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August 7, 2015

VIA ELECTRONIC FILING

Ms. Gail L. Mount
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

Re: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases From Qualifying Facilities – 2014
Docket No. E-100, Sub 140

Dear Ms. Mount:

Please find enclosed for filing Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's (collectively, the "Companies") Joint Reply Comments ("Reply Comments") in the above-referenced docket. The Reply Comments contain certain confidential information, including (a) financial information used to develop the Companies' filed avoided cost rates, (b) business or technical information filed confidentially in support of the Companies' respective 2014 Integrated Resource Plans, (c) the Companies' combustion turbine ("CT") cost projections, and (d) actual and estimated costs of the Companies' recently constructed gas-fired generating units. Such information designated by the Companies as confidential qualifies as "trade secrets" under N.C. Gen. Stat. § 66-152(3). If this commercially sensitive business and technical information were to be publicly disclosed, it would allow competitors, vendors and other market participants to gain an undue advantage, which may ultimately result in harm to ratepayers. The Companies respectfully request that the Commission treat the marked information as confidential and protect it from public disclosure pursuant to N.C. Gen. Stat. § 132-1.2. The Companies will make this information available to other parties pursuant to an appropriate confidentiality agreement.

Please do not hesitate to contact me if you have any questions.

Sincerely,

Kendrick C. Fentress
Associate General Counsel

Enclosure

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Joint Reply Comments in Docket No. E-100, Sub 140 has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 7th day of August, 2015.

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DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities	)))))	DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S JOINT REPLY COMMENTS

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies") hereby submit these Joint Reply Comments in this above-referenced proceeding. In support thereof, the Companies show the following:

INTRODUCTION

Consistent with the intent of the Public Utility Regulatory Policy Act ("PURPA") and the Commission's *Order Setting Avoided Cost Input Parameters*, issued in this docket on December 31, 2014 ("Phase One Order"), the Companies have proposed avoided cost rates to be paid to qualifying facilities ("QFs") that are based on reliable and current cost information. The intervenors in this phase of the proceeding, the Public Staff of the North Carolina Utilities Commission ("Public Staff"), the Southern Alliance for Clean Energy ("SACE"), and the North Carolina Sustainable Energy Association ("NCSEA") have raised various issues, for the most part, advocating changes to DEC's and DEP's calculation methods that result in higher avoided cost rates to be paid, ultimately by DEC's and DEP's customers, to the QFs. NCSEA, in particular, complains about almost every aspect of the Companies' avoided cost calculations to the point of internal inconsistency, in an effort to obtain increased avoided cost rates. For example, in one section of its initial comments, NCSEA criticizes the Companies for relying on data from the Electric Power Research Institute ("EPRI") to calculate their avoided capacity cost, but, in other sections of its comments, when it suits its purposes, NCSEA faults the Companies for not relying on EPRI data or similar data in developing a contingency adder or useful life input.[1] Taken together, adoption of the majority of NCSEA's and the other intervenors' recommendations would result in avoided cost rates far in excess of the Companies' avoided costs. These excessive costs would in turn be passed along to the Companies' customers, contrary to a primary tenet of PURPA, which is that the customers remain indifferent to whether the utilities purchase power from a QF or generate the power itself.

PROPOSED AVOIDED ENERGY RATES

1. The Companies Appropriately Calculated their Avoided Energy Rates by using the Generation Expansion Plans Approved in their Integrated Resource Plans without inclusion of uncertain costs.

In its initial comments, the Public Staff recommended that the Commission direct DEC and DEP to recalculate their energy rates utilizing generation expansion plan scenarios that do not include the costs of CO_2. In support, the Public Staff contends that, in the Phase One Order, the Commission held for the purpose of calculating avoided energy rates, the generation expansion plans used in the avoided cost production cost models should be based on Integrated Resource Plan ("IRP") expansion plans, accounting for only known and quantifiable costs. Citing the Phase One Order, the Public Staff further notes that the Commission found that CO_2 costs "are not sufficiently certain to be included in avoided costs at this time."[2] NCSEA likewise submits that DEC and DEP

[1] NCSEA's comments at 21-24 and NCSEA comments at 32-35.

[2] Public Staff Comments, at 27.

have not complied with the Commission's Phase One Order because they have used an IRP expansion plan that accounts for costs of carbon emissions control.

Both NCSEA and the Public Staff argue that the inclusion of the cost of carbon emissions control in its generation expansion plan may result in the selection of new nuclear units, which provide low cost energy, which in turn may result in an underestimation of avoided fuel costs. The reasoning seems to be that the Companies could eventually purchase significantly less fossil fuels in the future if the cost of carbon emissions increase, thus reducing avoided costs. These positions seem somewhat counterintuitive because NCSEA, at hearing, supported the inclusion of speculative and unquantifiable CO_2 costs in the determination of avoided costs.[3]

Contrary to the assertions of both the Public Staff and NCSEA, the Companies have complied with the Commission's Phase One Order by removing all but the known and quantifiable costs from its generation expansion plan. In its answer to the Public Staff's Data Request 6-3, which is the same response given to NCSEA's Data Request 2-6,[4] the Companies answered, "The costs of carbon emissions were assumed as an input in the 2014 IRP. The Phase One Order reflects the distinction between Companies' development of a long-term resource plan that is robust and accounts for the possibility that carbon costs may be imposed in the future with the intent of PURPA, which is to calculate avoided costs based on currently known and measureable costs that are avoided because of the purchase of power from the QF. To the extent carbon costs actually have

[3] Phase One Order, at 42 (citing the testimony of witness Beach).

[4] In footnote 14 of its comments, the NCSEA references NCSEA DR 2-6 and PSDR 6-3, but apparently did not read the Response correctly.

been incurred already in prudent preparation for potentialities, these costs are in fact known and quantifiable and have been included in the Companies' avoided costs.

In its Evidence and Conclusions supporting Finding of Fact No. 15, the Commission recounted the positions of the various witnesses at the proceeding and concluded that "[w]hile the [Environmental Protection Agency] EPA has proposed to regulate CO_2 under the Clean Air Act and the utilities have included forecasted costs in IRP scenarios, the costs are not sufficiently certain to be included in avoided costs at this time."[5] In compliance with this, the Companies removed CO_2 costs from the base case of its IRP for purposes of determining avoided costs. The IRP base case contains the expansion plan that the Companies currently use and will use in subsequent analyses until the next IRP is filed (September 1, 2015). Thus, it is true that the expansion plan for this approved base case was utilized in the Companies' avoided cost calculations filed in March 2015. However, the important factor is that those costs were removed for the avoided cost calculations, consistent with the intent of the Commission's Phase One Order.

Finally, it should be noted that the recently released EPA Clean Power Plan ("CPP") has no prescribed CO_2 tax but instead sets state specific volumetric limits. As such, it is entirely possible under the CPP that the Companies would need to replace retiring nuclear generation with new nuclear generation to meet the volumetric limits without the explicit imposition of a carbon tax.

2. **DEC's and DEP's Natural Gas and Coal Price Forecasts Are Reasonable And Appropriate.**

[5] Phase One Order at 44.

Both NCSEA and the Public Staff are aligned in faulting Companies' forecast of natural gas prices, alleging that they have changed their methodologies for forecasting natural gas prices from those used in their 2014 IRPs, resulting in avoided energy costs that appear to be too low.[6] Specifically, both parties object because the Companies incorporated ten years of market prices in their avoided cost calculations, whereas in their IRPs, filed six months prior to the proposed avoided cost rates in this docket, they incorporated five. The Public Staff notes that it typically does not object to "generally minor" changes between the IRP and the avoided cost filings when there is a short period of time between them. Nonetheless, when DEP's natural gas forecasts were "overly conservative" in the past, the Public Staff reports that it has recommended that DEP recalculate its natural gas prices, increasing the avoided cost rates it paid to QFs.[7] The Companies note, however, that when comparing actual market prices to the projected fuel prices utilized in developing the avoided energy costs in the previous dockets, the market prices have actually been lower than the prices utilized to set the avoided energy rate. As such, the QFs have benefitted from the higher rates over the term of the contracts that have been signed based on those rates. In fact, in the months since filing the currently proposed avoided cost rates, the market is approximately 5% lower than the market fuel prices used to set those rates. Market fuel prices have been lower than the fuel projections used to calculate avoided energy rates in the avoided cost dockets since 2006.[8] As such, the Companies' calculations in this docket are appropriate and realistic.

