PLACE: Dobbs Building, Raleigh, North Carolina

DATE: October 30, 2013

DOCKET NO.: E-100, Sub 136

TIME IN SESSION: 9:00 A.M. TO 12:31 P.M.

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding

Chairman Edward S. Finley, Jr.

Commissioner Bryan E. Beatty

Commissioner Susan W. Rabon

Commissioner Jerry C. Dockham

Commissioner James G. Patterson

IN THE MATTER OF:

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities - 2012

VOLUME 2

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

DUKE ENERGY CAROLINAS, LLC AND
DUKE ENERGY PROGRESS, INC.
Kendrick C. Fentress, Esq.
Lawrence B. Somers, Esq.
Duke Energy
NCRH 20
P.O. Box 1551
Raleigh, NC 27602

Dwight Allen, Esq.
Allen Law Offices, PLLC
1514 Glenwood Avenue
Suite 200
Raleigh, NC 27608

DOMINION NORTH CAROLINA POWER
Horace D. Payne, Jr., Esq.
Dominion North Carolina Power
120 Tredegar Street
Richmond, VA 23219

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

Andrea R. Kells, Esq.
McGuire Woods, LLP
434 Fayetteville Street
Suite 2600
Raleigh, NC 27611

Patrick T. Horne, Esq.
McGuire Woods, LLP
901 East Cary Street
Richmond, VA 23219

RENEWABLE ENERGY GROUP
Charlotte A. Mitchell, Esq.
Styers, Kemerait & Mitchell
1101 Haynes Street, Suite 101C
Raleigh, NC 27604

NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION
Michael Youth, Esq.
1111 Haynes Street
Raleigh, NC 27604

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

SOUTHERN ALLIANCE FOR CLEAN ENERGY
Gudrun Thompson, Esq.
Southern Environmental Law Center
601 W. Rosemary Street
Chapel Hill, NC 27516

Katie Ottenweller, Esq.
Southern Environmental Law Center
129 Peachtree Street, Suite 605
Atlanta, GA 30303

USING AND CONSUMING PUBLIC
Tim R. Dodge, Esq.
Public Staff - Legal Division
430 N. Salisbury Street
Raleigh, NC 27603

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

T A B L E O F C O N T E N T S (Cont'd)

E X H I B I T S

P R O C E E D I N G S

COMMISSIONER BROWN-BLAND: Good morning. We'll come back to order and go on the record. And just so you know, for now, depending on where we are, but if we're not there, it's the Commission's plan to break for lunch by at least 12:30, so you can kind of plan accordingly.

So we left off. We were beginning to have cross. Welcome back, Mr. Petrie. And cross is with Mr. Youth.

MR. YOUTH: I'd like to hand out a cross exhibit.

CROSS EXAMINATION BY MR. YOUTH:

Q **Good morning, Mr. Petrie.**

COMMISSIONER BROWN-BLAND: Excuse me. Mr. Youth, I think we need one more.

MR. YOUTH: We'll get you one.

BY MR. YOUTH:

Q **Good morning again, Mr. Petrie.**

A Good morning.

Q **You were present yesterday when I went through some of the Commission orders dealing with PAF with Ms. Bowman, correct?**

A That's right.

Q **Rather than hand you the same exhibit and ask** you the same questions, I'd like to try to hit the highlights. What I've handed to you, would you agree, subject to check, is an excerpt of a 1997 Commission Order in E-100, Sub 97 -- Sub 79?

A Subject to check, yes.

Q If you turn to page 17 of the Order, do you have any reason to dispute that it says, "The Public Staff" -- and this is at the arrow -- "The Public Staff therefore supported use of a 2.0 performance adjustment factor for hydro facilities with no storage capability and no other type of generation. The Public Staff agreed that use of a higher factor does not change the avoided costs of the utility. It merely changes the manner of pricing out such avoided costs in payments to the QF." Does the Order say that?

A Yeah. Yes.

COMMISSIONER BROWN-BLAND: All right. Mr. Youth, before we go ahead, let's get this identified for the record. The document that you passed out and are asking about should be identified as NCSEA Petrie Cross Examination Exhibit 1.

MR. YOUTH: Thank you, Commissioner Brown-Bland.

(Whereupon, NCSEA Petrie Cross

Examination Exhibit 1 was marked
for identification.)

BY MR. YOUTH:

Q If you'll turn now to page 19 of the Order, and I believe this is at the arrow, the Commission states, "Some parties comment that a higher performance factor for certain QFs is discriminatory or in excess of avoided costs decreed by PURPA." Does it say that?

A Yes.

Q And, finally, I think this may be down by the star on the left-hand margin, "Use" -- the Commission said, "Use of a higher performance factor for these hydro facilities does not exceed avoided costs; it simply changes the method by which avoided costs are paid." Did I read that correctly?

A Yes. That's what the words say.

Q Do you have reason to dispute what the Commission ordered or held in that Order?

A It depends on what they meant when they said, "Use of a higher performance factor for these hydro facilities does not exceed avoided costs." It -- it depends on what they meant by -- when they said "avoided costs."

Q Were you here yesterday when Mr. Snider was testifying?

A Yes.

Q I think even Mr. Snider agreed that Duke's opposition to a solar 2.0 PAF was based on the assumption that a solar 2.0 PAF would exceed avoided costs; is that correct?

A I believe that's what he said.

Q Now, I'd like to ask you to turn to your summary that you presented yesterday. Have you got that?

A Yes.

Q If you'll look at page 3, starting on the second line, you said, "A 2.0 PAF for solar and wind QFs is not necessary and not justified, especially in light of the fact that it would result in payments to solar and wind QFs in excess of Dominion's avoided costs." Can you explain that statement and how you can say it is a fact that a 2.0 PAF would exceed Dominion's avoided costs?

A Yes. I'll -- I'll try to explain. In the peaker method when -- in the development of the capacity rate, we use the full cost of a peaker, even though solar facilities do not avoid the full cost of a peaker, and we use a PAF of 2. When you take the resulting rates from -- from that rate calculation, and when you apply those to the -- those rates to a typical solar generation profile, the dollar payment that the QF would receive would be higher than our avoided cost. And it -- it comes down to -- the key point here is that the solar generation is only 38 percent effective in avoiding CT capacity. If we -- if we build a hundred -- if we buy 100 MW of solar generation, we only get credit for 38 MW from a capacity planning perspective.

Q Does that mean that a 2.0 PAF for hydro, in Dominion's opinion, also exceeds Dominion's avoided cost?

A It could if -- if you had a hydro facility that ran at 70 percent capacity factor during on-peak hours, that would -- that QF would be receiving higher than the avoided cost, because the PAF was based on -- the PAF of 2 gives up an allowance for 50 percent unavailability during on-peak hours, and if that hydro facility, in fact, runs at 70 percent capacity factor during on-peak hours, they would be receiving more than the avoided cost.

Q So with hydro you said it could exceed avoided cost; with solar you said it does. Is it true that with solar it could, also?

A That's right. The way we did the calculations was using a typical solar profile.

Q So I just want to make clear, it does not mean

it always necessarily does, correct?

A I would agree with that.

Q Another line of questions. And I think I asked Mr. Trexler this and he said you would be the better person to answer this. Does Dominion have solar in its North Carolina rate base?

A Currently, there's no solar facilities in our rate base. There -- there are some solar facilities in development. There's been -- there was a program approved in Virginia called the SPP, Solar Participation Program. It's approximately 24 MW of solar facilities, rooftop solar facilities, that are going to be installed on university buildings, business rooftops, et cetera. But currently there is -- we have not a rate base.

Q But you will in fairly short order; is that what you're saying?

A That's -- that's the direction we're moving.

Q And is there any reason to believe that that solar that will be in North Carolina rate base has a different capacity factor than most solar QFs?

A It most likely will have a similar capacity factor, 18, 20 percent, something like that. It's the same -- my understanding is it's the same types of solar panels that -- that are used industry wide.

MR. YOUTH: Thank you. No further questions.

MS. MITCHELL: No questions.

COMMISSIONER BROWN-BLAND: No further cross examination?

(No response.)

COMMISSIONER BROWN-BLAND: Any redirect?

MS. KELLS: Yes, please.

REDIRECT EXAMINATION BY MS. KELLS:

Q Mr. Petrie, Mr. Youth asked you about the -- the language from the Order in the Sub 79 docket you just read.

A Yes.

Q I just want to make sure we're clear, we understand, you know, your explanation for that discussion. Do you have your direct testimony with you?

A Yes.

Q Could you turn to that, please?

A Okay. What page?

Q Page 13.

A Okay.

COMMISSIONER BROWN-BLAND: Ms. Kells, will you keep the mic close?

MS. KELLS: Oh. Yes, ma'am.

COMMISSIONER BROWN-BLAND: Thank you.

BY MS. KELLS:

Q Page 13, lines 1 through 4.

A Okay.

Q Would you read the sentence that starts there, please?

A Starting at 1 -- at 1?

Q Uh-huh. The word because.

A "Because of this misalignment, and considering that solar panels are not functionally equivalent to a dispatchable CT, basing the capacity rate for solar QFs on the full cost of a peaker, plus requiring a PAF of 2.0, would result in a solar QF being paid for capacity that is not avoided by the Company."

Q Mr. Petrie, would you explain what you mean by the misalignment?

A Yes. The graph that shows up on that -- in that direct testimony, it shows -- it overlays the solar profile for a typical solar generator during the month of July, so it's -- it's an hourly generation profile overlaid against what the -- what the system hourly loads would look like. The solar output reaches its peak around 1:00 in the afternoon, and then falls steadily from there by -- versus the utility system load, it rises continuously throughout the afternoon and reaches a peak around 4:00 or 5:00 in the afternoon. So by the time the utility system is reaching its peak at 5:00 p.m., the solar output is only, on average, between 20 and 40 percent of its nameplate capacity.

So what we're saying is that the solar facilities, from a capacity planning perspective, they're not -- they're only 38 percent effective -- as effective as a -- as a combustion turbine.

Q Would you also turn to page 14 of your direct, and please read starting on line 8, "As with solar..."

A "As with solar QFs, paying a wind QF, the full cost of the peaker, plus requiring a PAF of 2.0, would result in overpayment to the QF for the capacity that is actually avoided."

Q Thank you. So would you agree that paying a solar or wind QF, the full cost of a peaker, plus a PAF of 2.0, would result in payment in excess of avoided cost?

A Yes, based on typical output profiles from these types of resources.

Q Do you recall the conversation you just had with Mr. Youth regarding the new program in Virginia?

A Yes.

Q And you testified that that program has been

approved; that is correct?

A That's right. The Virginia Commission has approved it.

Q It is not currently a rate base, but the plan is for it to be included in the rate base?

A That's right.

Q Mr. Petrie, are -- does the definition of avoided cost under PURPA account for utility rate base?

A No. It's based on the incremental cost to the utility for capacity and energy but for the purchases from the QFs.

Q And what are the obligations of the utility as a regulated utility in terms of planning for capacity needs?

A We're obligated by law to meet our -- to meet our system peak load, plus reserve requirements.

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

COMMISSIONER BROWN-BLAND: All right. Does anyone have any questions of a confidential nature for cross examination for this witness?

(No response.)

COMMISSIONER BROWN-BLAND: All right. Then questions from the Commission.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q Mr. Petrie, I have one question, and this is just for our information. Are you of the opinion that the issue of an adequate PAF to be used for certain types of generation, including run-of-the-river hydro, should be addressed in further proceedings?

A It could be if -- if the Commissioners decide to dive more into the topic.

Q Do you think if we were -- if we're going to look at PAF, particularly for different types of generation, that that's something that should be addressed in its own proceeding?

A I'm sorry. I didn't understand.

Q If we were going to look at PAFs based on different types of sources, generation sources, is that something that we should take up in a separate proceeding?

A Yes. I think I covered that in my testimony here somewhere, that said if the -- sorry. In my testimony on page 11, "If the Commission determines that a reexamination of its current PAF policy is needed, such an inquiry should include all QFs, including run-of-river and hydro QFs." So...

Q And I guess I'm trying to find out if the Company -- if you or the Company have a particular

opinion about that or whether we don't even need to take that up, I mean, if you know or if you have an opinion.

A Yeah. I -- I don't believe we have an opinion about whether we should dive into that -- dive into that topic.

Q All right.

COMMISSIONER BROWN-BLAND: Okay. Questions on Commission's questions?

(No response.)

COMMISSIONER BROWN-BLAND: All right. If there's no further questions, then this witness may step down.

(Witness excused.)

COMMISSIONER BROWN-BLAND: Mr. Youth, would you move your --

MR. YOUTH: Yes. Thank you, Commissioner Brown-Bland. May I move NCSEA Petrie Cross Exhibit Number 1 into evidence?

COMMISSIONER BROWN-BLAND: If there's no objection, that will be received.

(Whereupon, NCSEA Petrie Cross Examination Exhibit Number 1 was admitted into evidence.)

COMMISSIONER BROWN-BLAND: Are there further witnesses from Dominion?

MS. KELLS: That's all of our direct.

COMMISSIONER BROWN-BLAND: So Dominion is complete. So the case is moving over to the other side. Mr. Youth, are you ready with your -- are you next?

MR. YOUTH: I believe, Commissioner Brown-Bland, that Dr. Reading has an earlier flight to try to catch, so I think we've agreed that he would go up first.

COMMISSIONER BROWN-BLAND: All right. Call your witness.

MS. MITCHELL: The Renewable Energy Group calls Dr. Don Reading to the stand.

DON C. READING, PH.D.: Being first duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MS. MITCHELL:

Q Dr. Reading, would you please state your name, position, and business address for the record?

A Don C. Reading, R-E-A-D-I-N-G, Ben Johnson Associates. I'm Vice President and consulting economist. And my business address is 6070 Hill Road, Boise, Idaho.

Q And on whose behalf are you testifying today?

A REG.

Q Did you cause to be prefiled in this docket on September 27th testimony consisting of 37 pages in

question and answer format?

A Yes.

Q Do you have any additions or corrections to that prefiled testimony?

A Not at this time.

Q And if I were to ask you the same questions today as stated in the prefiled testimony, would your answers be the same as stated in your prefiled testimony?

A Yes, they would.

Q Do you have a summary of your testimony you'd like to provide?

A Yes, I do.

Q Please do so.

A Okay. My name is Don C. Reading. My business address is 6070 Hill Road, Boise, Idaho, 83703. I am a consulting economist and Vice President of Ben Johnson Associates, Inc. Ben Johnson Associates, Inc. has been retained by Renewable Energy Group, REG, to examine the filings of Duke, Progress and Dominion in Docket E-100, Sub 136.

In general, my testimony discusses the installed capacity estimates of Duke, Progress and Dominion, which form the basis of capacity credits of the avoided cost rates and makes recommendations related to establishing rates that reflect the utilities' full avoided costs. In addition, my testimony discusses the Commission's tradition of approving the use of a performance adjustment factor in the calculation of avoided cost rates and recommending an increased PAF for wind and solar to 2.0.

In the last eight avoided cost hearings, the Commission ordered that the PAF of 2.0 be utilized by both Progress and Duke in their respective avoided cost calculations for certain hydro facilities. The Commission also has ordered PAF 1.2 to be used by both Progress and Duke for all QFs that do not qualify for a PAF of 2. The Commission has explained that the use of higher PAF for these hydro facilities does not exceed avoided costs; it simply changes the method by which the avoided costs are paid to the QF. In recognition of the fact that certain QFs can't control their energy source, a PAF is intended to allow such QFs to receive full capacity payment to which they are entitled.

At the conclusion of the 2006 proceeding, Public Staff recommended that solar and wind receive a PAF of 2 based on variable nature of these resources. Public Staff correctly pointed out once the SB 3 rules are in effect and that the REPS market is in operation, the market for renewable energy in North Carolina will change dramatically, and in future cases, issues relating to PAF will be presented in an entirely new context. Ultimately, the Commission upheld that the issue should be further addressed in subsequent -- excuse me -- proceedings and assessing the impact of SB 3. As forecasted by the Public Staff, the time is ripe in this proceeding for the Commission to revisit applying a 2.0 PAF to solar and wind. Several factors justify this change.

First, it remains the case that solar and wind, like run-of-river hydro facilities, have no control over their energy sources. This creates a significant disadvantage for these since none of the utilities pay capacity credits in the off-peak hours. QFs that rely on variable resources such as wind and solar will receive only energy credit of avoided cost rate for power produced in the on -- only receive credit for avoided cost rate for power produced in the off-peak hours.

Utilities, on the other hand, recover full capacity costs regardless of whether their facilities produce power. By way of illustration, the capacity cost of a peaker that sits idle 90 percent of the year is fully recovered in the utility's rate base.

Additionally, wholesale power contracts typically include a capacity charge that is calculated on a per KW basis and is payable regardless of the number of kWhs the seller provides. Similarly situated QFs are penalized under the avoided cost calculation with a 1.2 PAF because they are not paid capacity unless they are producing 83 percent of the time on-peak hours.

Second, since the 2006 proceeding, Duke has added solar generation to its fleet. To the extent solar capacity additions were made by the utilities, the utilities end up recovering full cost for these facilities regardless of the fact that they have similar capacity factors as solar QFs.

Third, Senate Bill 3 has been in effect for five years. As the Commission previously stated, Senate Bill 3 is a clear expression of the state policy to encourage renewable energy.

For these reasons, it is appropriate, and with the Commission's authority, to apply a 2.0 PAF for rates available to solar and wind QFs, as well as run-of-the-river hydro QFs.

That is the end of my summary.

MS. MITCHELL: The witness is available for cross.

COMMISSIONER BROWN-BLAND: Ms. Mitchell, I think we need get his direct testimony in the record.

MS. MITCHELL: At this time, I'd like for the direct testimony of Dr. Don Reading to be moved into evidence.

COMMISSIONER BROWN-BLAND: All right. Without objection, that testimony will be received into the record as if given orally from the stand. It consists of 36 pages, was filed on September 27th, 2013. And I note that there is confidential version and a public version. This testimony confidential version shall remain confidential.

(Whereupon, the public version of the prefiled direct testimony of Don C. Reading, Ph.D. was copied into the record as if given orally from the stand. The confidential version was filed under seal.)

Q. Would you please state your name and address?

A. Don C. Reading, 6070 Hill Road, Boise, Idaho, 83703.

Q. Can you please briefly discuss your occupation, education and experience?

A. I am a consulting economist and Vice President of Ben Johnson Associates, Inc. I hold a PhD in economics from Utah State University, an MS in Economics from the University of Oregon, and a BS in Economics from Utah State University. I taught Economics at Middle Tennessee State University, Idaho State University, and the University of Hawaii at Hilo. I have worked in the area of utility regulation as Staff Director for the Idaho Public Utilities Commission, and as a private consultant for more than 30 years. My resume is attached.

My work has spanned a wide range of different subject areas, involving the application of economic theory and principles to public policy issues involving the electric, gas, water, wastewater, and telecommunications industries. My interest in the electric utility industry began in the late 1970s and early 1980s, leading me to work for the Idaho Public Utilities Commission, where I served as an Economist and Director of Policy and Administration.

I have provided expert testimony in proceedings in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Nevada, North Carolina, North Dakota, Texas, Utah, Wyoming, and Washington.

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I have prepared econometric forecasts for the Southeast Idaho Council of Governments and for the Revenue Projection Committee of the Idaho State Legislature. I have been a member of several Northwest Power Planning Council Statistical Advisory Committees. I was the vice chairman of the Governor's Economic Research Council in Idaho and have performed research projects for the Idaho Governor's Office.

While most of my work with Ben Johnson Associates, Inc. has been concentrated in the Pacific Northwest, I have participated in the following proceedings before the North Carolina Utilities Commission: i) Docket No. E-2, Sub 537, the 1986 CP&L rate case in which I assisted Public Staff with reviewing the prudence of the Shearon Harris nuclear plant; ii) Docket No. E-100, Sub 58, the 1988 proceeding concerning avoided costs; iii) Docket No. E-100, Sub 75, the 1995 proceeding concerning Integrated Resource Planning; and iv) Docket No. E-2, Sub 760, the 2000 proceeding in which CP&L Holdings, Inc. requested permission to acquire Florida Progress Corporation. I also provided testimony on behalf of EPCOR USA North Carolina LLC in Docket Nos. E-100, Sub 124, involving integrated resource planning, and E-2, Sub 966, involving the calculation of avoided cost.

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

A. Ben Johnson Associates, Inc. has been retained by the Renewable Energy Group ("REG") to examine the filings of Duke Energy Carolinas, LLC ("DEC" or "Duke"), Duke Energy Progress, Inc. ("DEP" or "Progress"), and

Dominion North Carolina Power ("DPNC" or "Dominion") (collectively, the "Utilities") in Docket No. E-100, Sub 136 related to the Utilities' calculation of their respective avoided costs. My testimony presents the results of my analysis and my recommendations to the Commission.

Q. What documents have you reviewed as part of your analysis?

A. I have reviewed the initial filings of DEC, DEP, and DNCP, along with the data request responses of the parties involved in this Docket, as well as the following:

a. Filings made in Docket No. E-100, Sub 137.
b. Filings made in Docket No. E-100, Sub 127.
c. Filings made Docket No. E-100, Sub 128.
d. <u>Cost Report: Cost and Performance Data for Power Generation Facilities</u>, prepared by Black & Veatch, February 2012 (the "Black & Veatch Report").
e. Responses to data requests provided by the Utilities.
f. Annual Reports and FERC Form 1s filed by the Utilities.

Q. Can you summarize your recommendations?

A. In short, the Utilities, in calculating avoided cost rates, have understated the capital cost component of the rates. As such, the rates proposed by the Utilities reflect less than the "full avoided costs" to which QFs are entitled under federal law. Based on my review of the aforementioned materials, I recommend that the Commission require the Utilities to recalculate their avoided cost rates as set forth below.

Q. Please explain how avoided cost rates are calculated.

A. Historically in North Carolina, as relates to DEC and DEP, avoided cost rates have been established using the "peaker" methodology. This methodology assumes that the QF output displaces the marginal, or most expensive, generation source on the utility's system; therefore, the peaker method assumes that the utility's long term avoided cost equals its system marginal cost of energy plus the fixed cost of a peaking unit. A natural-gas fired combustion turbine ("CT") is the peaking unit used to calculate avoided costs in North Carolina.

The avoided cost rate consists of an energy credit and a capacity credit. The energy credit is based on a utility system's marginal energy cost and is calculated using a production cost simulation model. The primary input to the model is fuel price forecast, including natural gas. The capacity credit is based on the "installed cost" of a CT, which is reported in dollars per kilowatt ($/kW) and includes, but is not limited to, costs such as plant equipment and installation, owner's contingency, engineering and project management, operation and maintenance expenses, taxes, summer and winter ratings, property acquisition, gas pipeline costs, and electric transmission costs.

Q. In general, what are your observations of the avoided cost rates proposed by the Utilities in this proceeding?

A. There has been a significant decline in both the avoided capacity rates and the avoided energy rates proposed by DEC and DEP. Specifically, DEC's proposed annualized avoided energy rate is 7% lower, and annualized avoided capacity rate is 29% lower than those approved by the Commission in Docket E-100, Sub 127. DEP's proposed annualized avoided energy rate is 20% lower, and the annualized avoided capacity rate is 25% lower than those approved in Docket E-100, Sub 127.

As displayed below in my Figure 1 (annualized avoided energy rates of DEC and DEP) and my Figure 2 (annualized avoided capacity rates of DEC-Option A and DEP), the dramatic decreases proposed by both DEC and DEP has reversed a general 25-year upward trend in the avoided cost rates. As this is the first proceeding in which DNCP has used the peaker methodology to propose avoided cost rates, there is not a comparable history for DNCP, though, notably, DNCP's avoided capacity rate is significantly higher than those proposed by DEC and DEP.

Figure 1

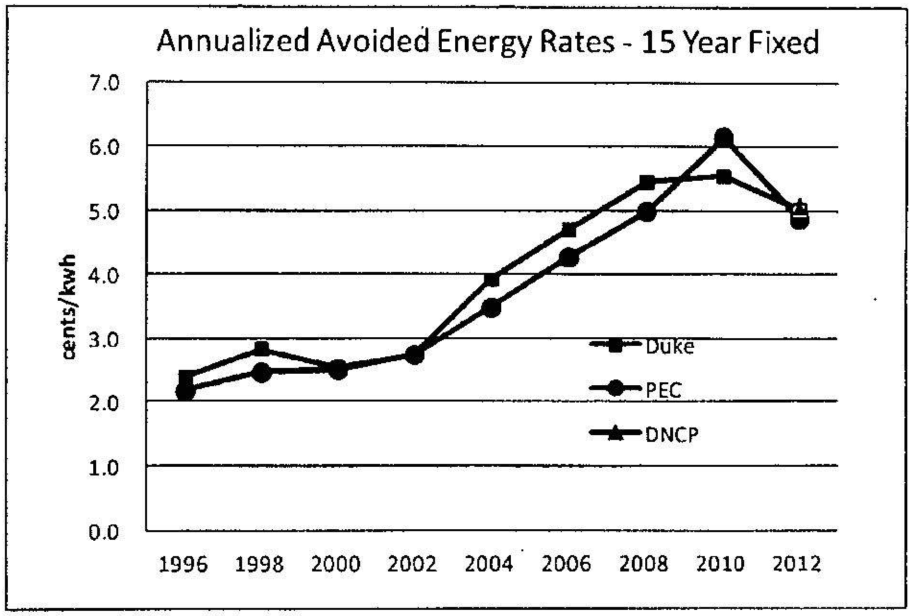
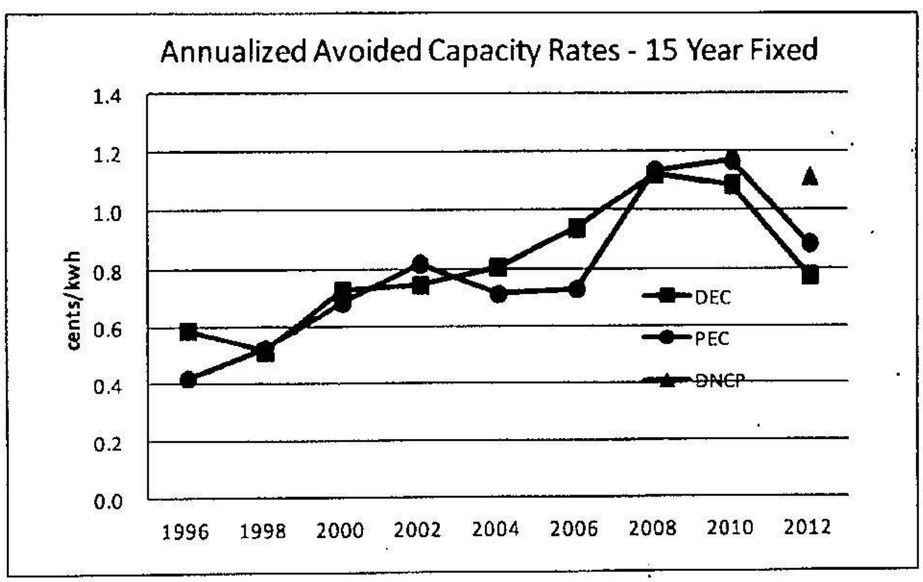


Figure 2



As indicated by Figure 1, DNCP, DEP, and DEC have proposed essentially the same annualized avoided energy rates in this proceeding.

