy purchases from QF generation in avoided energy cost rates. In the 2014 Phase 2 Order, the Commission required the utilities to use the Black-Scholes Model, or a similar model, to determine the fuel price hedging value of renewable generation.

Q. How is the fuel hedging benefit calculated?

A. For the energy rates that it is proposing in this proceeding, the Company has used the same Black-Scholes Model option pricing method to determine the fuel hedging benefits as proposed by the Public Staff in its June 22, 2015 Initial Statement in Docket No. E-100, Sub 140. Consistent with that approach, the Company input current Henry Hub gas pricing and volatility data into the option pricing model,[6] which resulted in a call option value of approximately $0.20 per mmbtu and a put option value of $0.18/mmbtu. The net option price, or difference between the call and put option values, of

[5] The Company proposes to reduce the Option A rates by 4.7% for both on- and off-peak periods.
[6] The option pricing model is available online at the following website: http://app.fintools.com/calcs/OptionsCalc.aspx.

$0.02/mmbtu represents the estimated fuel price hedging benefit. Multiplying $0.02 per mmbtu by a gas-fired combined-cycle plant heat rate of 7,000 btu/kWh results in a fuel price hedging value of $0.14/MWh, which is assumed constant for all years of the Schedule 19-FP contract.

Q. Are solar integration costs included in the calculation of the avoided energy cost rates?

A. No. Solar integration costs were not included in the production cost modeling. While the Company believes there are likely costs associated with the integration of distributed solar generation onto its North Carolina system, these costs have not been included in the avoided cost rates.

Q. Turning now to capacity, what is the Company proposing with regard to the avoided cost capacity rate?

A. Due to several factors, primarily related to the significant influx of Solar DG to DNCP's North Carolina service area that has occurred since the 2014 Avoided Cost Case, the Company is proposing to pay QFs eligible for standard rates and terms zero (0) cents/kWh for capacity.

Q. What is the rationale for this proposal?

A. The following factors, which I will discuss further below, support the Company's proposal:

1. The Company does not have a current near term need for additional capacity.
2. Because the Company's North Carolina service area is saturated with

Solar DG QF projects, any new Solar DG that is added going forward will have little to no peak load reducing effect on the system.

3. Due to the intermittency of the distributed solar generation coming online, the Company is considering adding aeroderivative CTs to its system, which have a higher installed cost than the large frame turbines that the Company has built since the year 2000, but also have faster start-up and ramping capability.
4. Solar generation is not dispatchable, and has limited usefulness during system emergencies, and should be priced accordingly, as allowed by FERC's rules.
5. Solar generation is not reliable on a year-round basis, and has limited value in PJM's Reliability Pricing Model ("RPM") capacity market, which requires capacity performance ("CP") type resources.
6. The addition of large amounts of distributed solar resources is likely to shift the time of the summer peak to a later hour in the day. This peak shift effect results in a diminishing capacity value of solar.

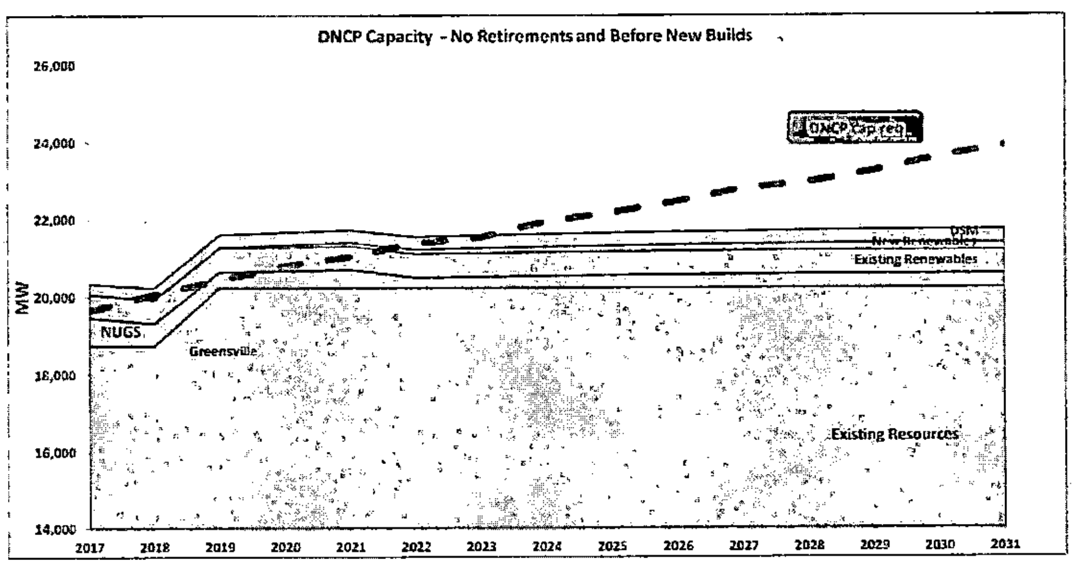
In light of these considerations, and because the addition of more Solar DG QFs in the North Carolina service area will not allow the Company to defer or avoid generation capacity related costs, the Company and its customers should not be required to pay for additional QF capacity.

Q. **The first factor you note is that DNCP does not have a current near-term need for additional capacity. Please explain why this is the case.**

A. DNCP's 2016 IRP, filed on April 29, 2016, in Docket No. E-100 Sub 147, showed that the Company did not have a capacity need until 2022 at the earliest.

Using the Company's preliminary updated load forecast as of December 2016, the need for incremental capacity is pushed to 2024. Figure 4 below shows the current generation capacity available, compared to the amount of capacity required (red dotted line), based on the Company's preliminary updated load forecast. The graph shows a need for capacity starting in 2024 (i.e., where the red-dotted line goes above the capacity available).

Figure 4 – Available capacity vs. capacity required



Finally, it is worth noting that using the most recent PJM load forecast (from January 2017), which is lower than the Company's peak demand forecast, a capacity need does not arise until after the 2026 timeframe.[7]

Q. You state that the Company's preliminary updated load forecast indicates that the system could see a capacity need around the 2024 timeframe. In that case, will the addition of more QF solar facilities in the North Carolina service area not allow the Company to defer or avoid generation capacity related costs?

A. No. Even if a need for new capacity were to exist within the Company's current long-term planning horizon, additional solar QFs in the Company's North Carolina territory are not an effective substitute for new dispatchable generation, such as a combustion turbine ("CT") facility, connected to the Company's transmission system.

CTs are dispatchable generation resources that are generally located near areas with increasing load growth and in areas where additional generation is needed to reduce congestion and improve reliability. Similar to CTs the Company has built in the past (e.g., Remington and Ladysmith power stations), it is expected that these CTs would be located in or around DNCP's high load centers, which are not in the Company's North Carolina service area. The addition of more Solar DG in the North Carolina service area will not postpone or avoid the Company's need for dispatchable CT capacity near

[7] *See* http://www.pjm.com/~/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx.

its load centers or connected to the Company's integrated transmission system.

Q. Are there any other reasons why new Solar DG will not avoid capacity costs?

A. Yes. Previously, QFs interconnecting at the distribution level acted as load reducers and, by reducing the Company's load obligation, deferred the need for new capacity. However, as discussed by Company Witness Gaskill, given that Solar DG in this area has reached the point where it exceeds the load in DNCP's North Carolina territory, this is no longer the case. Put another way, there is no more load that these QFs can offset. Moreover, for similar reasons, adding more Solar DG to the Company's North Carolina territory will not improve overall system reliability, especially as it relates to meeting winter-time peak demands.

In sum, the Company currently finds itself in a situation where, while there may be a need for new capacity in 2024 or later, DNCP cannot avoid building or buying that capacity through purchases from Solar DG in its North Carolina service area.

Q. Another factor you note is the potential for the Company to add aeroderivative CTs to its system. What types of conventional gas-fired generation has the Company added to its system in recent years?

