BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NOS. 2019-185-E and 2019-186-E – ORDER NO. 2019-881

DECEMBER 30, 2019

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| In the Matter of: | ) | ORDER APPROVING DUKE ENERGY CAROLINAS, LLC'S AND DUKE ENERGY PROGRESS LLC'S STANDARD OFFER TARIFFS, AVOIDED COST METHODOLOGIES, FORM CONTRACT POWER PURCHASE AGREEMENTS, AND COMMITMENT TO SELL FORMS |
| Docket No. 2019-185-E – South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A) | ) | |
| and | ) | |
| Docket No. 2019-186-E – South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Progress, LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A) | ) | |

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I. In addition to approving prospective application of changes, we also approve the principle that Duke's consent to material alterations will not be unreasonably withheld, conditioned or delayed. To hold otherwise would interfere with the party's ability to fairly negotiate changes in PPAs. Duke has already agreed to a similar condition in its Large QF PPAs. We agree that the provision is also reasonably applied to Standard Offer PPAs. Large QF PPA ..... 129
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## I. INTRODUCTION AND PROCEDURAL HISTORY

This matter comes before the Public Service Commission of South Carolina (the "Commission" or "PSC") on the Joint Application of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP," together with DEC, the "Companies" or "Duke") for Approval of Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Other Related Terms and Conditions filed August 14, 2019 (the "Joint Application"). The Joint Application requested approval of the Companies' application of the peaker methodology to calculate DEC's and DEP's avoided cost rates, DEC's and DEP's updated Standard Offer available to all qualifying cogenerators and small power production facilities ("QFs") up to 2 megawatts ("MW") in size, DEC's and DEP's form of power purchase agreement available to small power producer QFs that are not eligible for the Standard Offer ("Large QF PPA"), and DEC's and DEP's notice of commitment to sell form ("Notice of Commitment Form"). The Joint Application was filed in Docket Nos. 2019-185-E ("DEC Docket") and 2019-186-E ("DEP Docket," together with the DEC Docket, the "Duke Dockets") pursuant to S.C. Code Ann. § 58-41-20(A) and Commission Order No. 2019-524 to accomplish and further the purposes and goals of the South Carolina Energy Freedom Act ("Act 62" or the "Act").

## THE INTERRELATION BETWEEN RATEPAYER IMPACTS AND THE COST OF RENEWABLE ENERGY

This Order is of significant public importance and rests upon a foundational understanding of the interrelation between three entities in the electric sector: the utility,

renewable developers, and the ratepayer. Specifically, critical in the interpretation of this Order is the allocation of costs of energy between these three entities.

The utility, generally, sells electricity to the ratepayer for a fixed – or known - price per unit of power. The utility can only sell electricity at rates approved by the Public Service Commission, which are established in contested cases. The utility's rates are set at a level that gives the utility an opportunity to earn a return on its assets if it operates its company efficiently. A part of the utility's cost of service that is accounted for in the price of electricity that the ratepayer is to be charged is the cost of fuel and purchased power. Utilities are allowed to charge for the price of fuel used to generate power but are not allowed to make a profit on the fuel costs. Treated similarly to fuel costs, the utility is able to purchase power from another source – like a renewable generator – to sell to the ratepayers, but again is not allowed to make a profit on what it spends to purchase that power. This provides the utility an opportunity to earn profit from its own assets, but not overcharge ratepayers for fuel being consumed or power purchased from another source.

In the case of a renewable generator selling power to the utility, there are several financial events happening. At the highest level, shareholders or investors from an energy company must invest money in building a facility, during which process the energy company agrees to sell – and the utility agrees to buy – the electricity generated by the facility. The utility, having purchased the power as it is being generated, will sell the power to ratepayers. The price of that power, as reflected in the ratepayers' bills, will

be dependent on the price at which the utility agreed to purchase the electricity generated by the facility.

At issue is the minimum price at which the utility – and therefore also the ratepayer – must pay for electricity generated by newly built (predominantly solar) facilities. There are provisions requiring the utility to purchase power at its avoided cost rate, which is basically the cost the utility would have if it generated the next unit of power rather than purchased it. At an accurate avoided cost rate, the ratepayer would be receiving electricity at exactly the same rate as if the utility generated it. In other words, with an accurate avoided cost rate, the consumer does not pay more for electricity even though the power was purchased rather than generated by the utility.

This is the balance at issue in this case. If the avoided cost rate is higher than the utility's true avoided cost, developers would be more willing to build facilities, but ratepayers would pay a higher price. If the avoided cost rate is lower than the utility's true avoided cost, then developers would be less willing to build facilities. To the extent that they do not build new facilities, ratepayers would continue to buy electricity generated by the utility and existing renewable facilities. If the avoided cost is correctly determined, however, the ratepayers are protected, and the economic generating facilities will be built.

There is always a risk, even using the best available information to project avoided cost and set avoided cost rates, that the actual costs will change over time. This leads to the possibility of ratepayers paying an inaccurate rate for the power from renewable generators. If the cost of generation decreases over time, for example, the

ratepayer will be overpaying for electricity. Overpayment in that situation occurs because the ratepayer must continue to buy the power from the generator at the higher price that was in effect when the renewable developer agreed to sell the power. This overpayment risk is reduced when avoided costs are lower than historical average. The avoided cost rates set by the Commission in this Order are priced recognizing the risk of overpayment by the ratepayer.