However, notwithstanding that fact, DNCP's avoided cost rate filed this year for the first time using the peaker methodology is closer to the rates previously approved by the Commission for DEP and DEC in Docket No. E-100, Sub 127 as opposed to those proposed by DEP and DEC in this proceeding.

Q. How do you respond to DEC/DEP's contention that the magnitude of the decrease in proposed avoided cost rates should be expected?

A. In his testimony, DEC/DEP witness Snider suggests that biennial increases in avoided cost rates of more than 20% occurred between 2004 and 2006 and again between 2006 and 2008. Mr. Snider contends that these increases were accepted as "market driven," due primarily to increases in CT construction costs, as well as increases in natural gas prices. Mr. Snider contends that a "decrease of the same magnitude should be equally acceptable and to a large degree expected." [Direct Testimony of Glen Snider, DEC and DEP, p. 10]

Mr. Snider's testimony includes a table showing the "all-in rate" in DEP's biennial avoided cost proceedings, which indicates a steady increase from the 2002 through 2010 proceedings and then a drop of 21.4% in the instant proceeding. I agree that natural gas prices are notoriously volatile and am not taking the position that the avoided energy rates proposed in this proceeding are unreasonable. However, for the reasons discussed herein, the avoided capacity rates proposed by DEP and DEC, and to a lesser extent

DNCP, are unreasonable and understate the Utilities full avoided costs. I will address the proposed avoided capacity cost rates of each of the Utilities separately.

Q. What are your observations regarding DEC's proposed avoided cost rates?

A. DEC indicates that the primary drivers causing the decrease in its avoided cost rates are:

1) Lower natural gas price forecast;

2) Higher assumed ratings for the CT without a significant increase in the total cost of the CT; and

3) Increase in the useful life of the CT from [redacted] to [redacted] years.

As I previously testified, given the current historically low natural gas prices, a decrease in the rates associated with the energy credit of the avoided cost rates is expected. However, the nearly 30% drop in avoided capacity rates from just two years ago is not justified.

Each of the Utilities filed with the Commission a biennial 2012 Integrated Resource Plan ("IRP") in Docket No. E-100, Sub 137. The IRP is used by the Utilities in the development of the future resource strategy to meet expected loads. The cost of future generation plant stated in the IRP defines the long-run avoided cost of the utility at the time the IRP is filed at the Commission. The filing of the IRPs by the Utilities preceded the filing of their proposed avoided cost rates by just two months. Therefore, the input assumptions used in this proceeding should match those used in the IRPs filed just two months earlier. However, that is not the case. The CT costs used by DEC (and DEP, as discussed below) in the IRPs are significantly higher than those used in this proceeding to determine avoided cost. The installed cost of a CT as proposed by DEC has dropped dramatically in the last few avoided cost proceedings while, in contrast, it has increased in DEC's IRP proceedings. The table below, provided by DEC in response to a data request from Public Staff, depicts this contrast.

[redacted]

[PS DR DEC 3-1] DEC informed the parties to this proceeding that the CT cost reported in the 2012 IRP proceeding includes a [redacted]. Correcting for [redacted] results in a value of [redacted] per kW. The table shows that since 2008, the CT cost per kW as proposed by DEC has decreased by approximately [redacted] in the avoided cost proceeding while, over that same period, has increased by approximately [redacted] in the IRP proceeding.

In calculating the avoided cost rates proposed in this proceeding, DEC used the following input assumptions in calculating the avoided capacity rate:

1) Installed Cost of CT $/kW: [redacted] [PS DR – DEC 1-2D & 2E]
2) Contingency: [redacted] [PS DR – DEC 1-2D & 2E]
3) Useful life: [redacted] years [PS DR – DEC 2(a) FCR Model]

I will address why each of these assumptions is understated.

Q. Why is the decrease in DEC's installed cost of a CT not justified?

A. The following table, provided by DEC in response to a data request from Public Staff, illustrates the difference between the installed cost of a CT, broken down into cost components, as reported in the IRP and the installed cost as reported in this proceeding.

[redacted]

[PS DR DEC 1-2D &2E]

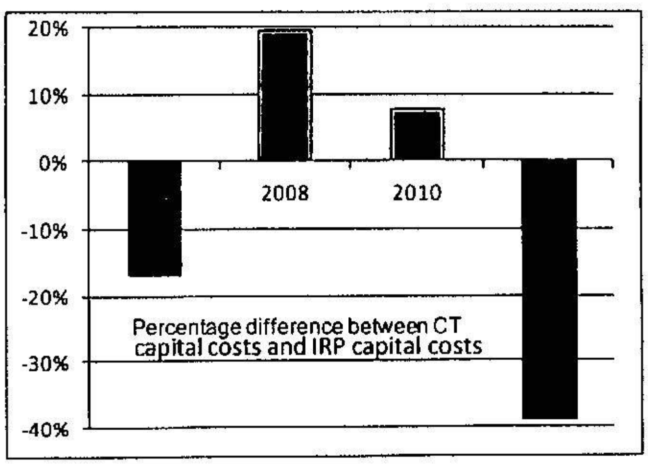
As shown in the table above, the $/kW total project cost (i.e., installed cost) used in DEC's 2010 avoided cost filing was [redacted] per kW, and, in the 2012 avoided cost filing, it dropped by 30% to [redacted] per kW. In DEC's 2012 IRP, the total project cost increased to [redacted] per kW (corrected) from the total project cost used for avoided cost calculations in 2010. In justifying the decrease in installed cost in this case, DEC stated:

[redacted]

According to DEC, [redacted]

Interesting to note in the DEC table above is that the two years when the IRP capital cost was less than that used by DEC to calculate avoided cost rates, capital cost did not include AFUDC (2008 and 2009). Note also the percentage differences between DEC's avoided cost estimates and IRP capital cost estimates, reflected on my Figure 3 below. In this proceeding, the avoided cost estimate is 24% lower than the corresponding (corrected) IRP value, which is twice the percentage difference than the other three years.

Figure 3



Finally, the [redacted] per kW installed cost used by DEC in calculating capacity cost in this proceeding is at odds with the capital costs indicated in other third party evaluations for the utility. For example, Duke Energy

Carolinas 2012 Generation Reserve Margin Study ("DEC Reserve Margin Study") prepared by Astrape Consulting produced an installed cost of CT of [redacted] per kW in 2016 dollars, adjusted to 2013 dollars at [redacted] per kW, or an amount 44% higher than that used by DEC in its calculations of proposed avoided cost rates in this Docket.

DEC's IRP uses a (corrected) installed cost of [redacted] per kW while the 2012 DEC Reserve Margin Study, which is filed as a component of the IRP, uses an installed cost of [redacted] per kW. Both the IRP and the margin reserve study entail forward looking analyses that are currently under review by the Commission and that are being relied upon in making future capacity additions. In the interest of consistency with my recommendation below related to DEP, the Commission could direct DEC to recalculate its avoided cost rates using the mid-point of the range of estimates provided in the IRP and the margin reserve study, which is [redacted] per kW. However, an installed CT cost of [redacted] per kW, based on my review of the data and information presented in this docket, is a reasonable estimate of installed CT cost and basis for avoided capacity calculation.

Q. **Do you have concerns regarding the reduced contingency used by DEC?**

A. The contingency component of the installed cost of the CT reflects the anticipated value of unforeseen cost categories that may fall outside of the original scope of the project. Both DEP and DEC, for this filing, have reduced the contingency to [redacted], [PS DR DEC 2] which is a reduction in the value used by DEC in the 2010 avoided cost proceeding. [PS DR DEC 1-2D, 2E] As I pointed out previously, the reduction in contingency has a significant impact on the installed cost values and, hence, lowers the avoided capacity rates proposed by the two utilities. Specifically, DEC states that its 2012 IRP value, [redacted] per kW, [redacted], highlights the significance of the impact of contingency on installed cost. DEC reports IRP value with the reduced contingency as [redacted] per kW, a [redacted] per kW decrease.

DEC justifies the decrease in the contingency component of the installed cost of a CT from that used in 2010 as follows:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

I have concerns with DEC's stated justifications for the reduction in contingency. First, the economic conditions of the 2008 downturn created uncertainty regarding future resource costs. However, today's economy is also fraught with significant uncertainty. The Dow Jones Industrial Average ("DJIA") has been hovering around 15,000 on a consistent basis this year, and, assuming the recovery continues, recovery will impose upward pressure on commodity prices and the cost of manufactured goods. Congress and the President have still not been able to put together a plan to solve our current fiscal crisis. In an increasingly global economy, Europe's challenges and China's challenges and the way these challenges are managed will impact economic conditions in the United States. Moreover, the rapid development of shale gas in the United States is changing the power generation market, and, likely, our energy future. Gas Turbine World's 2012 GTW Handbook reports that, during 2012, "the level of new gas turbine orders is expected to firm up and reflect an increase in price level of about 5-7%, compared with 2011 prices" and, therefore, is forecasting "a continued rise in prices for new orders during 2012 which should persist through 2014." 2012 GTW Handbook, p. 34. Today's economic conditions and the unknowns surrounding our energy future simply do not justify reducing contingency.

Second, one of the studies commissioned to provide an evaluation of installed CT cost, Evaluation of Installed Costs, Operating and Maintenance Costs and Performance for Simple-Cycle and Combined-Cycle Facilities, prepared by Sargent & Lundy, reported a contingency of [redacted] on the total cost estimate. [PS DR DEC 3-1, p. 2]

Third, DEC cites recent experience gained from construction as a reason for reducing its contingency component. However, as detailed in the Black & Veatch Report for non-site specific (i.e., generic) design projects, it is not unreasonable to have contingencies for CT construction projects in the 20 to 30% range:

> There are industry guidelines for different classes of estimate that provide levels of contingency to be applied for the particular class. A final estimate suitable for bidding would have lots of detail identified and would include a 5 to 10% project contingency. A complete process design might have less detail defined and include a 10 to 15% contingency. The lowest level of conceptual estimate might be based on a total plant performance estimate with some site -specific conditions and it might include a 20 to 30% contingency. Contingency is meant to cover both items not estimated and errors in the estimate as well as variability dealing with site -specific differences. [Black & Veatch Report, p. 8]

Additionally, DEC reports that the contingency incorporated into the cost for CTs in the 2012 IRP was approximately [redacted] of pre-contingency cost or [redacted] of total project cost. [PS DR DEC 2-5] DEP/DEC witness Snider testifies that, in its 2012 IRP, "DEC assumed a contingency adder of approximately [redacted]." [Direct Testimony of G. Snider, DEC and DEP, p. 16]

For these reasons, I believe the contingency of [redacted], which was used by DEC in calculating its installed cost of a CT of [redacted] per kW, is significantly understated.

Q. Do you have concerns regarding the useful life assumption used by DEC?

A. Yes. The useful life of a CT is the projected period of time, in years, that the CT will be in operation, assuming routine maintenance and operation. In the context of this proceeding, the useful life is used in calculating the installed cost of the CT. Although DEC has historically used a useful life of [redacted] years, the company has increased its useful life assumption in this proceeding to [redacted] years. In the past, DEC has used [redacted] years as a [redacted] [PS DR DEC 4-6] Notably, the 2012 DEC Margin Reserve Study used [redacted] years for useful life. [PS DR DEC 3-6] DEC's increase in useful life in this proceeding was a significant driver in the reduction of the installed cost of the CT.

An examination of the emails exchanged between DEC and DEP indicates that [redacted]. Also obvious from the emails [redacted].

Email of October 18, 2012 3:34 [redacted]

[redacted]

Email of October 19, 2012 [redacted]

[redacted]

Email of October 24, 2012 [redacted]

[redacted]

It appears that DEC's decision to extend the useful life of the CT to [redacted] years for the purpose of the avoided cost calculation was arbitrary and not based on any independent study or verification of the useful life of a CT. Moreover, DEC's fixed asset group admitted that it had "no backup" for useful life.

Moreover, this [redacted] year increase in useful life was not accompanied by any increase in variable operation and maintenance costs, even though it is likely that running a unit five years longer would increase the cost to operate and maintain it. [REG DR DEC 2-2]

Finally, I want to point out that DNCP used a useful life assumption of [redacted] years, which is [redacted], yet DNCP's proposed installed CT cost estimate is [redacted] per kW in 2016, which is [redacted] per kW when adjusted to 2013 dollars. This, also casts doubt on the reasonableness of DEC's and DEP's other input assumptions.

Given the evidence presented in this proceeding by DEC and DEP to support the proposed changes in useful life, there is no compelling reason to extend the useful life for DEC beyond [redacted] years.

Q. **What is your opinion regarding DEC's use of economies of scale for a four unit site in this proceeding?**

A. Economies of scale were not included in DEC's estimate of a four-unit CT site in the 2010 avoided cost proceeding. [PS DR DEC 4-14] Prior to 2010, DEC reports that the estimate of a four-unit CT cost would be estimated using available industry data, and DEC's estimate based on these sources would reflect economies of scale only if utilized by the source. [PS DR DEC 4-15] When asked why the company did not include the same economies of scale in the 2010 proceeding, DEC reported that "the Company felt that it was a better decision to utilize a more conservative estimate of a 3 unit CT site that was documented in [the Duke Energy commissioned] study, rather than estimate the savings of a 4-unit site." [PS DR DEC 4-14] In this proceeding, however, DEC has estimated the savings of a four unit site. As DEC has explained, it relied on the CT cost estimates from third party studies – EIA, GTW, Brattle, EPRI – to inform its own cost estimates. DEC [redacted]

In calculating a multiplier used [redacted] DEC reports that [redacted] DEC also reports that, [redacted]

First, I have concerns with the use of this type of adjustment to "normalize" data, as it is arbitrary and not based on site or specific design criteria for what would eventually occur at a four unit site. Second, I have concerns with DEC's increasing the size of a facility for the purpose of determining economies of scale. DEC's IRP indicates the next CT capacity addition is [redacted] of CT capacity in 2019. [REG DR DEC 1-1] In my experience, absent very unusual circumstances such as mass plant retirement, a utility would not add [redacted] of CT capacity at one time. Therefore, I suspect that it is unlikely that [redacted] CT capacity will be added in 2019. However, even if unusual circumstances lead to the addition of [redacted] of CT capacity in 2019, such an addition would not reflect normal load growth. In fact, DEC's 2012 IRP [redacted]. [REG DR DEC 1-1] As PURPA requires that the future need for capacity be used for avoided cost purposes, the use of economies of scale that do not accurately reflect DEC's future need for capacity is inappropriate.

Q. Please summarize your recommendation as to DEC.

A. For the reasons discussed above, and in light of the fact that input assumptions used by DEC in calculating its installed cost of a CT were understated, I recommend that the Commission direct DEC to recalculate rates based on an installed cost of a CT of [redacted] per kW.

Q. What are your observations of DEP's proposed avoided cost rates?

A. In short, like DEC, DEP has understated its installed cost of a CT. In the calculation of the avoided cost rates filed in this proceeding, DEP used the following input assumptions:

1) Installed Cost $/kW: [redacted] [PS DR DEP 1]

2) Contingency: [redacted]

3) Useful Life: [redacted] years [PS DR DEP 1]

The installed cost of a CT used by DEP in calculating avoided capacity rates—[redacted] per kW—is 6% lower than that used by DEC in this proceeding and 15% lower than that used by DEP in the 2010 avoided cost proceeding. [PS DR DEP 2-3] However, DEP's 2012 IRP—filed just two months before DEP's proposed avoided costs rates were filed in this docket—forecast that there would be no change in DEP's avoided cost rates through 2014, as depicted in the table below. [Progress Energy Carolina's, Inc.'s 2012 Integrated Resource Plan, Filed September 4, 2012, Appendix D-7, VII]

Table 7: Annualized Capacity and Energy Rates (cents per KWh)

	2012 (Current)	2013 (Projected)	2014 (Projected)
Variable Rate	5.786¢	5.786¢	5.786¢
5 Year	6.184¢	6.184¢	6.184¢
10 Year	6.816¢	6.816¢	6.816¢
15 Year	7.286¢	7.286¢	7.286¢

In stark contrast to the representation in the IRP, the avoided capacity rates proposed by DEP in this proceeding are 22% to 27% lower than the current avoided capacity rates and avoided energy rates are 15% to 29% lower. [PS DR DEP 1-1, Attach. 1] For reasons that I will discuss, my recommendation is that the Commission direct DEP to recalculate avoided cost rates based on an installed cost of [redacted] per kw.

Q. Do you have concerns regarding the difference in installed CT costs used by DEP in its 2012 IRP and those used in this proceeding?

A. Yes. While the Progress Energy Carolina's 2012 Generation Reserve Margin Study prepared by Astrape Consulting (the "DEP Reserve Margin Study") does not include an installed cost CT on a $/kW basis, the study does provide the following for a generic CT: economic carrying charge and fixed operation and maintenance costs of [redacted] per kW-yr for the first unit, [redacted] per kW-yr for the next unit, and [redacted] per kW-yr for the combined (using a 25%/75% ratio for first/next unit). [REG DR DEP 2-4] Using the inputs supplied by DEP, the DEP Reserve Margin Study provides a $/kW value that, when adjusted to 2013 dollars, is [redacted] per kW.

As an additional point of reference, DEP's 2012 IRP indicates that the next CT slated for construction is "undesignated" capacity to be on-line in December 2016. REG asked DEP to indicate the type of CT and the cost, for this "undesignated" CT capacity. REG data request 1-5(A) to DEP and DEP's response to that data request are as follows:

> DATA REQUEST:
>
> For purposes of the following questions, with respect to proposed avoided capacity credit rates filed by Progress Energy Carolinas, Inc. ("PEC" or the "Company") in Docket No. E-100, Sub 136:
>
> On page 25 of the Company's Public Version of its 2012 Integrated Resource Plan filed in Docket No. E-100, Sub 137, the Table lists an undesignated 126 MW CT with an in-service date of 12/16. Please provide

> support for the expected installed cost. The response should include the anticipated heat rate (for both summer and winter) and start costs. Please indicate if the estimated installed costs include land and interconnection costs.
>
> RESPONSE:
>
> The undesignated 126 MW resource in December 2016 is fast start combustion turbine capacity that is needed to provide operating reserves for the PEC generation system. This capacity is a different technology than the CT used in the peaker methodology to develop avoided cost rates. Thus, the installed cost for this resource has no impact on the Company's avoided capacity cost. [REG DR DEP 1-5(A)]

This 126 MW resource consists [redacted]. In data accompanying the above response, the installed cost of these [redacted] CTs is [redacted] per kW. While I am not advocating the use of DEP's proposed next CT unit to calculate avoided capacity cost rates, I have presented this information to show the CT cost DEP will actually incur versus the much lower CT cost proposed in this proceeding.

Q. Do you have concerns regarding the contingency and useful life assumptions used by DEP in this proceeding?

A. Yes. With respect to contingency, like DEC, DEP uses a contingency of [redacted] [PS DR DEP 2, p. 7] For the same reasons I provided with respect to DEC, this contingency is unsupported by evidence, and [redacted] is an understated contingency.

With respect to useful life, DEP has increased the useful life from [redacted] years, which the company has historically used in the avoided cost proceeding, to [redacted] years. This ten year increase in useful life—which is a 40% increase—was not accompanied by any increase in variable operation and maintenance costs, even though it is likely that running a unit ten years longer would increase the cost to operate and maintain it. [REG DR DEP 2-2] Although DEP has indicated that this change was motivated, in part, by experience with the most recently retired CTs, DEP provides no additional explanation regarding the operating parameters of these CTs, such that it is impossible to determine the extent to which these CTs were operated. Moreover, a [redacted] year useful life was assumed in the 2012 DEP Reserve Margin Study. [PS DR DEP 3-6] For these reasons, I believe DEP has not adequately supported its proposed increase in useful life by ten years or the resulting decrease in the installed cost of a CT.

Q. What is your recommendation on the appropriate installed cost of a CT for DEP?

A. DEP's IRP uses an installed cost of [redacted] per kW while the 2012 DEP Reserve Margin Study, which is filed as a component of the IRP, uses an installed cost of [redacted] per kW. Both the IRP and the margin reserve study entail forward looking analyses that are currently under review by the Commission and that are being relied upon in making future capacity additions. Given the range presented by these two estimates, my recommendation is that the Commission direct DEP to recalculate its avoided cost rates using the mid-point of the range, which produces an installed CT cost of [redacted] per kW.

Q. Do you have concerns regarding DEP's position on economies of scale in calculating installed cost of a CT?

A. Yes. DEP takes the position that, [redacted] I believe that this overstates economies of scale and, further, that the installed cost should be calculated using the cost to construct a single CT.

DEP's assumed number of units—four—and the associated [redacted] MW capacity addition are not justified as they do not reflect DEP's future investment expectations. While DEP's resource planning indicates the addition of multiple CT units over a 15-year planning horizon, the planned additions are at a much smaller capacity than assumed by DEP in its avoided cost calculation. Specifically, as set forth in its 2012 IRP, DEP plans an addition of [redacted] of CT capacity in 2016. Following that, DEP projects [redacted] of CT capacity in 2018. Then, [redacted]

[redacted] unit in 2019, and then [redacted] in each of the years 2026, 2027 and 2028. [REG DR DEP 1-1] By contrast, DEP's avoided cost calculation assumes four [redacted] units, for a total of [redacted] of capacity. This assumption does not align with DEP's forward-looking incremental peaking capacity needs in terms of numbers of units and amount of capacity.

DEP has not explained how its forward-looking resource needs justify the assumed total of addition of [redacted] (four [redacted]) of CT capacity. However, because DEP started with the position—in this docket—that a single CT of [redacted] MW represents a cost effective long-term peaking resource addition, this [redacted] MW of capacity is the appropriate basis for the total capacity that should be considered in calculating avoided cost rates.

Finally, DEP has not included transmission upgrades in its avoided cost calculations. [PS DR DEP 3-3(c)] Transmission upgrade costs in the amount of [redacted] million were included, however, in the 2012 DEP Reserve Margin Study [PS DR DEP 3-4] and DEP acknowledges that installing new CT capacity will typically involve some level of transmission system upgrade. [PS DR DEP 3-3(b)] It is reasonable to assume that if [redacted] MW of capacity were added to DEP's system, transmission upgrades would be required. DEP should not be allowed to use economies of scale generated by the addition of [redacted] MW while at the same time allowed to ignore any costs that this large capacity addition would impose on its system.

Q. Do you have additional concerns regarding input assumptions used by DEP in calculating its avoided capacity rates that you would like to bring to the Commission's attention?

A. Yes. To rebut the suggestion that DEC/DEP made deliberate changes in avoided cost calculations in order to lower their avoided cost rates, DEC/DEP witness Snider points out that DEP could have use its currently approved return on equity ("ROE") of 10.2% in calculating installed CT cost, rather than its previously approved ROE of 12.75%. Based on my calculations, assuming all other inputs remain the same and the ROE is reduced to 10.2%, DEP's avoided cost rates would decline below those proposed by an additional 14.5% to 15.0%.

The additional decrease in the avoided capacity cost rates skews DEP significantly from the rates proposed by DEC and DNCP, both of which used fairly recently approved ROEs, indicating that there is a misalignment of other inputs in DEP's avoided cost calculations. Put another way, the effect that decreasing ROE has on the avoided cost rates casts doubt on the reasonableness of the remaining input assumptions used by DEP to calculate its avoided cost rates.

Q. What are your observations of DNCP's proposed avoided cost rates?

A. DNCP's estimate of the installed cost of a CT is the highest estimate of the three Utilities. [PS DR DNCP 1-2d] And, in contrast to DEC and DEP, the CT costs used by DNCP in this proceeding are the same as those used in its

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2012 IRP. However, I still believe this estimate of installed cost of a CT value is understated.

Q. Please explain your concerns with DNCP's installed cost estimate.

A. When asked to provide overall installed cost per kW for a CT located at a greenfield site, DNCP responded:

[redacted]

However, the installed cost of a CT would be higher if financing costs and AFUDC were included, as would be proper in determining the installed cost of a CT. Financing costs and AFUDC are typically included in CT cost estimates. For example, the Brattle Group Report includes the financing fees paid to secure debt as a component of installed cost. [Brattle Group Report, p. 28] In addition, the Brattle Group Report includes interest during construction as a component of installed cost. [Brattle Group Report, p. 41]

In addition, DNCP proposed that land not be included as a cost component. This is inconsistent with the studies performed by third parties in estimating total cost to construct a CT. For example, the Brattle Group includes the cost of land in its estimate. [Brattle Group Report, p. 21] The Commission has historically required land to be included, and both DEC and DEP include land in their cost estimates. DNCP's calculation of installed cost of a CT with land included resulted in [redacted] per kW in 2016 dollars. [PS DR DNCP 2-1] Adjusted to 2013 dollars, this value is [redacted] per kW.

Therefore, I recommend that the Commission direct DNCP to recalculate its avoided cost rates using an installed cost of a CT estimate of [redacted] per kW.

Q. Please summarize your concerns and recommendations regarding capacity costs.

A. As I have testified, DEP and DEC have examined a wide range of estimated cost components in determining the installed cost of a CT for the purposes of calculating avoided cost rate. However, they have consistently selected from the bottom of the range of estimated costs, which result in significant decreases from currently approved avoided cost rates. Both DEP and DEC indicated significantly higher installed CT costs in their respective IRPs and reserve margin studies, which are used by the Commission and the utilities to ensure DEC and DEP have resources sufficient to provide adequate, reliable service and to meet future growth. Because the IRP and reserve margin studies are the primary planning tools for the utilities in terms of the addition of capacity, the capacity costs identified in such reports, to the extent they have been reviewed by the Commission, are reasonable cost estimates to be used in the avoided cost proceeding. The Commission should instruct the DEC and DEP to recalculate their proposed avoided cost rates using the following installed CT costs: DEC – [redacted] per kW (or [redacted] per kW, which the midpoint of the range, as discussed above) and DEP – [redacted] per kW.

55

With respect to DNCP, the installed cost of a CT used by DNCP did not include AFUDC, land and financing costs, which is inconsistent with the Commission's historical practice. Therefore, the Commission should direct DNCP to recalculate proposed avoided cost rates using the following installed CT cost [redacted] per kW.