A. The Company installed GE-technology, large frame combustion turbines at Remington and at Ladysmith during the period 2000 through 2009. Around the 2008 time period, DNCP transitioned to constructing combined-cycle ("CC") units, because of the need for low cost energy supplies, and because these units include duct-burner technology for peaking-type operation. The latest CC additions are the Warren and Brunswick stations, which used Mitsubishi GAC turbines, and the recently approved Greensville station, which will use Mitsubishi 501J turbines.

Q. Why is the influx of distributed solar generation in DNCP's North Carolina service area causing the Company to now consider adding a different type of peaking unit?

A. Due to the intermittency of the distributed solar generation being added to the system, the Company is considering the installation of aeroderivative CTs to the system because these aeroderivative turbines are quick-start and flexible units that can be used to balance the system as more intermittent resources are added.

These units have a higher construction cost than the large frame turbines that the Company has built since the year 2000. The estimated cost of aeroderivative turbine equipment is approximately 67% per kW more expensive than the large frame turbine equipment.[8] This cost differential further shows how additional distributed solar generation would not provide capacity value for DNCP because capacity costs are not actually avoided and may actually increase due to the need to add expensive quick-start units to the

[8] See 2014-2015 Gas Turbine World Handbook at 40-41.

Company's fleet to make up for distributed solar resources' intermittency and lack of dispatchability.

Q. **You mentioned that FERC's rules allow for consideration of intermittency of the generation resource in determining rates for QFs. Can you explain more?**

A. Yes. As I understand FERC's rules implementing PURPA, those regulations identify several factors that should be considered when determining the rates for purchases from QFs, including:

- The availability of capacity or energy from a QF;
- The ability of the utility to dispatch the QF;
- The expected or demonstrated reliability of the QF; and
- The usefulness of energy and capacity supplied from a QF during system emergencies.

It is also my understanding that FERC has recently spoken to this issue by explaining that its regulations allow state regulatory authorities to consider factors such as capacity availability, dispatchability, reliability, and the value of energy and capacity when establishing avoided cost rates, and to set lower rates for purchases from intermittent QFs than from firm QFs based on these factors.

Solar resources do provide some amount of reliability benefit during the summer peak season, but they cannot be dispatched on demand, and they cannot be relied on to generate during system emergencies or during the winter peak season. These deficiencies should be reflected in the capacity price paid to QFs as allowed by the FERC rules.

Q. Can you provide other support for DNCP's position that the intermittency of Solar DG justifies this proposal to eliminate capacity payments in this case?

A. Yes. Recent changes that PJM has made to its capacity market rules further demonstrate that the solar QF intermittent generation being added to DNCP's North Carolina service area is not the type of reliable capacity that would allow the Company to avoid capacity related costs.

The fundamental purpose of PJM's capacity market is to help ensure reliability through resource adequacy. To that end, resources that participate in that market are compensated based on their contributions to system reliability. After the 2014 polar vortex events, PJM found that certain generators that were being paid for capacity were underperforming during times of critical system need. As a result, during the 2014-2015 time period, PJM developed modifications to its capacity market rules to address the changing generation mix it was experiencing and to better align resource payments to resource performance, with the goal of making the capacity market more reliable and cost effective. In 2015, FERC accepted PJM's Capacity Performance and Energy Market ("CP") changes to its capacity market.

23b

Q. What do you understand PJM's expectation to be with regard to the operation and performance of a capacity resource?

A. To maintain system reliability, PJM's objective is to have resources that can be dispatched on demand, whose output is observable in real time, and that are capable of sustained and predictable operation during system emergencies.

Q. Is the output of a solar generator sustained and predictable, especially during system emergencies?

A. Unlike the dispatchable and reliable resources that the PJM CP market requires, intermittent resources are not capable of sustained, predictable operation during emergency conditions. Intermittent resources are particularly challenged under the new PJM capacity market, as they can be subject to severe penalties for non-performance during summer and winter peak hours. Subsequent to the FERC order on the CP filing, PJM issued training materials that suggested an acceptable offer for a 100 MW nameplate solar facility would be in the range of 0 to 20 MW of firm capacity. This demonstrates that in the new CP market a steep discount is justified for solar capacity, relative to the firm capacity of a dispatchable and reliable CT which PJM's capacity market requires. In short, if generating resources are not dispatchable and reliable at all times of the day or for the entire year, and especially during emergency conditions, they have limited value in the new PJM capacity market, from which the Company's actual avoided costs are derived.

Q. You also mention the importance of year-round resource reliability, including during winter-time peaks. Can you say more about that?

A. Yes. Both the Company and PJM have recently incorporated a new focus on planning for winter reliability, as two out of the last three years have yielded a winter peak for DNCP, with the Company realizing a new all-time peak demand on the morning of February 20, 2015, from 7 a.m. to 8 a.m.

Q. Please describe the Company's peak load experience over the past several years.

A. The table below shows the peak loads for the DOM Zone, in MWs, since 2013.

Figure 5 – History of seasonal peak loads in the DOM Zone

	Summer peak	Winter peak
2013	18,762	17,623
2014	18,692	19,784
2015	18,980	21,651
2016	19,538	18,948
2017	-	19,661 *

*as of 02/20/17

Q. What is noteworthy of these high winter season demands?

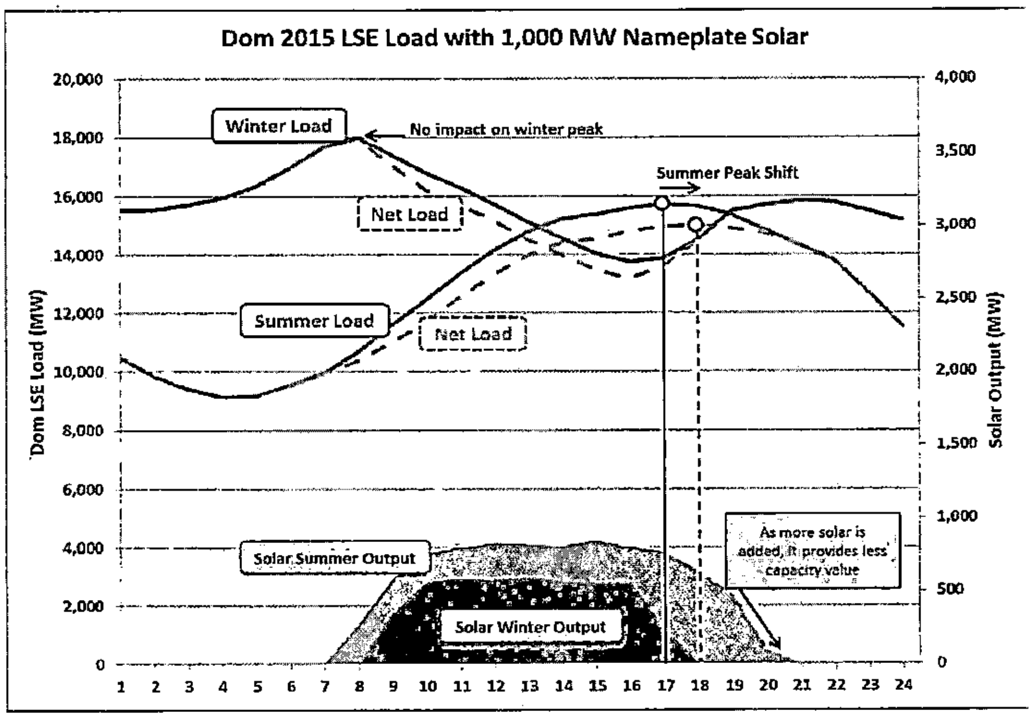
A. These spikes in demand during periods of extreme cold demonstrate the volatility of winter peak loads and the need for dispatchable generation in the system. In contrast, solar generation output is near zero at 7 a.m. on cold winter mornings when the system peak load occurs. In other words, a CT is still required in the winter since the solar generation is not producing energy at the time of the winter peak load. Much of the Company's recent planning and costs have been undertaken in order to improve winter reliability. Such plans and costs come in the form of fuel supply backup, additional gas pipeline capacity, and improved winter testing and operations. Solar generation will not and cannot defer these types of costs.