This Order establishes an avoided cost rate that is accurate, which provides both the maximum protection for ratepayers and the opportunity for economic renewable generators to participate in the market.

PROCEDURAL HISTORY

Along with its Joint Application, on August 14, 2019, Duke filed the direct testimony of George Brown, General Manager of Strategy, Policy, and Strategic Investment in the Distributed Energy Technology group at Duke Energy Corporation ("Duke Energy"); Glen A. Snider, Director of Carolinas Integrated Resource Planning and Analytics for Duke Energy; Steven B. Wheeler, Director of Pricing and Regulatory Solutions for Duke Energy Business Services, LLC ("DEBS")[1]; David B. Johnson, Director of Business Development and Compliance for Duke Energy, and Nick Wintermantel, Principal Consultant and Partner at Astrapé Consulting. Exhibits were included with the direct testimony of Witnesses Snider, Wheeler, Johnson and

[1] DEBS provides various administrative and other services to DEC, DEP and other affiliated companies of Duke Energy.

Wintermantel. The Commission granted confidential treatment of Snider DEC Exhibit 1 and Snider DEP Exhibit 1 in Order No. 2019-684.

The Companies' most recently approved avoided cost rates and Standard Offer Tariffs, which became effective July 1, 2016, were approved by the Commission in Docket No. 1995-1192-E by Order No. 2016-349. In particular, the Order approved the Companies' offer of variable, 5-year and 10-year[2] term avoided cost rates for QFs up to 2 MW in size.

On July 18, 2019, the Commission Clerk's Office issued the Notice of Filing and Hearing and Prefile Testimony Deadlines (the "Notice") in the Duke Dockets and instructed the Companies to publish it in newspapers of general circulation in the areas affected by the Companies' Joint Application on or before July 29, 2019, and provide Proof of Publication to the Commission by August 12, 2019. On August 9, 2019, DEP filed affidavits with the Commission demonstrating the Notice was duly published in accordance with the Clerk's Office instructions. On August 9, 2019, DEC advised the Commission that due to a "system error," one of the newspapers in the DEC service territory did not publish the Notice by July 29, 2019, but the Notice was subsequently published on August 9, 2019. DEC also provided the affidavits of publication to the Commission in its August 9, 2019, filing.

Johnson Development Associates, Inc. ("Johnson Development"), represented by James H. Goldin, Esquire, Weston Adams, III, Esquire, Jeremy C. Hodges, Esquire and Harold W. Gowdy, Esquire, filed a Petition to Intervene in the Duke Dockets on June 13,

[2] See Order page 18-19

2019.[3] South Carolina Solar Business Alliance, Inc. ("SCSBA"), represented by Richard L. Whitt, Esquire, Weston Adams, III, Esquire, Jeremy C. Hodges, Esquire and Benjamin L. Snowden, Esquire, filed a Petition to Intervene in the Duke Dockets on June 14, 2019.[4] Nucor Steel – South Carolina ("Nucor"), represented by Robert R. Smith, II, Esquire, filed a Petition to Intervene in the DEP Docket on July 3, 2019.[5] The South Carolina Coastal Conservation League and Southern Alliance for Clean Energy ("SACE/CCL"), represented by James Blanding Holman IV, Esquire, Stinson W. Ferguson, Esquire, Lauren Joy Bowmen, Esquire and Maia Danaid Hutt, Esquire filed a Petition to Intervene in the Duke Dockets on July 12, 2019.[6] Walmart, Inc. ("Walmart"), represented by Stephanie U. Eaton, Esquire, Carrie Harris Grundmann, Esquire, and Derrick Price Williamson, Esquire, filed a Petition to Intervene in the Duke Dockets on July 30, 2019.[7] The South Carolina Energy Users Committee ("SCEUC"), represented by Scott Elliott, Esquire, filed Petitions to Intervene on August 7, 2019, in the DEC Docket, and August 12, 2019, in the DEP Docket.[8] Ecoplexus, Inc. ("Ecoplexus"), represented by Richard L. Whitt, Esquire, filed a Petition to Intervene in the Duke Dockets on August 12, 2019.[9] The South Carolina Department of Consumer Affairs ("Consumer Affairs"), exercising its right to intervene was represented by Becky Dover, Esquire and Carri Grube-Lybarker, Esquire. The Office of Regulatory Staff ("ORS"), automatically a party

[3] Johnson Development's Petition was granted by Order No. 2019-442 (DEC) and Order No. 2019-443 (DEP).
[4] SCSBA's Petition was granted by Order No. 2019-446 (DEC) and Order No. 2019-447 (DEP).
[5] Nucor's Petition was granted by Order No. 2019-520.
[6] SACE/CCL's Petition was granted by Order No. 2019-544.
[7] Walmart's Petition was granted by Order No. 2019-568.
[8] SCEUC's Petitions were granted by Order No. 2019-587 (DEC) and Order No. 2019-605 (DEP).
[9] Ecoplexus's Petition was granted by Order No. 2019-613.