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[6] Public Staff's Comments at 33.

[7] Public Staff's Comments at 33.

[8] Actual historic market data based on United States Energy Information Administration (EIA) Henry Hub natural gas spot prices. Current market projections as of August 6, 2015.

Contrary to NCSEA's and the Public Staff's assertions, the Companies employed the same methodology in this docket that they have employed historically to calculate their avoided energy costs. The Companies update fuel prices during the year by using market data where market data is liquid – that is, when transactable prices are available from market prices. Market prices represent the price willing buyers and sellers agree to transact at a future point in time. When market data is not observable, a modeled forecast of future prices is the best alternative. In the 2014 IRP filing, market dat was used for the first five years and the fundamental forecase was used for the longer-term fuel prices. In this case, due to improved liquidity in the market, the Companies used market data over ten years, instead of five, and then transitioned to the fundamental forecast for the longer term prices. This simply represents a change in market liquidity rather than a change in methodology. The Companies have demonstrated this liquidity by acquiring transactable price quotes for a ten-year period from four separate market participants.

The volumes of natural gas have risen significantly over the past decade, primarily driven by an increase in shale gas production in the United States. Although the Companies have used two- to five-year market data in the past, the natural gas market has evolved as the volume of natural gas has risen. Additionally, due to this expansion, there are now multiple buyers and sellers of natural gas in the market that are willing to enter into ten-year transactions. To update its fuel forecasts prior to filing its proposed avoided cost rates, the Companies requested quotes from four different financial institutions for 20,000 MMBtu/day each from 2016 to 2025. The total MMBtu volume was 80,000 MMBtu/day, and the total nominal value of those bids was over $1.1 billion over 10 years. Based on the received quotes, the Companies considered the ten-year market for natural gas to be liquid, and, therefore, reasonable for use in the calculation of avoided energy rates.

NCSEA claims, however, that the Companies are being inconsistent in their usage of market data to prepare fuel forecasts, which it alleges is to give an advantage to the Companies. In support, NCSEA refers to the Sutton BlackStart CT Project, contending that: "DEP: 1) developed and relied on a fuel price forecast for its 2014 IRP; 2) developed a new forecasting method and a new forecast for the purposes of the March 2015 Filing, in which the forecasted natural gas prices are suppressed over the 15-year term, relative to the IRP forecast; and then 3) reverted back to the 2014 IRP method and forecast to support its April 2015 CPCN application for the Sutton Blackstart CT Project."[9] The Companies address each of these claims, and refute them below.

With respect to DEP's application for a certificate of public convenience and necessity ("CPCN") to construct the 84 MW Sutton Blackstart CT, NCSEA incorrectly claims that DEP "***relied*** on the same fuel price forecasting method used in the 2014 IRP."[10] It is true that DEP referenced the 2014 IRP in its CPCN application. NCSEA is incorrect, however, in alleging that DEP "relied" on fuel prices to justify the Sutton Blackstart CT Project. The record in DEP's CPCN filing demonstrates that DEP justified the Sutton Blackstart CT Project exclusively for operation requirements, with no reliance on fuel costs. When the electrical system has gone "black" and needs to be supported, fuel costs are less than secondary to DEP's operational and reliability commitments. In its CPCN filing, DEP noted that, unlike an IRP that seeks to balance

[9] NCSEA Comments at 6 (Emphasis added).

[10] Id.

price sensitivities, the Sutton Blackstart CT Project would be operated to provide blackstart capabilities, voltage, and system capacity support. A CPCN application requires inclusion of the applicant's IRP[11], which contains the fuel forecast; however, as DEP's witness Mr. Snider explained, gas prices have a limited impact on DEP's use or dispatch of assets for operational support. In its haste to criticize the Companies, NCSEA also fails to point out that if DEP needed to rely on natural gas prices to justify the Sutton Blackstart CT Project, then a lower – not a higher – natural gas forecast would have been more helpful. With market liquidity expanding and natural gas prices dropping, the Sutton Blackstart CT Project only becomes more economical to operate – but it is operational needs and not natural gas prices that will drive DEP's decision to call on this type of asset. NCSEA's allegation that DEP is manipulating its forecasting to "suppress" fuel forecasts when advantageous to DEP is demonstrably without any merit.

NCSEA's claim that the Companies are inconsistent in how they prepare their fuel forecasts is also demonstrably without merit. The Companies have used, and will continue to use, market pricing to the extent reliably available, and will use forecasted fuel information for periods where market data is not available or is unreliable. The markets, not DEP or DEC, establish whether price transparency and liquidity exist, determined by the simple market-based test of whether there are willing seller and buyers and whether there is a reasonable "spread" between the bid and ask price action. The Companies can do nothing to influence that – either such pricing exists or it does not. The Companies' forecasting approach is fully consistent with past practices of using market data to the extent available, and then using price projections for the remainder.

[11] Commission Rule R8-61(b).

For example, in its 2012 and 2013 IRPs, DEP used market data only over a two-year period and used a forward forecast beyond two years, because market data beyond the two-year horizon, at that time, was illiquid and unreliable. However, in its 2014 IRP, DEP used market data over a five-year period and used a forward forecast beyond the five-year horizon, because market data after five years, at that time, was less liquid. Currently, the Companies have demonstrated, by way of actual and multiple bid-ask quotes that could be transacted on from sophisticated market-makers that are ready, willing, and able to enter into ten-year transactions, that there is liquidity in the natural gas forwards markets over a ten-year period. Beyond the ten-year horizon, the Companies have used forecast projections. This approach is the same as the Companies' historical practice – there is no inconsistency. There is also no attempt to "suppress" prices – the Companies are merely using actual market prices for transactions with market participants.

The Public Staff has taken the view that market-based prices should arbitrarily be truncated at 5 years, because doing so will increase the avoided cost, regardless of actual market prices. The Public Staff turns to the "futures" market to support its position. The Public Staff concludes that the "use of five years is appropriate, because the market for ten year *futures* is relatively illiquid."[12] The Public Staff misapprehends the role of the futures market. In this regard, the Companies especially disagree with the foundation of Public Staff's argument that "futures" prices are determinative of long-term "forward" supply prices – they are not. A "futures" contract for an agreement five years from now is just that – a single price for a single period to be made five years in the future – and

[12] Public Staff Comments at 29-30 (Emphasis added).

such a price also has nothing to do with actual deliveries to the burner tip. Additionally, futures are valued to account for or insure against price movement of the underlying asset, and therefore, also serve as a risk mitigation (hedging) mechanism. Futures prices are traded as financial instruments that value the anticipated volatility of the underlying asset class – not the forward transactional value of the asset class. The Companies' price forecasts have always been based on the value of forward sale and purchase commitments, not futures contracts. Therefore, Public Staff's reliance on natural gas futures to challenge the Companies' forward natural gas price forecast is misplaced.

The Public Staff also alleges, but fails to provide any actual support, for its view that the market for "forward" deliveries suddenly becomes illiquid after 5 years. The Public Staff's statement that the "market for ten year *futures* is relatively illiquid." [13] is irrelevant for two reasons: (i) the Companies do not obtain gas for ten-year deliveries using a ten-year futures contract; and, (ii) it is incorrect to assume that liquidity dries up just because there are fewer market participants over the five-year to ten-year time period relative to the number of participants over a five-year period. A reduction in futures contracts over the five to ten year period is not evidence of illiquidity in a forward market to sell, deliver, and buy natural gas – it only shows that, at this time, fewer market participants are using long-dated futures contracts, for the good reason that there are better risk mitigation alternatives than the futures instrument over that period, such as the over-the-counter financial "swaps", which are another form of risk-mitigation derivative instrument. Moreover, even if there are "relatively" fewer participants for that period in the futures market, it does not automatically mean the market is illiquid. To the contrary,

[13] Id. (Emphasis added).

futures dealers are responsible to provide liquidity for their customers regardless of futures volume on any given day. They are professionals that have many alternate ways of offsetting risk and are not limited to an exchange.