Q. Do you have a recommendation related to performance adjustment factor ("PAF")?

A. Yes. The Commission uses a performance adjustment factor in calculating the capacity credit of avoided cost rates for those utilities that rely on the peaker methodology to determine avoided costs, in recognition of the fact that generating facilities cannot operate at all times. In the last eight avoided cost proceedings, the Commission has ordered that "a PAF of 2.0 shall be utilized by both Progress and Duke in their respective avoided cost calculations for hydroelectric facilities with no storage capability and no other type of generation," most recently in its Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 127, dated July 27, 2011, ¶ 7. The Commission also has ordered that "a PAF of 1.2 shall be utilized by both Progress and Duke for all QFs that do not qualify for a PAF of 2.0 . . . ." Id. at ¶ 8.

The Commission explained the reason for the 2.0 PAF for run-of-river hydro in the 2006 biennial proceeding:

> The actual reason for using a 2.0 PAF for run-of-river hydro QFs has been that doing so allows them to receive the full

> capacity payments to which they are entitled while operating under the constraints created by their stream flows. As the Public Staff witnesses pointed out, using a 2.0 PAF places run-of-river hydro QFs on an equal footing with run-of-river hydro generating facilities included in the rate base of the State's utilities, which are able to cover the full costs of these facilities. With respect to solar and wind QFs, however, this comparison has no relevance, because the State's utilities have no solar or wind facilities in rate base. On the other hand the Commission agrees that solar and wind QFs, like run-of-river facilities, have no control over their energy sources. This is a legitimate argument for treating them in the same manner as run-of-river hydro QFs.

Order Establishing Standard Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 106, December 19, 2007 ("2006 Order"), p. 20. At the conclusion of the 2006 proceeding, Public Staff recommended that solar and wind QFs receive a 2.0 PAF based on the variable nature of the resources. Proposed Order of the Public Staff, Docket No. E-100, Sub 106, September 19, 2007, p. 19. Public Staff correctly pointed out that once the SB 3 rules are in effect and "REPS is in operation, the market for renewable energy in North Carolina is likely to change dramatically, and in future cases, issues relating to PAF will be presented in an entirely new context" and noted that, therefore, any decision reached by the Commission in that docket would be "in the nature of an interim decision." Id., p. 20. Ultimately, the Commission concluded that the issue should be further addressed in subsequent proceedings after assessing the impact of SB 3. 2006 Order, p. 22.

In the last two biennial proceedings, no party has proposed any changes to the approved PAFs. As forecasted by Public Staff and the Commission, the time is ripe in this proceeding for the Commission to revisit applying a 2.0 PAF to solar and wind QFs. Several factors justify this change, including those advanced by the Public Staff in the 2006 proceeding.

First, it remains the case that solar and wind QFs, like run-of-river facilities, have no control over their energy sources and no storage capability. This creates a significant disadvantage for these facilities since none of the Utilities proposes to offer capacity credit in the off-peak hours, which means that QFs that rely on variable resources will receive only the energy credit of the avoided cost rate for the power produced in the off-peak hours. However, utilities recover their full capacity costs regardless of when their facilities produce power. By way of illustration, the capacity cost of a peaker that sits idle 90% of the year is fully recovered in the utility's rate base. Additionally, wholesale power contracts typically include a capacity charge that is calculated on a per KW basis and is payable regardless of the number of kWhs the seller provides.

Second, since the 2006 proceeding, DEC has added and both DEC and DNCP have stated they have plans to add solar capacity to their resource mix. See Duke Energy Carolinas' 2012 Integrated Resource Plan and 2012 REPs Compliance Plan, Docket No. E-100, Sub 137, p. 16; Integrated

Resource Plan of Dominion North Carolina Power, Docket No. E-100, Sub 137, p. 7. To the extent solar capacity additions are made through self-build programs, the utilities end up recovering the full cost of constructing these facilities regardless of the fact that they have similar capacity factors as solar QFs. Similarly situated QFs are penalized under the avoided cost rates calculated with a 1.2 PAF because they are not paid for capacity unless they are producing 83% of the on-peak hours.

Third, SB 3 has been in effect for five years. 2012 marks the first major milestone in the legislation, with the Utilities' being subject to the first increase in the REPS requirement. The long session of the 2013-2014 Legislative Session ended with SB 3 intact, indicating a clear expression of state policy in support of renewable energy.

Finally, FERC recently ruled that it is permissible for states to differentiate among QFs using various technologies when establishing avoided cost rates. "Because avoided cost rates are defined in terms of cost that an electric utility avoids by purchasing capacity from a QF, and because a state may determine what particular capacity is being avoided, the state may rely on the cost of such avoided capacity to determine the avoided cost rate. Thus, the avoided cost rate may take into account the cost of electric energy from the generators being avoided, *e.g.*, generators with certain characteristics." California Public Utilities Commission, Docket No. EL 10-

64-002, Southern California Edison Company, Docket No. EL 10-66-002, 133 FERC ¶ 61,059 (2010), Order Denying Rehearing, 134 FERC ¶ 61,044 (2011), p. 15 (emphasis added) (footnotes omitted).

For all of these reasons, it is appropriate, and within the Commission's authority, to apply the 2.0 PAF to solar and wind QFs in addition to run-of-river hydro.

Q. Does this conclude your testimony?

A. Yes.

MS. MITCHELL: He is available for cross.
COMMISSIONER BROWN-BLAND: Is there cross examination for this witness? Mr. Youth?
MR. YOUTH: Ask a few questions.

CROSS EXAMINATION BY MR. YOUTH:

Q **Good morning, Mr. Reading -- Dr. Reading.**
A Good morning. That's -- whatever.
Q **I think you're familiar with Ms. Bowman's testimony, and that she suggests the Commission should reject the proposed PAF increase for solar and wind QFs as it would effectively increase avoided capacity rates by 67 percent.**
A Yes.
Q **Is it your understanding that an increase in the PAF for solar and wind to 2.0 would increase Progress' proposed 2012 capacity rates by 67 percent?**
A Just the capacity rate, yes.
Q **That sounds big. Is it also your understanding that an increase in the PAF to 2.0 for solar and wind would result in an increase of only 10.3 percent in the overall 15-year fixed rate option for the proposed Progress 2012 REPS?**
A From the 2010 rates, yes. Oh, no. Excuse me. From -- from the proposed rates. An increase from the

proposed rates, yes.

Q So 10.3 percent increase from the proposed rates, --

A Right.

Q -- if you were to bump the PAF up to 2.0?

A Right. On capacity because energy is also included in the overall rate.

Q Now I'd like to ask you to compare or explain to us what would be going on vis-à-vis the 2010 rates. Is it your understanding that an increase in the PAF to 2.0 for solar and wind would still yield a decrease in avoided cost rates, overall avoided cost rates, of 12.9 percent?

A Yes, over the 2010 rates.

Q I'd like to move to Duke's rates now. Similar questions. If you were to increase the PAF to 2.0 for solar and wind, Duke's proposed rates, 2012 proposed rates, would be increased by about 7.4 percent?

A That sounds right.

Q And that's for the 15-year fixed rate, obviously?

A Fifteen-year fixed, yes.

Q Is it also your understanding that increasing the PAF to 2.0 for solar and wind for Duke would result

in a decrease, an overall decrease of 6.4 percent in the 15-year fixed rate option when you look back at 2010's rates?

A Yeah. That sounds correct.

Q **So to sum up, even if the Commission approved a PAF of 2.0 for solar and wind QFs, the rates available to them would still be lower than those approved by the Commission in the 2010 proceeding?**

A That is correct.

MR. YOUTH: No further questions.

THE WITNESS: Just the capacity rate goes up, and the overall rate would actually go down over those if a PAF of 2 is -- is approved by the Commission.

MR. YOUTH: No further questions.

COMMISSIONER BROWN-BLAND: Okay. Any further cross examination?

MR. ALLEN: Thank you very much, Madam Chairman.

CROSS EXAMINATION BY MR. ALLEN:

Q **Good morning, Dr. Reading.**

A Good morning.

Q **My name is Dwight Allen, and I'm appearing on behalf of the Duke companies in North Carolina.**

A Yes. I remember you from EPCOR.

Q Welcome to North Carolina. I think we've run into each other before, --

A Yeah.

Q -- and you're a colleague of Dr. Johnson as well. Let me ask you just for clarification, did you have any conversation with Mr. Youth this morning about the calculations he just asked you about prior to coming to the hearing room?

A No, I did not.

Q Now, I am going to restrict my questions to you to your testimony related specifically to the performance adjustment factor and not the CT cost portions of your testimony, okay?

A Okay.

Q And you would agree with me, would you not, that that testimony begins on page 32, line 8 of your testimony, and continues through the end of your testimony on page 36; is that correct?

A That's correct.

Q So out of your 36 pages of testimony, approximately four pages or so are related to the performance adjustment factor?

A Correct.

Q You are a consulting economist and you have

been such for about almost 30 years, have you not?

A Yeah. A little more. I look back, I don't believe it, but yes.

Q Well, you were also Director of Policy and an economist with the Idaho Public Utilities Commission. Do you include that as part of your consulting economic work?

A I'd have to parse the years out. I left the Commission in '86, and -- and went with Ben Johnson Associates, so whatever the arithmetic is.

Q That would be about 27 years or so, --

A Yeah.

Q -- about 30 years or so.

A Uh-huh.

Q And you are an economist and you are not a lawyer; is that correct?

A Yeah. That is correct.

MR. ALLEN: And you can be thankful for small favors, I know.

THE WITNESS: My two -- my two daughters are -- one is a One L and the other is a lawyer, so...

MR. ALLEN: Well, my condolences to them as well.

THE WITNESS: I went somewhere wrong along the line.

BY MR. ALLEN:

Q Now, you are testifying as an economist, and you are not offering any legal opinions at all as to whether any of your recommendations comply with any federal law or any laws of the state of North Carolina, are you?

A Not in a legal sense, but as an economist who lives in this world, I guess I can say I read and have my interpretations.

Q But you --

A I am not a lawyer.

Q And you're -- and because you're not a lawyer, you are not offering a legal opinion; that would be correct?

A Oh, absolutely, yes.

Q Now, the effect of your 2.0 recommended change to the PAF for solar produces is that the Company would take an approved capacity rate and double that rate for payment to the solar QFs; is that correct?

A That's what PAF 2 means, yes.

Q Okay. Look at page 23, please, if we could just -- of your testimony. Are you with me there?

A Twenty-three?

Q Yes. Page 23. There's a chart there about the middle of the page.

A Where are you?

Q Do you have your testimony?

A I just brought the pages with the PAF.

(Ms. Mitchell provides the witness his testimony.)

A I will try to be careful. Counsel says this is a confidential version, so --

Q Well, I'm not going to ask you about any -- I don't want you to say any numbers and I'm not going to ask any numbers, so I think we can do this without --

A Okay.

Q -- disclosing any confidentiality. Reflecting on that Table 7 there, there are certain numbers that indicate that they are annualized capacity energy rates for Duke Energy Progress on a cents per kWh basis; is that correct?

A That is correct.

Q Now, do you know what percentage of the per kWh rate, within a range of reasonableness, is associated with capacity and what percentage is associated with energy?

A I would have -- if you know the answer, I'll accept it, subject to check.

Q Would you accept, subject to check, that the record reflects that it's about 70 percent energy and about 30 percent --
A That -- that --
Q -- capacity?
A -- sounds -- certainly, yes.
Q Does that sound reasonable --
A Yes.
Q -- based on --
A Absolutely. Yes.
Q -- based on your experience? So if we wanted to know what the increased amount of your payments would be, we could take a third of any of these numbers, and that would give us what the approximate capacity rate would be, wouldn't it?
A The proportion of the overall rate for capacity, yes.
Q That would be the rate. And then we could double that rate and then divide it by 1.2, and that would give us the increase in the capacity rate that you would receive if the 2.0 was approved.
A That --
Q Isn't that correct?
A That would be the effect -- I'm trying to think

how to put it. That would be the effect on the overall rates for applying the 1.2 PAF.

Q And we apply that 1.2 PAF to make that adjustment because you're already receiving that, isn't that correct, so that would be an appropriate adjustment to make.

A Oh, I think it's appropriate, yes.

Q And if you weren't receiving the 1.2, we wouldn't make that adjustment.

A Yeah.

Q All right. And so if we wanted to take these numbers out and decide what exactly the percentage is based on 2010 rates, 2012 rates, proposed rates or stipulated rates, we could simply do the math and then we would know what the actual percentage might be?

A Yeah, the arithmetic.

Q That arithmetic, that's all that --

A Yeah. Right.

Q -- would be, wouldn't it? Okay. Now, is one of the purposes of a PAF to encourage the development of certain types of generation?

A That would be the effect of applying a PAF.

Q Well, if, from a policy standpoint, you were policy director of the Idaho Commission, that would be a policy goal of a Commission that approves such a --

A Yeah, the policy.

Q -- factor, wouldn't it?

A Yes. Yes, as -- as this Commission has stated and as the North Carolina Legislature stated.

Q In fact, today in another of the selected readings from Mr. Youth, it, in fact, said for the run-of-the-river hydro plant, that was, in fact, a reason that the Commission did that because there was a statute in North Carolina G.S. 62-156 that encouraged the development and the continued use of run-of-the-river hydroelectric facilities. You recall that, don't you?

A Yes.

Q Now, on page 33 of your testimony -- I'm sorry, this is also -- it may be falling in the PAF section -- specifically line 20, you state in there, do you not, and you were quoting, I believe, from a proposed order of the Public Staff, and it begins at the end of line 21, pardon the pause, "The market for renewable energy in North Carolina is likely to change dramatically, and in future cases, issues related to PAF will be presented in an entirely new context." Is that what you say in that testimony?

A Yes.

Q Now, in making that decision in that case, the context in which it was made was that the Commission approved a 2.0 PAF for run-of-the-river hydro, but declined to approve it for any other small QFs.
A That's correct.
Q Isn't that correct?
A Yes.
Q And they decided for whatever reason, at least at that time, that that was not the appropriate thing for the Commission to do from a policy standpoint.
A I -- I think your question extends to what was going on in the minds of the Commission, but that was certainly the outcome.
Q Well, if they had thought it would have been a good policy, we'd like to think they would have had the knowledge to approve it, wouldn't they?
A Yes.
Q Do you know how much solar generation existed in North Carolina in 2007?
A You're -- you're stretching back, but there was very little, if any.
Q Probably could have been none.
A I would accept that.
Q So we certainly have a much greater amount of

solar generation today in North Carolina than we had in 2007, do we not?

A Yeah. An increase of any from zero is dramatic.

Q And we can argue about whether it's a lot or whether it's not a lot, but it's certainly more.

A More, yes.

Q You would agree with that? Okay. Have you done any analysis on your own to determine in the last three years how many certificates of public convenience and necessity have been issued by the Commission in terms of total MW for the generation of solar energy in North Carolina?

A I haven't done a study, but they're -- relative to the size of the utilities, there have been very little.

Q Relative to the size of what we had in 2007, there's been a lot, hasn't there?

A Yeah. Of those percentage. The point I was making, relative to the total MWh generation of the utilities, not very much.

Q Well, in terms of the total MWh generation of the utilities since 2007, we could probably say there hasn't been very much of any kind of generation added to

it.

A Of solar.

Q Of any. I mean, they had a whole lot more before 2007 than they've built since, haven't they?

A Yes.

Q Now, I believe you said in response to questions from Mr. Youth that you were familiar with the testimony of Duke witness Bowman, did you not?

A I was in -- I was in the hearing room and reviewed her testimony.

Q Okay. So did you read her testimony in preparation for this proceeding?

A Yes.

Q Okay. Now, on page 16 of her testimony, I would like to read you a section of that and ask you if you agree with me or agree with her or have reason to dispute what she says, okay?

A Okay.

Q And I'm reading from page 16 of Ms. Bowman's testimony beginning on line 5.

MS. MITCHELL: Will you specify whether it's direct or rebuttal?

MR. ALLEN: It's direct.

MS. MITCHELL: Okay.

BY MR. ALLEN:

Q "Despite this imminent decline in avoided cost rates," and she's referring there to a decline in avoided cost rates based on the revised avoided cost rates filed in--

MR. YOUTH: Mr. Allen, the witness doesn't have a copy of it yet.

MR. ALLEN: Well, I don't know that he needs it.

MR. YOUTH: We're just asking you to hold off for a second.

MR. ALLEN: I mean, I'm happy for him to have it if he wants it.

THE WITNESS: Which page?

MR. ALLEN: Page 16 of the rebuttal. I'm sorry.

MS. MITCHELL: So it's -- is it the rebuttal testimony?

MR. ALLEN: It's the rebuttal testimony.

MR. YOUTH: It's the rebuttal.

MR. ALLEN: Do you have the rebuttal? I'll be glad to go up and show it to him. May I approach?

COMMISSIONER BROWN-BLAND: Yes.

BY MR. ALLEN:

Q I'm referring now to page 16, line 5. First, let's look at page 15, --

A Okay.

Q -- line 21.

A Got it.

Q As she says there that the utilities filed revised avoided cost rates in November of 2012.

MS. MITCHELL: Commissioner Brown-Bland, I'd like to object. Witness Bowman's rebuttal testimony is not in evidence at this time.

COMMISSIONER BROWN-BLAND: It's not been moved into evidence, but he can ask questions.

MR. ALLEN: It's really related to filings that were made with the Commission.

BY MR. ALLEN:

Q Are you aware or would you accept, subject to check, that the revised avoided cost rates were filed with the Commission on November 1, 2012?

A Subject to check. I know they are -- they're on file if you go to the webpage and pull up the tariff.

Q So if that's been -- if that's true, they would have been in effect or been filed for about a year?

A Yes.

Q Now, if Ms. Bowman were to testify in her

revised -- or in her rebuttal testimony, as appears on page 16, line 5, "Despite the imminent decline in avoided cost rates, solar development (and investor interest) in North Carolina has trended sharply upwards in the past year. Certificate applications with the Commission have increased exponentially in 2013," would you have any reason to disagree with that statement?

A I wouldn't have any reason to disagree with that statement. I haven't got the tariff with me, so I can't remember the exact language, but the rates are posted, and then before you get to the rates, it says these rates will be subject to change or whatever in this existing proceeding. And I can't member whether there's an indication they might go up or they might go down. And if I were a developer and I know that it takes time for utilities to process -- there's -- you know, there's queuing, you get a lot of queuing, I would certainly say, well, this is what the rates are. I know that there are numerous parties in a proceeding that think those rates are too low and it's contested, so I think I'll -- I'll throw my application in the stack and then I will see what the final rates resulting are, and then I'll either go forward or not go forward. But with that proviso in the tariff, the existing rates I'm looking at wouldn't be the total controlling reason that I would or would not make an application.

Q It wouldn't be the controlling reason, but if you were an investor going to a bank or to seek financing for a solar project, it would certainly be a factor that you would want to take into consideration, would it not?

A Yes, when the rates are finally approved. If I go to a banker and say these rates might change, I think the banker would say you all come back later.

Q If you went in and said that it might be a decrease in those rates, you would particularly want to disclose that to your banker, might you not?

A Yeah. Yes. Bankers are -- they tend to ferret those things out.

Q When you go to a bank to borrow money, do you generally tell them that you're just filing a certificate and put it in the queue, or do you give them a business case as to what you plan to do in terms of developing that project, or do you know?

A I would -- I think I would say to the banker I'm considering this investment and I'll be back with the real numbers when I know the real numbers.

Q Well, until you have the real numbers, the bankers are not likely to talk with you very much, are

they?

A Until you get the real numbers, yeah.

MS. MITCHELL: Commissioner Brown-Bland, I'm going to object to this line of questioning. Dr. Reading is not a developer of a qualifying facility. He's an economist. And the questions go to the development process of a qualifying facility.

COMMISSIONER BROWN-BLAND: He can testify to the extent of his knowledge, and that's all he can do.

BY MR. ALLEN:

Q In further reading from Ms. Bowman's testimony, it says, "A recent September 13 analysis of North American solar PV markets forecasted installed, solar PV in North Carolina to increase by 80 percent in fiscal year 2013, second only to California. By contrast, solar PV across the United States will increase only about 17 percent year over year."

A Yes. And I heard her testimony North Carolina is fifth in the nation, something like that.

Q Would you have any reason to disagree with that assessment?

A No, no. And I might add, percentage increases from a low number are -- if it's a very low number, they're not particularly significant in a total MWh or MW situation.

Q Now, in setting the 2.0 for hydro, the Commission limited the PAF to run-of-the-river hydro, didn't they?

A That is correct.

Q Why, from a policy standpoint, would you think as an economist that they would do that?

A I can -- I guess as an economist or as someone who can read orders, I read the logic of the Commission in making those decisions, and it was the fact that the run-of-the-river hydro do not control their fuel source or -- or when they can produce power. The Commission has said in its orders that solar and wind are similarly situated and that the decision not to apply a 1.2 increase, the 1.2 PAF, was because there wasn't solar and wind on the system, so that could be looked at at a later date. That's what I gained from their order.

Q Well, did they say that or did they say the circumstances might be very different --

A They said both.

Q -- once the Senate Bill 3 was entered?

A Yeah. Yeah. They said both.

Q Now, I know you're from the Northwest, and while it's a lovely place, it rains a lot up there, but

do you have droughts in the Northwest?
A Oh, yeah.
Q Are you aware that we also have droughts in North Carolina?
A Yes, and Florida where the headquarters of my company is.
Q If the stream flows from a run-of-the river hydro falls below a certain level or dries up, how much electricity can a run-of-the-river hydroelectric facility generate?
A Depending on how far it goes down, the head decreases. If it goes down too much, then zero.
Q And if it's dry, they certainly would be zero as well, wouldn't they?
A Oh, absolutely.
Q Have you looked at North Carolina within the last three to five years to know whether or not North Carolina has experienced extensive droughts in the areas where hydro facilities are located?
A I have not.
Q Well, if, in fact, the state policy is to encourage hydro facilities, run-of-the-river hydro specifically, and you want to make sure that they don't go through a period of time, a year, two years, three

years, whatever it is, without financial resources, there might be some policy reasons for giving special treatment to run-of-the-river hydroelectric facilities, might there not?

A Yes.

Q Do you agree with me that there are a finite number of hydroelectric facilities in North Carolina?

A Well, I'm not -- I'm not sure I can opine on that. There's only so many streams and there's only so many places that you can put hydro facilities.

Q So if there's only so many places --

A So it would have to -- the physical hydrologic conditions of the state would place a limit on it. Beyond that, I don't know where to go.

Q Well, there were questions yesterday of other people about whether or not they had looked into how many hydroelectric locations we might have in North Carolina, and I don't think any of them had an answer. Have you looked into that and determined how many we have?

A No.

Q Have you made any determination to find out how many hydroelectric facilities have been added in North Carolina since 2007?

A My general understanding is not very many or zero. I think I heard that --

Q **Have you --**

A -- in the hearing room.

Q **-- done any study to find out how many hydroelectric facilities in North Carolina have been closed because of activity by fishing and wildlife and other environmental groups concerned with those sorts of things?**

A No, I have not.

Q **Now, are there any limits on the number of solar sites in North Carolina?**

A Again, there would be some -- some physical, certainly some -- as was discussed yesterday by some of the cross examination, the environmental community looks at how much land is taken. Some subdivisions have restrictive covenants on solar, et cetera, but I would assume that it's fairly unlimited.

Q **Much more unlimited than for rivers and streams related to hydroelectric facilities. That would be true, wouldn't it?**

A That's what my gut tells me, yes.

Q **And are you aware that the sun shines fairly frequently in North Carolina?**

A When I've been here, yes.

Q And sunshine is not affected by droughts.

A No. I'd say there is somewhat an inverse correlation.

Q What fuel source do solar providers use to generate electricity?

A Well, the sun.

Q How much do they pay for that?

A Well, that's one of the real advantages and -- and one of the reasons I think North Carolina is, as you have explained, in a relatively good condition, good situation to really develop solar.

Q Do they buy any gas to generate electricity?

A Do they drill holes and get natural gas? Oh, yeah, yeah.

Q Do they have buy -- do they have to buy any gas to -- as a fuel source?

A Oh, oh, certainly. Oh, yeah. Yeah.

Q To generate electricity? Gas solar power --

A Oh, solar. Oh, no. No. There is some movement around the country that utilities are attempting to increase significantly the rates that residential and commercial customers have on, for instance, net metering tariffs, and so there is some development and looking at using gas as a backup, but that's the only case. They're general fuel source is --

Q **Is the sun.**

A -- the sun. Oh, yeah. Yeah. That's -- and it's --

Q **And --**

A -- free, and that's a good thing.

Q **And you agree with me that in terms of the avoided cost payments that solar generators receive from utilities like Duke Energy Carolinas and Duke Energy Progress, they receive an energy payment, and included in that energy payment is an increment for fuel?**

A Yes. And that's --

Q **And that's fuel --**

A -- because of the -- the methodology this Commission -- and not a criticism -- this Commission has accepted to determine avoided cost, and that's the peaker method. And the peaker method has the one category, as the Chair of the Commission questioned one of the witnesses, they have a bucket over here that says capacity and they have a bucket over here that says energy, and energy comes from -- from the natural gas forecast, which nobody in this proceeding --

Q **And so the -- the 70 percent -- we agreed 70 percent was the percentage of energy payments that you**

receive as opposed to 30 percent for capacity. You receive an energy payment that has in it an increment for the cost of gas incurred by the utility.

A Yes, because that's what the peaker method says you do to calculate avoided cost.

Q **That's what the peaker method does, but we have agreed that solar generators pay nothing for the fuel they use to generate power; is that correct?**

A Well, as a fact, certainly that's correct, but if --

Q **Thank you.**

A -- if they're allocating -- if they're establishing rates based on the utility's avoided cost, the peaker method includes fuel, so I don't -- I guess my bottom line is so what.

Q **Now, when a utility puts its solar unit, assuming it had any solar units, in rate base, they get a return on that investment?**

A If they roll it into rate base, correct.

Q **And it would be a mix of equity, preferred stock, --**

A Whatever the capital structure is.

Q **-- whatever the capital structure happens to be.**

A Yeah. Depreciation rates, whatever, investment, tax credit, you know, all the kinds of things that would go into it, but the -- the check they write for the solar facilities goes into rate base.

Q And that basically is paying them for the capacity they built and put in their rate base, right?

A Correct. Right.

Q Now, when they file their fuel clauses and it has an increment in there for the solar power that they produce, they incur no cost for fuel, just like other solar providers in generating that solar power; is that correct?

A Would you restate that question?

Q Yes. And when they develop their fuel adjustment clauses to recover their cost of fuel, there would be no cost of fuel related to solar capacity or solar energy generated by the electric utilities, would there?

A Right. There -- there would not be an increment there.

Q Because their cost would be zero for the sun, just like yours.

A For fuel. And I -- I would think that would be a real incentive for you -- for a utility to want to add solar, given the conditions you just explained exist in North Carolina, to their generation fleet.

Q Now, you refer also in your testimony on page 35, line 11, to the long session of the General Assembly, do you not? For 2013 and 2014, on line 11 you say, "The long session of the 2013/2014 Legislative session ended with Senate Bill 3 intact, indicating a fair expression of state policy in support of renewable energy."