pursuant to S.C. Code Ann. § 58-4-10(B), was represented by Andrew M. Bateman, Esquire, Alexander W. Knowles, Esquire and Nanette S. Edwards, Esquire. The Companies were represented by Rebecca J. Dulin, Esquire, Heather Shirley Smith, Esquire, E. Brett Breitschwerdt, Esquire, Frank R. Ellerbe III, Esquire, Samuel J. Wellborn, Esquire and Len S. Anthony, Esquire. Collectively, DEC, DEP, Johnson Development, SCSBA, Nucor, SACE/CCL, Walmart, SCEUC, Ecoplexus, Consumer Affairs and ORS are referred to as the "Parties" or individually as a "Party."

Pursuant to S.C. Code Ann. § 58-41-20(I) by Order No. 2019-621 on August 28, 2019, the Commission selected John Dalton of Power Advisory, LLC ("Power Advisory") as the independent third-party consultant to advise and report to the Commission on the Companies' avoided costs. In addition to receiving and responding to requests for information and discovery from ORS and intervenors, the Companies received Power Advisory's First Set of Interrogatories and First Requests for Production of Documents on September 12, 2019. The Companies provided initial responsive documents on September 18, 2019, and followed up with the remaining requested documents and information on September 20, 2019. The Companies received Power Advisory's Second Set of Interrogatories on October 2, 2019, and provided responses on October 10, 2019. By Order 2019-107-H, the Commission set a date of November 4, 2019, by which Power Advisory shall provide the Commission and Parties with its Final Report. On November 1, 2019, Power Advisory provided its Final Report[10] to the Commission and Parties. The Parties were to provide comments on the Power Advisory

[10] Attached as Order Exhibit 1.

Report by 12:00 p.m. on November 8, 2019. The parties have provided those comments to the Commission in a separate filing.

As set forth in Order No. 2019-107-H, the Parties filed prehearing briefs on September 30, 2019.[11] In the prehearing briefs, the Parties provided their statement of the case, identified witnesses and provided brief summaries of witness testimony as well as outlined the legal issues before the Commission.[12] On October 8, 2019, the parties filed responsive prehearing briefs in which they provided a summary of their responses to other Parties' positions, outstanding procedural and evidentiary issues, summaries of testimony filed since September 30, 2019, and discussions of any stipulations reached or issues not in controversy.

On September 11, 2019, Johnson Development filed the direct testimony of Rebecca Chilton, an independent consultant doing business as Izuba Consulting. On September 11, 2019, SCSBA filed the direct testimony of Steven J. Levitas, Senior Vice-President for Strategic Initiatives for Pine Gate Renewables, LLC; Hamilton Davis, Director of Regulatory Affairs for Southern Current, LLC; and, Jon Downey, President and CEO of Southern Current, LLC.[13] Exhibits were included with the direct testimony of Levitas. On September 12, 2019, SCSBA filed the direct testimony and exhibits of Ed Burgess, Senior Director at Strategen Consulting.[14] SCSBA filed amended direct

[11] The Prehearing Brief Schedule was originally set in Order Nos. 2019-104-H and 2019-105-H and subsequently clarified and adjusted in Order No. 2019-107-H.
[12] Intervenors Walmart, SCEUC and Nucor submitted letters in lieu of prehearing briefs.
[13] SCSBA inadvertently failed to file the Direct Testimony and Exhibits of Witness Levitas in Docket No. 2019-186-E and did so on September 17, 2019.
[14] Portions of Burgess's Direct Testimony contain confidential information and were filed under seal pursuant to Order No. 2019-680.

testimony of Witness Burgess on October 17, 2019. On September 11, 2019, SACE/CCL filed the direct testimony and exhibits of James F. Wilson, an independent consultant and economist doing business as Wilson Energy Economics, and Brendan Kirby, a private consultant. SACE/CCL subsequently filed amended direct testimony and exhibits for Witness Kirby on September 19, 2019. On September 11, 2019, ORS filed the direct testimony of Robert A. Lawyer, Senior Regulatory Manager in the Utility Rates and Services Division, and Brian Horii, Senior Partner at Energy and Environmental Economics, Inc. ("E3"). Exhibits were included with the direct testimony of Witness Horii.

On September 30, 2019, Nucor filed a letter in lieu of prehearing brief in which Mr. Smith also requested protection from appearing at the hearing.

On October 2, 2019, the Companies filed the rebuttal testimony of Witnesses Brown, Snider, Wheeler, Johnson, Wintermantel, and John Samuel Holeman III, Vice-President of the System Planning and Operations Department for Duke. Exhibits were included with the rebuttal testimony of Wheeler, Johnson, and Wintermantel.[15]

On October 11, 2019, Johnson Development filed the surrebuttal testimony of Witness Chilton, and SCSBA filed the surrebuttal testimony of Witnesses Levitas, Davis, Downey, and Burgess. SACE/CCL filed the surrebuttal testimony of Witness Wilson and Kirby on October 11, 2019. ORS filed the surrebuttal testimony of Witness Horii on October 11, 2019. SCSBA filed amended surrebuttal testimony of Witness Burgess on

[15] The Companies did not request Mr. Wintermantel's rebuttal exhibit be entered into the record during the hearing.