As discussed above, futures contract trading relates to price action in the futures markets, which is not where the Companies obtain their financial gas hedge quotes. A far more reliable actual indicator of a price in the future – as opposed to a price of futures contracts that are dated further out – is the price of a forward transaction quoted by a willing seller to a willing buyer. The actual forward prices that the Companies obtained from multiple willing sellers are evidence of market liquidity, transparency, and accuracy. The Companies have in fact demonstrated actual market liquidity – through the obtaining of actual prices from major dealers who were willing to transact. The actual fact of multiple prices being obtained with narrow price spreads means there is actual liquidity in the forward contracts market over a ten-year period. If the market were illiquid, the Companies would not have been able to obtain multiple prices within narrow spreads.

The United States is continuing to increase its supply for natural gas, and the North Carolina region is benefitting from increased supply and lower prices. The increasing supply for natural gas is both increasing liquidity over a longer time horizon and is driving down prices. The lower natural prices are reducing the Companies' actual fuel expenditures. Just because these prices happen to be lower at this time, does not mean they are inaccurate or unreliable. In recent history, QFs have benefitted from higher natural gas prices being used to calculate avoided energy costs, which were incorporated into the rates paid to QFs when their contracts were put in place, even though natural gas prices have decreased sharply. NCSEA and the Public Staff have not recommended that the higher rates be adjusted downward to reflect the reality of decreasing natural gas prices. Furthermore, natural gas prices are lower today than prices used to prepare the Companies' proposed rates. Although the Companies are not suggesting that they recalculate their proposed rates using today's lower prices, the current price for natural gas demonstrates that prices used to prepare the proposed rates were clearly not at the bottom of a price cycle.

Finally, the Companies believe that as ratepayers are benefitting from lower natural gas prices as part of the Companies' native load generation, they should likewise benefit from lower avoided costs based on actual lower natural gas prices and increasing supply in the market place. The Companies have accurately and transparently reflected natural gas prices in their fuel forecasts, and therefore, respectfully request the Commission to accept their fuel forecasts and calculation of avoided energy costs.

3. DEC's And DEP's Method Of Determining The Value Of Hedging For Purposes Of Avoided Cost Produces A Fair Result That Gives The Benefit Of The Doubt To The QF.

In its Phase One Order, the Commission determined it appropriate to recognize hedging costs that are avoided as a result of energy purchases from QF generation. Unlike traditional ratemaking, which looks to a historical test period, hedging is a difficult and complex exercise requiring the regulated utility to look into the future and make customer impacting decisions on this unproven look into the future. The Commission's Discussions and Conclusions related to the inclusion of hedging costs in the determination of avoided costs consist of two paragraphs of the 67 page Phase One

Order.[14] While the Commission's Discussions and Conclusions offer some guidance, the Commission offers no further details and directs the utilities to calculate and include fuel hedging benefits associated with purchases of renewable energy. Prior to reaching its Conclusions, the Commission provided an extensive review of the testimony offered by multiple witnesses regarding whether hedging costs should be considered in avoided cost calculations, the difficulties inherent in making those calculations and the different approaches that might be used. None of the approaches are simple, and none of them are perfect.

Fundamentally, hedging is a method of purchasing a commodity in the future at a price determined in the present. It is not a matter of forecasting. In its Comments, SACE states that gas commodity price forecasts do not have a "bid" and "ask' price, just a clearing price.[15] SACE misses the point. Rather than using a forecasted approach, the Companies have utilized a 10-year liquid market approach, which uses actual, quoted transaction costs rather than forecasted, speculative information.[16] The Companies were able to obtain both "bid" and "ask" prices from different suppliers of natural gas over a ten-year period.[17] The "bid" price is the price at which the third party is willing to "buy" and the "ask" price is the price at which the third party is willing to sell. For planning purposes, the Companies, in other dockets, have often used the mid-range between the

[14] Order, page 42.

[15] SACE Comments, p. 10.

[16] To the extent hedging value was determined for years 10 through 15, some forecasting was required due because liquid price quotes were not available beyond year ten.

[17] Contrary to assertions by NCSEA and the Public Staff, the Companies did not use forecasted or hypothetical numbers. The Companies' numbers are based on actual price quotes. The quotes are current prices and not future prices as the Public Staff suggests.

"bid" and "ask" price as a reasonable proxy for future gas markets. For purposes of this docket, however, the Companies recognized that, while they seek to negotiate the most favorable price possible, they sometimes might have to pay the full "ask" price to complete the transaction. Thus, in order not to underestimate the hedge price in this docket, the Companies assumed that they would pay the full "ask" price rather than the mid-point. This inures to the benefit of the QFs because the "ask" price is always higher than the "bid" price and the mid-point.

NCSEA offers nothing in the way of a definitive proposal but simply criticizes the approaches used by both the Companies and Dominion North Carolina Power ("DNCP"). NCSEA criticizes DNCP because, in its view, DNCP failed to capture the full level of risk that can be avoided by customers over the appropriate time horizon by only capturing the portion of that risk against which the utility is actually hedging.[18] In criticizing the Companies and stating its own opinion, NCSEA states that the hedging allowance must be provided in each year of the contract term to reflect the fuel hedging benefit year to year.[19] While it is difficult to determine exactly what NCSEA would suggest doing, it appears to be stating that one approach uses a period that is too short and one uses an approach that is too long. In their approach, however, the Companies have adopted a methodology that uses actual quoted prices to develop a hedging value that is more closely aligned with the period in which the QF contracts will be in place.

Notably, the process adopted by the Companies provides the equivalent of a no cost reverse hedging benefit to the QFs. If the price of gas declines, QFs are protected

[18] NCSEA Comments, at 16.

[19] Id., p. 18.

because the QF will continue to enjoy the benefits of the higher gas prices for the term of the existing contract. Even if gas prices dropped to a level where the Companies and their retail customers would be economically benefited by self-generation, the Companies continue to purchase from the QF at the higher price for the duration of the contract. If the price of gas should increase, the QF would have the option of increasing the capacity size of a potential project above the 5 MW eligibility limit to negotiate a separate contract based on the higher price of gas. In many instances, the QF chooses to build facilities only slightly below the threshold that would disqualify it from taking advantage of the standard tariffs, so the capital costs associated with such a modification should not be impossible to accomplish. QFs enjoy these potential benefits at no cost to them. Simply put, the owner of an option has a right to buy or sell at a specified price without an obligation to do so. Conversely, the seller of an option has the obligation to purchase or sell at the specified price at the sole discretion of the option owner. In this case, the QF tariff provides QFs with a right, but not an obligation, to sell to the Companies' customers at a tariff price that is held constant for two years. The Companies, and by extension, their customers, have an obligation to purchase at the tariff price. The issue from a hedge perspective is that the QF did not pay for its option to put power to the Companies and their customers, thus receiving a free option. The Public Staff mentions the Black-Scholes model, which could be used to calculate the reduction in the QF rate that would occur if the negative hedge value were to be incorporated into the rate calculation. The Companies are not presently suggesting that a cost be imposed but rather offers this as an indicator that many factors must be considered in determining whether the method used to quantify hedging benefits produces a reasonable result.

In its comments, the Public Staff mentions the hedging fees that DNCP incurs and seems to intimate that the Companies' analysis includes no such fees. That is because the Companies incur no such fees. As one of the largest purchasers of gas in the country, the Companies are able to purchase gas without paying transaction fees to suppliers or brokers of gas. The Companies receive a quoted a "bid" and an "ask" price, and the suppliers or brokers make their money on the spread between the two quotes. In their comments, none of the parties, other than the Companies and DNCP, offer detailed proposals for determining the hedging value for natural gas.

Establishing a hedge value is a difficult exercise, and many approaches exist. However, the Companies are the only party in this proceeding to offer a concrete method, using actual prices received from actual parties. In the final analysis, the use of the higher ask price and the benefit of the hedge provided to QFs by the avoided cost process produces a reasonable result. The final test in determining an appropriate hedge value should be based on whether the final result is reasonable. Ultimately, it is more accurate to use actual "bid" and "ask" prices and not selective input variables inserted into computer models, such as the Black-Scholes.