A Correct.

Q Is that correct? Now, did you follow the 2013/2014 session of the General Assembly personally?

A No, I did not.

Q Well, who told you that the 2013/2014 session ended indicating a clear expression of state policy in support of renewable energy?

A I'm trying to remember. Certainly, all testimony is discussed with counsel. The statement came from the fact that SB 3, as I read it as a non-lawyer -- as I read it, it has statements in there that encourage renewable energy. That's still the state policy.

Q Well, Dr. Reading, I don't -- I don't want to quibble with you about what Senate Bill 3 says. What I want to talk to you about is what you said happened in the long session of 2013/2014. And on what did you base your opinion that the long session of 2013 and 2014 indicated the clear expression of state policy in support of renewable energy?

A Because it didn't change that section of SB 3.

Q Do you know whether any effort was made during that session to repeal Senate Bill 3?

A No, I do not.

Q Do you know whether any provisions were offered to repeal the tax credits available to solar producers in North Carolina in the 2013/2014 session?

A No, but it certainly wouldn't surprise me. Any jurisdictions I'm familiar with, that tends to be the general situation, but I did not follow it, no.

Q Do you know whether a bill to repeal Senate Bill 3 was considered by the environmental community of the North Carolina State House of Representatives during the 2013/2014 session?

A If I didn't follow it, I wouldn't know that.

Q So then you wouldn't know if the committee took a vote, what that vote might have been?

A No idea.

Q Now, in your testimony, you also refer on page 35 and 36 to a couple of FERC decisions, do you not?

A Yes.

Q And I'm a bit curious, Dr. Reading, as to why you put that in your section related to the performance adjustment factor.

A Where -- where -- let me refresh my memory specifically --

Q Okay. Yeah. It's at the bottom of page -- I'm sorry. I apologize for that. Bottom of page --

A Thirty-five.

Q Page 35 down at the bottom, line 23, I guess, is where you really first make a cite or reference to it, and then going over to the first three lines on page 37.

A That primarily, as I go on and say there, it was the -- the California Commission on the Southern Cal case.

Q Well, you cited the FERC cases. Are you suggesting anything in these cases said that the FERC said that a PAF was consistent with the guidelines of PURPA?

A As a non-lawyer reading these decisions, the philosophy of encouraging renewables is part of what the California Commission said, and as Mr. Petrie went through in his -- his testimony, numerous pages saying he didn't think that the California decision had any applicability in this case, I would disagree with that and I would say if you want to get down in the nitpickies of the kind of regulation this Commission has and the kind California has, that I would say, well, yeah, there are differences. But the philosophy behind it, the public policy behind it, is to encourage renewable development, so in that sense, I see a relationship between that decision and what this Commission decides it wants to do with PAF.

Q Let me show you a copy of the Order on Rehearing, which is 134 FERC 61,044, if I can. Now, can you point me to anything in that order that makes any reference to a performance adjustment factor?

A There's no -- as I --

MS. MITCHELL: Commissioner Brown-Bland, I'm going to object. Dr. Reading is not a lawyer, and to the extent that counsel's question goes to asking him to interpret this order, he's not a lawyer.

MR. ALLEN: He cited it in his testimony, and I'm asking under the section dealing with the PAF, and I'm wanting to know does it say anything in there about PAF, to the best of his knowledge, because I can't find it.

COMMISSIONER BROWN-BLAND: The witness can answer to his knowledge whether this order addresses PAF or if there's any part of it that he thinks addresses PAF, with the understanding that he is not an attorney.

A If I would go through the order, I would be surprised if I would find either the term PAF or performance adjustment factor, given the regulatory regimen that California has. As I attempted to explain just a few minutes ago, we're nitpicking on PAF specifically being in this order and the policy and philosophical approach that renewable energy should be encouraged. That is also the philosophy, one of the philosophies and policy behind the PAF.

BY MR. ALLEN:

Q So when you included those references in the section of your testimony dealing with your recommendation for the PAF, you didn't mean to say that it really addressed PAF specifically?

A No. I did. It addressed that -- that a discussion of avoided cost. As I remember, it actually says states can have avoided costs for particular kinds of generation that is "above avoided cost," and, of course, what avoided cost is, is -- if we knew exactly what avoided cost was, we wouldn't be in this hearing room. There is -- there are different ways to calculate it and different ways to interpret it.

Q Let's look at page 13 of that order, if you would, please. At the top of the page, first full sentence, it says, "In both orders..." It's talking about what the Commission FERC really was doing. It says, "...the Commission made clear that it was providing guidance on the approaches the" -- California Public Utilities Commission -- "CPUC proposed to take, as it was asked to do, and was not ruling on whether the CPUC's actual offer price under its program" -- "is, in fact, consistent with the avoided cost rate requirements of PURPA."

A That's it.

Q That's it.

A Yeah. And, again, as a non-lawyer, I would interpret that as -- as saying their -- FERC is not stepping into the state's jurisdiction, as outlined by PURPA, that the state commissions are the ones that determine what avoided cost is. What this says to me is we're simply saying that the Commission can determine what avoided cost is, and we're saying there's various ways that the QF can be compensated without affecting the decision of the Commission on what avoided cost is. As a non-lawyer, that's the way I read it.

Q Now, you said that it allowed the states to do what they wanted to do, try not to infringe on the state's prerogatives under PURPA. Do you know whether California is a low-cost state and that they have to require their utilities to use the lowest cost source of generation available?

A Not familiar with that.

Q Do you know whether they are or whether they're not?

A No, no.

Q Well, do you know how this order arose from California?

A My understanding, it arose, use another term, feed-in tariffs. It arose in the way that the QFs were being compensated.

Q So you have no knowledge as to whether it resulted from a change made by the legislature in California that allowed the Commission to consider factors other than whether a generating source --

A Yeah.

Q -- was a least cost provider?

A Yeah. That's my understanding, yes.

Q And there was a statute in California that was passed which said you no longer have to use least cost, and so the California Commission decided to change its

policies.

A Okay. I would accept that, yes.

Q Do you know whether we have a similar law in North Carolina?

A I would be surprised. I haven't heard of it. And I'm sure that --

Q You would have been advised by counsel.

A -- my clients would have informed me of such a law, yes, and they haven't.

Q Well, I certainly hope they would have, Dr. Reading. Let me just ask you one -- let me -- were you in the hearing room yesterday when Mr. Youth was asking or making his opening statement about peanut butter?

A Yes. The microphone wasn't working that well, and as a 73 year old, my hearing is about average, I would say, so I missed part of it, but yes, I was here.

Q With Mr. Youth, it's kind of hard to miss what he says --

A Yeah, yeah.

Q -- because he talks --

A He's -- he --

Q And I mean that as a compliment.

A -- spoke out better than others, yes.

Q I mean that as a compliment. My wife tells me

I don't know how to whisper, either, so I share his malady. And you can look at me and tell me I have a particular affinity for peanut butter, so that's why I want to ask you just a little about that, if you don't mind. And some of this is my hypothetical, but I'm going to try to go along with his as much as I can, as I recall.

Do you recall and agree with me that he said if somebody showed up for work one morning, they would get a spoonful -- a teaspoon -- let's say a teaspoon of peanut butter. And if they worked all day, however many hours, they get a piece of bread to go with that. And he likened, did he not, the teaspoon of peanut butter with capacity and the bread to energy?

A Yes.

Q Now, let's assume that you were engaged in employing me, and I showed up in the morning for my teaspoon of peanut butter and I worked all day. I would get a teaspoon of peanut butter and a piece of bread at the end of the day; is that correct?

A Yeah. If you worked all day, yeah.

Q Now, let's assume I decided that I had something better I would like to do that day, and I decided to send my son to work for you that day, and he was 15 years old and his productivity rate was 40 percent of what mine was. And he worked all day, but the productivity you got from him was 40 percent of what I did. Would you feel as good about giving him a piece of bread and a teaspoon of peanut butter as you felt about giving it to me?

A Well, I guess -- no, I wouldn't.

Q And let's suppose that you were at a number of businesses, and the other business you had was a jelly business. And because you were doing so well in the business that utilized bread and peanut butter, you were giving out so much peanut butter as a capacity charge that your jelly customers started feeling they were having to pay too much of a subsidy for jelly to help subsidize the peanut butter. Can you accept that?

A I -- I missed the link on subsidy.

Q Well, okay. Let's forget the subsidy. Let's assume that the public policymakers, in their infinite wisdom, passed a law saying in the future no one can receive more than one teaspoon of peanut butter for the work that they do. Will you accept that?

A Well, it's your hypothetical.

Q And I went back to work for you, and at the end of the day I said, you know, I would like -- I worked pretty hard today, Dr. Reading, and I would like to have two teaspoons of peanut butter. Could you give me that if the law restricted you to one spoon of peanut butter?

A Assuming I was a law abiding person, yes.

Q And you look like you certainly are. Just one final question. If a wholesale CT provider was unable to deliver power when it was called upon to deliver the power, do you know whether they would get a full capacity payment out of that?

A What kind -- I missed --

Q A CT.

A Oh, a CT. Okay. Would they -- a utility-owned CT?

Q No. It would be wholesale CT providing power, yeah.

A Oh, a wholesale CT. Okay. Would depend on the kind of contract that was signed with whoever they were selling the power to.

Q But are you familiar with those contracts where --

A In general, yes.

Q And there is a -- generally, a provision in there that if you fall below a certain amount of capacity, don't deliver when it's called upon, there is a

penalty for not being able to deliver.

A Yes. That's standard in those contracts.

MS. MITCHELL: I'm going to object. What is the intent in this line of questioning?

MR. ALLEN: I have no further questions.

MS. MITCHELL: I'm going to -- I'm going to ask that those questions and Mr. Reading's responses be stricken from the record, to the extent they go to the contract provision that we have agreed to litigate on the pleading.

MR. ALLEN: Well, I think if you go back and you read the testimony, there was a reference to other types of generation. And the record will speak for itself.

(Mr. Allen and Ms. Fentress confer.)

MR. ALLEN: No. It has nothing to do with reduction in contract, either.

MS. MITCHELL: I'd like the record to reflect Mr. Allen's statement.

MR. ALLEN: I have no problem with that. We're not talking about the long-term contract energy issue that has been given to the Commission on the pleadings. I'll stipulate --

COMMISSIONER BROWN-BLAND: The record will so reflect, and I sustain the objection to the extent that it goes to or reflects on the contract issue that is not to be litigated.

MR. ALLEN: Thank you. That's all the questions I have. Thank you.

COMMISSIONER BROWN-BLAND: All right. Any other redirect?

MS. MITCHELL: Yes, ma'am. Just a few.

REDIRECT EXAMINATION BY MS. MITCHELL:

Q **Dr. Reading, just a few questions for you on redirect.**

A Okay.

Q **Do you recall counsel for Duke's questions related to CPCNs for total MW of generation since 2007? He asked you how many CPCNs had been issued since 2007?**

A Yes, he asked.

Q **Does the issuance of a CPCN mean that the MW that are certificated will actually be installed?**

A Not necessarily.

Q **So --**

A In general, but not necessarily, no.

Q **So would you agree that just because a project is certificated doesn't mean it actually is placed -- is constructed and placed into service?**

A There are some CPCNs that are not actually -- yes. I would agree with that.

Q Do you recall the questions that counsel for Duke and Progress asked you regarding the changes in the market for renewable energy that the Commission predicted might occur since the -- following the enactment of Senate Bill 3?

A Yes.

Q And would you agree that some changes in the market have occurred?

A Yes.

Q Might that mean that Senate Bill 3 is functioning as the General Assembly intended?

A I'm not sure how far I could -- could go on that. Listening to Ms. Bowman yesterday, you know, the increase in activity, I would say it's functioning, but again, when I see the -- as I explained earlier on, just because you're in the queue doesn't mean it's going to go, but the total MWs for wind and solar in North Carolina isn't very big.

Q Dr. Reading, do you recall when counsel for Duke and Progress referenced Ms. Bowman's rebuttal testimony, --

A Yes.

Q -- specifically the provision in her rebuttal testimony related to the 80 percent growth that's predicted to occur in North Carolina?

A Yes.

MS. MITCHELL: I'd like to pass out an exhibit.

BY MS. MITCHELL:

Q Dr. Reading, you've reviewed witness Bowman's rebuttal testimony, have you not?

A Yes.

Q And you have -- would you agree that this is the article that witness Bowman references?

A I will accept that.

Q And can you -- I want to draw your attention to the bottom of the first page.

COMMISSIONER BROWN-BLAND: Ms. Mitchell, can we get this marked?

MS. MITCHELL: Oh, yes, ma'am.

COMMISSIONER BROWN-BLAND: We'll mark it REG Reading Redirect Exhibit Number 1. It will be identified as such. Go ahead.

(Whereupon, REG Reading Redirect Exhibit Number 1 was marked for identification.)

BY MS. MITCHELL:

Q Would you please look to the -- near the bottom of the page, you'll see a sentence that's underlined.
A Yes.
Q Can you read that sentence to me, please, sir?
A "In particular, North Carolina is forecast to grow by 80 percent Y/Y," year over year, "in 2013 to reach 285 MW, with further growth of 30 percent in 2014 as leading project developer in the state, Strata Solar" --
Q You can -- you can stop there. I'm sorry. I should have indicated. I just wanted you to read that one sentence --
A Right.
Q -- for the purposes of my redirect.
A Right. Correct.
Q So that sentence says, in particular, North Carolina is forecast to grow by 80 percent in 2013 to reach 285 MW.
A Yes.
Q So does that mean that the article assumes that there was already installed capacity, if the growth has -- if the 80 percent growth will reach 285?
A Yes.
Q Okay.

A There has to be some there --

Q Okay.

A -- or it doesn't work.

Q Thank you. And then does the last phrase of that sentence read as follows, "...with further growth of 30 percent in 2014"?

A Yes.

Q So does that predict a slowing in the industry?

A In the growth rate, yes.

MS. MITCHELL: Okay. Thank you. No further questions.

COMMISSIONER BROWN-BLAND: All right. Questions from the Commission?

(No response.)

COMMISSIONER BROWN-BLAND: Okay. That seems to be it for this witness. You may step down.

THE WITNESS: Thank you.

(Witness excused.)

COMMISSIONER BROWN-BLAND: Well, I forgot. Did we want to move it in?

MS. MITCHELL: Commissioner Brown-Bland, I'd like to ask the REG Reading Redirect Exhibit 1 be moved into evidence.

COMMISSIONER BROWN-BLAND: It will be received without objection.

(Whereupon, REG Reading Redirect Exhibit Number 1 was admitted into evidence.)

COMMISSIONER BROWN-BLAND: All right. Ms. Mitchell -- well, we're at a good place to take a break, but I think if you're prepared, we'll stick with you since you've already begun to put your case on.

MS. MITCHELL: Okay.

COMMISSIONER BROWN-BLAND: So we'll start with your witness when we come back.

MS. MITCHELL: Okay. Thank you.

COMMISSIONER BROWN-BLAND: We're going to take a break, 15 minutes from now, so let's just say we'll be back at 10:40.

(Recess taken from 10:25 a.m. to 10:41 a.m.)

COMMISSIONER BROWN-BLAND: We can go back on the record. Ms. Mitchell, if you'd call your next witness.

MS. MITCHELL: The Renewable Energy Group calls Mr. John Morrison to the stand.

JOHN E.P. MORRISON: Being first duly sworn,

Testified as follows:

DIRECT EXAMINATION BY MS. MITCHELL:

Q Mr. Morrison, would you please state your name, position, and business address for the record, please?

A I'm John E.P. Morrison. I'm the Chief Operating Officer for Strata Solar. Address is 50101 Governors Drive, Suite 280, Chapel Hill, North Carolina.

Q And on whose behalf are you testifying?

A On behalf of the Renewable Energy Group, often referred to as REG.

Q And did you cause to be prefiled in this docket on September 27th testimony consisting of 15 pages in question and answer format?

A Yes, I did.

Q Do you have any additions or corrections to that prefiled testimony at this time?

A There's one correction I'd like to make. In my testimony I had indicated that Strata Solar has one solar farm producing energy under the new proposed rates. That was incorrect. That farm has not yet been completed, and so it is not yet producing.

Q And is that provided on page 9, lines --

A At page 9, I believe paragraph starting --

Q -- 10 through 14 of your testimony?

A Yes. That's correct.

Q Okay.

MS. MITCHELL: At this time I'll ask that John E.P. Morrison's prefiled testimony be copied into the record as if given orally and be received into evidence in this case.

COMMISSIONER BROWN-BLAND: Let me ask for clarification. I believe the testimony was that his testimony consists of 15 pages, and what I have indicates 14. Are we -- do we need to correct?

MS. MITCHELL: I'm sorry. That's my -- that is my error. It's 14 pages.

COMMISSIONER BROWN-BLAND: All right. So the motion will be allowed, and the direct testimony of John E.P. Morrison, consisting of 14 pages, filed September 27th, will be admitted into evidence as if given from the witness stand.

(Whereupon, the prefiled direct testimony of John E.P. Morrison, as corrected, was copied into the the record as if given orally from the stand.)

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John E. P. Morrison. My business address for the record is 50101 Governors Drive, Suite 280, Chapel Hill, North Carolina 27514.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Chief Operating Officer ("COO") of Strata Solar LLC. Strata is a solar development and construction company headquartered in Chapel Hill, North Carolina.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I hold engineering degrees from Yale and Stanford universities, and an MBA from Harvard University. I am a Professional Engineer, licensed in the state of North Carolina.

Prior to joining Strata, I served as the Assistant Secretary for Energy at the North Carolina Department of Commerce. For most of the past 30 years I have been working in the clean energy arena at various times researching proliferation resistant fuel cycles for nuclear energy, developing prototype flue gas scrubber technology and emissions standards, establishing a solar application unit at a company then called Carolina Power and Light, and for 11 years serving as the Chief Operating Officer of Advanced Energy.

Over the years I have also had the opportunity to serve on a number of clean energy related boards including, the Advisory Council of the Electric Power Research Institute ("EPRI"), the North Carolina Clean Energy Business Alliance, North Carolina Biofuels Center, the Southern States Energy Board, and the Association of State Energy Research and Technology Transfer Institutions where I also served as chair for two years.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES AS COO?

A. As COO at Strata Solar, I oversee the construction and operation of the company's solar facilities. The company has developed more than 250 MW of solar QFs (defined below) and operates more than 200 MW. In 2012, Strata was ranked the sixth largest solar company in the country and is the largest solar developer and builder in North Carolina.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Renewable Energy Group ("REG"), which is a consortium of operators, developers, suppliers, installers, designers, builders and/or managers of the types of facilities entitled to the avoided cost rates established in this proceeding, referred to as "Qualifying Facilities" or "QFs" in the Public Utility Regulatory Policy Act of 1978 ("PURPA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony provides a brief narrative on the development of the renewable energy industry in North Carolina and summarizes the potential impact to the industry of the rates proposed by Duke Energy Carolinas ("DEC"), Duke Energy Progress ("DEP") and Dominion North Carolina Power ("DNCP") (collectively, the "Utilities") in this proceeding, based on my experience as a developer of QFs in North Carolina.

Q. WHAT IS REG ASKING THE COMMISSION TO DO IN THIS DOCKET?

A. Irrespective of what the Utilities would have the Commission believe, REG is not asking the Commission to establish rates "that provide a financial windfall to QFs" or "at levels well above the Utilities' avoided costs." <u>See e.g.</u>, <u>Direct Testimony of Kendal C. Bowman on behalf of Duke Energy Carolinas, Inc. and Duke Energy Progress, LLC</u>, p. 13, ll 18-19, p. 1, l. 23 – p. 14, l. 1, filed August 13, 2013. Rather, REG simply requests that the Commission establish rates that are "equal to the purchasing utility's full avoided cost" as required by PURPA. To this end, REG respectfully requests that the Commission carefully scrutinize the methodology, assumptions and data used by the Utilities in calculating avoided costs to ensure that the rates established in this docket reflect nothing less than the Utilities' <u>full</u> avoided cost.

REG lauds the Utilities' concerns regarding potential impact to ratepayers and careful attention in this docket to the fact that "every dollar paid to a QF is borne ultimately by the Utilities' customers." Bowman, p. 8, ll 6-7. REG, too, is cognizant of the fact that costs associated with the purchase of power from QFs are passed through to the ratepayers, as are all of the costs prudently incurred by the Utilities in the construction, operation and maintenance of their respective systems. But, I want to emphasize for the Commission, as counsel has advised me, that the Supreme Court, in analyzing the rules adopted by the Federal Energy Regulatory Commission ("FERC") to implement PURPA, noted that though the full avoided cost rule would not provide savings to ratepayers, the rule would provide incentive for the development of QFs and, as a result, these ratepayers would benefit from decreased reliance on fossil fuels.

Q. BRIEFLY DESCRIBE YOUR EXPERINCE IN DEVELOPING QFS IN NORTH CAROLINA.

A. I have been involved in the development and construction of more than 30 QFs in North Carolina, primarily solar generation, ranging in nameplate capacity from 1 to 5 MW. Strata also has a similar number of solar facilities under development for future construction, ranging in size from 5 to 100 MW. The company arranges the financing for all of the solar farms it builds, combining debt and equity investments from the financial community. On many farms, Strata maintains an equity portion while on others it sells the farms to investors once the facility is built and operational.

Q. BRIEFLY DESCRIBE YOUR PERSPECTIVE ON THE DEVELOPMENT OF THE RENEWABLE ENERGY INDUSTRY IN NORTH CAROLINA.

A. DEC/DEP Witness Bowman provides an overview of PURPA and the requirement that electric utilities offer to purchase the output of the QF at a rate that equals the cost to the electric utility of the electric energy which, but for the purchase from the QF, the utility would generate or purchase from another source. While PURPA establishes a specific legal and economic framework for the obligation to purchase power from the QF, the objective of PURPA is clear – to encourage the development of the QF in order to reduce reliance on fossil fuels. As discussed above, the Supreme Court has recognized this legislative intent and upheld the FERC's decision "to prescribe the maximum rate authorized by Congress and thereby provide the maximum incentive for the development of [QFs]." American Paper Institute, Inc., 461 U.S. at 418.

Witness Bowman also points out that North Carolina has adopted the requirements of PURPA for small power producers (defined as hydroelectric generators no larger than 80 MW), which is codified in section 62-156 of the North Carolina General Statutes. Analogous to PURPA, North Carolina's law provides that the rate paid by the utility to the QF shall not exceed, over the term of the purchase power agreement, the incremental cost to the electric utility of the electric energy which, but for the purchase from the QF, the utility would generate or purchase from another source. North Carolina's law emphasizes

PURPA's objective of encouraging QF development by establishing the standard that the Commission should require purchase power agreements of sufficient length "to enhance the economic feasibility of small power production facilities." N.C. Gen. Stat. § 62-156(b)(1). Thus, both Congress and the North Carolina General Assembly have developed a legal framework that encourages the financial feasibility, and therefore, the development of QFs.

Q. HOW DO YOU RESPOND TO THE DEP/DEC CONTENTION THAT THE CURRENT POLICIES IN PLACE TO ENCOURAGE THE DEVELOPMENT OF RENEWABLE ENERGY RESOURCES ARE MORE THAN SUFFICIENT?

A. DEP/DEC point out that, as of March 28, 2013, there were more than 1650 MWs of proposed solar generation facilities in the interconnection queues of the two companies and that this number has increased since that time. DEC and DEP would have the Commission believe that the rates and policies in place are sufficient based on the proposed capacity in the interconnection queues alone. However, DEC and DEP fail to point out that many of the proposed solar facilities never get built. Thus, not all proposed capacity is actually built and placed in service, and the utility does not pay for capacity that is not placed in service.

Moreover, in my experience, an application for interconnection typically is the first step in the development of a QF. As there is a queue of projects waiting for interconnection in DEC and DEP service territories, submitting an application as early as possible in the development process ensures that a project has a place in the queue, while the applicant secures the additional approvals, site control and financing necessary for the project. To this end, an applicant for an interconnect request does not have to demonstrate site control or financing for the project. The fee associated with the interconnection request is minimal relative to total project cost—$500 for projects larger than 100 kW but smaller than 2 MW and $1000 for larger projects. Thus, there is little barrier to entry into the interconnect queue. Therefore, the amount of capacity in the interconnection queues is not an accurate reflection of whether and the extent to which conditions in North Carolina are sufficient to aid and encourage the development of QFs.

In addition, DEC and DEP fail to identify for the Commission which of this proposed capacity is eligible for the rates approved by the Commission in Docket No. E-100, Sub 127 (the previous avoided cost proceeding) and which is eligible for the rates that will ultimately be approved in this proceeding. In fact, counsel advises me that only a very small percentage of that proposed capacity is eligible for rates approved by the Commission in Docket No. E-100, Sub 127.

As pointed out by the Public Staff, the rates proposed by the Utilities in this docket are significantly reduced from the previously approved rates, in some cases by as much as 29%. On December 21, 2012, the Commission issued an order requiring DEP to offer to QFs the long-term, fixed rates proposed in this docket, subject to true-up if the Commission approves rates higher than those proposed. Thereafter, on May 14, 2013 the Commission issued an order in this docket, requiring DEC and DNCP to offer to QFs the long-term, fixed rates proposed in this docket, also subject to the same true-up. Therefore, the rates to be approved by the Commission in this proceeding are actually unknown, and the amount of proposed capacity that is actually built depends in large part on the outcome of this proceeding.

To illustrate the example of the effect of the proposed rates on QF development, of the solar QFs developed by Strata and currently selling power to the Utilities, only one of those projects sells power to the Utilities at the rates proposed in this proceeding, and that project was economically feasible for reasons specific to the project, that would not be applicable to future projects.

Q. PLEASE EXPLAIN HOW THE RATES PROPOSED BY THE UTILITIES, IF APPROVED BY THE COMMISSION, WOULD AFFECT DEVELOPMENT OF QFS IN NORTH CAROLINA.

A. The QF development process is capital intensive and requires significant up-front capital investment. In evaluating the overall economic profile of a QF development project, investors consider the project's internal rate of return ("IRR"), which is the annualized effective compounded return rate or the interest rate at which the net present value of costs of the investment equals the net present value of the benefits of the investment. The IRR is a measure of the yield of an investment. Calculating the IRR takes into account the project's cash flows over periods of time.

A project's revenue is wholly dependent on the rates offered by the Utilities, so as rates decrease, cash flow decreases, and IRR decreases. Decreasing IRRs jeopardize the project developer's ability to secure financing. Specifically, as IRRs decrease, securing debt financing is increasingly difficult, as debt investors are less willing to invest in the project. If the capital structure of a project involves less debt financing, more equity financing is required. As a general rule, equity financing is more expensive than debt financing. Therefore, the more that decreasing IRR shifts capital structure away from debt and toward equity, the less likely that a QF project developer will be able to access sufficient capital to develop the project.