Q. **You also noted that, with the addition of large amounts of Solar DG, DNCP's summer peak load hour could shift to later in the day. Can you explain this possibility in more detail?**

A. Yes. The concept is illustrated in Figure 6 below, which shows the system hourly loads, net of solar generation, on a peak summer day and a peak winter day. As more solar generation is added to the system, the summer peak load shifts to a later time in the day. In contrast, there is no impact on the timing of the winter peak load because the solar output is minimal at the time of the morning peak load on a cold winter day.

As more solar generation is added, and as the summer peak hour shifts to a later time in the day, any additional solar has less of an impact on reducing the system summer peak load (because solar output decreases in the later hours of the evening), and therefore, lower capacity value. In other words, the marginal value of solar capacity decreases as more solar is added to the system. With aggregate solar additions of about 1,000 MW across DNCP's North Carolina service area (which threshold the Company is fast approaching), the summer peak hour is expected to shift to between 5 p.m. to 6 p.m. or even later, which means that any additional solar will have diminishing capacity value.

Figure 6 – Impact of solar generation on the system net load



As shown in Figure 6, each tranche of new solar that is added has less peak reducing effect on the system, and consequently is less effective in deferring or avoiding the next required capacity resource.

Q. Please summarize the Company's proposal as it pertains to the avoided capacity rate.

A. Due to the aggregate effect of the multiple factors described above, the addition of QF solar resources in DNCP's North Carolina service area will not allow the Company to defer or avoid capacity related costs. To account for

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this situation and avoid burdening its customers with avoided cost payments in excess of DNCP's actual avoided costs, the Company is proposing to make no payments for capacity.

Q. Does this conclude your testimony?

A. Yes.

APPENDIX A

BACKGROUND AND QUALIFICATIONS
OF
BRUCE E. PETRIE

I graduated from Clarkson University in 1983 with a Bachelor of Science degree in Mechanical Engineering. From 1983 to 1986, I worked for Babcock and Wilcox designing tools for nuclear power plant maintenance. In 1988, I earned a Master of Business Administration degree from Virginia Tech.

I worked for Niagara Mohawk Power Corporation from 1988 through 1998 in generation planning, fuel procurement, and wholesale power marketing, and then at Old Dominion Electric Cooperative from 1998 until 2001 as a power supply analyst. I joined the Company in April 2001 as an electric pricing and structuring analyst. My responsibilities included the pricing and structuring of wholesale electric transactions, project financial analysis, and analytical support to the Energy Supply group.

In October 2007, I was promoted to Manager of Generation System Planning. I am currently responsible for the Company's mid-term operational forecast (PROMOD model) and forecasting of the Company's long term avoided costs.

(Whereupon, Exhibits BEP-1 and BEP-2 were identified as premarked. Because of the proprietary nature of Confidential Exhibit BEP-1, it was filed under seal.)

Q Mr. Petrie, did you also cause to be prefiled in this docket on April 10th of this year 33 pages of rebuttal testimony?

A Yes.

Q Do you have any changes or corrections to that rebuttal?

A No.

Q If I were to ask you the same questions that appear in the rebuttal today, would your answers be the same?

A Yes.

MS. KELLS: Mr. Chairman, at this time I move that Mr. Petrie's rebuttal testimony be copied into the record as if given orally from the stand.

CHAIRMAN FINLEY: Mr. Petrie's rebuttal testimony filed April 10, 2017, consisting of 33 pages, is copied into the record as though given orally from the stand.

MS. KELLS: Thank you.

(Whereupon, the prefiled rebuttal testimony of Bruce E. Petrie was copied into the record as if given orally from the stand.)

**REBUTTAL TESTIMONY
OF
BRUCE E. PETRIE
ON BEHALF OF
DOMINION NORTH CAROLINA POWER
BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100 SUB 148**

Q. **Please state your name, business address, and position of employment.**

A. My name is Bruce E. Petrie, and my business address is 5000 Dominion Boulevard, Glen Allen, Virginia 23060. I am the Manager of Generation System Planning for Dominion North Carolina Power ("DNCP" or the "Company"). My responsibilities include forecasting total system fuel and purchased power expenses, and forecasting the Company's long term avoided costs.

Q. **Have you filed other documents or comments in this proceeding?**

A. Yes. I prepared direct testimony in this case, and have participated in responding to data requests of other parties to this proceeding.

Q. **What is the purpose of your rebuttal testimony in this proceeding?**

A. My rebuttal testimony will respond to certain comments offered in the testimony of Mr. Dustin R. Metz and Mr. John R. Hinton on behalf of the Public Staff, Dr. Thomas Vitolo on behalf of the Southern Alliance for Clean Energy ("SACE"), and Dr. Ben Johnson on behalf of the North Carolina Sustainable Energy Association ("NCSEA"). Specifically, I will address comments regarding the significant over-payments that our customers will be making over the next 15 or more years under currently effective standard rate power purchase agrements ("PPA") with Qualifying Facilities ("QF"). I will also address comments pertaining to DNCP's determination of avoided energy cost rates, including our production cost modelling input assumptions and commodity price forecasts. Finally, I will address comments regarding the Company's proposal to offer capacity rates of zero, as well as other capacity rate-related issues.

I. RISK OF CUSTOMER OVER-PAYMENTS

Q. Please summarize your analysis of DNCP's currently projected over-payments to QFs.

A. As discussed in my direct testimony, there is significant disparity between the rates that DNCP is committed to pay QFs pursuant to PPAs entered into under the 2012 and 2014 biennial avoided cost proceedings (Docket Nos. E-100, Sub 136 and Sub 140, respectively) and the current expected value of those contracts.

Specifically, for the approximately 680 MW of solar QFs that established a legally enforceable obligation ("LEO") under either the Sub 136 or Sub 140 rates, the Company is committed to make payments to QFs totaling approximately $100 million per year for the next 15 years, for a total of $1.4 billion. These projected payments exceed the current market value of these contracts during the same time frame by approximately $381 million. That means that the rates DNCP and its customers are paying under these QF contracts is 46% above our actual avoided costs, and will result in $381 million in overpayment over the lifetime of these PPAs. (Direct at 2-4.)

Q. What is causing these significant overpayments to QFs?

A. These overpayments are the result of a combination of factors that are rooted in the current structure of the standard offer. First, under the current structure, avoided cost rates are determined in two-year intervals. QFs can establish an LEO anytime during this biennial period, and it is likely that standard rates approved by the Commission will no longer represent the Company's actual avoided costs at the time of the LEO. Moreover, because even more time, maybe another couple of years, may pass before a QF facility is on line and providing power to serve customers, the disparity between the locked-in standard avoided cost rate that the Company will pay over the term of a PPA and the Company's actual avoided costs is more pronounced.

Q. What is causing the Company's lower avoided costs?

A. As noted in my direct testimony, forward prices of fuel and power have dropped precipitously over the last several years. This is demonstrated by the fact that the average energy price that DNCP paid in 2016 to contracts from the Sub 136 and Sub 140 dockets was approximately \$54/MWh and \$48/MWh respectively, as compared to an average on-peak LMP during 2016 of approximately \$34/MWh.

Q. Does the size of standard rate QFs and the 15-year contract term exacerbate the overpayment problem?

A. Yes, the problem of over payments created by the two-year lag combined with the significant drop in fuel and power prices is exacerbated because the standard contract is available to solar QF projects up to 5 MW. As a result, large numbers of projects sized at or just below the 5 MW threshold are able to qualify for the biennially established standard rates and terms. As Company Witness J. Scott Gaskill noted in his direct and rebuttal testimonies, 83% (60 out of 72) of the QF PPAs the Company had signed as of February of this year are for projects sized 5 MW and below.