PROPOSED AVOIDED CAPACITY RATES

1. The EPRI Database Utilized By DEP And DEC Meets The Publicly Available Standard Adopted By The Commission And Accurately Accounts For Economies Of Scale While Excluding Economies Of Scope.

In its Phase One Order, the Commission stated, "because the focus of the peaker method is on a "hypothetical CT", for the next phase of this proceeding the Commission concludes that the utilities should use installed cost of CT per kW from publicly available industry sources, such as the EIA or PJM's cost of new entry studies or comparable data."[20] Both SACE and NCSEA complain that the data used by the Companies is not public simply because it is not free. This, however, misses the point. The clear intention in the Phase One Order was to provide all parties with a robust set of baseline data, which could be reviewed and utilized to produce the best possible result. In Phase One, the principal criticism by the parties and the Commission's concern was that the Companies had used hypothetical CTs with costs that were Company-specific. While the Companies continue to believe that this is the best evidence of actual CT costs, the concern was that the other parties did not have the same knowledge of the Companies' specific costs. Accordingly, the Commission ordered the use of publicly available data and also required it be "tailored only to the extent clearly needed to adapt such information to the Carolinas and Virginia." The Phase One Order clearly placed restraints on the data available to the Companies, but it is unreasonable to conclude that the Commission intended the parties to use anything other than the most robust non-company specific data available.

To some degree, the use of the most robust data available and data that is "publicly available" are mutually inconsistent concepts. It is axiomatic that the more public the data is, the more generalized it tends to be. Data such as that provided by EIA and PJM[21] is generalized and therefore likely require more adjustments to reflect an accurate cost that is both fair to QFs and the Companies' customers.[22] EPRI offers more robust, specific and accurate data where adjustments can be more limited. The

[20] Phase One Order, p. 48.

[21] The Commission's Order did not require that EIA and PJM data be used and clearly said that comparable sources could be used. Order, Id.

[22] In fact, DNCP utilized PJM data prepared by the Brattle Group and was criticized by the NCSEA for making too many adjustments to that information. NCSEA Comments, p. 20.

Companies made a reasonable decision in complying with the Commission's Order by using more specific data available from EPRI that limited the need for adjustments. EPRI is an independent and highly respected industry source. It is a worldwide organization with membership of more than 1,000 organizations. Its membership includes electric utilities, government agencies, non-utility corporations and both public and private organizations engaged in the generation, delivery or use of electricity. Completed research papers are available for purchase. However, more importantly, for purposes of this docket, the Companies' agreement with EPRI specifically permits them to share the information with parties to regulatory proceedings, and it has done so. The only restriction is the reasonable expectation that the participating parties honor the copyrights held by EPRI. Complaints from the parties that they had to ask for the data or that some of it is marked confidential for purposes of copyright protections are insufficient excuses to prohibit the use of this highly respected industry resource. The Companies have made the information available to each intervenor and will continue to do so with the appropriate confidentiality agreements in place.

DNCP took a different approach and used what appears to be more generalized data, which apparently requires more adjustments to produce an accurate result that is fair to both their customers and QFs.[23] NCSEA and SACE also complained about the method used by DNCP. Considering their positions against the methods used by all utilities, it is difficult to understand how NCSEA and SACE expect the utilities to come to an accurate number under the Phase One Order requiring both publicly available data and limited adjustments. Accurate information of the type required is simply not available from "off

[23] This should not be considered a criticism of DNCP's approach. Clearly many approaches are possible, and any approach will likely require an element of judgment.

the shelf" resources that completely eliminate the need for reasoned analysis and judgment.

Both SACE and NCSEA assert that the Companies did not completely exclude economies of scope from their calculations. In its Phase One Order, the Commission concluded that economies of scale are appropriate for up to four units, but economies of scope are not. Generally speaking, economies of scale in this context refer to the site preparation costs associated with preparing a construction location that can, over time, accommodate four separate CTs. Economics of scope would contemplate that four CTs would be constructed on the site at the same time. It is unquestioned that in preparing a location for CT construction, the Companies include the infrastructure for four separate CTs to provide customers with the benefits of the economies of scale, but sometimes places separate CTs on the site over a period of time. SACE's arguments are extreme as they apparently view this process as a quantitative science that can produce accurate results with a total absence of judgment. SACE states, "The Commission's order explicitly refers to economies of scale of *up* to four CT units. In other words, the Commission's Phase One Order does not require that economies of scale be included if that data is unavailable."[24] SACE seems to suggest that if the Companies cannot wholly and completely isolate economies of scope from economies of scale, they and its customers should be prohibited from incorporating any benefits of economies of scale.

Of course, in its Phase One Order, the Commission explicitly acknowledged the existence of economies of scale. For purposes of this proceeding, the Companies utilized an EPRI study performed by Sargent and Lundy and published in the spring of 2014. For

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[24] SACE Comments, at. 9.

purposes of the 2014 IRP filing, they included both economies of scale and scope for a four-unit site. However, for the current avoided cost filing, the Companies included economies of scale but excluded economies of scope by eliminating the assumption that four CTs were contracted under a single EPC contract simultaneously at the same site. They made the reasonable assumption that they would purchase at least two turbines at the same time that could be placed at locations within its six jurisdictional service territories. This is consistent with the DEC's and DEP's purchasing practices.

PURPA requires an avoided cost rate that assures that customers are indifferent as to whether the energy is produced by a QF or the utility. Additionally, North Carolina law requires just and reasonable rates. The Commission is not dealing with a hypothetical exercise in this Docket. The decisions made by the Commission impact real customers paying real rates. The Commission appropriately recognized that economies of scale exist. Therefore, any rate that excludes economies of scale violates the indifference standard of PURPA and is neither just nor reasonable.

The type of data available publicly makes it impossible to isolate economies of scale from economies of scope to an empirical certainty. Sound judgment is required. Not surprisingly, NCSEA would prefer it to be done differently and argues that the Companies could have started with a one-unit CT and adjusted the cost estimates to arrive at the final number. Perhaps a calculation could have been done that way, though the Companies believe that to be inappropriate. The Companies chose a different method and adjusted from a 2x2-unit site to ensure an accurate number that included economies of scale and excluded economies of scope to the greatest extent possible. It is noteworthy that the Public Staff has not objected to the Company's method regarding the calculation of economies of scale and the exclusion of economies of scope. The question for the Commission should not be what equation was used, but whether the result complies with the PURPA standard of providing an avoided cost payment that makes customers indifferent as to whether the capacity is provided by a CT or a QF. In reviewing the calculation, the Commission should note that the capacity value utilized in the avoided cost rate is higher than the numbers used for the Company's internal budgeting and its IRP. The Companies may have chosen a different method than NCSEA might have liked, but they arrived at a reasonable result that is compliant with PURPA.

2. The Companies Used An Appropriate Contingency Adder That Is Based On Their Experiences In Planning And Constructing CTs In The Carolinas.

Neither the Public Staff nor SACE contested the contingency adder used by DEC and DEP in the calculation of their avoided capacity costs. NCSEA, however, criticizes the Companies for employing their experience in constructing and operating CTs in developing the contingency adders used in calculating DEC's and DEP's avoided costs. NCSEA's proposed increased contingency adder of [CONFIDENTIAL] [redacted] [CONFIDENTIAL] more than *triples* the contingency adders that the Companies have proposed and, more significantly, have experienced in their operations in the Carolinas. Instead, DEC and DEP's contingency adder is just and reasonable, in contrast to NCSEA's proposed contingency adder, which is overly high and utterly unrelated to DEC's and DEP's experiences.

Contrary to NCSEA's comments, the Commission has not rejected DEC's and DEP's [CONFIDENTIAL] [redacted] {CONFIDENTIAL] contingency adder, which the Companies have used in their IRPs since 2013 and in the past two avoided cost proceedings (Docket Nos. E-100, Sub 136 and Phase One of this proceeding). In Docket No. E-100, Sub 136, the Public Staff and the Companies settled on an installed CT cost per kW for purposes of calculating the Companies avoided capacity rates in this proceeding; thus, the Commission did not directly approve or disapprove the contingency adder proposed by DEC and DEP. In Phase One, however, the pre-filed testimony of the Public Staff did not address the specific contingency adder proposed by DEC and DEP, and the Commission did not directly approve or reject the proposed contingency adder (or useful life, as discussed below). Instead, the NCUC set the parameters of the inputs to be considered in calculating an avoided capacity cost by stating as follows:

> [T]ransmission system impacts, a reasonable contingency adder for a hypothetical plant in relatively early stages of planning, and a reasonable estimate of useful life of a CT are appropriate to include in the calculation of the installed cost of a CT and should be included in the calculation of avoided capacity costs.