My experience is that the typical capital structure of solar QFs in North Carolina is approximately 60% equity and 40% debt. Based on our experience with the capital markets, IRRs in the range of 8-12% are necessary to attract investors. Based on my experience in the industry, projects that sell power at the rates approved in Docket No. E-100, Sub 127 produce IRRs at that threshold. A 20% decrease in rates, as proposed by the Utilities, will drop IRRs below that threshold, even in a decreasing cost environment.

Given the proposed rates, I am aware that some QF developers, including my employer, which is one of the most prolific developers in the state, are investigating development opportunities in states other than North Carolina. If the Commission approves the rates as proposed, my experience leads me to conclude that many QF developers will cease to do business in North Carolina.

Q. ARE THERE OTHER ISSUES YOU WOULD LIKE TO BRING TO THE COMMISSION'S ATTENTION?

A. Yes. Several provisions in the Utilities' terms and conditions for the standard purchase power agreements are particularly problematic to QF developers and constitute barriers to financing a project.

First, DNCP's proposed standard contract requires a QF to accept payments that are reset at new rate levels or repay certain sums to DNCP in the event a regulatory body with jurisdiction, such as the Commission or FERC, issues an order that: 1) disallows payments of energy or capacity to non-utility generators; 2) prohibits DNCP from recovering through rates any sums previously paid to non-utility generators; or 3) requires DNCP to repay to ratepayers sums already paid to non-utility generators. <u>See</u> Article 6, Agreement for the Sale of Electrical Output to Virginia Electric and Power Company, Schedule 19-FP. The uncertainty created by this provision is a barrier to financing a QF project, as investors are unwilling to overlook the asserted right of DNCP to modify rates and collect a refund. This contract provision is one of the primary reasons why QF development in DNCP's service territory is minimal, relative to the service territories of DEC and DEP. Furthermore, as explained by the FERC in its Order No. 69, "in order to be able to evaluate the financial feasibility of a [QF], an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before the construction of a facility." Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,868. This contract provision creates unnecessary uncertainty regarding an investor's expected return on a potential investment, in what appears to me to be a violation of Order No. 69. Additionally, the contract provision is inconsistent with the clear and unambiguous right of the QF set forth in 18 C.F.R. § 292.304(d)(2) to fixed rates over the term of the power purchase agreement. In my own experience, Strata has not developed solar facilities in DNCP service territory because of this provision. Thus, the contract provision discourages QF development.

Second, Section 2 of DEC's Standard Purchased Power Agreement addresses the rate schedule and service regulations. The final sentence of this section provides that the:

> Rate Schedule and Service Regulations are subject to change, revision, alteration or substitution, whether in whole or in part, upon order of said Commission or any other regulatory authority having jurisdiction, and any such change, revision, alteration or substitution shall immediately be made a part hereof as though fully written herein, and shall nullify any prior provision in conflict herewith.

See Duke Energy Carolinas, LLC, Initial Statement and Exhibits, Exhibit 5, Docket No. E-100, Sub 136 ("DEC Standard Contract"). The Commission has previously rejected an analogous provision in DEC's PPA be limited to changes in variable rates and has not allowed fixed rates in executed contracts to be changed. As the standard contract proposed by DEC in this proceeding does not contain this limitation, both the variable rates and fixed rates would be subject to change. This provision casts such uncertainty on the stability of the standard contract that it will be difficult, if not impossible, for small power producers to obtain long-term financing. In addition, the removal of this limitation undermines the availability of fixed long-term rates "calculated at the time the obligation is incurred" as required by PURPA, 18 C.F.R. § 292.304(d)(2)(ii).

Third, Section 6 of DEP's Terms and Conditions for the Purchase of Electric Power addresses early contract termination or changes in contract capacity or contract energy. See TERMS AND CONDITIONS FOR THE PURCHASE OF ELECTRIC POWER, Progress Energy Carolinas, Inc., Initial Statement and Exhibits, Attachment 4, Docket No. E-100, Sub 136 ("DEP Terms and Conditions"). The subsection on the reduction in contract energy contains a Reduction-In-Contract-Energy-Charge if the "[s]eller's average energy generated in the on-peak or off-peak periods during any 12-month period falls below 80% of the Contract On-Peak or Off-Peak energy level." The Reduction-in-Contract-Energy-Charge is unnecessary and unduly punitive for QFs that generate electricity using variable resources. The Utilities do not pay a QF unless electricity is generated by and received from the QF. Charging a small QF when production is off by 20% (or falls below 80%) unfairly enriches the electric utility at the expense of the QF. This is particularly unfair when the QF relies on variable resources such as hydro, solar or wind and causes hardship for the QF developer when attempting to access capital on reasonable, workable terms. Therefore, the Reduction-In-Contract-Energy-Charge should be removed from the DEP Terms and Conditions. It is worth noting that the DEC Standard Contract does not contain an identical provision, which is an improvement in process and practice that DEP should be required to adopt.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BY MS. MITCHELL:

Q Mr. Morrison, did you provide a summary of your testimony that you would like to provide at this time?

A Yes, I did.

Q Please do so.

A My name is John E.P. Morrison. My business address 50101 Governors Drive, Suite 280, Chapel Hill, North Carolina, 27514. I'm the Chief Operating Officer of Strata Solar, LLC. Strata is a solar development and construction company headquartered in Chapel Hill. As Chief Operating Officer of Strata Solar, I oversee the construction and operation of solar facilities.

I'm testifying on behalf of the Renewable Energy Group, which is a consortium of operators, developers, suppliers, installers, designers, builders, and/or managers of the types of facilities entitled to the avoided cost rates established in this proceeding referred to as qualifying facilities, or QFs, in the Public Utility Regulatory Policy Act of 1978.

The purpose of my testimony is to summarize the potential impact on the renewable energy industry of the rates proposed by the utilities in this proceeding. The rates proposed by Duke and Progress in this docket are significantly reduced from those rates approved by the

Commission in the last biennial proceeding, in some cases by as much as 20 percent. The impact of these rates on the development of renewable energy resources will be grave. In fact, given the proposed rates, many, if not all, of the developers will cease to do business in North Carolina. Despite what the utilities would have the Commission believe, the industry is not looking for a windfall; rather, the industry is participating in this docket to ensure that the rates approved by the Commission reflect the utilities full avoided cost.

My testimony also discusses two contract provisions, the reduction in contract energy provision in Progress' standard terms and conditions, and the regulatory disallowance provision in Dominion's standard purchase power agreement. Both of these contract provisions are unfairly punitive to the QF and discourage QF development.

The regulatory disallowance provision contained in Dominion's standard purchase power agreement requires QF to refund to the utility any amounts that are disallowed from recovery by the utility as a result of a disallowance order from a regulatory body, such as the North Carolina Utilities Commission. In addition, the contract provision allows the Company to reset the rate paid to the QF in accordance with the amount deemed by the regulatory body to be recoverable from the ratepayers. The contract provision inequitably places the entire burden of a regulatory disallowance clause on the QF. In addition, the contract provision effectively nullifies the QF's right to a fixed rate over the term of the contract, as that rate would change in the event of a disallowance order. The uncertainty created by this provision is a barrier to financing a QF project, as investors are unwilling to overlook the asserted right in the contract of Dominion to modify rates and collect a refund.

This contract provision is one of the primary reasons why QF development in DNCP's service territory is minimal, relative to the service territories of Duke and Progress, whose PPAs do not contain an analogous provision. My understanding, based on a familiarity with the solar industry in North Carolina, is that this contract provision has been a barrier to finance for developers attempting to secure debt financing for projects in Dominion's service territory. In my own experience, Strata has not been able develop solar facilities in DNCP service territory because of the provision, and Strata has good relationships with several leading institutions, as evidenced by our ability to secure financing for projects in other service territories in North Carolina. Thus, the contract provision clearly discourages QF development.

That is my summary.

MS. MITCHELL: Thank you. The witness is available for cross.

COMMISSIONER BROWN-BLAND: Okay. Is there cross from -- Mr. Youth.

CROSS EXAMINATION BY MR. YOUTH:

Q **Good morning, Mr. Morrison.**

A Good morning.

Q **Were you in the hearing room during the direct and cross of Dr. Reading?**

A Yes, I was.

Q **And did you hear the questions Mr. Allen asked and Dr. Reading's responses regarding whether solar was constrained in any way?**

A Yes, I did.

Q **Can you tell me, is there a difference between all solar and QF solar, and is QF solar constrained in any way in North Carolina?**

A Well, I would simply -- would certainly agree with the comments earlier that the sun does shine very abundantly on North Carolina; however, QF facilities are not unconstrained in where they can be located and developed. It's actually rather difficult to find locations for QF facilities where we can meet the necessary environmental conditions where we have access and effectively -- cost effective access to the grid, and so the -- what seemed to be the comment earlier was that it's unconstrained is actually not our experience. We are rather quite constrained in where we can put our QF facilities.

Q So I think the word that was used was solar's ability to be placed in North Carolina is unlimited. You would disagree with that, correct?

A Well, I think if you were looking at net metered systems and the like, but that's not what we're talking about here. We're talking about systems that would qualify under a QF facility and -- and, yes, if we're referring to QF facilities, that statement is not correct, in our experience.

Q I'm going to toss you a softball.

A Thank you.

Q Mr. Allen asked Dr. Reading a lot of questions that might have been addressed to a developer of QF solar.

A Sure.

Q **Do you recall any of those questions, or would you like to comment on any of those questions or any lines of inquiry that you overheard?**

A Well, certainly. I mean, I think, you know, one of the lines of questioning --

MR. SOMERS: Let me just object. This Commission consistently has prohibited sweetheart cross, which this clearly sounds like to me.

COMMISSIONER BROWN-BLAND: Overruled.

A As I was going to say, we've heard a lot of comments about the pipeline or the number of projects that have been filed for CPCN as indicative of a marketplace that is booming in -- in solar, and I would simply note that the CPCN is the first step in a very long, laborious process of developing a project. Fortunately, it's a step that is relatively low cost and, therefore, there's a relatively low barrier entry, so it's very easy for a developer to file for a CPCN, but then to actually go through the process of all the interconnection studies, interconnection upgrades, the environmental permitting, the Corps of Engineers and the like, what you see is a lot of projects that fail to actually make it to actual construction, and the biggest hurdle being, one, the ability to get financing for the projects.

Q **Anything else? There doesn't have to be.**

A No, no.

MR. YOUTH: No further questions.

COMMISSIONER BROWN-BLAND: Okay. Further cross? Ms. Ottenweller?

CROSS EXAMINATION BY MS. OTTENWELLER:

Q **Good morning.**

A Good morning.

Q **Mr. Morrison, you stated in your testimony that you are the COO of Strata Solar.**

A That's correct.

Q **So you oversee construction and operation of solar facilities?**

A That's correct.

Q **Strata Solar has developed more than 250 MW of solar QFs, right?**

A We're rather proud of that, yes.

Q **Okay. In your experience, what is the typical size of a solar QF?**

A The ones that Strata develops are right at or just below the 5-MW limit.

Q **Okay. And how long, on average, does it take**

for a project of that size to get up and running?

A The development process can be anywhere from six to 12 months, and longer in some cases. The construction process is typically around three months for that average -- for that typical 5-MW solar farm.

Q So the lead time from planning to commercial operation is somewhere around a year, maybe longer?

A Yeah, a year.

MS. OTTENWELLER: Thank you. No further questions.

COMMISSIONER BROWN-BLAND: Any cross?

MR. SOMERS: Based on the settlement with the REG group and Duke energy companies, we have no cross for Mr. Morrison.

COMMISSIONER BROWN-BLAND: And I take it Dominion --

MR. HORNE: Dominion does, just on the regulatory disallowance clause, Your Honor.

COMMISSIONER BROWN-BLAND: All right.

CROSS EXAMINATION BY MR. HORNE:

Q Mr. Morrison, my name is Pat Horne --

COMMISSIONER BROWN-BLAND: Mr. Horne, can you get that mic?

MR. HORNE: Oh, sorry. Yes, ma'am.

BY MR. HORNE:

Q Mr. Morrison, my name is Pat Horne, and I'm representing Dominion North Carolina.

COMMISSIONER BROWN-BLAND: You might have to sit up there near it. I assume that one is working, unlike the other one from yesterday.

MR. HORNE: Can you hear me now?

COMMISSIONER BROWN-BLAND: There you go.

BY MR. HORNE:

Q Mr. Morrison, is a utility compelled by law to purchase energy and capacity from a QF?

A That's my understanding of PURPA 1978.

Q And if a utility were to attempt to refuse to buy from a QF, that QF could come to this Commission and ask it to force the utility to make it -- to make the purchase?

A That's my understanding of the provisions of the law, yes.

Q Does DNCP earn any return on its purchases from a QF?

A I'm not in a position to know whether or not they do.

Q Do you know whether this Commission or the Virginia Commission has disallowed DNCP's recovery of QF

payments in the past?

A In preparation for this, I was informed that that has occurred in the past.

Q If a regulatory body issues a disallowance, do ratepayers continue paying for the disallowed portion?

A I'm not in a position to be able to answer that question.

Q Will you assume with me, for the purposes of this next question, that for -- will you assume with me that ratepayers do not continue to pay?

COMMISSIONER BROWN-BLAND: Mr. Morrison, we -- will you please --

A If that's what you say.

COMMISSIONER BROWN-BLAND: -- will you please also speak up into the mic?

THE WITNESS: I'm sorry. Yes.

BY MR. HORNE:

Q So ratepayers stop funding the portion that's disallowed, if you will assume that, subject to check.

A Certainly.

Q Okay. Now, if a regulatory body issues a disallowance order, and this is in a contract without a disallowance -- a reg-out clause, what happens to the payments to the QF?

A If I understand your scenario, that if there is no clause, the payments -- I would presume the utility would continue to honor its contract.

Q And the utility -- and then the QF would get its full payments?

A If that's what their contract says, yes.

Q Okay. And assuming that the utility is not recovering the QF payments from its ratepayers, where does the money for the continued payments to the QF come from?

A I wouldn't be in a position to know that.

Q Would it perhaps be the Company and its shareholders?

A I presume so, yes.

Q Thank you. To sum up, just to make sure we're on the same page here, would you agree that the end result of a disallowance is that the QF retains all the benefits of the contract, and the entire burden of disallowance is borne by DNCP and its shareholders?

A In the scenario you constructed, yes. Sounds like that would be the case.

Q Mr. Morrison, you stated that the contract revision we're talking about, the reg-out clause now, inequitably places the entire burden of a regulatory

disallowance on the QF. That was in your summary.

A Yes.

Q Are QF developers willing to share any of the burden of a disallowance?

A I don't think the developers are sufficiently familiar with provisions under which one would occur. The issue that we have is that that statement makes it virtually impossible to get -- does make it impossible to get financing for -- for a project to go forward.

Q So if the Company were to offer to split the burden of a disallowance with a QF so that the QF would bear 50 percent of the burden and the shareholders would bear 50 percent of the burden, do you think that would change an investor's evaluation of the risk of the regulatory out clause?

A It's exceedingly unlikely it would change their evaluation.

Q So it's your testimony that a QF should not or would not bear any of the risk of a disallowance or share that risk with the Company?

A I'm not certain it would be our position. I mean, it's hard to see why Dominion has that clause, whereas the other utilities in this proceeding do not, so it begs the question as to why the other utilities seem to feel there's no issue here, but Dominion does.

Q Because Dominion -- well, we talked a moment ago, and I think you agreed, that you've been informed that we have actually had two disallowances of our regulatory --

A And my understanding of that was that those were not under QF contracts. I stand to be corrected on that, but that's what I've been told.

Q Assume -- assume for me, if you will, without pulling out the orders, that those were a QF contract, please.

A Okay.

Q So -- and are you aware of any disallowance of QF payments by Duke or Progress?

A No, I'm not.

Q Thank you. Mr. Morrison, in your testimony on page 11, lines 21 through 23 -- let me know when you're there.

A Line 21, okay.

Q Okay. You stated that investors are unwilling to overlook the asserted right of DNCP to modify the rates and collect a refund. Is that correct?

A That's -- yes.

Q Paraphrased.

A That's -- that's what it says.

Q Can you point me to the provisions of Article 6 of the contract that gives DNCP the unilateral right to modify rates and collect a refund?

A I don't have that with me.

Q But you reviewed the clause before you gave -- you made your testimony, didn't you?

A Yes. I mean, we've -- and believe me, we've attempted to finance with that clause in place and been unsuccessful in doing so.

Q I do not have 30 copies of the provision in here, but if I showed it to you, could you show me where in the clause it gives Dominion the unilateral right to -- to just change the contract, absent a regulatory order?

A If that's the way that you're interpreting my testimony, then that interpretation is not what was intended. It's the right to modify that based upon the regulatory action.

Q But the regulatory modification would only occur if there had been a regulatory body that ordered the disallowance; is that your understanding?

A That's my understanding, yes.

Q You're not saying that Dominion has a

unilateral right just to change this contract?

A No.

Q Okay. And if investors were laboring under the misapprehension that Dominion had the right to unilaterally change these rates, they would be operating under an incorrect assumption, would they not?

A That certainly would be the case, though that's not the -- I mean, if the clause specifically related to the regulatory move that's -- that's causing the problem with our investors.

Q Mr. Morrison, have you ever asked the Company to talk to your lenders and investors about the disallowance clause or reg-out clause?

A I'd have to check with our development group. I don't know whether they have actually made that approach or not.

Q Is it possible that if such discussions took place, that it might be -- that it might allay some of the concerns of potential investors in QF projects if they actually understood how the clause worked?

A That's certainly -- we spend a lot of time in educating investors, and that probably would be helpful, yes.

Q Okay.

A Whether they would change their mind, I don't know.

Q So -- but bringing the Company in might remove the uncertainty or some of the uncertainty that these investors have?

A I can speculate that it might, yes.

Q But that hasn't been attempted, to your knowledge?

A Not to my knowledge, no.

Q On page 12 of your testimony, you -- lines 3 through 8, you testified that a QF is entitled to reasonable certainty on its expected return on its investment in a QF.

A I'm sorry. I missed the number you were on.

Q Page 12, lines 3 through 8.

A Three, okay.

Q And you testified that a QF is entitled to reasonable certainty on its expected return on its investment in a QF.

A Uh-huh.

Q Does PURPA entitle an investor in a QF absolute certainty of return on its investment?

A I don't think anybody could ever promise absolute certainty on a return on investment.

Q If a QF contract provides a loss of QF status as a termination event, does an investor have to evaluate the risk that a QF will lose its status in deciding whether to --

A Certainly.

Q Does the effect of the potential loss of QF status in the contract mean that the investor does not have reasonable certainty of its investment?

A I think what we've seen, based on the history of developing projects, that investors do have reasonable certainty. That certainly has been our experience in developing these projects.

Q So has there never been a project that lost its contract because it lost its QF status?

A Not in our experience. I'm sure there's somebody out there who has.

Q So it's a risk that investors can evaluate based on probability.

A Yes.

Q Okay. And to your knowledge, accepting my representation that there have been two incidences where Virginia has had a reg-out. So investors can assess the probability of that occurring again.

A They certainly do, and unfortunately, we have been unable to convince them to fund a project in Dominion territory. Their assessment has been that it creates too much of a risk --

Q **Is their assessment --**

A -- for them to finance a project.

Q **So there -- is their assessment that this Commission is a particularly risky commission for disallowance?**

A I can't speak to the, you know, the analysis that was done by the investors. I can only speak to the fact that we have -- believe me, we have tried on numerous occasions. Avoided cost rates in Dominion service territory are preferable to those -- to the other utilities, but we have been unable to convince any of the investors that we currently work with to fund a project in Dominion territory.

Q **Again, these investors have not -- you have not had these investors actually talk to the Company about the disallowance clause?**

A Not to my knowledge.

Q **Okay. Does the effect of potential loss -- excuse me for one second. Does an investor have to evaluate the risk that something will go wrong in construction such that a QF failed to meet the**

construction deadlines under the contract?

A For -- that depends on how the investor is investing in the particular project. Some investors come in prior to completion of construction, in which case the answer is yes. Many investors, however, wait until the completion of construction, in which case construction risk is borne entirely by the developer.

Q Preconstruction for purposes of this question. Is that a risk they have to evaluate, that something will go wrong in construction and they'll -- they'll miss the construction deadlines under the contract?

A Again, it depends on when they come into the project. Many investors do not come in until construction is completed and, therefore, no, they do not have to assume construction risk.

Q Assume to me -- assume with me that it's a preconstruction investment.

A If they came in -- yes, that would be a risk that they would have to assess.

Q They would have to evaluate and they'd have to make an assessment on --

A And let me -- I would -- I would add, that's not a financing mechanism that we see as very prevalent in the industry.

Q But that is an assist -- a risk that they would have to assess based on this probability?

A If they were an investor that came in at that point in the project, yes.

Q Have you reviewed the testimony of -- the rebuttal testimony of Mr. Trexler?

A I have not.

Q You have not?

A No.

Q Okay. So you have no opinion on the comments that Mr. Trexler made in his rebuttal testimony?

A I do not.

COMMISSIONER BROWN-BLAND: Gentlemen, if you both would continue to speak up so we can hear up here.

THE WITNESS: Sorry.

MR. HORNE: Sorry, Your Honor.

BY MR. HORNE:

Q Well, since you haven't reviewed it, assume with me that in the past two years, Dominion has entered into five Schedule 19 contracts that contain the reg-out clause, and an additional 20-MW contract that has an analogous clause. Doesn't that suggest that there are some lenders and investors capable of evaluating -- evaluating and accepting the remote risk of a regulatory

disallowance?

A It certainly would suggest there are some investors, yes.

Q Thank you. And could you -- and if no investor -- Mr. Trexler's testimony -- I'm trying -- you haven't read it. There are -- assume with me that 44 CPCNs were filed in the past year in Dominion's service territory, 30 of which are Schedule 19 size CPCNs. If there are no investors or lenders that are willing to overlook the presence of the regulatory-out clause for the uncertainty that you -- you've asserted to this -- interject -- why would they bother filing a CPCN?

A I think what you're seeing is the optimism of an entrepreneur, because some of those CPCNs are Strata Solar CPCNs.

Q And we noted that.

A And as an entrepreneurial organization, we -- we live in a world of optimism, and expect and hope for a favorable outcome of these particular hearings. We're creating a pipeline so that in the event that things go our way, we can be ready to move.

Q So if the regulatory clause is continued in this contract, Strata will not develop or seek to develop QFs in --

A We will --

Q -- the Company's service territory?

A We will spend our time and energy and efforts in other service territories where they can be -- where we can be sure of better success.

Q And you will not seek out -- seek discussions between your investors and the Company so that they can discuss how the clause works?

A Well, I think you've given us a good idea that maybe we should do that, and at a later point I'd love to get an individual to talk to, to follow up on that. I think it's a good suggestion.

MR. HORNE: I think that's all I have at this time. Thank you, Mr. Morrison.

COMMISSIONER BROWN-BLAND: All right. Redirect?

MS. MITCHELL: Yes, ma'am.

REDIRECT EXAMINATION BY MS. MITCHELL:

Q Mr. Morrison, just a few questions on redirect.

A Uh-huh.

Q Do you recall when counsel for Dominion asked you about the two instances of disallowance that Dominion has experienced?

A Yes.

Q And he asked you if those involved QF contracts. I'm summarizing, but I believe I'm representing his question correctly.

A Yes.

Q And you said you didn't think they were QF contracts?

A My understanding was that they had provisions and things that went above and beyond the standard QF avoided cost contract.

Q So did you mean that -- that those disallowance instances did not involve QFs who were under contract at the standard rates and terms approved by the North Carolina Utilities Commission?

A I'm sorry. Say that again.

Q So it was your understanding that those two instances of disallowance didn't involve QFs --

A Yes. That was my understanding.

Q -- that were under contract at rates and terms that were the standard rates and terms approved by this Commission?

A That was my understanding, --

Q Okay.

A -- yes.

Q Do you recall when counsel for Dominion asked

you about the QF projects that have proceeded to development, the five QF projects that have proceeded to development --

A Yes.

Q -- in Dominion service territory? Do you have any knowledge about the size of those QF projects?

A I do not.

Q Do you have any knowledge about how those projects were financed?

A I do not.

Q Do you know whether those projects were financed?

A I do not.

Q Do you know who owns those projects?

A No, I do not.

MS. MITCHELL: No further questions.

COMMISSIONER BROWN-BLAND: All right. Questions from the Commission?

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q Mr. Morrison, earlier in this proceeding, the REG group, or REG, filed comments, and in those comments there were more contractual issues that were addressed than were subsequently addressed in the testimony. Is that an indication that some of those contractual issues

went away or were resolved?

A In some of the rebuttal testimony, my -- reading that, my understanding was that, yes, some of those were resolved or language was proposed that would deal with the issues that we saw.

Q And is the only remaining concern concerning the disallowance clause, to your knowledge?

A Well, the reduction in energy clause that's in the Progress Energy one still is problematic. It's not as bad as the issue we see at Dominion.

Q So would those --

A But we still spend a lot of time working with our investors to help them understand the uncertainty that it creates.

Q All right. So the DEP clause that you just identified and the Dominion clause that we've been discussing, does that summarize the -- fairly summarize the current concern?

A Yes, it does.

Q All right.

COMMISSIONER BROWN-BLAND: Questions on Commission's questions?

MS. MITCHELL: Just one question.

FURTHER REDIRECT EXAMINATION BY MS. MITCHELL:

Q So Mr. Morrison, just so I understand your response to Commissioner Brown-Bland's questions, assuming that the third contract issue is resolved, as indicated in the rebuttal testimony filed by Duke and Progress, then the only two remaining issues are the regulatory disallowance clause and the reduction in energy charge clause; is that correct?

A That's correct.

MS. MITCHELL: Thank you.

COMMISSIONER BROWN-BLAND: Then Mr. Morrison, you may be excused.

THE WITNESS: Thank you.

(Witness excused.)

COMMISSIONER BROWN-BLAND: All right. Mr. Youth, are you -- is your client ready?

MR. YOUTH: We are ready. I will let the Commission know at this point I would, I think, normally hand out a summary, but I anticipate there might be a question or a motion, and so until I know how that might be resolved, if it's raised, --

COMMISSIONER BROWN-BLAND: Well, --

MR. YOUTH: -- I will not hand out the summary.

COMMISSIONER BROWN-BLAND: All right. Call your witness.

MR. YOUTH: NCSEA calls Karl R. Rabago to testify.

KARL R. RABAGO; Being first duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MR. YOUTH:

Q Mr. Rabago, can you please state your name and business address for the record?

A Yes. My name is Karl R. Rabago. My business address is 8904 Granada Hills Drive, Austin, Texas, 78737.

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

A I am the sole employee and principal of Rabago Energy, LLC, a Texas limited liability company.

MR. YOUTH: Can you hear?

COMMISSIONER BROWN-BLAND: Yes.

THE WITNESS: I didn't want to pop the microphone because I tend to boom sometimes.