The standard 15-year contract term also magnifies this disparity, because DNCP and its customers are required to pay a standard avoided cost rate for a longer period of time that does not account for changes in the market. Once again, the financial risk to customers is that they will pay more for the energy and capacity than the actual avoided cost of that energy and capacity.

Q. **Does the magnitude of the solar QF development in the Company's service territory contribute to the overpayments?**

A. Absolutely, the combination of the structural factors discussed above and the significant volume of solar capacity that has occurred in DNCP's North Carolina service area since 2012, and particularly since 2014, further magnifies the disparity between the estimated and actual costs. As Company Witness Gaskill explained in his direct testimony, since February 2014 the amount of solar capacity under contract to sell to DNCP has increased from 58 MW to approximately 500 MW (with another approximate 180 MW having established LEOs), and the amount of solar capacity with CPCNs has increased from approximately 100 MW to around 1500 MW. The already significant disparity between rates paid and actual avoided costs becomes an even greater problem when it is magnified by this amount of volume.

Q. Did the Federal Energy Regulatory Commission ("FERC") contemplate some disparities between estimated avoided costs and actual avoided costs, when it implemented its Public Utility Regulatory Policies Act ("PURPA") regulations?

A Yes, conceptually. FERC stated in implementing its PURPA rules that in the long run, overestimations and underestimations of avoided costs would balance out. As shown by our analysis of the overpayments that have occurred since 2012 and that are projected to occur for the next 15 or more years, however, the disparity between estimated avoided costs and actual avoided costs is *not* balancing out.

In addition, FERC's PURPA regulations also require that avoided cost rates be just and reasonable to a utility's ratepayers and not exceed a utility's avoided costs. While some discrepancy between estimated and actual avoided costs may be expected, in North Carolina the magnitude of the disparity between avoided cost estimates and the Company's actual avoided costs is already significant and will continue to grow, all to the detriment of the Company's ratepayers.

Q. Why does the overpayment matter for purposes of this case?

A. This case is about determining avoided costs that are as accurate as possible, in a manner that is consistent with the PURPA requirements that avoided costs be in the public interest, just and reasonable to utility customers, and nondiscriminatory to QFs, and that customers should be indifferent to whether the utility buys power from a QF or builds the generation itself or purchases it from another source. The extreme disparity between the rates that DNCP is paying, and will continue to pay for the next fifteen or more years, and the Company's actual avoided costs, means that customers are at substantial financial risk of paying grossly more for QF output than they should, therefore violating these fundamental requirements of PURPA.

The proposals that DNCP has made in this case are therefore made with the intention of reducing this risk of overpayment going forward and with the goal of restoring the balance between encouraging QF generation and protecting customers from overpayments and stranded costs.

Q. Do you agree with NCSEA Witness Ben Johnson's benchmark cost comparisons and critique of the Company's payment analysis?

A. No. Distilled to its essence, Dr. Johnson's testimony encourages the Commission to set standard avoided costs above the avoided costs that are derived from applying the peaker method. The objective in these biennial proceedings, using the peaker method, is to calculate avoided cost rates that are as accurate as possible, that reasonably represent the costs that we expect to avoid by purchasing power from QFs, during the term of the contract. The Commission should not, and indeed cannot consistent with PURPA, set rates above avoided costs to artificially encourage QF development.

Q. Please explain.

A. Dr. Johnson describes the mechanism and theory underlying the peaker method but then, based on his analysis of Duke Energy Carolinas, LLC's

("DEC") and Duke Energy Progress, LLC's ("DEP" and together, "Duke") marginal and average fuel costs, concludes that the peaker method is providing low-end estimates of avoided costs. He then presents "benchmark" cost estimates for different types of units (baseload, combined cycle ("CC"), combustine turbine ("CT")) derived using the proxy method (not the peaker method), and concludes, based on the comparisons of those estimates to the 2014 rates, that "the long run costs the Utilities are incurring when they build and operate new combined cycle plants [are] in the same general range as what ratepayers have been paying for power obtained from QFs over the [last] five to ten years pursuant to the current approved QF tariffs." (Johnson at 55-85.) Remarkably, Dr. Johnson suggests that QF avoided cost rates should be comparable with what it costs to obtain power from a new combined cycle plant. (Johnson at 79.) Furthermore, he says that rates lower than the equivalent for the cost of a CC power plant would be "artificially low," with detrimental effects on customers as a result. (Johnson at 80.)

Dr. Johnson's proposed "benchmark" comparisons and resulting critique are wrong. As an initial matter, Dr. Johnson mistakenly used the CT cost data for his CC-based comparison (Johnson at 77-79), undercutting his point that the Sub 140 rates are very similar to or lower than the cost of a CC unit. Using the correct comparison, his analysis would have shown, for example, that the DEC 2014 rate of 4.85 c/kwh is too high because it is approximately 1 c/kwh, or 26%, higher than the CC cost of 3.83 c/kwh (based on the EIA 2017 price forecast). (Johnson at 77.)

More fundamentally, it is not at all consistent or appropriate in these biennial proceedings to use cost estimates derived using the proxy method to evaluate cost estimates derived with the peaker method. As made clear through multiple witnesses' testimony in this case, including that of Dr. Johnson himself, the Commission has consistently—most recently in the Sub 140 proceeding—approved the use of the peaker method for determining avoided costs. It thus does not make sense to evaluate avoided cost outcomes of the peaker method by applying the proxy method. In contrast, the Company has appropriately compared the rates it is committed to paying to QFs with Sub 136 and Sub 140 contracts to the current market value of those contracts, and that comparison clearly shows that customers are *not* indifferent as between purchases made from those QFs and other purchases or build options.

II. <u>AVOIDED ENERGY COST RATES</u>

<u>Overview</u>

Q. Please summarize your rebuttal testimony as it relates to avoided energy cost rates.

A. My rebuttal addresses comments regarding modeling issues, commodity price forecasts, and the Company's on- and off-peak hours designations. Company Witness Gaskill's rebuttal testimony will address comments pertaining to the Company's proposals to remove the line loss adjustment for standard QF contract avoided energy rates and to adjust avoided energy rates to reflect North Carolina LMPs.

Q. Can you summarize Public Staff Witness Hinton's testimony regarding DNCP's proposed avoided energy costs and rates?

A. Yes. Public Staff Witness Hinton found the Company's fuel forecasts and other inputs used in its determination of avoided energy costs to be reasonable (Hinton at 36.) In addition, and as discussed further by Company Witness Gaskill, Mr. Hinton agreed that it is reasonable for DNCP to adjust its avoided energy rates to reflect NC LMPs, which are lower than DOM Zone average LMPs, as proposed by the Company. (Hinton at 61.)

<u>Modelling Issues</u>

Q. SACE Witness Vitolo requests that the Company recalculate its proposed avoided energy rates with the assumption that the block of QF power added to the PROMOD model is available 100% of the time (Vitolo at 45). Do you agree with that modeling approach?

A. No. No generator is 100% available, regardless of whether the unit is utility owned or not and regardless of the type of energy source.

As discussed in my direct testimony, the Company calculates the avoided energy cost for Schedule 19-FP using PROMOD, an accepted utility production costing model. (Direct at 6-7.) The starting point for the analysis is the PROMOD base case, which includes the generation expansion plan "A" from the Company's most recent Integrated Resource Plan ("IRP"). This first simulation is referred to as the "without QF" case. A second PROMOD case, referred to as the "with QF" case, was run with an additional QF resource. The additional QF resource was modeled with the following operating parameters: 100-MW unit; must-run; 85% availability; and zero energy cost. All other assumptions from the base case remained the same. The difference in the annual system production costs between the "with QF" and "without QF" cases represent the Company's forecasted avoided energy costs. DNCP then divided the resulting system cost savings output from PROMOD by the amount of corresponding avoided energy (100 MW x 0.85 x 8760 hr = 744,600 MWh) to calculate the levelized on-peak and off-peak long-term fixed energy rates for the various contract durations under Schedule 19-FP.