Order Setting Parameters, p. 48. The Companies' contingency adder is reasonable for use in the relatively early stages of planning because it is based on real-world experience in constructing CTs and consistent with the use of contingency adders.

AACE International defines "contingency" as:

> an amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and *that experience shows will likely result, in aggregate, in additional costs*. Typically estimated using statistical analysis or *judgment based on past asset or project experience*, contingency usually excludes: 1) major scope changes such as changes in end product specification, capacities, building sizes, and location of the asset or project; 2) extraordinary events such as major strikes and natural disasters; 3) management reserves; and 4) escalation and currency effects.

Cost Engineering Terminology, AACE International Recommended Practice No. 10S-90, April 25, 2013 at 21 (emphasis added).

The equipment for constructing a CT is generally uncomplicated and standardized; the construction process for a CT is relatively quick and straightforward. No party has contested this as factual. Consequently, higher contingency adders are neither required nor justified in the Companies' experience in constructing CTs in the Carolinas. Because of their uncomplicated nature, CT projects are not prone to the unforeseen risks and circumstances that a contingency adder is intended to cover. As the Companies have previously noted in Phase One and Sub 136, that point is demonstrated by the fact that the Companies' six most recent CT *and* Combined Cycle ('CC") projects (which include CT technology) have used little to no contingency. Notably, only two of the six projects require a portion of the small contingency adders that the Companies had included.

None of the parties to this proceeding have challenged or even discussed the Companies' operational experience in the Carolinas. NCSEA instead complains that the Companies took the contingency adder provided in the EPRI TAG data (the use of which NCSEA criticizes in other portions of its comments) and "slashes" it to [CONFIDENTIAL] [redacted] [CONFIDENTIAL] when the Companies should have used a contingency adder of [CONFIDENTIAL] [redacted] [CONFIDENTIAL] based upon other generic industry data, unrelated to the Companies' actual experiences constructing CTs in the Carolinas. NCSEA also cites pre-filed testimony from the Public Staff witness Hinton in 2012 avoided cost proceeding to support its contention that the contingency adder ought to be higher, but that citation is unavailing. Because of the settlement in the Sub 136 hearing between the Companies and the Public Staff, witness Hinton's pre-filed testimony was entered into the record in that proceeding. However, due to the terms of the settlement, it was not subject to cross-examination by the Companies and, consequently, not cited or credited in the Commission's Order in Sub 136. Notably, in Phase One, Public Staff witness Hinton did not present pre-filed testimony on the contingency adder; nor did the Public Staff raise the issue in its initial comments in this phase of the proceeding. Additionally, witness Hinton testified on cross-examination in Phase One of this proceeding that he reviewed studies from other jurisdictions to inform his opinions on appropriate contingency adders and that the subject of contingency adders from 5%- 10% was an "area of debate."[25]

Based on the foregoing, the Companies have appropriately employed their uncontested, operational experience in constructing CTs and CCs in the Carolinas in developing their contingency adders. The Companies submit that their actual operational experiences in the Carolinas are the best and most appropriate methods to determine the appropriate contingency adder. In this case, as in previous cases, the operational experiences in building CTs or CCs with CT technology clearly support a contingency adder for DEC and DEP of [CONFIDENITAL] [redacted] [CONFIDENTIAL] and the Companies' operational history indicates this could be reduced. Employing NCSEA's suggestion that the contingency adder should be higher only results in an avoided capacity cost rate that is in excess of DEC's and DEP's actual avoided costs and produces an unreasonable result.

3. **The Companies used a useful life that is justified by their forty-plus years of combined experience in constructing and operating CTs in the Carolinas.**

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[25] Tr. Vol. 7 at 201-02.

In its Phase One Order, the Commission stated that the Companies should use "a reasonable estimate of a useful life of a CT" in the calculation of the avoided capacity costs.[26] In this docket, as they have previously, the Companies estimated a [CONFIDENTIAL] [redacted] [CONFIDENTIAL] year useful life for a CT in calculating their avoided capacity costs. Relying on their more than four decades of combined experiences with building and operating dozens of CTs in the Carolinas, the Companies believe this estimate is reasonable. No party challenged evidence produced in Phase One that showed that the vast majority of CTs on the Companies' systems have operated or are expected to operate for [CONFIDENTIAL] [redacted] [CONFIDENTIAL] years or more.[27] Thus, the Companies experiences could actually support a longer useful CT life than [CONFIDENTIAL] [redacted][CONFIDENTIAL] years.[28]

In addition in Phase One, witness Snider referred to the useful life assumptions applied in the Companies' must recent general rate cases in each of the Companies' independently completed updated depreciation studies supporting their proposed depreciation rates.[29] DEP's most recent depreciation study uses a [CONFIDENTIAL] [redacted] [CONFIDENTIAL]-year useful life for its CTs. DEC's most recent depreciation study considered a lifespan of a new CT to be [CONFIDENTIAL] [redacted] years[CONFIDENTIAL].[30]

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[26] Phase One Order at 9.

[27] Tr. Vol. 1 at 192

[28] Id.

[29] Tr. Vol. 1 at 190-93.

[30] Id.

NCSEA presents no compelling reasons why DEC and DEP should depart from their operational experiences and their depreciation studies utilized in the most recent rate case before the NCUC and instead utilize a proposed shorter useful life, resulting in higher avoided capacity rates. NCSEA argues that that the EPRI TAG data assumes a useful life of [CONFIDENTIAL] [redacted] [CONFIDENTIAL], and that prior to the 2012, DEC had used a [CONFIDENTIAL] [redacted] [CONFIDENTIAL] year life and that DEP had used a [CONFIDENTIAL] [redacted] [CONFIDENTIAL] year useful life. From there, NCSEA recommends that the NCUC direct the Companies to decrease their useful life estimation to that used in the EPRI TAG data, without reference to the Companies' forty plus years of experience in the Carolinas.

The Companies' estimates of the useful life of a CT, however, are reasonable and appropriate. Avoided capacity rates should reflect the capital costs that the purchasing utility actually avoids if it purchases power from a QF rather than generating the power itself. The rates paid by customers for QF power should not exceed the purchasing utility's avoided cost. Thus, it follows that the best reference points to use in determining the useful life of a CT in setting avoided cost rates are: (1) the actual operating lives of the utility's CT fleet and (2) the CT useful life assumptions used in setting the utility's base rates. No party has presented evidence contesting the Companies' system operation. In addition, the Companies' most recent depreciation studies use a [CONFIDENTIAL] [redacted] [CONFIDENTIAL]-year useful life for DEP and a [CONFIDENTIAL] [redacted] [CONFIDENTIAL] useful life for DEC. The costs that North Carolina customers bear for a CT in a rate case and the reasonable expectation of how long a CT should operate in the Carolinas are appropriate to consider in estimating the useful life for the calculation of the avoided capacity rates in this docket. By those measures, the Companies have justified their reasonable estimation of the useful life.

CALCULATION OF RATES

1. The Companies' Weighting Given To Summer And Non-Summer Months Results in Appropriate Price Signals and is Justified by the Supporting Data.