BY MR. YOUTH:

Q Did you cause to be prefiled in this docket on September 27th, 2013, direct testimony consisting of 26 pages, with six attached exhibits?

A Yes, I did.

Q And since September 27th, 2013, has anything

changed such that your prefiled testimony needs to be amended?

A Yes, it has.

Q Can you tell the Commission what needs to be amended?

A Yes. Beginning at page 11 of my prefiled testimony, at line 7, --

MS. FENTRESS: Madam Chair, at this time DEP, DEC, and Dominion North Carolina would object if Mr. Rabago is seeking to amend his prefiled testimony with an amendment to testimony that was filed outside of the Commission's rules.

THE WITNESS: That's Rabago.

MS. FENTRESS: I apologize.

COMMISSIONER BROWN-BLAND: Do you want to be heard, Mr. Youth?

MR. YOUTH: I would.

THE WITNESS: Should I -- should I finish pointing out where it is or before we get --

COMMISSIONER BROWN-BLAND: Well, wait until -- let's see.

MS. FENTRESS: Madam Chair, just to expound on what I said, the Commission's rules, Rule R1-24(g), I believe, indicates that intervenor testimony should be filed at least 20 days prior to an evidentiary hearing, and this -- we're not arguing merely that there was a technical violation of the rule, but rather that this late filing goes to the heart of what the rule is supposed to protect and preserve, and that is each party's rights to present their case fairly. The utilities here have the burden of proof.

This late-filed amendment was done far later than the time that the intervenors filed their direct testimony. The intervenors had six weeks after the utilities filed their direct testimony to put on their case. This amendment was not part of that case, and this amendment and additional exhibit was filed simultaneously, at best, with the rebuttal testimony and, therefore, the utilities are prejudiced. We have not been able to respond in our rebuttal testimony, and have had an extremely abbreviated time to even review the information contained therein.

I would also say that the rules have a different purpose as well. They help the Commission with the efficient administration of these proceedings. If -- if the rule was not in place, all the parties could simply file testimony, supplementing and updating their previously filed testimony, right up to the day of hearing, and I don't believe that would be very helpful to the Commission or to any of the parties in the efficient administration of these proceedings.

And, therefore, for those reasons, we request that the Commission uphold that rule and strike the proposed amendment to Mr. Rabago's testimony and the proposed exhibit to be added to his testimony. Thank you.

COMMISSIONER BROWN-BLAND: Okay. Mr. Youth?

MR. YOUTH: Thank you. General Statute 62-65(a) indicates, first sentence, "When acting as a court of record, the Commission shall apply the rules of evidence applicable in civil actions in the Superior Court insofar as practicable."

I would ask the Commission to take note of General Statute 8C-102, this is Rule 102, that talks about the purpose and construction of the rules of evidence, and subsection (a) says, "These rules shall be construed to secure fairness in administration, elimination of unjustifiable expense and delay, and promotion of growth and development of the law of evidence to the end that the truth may be ascertained and proceedings justly determined."

I would also ask the Commission to look at Rule

401. That defines what relevant evidence is. I think this is relevant to this proceeding. I will ask that my filing from several days ago supplement that point. Rule 402 and 403 also talk about the fact that relevant evidence is generally admissible. 403 says, "You can't exclude evidence on grounds of prejudice, confusion, or waste of time."

There wasn't any more prejudice in this case, based on the filing and the notice that was given by NCSEA, than parties on this side of the table face when a settlement that agrees on a CT cost is filed into the record two or three days before the hearing. That CT cost doesn't attribute the aggregate cost to useful life or contingency adder, and yet we deal with that. We come here and we put on the best case we can.

I believe the utilities had enough time to consider this. They have the ability to cross examine Mr. Rabago.

COMMISSIONER BROWN-BLAND: All right, Mr. Youth. I've heard enough. I'm going to deny the motion to strike and deny the motion by Duke, Dominion, and DEP, and I'm overruling it in part, among other reasons, because the witness is obligated to inform this forum if there is a change during the pendency of the proceeding that makes his prefiled testimony incorrect or misleading, and he -- I believe that this correction goes to that purpose, and also the report was only made available after the time had passed for filing, for the intervenors to file their testimony.

Also, I believe this report was filed on October the 10th -- I mean, October the 18th, and I believe they gave sufficient time to avoid undue prejudice to Duke. There are other reasons, but those are the main ones, so the motion is denied.

You may proceed to question.

MR. YOUTH: Thank you, Commissioner Brown-Bland.

BY MR. YOUTH:

Q Mr. Rabago, I'll repeat the question that was pending. Can you tell the Commission what needs to be amended in your testimony?

A Yes. Again, that was beginning on page 11 of my prefiled testimony at line 7, and continuing through to page 14 at line 3, where I was asked and answered four questions that touch on or relate to whether or not I was aware of any public solar cost benefit study results for North Carolina.

At the time I answered the questions, I was not aware of such studies. Now, the Crossborder Energy report, which was released on October 18th, I first want to note that I am now aware of that study and have familiarized myself with it, I have reviewed it, and I find it consistent with my earlier conclusions, and it does not alter my testimony.

Q It does not alter your recommendation?

A Or my recommendation.

Q But your testimony --

A Or my conclusions. My conclusions, my recommendations, or my testimony in, yeah, the substance of my testimony.

Q Okay. Would you like the North Carolina study to be attached to your testimony as Exhibit KRR-7?

A Yes, I would. If it had been available, I would have attached it when I filed my testimony in the first place.

MR. YOUTH: Commissioner Brown-Bland, I would ask that the North Carolina Crossborder study that's been filed with the Commission be marked as Exhibit KRR-7.

COMMISSIONER BROWN-BLAND: It will be so marked.

(Whereupon, Exhibit KRR-7 was marked for identification.)

BY MR. YOUTH:

Q **Mr. Rabago, are there any other changes or amendments?**

A There are none.

Q **Taking your amendments from the stand into account, if I were to ask you the questions posed in the prefiled testimony today, would your answers be the same?**

A They would be substantially the same.

MR. YOUTH: Commissioner Brown-Bland, at this time I would ask that Mr. Rabago's prefiled direct testimony and exhibits, as amended from the stand, be entered into the record as if given orally from the stand, and that Rabago Exhibits KRR-1 through KRR-7 be marked for -- marked for identification as prefiled.

COMMISSIONER BROWN-BLAND: All right. That motion will be allowed, and the direct testimony of Karl R. Rabago, consisting of 26 pages and as amended here today on the record, and the seven exhibits -- well, and seven exhibits will -- the testimony will be received into evidence as if given orally from the stand, and the seven exhibits will be identified as premarked.

(Whereupon, the prefiled direct testimony of Karl R. Rabago, as amended, was copied into the record as if given orally from the stand.)

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 136

Testimony of Karl R. Rábago
On Behalf of the North Carolina
Sustainable Energy Association

September 27, 2013

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Karl R. Rábago. My business address is 8904 Granada Hills Drive, Austin, Texas.

Q. BY WHOM ARE YOU EM PLOYED AND IN WHAT CAPACITY?

A. I am the principal of Rábago Energy LLC, a Texas limited liability company.

Q. WOULD YOU DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. As to my education, I hold a B.B.A. in management (1977) from Texas A&M University, a J.D. with honors (1984) from the University of Texas School of Law, and LL.Ms in military law (1988) and environmental law (1990) from, respectively, the U.S. Army Judge Advocate General's School and Pace University School of Law. As to my work experience, I served for more than twelve years as an officer in the U.S. Army, including in the Judge Advocate General's Corps and as an assistant professor of law at the United States Military Academy at West Point, New York. I have also worked for more than 20 years in the electricity industry and related fields. I have served as a Commissioner with the Texas Public Utility Commission (1992-1994) and as a Deputy Assistant Secretary for the Office of Utility Technologies with the U.S. Department of Energy (1995-1996). More recently, I have served as Director of Government and Regulatory Affairs for the AES Corporation (2006-2008) and as Vice President of Distributed Energy Services for Austin Energy, a large urban municipal electric utility in Texas. In 2012, I founded and became the principal of Rábago Energy LLC. I also currently serve as Chairman of the Board of Directors of the Center for Resource Solutions (1997-present) and as a member of the Board of Directors of the Interstate Renewable Energy Council (2012-present). My education and work experience is set forth in detail on my resume, attached as **Exhibit KRR-1**.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION") OR OTHER STATE OR FEDERAL BODIES?

A. While I have not previously submitted testimony before the Commission, I have testified under oath before several state regulatory agencies, including the Georgia Public Service Commission, the Louisiana Public Service Commission, and the Michigan Public Service Commission, and before Congress and state legislatures, including most recently the Minnesota State Senate and House of Representatives.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The electric utilities' proposed 2012 biennial avoided cost rates were filed with the Commission in November of last year. The Public Staff of the North Carolina Utilities Commission ("Public Staff"), the Renewable Energy Group ("REG"), and the North Carolina Sustainable Energy Association ("NCSEA") have asserted, in their pre-hearing comments, that the electric utilities' proposed rates do not accurately represent the electric utilities' "full avoided costs."[1] The purpose of my testimony is to help demonstrate that traditional avoided cost calculations are inadequate to objectively capture the "full avoided costs" associated with solar electric facilities, and that valuation studies and analyses published over the last several years demonstrate this inadequacy with empirical data. I recommend that the Commission address this inadequacy by implementing a short-term and a longer-term approach that will better ensure that "full," non-discriminatory avoided cost rates are offered to qualifying solar electric facilities in both the short-term and the longer-term.

[1] In multiple Commission orders, such as those issued in Dockets E-100, Sub 100 and E-100, Sub 127, this Commission has indicated that the rates it approves must represent the utilities' "full avoided costs."

Q. PLEASE EXPLAIN HOW YOUR TESTIMONY IS ORGANIZED FOR PRESENTATION.

A. I begin my testimony with a brief overview of Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") and the primary purpose of this Commission's biennial proceeding to determine avoided cost rates for electric utility purchases from qualifying facilities. I then speak to the value of solar electric facilities and how traditional avoided cost calculations, such as the "peaker" methodology currently used by this Commission, can fail to adequately capture the "full avoided costs" associated with qualifying solar electric facilities, leading to unintentional but nonetheless impermissible discrimination against qualifying solar electric facilities. Finally, I propose an approach that this Commission can take to more accurately recognize the full avoided costs associated with qualifying solar electric facilities.

OVERVIEW OF PURPA AND PURPOSE OF COMMISSION'S BIENNIAL PROCEEDING TO DETERMINE AVOIDED COST RATES

Q. WHAT IS PURPA?

A. PURPA refers to the Public Utility Regulatory Policies Act of 1978. PURPA is federal legislation that was enacted by Congress and signed into law in 1978. Congress has amended PURPA several times since 1978.

Q. WHAT FEDERAL AGENCY IS CHARGED WITH INTERPRETING PURPA?

A. The Federal Energy Regulatory Commission ("the FERC") is the primary federal agency charged with interpreting and implementing PURPA by making rules and issuing orders.

Q. CAN YOU PROVIDE A BRIEF OVERVIEW OF PURPA AS IT RELATES TO THE AVOIDED COST RATES BEING SET IN THIS PROCEEDING?

A. Yes. In this Commission's 2011 final order in Docket No. E-100, Sub 127, the Commission itself provided an overview of PURPA as it relates to the avoided cost rates being set in this proceeding (I have italicized a portion of the Commission's overview to emphasize it):

> Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities that meet certain standards and are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities (QFs), and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA. *Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities that obtain qualifying facility status under Section 210 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, are in the public interest, and do not discriminate against cogenerators or small power producers.* The FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers reflect the cost that the purchasing utility can avoid as a result of obtaining energy and

capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers.

Q. GIVEN THE COMMISSION'S OVERVIEW OF PURPA, WHAT IS YOUR UNDERSTANDING OF THE PRIMARY PURPOSE OF THIS PROCEEDING?

A. In this proceeding, I believe the Commission's primary task is setting "full" avoided cost rates which (1) are just and reasonable to the ratepayers of North Carolina's electric utilities, (2) are in the public interest, and (3) do not discriminate against cogenerators or small power producers.

VALUE OF SOLAR ANALYSIS

Q. WHAT IS "VALUE OF SOLAR" ANALYSIS?

A. Value of solar ("VOS") analysis is, in essence, a full avoided cost approach with a long term valuation perspective. Most VOS studies share a common general approach and fairly common general structure. VOS analysis identifies and characterizes the value attributes of distributed solar energy generation in two steps: First, benefits and costs are identified and grouped. Second, the benefits and costs are quantified. Valuation results vary depending on specific methodologies, local energy markets, and other factors, but a growing body of VOS research consistently demonstrates that distributed solar energy has value that significantly exceeds electric utility and ratepayer costs.

Q. GENERALLY, WHAT ARE THE BENEFITS AND COSTS STUDIED IN VOS ANALYSIS?

A. The benefits and costs studied in a VOS analysis are those that accrue to the utility and its ratepayers as a result of meeting demand for electricity services using a distributed solar electric facility rather than the incumbent electric utility's current and planned system resources. These benefits and costs are created when energy generated at the solar facility is generated and consumed over the entire useful life of the facility and are quantified using system average and locationally-specific values associated with displaced utility "system" energy.

Q. CAN YOU IDENTIFY GENERAL CLASSES OR CATEGORIES OF BENEFITS AND COSTS EXAMINED IN VOS ANALYSIS?

A. Yes. At a high level, the benefits and costs studied in VOS analysis fall into the following classes or categories:

- Energy: The basic electrical energy created by the distributed solar electric facility, plus a credit for line-loss savings that accrue because distributed solar displaced generation from remote, central station plants.

- Capacity: Also referred to as "demand." Capacity values capture the avoided capital investments in generation, transmission and distribution that flow from distributed solar generation units.

- Grid support (interconnected operations services): Often referred to as "ancillary services." These benefits include affirmative provision of services and avoidance of costs related to a range of services inherent in maintaining a reliable, functioning grid network. This grid support or ancillary services include, at both the transmission and distribution level, reactive supply and voltage control, regulation and frequency response, energy and generator imbalance, scheduling, forecasting and system control and dispatch.

- Customer benefits: Customers accrue a number of benefits from hosting and operating distributed solar systems including reputational, community participation, bill management and stability, and efficiency support benefits. While some of these benefits do not accrue to the utility, some do, such as the reduced bad debt and delayed payment costs that accompany self-generation.

- Financial and security benefits: These benefits generally reduce both the cost and risk associated with maintaining reliable electric service for customers, especially in the face of variable regulatory, economic, and grid security conditions. These benefits include control of the utility's fuel price volatility and the costs associated with emergency customer power and outages, as well as more rapid and less costly recovery from outage events.

- Environmental benefits: Distributed solar creates benefits in reducing the supply portfolio costs associated with control of criteria pollutants, greenhouse gas emissions, water use, and land use. Where control regimes exist, these costs may be reflected in the cost of operating polluting resources. Distributed solar valuation goes beyond traditional avoided cost approaches in recognizing that these resources also affirmatively reduce financial risks associated with compliance with future control regimes.

- Social benefits: Distributed solar also generates social benefits associated with net job growth benefits compared to "conventional" generation options, increased local tax revenues, reduced occupational safety costs (such as black lung insurance), and others.

Q. EARLIER YOU TESTIFIED THAT A GROWING BODY OF VOS RESEARCH CONSISTENTLY DEMONSTRATES THAT DISTRIBUTED SOLAR ENERGY HAS VALUE THAT SIGNIFICANTLY EXCEEDS THE INCUMBENT ELECTRIC UTILITIES' AND UTILITY RATEPAYERS' COSTS. CAN YOU MORE CLEARLY IDENTIFY THE BODY OF VOS RESEARCH TO WHICH YOU REFERRED?

A. Yes. A representative list of the studies is described in greater detail in attached **Exhibit KRR-2**. The exhibit is a recent report from the Rocky Mountain Institute's ("RMI") eLab Project entitled "A Review of Solar PV Benefit and Cost Studies."

Q. WHAT, IF ANY, CONCLUSIONS HAVE YOU DRAWN FROM YOUR REVIEW OF THE BODY OF VOS RESEARCH?

A. My review of the RMI meta-analysis of the published studies on the value of solar reveals substantial value in each of the categories described above. While the published studies differ in important respects so that they cannot be simply averaged or summed, I reach the following conclusions:

- Studies with more comprehensive analysis discern greater value in a greater number of categories.

- Studies that calculated the levelized value of a stream of benefits and costs associated with solar electric generation over the useful life of the facilities reveal substantially greater value than those using annualized estimates of value. "Snapshot" analyses are highly influenced by current rate, fuel price, and other parameters.

- Studies that internalize planning assumptions that are biased against distributed resource scale and other characteristics systematically underrate the value of distributed solar.

- Studies that quantify risk, such as the risk of fuel price volatility and the risk of environmental regulation, find greater value in solar electric generation, which has little or no risk in these categories.

- Non-utility solar electric generation mitigates significant risk associated with utility-owned facilities, and substantially reduces the net investment cost for generation for all ratepayers.

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In sum, based on my review of the RMI analysis and the body of published VOS studies, a comprehensive and unbiased analysis of the benefits and costs of solar electric generation will reveal net value that substantially exceeds the cost to the utility and its ratepayers to stimulate development and use of this resource option.

Q. ARE YOU ASSERTING THAT QUALIFYING SOLAR ELECTRIC FACILITIES IN NORTH CAROLINA ARE CONFERRING NET BENEFITS TO THE ELECTRIC UTILITIES AND THEIR RATEPAYERS?

A. None of the VOS studies used in the RMI analysis or in my analysis were based on specific data from a North Carolina electric utility's service territory. That said, enough research is complete in the United States that general application is reasonable. Given the diversity of the data sets from which the completed VOS studies are drawn, and the relatively high importance of energy costs in the estimation, it is reasonable to conclude that the value delivered by distributed solar generation to North Carolina electric utilities and their ratepayers is comparable to that revealed in the body of VOS research that both RMI and I have analyzed.

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Q. YOU STATED THAT NONE OF THE VOS STUDIES YOU USED IN YOUR ANALYSIS WERE BASED ON SPECIFIC DATA FROM A NORTH CAROLINA ELECTRIC UTILITY'S SERVICE TERRITORY. DID YOU SPECIFICALLY EXCLUDE ANY NORTH CAROLINA VOS STUDY RESULTS?

A. No, I did not. I am not aware of any published VOS study results in North Carolina.

Q. DOES THE ABSENCE OF VOS STUDY RESULTS FOR NORTH CAROLINA ALTER YOUR POSITION?

A. No, it does not. It is worth repeating: A strong body of research exists on this topic nationally. The RMI eLab report that I cited earlier and have attached as an exhibit reviews fifteen VOS and other studies addressing distributed solar generation benefits and costs. Among the more prominent researchers, Richard Perez led a team that published a study titled "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania." That study modeled the value of a 15% peak load penetration of distributed solar electric generation at seven locations in the region. The model addressed the following values:

- Market Price Reduction
- Environmental Value
- Transmission and Distribution Capacity Value
- Fuel Price Hedge Value

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- Generation Capacity Value.

The study found that the total value of distributed solar ranged from $0.256 to $0.318 per kWh. I submit this VOS study, attached as **Exhibit KRR-3**, as an indicator of how a comprehensive study can be conducted and the value revealed by such efforts.

Q. ARE YOU AWARE OF ANY VOS STUDY RESULTS FOR SERVICE TERRITORIES IN THE SOUTHEASTERN REGION OF THE UNITED STATES?

A. Earlier this year I served as an expert witness in Georgia's integrated resource planning proceeding. During that proceeding, I became aware that Georgia Power conducted an analysis that relied upon the solar valuation methodology that I used when I worked at Austin Energy. Detailed results of Georgia Power's VOS study are not, to my knowledge, public. Georgia Power attorneys stated on the record that the $0.13 offer price for utility scale solar generation in the company's Advanced Solar Initiative ("ASI") was: (1) higher than the company's traditionally calculated avoided cost, (2) derived with reference to the Austin Energy Value of Solar methodology, and (3) not going to put any upward pressure on rates. I understand that, based at least in part on its internal VOS study findings, Georgia Power is offering certain qualifying solar electric facilities an additional $0.01/kWh (on top of Georgia Power's $0.12/kWh avoided cost offering) to account for the transmission and distribution benefits conferred by distributed solar generation, including avoided transmission, avoided distribution, and avoided line loss.[2] This position is consistent with the results of the work I did on solar valuation in Austin.

VOS AND TRADITIONAL AVOIDED COST METHODOLOGIES

Q. HOW IS VOS ANALYSIS RELEVANT TO THE COMMISSION'S PRIMARY TASK IN THIS PROCEEDING (I.E., SETTING "FULL" AVOIDED COST RATES)?

A. As I stated earlier, VOS studies are, at heart, avoided cost calculations that embrace a full range of costs avoided by distributed solar generation, including savings over the life of the solar generation system. In other words, VOS analysis achieves a better approximation of the "full avoided costs" associated with distributed solar generation. Consequently, VOS studies offer improved market pricing signals over traditional avoided cost calculations, including calculations made under the traditional "peaker" methodology.

Q. WHY DO TRADITIONAL AVOIDED COST CALCULATIONS PROVE INADEQUATE TOOLS FOR CAPTURING THE FULL AVOIDED COSTS ATTRIBUTABLE TO DISTRIBUTED SOLAR GENERATION?

A. Traditional avoided cost calculations evolved at a time when most of the

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[2] An excerpt of the transcript for the Georgia proceeding that supports this assertion is attached as **Exhibit KRR-4**.

classes or categories of benefits and costs I mentioned earlier were not as well understood and grid generation was centralized. The calculations were not designed to recognize all of the benefits and costs, such as the full amount of transmission, distribution, and line loss costs avoided by distributed generation. Additionally, the spectrum of viable generation resources has broadened since the traditional avoided cost methodologies were developed. Not all generation resources bear the same risks. Risk is not well addressed in traditional avoided cost methodologies. For example, distributed solar and wind generation may have higher up-front costs, but they do not have ongoing fuel costs, they do not produce emissions, and they are not affected by drought-related water scarcity because they are not steam-driven or water cooled. The higher up-front "capacity" cost essentially eliminates the need to pay for a lifetime of fuel and also eliminates the emissions associated with combusting fuel and all water costs and risks.

Q. DO ANY OTHER FACTORS LIMIT THE RANGE OF BENEFITS AND COSTS REVIEWED UNDER TRADITIONAL AVOIDED COST METHODOLOGIES?

A. Yes. It is important to remember, as I pointed out earlier, that avoided cost estimation derives from the federal PURPA law. The law and the agency that implements it, the FERC, are jurisdictionally limited to power sales and related transactions in the wholesale market. The law and the FERC are not designed or authorized to fully address all of the issues associated with

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distributed resources that must be reviewed in determining the full extent of costs avoided by a utility when these resources are installed. Only the State commissions can ensure that these benefits and costs are captured properly through state-level implementation of state and federal regulatory law.

Q. DOES THE COMMISSION ENJOY SUFFICIENT AUTHORITY TO REQUIRE THE DEVELOPMENT OF, AND APPROVE THE IMPLEMENTATION OF, A FULL AVOIDED COST FOR SOLAR ELECTRIC GENERATION?

A. Yes. While a VOS analysis would be more comprehensive and support greater accuracy in valuing solar electric generation, the Commission does enjoy considerable authority under PURPA and FERC regulations to require quantification of the full avoided cost for solar electric generation. The FERC has granted broad latitude to states to account for all the costs avoided when electricity from a QF displaces a unit of system electricity. FERC's regulations allow consideration of numerous factors in determining full avoided costs. These factors include, but are not necessarily limited to:

- Reduced line losses;
- Ability to install smaller increments of capacity with shorter lead times;
- Ability to avoid or defer transmission and distribution costs;
- Value of QF capacity and energy;

- Ability to dispatch QF output; the expected or demonstrated reliability of the output; and the usefulness of QF production during system emergencies;
- Environmental benefits and renewable attributes of QF power; and
- Duration and enforceability of QF contracts.[3]

Q. FOR ILLUSTRATIVE PURPOSES, CAN YOU ELABORATE ON THE FUEL PRICE RISK YOU MENTIONED?

A. Yes. A resource that depends on long-term availability of fuel at an affordable price is very different from distributed solar generation, which has no fuel cost, now or in the future. The risk of natural gas price volatility is either ignored or undervalued in the electric utilities' avoided cost calculations. Instead, these costs are passed through annual fuel cost recovery riders, or routinely incurred without robust consideration of resources, like solar, that offer the benefit of reducing these costs. Undervaluing fuel volatility risk causes a generation option like distributed solar generation to seem to avoid less cost than it actually does. The electric utilities' "peaker" approach to avoided cost calculations essentially gives no value to resources that reduce fuel price volatility and instead affirmatively favors resources with low capacity costs, even if the long-run fuel costs for the resource are

[3] The authorization for consideration of these factors, respectively, can be found at: 18 C.F.R. § 292.304(e) (4); 18 C.F.R. § 292.304(e) (2)(vii); 18 C.F.R. § 292.304(e) (3); 18 C.F.R. § 292.304(e) (2)(vi); 18 C.F.R. § 292.304(e) (2)(i); 18 C.F.R. § 292.304(e) (2)(ii); 18 C.F.R. § 292.304(e) (2)(v); *see, e.g., Southern California Edison* , 133 FERC ¶ 61,059 at P 31 ("[I]f the environmental costs 'are real costs that would be incurred by utilities,' then they 'may be accounted for in a determination of avoided cost rates.'"), *rehearing denied*, 134 FERC ¶ 61,044; 18 C.F.R. § 292.304(e) (2)(iii).

variable, difficult to predict, and would require expensive hedging practices to mitigate the volatility risk.

Q. CAN YOU PROVIDE AN EXAMPLE OF WHAT YOU MEAN WHEN YOU SAY "EXPENSIVE HEDGING PRACTICES?"

A. Yes. Each year in its fuel cost recovery rider, Duke Energy Progress, Inc. ("DEP") passes through to customers natural gas hedging costs. Over the past several years, these additional costs amounted to approximately $39 million in 2010, $51 million in 2011 and $70 million in 2012. Even if DEP's hedging practices have changed recently such that it is entering into shorter-term hedges and hedging a smaller percentage of its overall consumption, these changes are offset to a degree by the fact that DEP's overall natural gas consumption is increasing. DEP consumed 72 billion cubic feet ("bcf") of natural gas in 2011-2012, 91 bcf in 2012-2013, and anticipates consuming 158 bcf in 2013-2014. This represents a 100+% increase in overall consumption in a three-year span. While Duke Energy Carolinas, LLC ("DEC") does not currently have a natural gas hedging strategy, it has been ordered to propose a strategy by the end of 2013 and its natural gas consumption has risen from 10 bcf in 2011 to 42 bcf in 2012 and is expected to be 74 bcf in 2013 – a 600+% increase in overall consumption in a three year span. I am not taking issue with the practice of hedging against fuel price volatility, but it is important to note that fuel-free solar electric generation offers true financial and physical hedging benefits to the utility resource portfolio, a value that should be captured in an objective avoided cost estimation process. The data responses which serve as the basis for my answer to this question are attached as **Exhibit KRR-5**.