The Company's assumption of 85% availability for the calculation of standard offer energy rates reflects the availability of a baseload unit, which is consistent with the theory behind the peaker method as it pertains to the calculation of avoided system energy costs from a typical QF. That theory provides, as the Commission has explained, that "if the utility's generating system is operating at equilibrium (i.e., at the optimal point), the cost of a peaker (a combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost. It will also equal the cost of a baseload plant…." (Order Establishing Standard Rates and Contract Terms for Qualifying Facilities at 17, Docket No. E-100, Sub 100 (Sept. 29, 2005)). In contrast, Dr. Vitolo's assertion that we should calculate avoided cost rates based on a block of QF energy that is 100% available is not reasonable, because that type of QF power does not exist. Notably, this modeling approach has been used by the Company and accepted by the Commission for many years, including in the Sub 140 proceeding.

Q. It appears, however, that Dr. Vitolo is concerned that the Company may be under-estimating the energy rates due to a mismatch between the PROMOD modeling and the energy rate calculation. Do you agree?

A. No. Dr. Vitolo stated that "If, however, DNCP divided the total dollars of savings by 876,000 MWh, DNCP's avoided energy rate will be approximately 15% too low." (Vitolo at 44.) To be clear, the Company did *not* divide the total dollar savings by 876,000 MWh, but rather by 744,600 MWh, to be consistent with the 85% availability. I believe, therefore, his objection was simply a misunderstanding of the Company's methodology for calculating the avoided energy rates. In other words the system cost savings in the numerator are consistent with the QF energy production in the denominator.

<u>Fuel Forecast</u>

Q. How did DNCP forecast fuel costs for purposes of determining the Company's avoided energy costs in this biennial proceeding?

A. Consistent with the Commission orders in the Sub 140 proceeding, in this proceeding DNCP has maintained its approach of using, for the first 18 months of the forecast period, estimated forward market prices for fuel, PJM power, and emission allowance as of September 29, 2016. For the next 18 months, the prices are a blend of the forward market prices and the ICF commodity price forecast as of early October 2016. For the remainder of the term (starting October 2019), the prices are based exclusively on ICF's commodity price forecast. This is consistent with the price forecasting methodology in the 2016 IRP, as well as prior IRPs before that.

Q. What is the Public Staff's position on DNCP's fuel price forecasting approach?

A. The Public Staff supports DNCP's approach to fuel price forecasting. (Hinton at 32-33.)

Q. What is NCSEA Witness Johnson's testimony with regard to DNCP's fuel forecast?

A. Dr. Johnson finds DNCP's method of blending forward prices with fundamentals before transitioning to full fundamental prices to be reasonable. (Johnson at 146.) He also, however, proposes that the Commission direct DNCP to use either the 2017 EIA forecast (which was published in March 2017), or the fundamental commodities forecast that DNCP used in preparing its 2016 IRP, for purposes of calculating its avoided energy cost rates in this case. (Johnson at 142-146.)

Q. Do you agree with Dr. Johnson's recommendation?

A. The Company appreciates Dr. Johnson's acceptance of our commodities forecast approach, but I do not agree with his recommendation regarding the vintage of the forecasts used.

For this case, the Company appropriately used the price blending methodology that it used in prior IRPs, including the 2016 IRP. However, because the commodity prices for the 2016 IRP were developed by ICF in the December 2015 timeframe, the Company used updated, October 2016 data for fuel and power prices in applying that price blending methodology for its November

2016 avoided cost filing. This approach is consistent with the Commission's Phase 2 Order from the Sub 140 proceeding (Phase 2 Order at 27, 54 (Dec. 17, 2015)), which determined that the utilities should calculate avoided energy rates using commodity forecasts that are put together in a way that is consistent with their IRPs (not that the same price forecast must be used). Additionally, as several witnesses in this proceeding have noted, one of the problems with the standard contract is that prices are only updated every two years. Thus, QFs establishing an LEO late in the two-year window receive avoided cost rates that can be several years old by the time they commence operations. Dr. Johnson's proposal that DNCP base its avoided energy rates on forecasts that are an additional year older should therefore be rejected because it would exacerbate the disparity between contracted rates and actual avoided costs.

Using the 2017 EIA price forecast would also not be appropriate, because that approach *would be* inconsistent with our use of prices developed by ICF for IRP and avoided cost case purposes and therefore with the Commission's directive that we use a forecast structure for avoided cost that is consistent with the forecasts we develop for the IRP.

Q. **NCSEA Witness Johnson also asserts that the utilities' natural gas price forecasts should approach a long term gas price trend as depicted on the graph at page 145 of his testimony. Please comment.**

A. Dr. Johnson's long-term natural gas price trend line does not reflect current natural gas market fundamentals, and seems to discount the fact that technology improvements (such as better natural gas production methods) continue to create production benefits that result in reduced long term natural gas prices. His data gives too much weight to the years 1990-2008 when natural gas prices were rising, and not enough weight to the downward trend in prices from 2009 to 2016.

<u>**Hours designations**</u>

Q. Please review the Company's on- and off-peak hours for its proposed standard Schedule 19-FP.

A. The Company has proposed to keep both the Option A and Option B rate options for its standard Schedule 19-FP contract. On-peak hours are currently defined in Schedule 19-FP as follows:

- for Option A, non-holiday weekdays April-September, 10 am – 10 pm and October-March, 6 am – 1 pm and 4 pm – 9 pm;
- for Option B, non-holiday weekdays June-September, 1 pm – 9 pm and October-May, 6 am – 1pm.

The Option A hours have been used in the Schedule 19 rate schedule for many years. As part of a settlement in the Sub 136 docket, the Company adopted the Option B hours that DEC was using at that time. This definition of on-peak hours includes fewer hours than Option A, and strikes a balance to include the likely high-load hours of the utility, and daytime hours when solar is likely to be generating.

Q. Please summarize Mr. Hinton's suggestion that the Commission direct the utilities to calculate solar-specific off-peak energy rates with the definition of off-peak hours aligned with a solar QF generation profile.

A. Mr. Hinton notes that, in the Sub 140 proceeding, the Public Staff agreed with NCSEA Witness Tom Beach's suggestion that defining off-peak hours for solar QFs in a way that aligns with those facilities' diurnal profile would increase off-peak energy rates, and that discovery in that proceeding indicated that those rates under Option B would increase between 8 and 10%. He explains that in its Phase 1 Order, the Commission declined to approve Mr. Beach's proposal, finding that this approach would isolate one potential benefit of solar generation while failing to account for any potential costs inherent in such intermittent facilities. (Hinton at 61-62, citing Phase 1 Order at 62 (Dec. 31, 2014).)

Mr. Hinton asks the Commission to revisit this issue, and contends that the issue is more related to modeling or allocation than to solar integration. In the Sub 140 Phase 1 proceeding, NCSEA Witness Beach cited the Crossborder Study, which he argued showed that the output of a typical solar resource had more avoided energy value than a flat 24x7 block of power. In this proceeding, Mr. Hinton asserts that from a customer perspective, solar energy provided during off-peak daylight hours has value not currently being fully recognized and properly allocated in off-peak avoided energy rates. As discussed in his testimony and shown by his Table 8, this proposal would result in an increase in the off-peak energy rate paid to solar QFs under this proceeding. (Hinton at 62-65.)