As part of an overall effort to transition DEC and DEP to a more standardized approach in the calculation of Avoided Costs, a uniform methodology was incorporated for both DEC and DEP to calculate the seasonal allocation factors ("SAF"). Historically each Company has conducted its own legacy avoided capacity rate calculations. DEP and DEC, have tried to standardize their best practices and methodologies to achieve administrative efficiencies and to lessen the chance for confusion and mixed messaging. Where possible, the Companies have sought to adopt each other's best practices. The Companies have determined that the continuation of differing legacy allocation approaches for similar seasonal definitions results in an unjustifiable difference in price signals between the two operating companies for QFs doing business in North Carolina. DEC Option B and DEP Options A and B share the tariff definition of June through September as summer months, with the remaining months designated as non-summer. Nevertheless, the weighting of the seasonal allocation between the Companies currently varies, as shown below in the "Currently Approved Summer Allocation" and "Currently Approved Non-Summer Allocation" columns below:

	Months	Proposed 2014 Summer Allocation	Currently Approved Summer Allocation	Change
NC DEC Option B	June-September	60%	79%	-19%
NC DEP Option A	June-September	60%	38%	22%
NC DEP Option B	June-September	60%	43%	17%

	Months	Proposed 2014 Non-Summer Allocation	Currently Approved Non-Summer Allocation	Change
NC DEC Option B	October - May	40%	21%	19%
NC DEP Option A	October - May	40%	62%	-22%
NC DEP Option B	October - May	40%	57%	-17%

DEC and DEP will now send more consistent price signals across their North Carolina service territories. The "Proposed 2014 Summer Allocation" and "Proposed 2014 Non-Summer Allocation" columns above show that for the summer months, DEC Option B decreased by 19%, but the DEP Option A and Option B increased by 22% and 17%, respectively. The change was symmetrically reversed for non-summer months, with DEC Option B increasing by 19% and DEC Option A and B decreasing by 22% and 17%, respectively.

Notably, the goal of sending consistent price signals is supported by the Companies' analysis of its data. Consistency in methodology does not imply that the allocations should be same, however. In this case, the individual analyses for DEC Option B, and DEP Options A and B based on CT production support the use of the 60% summer and 40% non-summer allocation in each instance. The Companies made this data available to the Public Staff and to NCSEA through data requests after the

Companies filed their proposed avoided cost rates.[31] In its comments on this matter, however, NCSEA does not challenge, or, for that matter, even mention, the data that the Companies produced in support of their methodologies, despite copiously citing the Companies' responses to other data requests throughout its comments. Instead NCSEA takes it upon itself to accuse the Companies, "upon information and belief", of violating a settlement agreement in Sub 136 to which NCSEA was not actually a party.[32] The Public Staff, however, was a party to that settlement agreement. In contrast to NCSEA's comments, the Public Staff's comments do not mention the settlement agreement but do reference the data supporting the Companies' proposal. These comments provide the following:

> In a response to a Public Staff data request, both DEC and DEP provided information indicating that their CT fleets were used more during the summer months than winter months. The data supported the 60%/40% weighting for summer and non-summer months for the proposed avoided capacity rates under DEC Option B and DEP Options A and B and the 80/20 (summer/non-summer) weighting for DEC Option A.[33]

The Public Staff did not take issue with the weightings or methodologies used by the utilities to weight avoided capacity costs in this proceeding.

Based on the foregoing, the Companies' proposed seasonal allocations are appropriate and justified.

<u>STANDARD TERMS AND CONDITIONS, THE PURCHASE POWER AGREEMENT AND SCHEDULE PP</u>

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[31] In response to this request, NCSEA was sent all of the Companies' responses to data requests from the Public Staff.

[32] NCSEA's Initial Comments at 37.

[33] Public Staff Initial Comments at 43-44.

1. **The Companies' provisions that define the applicability of Schedule PP-1 are long-established and consistent with the Commission's 5 MW eligibility threshold for QFs to obtain the standard offer.**

DEC's approved Schedule PP-N and PP-H have included a provision that stated, "This Schedule is not applicable to a qualifying facility owned by a Customer, or affiliate or partner of a Customer, who sells power to the Company from another facility within one-half mile" since 1997, where the Commission first approved inclusion of that provision as part of its standard offer to QFs 5 MW or less.[34] The Commission adopted the 5 MW eligibility threshold for the standard offers in North Carolina in Docket No. E-100, Sub 41A to ensure that developers of smaller projects that do not have the resources or expertise to negotiate a contract with a utility could avail themselves of the utilities' standard offer. Thus, the intent of the provision included in DEC's former Schedules PP-N and PP-H was to ensure that larger developers of QFs do not thwart the Commission's intent by breaking up their facilities to geographically adjacent facilities of 5MW or less to avail themselves of the standard offer. In other words, by adopting the 5 MW or less threshold for availability of the standard tariff, the Commission did not intend for larger QF developers to evade negotiating with the utility by breaking up larger facilities into multiple, closely-located 5 MW or less facilities.

Until now, no party appears to have challenged inclusion of this provision in the DEC tariffs in any of the biennial proceedings. As has been discussed throughout these reply comments, DEC and DEP have worked to unify, to the extent practicable, their terms and conditions and PPAs to lessen confusion and to achieve best practices.

[34] Docket No. E-100, Sub 79.

Therefore, DEP has now included this long-established DEC provision in its terms and conditions.

Now, however, after more than 18 years of DEC including, and the Commission approving, this provision in DEC's avoided cost schedules, SACE argues that this "broad language" goes beyond what FERC orders permit.[35] In support of its position SACE cites a recent FERC opinion that addresses whether two generators near one another should be viewed as a single facility or two separate facilities for purposes of a reaching a capacity threshold under PURPA. SACE's argument, however, misses the point, comparing apples to oranges. The case that SACE cites in support of its argument pertains to the FERC requirements for *certification of a facility as a QF under the "one mile rule"*, not to the availability of standardized rates, terms and conditions to QFs as is appropriately determined by this Commission.

In 18 C.F.R. Sec. 292.204, the FERC established the criteria for qualifying as a small power production facility. It provides that:

> the power production capacity of a facility for which qualification is sought, together with the power production capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 MW.

18 C.F.R. 292.204(a). It further provides that "facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought . . . " 18 C.F.R. 292.204(b). This is typically referred to as FERC's "one mile rule", and it controls what facilities may certify as QFs in the first place. Both DEC and DEP's terms and conditions are entirely

[35] SACE initial comments, at 10-11.

consistent with the FERC's one mile rule, indicating that the Schedule is available to facilities that are certified as QFs as defined by FERC's 18 C.F.R. §§ 292.203, 292.204, and 292.205.[36]

The issue at hand, however, is not whether a facility meets the FERC criteria to be certified as a QF; the Companies do not deny that is a FERC decision controlled by 18 C.F.R. 292.203, et seq. The issue is whether QFs that are owned by the same seller, or an affiliate or partner of that seller, who sells power to the Company from another QF within one-half mile are able to avail themselves of Schedule PP, which is intended for QFs 5 MW and less. Like the 5 MW eligibility threshold, this is a Commission determination; not a FERC determination.[37] The Commission has determined to limit the standard offer's availability to 5 MW QFs, and the provision SACE objects to maintains that threshold. As noted, the Commission has approved this provision in its avoided cost proceedings since 1997. In this proceeding, neither the Public Staff nor NCSEA object to this long-established provision, and SACE has failed to present a compelling reason why the Commission should depart from its prior approvals now.

2. **The Companies' Reduction in Contract Energy Charge and Reduction in Contract Capacity Charge are reasonable and should be retained.**

The Companies have included the following provision in their Terms and Conditions (Exhibit No. 6 to the March 2 filing):

[36] See Purchased Power Schedule PP-1, at Para. 1.

[37] Phase One Order, at 3 ("With respect to electric utilities subject to state jurisdiction, the FERC delegated the implementation of these rules to the state regulatory authorities. State commissions may implement these rules by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the FERC's rules").

> If Seller's average energy generated in the on-peak or off-peak periods or capacity during any 12-month period falls significantly below the Contract annual kilo-watt hours or Contract Capacity, the Company may petition the North Carolina Utilities Commission to invoke a Reduction in Contract Energy Charge or Reduction in Contract Capacity Charge and establish a new Contract Energy and Capacity level.

As NCSEA notes, the Companies' filings in Docket No. E-100, Sub 136, contained similar, but not identical, language. In Sub 136, DEP's Terms and Conditions provided for the following:

> After the first two years of operation of the Facility, if Seller'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 level, the Company may invoke a Reduction-In-Contract Energy Charge and establish a new Contact Energy level for on-peak and off-peak energy periods, respectively.