Q. CAN YOU ELABORATE ON THE WATER COOLING AND ENVIRONMENTAL REGULATION RISKS YOU MENTIONED?

A. Yes. Whether you subscribe to a belief that the climate changes currently being observed are man-made or just part of a planetary cycle, such changes *are being observed* and they introduce a risk of increased generation costs for traditional fleets. Distributed solar generation avoids these potential costs, and importantly, reduces portfolio exposure to the risk of these costs. For example, in Docket No. E-7, Sub 849, DEC indicated it purchased capacity because a drought was causing system deratings and had an impact on power supply. On page 1 of DEC's application in the proceeding, DEC acknowledged that the drought "may be the harbinger of ongoing weather patterns." On page 5, DEC disclosed that it relies on water to, among other things, "[c]ool generating equipment at its . . . combustion turbine power plants." On the same page, DEC disclosed that 70% of its generation capacity at that time was subject to the water levels in just two basins. DEC incurred (and sought immediate recovery for) additional costs when water scarcity became an operational problem for its traditional generation resources. There is significant value in a generation resource that has no exposure to water scarcity over its entire useful life, both on a stand-alone basis and as a component of a generation portfolio. Similarly, DEC's and DEP's recent integrated resource plans indicate that environmental regulations dealing with carbon and other emissions present risks of increased cost. Finally, the development of domestic shale gas plays faces regulatory uncertainty (and a risk of increased costs) in a carbon-constrained future where impacts associated with development are still uncertain and under examination. Distributed solar generation avoids these potential costs.

Q. HOW IS THE OUTPUT OF A QUALIFYING SOLAR ELECTRIC FACILITY VALUED UNDER TRADITIONAL AVOIDED COST METHODOLOGIES?

A. For some of the reasons I have just discussed, distributed solar resources have historically not been offered "full avoided costs" under traditional avoided cost methodologies. Traditionally utilized preferences tend to assign higher value to dispatchable generation options with low capacity cost, while undervaluing several increasingly valuable and important components, such as: fuel price volatility, regulatory (especially environmental) risk, water supply risk, transmission infrastructure requirements, and other risks. Traditional avoided cost methodologies can reduce the value of low- or zero-risk resources and long-run marginal cost and risk reductions.

Q. HOW SHOULD VOS RELATE TO THE PRICE PAID BY AN ELECTRIC UTILITY WHEN IT PURCHASES ELECTRICITY GENERATED BY SOLAR FROM A THIRD PARTY?

A. The VOS should serve as a benchmark for the price an electric utility pays or credits for third-party distributed solar generation. As with the theory behind avoided cost calculation, VOS analysis quantifies the value equal to what it would cost either the utility or a third party to provide solar energy to the point where the energy does its work. It sets an "indifference price" just as avoided cost calculations are intended.

Q. EARLIER, YOU TESTIFIED THAT IT IS REASONABLE TO CONCLUDE THAT THE VALUE DELIVERED BY DISTRIBUTED SOLAR GENERATION TO NORTH CAROLINA ELECTRIC UTILITIES AND THEIR RATEPAYERS IS HIGHER THAN THE COST REQUIRED TO OBTAIN THAT GENERATION. PLEASE EXPLAIN.

A. The electric utilities' proposed avoided cost rates, for both energy and capacity on a composite basis, are in the $0.06/kWh range. Based on the RMI review and my review of the many VOS and other studies, this number undervalues the utilities' "full avoided costs" that are associated with the addition of distributed solar generation. From a review of the filings in this case, there is no evidence that the proposed avoided cost calculations fully quantify the benefits described above, or even approximate the benefits captured by the calculations performed by Georgia Power in the neighboring state of Georgia.[4]

Q. WHAT DOES THIS MEAN IN PRACTICAL TERMS?

A. Earlier I stated that I believe the Commission's primary task in this proceeding is setting "full" avoided cost rates which (1) are just and reasonable to the ratepayers of North Carolina's electric utilities, (2) are in the public interest, and (3) do not discriminate against cogenerators or small power producers. In practical terms, where distributed solar facilities are concerned, the electric utilities' proposed avoided costs are not just and reasonable to the ratepayers. By systematically undervaluing the solar electric generation resource, the utilities are denying ratepayers the benefit of procuring this resource at a cost that will yield substantially greater benefits, including downward pressure on rates, over time. Furthermore, undervaluing solar electric generation discriminates against the small power producers who would otherwise offer this resource into the mix at rates that are just and reasonable to ratepayers. Finally, the systematic undervaluation of solar electric generation under the utility's proposed avoided cost rates is not in the

[4] Georgia Power is offering certain qualifying solar electric facilities an additional \$0.01/kWh (on top of Georgia Power's \$0.12/kWh avoided cost offering) to account for the transmission and distribution benefits conferred by distributed solar generation, including avoided transmission, avoided distribution, and avoided line loss. For comparison purposes, it appears as though DEC quantified an avoided line loss benefit at \$0.0001/kWh for interconnection to its transmission system and at \$0.0012/kWh for interconnection to its distribution system. Similarly, it appears as though DEP quantified an avoided line loss benefit at \$0.0005/kWh to \$0.0011/kWh. These DEC and DEP figures are derived from attached **Exhibit KRR-6**.

public interest because it promotes suboptimal and economically inefficient investment levels in the solar resource, and by definition leads to overinvestment in second-best resource choices and riskier generation alternatives.

RECOMMENDATION

Q. IN LIGHT OF THE FOREGOING, WHAT IS YOUR VIEW OF THE POSTURE OF THE ISSUES BEFORE THE COMMISSION?

A. DEC and DEP have both acknowledged in a June 10, 2013 filing with the Commission in Docket No. E-100, Sub 137 that a VOS analysis they are conducting may impact avoided cost calculations. The Commission's order scheduling an evidentiary hearing in this proceeding indicated that it was open to re-examining traditional avoided cost methodologies. Thus, the Commission is well positioned to scrutinize and modify the electric utilities' avoided cost methodologies in this proceeding. With that preface, I believe the Commission has several alternatives some of which could be combined over time, for setting "full" avoided cost rates for qualifying solar electric facilities.

Q. WHAT ALTERNATIVES ARE AVAILABLE TO THE COMMISSION TO ADDRESS THE INADEQUACY OF THE ELECTRIC UTILITIES' PROPOSED AVOIDED COST RATES?

A. Aside from addressing the questions relating to the appropriate cost of a combustion turbine, I believe the Commission has two basic alternatives to address the inadequacy of the electric utilities' proposed rates in the current biennium.

First, based on my review of the filings, REG has provided a *legal* argument for increasing North Carolina's performance adjustment factor ("PAF") for solar from 1.2 to 2.0. REG's discrimination argument is consistent with the Public Staff's own past arguments, in Dockets Nos. E-100, Sub 79 and E-100, Sub 106, that resulted in the PAF for run-of-the-river hydro being set at and remaining at 2.0. My review of VOS studies and analysis provides an additional *equitable* basis for increasing the PAF for solar pending a more comprehensive and precise valuation. While the 2.0 PAF for hydro was designed to serve as a kind of equitable relief for QFs that do not have control over their "fuel" source and therefore otherwise are denied the opportunity to recover full capacity payments, a 2.0 PAF for solar can similarly serve to address the discrimination that qualifying solar electric facilities currently face.[5] If the PAF is set to 2.0 for solar, the utilities' proposed offerings to

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[5] It seems worth noting that an appropriate increase in the PAF for qualified solar electric facilities would not result in unjust or unreasonable payments being borne by ratepayers. As this Commission stated, in the hydro context, on page 19 of its final order in Docket No. E-100, Sub 79: "[U]se of a higher performance factor for these hydro facilities does not exceed avoided costs; it simply changes the method by

solar QFs will better approximate the full avoided costs associated with their facilities.

Second, in the wake of the *Southern California Edison* FERC Order, 134 FERC ¶ 61,044, the Commission could direct that a North Carolina solar avoided cost rate be calculated and made available based on reasonable North Carolina-specific VOS study results. It is my understanding that both DEC and DEP are conducting a VOS analysis. Others are likely conducting or considering North Carolina-specific VOS analyses as well.

Q. GIVEN THE NEAR-TERM ALTERNATIVES, WHAT IS YOUR RECOMMENDATION?

A. Given the growing body of VOS research and Georgia Power's recent recognition of some of the additional value of solar generation in its ASI offering, I believe there is no question that traditional avoided cost calculations, including the calculations used by the electric utilities in this proceeding, are undervaluing the costs avoided by the utilities when distributed solar generation is installed. Consequently, qualifying solar electric facilities face discriminatory rates that do not represent the utilities' full avoided costs. The Commission should address this discrimination in this proceeding. From a very practical viewpoint, I believe a PAF adjustment to 2.0 for solar is the least disruptive way to address the discrimination in this

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which avoided costs are paid. It allows these QFs to operate less in order to receive the full capacity payments to which they are entitled, and this seems appropriate and reasonable considering the limitations on their control of their generation."

proceeding. A PAF adjustment could serve as a near-term and longer-term "fix," but I recognize that, with the advent of VOS analysis, such an adjustment may prove to be too imprecise for the longer-term. For the foregoing reasons, I recommend that the Commission (1) increase the PAF for solar electric generation in this proceeding to 2.0 to make the electric utilities' offerings to distributed solar facilities better approximate full avoided costs, and (2) indicate that the increased PAF is intended as an interim measure and will be re-examined in the 2014 biennial avoided cost proceeding (which will be opened less than a year after the final order is issued in this proceeding), at which time the Commission will determine whether to make permanent any PAF adjustment or to establish a solar-specific avoided cost rate or take other action in light of any North Carolina-specific VOS studies.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

(Whereupon, Exhibits KRR-1 through KRR-7 were identified as premarked.)

MR. YOUTH: I would now like to hand out a summary. I think everybody has got a copy.

BY MR. YOUTH:

Q Mr. Rabago, would you read the summary of your testimony?

A Yes, I will. Good morning, Commissioners. I have served as a Public Utility Commissioner for the State of Texas, a Deputy Assistant Secretary for the US Department of Energy, and as a utility executive with Austin Energy, the municipal electric utility for the City of Austin, and with AES Corporation, a global power company with operations in more than 25 countries, in leadership positions at several research and nongovernmental organizations, and for some 12 years as an officer in the United States Army as a calvary officer, a JAG officer, and a professor at the US Military Academy at West Point.

I am here to testify on behalf of the North Carolina Sustainable Energy Association to propose that the Commission address inadequacies in the utilities' proposed avoided cost, or avoided costs proposals by implementing a shorter-term and a longer-term approach that will better ensure that full, nondiscriminatory avoided cost rates are offered to qualifying solar electric facilities over both those time frames.

My testimony makes the following key points: First, the goal of setting avoided cost rates is to establish accurate indifference rates for alternatives to utility-built generation and to create a fair opportunity for qualifying facility generation to enter the electric generation market. An indifference rate serves society, the utility, and its customers by supporting the most cost-effective and economically efficient portfolio of resources to meet the demand for electricity services. In other words, in order to properly compare alternative resources and to contract for them, each resource must be valued correctly.

Second, valuation techniques for distributed solar energy have significantly improved over time and with decades of deployment experience, allowing utilities, regulators, and policy makers to make better informed decisions about how distributed solar can maximize benefits to the utility and to ratepayers. The value of distributed solar to utilities and ratepayers is now well documented. Importantly, this means that utilities in North Carolina have access to the tools necessary to address biases against renewable energy resources in traditional avoided cost methodologies. These biases include, for example, undervaluation of risk reduction, especially fuel price risk, which translates directly into fuel and fuel-related costs, and similar risks relating to water, carbon regulation, and other factors.

Third, numerous published solar valuation studies confirm that distributed solar resources cumulatively offer energy, capacity, line loss savings, financial, and security benefits that exceed retail rates for electricity and, therefore, these resources should be paid their full avoided costs. Additional elements of value include fuel price hedging value, transmission and distribution investment savings, environmental benefits beyond compliance costs, merit order benefits, competitively induced fuel price reductions, economic development and tax base benefits, volatility in water availability and price benefits, and others. Of course, fair valuation includes assessments of integration -- integration costs as well. Now, not all these value components can be precisely quantified and not all are fairly applied to electricity rates, but all merit some attention in an effort to make fully-informed, economically-efficient resource investment decisions. That's what avoided costs drive. I point out in my testimony that many of these values are explicitly recognized as a basis for calculating avoided costs by the Federal Energy Regulatory Commission regulations in 18 C.F.R. § 292.304(e), and that this Commission enjoys broad additional authority to establish a full avoided cost appropriate to solar generation under recent FERC decisions like the Southern California Edison decision.

Fourth, while the studies and experience of other jurisdictions suggest this Commission should investigate more detailed and complete evaluation of the full avoided cost of solar generation in the mid-term, the Commission has already established a mechanism that allows a reasonable and appropriate near-term adjustment of avoided capacity payments for solar generation in the Performance Adjustment Factor, or PAF. Setting the PAF to 2.0 for solar generation is reasonable based on the evidence of higher solar avoided cost.

Finally, I would like to point out that since my testimony was filed, the Commission has received independent North Carolina-specific confirmation of my assertions regarding the value in the report filed by NCSEA independent to my testimony as Exhibit 7, authored by Crossborder Energy. This study finds that the value of solar and, hence, the appropriate avoided cost, is significantly higher than that proposed by the utilities.

Now, I need -- I would also like to emphasize at this point what my testimony does not do. First, while it reports on and recognizes studies conducted by others, my testimony does not propose a specific avoided cost value for solar generation beyond, of course, the PAF adjustment that I suggest in the near term. My objective is to point out that the avoided cost that the utilities would have you set for solar generation is flawed and incomplete. As a result, solar generation in North Carolina would be unfairly discriminated against in North Carolina electricity markets.

Second, while I note that the range of solar generation benefits is broad and includes a wide range of factors, it is not my proposal that the Commission direct the establishment of a solar avoided cost based on externality values that are impossible to accurately quantify or that are not appropriate costs faced by the Utilities. While I note the categorical fallacy in drawing distinctions between utility customers and the citizens of North Carolina society, I do recognize that some benefits do not accrue to the utility directly and, therefore, may not be appropriate for inclusion in avoided costs at this time.

Third, in pointing out the significant gaps between comprehensive solar valuation and the avoided cost methodologies used by the utilities, I do not concede that the utilities' approaches are correct. Quite the opposite. My testimony is that the evidence shows that the avoided cost methodologies used by the utilities are deficient and should be improved in order to more accurately capture the full avoided cost of solar generation.

Finally, I wish to emphasize that while locally-derived analysis is more empirically probative of the gap between the utilities' proposals and a full avoided cost, it is not my intention that the Commission substitute non-jurisdictional analysis for utility-specific data. My testimony is that this information demonstrates that the utilities have not done enough to capture and demonstrate the full avoided cost of solar for which they seek to establish a rate.

In closing, I want to reassert that based on the studies of others, but not the utilities, solar generation appears to offer resource value that greatly exceeds the utilities' proposed avoided costs and justifies a PAF adjustment now, and then further analysis following this proceeding to quantify and characterize the full avoided cost of solar -- the avoided cost value of solar.

Time is of the essence, and approval of the utilities' proposed avoided costs for solar comes with a significant opportunity cost. Solar markets are largely driven by economics of manufacturing scale. That is, the more systems that are deployed, the faster the market moves to lower prices and greater value. Now is the time for the utilities to accurately value solar generation in North Carolina. Doing so will benefit their customers.

That concludes my summary. Thank you.

Q Mr. Rabago, I would ask you to go back to line 7 and 8 on page 5, and I think you said, "In closing, I want to reassert that based on studies of others, but not the utilities..." Just to be clear, are you saying there that you understand the utilities, Duke and Progress, are engaging consultants to do a study and you don't -- you have not seen that information?

A Right. I understand and I heard yesterday the witness -- I think it was Witness Bowman -- said that there was an impact study going on about the operational impacts involving several consultants. I said, well, I understand that is happening and I -- and I think you've told me as well, but I've seen no such study, so I -- I've seen no studies done by these utilities or by others for North Carolina.

Q But the Crossborder study does use the utilities' publicly available information?

A Yes. The Crossborder -- the Crossborder study is mostly based on utility information derived from integrated resource plans and other filings in order to do most of its calculations. In some places where only sensitive information was available, the study relied on external data from other jurisdictions and attempted to adjust it or recognize the differences through the use of ranges in the responses.

MR. YOUTH: Commissioner Brown-Bland, I would ask your permission -- since Mr. Rabago prefiled his direct testimony, rebuttal testimony has been filed, and I would ask your permission to ask him a couple of questions about that rebuttal testimony that addresses his statements. I've got two questions.

MR. SOMERS: I would object. There's no provision under this Commission's rules for re-redirect surrebuttal testimony or whatever Mr. Youth is going to characterize what he is attempting to do here.

MR. YOUTH: It is direct testimony, Commissioner Brown-Bland.

MR. SOMERS: It's responding to rebuttal testimony of the companies, and I don't know which witnesses specifically, but that's clearly surrebuttal.

COMMISSIONER BROWN-BLAND: I'm going to sustain the objection.

MR. YOUTH: Thank you. Mr. Rabago is now available for cross.

COMMISSIONER BROWN-BLAND: Is there cross examination? Mr. Dodge.

CROSS EXAMINATION BY MR. DODGE:

Q Good morning, Mr. Rabago. I do have just one line of questions for you. On page 17 to 20 of your testimony, you discuss the environmental benefits and renewable attributes of QF generation.

A Say that page and line again, please.

Q Pages 17 to 20.

A Got it.

Q You have a discussion of some general benefits, but you specifically elaborate on the environmental and renewable attributes of QF generation?

A Yes.

Q Are you aware that North Carolina has a

renewable energy portfolio standard and that the RECs that are utilized as the currency for that -- for compliance in that embody some of those benefits?

A Yes, I am, and that approach was taken by the Crossborder study. They assume that some of these hard to quantify or hard to specify additional values could fairly be imputed into the REC value in what they called their avoided -- avoided RPS savings.

Q But to the extent that the REC has -- the REC value reflects some of those environmental values or renewable attributes, do you feel that those should be -- those costs or benefits should be excluded from the value of solar analysis if they're already captured in a compliance mechanism?

A No, not necessarily. I do not necessarily think they should be excluded. I think that you -- care needs to be taken, as with doing any of these things, to not double count. So you just need to make sure where those -- where those attributes are accounted for. The values that are embodied in the REC do, in fact, represent avoided costs if those -- when those values are monetized. I would point out that considering them inside of a REC is one way of monetizing them.

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

COMMISSIONER BROWN-BLAND: All right. Further cross examination? Mr. Somers.

CROSS EXAMINATION BY MR. SOMERS:

Q Good morning, Mr. Rabago. How are you?

A I'm fine, thank you. I'm going to try to keep facing that way when I answer. Please don't consider me rude. I promise, I don't mean --

Q Don't -- don't injure your neck turning it hard this way. I understand that. Have you seen the article that was posted online two days ago on the Midwest Energy News that purports, anyway, to be a summary of an interview with you?

A I have seen it. I read it quickly.

Q And --

A I don't have it committed to memory, but if you want to walk me through it.

Q I'm pretty sure you will remember the headline.

A Okay.

Q And that refers to Karl Rabago, Grandfather of the Value of Solar Tariff. Do you remember that?

A Yeah. I thought that made me -- I am a proud grandfather, but yeah. I actually more am -- more am -- would be closer in generation to it.

Q Now, my understanding --

MR. YOUTH: I'd like to object at this time. Can I see -- do you have a copy of that -- of what you're referring to?

(Copy provided.)

COMMISSIONER BROWN-BLAND: Do you withdraw your objection?

MR. YOUTH: I do.

COMMISSIONER BROWN-BLAND: All right.

BY MR. SOMERS:

Q Now, the reference there to the grandfather of the value of solar tariff, my understanding is that Austin Energy, where you previously worked, had the first tariff based on a value of solar concept in the country; is that correct?

A Yes. That's my understanding.

Q Okay. And I believe that was first -- or first went into effect in October of 2012, so just a little over roughly a year ago; is that correct?

A Right. It was formerly approved by the City Council in a meeting held in June, and the rates went into effect for the fiscal year on October 1st, 2012.

Q Okay. And from reviewing the City of Austin's rate schedules for their residential solar program, that is -- it's limited to solar PV systems with a capacity of

20 kW or less, --

A Right.

Q -- correct?

A We introduced it for residential customers only.

Q Right.

A And the 20 kW corresponds to the net metering, the old net metering cutoff.

Q And the rate that Austin currently pays under that residential solar tariff is 12.8 cents a kWh; is that right?

A I'm not sure that's completely true. I -- 12.8 cents was the value when the rate was put in place. Since then, Austin Energy hired Clean Power Research, one of the firms you guys hired, and they have updated the numbers. I understand they are -- they have been reduced due to gas prices to, I think, something like 10.7, but I don't know if that's been formally adopted and when that will be implemented.

Q Okay. And as part of that residential solar PV program, Austin Energy also has a -- it's a rebate of $1.50 per watt; is that correct? Are you familiar with that?

A That's correct. I understand it's $1.50 now.

I haven't kept complete track.

Q Okay. Well, that's fair. And the stated purpose by Austin Energy for this residential solar program is to encourage residential customers to install solar energy systems. You would agree with that, right?

A Yes, pursuant to a Commission directive that was originally embodied in an RPS-like mechanism that was the Austin Climate Protection Plan adopted in 2007, subsequently modified in resource plans and other Commission -- I mean, council resolutions.

MR. YOUTH: Commissioner Brown-Bland, I'm going to object at this time on relevance grounds. I imagine you'll be given some leeway, but how does this relate to what we're talking about?

MR. SOMERS: Well, it's already in evidence.

BY MR. SOMERS:

Q My next question, Mr. Rabago, is you testified in this --

COMMISSIONER BROWN-BLAND: Overruled.

BY MR. SOMERS:

Q -- you testified in this case about your prior testimony in the Georgia IRP proceeding from earlier this year, correct?

A I did testify in that proceeding.

Q In that case you testified on behalf of the Georgia Solar Energy Industry Association; is that correct?

A That is correct.

Q And that testimony was filed on about May the 10th, 2013?

A That sounds about right.

Q Okay. Now, in your testimony in this case, you described that Georgia proceeding. That was Georgia's -- Georgia Power's Integrated Resource Plan docket; is that correct?

A That is correct.

Q And in this case you described the program at issue there as Georgia Power was offering an additional penny per kWh on top of Georgia Power's 12 cents per kWh of what it cost to operate. Do you remember describing it that way in your testimony in this case?

A In my testimony in this case, yes, right.

Q Well, it -- but the 12 cents is not actually the avoided cost offering in Georgia, is it?

A It's a little hard to figure out. Georgia -- Georgia Power has not publicly revealed the exact algorithm that they use to determine the ASI rate of 13 cents. What they did was in the IRP hearing, they said that they had used the Austin Energy value of solar methodology to derive -- to inform that process, that rate setting, that it did not put upward pressure on rates, and then subsequently in discussions, I think it was Commissioner Echols basically characterized it as that penny process of adding -- adding a penny on top of the value. So that's what -- that's the best I have to go on because a Commissioner said it.

Q And it -- and its ASI program that you just referenced, that was Georgia Power's program, that they offered this as an incentive to encourage solar development in their service area; is that correct?

A Yeah. It's -- ASI stands for the Advance Solar Initiative, and it was a previously approved plan for 210 or 285, depending on how you count it, MW of solar development independent of the Integrated Resource Plan.

Q So, again, my question was that ASI program was a specific program offered by Georgia Power to incent solar energy development in Georgia Power's service area, correct?

A As -- that is true as far as it goes. I also understand it's a much more complicated path how they got there.

Q And to your earlier comment about the state of

avoided cost in Georgia, you understand that the Georgia Commission has not set avoided cost rates since 1994, correct?

A I will -- I will take that on faith. Avoided cost was not in the IRP.

Q Okay. And you're aware that Georgia has a separate avoided cost for facilities that provide capacity which does not include solar, correct?

A Say that again.

Q You're aware that in Georgia they have a separate avoided cost for facilities that provide capacity?

A That sounds like what I recall from reading things that Georgia -- I'll agree, subject to check, on that.

Q That's fair enough. And you -- but you would certainly agree that a capacity payment is necessarily dependent upon a QF's ability to produce power during the peak, correct?

A A capacity payment is necessary. Capacity payments are normally made for production that occurs during peak, yes.

Q Okay.

A I don't know -- the necessary thing is throwing me off, but I will agree that it's supposed to be a payment for appearing during the time when capacity requirements are higher.

Q Okay. Now, in your testimony both in Georgia and here in North Carolina, you talk about several studies that you attached to your testimony that were conducted by others as to a "value of solar," correct?

A Right. That's a -- that is not necessarily a term that they all used, but it is one that I apply to studies that were characterized and summarized in the Rocky Mountain Institute Benefits and Cost of Solar report that is included as Exhibit 2.

Q To summarize your testimony, I mean, essentially after reviewing those studies that you've talked about, your premise is that the value of solar is always higher than the retail electricity rate, correct?

A What I'm saying is that there is strong evidence that the value of solar is higher than retail rates, that it is backed up by many studies. I can tell you from my personal examination of the various reports and studies, that even where the number doesn't come that high, it can be explained by assumptions or machinations in the study that could yield a different result if all the studies had a matching methodology. So I am confident that it -- that the body of work that is these, as I call them, value of solar studies, shows that solar is generally worth more than retail. And I will also add that that squares with reality. It's a -- when the electricity is produced, it does the same work as a kWh made at a remote power plant transmitted, distributed, and served to the customer, but because it only has to fall from the roof and it is waterproof and climate proof and fuel price risk proof, it is worth more. So the studies tend to confirm that for me, so that's the basis of my conclusion.

Q Okay. So flushing out your conclusion a little bit, if you assume that the electric retail rate is eight cents, --

A Okay.

Q -- and I'll just pick one of the value of solar studies that you had that had a value of, let's say, 16 cents, --

A Okay.

Q -- under your theory, then, if the utility can buy that solar power for 13 cents, that's a good value and they should do it?

A Assuming all those numbers are sort of right, yes. My general -- my general position would be that when you get something at a price that is less than its value, you should make that purchase and it will stimulate over the long term, in the case of solar, downward pressure on rates.

Q And in your testimony in this case, you were -- you were fairly critical of the peaker methodology that this Commission uses in setting avoided cost rates, weren't you?

A I'm -- again, I'll -- I am somewhat critical of the peaker methodology. I think it's -- I think it's sort of a legacy methodology, and I think that this case is evidence of the contortions that everyone has to go through to try to address a fuel-free resource like solar in a fuel-based methodology like the peaker methodology. Even discussions about -- well, anyway. So yes, I think -- I think that -- well, I conclude that it would be appropriate to look at a solar avoided cost rate rather than try to hammer this square peg into the round hole of peaker methodology.