October 17, 2019. SACE/CCL filed amended surrebuttal testimony for Witness Kirby on October 18, 2019.

On October 15, 2019, ORS filed the unredacted direct testimony and surrebuttal testimony of Witness Horii that was previously filed under seal, but after consultation with the Companies, determined that the previously redacted versions of Witness Horii's testimony did not contain confidential information.

On October 21, 2019, at the beginning of the hearing, counsel for the Companies notified the Commission that the Companies and SCSBA, Johnson Development and SACE/CCL (the "Settling Parties") had come to an agreement regarding the solar Integration Services Charges ("SISC").[16] Ecoplexus, while not a signatory, supported the Settlement. The Settling Parties agreed to the use of the SISC proposed by the Companies which is $1.10/MWh (DEC) and $2.39/MWh (DEP), and agreed that the SISC should be fixed for the duration of the PPA. As part of the Agreement, the Companies agreed to submit proposed guidelines by November 18, 2019, outlining the requirements for QFs to become "controlled solar generators" and thereby avoid the SISC. Such guidelines were filed on November 18, 2019. In accordance with the terms of the Settlement, the Settling Parties agreed to waive cross-examination of Duke Witnesses Wintermantel and Holeman and SACE/CCL Witness Kirby. The Settling Parties further agreed to waive cross-examination on the portions of testimony from Duke

[16] The Partial Settlement Agreement was entered into the record as Hearing Exhibit 1 and is attached as Order Exhibit 2.

Witnesses Snider and Wheeler, SCSBA Witness Burgess and ORS Witness Horii that related to the SISC.

The Commission conducted an evidentiary hearing on this matter on October 21, 2019, and October 22, 2019, in the hearing room of the Commission with the Honorable Comer H. Randall presiding.

On October 21, 2019, Duke Witnesses Brown and Snider appeared as the Companies' first panel of witnesses. Witnesses Brown and Snider gave summaries of their direct testimonies and answered questions from counsel and the Commission. Witness Brown testified regarding the requirements of PURPA, specifically as it relates to the mandatory purchase obligation, and the requirements of Act 62 as they relate to PURPA. Witness Snider provided testimony in support of the Companies' use of the peaker methodology for the calculation of avoided cost and the Companies' rate design. Next, Duke presented its second panel of witnesses, Witnesses Wheeler and Johnson, who provided summaries of their direct and rebuttal testimonies and answered questions from counsel and the Commission. Witness Wheeler provided testimony in support of the Companies' Standard Offer Tariffs, Standard Offer PPA and the standard offer terms and conditions applicable to QFs with a capacity of 2 MW or less. Duke Witness Wheeler also provided testimony in support of requiring a QF to deliver power within 30 months to address a concern that retail customers are not paying stale and inaccurate avoided cost rates due to extended delays in the construction of a QF. Witness Johnson's testimony was given in support of the Companies' Large QF PPA available for projects greater than 2 MW as well as the Companies' Notice of Commitment Form. The

Companies then presented Witness Wintermantel who provided a summary of his direct and rebuttal testimony and answered questions from the Commission. Duke Witness Wintermantel provided testimony to the Commission in support of the solar ancillary service study completed by Astrapé for the Companies, which supports the calculation of the SISC.

SCSBA and Johnson Development then presented a joint panel of SCSBA Witness Levitas and Johnson Development Witness Chilton. Witness Levitas testified regarding his concerns with the Companies' proposed Standard Offer PPA and terms and conditions, Large QF PPA and Notice of Commitment Form. Witness Chilton provided testimony regarding PPA duration and market rate financing. SCSBA then presented its second panel, which included SCSBA Witnesses Burgess, Davis, and Downey. Witnesses Burgess and Davis provided summaries of their direct testimony. Witness Burgess testified regarding his concerns of the Companies' incentive structure, which he suggested provides an incentive to pursue low avoided cost rates, as well as his concerns regarding traditional utility-owned generation. Witness Davis provided testimony concerning Act 62's avoided cost requirements. SCSBA Witness Downey then provided a summary of his direct and surrebuttal testimony in which he addressed the economic development of solar companies as it relates to increased competition in electric generation.

The Commission reconvened the hearing on October 22, 2019, at which time SACE/CCL presented Witness Kirby. Witness Kirby provided a summary of his direct and surrebuttal testimony, which included his comments about the SISC as well as the