Q. What is DNCP's position with regard to Mr. Hinton's suggestion?

A. As Mr. Hinton notes, this subject was addressed in the 2014 proceeding, where the Commission declined to accept Mr. Beach's proposal. The Commission recognized that this proposal "isolates one potential benefit of solar generation, but fails to account for any of the potential costs inherent in such intermittent resources. The Commission finds it difficult to square such an unbalanced approach with PURPA." (Phase 1 Order at 62.)

The Company believes the same concerns exist today, and the proposal to develop off-peak energy rates based on a solar profile should therefore once again be rejected. If solar-specific rates were to be developed, the capacity rate should not include the full value of a peaker since, in PJM, it only accounts for between 0-20% capacity value. A solar specific rate would also need to account for additional costs such as increased operating reserves, load deviation charges, and increased O&M on the transmission and distribution system.

In lieu of a solar-specific rate, the Company continues to support the Option B hourly designation that was proposed and accepted in the Sub 140 proceeding as more appropriately reflecting the benefits that a typical solar facility provides. Indeed, nearly all solar QFs select Option B, because it results in more revenue than Option A, based on these QFs' expected solar generating profile.

Finally, the Company also continues to offer Schedule 19-LMP, which will precisely match the generation profile of a solar QF with hourly market prices. If solar QFs want better price signals and more granularity, an LMP-based rate schedule provides just that. The Company therefore believes that the current Option A and Option B definitions reflected in its Schedule 19-FP, with the alternative of Schedule 19-LMP, should continue to be retained, and that an additional schedule is not required at this time.

Q. NCSEA Witness Johnson contends that DNCP's on- and off-peak hours designations are inappropriate. What is your response?

A. Dr. Johnson claims that DNCP's (and Duke's) proposals to retain their existing on-peak and off-peak hours, which he terms as "very broadly defined time periods," are "anomalous" in light of the utilities' concerns related to the growing volume of solar being generated during certain hours of the day and specific parts of the year. (Johnson at 193.) He states that "[s]tronger, more precise price signals are needed, which are narrowly tailored to carefully identified hours during the summer and deep winter months." (Johnson at 197.)

I find Dr. Johnson's assertion that utilities should provide better price signals inconsistent with the positions he has taken in this case regarding the Company's changes to the standard contract. All of the elements of the standard contract for which he advocates—5 MW size threshold, 15-year fixed pricing terms, no locational price adjustment, capacity payments even when no capacity is needed, use of outdated pricing—are contrary to the goal of providing more precise price signals to individual QFs. Again, the Company believes that by including Option A, Option B, and its Schedule 19-LMP in its standard offer, small QFs have sufficient optionality to match their expected generation profile. In addition, the Company's proposal to move more QFs toward non-standard contracts by reducing the size threshold for the standard offer will allow more prècise price signals for QFs, because the rates will more closely align with the LEO and the prices can be adjusted to the timing and location of the individual QF.

III. AVOIDED CAPACITY COST RATES

DNCP capacity proposal

Q. Please summarize the Company's proposal and rationale with regard to avoided capacity rates in this proceeding.

A. As discussed in my direct testimony, the Company has proposed to offer a capacity rate of zero for new QFs in its North Carolina service area. In order for new QFs to avoid future capacity costs, (1) there must be a need for capacity and (2) the QF generation must be of the type and location to actually avoid that need. Neither of these criteria are true for additional solar QFs located in the Company's North Carolina service territory. As explained in my direct testimony, this conclusion is based on several factors:

1. The Company does not have a current near term need for additional capacity. In the 2016 IRP, the Company does not reflect a need for additional capacity until 2022 at the earliest. According to the Company's current load forecast, the earliest capacity need would not arise until the 2024 timeframe.

2. Because the Company's North Carolina service area is saturated with distributed solar QF projects, any new distributed solar generation that is added going forward will have little to no peak load reducing effect on the system.

3. Due to the intermittency of the distributed solar generation coming online, the Company is considering adding aeroderivative CTs to its system to take advantage of these units' faster start-up and ramping capability. However, because these aeroderivative CTs, which the Company would only build to accommodate large amounts of intermittent generation, have a higher installed cost than the large frame turbines that the Company has built since the year 2000 (they cost an estimated 67% more than other CTs), their addition will result in increased long-term capacity costs for customers.

4. Solar generation is not dispatchable, and has limited usefulness during system emergencies, and should be priced accordingly, as contemplated by FERC's rules.

5. Solar generation is not reliable on a year-round basis, and has limited value in PJM's Reliability Pricing Model ("RPM") capacity market, which requires capacity performance ("CP") type resources.

6. The addition of large amounts of distributed solar resources is likely to shift the time of the summer peak to a later hour in the day. This peak shift effect results in a diminishing capacity value of solar.

Q. Does DNCP continue to support its initial proposal of capacity rates of zero for the duration of the standard offer contract?

A. Yes. For the reasons described in my direct testimony and discussed further in this rebuttal testimony, the Company continues to support the position that the appropriate capacity rate is 0 cents per kWh for new QFs located in the Company's North Carolina service area for the duration of the standard offer contract.

Q. What is the testimony of Public Staff Witness Hinton with regard to the Company's proposal?

A. Public Staff Witness Hinton does not agree with the Company's proposal. He states that "[u]tility planning is not performed on a state-by-state basis; rather, the generation and transmission systems are planned on a system-wide basis." (Hinton at 18.) He concludes that additional generation in North Carolina can help offset future system capacity costs and therefore the rate should not be set to zero for all years. (Hinton at 18-19.)

However, Mr. Hinton does support limiting the capacity payments until the utility's IRP dictates a capacity need. (Hinton at 14.) In DNCP's case, the 2016 IRP first reflects a need in 2022[1] at the earliest, and as I noted already our most recent load forecast shows that need appearing not until 2024.

Q. What is your response to Mr. Hinton's testimony?

A. Mr. Hinton states correctly that generation and transmission planning is done on a system-wide basis. However, it is important to recognize that location does matter in regards to resource expansion planning. Adding more intermittent generation to northeastern North Carolina, which is already saturated with such generation, will not allow the Company to avoid or defer future capacity needs. This is because, given that generation from solar QFs in this area has reached the point where it exceeds our load, solar QFs interconnecting at the distribution level in this area are no longer reducing load, and therefore are not reducing DNCP's load obligation and not deferring the need for new capacity. For this reason, and the others described above and in my direct testimony, the avoided capacity cost rate should be zero.

Q. What is your general response to the testimony offered by SACE Witness Vitolo on the topic of capacity payments?

A. Dr. Vitolo's disagreement with our capacity proposal and rationale seems to be based primarily on his assertion that the Company only has summer

[1] On page 19 of his testimony, Mr. Hinton states that DNCP's first capacity need is in 2012. After conferring with Public Staff, it was confirmed that Mr. Hinton intended to reference 2022 as DNCP's first capacity need as reflected in the Company's 2016 IRP.

capacity needs. (Vitolo at 31-33.) For instance, he also contends that PJM is a "summer-peaking system" and that "[t]he PJM wholesale generation capacity market has a surplus of capacity during winter months but a market demand for summertime capacity." (Vitolo at 32.)

Dr. Vitolo's statements regarding capacity needs in PJM are not correct. First of all, there is a need for capacity planning to meet both the summer and winter peak and the PJM capacity market reflects such needs. It is an oversimplification to state that PJM only plans for the summer and that there is surplus of capacity in the winter months. Under the Capacity Performance ("CP") capacity market rules, generators in PJM are responsible for providing reliable capacity in all months of the year, not just summer. Since solar resources have little or no capacity to generate at the winter morning peak, they are subject to significant capacity performance penalties if they choose to bid into the RPM. Furthermore, I do not necessarily agree with Dr. Vitolo's oversimplification that PJM has a surplus of winter capacity. It was the shortage of available generation in the winter of 2014 that resulted in the need for the CP rules in the first place.