The rationale for inclusion of this language was simple – protection of DEC's and DEP's customers. Long-term levelized rate QF contracts create a tension between encouraging QF development, on one hand, and the risk of overpayments to QFs, on the other.[38] Long-term levelized rates tend to overpay the QF in the early years and underpay the QF in later years. Consequently, a QF's economic incentive to incur the costs of operating and maintaining its facility diminishes, and could even disappear over the life of a long-term levelized contract. It would be unfair to the Companies and their customers for a QF to underperform during the latter part of its contract having already reaped the excess benefits provided by levelized rates in the earlier years of the agreement. The Reduction-In-Contract-Energy charge addresses that situation by providing a mechanism to adjust

[39]Available at http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=c5a1f4f7-b598-4360-8b5d-5650941f8c1c, June 17, 2015 presentation on the NCUC website under Docket No. E-100, Sub 37A.

the contract to restore the expected balance of the economic benefits to both parties in the event the QF's performance falls materially short of its contractual obligation.

The Commission directed the Companies to remove this provision from DEP's terms and conditions in Sub 136, because the two year period was inconsistent with previous Commission rulings and with the stated purpose of ensuring QFs do not decrease production in later years of levelized QF contracts. However, the Commission invited DEP to propose a provision that allows it to take action if the QF has lower production in the later years of a long-term levelized contract.

The Companies' concerns about QF long-term performance in later years and the impact that underperformance would have on the Companies' customers have not abated, and, in fact, they are more pronounced than before. Recently, Advanced Energy conducted inspections of photovoltaic facilities in the DEC and DEP service territories and presented its findings to the Commission.[39] The performance evaluations for the DEP and DEC service territories found some sites with portions of the array out of service or facing north; several others had substantial shading from vegetation. In one photograph of the presentation, trees had grown up between the solar panels. Allowed to continue, those trees will degrade the performance of those panels, leading to exactly the situation at issue here. The troubling lack of oversight on performance and maintenance issues, as well as other issues raised in the presentation, signals that the Companies' Reduction in Contract Energy and Contract Capacity provisions are necessary and appropriate to encourage continued performance by the QF, so that ratepayers have not overpaid in early years for under-production in later ones.

[39] Available at http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=c5a1f4f7-b598-4360-8b5d-5650941f8c1c, June 17, 2015 presentation on the NCUC website under Docket No. E-100, Sub 37A.

Based on the foregoing, the Companies have proposed a provision that is more narrowly tailored to the harm it is intended to prevent. Furthermore, it is not punitive because the Companies will not impose a charge without Commission approval, after making a showing satisfactory to the Commission that such a charge is justified. For these reasons, the Companies respectfully request that the Commission approve inclusion of its Reduction in Capacity and Energy provision as proposed to protect the long-term interest of the Companies' customers.

3. DEC's Terms and Conditions contain conditions for termination of QFs that protect its customers from dangerous situations and non-performance by the QF, which have been previously approved for DEP.

DEC's Proposed Terms and Conditions contains a provision taken from the current DEP terms and conditions, which were filed with and reviewed by this Commission as part of Docket No. E-100, Sub 136. [40]

In its Terms and Conditions, DEC has adopted a provision from the current DEP Terms and Conditions that outlines DEC's right to terminate or suspend an agreement. Under the provision, DEC may terminate the PPA or suspend purchase of electricity from the Seller: (1) for any default or breach of the PPA, (2) for fraudulent or unauthorized use of the Company's name; (3) for failure to pay any applicable bills when due and payable, (4) for a condition on the Seller's side of the point of delivery actually known by the Company to be, or which the Company reasonably may be, dangerous to life or property, or (5) due to the Seller's inability to deliver to the Company the quality and/or quantity of electricity mutually agreed to in the Purchase Agreement. The purpose of these

[40] Duke Energy's Compliance Rate Schedules and Contracts, Docket No, E-100, Sub 136, Attachment E, Sec. 1 (h), filed March 13, 2014.

conditions is to protect against dangerous situations, fraud, or under-performance. It is difficult to see how these common-sense conditions are in any way "draconian."

NCSEA and the Companies have discussed NCSEA's concerns about Companies terminating under the above conditions, instead of merely suspending. The Companies have agreed that termination should be a last resort. Therefore, to address NCSEA's concerns the Companies offered to add the following sentence to this section "Termination of the contract is at the Company's sole option and is only appropriate when the Seller either cannot or will not cure its default or it the Seller fails to deliver energy to the Company for more than six months." NCSEA accepted the Companies offer.

NCSEA argues that most circumstances of default are temporary or curable and that it is commercially unreasonable not to include a cure period. The Company further agrees that QFs should be allowed an opportunity to cure before termination (except in dangerous conditions and in cases of fraud). The Companies acknowledge that in Sub 136, DEP agreed to insert a 30 day cure period into this provision. However, upon review of that period, the Companies believe that 30 days is in excess of what is required to cure in the situations listed above, as the QF should hardly be taken by surprise by any of them (the exception being dangerous conditions). Furthermore, since that time, the new Interconnection Agreement now allows for a five day cure period. To be consistent and lesson confusion, and because a 30 day period is excessive, the Companies agree to include the additional sentence above and proposed to include a five day cure period in Section 1(h) of its Terms and Conditions. The Companies respectfully submit that the added sentence and proposed cure period address NCSEA's concerns.

4. **The Companies' Standard Contracts' Protect Customers by Providing that the PPAs can only be assigned to a third party if the assignee is able to assume the QF's outstanding financial responsibilities.**

The Standard PPAs provide that the contract may be assigned to a third party if DEC or DEP is reasonably satisfied that the assignee will fulfill the financial obligations of the QF. This provision is similar to a provision that is currently in the DEP Terms and Conditions that are on file at the Commission in Sub 136, except that the Companies have added a sentence in reference to the regulatory approvals required to reassign a certification of public convenience and necessity ("CPCN") or RECs at the Commission. Again, with this provision, the aim is to protect the Companies, and ultimately, the Companies' customers, from assignment of a PPA to a QF that is not able to pay the bills.

NCSEA claims, once again, that the only point of this provision is to allow the Companies to exercise "undue discretion" in impeding the development of QF development. Not so. A review of the Companies' records reveals that they have not withheld any assignments other than declining to accept a bank as a second counterparty. The Companies respectfully submit that assignment of PPAs is not uncommon and the provisions at issue are designed to protect its customers from QF developers that may assume a PPA and are unable to fulfill their obligations under it.

5. **The Companies' Standard Offer Documents Are Consistent with Prior Commission Precedent Concerning the Effect of Government Action and Changes in Law.**

In the Sub 136 proceeding, the Public Staff and the Renewable Energy Group objected to DEC's deletion of a sentence in its Terms and Conditions that pertains to the effect of changes made by the Commission to DEC's rate schedules and service regulations. At that time, Section 2 of DEC's Terms and Conditions provided that those rate schedules and service regulations are subject to change by the Commission and such changes shall immediately be part of the QF's contract and shall nullify any prior provision in conflict therewith. The sentence that DEC deleted had included a limitation to changes in the rate schedules to "variable rates only."

DEC removed this language because it had appeared overly broad and suggestive that long-term fixed rate contracts would not be subject to change in non-rate terms and provisions. DEC did not mean to imply, however, that the long-term fixed avoided cost rates themselves were subject to change during the term of the contract. Therefore, to respond to the intervenors' concerns in Sub 136, DEC agreed to include the following in its Terms and Conditions:

> The language above beginning with "Said Rate Schedule" shall not apply to the Fixed Long-Term Rates themselves, but it shall apply to all other provisions of the Rate Schedules and Service Regulations, including but not limited to Variable Rates, other types of charges (e.g., facilities charges), and all non-rate provisions.

The Public Staff and the Renewable Energy Group agreed with this proposal, and DEC included it in its Compliance Filing in Sub 136. Notably the Commission then ruled that DEC's contracts from November 1, 2010 to November 1, 2012 be retroactively deemed to have included this sentence. Although it appears to be counter to NCSEA's position in this docket, the Companies note that the Renewable Energy Group did not object at that time to the Commission's retroactive modification of existing DEC's PPAs in its favor in the last avoided cost docket.

Nevertheless, the Companies' intent in including the language NCSEA protests is simply to comply with and be consistent with the Commission's decision in Sub 136.

The Companies respectfully contend that their language is not contradictory, is consistent with the principle set forth in the paragraph above, and that no changes to this language are necessary.