solar ancillary service study. Next, SACE/CCL Witness Wilson provided a summary of his direct testimony in which he addressed aspects of the Companies' proposed avoided capacity rate design. ORS then presented its panel of witnesses, Horii and Lawyer. Witness Horii provided a summary of his direct and surrebuttal testimony in which he supported the Companies' avoided energy costs and generally supported the proposed avoided capacity costs, but offered proposed changes to the lifetime of a CT and provided recommendations for the seasonal allocation of capacity costs. Witness Lawyer testified regarding the Companies' compliance with sections of Act 62. Next, the Companies presented their rebuttal case and recalled Witnesses Brown and Snider. Witness Brown provided testimony regarding the recent Notice of Proposed Rulemaking on PURPA implementation issued by FERC. Witness Snider testified that SCSBA's emphasis on the need to promote competition between the utilities and QFs demonstrates a fundamental misunderstanding of Act 62 and PURPA. Next, the Companies presented rebuttal Witness Holeman who testified regarding the challenges and operational circumstances that the Companies' system operators experience with growing levels of solar QFs. SCSBA then recalled Witnesses Burgess and Davis to give summaries and testify regarding their surrebuttal testimony. Witness Burgess testified that the Companies' inclusion of coal in DEC's and DEP's Integrated Resource Plans ("IRPs") could have the effect of suppressing avoided cost values, and provided updated calculations for his proposed alternative seasonal allocation of capacity values. Witness Davis testified regarding the Companies' failure to appreciate the historical and future capacity contributions from solar. SACE/CCL then recalled Witness Wilson to provide his

surrebuttal testimony in which he further explained his concerns regarding the studies used to support the Companies' proposed seasonal capacity payment allocation.

At the conclusion of the evidentiary hearing, at the request of Johnson Development counsel to include late-filed exhibits regarding alternative PPA contract terms, and after objection, it was agreed that Johnson Development and SCSBA would provide a proposal of dates for post-hearing submission of documents for consideration by the Commission, which were also subject to objection. Johnson Development and SCSBA jointly filed a proposed schedule for post-hearing submissions on October 23, 2019. The Hearing Officer issued a Directive for parties to respond by October 28, 2019.[17] The parties filed responses as directed, and on October 31, 2019, a Directive was issued by the Hearing Officer stating it is permissible to include proposals that are based on the evidence and testimony in the record of the case in the Parties' proposed orders, but that it would be inappropriate to attempt, at this time, to enter additional evidence or testimony into the record.[18] The parties filed proposed orders on November 8, 2019.

## II. SUMMARY INTRODUCTION TO COMMISSION DECISION

This case is the first proceeding to address the Companies' avoided costs and PURPA implementation following enactment of Act 62. The record in this case is robust—over 800 pages of testimony and over 700 pages of exhibits were submitted by Duke, ORS, and intervening parties. This is also the first case in which the Commission retained an independent third-party consultant to help inform the Commission's decision

[17] Order No. 2019-126-H.
[18] Order No. 2019-128-H.

regarding Duke's avoided costs, as provided for under Act 62. The statutorily-mandated purpose of the case is for the Commission to set avoided cost rates for QFs selling their output to Duke pursuant to PURPA and to approve contract terms to govern those sales of power, consistent with PURPA and Act 62

The Commission heard extensive arguments, over the potential for utility bias against QFs, inherent risks to customers in developing utility and QF generation sources, and the existence (or lack thereof) of competition between utility generation and QF power. As a basic premise, the Companies maintained that, because costs associated with PURPA contracts are statutorily passed through to customers, the Companies are financially indifferent to QF purchases. Customer groups including SCEUC and Nucor have advocated for the Commission to set avoided cost rates as low as reasonably possible consistent with the statutory requirements of Act 62. (Tr. Vol. 2, p. 588-589; Exhibit No. 18.) In contrast, SCSBA has advocated that avoided cost rates should be set at the higher end of a "zone of reasonableness" to foster Act 62's goal of encouraging renewable energy. Additionally, Duke emphasized that the "indifference principle" under PURPA prohibits the Commission from setting avoided costs to incentivize or subsidize the development of QFs above the actual costs to be avoided by purchasing power from QFs.

Duke also raised concerns about the significant financial obligation its customers may face as a result of the unprecedented amount of solar QFs selling their output to the Companies under PURPA at rates that exceed the utilities' most current projections of avoided cost. According to Duke, its customers have experienced risk associated with

longer-term fixed avoided cost rates that declined as time progressed. In considering these challenging issues, the Commission's decision appropriately balances the risks to customers of longer-term fixed price rates with the interests of the QF industry in the near term.

In assessing risks for the using and consuming public in this proceeding, the Commission has carefully considered the possibility that utility customers could overpay for QF purchases if avoided cost rates in the future turn out to be lower than the administratively-forecasted avoided cost rates established by the Commission today. This "over-payment" risk is a concern the Commission has attempted to manage in this Order by accurately setting avoided cost rates to be paid to QFs.

SCSBA and Johnson Development have also characterized the utilities as attempting to oppose competition from solar generation, arguing that the influx of solar generation endangers the ability of the utility to build new generation. These parties have suggested that the development of utility generation is riskier than development of QF facilities due the potential for cost overruns. The Companies respond that Duke is fully committed to competitively procuring significant solar energy for its customers, and that the Commission and intervenors have opportunities in rate proceedings to ensure that only prudently incurred costs of utility owned generation are recoverable, and that cost savings are passed onto customers through lower cost of service.