Q. Can you respond to Dr. Vitolo's testimony regarding the 38% capacity credit that PJM applies to solar generation?

A. Yes. Dr. Vitolo points to PJM Manual 21, which he states provides "the procedures for calculating the capacity value of solar." (Vitolo at 33.)

The 38% capacity value cited by Dr. Vitolo only denotes the capacity

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injection rights, not the market capacity value, of solar. For capacity value, the 38% class average is no longer relevant under the capacity performance market. Solar units that offer into the RPM auction today are subject to the same financial penalties that apply to conventional fossil-fueled resources for non-performance on critical days. The key point is that, on a risk adjusted basis, the capacity credit of a solar resource offered into the CP market is in the range of 0 to 20% of nameplate capacity.[2] The maximum of 20% is based on PJM's assumption that a typical solar facility may provide 38% in the summer, but only 2% in the winter. Therefore, they note that "an acceptable" capacity bid for a solar generator would be between 0-20%, depending on how much CP penalty risk the generator is willing to accept. This reduced capacity percentage, along with CP financial penalties, demonstrates that from a reliability perspective, solar resources can only be counted on for a small portion, if any, of their nameplate capacity. Therefore, continuing to pay new solar QF resources rates for avoided capacity, when they do not defer or avoid capacity need for the Company, results in an overpayment beyond our actual avoided costs.

Q. Does NCSEA Witness Johnson directly address DNCP's proposal to pay capacity rates of zero for the entire contract term?

A. No. Dr. Johnson focuses his testimony primarily on Duke's proposal to pay capacity rates of zeros for the years of the contract in which there is no

[2] http://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150709-capacity-performance-training.ashx See page 30 of the presentation.

demonstrated capacity need. However, he makes several arguments that could apply to DNCP's proposal as well. He states his belief that "the use of zeros is inconsistent with the fundamental goals of PURPA, as well as the most appropriate interpretation of the concepts of 'incremental cost' and 'avoided cost.' Futhermore, the use of zeros is inconsistent with the concept of 'ratepayer indifference….'" (Johnson at 183.)

Q. What is your response to Dr. Johnson's testimony on this topic?

A. I disagree with Dr. Johnson. As Company Witness Gaskill explains, FERC's rules implementing PURPA define avoided costs as the incremental costs to an electric utility of electric energy or capacity or both which, *but for* the purchase from a QF, the utility would generate itself or purchase from another source. The fact of the matter is that DNCP will not avoid or defer future capacity needs because of additional solar QF generation in its North Carolina service area; therefore, avoided capacity costs are appropriately set to zero. Contrary to Dr. Johnson's assertion, the principle of "ratepayer indifference" is actually violated if customers are paying capacity to the QF that is not actually avoided, because as I explain above those customers are paying for something they are not receiving.

<u>Other issues related to avoided capacity cost rates</u>

Q. In the alternative to DNCP's proposal to set capacity rates at zero in this case, would you support Duke's proposal to include zeros in the calculation of the capacity rates for the years where the Company does not have a capacity need?

A. DNCP's position remains that no capacity should be paid to QFs in the Company's service area for the duration of the standard offer contract. However, should the Commission decline to accept the Company's proposal not to pay capacity, then yes, the Company would agree with Mr. Hinton's conclusion, in response to Duke's proposal, that including zeros in the capacity rate calculations in the years prior to the first year of system capacity need is reasonable and appropriate. (Hinton at 13-14.)

This is because, in the Company's view, the addition of QF power during this capacity surplus period will not avoid or defer the need for capacity. Including zeros for the years where there is no capacity need, while still in the Company's view overpaying QFs for capacity, will come closer to valuing the capacity appropriately over the term of the long term contract with the QF than paying a QF for capacity over the entire term including for years in which there is no demonstrated need.

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Q. Dr. Johnson points to the Commission's decision in the Sub 140 case to reject a similar proposal the utilities made in that proceeding (Johnson at 181-183). What is your response?

A. As Public Staff Witness Hinton notes:

> Contrary to the Public Staff's position in prior proceedings regarding the use of zero capacity value in certain years, I believe that in light of current circumstances, it is appropriate for utilities to make a capacity payment to QFs only when additional capacity is needed on the system. I believe that the level of solar generation and the amount of solar generation in the interconnection queue warrant a departure from a traditional application of the peaker method. By restricting the payment until the IRP has established a capacity deficiency will minimize the overpayment risk to ratepayers, while providing a reasonable level of financial compensation for avoided capacity costs and sending a better price signal to the market. (Hinton at 13-14.)

I agree with Mr. Hinton that current circumstances make it appropriate for the Commission to reconsider this issue. The traditional application of the peaker method is resulting in an overpayment of actual avoided costs and is not sending a proper price signal to the market.

I would also note that this is a topic that the Commission has reviewed several times in the past, and there is historical precedent for the utility to pay zero for capacity during the front-years of a contract. In the 1994, 1996, and 1998 avoided cost cases the Commission recognized that no capacity credit should be included in the capacity rate calculation where no capacity costs were avoided. (See Order of July 16, 1999 in Docket No. E-100, Sub 81, Order of June 19, 1997 in Docket No. E-100, Sub 79, and Order of June 23, 1995 in Docket No. E-100 Sub 74.)

The evidence in this case likewise shows that there is no capacity need for the foreseeable future and that paying for capacity when it is not actually avoided results in an overpayment risk for customers.

Q. What about his argument that using zeros discriminates against small power producers (Johnson at 183, 186-187)?

A. I disagree that paying a capacity rate to QFs only when we actually show a need for capacity is discriminatory to QFs. DNCP is a regulated utility, with an obligation under the law to serve its customers reliably and at least cost. To meet that obligation, we must make capacity commitments years in advance of our forecasted needs. These are commitments that new distributed solar QFs located in our North Carolina service area cannot avoid, because as we have shown we cannot plan and account for their future capacity, and they are not reducing load on our system. In addition, paying for capacity when it is not needed or avoided is contrary to the PURPA requirement that the rates that a utility pays for QF output should not exceed the utility's avoided costs. The determination of avoided costs and rates in this proceeding is not a theoretical exercise. The standard avoided cost rates determined here represent real, actual customer costs, and we do not believe customers should be required to pay for avoided costs that are not actually being avoided.

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Q. **Dr. Vitolo states that in the Sub 140 proceeding the Commission determined that the findings from the *Ketchikan* case do not apply in North Carolina's proceedings, and are not applicable to the Company's current capacity surplus situation. (Vitolo at 34.) Do you agree?**

A. No. In my opinion, the circumstances in the *Ketchikan* case seem similar in many respects to the current situation. The Company currently finds itself in a position where it has no incremental capacity needs in the front-years of the planning horizon. I am not a lawyer, but as I understand it, in *Ketchikan*, FERC found that if the utility does not have a demonstrated need for capacity it should not be required to pay for incremental QF capacity. In the Sub 140 proceeding the Commission cited FERC's later *Hydrodynamics* decision as supporting its determination in that case that the utilities should not include zeros in the early years when calculating avoided capacity rates. *Hydrodynamics*, however, was a different situation than *Ketchikan* and different than the situation facing us, because it addressed a utility's proposal to limit installed capacity purchases with no connection between that limit and its own actual need. In *Hydrodynamics*, FERC reiterated its earlier decision that when a utility's demand or need for capacity is zero, avoided cost rates need not include capacity cost. That is the case here, and therefore DNCP's position is that the rationale in *Ketchikan* is indeed applicable to this case and to our proposal.

Q. Turning now to other issues related to the avoided capacity cost determination, what is the PAF?

A. Under the current application of the peaker method, capacity costs are converted to a c/kWh rate and paid to the QF on the basis of its generation during the on-peak periods. Since all generators would be expected to have some outages, the current 1.2 PAF is a multiplier against the capacity rate to allow the QF to obtain the full cost of the peaker with only an 83% capacity factor.