6. The Companies' Proposed Adjustments for Reactive Power are Reasonable and Appropriate.

The Companies revised the power factor provisions found in the Purchased Power Schedule and the Terms and Conditions for the Purchase of Electric to clarify that a QF is expected to operate their generation in a manner that will not adversely impact voltage. QFs without specific Operating Agreements are requested to operate at a unity or 100% power factor without either supplying or consuming VARs. This approach eliminates potential conflicts with normal system operations which could adversely impact service to retail customers in the surrounding area. The supply of VARs using system capacitors is a common approach to controlling voltage on distribution circuits; therefore, if the QF supplies reactive power it can often conflict with DEC's or DEP's normal operating scheme and cause high voltage conditions. An Operating Agreement may be appropriate for larger QFs with the capability to actively provide direct voltage support. The Operating Agreement specifies the ancillary service requirements and the compensation for providing ancillary services as permitted in the QF's Interconnection Agreement. Operating Agreements are not appropriate for smaller generators because DEC or DEP must still install its own capacitors in the event that the QF is not operating during a low voltage event; therefore, no costs are avoided. QFs not operating at a unity power factor are proposed to be charged for VAR consumption or supply in the same manner and using the same rate approach as retail customers.

NCSEA's comments indicate that the proposed power factor provisions were confusing and may potentially unfairly penalize QFs. While the Companies recognize that reactive power is complex, QFs are not treated any differently than retail customers that deviate from their power factor requirement. NCSEA's comments erroneously assumes that providing VARs benefits the Companies, but their supply of VARs conflicts with the Companies' normally operating schemes and potentially creates higher cost to maintain voltage in the area. It is important to note that operating at a unity power factor maximizes the QFs kilowatt-hour production which is the unit of measure used to compensate the QF for their electricity production; therefore, a unity power factor should be desirable from the QFs perspective.

7. The Companies' Single, Contiguous Premise Provision is Consistent with Well-Established Retail Service Practices.

NCSEA objects to the Companies' provision in their Rate Schedules that:

> Service necessary for the delivery of power from the Seller's generating facilities into the Company's system shall be furnished solely to the individual contracting Seller in a single enterprise, located entirely on a single, contiguous premise.

As with several of the other provisions in the Companies' proposed PPA, Standard Terms and Conditions, and Rate Schedules, NCSEA strains to find some perceived adverse impact from this provision, concludes it must be intended to restrict QF development, and recommends its removal.

NCSEA's concerns are unfounded. Service to a single contiguous property is a well-established retail service practice and is intended to minimize the cost of providing electric service to a site, which minimizes the costs passed on to DEC's and DEP's customers. The provision does not preclude a QF's ability to wire its entire site's electrical requirements to a single point of interconnection if its property happens to be bisected by a public right-of-way. As such, it is not more prohibitive than the one-half mile provision. No change in this provision is required.

8. Revised Reporting Requirements Proposed By the Public Staff Are Appropriate To Aid in Efficient System Operations.

The Public Staff's Initial Comments included a revision to paragraph 5 in the Companies' PPAs that was jointly prepared with the Companies to clarify the provision by Sellers of annual, monthly, and day-ahead forecast of hourly generation production. The revised paragraph 5 states:

> Upon request, facilities larger than 3,000 kW may be required to provide prior notice of annual, monthly, and day-ahead forecast of hourly production, as specified by the Company. If the Seller is required to notify the Company of planned or unplanned outages, notification should be made as soon as known. Seller shall include the start time, the time for return to service, the amount of unavailable capacity, and the reason for the outage.[41]

This provision allows the Companies to request QFs in excess of 3,000 kW to provide operational information to assist the Companies in more efficiently scheduling the operations of its other generation resources. This information will aid the Companies in securing other resources during times when the QF is planning to have reduced operations. The revisions sought by the Public Staff clarify that a request for planned operational information is unlikely for QFs below 3,000 kW and is therefore deemed to be reasonable based upon current system operations.

ISSUES THAT HAVE BEEN RESOLVED

[41] Initial Statement of the Public Staff dated June 22, 2015 in Docket No. E-100, Sub 140 at page 55.

Through discussions with the Public Staff and NCSEA, the Companies were able to resolve certain of the issues raised in their comments. The Companies have already discussed an agreement between them and NCSEA to add language about the termination of a PPA. The additional issues that have been resolved are as follows.

1. Thirty Month Deadline for Achieving Commercial Operation

With respect to NCSEA's concern regarding the 30 month deadline for achieving commercial operation,[42], the Companies have agreed with NCSEA to insert clarification in both the Schedule PP and the Purchased Power Contract to indicate that the 30-month deadline can be extended. Additionally, NCSEA sought clarification requesting that the Contract Term commence on the date the Seller (QF) first delivers electricity rather than on the contract date as stated in the following:

> **3. <u>Initial Delivery Date</u>**
>
> The term of this Agreement shall begin upon the first date when electrical output is generated by the Facility and delivered to Company and continuing for the term specified in the Rate Schedule paragraph above and shall automatically extend thereafter unless terminated by either party by giving not less than thirty (30) days prior written notice. The extension will be at the Variable Rates in effect at the time of extension. The term shall begin no earlier than the date Company's Interconnection Facilities are installed and are ready to accept electricity from Seller, which is requested to be ________________, 20__. Company at its sole discretion may terminate this Agreement on ________________, 20__ (30 months following the date of the order initially approving the rates selection shown above which may be extended beyond 30 months if construction is nearly complete and the Seller demonstrates that it is making a good faith effort to complete its project in a timely manner) if Seller is unable to provide generation capacity and energy production consistent with the energy production levels specified in Provision No. 2 above.

[42] NCSEA's comments at 44.

Additionally, the Availability section of Schedule PP will be revised as follows to resolve NCSEA's concern with respect to the 30-month deadline for achieving commercial operation:

> All qualifying facilities have the option to sell energy to the Company on an "as available" basis and receive energy credits only calculated using the Variable Rates identified in this Schedule for the delivered energy. The Variable Energy Credit shall constitute the "as available" avoided cost credit for Non-Eligible Qualifying Facilities. The Fixed Long Term Credit rates on this schedule are available only to otherwise eligible Sellers that establish a Legally Enforceable Obligation on or before the filing date of proposed rates in the next biennial avoided cost proceeding, provided eligible Seller begins delivery of power no later than thirty (30) months from the date of the order approving avoided cost rates in Docket No. E-100, Sub 140, *but may be extended beyond 30 months if construction is nearly complete and Seller demonstrates that it is making a good faith effort to complete its project in a timely manner*. (emphasis added to highlight the revision)

2. Interconnection Terms

With respect to NCSEA's concern that the PPA included interconnection terms, NCSEA and the Companies agree that inclusion of those terms is intended to enhance clarity and transparency. In the event of any conflict between interconnection terms are in conflict with each other, the interconnection agreement will control.

3. Legally Enforceable Obligation "LEO" Form

Although not substantively resolved, the Companies agree with the Public Staff's proposal in its reply comments on the development of a LEO form.

PROTECTION OF CONFIDENTIAL DATA

In its Comments, NCSEA recommends that the Companies file the data from which they derive their avoided costs publicly, indicating that FERC requires transparency of underlying data. NCSEA specifically complains that it had to "resort to the discovery process to obtain data, much of which was marked a 'confidential' when provided."[43] NCSEA also notes that DNCP made its underlying data available.

As discussed above, DNCP took a different approach than the Companies in developing its avoided capacity costs. A review of NCSEA comments, however, reveals that it failed to cite to G.S. 66-152(3) which defines a "trade secret" under North Carolina law. The Companies contend, for the reasons discussed earlier, that some of the data used to calculate avoided costs is a trade secret, and, as such, they redacted the information as is allowed by the Commission pursuant to G.S. 132-1.2. NCSEA does not complain that the Companies withheld the data from its review; only that it had to "resort" to extraordinary lengths (intervening and discovery) to get it. Nevertheless the Companies are willing to discuss this issue further with NCSEA to determine if some resolution of NCSEA's concerns can be found. The Companies are willing to make a supplemental filing to report on these discussions.

Respectfully submitted, this the 7th day of August, 2015.

By: ______________________
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[43] NCSEA Comments at 80.