Duke has highlighted the significant additional amounts of solar it plans to incorporate in the near-term and long-term. The Companies project up to 1,300 MW of solar capacity to be procured through the independently-administered North Carolina

Competitive Procurement of Renewable Energy ("CPRE") Program over the next few years[19] and anticipate 8,300 MW of total installed solar capacity combined between DEC and DEP, to serve customers' energy needs over the next 15-year IRP planning period.

The Commission is also mindful that setting avoided cost rates is not wholly discretionary to this Commission. In this Order, we fully explain the legal framework that guides us to determine the utilities' avoided costs as defined by PURPA and have endeavored to set rates that reflect the utilities' full and accurate avoided costs. As argued by Duke, the setting of those rates cannot be used to incentivize solar and other renewable generation at the expense of ratepayers as such an outcome is beyond the Commission's authority under PURPA and thereby prohibited by Act 62. The Commission notes that, while Act 62 is unquestionably designed to *encourage* renewable energy, the General Assembly provided a variety of provisions (such as net metering, the voluntary energy renewable programs, and others) to encourage renewable energy, and not specifically through the PURPA provisions of Act 62. The PURPA provisions of Act 62 reinforce the level playing field established for QFs by Congress and FERC, supporting nondiscriminatory treatment for all sources of generation. The Commission's task here is to fully and accurately determine the utilities' real and quantifiable avoided

[19] Witness Brown highlighted that both Southern Current and JDA successfully participated in CPRE Tranche 1, with affiliates of each of these developers winning proposals. He further testified that Duke's now-open "Tranche 2" CPRE solicitation will solicit a total of 680 MW of additional new renewable energy resources to be constructed between now and 2023. In total, Mr. Brown explained that Duke is planning to solicit up to 1,300 MW of new renewable energy capacity under the CPRE Program at rates below avoided costs over the next few years. (Tr. Vol. 2, p. 621.17-18.) [See Order page 49]
Incident to the CPRE bid process, ten of the projects will be located in North Carolina and three projects will be located in South Carolina. Tr. p. 630.60, 11. 6-8. [See Order page 110].

costs, consistent with long-standing PURPA principles, despite the policy positions advanced by parties to this case.

Through this Order, the Commission is also approving the terms of the SISC Settlement between Duke, the solar industry, and environmental intervenors in this proceeding. The Commission believes the Settlement presents a reasonable accommodation among the parties regarding the contentious and complex issues surrounding variable resource integration charges. The Commission appreciates the Settling Parties' efforts to reach an agreement on this issue.

In addition to establishing avoided cost rates pursuant to PURPA, Act 62 also requires the Commission to approve contracts with terms and conditions through which QFs may sell their output to the utilities. We are pleased at efforts undertaken by the Companies and the intervenors to cooperate and incorporate the recommendations of each others' witnesses and work toward reaching agreement on as many provisions of the contracting documents as possible. As such, only a handful of contracting issues remain in dispute for the Commission to decide in this Order.

Act 62 Section 58-41-20 (F)(1) requires:

> Electrical utilities, subject to approval of the commission, shall offer to enter into fixed price power purchase agreements with small power producers for the purchase of energy and capacity at avoided cost, with commercially reasonable terms and a duration of ten years. The commission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including, but not limited to, a reduction in the contract price relative to the ten year avoided cost.

In all cases in this Order, all references to the requirement for the utility to offer - and the Commission to order – 10-year contracts are to be understood to be in the context of this provision. It is clear that, absent persuasive evidence in the record of additional terms, conditions, and/or rate structures to support a term longer than 10-years, as required by the plain language of the statute, Act 62 requires 10-year contract terms to be offered by utilities to QF's.

As to the term of contract for larger QF power purchases, the Commission has—very late in the proceeding—been asked through SCSBA and Johnson Development's Proposed Orders to consider extended contract terms longer than the 10-year term prescribed by Act 62. SCSBA and Johnson Development have not explained their failure to properly put forward such proposals into the evidentiary record in this proceeding. Regardless of the rationale for this approach, as a threshold matter, such late-filed proposals do not satisfy the procedural requirements of Act 62, the Commission's Rules of Practice and Procedure, or the South Carolina Administrative Procedures Act. As a result, the Commission declines to consider this untimely-presented information, as it is not evidence in the record of this proceeding upon which the Commission may make a conclusion in this case. A contract length of 10 years, as timely proposed by the Companies and properly entered into the evidentiary record, is, indeed, consistent with the Act. If intervenors choose to make such alternative proposals in future avoided cost cases, the Commission urges the proposals to be presented on the record in a timely manner that complies with Act 62, the Commission's Rules of Practice and Procedure,

and the South Carolina Administrative Procedures Act, and affords all parties a reasonable opportunity to consider and respond to such proposals.

The issues put forward by the parties in this proceeding are representative of the dialogue surrounding the energy future of South Carolina as renewable energy continues to become a more significant component of the State's generation mix, and this will not be the last the Commission considers such issues. However, the scope of the PURPA implementation issues to be addressed pursuant to Act 62 is explicit, and the Commission's determinations in this case reflect that scope set forth by the General Assembly. This Order represents a logical and evidence-based determination of all issues in this docket, informed by the opinion of the Commission's third-party independent consultant, and follows the intent and direction of the General Assembly in Act 62, which gave rise to this proceeding.