Q. Has DNCP in this case proposed any change to the PAF that was approved in the Sub 140 proceeding?

A. Since DNCP's position in this case is that no capacity payment should be made to QFs because no capacity is being avoided, the Company did not propose any adjustment to the PAF.

Q. To the extent that DNCP is directed to offer avoided capacity rates to QFs in this proceeding, does DNCP agree with Duke's proposal to reduce the PAF to 1.05?

A. Yes. The Company's position is that the PAF is not applicable to DNCP because capacity is not actually being avoided. If, however, the Commission finds otherwise, then consistent with the position the Company put forth in the Sub 140 docket, I believe that a PAF of 1.05 is appropriate. Since the peaker method determines avoided capacity costs based on the installed cost of a peaking CT unit, it is logical to use the peak hours availability of that type of resource to determine the PAF.

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I recognize that the Commission disagreed with that position in its Phase 1 Order, but believe that this issue is worth reevaluating in this case. First, I would say that to the extent a QF cannot operate at an availability level that is similar to or better than a CT during peak periods, that QF should not be entitled to the avoided cost as a full CT. In other words, if the QF is assumed to defer the need to construct a CT with a peak hours availability of 95%, the QF should not receive the same capacity payment if it is only available 83% (or less) of the time. In addition, when the Commission decided in the 2014 case to retain the 1.20 PAF, it also stated that there had been widespread QF development under the "existing framework without adverse impacts to utility ratepayers." (Phase 1 Order at 56.) As we have shown throughout this case, that is no longer true; circumstances have changed, and utility ratepayers are being adversely impacted. To the extent that the utilities are required to pay capacity to standard QFs, the PAF should be reduced to 1.05.

Q. What is your response to the testimony of Witnesses Vitolo and Johnson on the PAF?

A. Witnesses Vitolo and Johnson favor a higher payment to the QFs, but their reasoning is not compelling.

For instance, Dr. Johnson states that "a solar generator would not receive full payment of the avoided capacity costs, because it is incapable of generating electricity during 95% of the on peak hours due to the fact that many on peak hours occur when the before the sun rises or after the sun sets." (Johnson at 191.)

This is precisely the point. A solar QF should not be entitled to the full avoided cost of a CT because it is not available during all the on-peak hours, nor does it provide the same level of reliability as a CT.

Dr. Vitolo recommends the Commission maintain a PAF of 1.20 because it better aligns with the availability of units in the fleet. (Vitolo at 25.) The year-round availability of the all the units in the fleet is not the correct metric to use because it includes maintenance and planned outages that are purposely scheduled to occur during non-peak conditions. The appropriate measure for the PAF is the availability of the CT during summer and winter peak hours.

Q. What is your response to the testimony of the Public Staff witnesses that the PAF should be reduced to 1.16?

A. Notably, Public Staff Witness Metz "agree[s] that a 1.2 PAF may no longer be appropriate for use in calculating avoided cost rates." (Metz at 16.) I agree with Mr. Metz on this point. However, both he and Public Staff Witness Hinton recommend adjusting the PAF to 1.16 based on an average fleet-wide availability factor. (Hinton at 22-23; Metz at 17-19.) For the same reasons that I explained above, I believe that since it is the CT that is the basis of the capacity costs under the peaker method, it should be the CT availability that should be used. Thus, a 1.05 PAF is appropriate.

Q. Please summarize your rebuttal testimony.

A. DNCP has proposed several modifications to the Company's standard avoided cost offer to mitigate going forward the significant overpayment risk to our customers posed by avoided cost contracts. As the Company has demonstrated through testimony and discovery in this case, the estimated cumulative over-payments for legacy QF contracts in North Carolina above the current forecast of DNCP's avoided costs is approximately $381 million over the next fifteen years, a 46% premium above our expected avoided costs. This disparity shows that the balance the Commission seeks to strike in these proceedings between encouraging QF development and protecting customers has come undone and needs to be revisited.

With regard to DNCP's proposed avoided energy rates, the Company has complied with the Commission's directives regarding fuel price forecasting, used appropriate modelling inputs and hours designations, and has calculated energy rates that have been adjusted to reflect the locational value of QF projects that are located in the North Carolina service area. As with other modifications the Company is proposing in this case, this adjustment results in rates that more accurately reflect the true avoided cost of these projects.

Finally, due to the lack of need for incremental capacity in the Company's North Carolina service area, the inability of incremental solar generation in this area to reduce load or otherwise allow DNCP to avoid building or buying capacity, and the other reasons I have discussed in my direct testimony and in this rebuttal, the Company believes its proposal to make no capacity payments to QFs that sign a contract during this biennial period complies with PURPA and FERC requirements, is consistent with PURPA's indifference

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requirement, and more accurately strikes the balance the Commission seeks between encouraging QFs and protecting customers.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Q Mr. Petrie, do you have a summary of your direct and rebuttal testimonies?

A Yes, I do.

Q Would you please present that now for the Commission?

A Yes. Good afternoon. My name is Bruce Petrie. I'm the Manager of Generation System Planning for Dominion North Carolina Power. My direct testimony supports the avoided energy and capacity rates that Dominion has proposed in this case.

Under QF Purchase Power Contracts that Dominion is party to under the standard offers approved in the last two avoided cost proceedings, we are committed to paying QFs around $100 million per year over the course of the next 15 years, totaling $1.4 billion. This amount exceeds our actual avoided cost for energy and capacity produced by these QFs by 381 million, or 46 percent. This disparity shows that the balance the Commission seeks to strike in these biennial avoided cost proceedings between encouraging QF development on the one hand and protecting utility customers on the other is no longer working.

To find that balance again, Dominion has proposed several modifications to our standard offer. My testimony focuses on two of those changes.

First, we have adjusted our production cost model results to reflect the locational value of energy in our North Carolina service area as opposed to our system as a whole. The result is that Dominion's true avoided energy costs are better reflected in avoided energy cost rates that our customers pay.

Second, we have proposed to pay QFs that qualify for the standard offer a rate of zero for capacity for the term of the PPA. In my testimony I describe numerous reasons supporting this change, including the lack of need for incremental capacity in our North Carolina service area, the inability of incremental distributed solar generation in this area to reduce our load or otherwise allow us to avoid building or buying capacity, and FERC's provisions and its rules for accounting for these factors. But to put the reason for this proposal in -- in the most simple terms, when it comes to capacity, location matters.

In my rebuttal testimony I provide additional support for Dominion's comparison of currently projected contract payments against our actual expected avoided cost. I also offer further support for our proposed standard offer modifications and for our production cost modeling and proposed avoided cost rates, energy cost rates, as well as our current on- and off-peak hours designations.

As an alternative to our full-term capacity proposal, my rebuttal presents support for Duke's proposal to include zeros in the calculation of capacity rates for years when we do not show a capacity need in our expansion plan. To the extent the QFs should be paid for capacity, I also explain that reducing the PAF to 1.05 is appropriate as being consistent with the availability of a combustion turbine.

In sum, I believe that the proposals Dominion has made in this case should be approved. These changes will better ensure that utility customers are indifferent as to QF purchases as PURPA requires. They will also more accurately strike the balance the Commission seeks in these proceedings between encouraging QFs and -- and protecting customers from the risk of overpayment that we are currently experiencing, while helping make sure the customers realize the benefits that -- that they pay through avoided cost rates.

This concludes my summary. Thank you.

Q Thank you.

MS. WELLS: Mr. Chairman, the witnesses are available for cross examination.

CHAIRMAN FINLEY: All right. We're going to break for the day and come back tomorrow at 9:30.

(The hearing was adjourned, to be reconvened on April 20, 2017 at 9:30 a.m.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-100, Sub 148, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

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

IN WITNESS WHEREOF, I have hereunto subscribed my name this 2nd day of May, 2017.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150