Q So the answer to my question was yes?

A Yes. Sorry. Yes.

Q In your testimony, when you describe the general classes or categories of benefits that are examined in value of solar studies, you list, on pages 7

through 9 of your testimony, several of those classes or categories, correct?

A Yes, I do.

Q And the headings for those are Energy Capacity, Grid Support, Customer Benefits, Financial and Security Benefits, Environmental Benefits, and Social Benefits, correct?

A Yes. Those are the same ones -- yes.

Q Well, that -- yeah. Those are the same ones you listed in your Georgia testimony, --

A Right.

Q -- which was essentially identical to North Carolina testimony?

A In many -- in many aspects and to the RMI study and a couple of other things.

Q Right. And so essentially what your testimony summarizes is that you look at these different categories or classes of benefits or costs, some might call them, a value of solar analysis will essentially assign a value for each of those classes or categories and then sum them up for a total that you assert is the true value of solar; is that a fair characterization?

A Sure, which should be roughly equal to a full avoided cost, depending on whether or not certain cost categories get into the avoided cost or not. So you start with a full value and then -- yes.

Q **And there's a wide range of what those values may be, based on what the particular author or authors of the study assumed were values or other inputs that they chose to put into their study, correct?**

A Or other assumptions, yes, correct.

Q **Right. And in the one that you discuss in perhaps some more detail in your North Carolina testimony is one based on New Jersey and Pennsylvania, correct?**

A That is correct.

Q **And that one, the sum total of the value that that -- or at least that you reported that study shows is roughly 25 to 31 cents a kWh?**

A I believe that's the number. I think I cited that number specifically, and I believe that's also the conclusion of the study, which is attached as Exhibit, I think, 4.

Q **Okay. So were you here -- you've been present for the entire hearing thus far, haven't you?**

A I have, yes.

Q **And so you heard the opening statement made by NCSEA's counsel yesterday, and some questions by him and others related to an analogy to peanut butter and bread,** haven't you?

A I was hoping we'd talk about peanut butter.

Q Are you getting hungry yet?

A Yeah. That, too.

Q So in the analogy that NCSEA's counsel offered yesterday, the peanut butter is the capacity and the bread represents the energy, correct?

A That's how I understand the analogy.

Q Okay. And under that analogy, a QF provider, such as a solar developer, would, after working throughout the day at intermittent times, they would be paid under this contract some peanut butter and a piece of bread, right?

A Right. I understand the condition of the contract was if you arrive for work, you will be immediately entitled to one spoonful of peanut butter, and that your -- the size of your bread would be ratably attributed to the duration of the workday in which you were usefully employed.

Q And if you include the value of solar categories that you discuss in your testimony, as we just went through, such as energy capacity, grid support, customer benefits, financial and security benefits, environmental benefits, and social benefits that you

assert are the true value of solar, in essence, at the end of that workday, your contention is that the solar QF should, in addition to peanut butter and bread, also get jelly, bananas, sprinkles, whipped cream and a cherry on top, right?

A I love that. No. You would get a livable wage worth of peanut butter and bread, because that was the employment contract.

Q Utilities like Duke Energy Carolinas and Duke Energy Progress have rates that are set to recover their costs rather than the value of the energy that they provide; is that correct?

A That is correct.

Q And you would certainly agree that customers in North Carolina, most, if not all of them, place a high value on affordable, reliable energy that's available 24 hours a day, 365 days a year, wouldn't you?

A I would assume they do, like customers everywhere do.

Q And you would also agree that PURPA does not allow QFs to receive rates that are in excess of a utility's avoided cost, correct?

A PURPA is limited to treatment of -- to inclusion of actual utility costs in an avoided cost rate.

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

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

MR. HORNE: Yes. Thank you. I'll try to stay near the microphone this time.

COMMISSIONER BROWN-BLAND: Might want to pull it a little bit closer.

MR. HORNE: Folks from Dominion are just too genteel. That's what it is.

CROSS EXAMINATION BY MR. HORNE:

Q **Mr. Rabago, --**

A Rabago.

Q **Rabago. I am sorry.**

A That's all right.

Q **I believe I heard you just agree with Duke's counsel that FERC says that a utility doesn't have to pay any more than its avoided cost.**

A What -- what it says is that a rate to a qualifying facility shall be based on cost. So the thing about it is, of course, is that avoided costs are different. The CPUC decision, for example, implies that a -- their technology specific avoided costs are available so -- but yes. It all has to be cost. It has to be real cost to the utility. That's how I understand it.

Q Subject to check, and I can hand you the document if you want me to, the FERC regulations provide that nothing in this subpart -- they're talking about provision where rates are set -- requires any utility to pay any more than its -- more than its avoided cost for purchase.

A Yes.

Q Okay. Thank you. And while we're at it, would you accept, subject to check, that the FERC regulations define avoided cost as the incremental cost to an electric utility of electric energy or capacity, or both, which but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source?

A I would agree with that. That sounds very familiar.

Q Thank you. Okay. Ask you to turn to page 17 of your testimony, please.

A Okay. I'm there.

Q Okay. Thank you. In footnote 3 on page 17 of your testimony, you quote language from the FERC's order in Southern California Edison, 133 FERC 61,059, "For the proposition that if the environmental costs are real, costs are real costs that would be incurred by the utilities that they may be accounted for in a determination of avoided cost rates." Is that correct?

A Yes.

Q Okay. The FERC language you quoted was from another FERC Southern California Edison case, and with the Commission's permission, I'd like to hand you at this time.

A Actually, somebody left one up here.

Q This is a different order.

A Oh, sorry.

Q This is the one the -- the FERC was citing from.

A Okay.

THE WITNESS: Just in honor of my state bar, I want to make it clear that I'll be offering any opinions on this based on my experience and expertise as a utility regulatory expert, not as a licensed attorney.

MR. HORNE: Bear with me one second. I apologize to the Commission and to the witness. All right. I'm going to move on. I don't appear to have it with me. Yes, we do.

MS. KELLS: I apologize. Sorry.

BY MR. HORNE:

Q **I'm going to ask you a question about page 12 of the --**

A All right.

MR. YOUTH: Commissioner Brown-Bland, I'm -- I'm going to object at this point. Unless Mr. Rabago indicates that he is familiar with this order --

MR. HORNE: Commissioner Brown-Bland, he cited to this order, which was quoting this order, in his testimony.

MR. YOUTH: Okay. This is the order footnoted.

MR. HORNE: The footnote, and the FERC cited -- the FERC was referring to this order, okay, correct. May I continue, Your Honor?

COMMISSIONER BROWN-BLAND: Do you withdraw your objection or do I need to rule?

MR. YOUTH: Are you saying the order footnoted cited to this order, or this order is cited in the footnote?

MR. HORNE: The FERC language that Mr. Rabago cited was citing to this order. So this is the FERC -- the order that FERC was using, was citing to for the proposition in that footnote.

MR. YOUTH: Mr. Rabago, are you familiar with this order?

THE WITNESS: I'm not, in heavy detail, familiar with this order, and I noticed that -- I mean, it might take a couple of minutes.

COMMISSIONER BROWN-BLAND: I'm going to -- I'm going to overrule the objection, I mean. Give him the time that he needs to familiarize himself to answer your question. He can answer to the extent of his knowledge or what he feels comfortable answering. If he doesn't feel comfortable answering, I'm confident this witness will let us know.

THE WITNESS: You know he will already.

(Witness reviews document.)

COMMISSIONER BROWN-BLAND: Mr. Horne, while he's looking at it, should we identify it?

MR. HORNE: Yes, ma'am. That would be identified as --

COMMISSIONER BROWN-BLAND: Dominion Rabago Cross Examination Exhibit --

MR. HORNE: One, I believe.

COMMISSIONER BROWN-BLAND: -- 1.

MR. HORNE: Yes, ma'am. Thank you.

(Whereupon, Dominion Rabago Cross Examination Exhibit 1 was marked for identification.)

THE WITNESS: Okay. I think I'm ready to answer --

MR. HORNE: Okay.

THE WITNESS: -- a question or two, --

MR. HORNE: Okay.

THE WITNESS: -- as quickly as I could look at it.

BY MR. HORNE:

Q **If you could go to the third paragraph on page 12 for me, please.**

A I see it.

Q **Okay. Could you read that for me?**

A There the -- there FERC said, "A state, however, may not set" -- is that the one you wanted?

Q **Yes, sir.**

A Good. Okay. "...may not set avoided cost rates or otherwise adjust the bids of potential suppliers by imposing environmental adders or subtractors that are not based on real costs that would be incurred by utilities. Such practices would result in rates which exceed the incremental cost to the electric utility and are prohibited by PURPA."

Q **Do you agree with the -- the FERC statement?**

A Subject to all the conditions, the context in which it was stated, this is -- this sounds like a pretty good encapsulation of the law as it existed in 1995 when this Order on Rehearing for -- and Request for Consideration was granted.

Q But this 1995 order was cited in the 2010 order --

A Yes.

Q -- that you cited in your testimony?

A Right. That sentence, that one sentence.

Q Okay. If it violates PURPA for a state to set avoided cost rates, including environmental adders that are not based on real costs that a utility will incur, would it not also violate PURPA to include adders for other types of externalities, such as reputational community participation that are not based on real costs incurred by a utility?

A Two things. First, by definition, an externality is not included in costs. It is included in costs once analysis is done of the existing externality and that it is no longer an externality; it's an internalized cost. But getting to where you really wanted to go, I think, yes, this is exactly the kind of thing I was pointing to in my summary that we -- when we examine a resource like solar or nuclear or any other resource that the utility has as its -- at its disposal, there will be benefits and costs, and some of them are not appropriately included. This rule -- this law is one reason for not including such things, because they haven't been reduced to cost or, using your word, they have not been internalized. They remain externalities. So I can -- I agree.

Q Okay. I'm going to now hand you the order you cited in your testimony, because I have a couple questions on that.

A Okay.

Q It's the Southern California Order Granting Clarification and Dismissing Rehearing, 133 FERC 61,059.

A All right. I'm ready. Oh, I'm sorry.

COMMISSIONER BROWN-BLAND: Let this be identified for the record as Dominion Rabago Cross Examination Exhibit 2.

(Whereupon, Dominion Rabago Cross Examination Exhibit 2 was marked for identification.)

BY MR. HORNE:

Q I'll direct your attention to page 16, Mr. Rabago, the sentence that starts, "We also note," the

very last sentence of the paragraph before the Commission order. Could you read that for me, please?

A Yes. That sentence, again, by FERC, "We also note that although a state may not include a bonus or an adder in the avoided cost rate unless it reflects actual costs avoided, a state may separately provide additional compensation for environmental externalities, outside the confines of, and in addition to, the PURPA avoided cost rate through the creation of renewable energy credits."

Q Thank you very much. In addition to RECs the FERC notes in -- footnote 62 of the same page, that a state can also provide additional compensation or incentive through loan subsidies or tax credits or on environmental policy grounds outside of avoided cost rates; is that correct?

A Loan subsidies -- I'm looking for that language. Where --

Q Looking at 62.

A Sixty-two -- oh, the -- it appears to say that, yes.

Q Okay. Thank you. And I believe you -- in an earlier question from the Public Staff, you acknowledged that or at least accepted that North Carolina had created RECs?

A Right.

Q Okay. Can you look again in footnote 62 of the -- the order you have? What does it say about the status of a REC?

A Well, it says for such RECs -- for -- it says, "Compensation for such environmental externalities through RECs is outside of the PURPA," so RECs that include environmental externalities are outside of PURPA. I'm assuming they mean these "RECs are separate commodities from the capacity and energy produced..." So it says -- so is that what you wanted me to say?

Q Yes.

A Did I -- did I characterize the footnote --

Q Would you agree that RECs are outside of avoided cost?

A No. I can't agree with that, because it depends on how the RECs go. If the utility is required, for example, to purchase RECs from solar providers, it becomes a very real cost, and then it becomes a cost associated with that technology. Or if, you know, if -- so it -- it all depends on how the REC is structured. My experience with RECs is pretty deep and long, and I can tell you they're done a lot of different ways.

So -- but as the RECs in California were characterized and as these RECs, where they talk about a compensation for externalities through RECs, which was in the American Ref-Fuel case, I agree with that.

Q All right. Moving to page 17, line 4.

A Okay. 17 -- wait. I don't have a 17. Okay.

Q Of your testimony. I'm sorry.

A Oh, okay. That's easier. Okay. Line 4, environmental benefits in renewable -- okay.

Q Right. You list environmental attributes and renewable attributes of QF power as one of the factors the Commission can take into account when determining avoided cost; is that correct?

A Right.

Q And am I correct that one of the things you're relying for that statement is 18 CFR Section 292.304?

A Yes. And, of course, in the context of the broader things, because renewable attributes of QF power are things like that they might be fuel free for solar or wind or whatever.

Q But you cited the --

A Yes.

Q -- 292 in the --

A Right.

Q -- Southern California Edison --

A Right.

Q -- case for that.

A Yes, yes.

Q Okay. Mr. Rabago, I'm going to hand you a copy of the FERC's order in American Ref-fuel.

A Okay. I haven't read that in a long time, so... Thank you. You want to point me to any particular provisions so I can skim?

Q Yes, sir. I would -- if I could point you to page 6, paragraph 22.

A Okay.

MR. YOUTH: Mr. Horne, I'm going to ask, with Commissioner Brown-Bland's permission, if you would repeat the cite once I get a copy of the order.

MR. HORNE: Yes, sir. I will. Be happy to do so.

BY MR. HORNE:

Q You ready?

A Yes.

MR. HORNE: It's American Ref-Fuel 105 FERC, paragraph 61,004, October 1st, 2003.

MR. YOUTH: And where in the order did you direct Mr. Rabago's attention?

MR. HORNE: Paragraph 22, which I believe is found on page 6 in the order.

BY MR. HORNE:

Q And when you're ready, Mr. Rabago --

COMMISSIONER BROWN-BLAND: Let us get this one identified for the record as well. Dominion -- this will be Dominion Rabago Cross Examination Exhibit 3.

(Whereupon, Dominion Rabago Cross Examination Exhibit 3 was marked for identification.)

BY MR. HORNE:

Q Have you had a chance to --

A Yeah. Just one second.

Q Sure. I understand. And for context, you might want to look back at paragraph 21 where they --

A Okay. I think I'm ready.

Q Okay. Would you agree with me that in this order, the FERC was talking about the factors to be considered in avoided costs in referencing 292.304, one of the things you referenced in your testimony?

A Uh-huh.

Q Is that yes?

A Yes. Oh, yeah. I'm sorry. Yes.

Q Thank you. Thank you very much.

A Yes. That was -- sorry.

Q And could you read to me what they said in paragraph 22 of their evaluation of those issues?

A I'm sorry. Say that again. You want me to read 22 to you?

Q Please.

A Okay. Sure. Paragraph 22 of this decision says, "Significantly, what factor is not mentioned in the Commission's regulations is the environmental attributes of the QF selling to the utility. This is because avoided costs were intended to put the utility into the same position when purchasing QF capacity and energy as if the utility generated the energy itself or purchased the energy from another source. In this regard, the avoided cost that a utility pays a QF does not depend on type of QF, i.e., whether it is a fossil fuel cogeneration facility or a renewable energy small power production facility. The avoided cost rates, in short, are not intended to compensate the QF for more than capacity and energy."

Q Now, doesn't that indicate that the environmental attributes of a QF is not one of the factors to be considered in determining avoided cost?

A Well, in light of the CPUC decision, which I read allows, for example, a solar specific case -- solar specific avoided cost, I would say that the way you phrased the question is an unnecessarily narrow interpretation of the word "environmental benefits." My understanding would be that if those environmental benefits translate into real costs that the utility would avoid by procuring power from a renewable energy facility, then they would, in fact, be legitimate costs for reflection in the avoided cost rate.

Q But that is not what the language of paragraph 22 says, is it?

A Right. And I'm -- and I am not -- I understand the conflict that you are attempting to sort of get me to agree to, and I do agree to it. Read narrowly, this says you can't do what the Commission in 2010 says you can do if you think of environmental benefits as translating into real costs.

Q Well, let's go back to the Commission 2010 order. In that case, they said you could establish avoided cost on a segmented basis, you could establish the avoided cost for a solar facility, you could establish the avoided cost for a combined heat and power facility, but it didn't say that those avoided costs could include adders for environmental benefits. You could calculate them separately, but energy and capacity

is all you're getting compensated for.

A I understand the way you're asking it. I'm -- in the -- in the time we have, and based on what I see in these decisions, I cannot come to the same categorical conclusion that you would like me to, because we've got direct evidence that environmental costs are real costs that would be incurred by utilities, then they may be accounted for in the determination of avoided cost rates. I -- that quote that's in my footnote is irreconcilable with the absolutist position you're trying to do, and I can't tell if it's because you're using the word adder or anything else. But that's as far as I can go.

Q **Real -- real costs, but not just simple environmental adders, a benefit. It's a -- it's a real cost.**

A Yes, yes. Now, if you're trying to get me to say perhaps that in my testimony I was inappropriately broad with the use of the term environmental benefits and that it led you to think that I was arguing for unreal cost, if there's such a thing, then I was not attempting to take that position. I agree that the -- the FERC cases and my understanding of the way PURPA works is that you've got to come down to real costs. That -- okay.

Q **Thank you, sir.**

A Uh-huh.

MR. HORNE: I have nothing further, Your Honor.

COMMISSIONER BROWN-BLAND: All right. Redirect?

REDIRECT EXAMINATION BY MR. YOUTH:

Q **Mr. Rabago, I'm not sure how familiar you are with North Carolina's definition of a renewable energy certificate. Have you seen that definition at any time?**

A If I have, I don't recall it.

Q **I do not have it in front of me; somebody else may, but Mr. Dodge asked you a question about North Carolina's RECs include some attributes and maybe don't include others. I'm going to propose, if my recollection of the statutory definition is correct, that our RECs specifically exclude carbon attributes.**

A I would -- I would --

Q **Would you accept that, subject to check?**

A I would accept that, that that's possible. I'll believe it if you say it is, subject to check.

Q **And we may be able to check that on a smart device.**

A Well, we could just go forward assuming.

Q **So I think I'm going to ask you some questions that are fairly scattershot, but you are an attorney; is** that correct?

A I am an attorney licensed in the state of Texas.

Q **And you're not only an attorney, but you've got, I believe, two LL.Ms?**

A I have two post-doctorate law degrees, and then my wife said no more.

Q **And my -- the way I practice is you don't just look at old decisions or orders. You Shepardize and you try to find the most recent order from a commission or a court; is that correct?**

A That is the principle of the common law, yes, I agree with that.

Q **So would you agree that -- and I apologize, I don't have the cross exhibits, but you were handed a 1995 FERC order?**

A I was handed a 1995, a 2003, and a 2010.

Q **And the 2010 is the most recent order --**

A Yes.

Q **-- that you were handed.**

A It is.

Q **But if you look at your footnote at the bottom of page 17 of your testimony -- this is footnote 3 -- even that 2010 decision which you were handed, there is**

another word from FERC that comes after that in the decision denying the rehearing; is that correct?

A Where are you at now?

Q If you look at page 17 of your direct testimony, --

A Right. Yes.

Q -- bottom line --

A In -- for a -- "may be accounted for in a determination of avoided cost rates."

Q And after that, there's "rehearing denied"?

A Rehearing denied, right. Right.

Q So that order 134 FERC, paragraph 61,044, you have not been asked to review that today?

A No. Actually, I think the one he handed me was 140 -- no. He handed me 61,059, which is the original opinion order. I don't have 144 formally in front of me -- 61,044. Sorry.

Q Correct. And that -- that decision, 61,044, does speak to breaking out separate avoided cost rates for different technologies. Will you accept that, subject to check?

A I will accept that. That -- that's what I understand the CPUC decision, as it's commonly called these days, stands for.

Q You were asked by Mr. Somers about the ASI program in Georgia; is that correct?

A Yes, I recall that.

Q Do you recall, as you were a participant in that proceeding, did Georgia Power state that the 12 cents and the 13 cent rates for solar under that program would not put any upward pressure on rates?

A Yes. I do recall them saying that, and I've seen other statements from the utility confirming that or repeating that.

Q I think you were asked a number of questions about -- strike that.

I'll ask you to refer to your direct testimony at pages 16 and 17.

A Yes, sir.

Q You were asked some questions about what FERC permits and what it does not permit. On those pages of your testimony, you explain what you believe FERC regulations allow to be considered in determining full avoided cost rates; is that correct?

A Right. And the purpose of my testimony was to -- to make it clear that FERC has explicitly dealt with a number of these issues, and that these kinds of factors are fairly included in avoided cost calculations where they've been monetized and where they're real costs, under the general rubric that this Commission actually enjoys considerable authority under PURPA and for law and regulation to account for the full avoided cost of solar.

Q And I think some of the questions that were posed to you focused on environmental benefits, reputational benefits, and would you agree the implication seemed to be those things cannot be quantified?

A Well, it -- it's a little bit of hyperbole, right? I mean, if you think about it, even reputational benefits, right, we cite -- I cite those as an example that the, you know, utilities get benefits in their stock price, in their -- in other things from being progressive, from being environmentally responsible. There's a lot of well-established data that organizations with environmental responsibility plans have better stock prices. The utilities who like -- utilities who do these things tend to be more liked by their customers. Their JD Power rates go up; their cost of capital goes down. There is goodwill in mergers and other transactions, which is reputational value that is monetized in rate cases and mergers. But in the hyperbolic sort of sense of, you know, the customer saying -- of giving your customers bragging rights about having solar on their roof and trying to turn that into avoided cost, while it's -- I think it's real, it's not -- we don't have yet enough analytical rigor around it to fairly impose it here, and the risks of double counting and double -- double accounting are high enough that it would -- it would cause problems in ratemaking. So that's -- that's sort of the full answer on the sort of the hyperbolic examples that -- that I saw in rebuttal testimony and that were sort of hinted at with the questions.

Q **And is that to reputational benefits?**

A Right, that kind of thing, but in general, right?

Q **Well, with your new knowledge that RECs in North Carolina do not include a carbon attribute, with that in mind, it's my understanding that you reviewed the IRPs of the utilities in North Carolina; is that correct?**

A I did.

Q **And is it your understanding that there is some sort of quantification or incorporation of avoided carbon emissions that is being used in the planning process?**

MR. SOMERS: Objection. This is outside the scope of cross.

MR. YOUTH: I don't think I'm crossing, but I do believe so --

COMMISSIONER BROWN-BLAND: Your redirect -- your redirect should go to the scope of cross.

MR. YOUTH: So they were asking about environmental benefits, and I think all these orders that we saw said actual costs, real costs, and I'm going to -- I'm asking the question is there a way that the utilities themselves are actually quantifying the costs of some of these environmental benefits or avoided emissions.

MR. SOMERS: The question is based on the Company's IRPs. I heard no questions about the Company's IRPs. The only questions about environmental methods came in the context of the FERC order.

COMMISSIONER BROWN-BLAND: I'm going to overrule the objection and allow the question.

A Here's -- here's how I did it together, as briefly as I can be, although I don't have that reputation yet. Several of the rebuttal testimonies and -- and the line of questioning was essentially that we have things like climate regulation, which is not in place and, therefore, is not a real cost. That sort of -- in this very constrained world of this avoided cost proceeding, you -- the argument is being made that those are not real costs. I don't agree with that as a general principle. I think that future costs associated with operating any kind of facility, especially one that burns a fossil fuel, will include some reasonably assigned risk of climate carbon regulation.

I note that the utilities agree with me, that they don't want to do resource planning without some kind of assessment of this risk. And when they propose to go down a path of continuing to spend money on things like the fuel diversity option one utility had, and I'm sorry, I can't remember which one had it, they are spending real money and incurring real costs that will be passed on to ratepayers that are associated with the path that they are on.

So it is -- the utilities themselves are trying to come to grips with this, and it is appropriate, to the extent those can be monetized and quantified, even if they're not yet present. FERC doesn't say that. It doesn't say that they have to be current costs. It says that they have to be real costs. And there is a -- there is an evaluation mechanism that says for a variety of reasons, this might -- this is very likely a real cost, like mercury compliance or other things that aren't settled now or Casper or whatever. So my argument is that you ought to fully assess it, then you can make a decision about whether or not you have sufficient confidence in the number to include it as a real avoided cost. But if you don't ask, the answer will always be zero and the answer of zero is always wrong.

BY MR. YOUTH:

Q I'm going to switch a little bit. Was it your intention that the Commission require the utilities to include avoided cost components for every benefit of solar generation, whether direct or indirect, quantified or unquantified, current or future, certain or speculative?

A No. While I respect the litigation posture of the witnesses who tried to characterize my testimony from sort of pulling out those pieces and trying to make a point of them, they are a minor part of -- of what I listed, and even I did not suggest that that is what I'm asking the Commission to do, and I reaffirm that in my summary.

Q Was it your testimony that what you describe as value of solar analysis is separate and apart from PURPA avoided cost analysis?

A No. In fact, my -- what I was trying to say in my testimony is that a value of solar analysis is just a richer, fuller avoided cost, basically marginal cost analysis where you take a longer view, like the Crossborder study did, and say let's see what impacts there are going out forward in time. So it is an -- it offers the Commission and, ultimately, the ratepayers of the utilities an opportunity for an improvement in the accuracy of the avoided cost applicable to solar, and that goes directly to economic efficiency in the provision of electric services.

Q And I hope this is my last or second-to-last question. With all that you've said, you're not advocating for the overthrow of the peaker methodology. Is it correct that you are basically saying within the peaker methodology that already exists and that this Commission has approved and adopted, there is a mechanism in place, the performance adjustment factor, that can be used to address the concerns that you have raised in your direct testimony?

A Yes.

MR. SOMERS: Objection. Leading.

A Yes.

COMMISSIONER BROWN-BLAND: Overruled.

A I'll just --

COMMISSIONER BROWN-BLAND: You can answer the question.

A Yeah. I'll just -- yes, that is exactly my position, that this kind of analysis takes time, that even with one utility having the start of this going on, I understand that it would be ill advised to suggest this long-running procedure be further -- proceeding be furthered delayed, but from what I've heard of the other witnesses, from what I've seen of the discussion around the PAF, that is a reasonable, probably a little low, but reasonable valuation, a 2.0 adjustment -- PAF adjustment would be, let's say, rough justice until a full avoided cost could be calculated.

MR. YOUTH: No further questions.

COMMISSIONER BROWN-BLAND: All right. We will continue with this witness after our lunch break. And we will now stand in recess until 2:00.

(The hearing was adjourned,
to be reconvened at 2:00)

STATE OF NORTH CAROLINA
COUNTY OF WAKE

CERTIFICATE

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 136, 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 12th day of November, 2013.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150