## III. GUIDING LEGAL FRAMEWORK: PURPA AND ACT 62

### A. Jurisdiction

This Commission has jurisdiction over the Companies' Joint Application, as the Companies are electrical utilities under the laws of South Carolina and their operations are subject to the jurisdiction of this Commission. The Companies are also subject to Act 62, which, in pertinent part, requires the Commission to conduct biennial (or more frequent) proceedings to oversee South Carolina's electrical utilities' compliance with the federal PURPA law, including review and approval of the Companies' avoided cost methodologies and rates, Standard Offer, form PPAs for QFs not eligible for the Standard Offer, as well as standard notice of commitment to sell forms available to all small power

producer QFs as part of the State's PURPA implementation framework. S.C. Code Ann. § 58-41-20(A). Accordingly, the Companies' Joint Application seeks Commission approval of DEC's and DEP's avoided cost methodologies and rates, Standard Offer tariffs, form contract power purchase agreements, commitment to sell forms, and other related terms and conditions as required by Act 62.

**B. PURPA Framework and Mandatory Purchase Requirements**

Pursuant to Sections 201 and 210 of PURPA, electric utilities, such as DEC and DEP, are required to interconnect with and to offer to purchase electric energy from qualifying cogeneration and small power production facilities or "QFs." *See* 16 U.S.C. § 824a-3(a). This is known as the "mandatory purchase obligation" under PURPA. *See generally Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, 168 FERC ¶ 61,184 at ¶76 (Sept. 19, 2019) ("PURPA NOPR") (noting that PURPA's mandatory purchase requirements are a benefit of QF certification). PURPA requires the rates that electrical utilities pay to purchase QF energy shall not exceed the purchasing electrical utilities' "avoided costs," which PURPA defines as the incremental cost to the electric utility of the electric energy, which, but for the purchase from such QFs, such utility would generate or purchase from another source. *See* 16 U.S.C. § 824a-3(b), (d.) PURPA also requires that the rates for purchases of QF power be set at levels and in a manner that is just and reasonable to the utility's customers, in the public interest, and nondiscriminatory towards QFs. *See* 16 U.S.C. § 824a-3(b)(l); (2).

In enacting PURPA, Congress directed FERC to prescribe regulations to encourage the development of cogeneration and small power production facilities under

PURPA, and delegated to state commissions the responsibility of implementing FERC's regulations, including PURPA's mandatory purchase obligation. *See* 16 U.S.C. § 824a-3(f); *see also FERC v. Mississippi*, 456 U.S. 742,750-51, 102 S.Ct. 2126 (1982). In 1980, FERC issued its rulemaking order, Order No. 69, establishing regulations to implement PURPA. *See Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128, (1980) ("Order No. 69"). Among FERC's regulations to implement PURPA, FERC prescribed additional details regarding electric utilities' obligation to purchase energy and capacity made available by QFs, including expressly prescribing that electric utilities shall not be required to pay more than the avoided costs for purchases from QFs. *See* 18 C.F.R. § 292.303(a); 18 C.F.R. § 292.304(a)(2).[20]

FERC also recognized in Order No. 69 that smaller QFs could be challenged by the transactional costs of bilaterally negotiating individualized rates with electric utilities, and required states implementing PURPA to make standard rates and terms available to QFs that are 100 kilowatts ("kW") and smaller. 18 C.F.R. § 292.304(C). FERC's regulations therefore provide that states "may" put into effect standard rates for purchases for QFs larger than 100 kW, explaining "that the establishment of standard rates for purchases can significantly encourage cogeneration and small power production, provided that these standard rates *accurately reflect the costs* that the utility can avoid as a result of such purchases." *See Order No. 69,* at 12,223 (emphasis in the original).

[20] The Commission recognizes that FERC recently issued the PURPA NOPR to reconsider certain aspects of the mandatory purchase requirements prescribed in 18 C.F.R. § 292.304. These proposed regulations are not final regulations and have not yet been adopted by FERC. Accordingly, they are not binding on the Commission in its efforts to implement PURPA in South Carolina at this time.

Thus, in setting the mandatory purchase obligation requirements under its regulations, FERC mandated that standardized avoided cost rates should be made available to small QF generators of 100 kW or less (which became known as the "standard offer"), while leaving it to the implementing states and state commissions to determine whether to set standardized avoided cost rates for QF generators sized greater than 100 kW. As discussed further below, Act 62 now extends the standard offer requirements in South Carolina to all small power producer QFs 2 MW or smaller. *See* S.C. Code Ann. § 58-41-10(15).

**C. Act 62 Requirements**

The General Assembly's recent enactment of Act 62, in part, enacted S.C. Code Ann. § 58-41-20, which prescribes a new biennial (or more frequent) review and approval process for the Commission to administer PURPA implementation in South Carolina. While the Commission has always had the exclusive authority and responsibility to oversee the State's implementation of PURPA in compliance with the regulations established by FERC, Act 62 sets a specific procedural framework through which the Commission must consider these issues. Also, while the Commission's previous review of the Companies' PURPA implementation has been specific to each electrical utility's Standard Offer, Act 62 expressly requires the Commission to review and approve form PPAs for QFs not eligible for the Standard Offer as well as standard notice of commitment to sell forms available to all small power producer QFs as part of the State's PURPA implementation framework. *See* S.C. Code Ann. § 58-41-20(A),(C),(D).

Importantly, Act 62 does not modify the foundational requirements of PURPA and defines "avoided cost" consistently with FERC's implementing regulations. *See* S.C. Code Ann. § 58-41-20(A); *c.f.* 18 C.F.R. § 292.304(A). In fact, Act 62 mandates that South Carolina's PURPA implementation must be "consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders," and expressly requires the Commission's determination of the rates for purchase from QFs to be "just and reasonable to the ratepayers of the electrical utility, in the public interest . . . and nondiscriminatory to small power producers." *See generally* S.C. Code Ann. § 58-41-20(A). In addition, Act 62 further prescribes that the Commission's implementation of PURPA in South Carolina "shall strive to reduce the risk placed on the using and consuming public." *Id.* The risk of PURPA implementation exists for electrical utility customers, in part, because customers are responsible for paying the cost of all power purchased from QFs through the annual fuel factor. *See* S.C. Code Ann. § 58-27-865.

Act 62 also prescribes that the Commission shall "treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that:

(1) rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs;
(2) power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA; and
(3) each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment. Avoided cost methodologies approved by the commission may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility."

S.C. Code Ann. § 58-41-20(B). For larger QFs not eligible for the Standard Offer, the avoided cost rates offered by an electrical utility to a small power producer not eligible for the Standard Offer must be calculated based on the avoided cost methodology most recently approved by the Commission. S.C. Code Ann. § 58-41-20(C).

Act 62 further prescribes certain express requirements for purchased power agreements ("PPA") offered by electrical utilities to small power producers, as well as requirements to be included in notice of commitment forms, each of which is further addressed in this Order. S.C. Code Ann. § 58-41-20(D)-(E).

In sum, Act 62 directs the Commission to review each South Carolina electric utility's avoided cost rates and PURPA implementation at least every two years with an initial avoided cost setting order to be issued no later than six months from the Act's effective date, specifically including approving the utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement the mandatory purchase requirements of PURPA. This proceeding is the Commission's first review of DEC's and DEP's avoided cost rates under the new requirements of Act 62.

**D. Independent Third-Party Consultant Review of Electrical Utility's Calculation of Avoided Costs and PURPA Implementation under Act 62**

Section 58-41-20(I) of the Act authorizes the Commission "to employ, through contract or otherwise, third party consultants and experts in carrying out its duties under [the Act], including, but not limited to, evaluating avoided cost rates, methodologies, terms, calculations, and conditions[.]" Pursuant to that authority, on September 3, 2019,

the Commission engaged Power Advisory LLC ("Power Advisory") to serve as the independent third-party consultant. On November 1, 2019, Power Advisory submitted its *Independent Third Party Consultant Final Report Pursuant to South Carolina Act 62* ("Power Advisory Report") to the Commission, presenting its independently derived conclusions as to DEP's and DEC's calculation of avoided costs as well as other aspects of Act 62 implementation. The Power Advisory Report found Duke's avoided cost filing and subsequent responses to data requests and requests for production of documents in support of the Companies' avoided cost filing to be reasonably transparent, as required by S.C. Code. Ann. § 58-41-20(J). *Power Advisory Report*, p. 9. The Act provides that "[a]ny conclusions based on the evidence in the record and included in the report are intended to be used by the commission along with all other evidence submitted during the proceeding, to inform its ultimate decision setting the avoided costs for each electrical utility." *See* S.C. Code Ann. § 58-41-20(J). The Commission's Order addresses Power Advisory's substantive findings and conclusions and the Commission has appropriately considered Power Advisory's conclusions based on the evidence in the record to inform the Commission's ultimate decision in setting DEC's and DEP's avoided cost rates as well as other Commission determinations in these proceedings.

## IV. FINDINGS OF FACT

Based upon the Joint Application, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission hereby makes the following findings of fact:[21].

### A. Risks of PURPA Implementation for the Using and Consuming Public

1. In implementing the PURPA rate setting requirements of Act 62, the Commission must strive to reduce the risk placed on the using and consuming public. Risks exist with both longer-term fixed price contracts paid to QFs under PURPA as well as with traditional utility generating resources. In this proceeding, the Commission is tasked with setting avoided cost rates that are nondiscriminatory to QFs, just and reasonable for consumers, and that minimize the risks to consumers of South Carolina's implementation of PURPA.

2. The Commission's comprehensive regulation of public utility generation through certification of planned new generating facilities and cost of service-based ratemaking is fundamentally different from the Commission's task in these proceedings to approve forecasted avoided cost for energy and capacity to be paid to QFs under PURPA.

3. Risks associated with construction of public utility generation are not necessarily offset by QF solar generation because solar generation cannot fully replace non-solar generation as a capacity resource.

[21] The evidence for the Findings are discussed starting at page 35 below:

4. Act 62 requires electrical utilities to offer 10-year[22] fixed price power purchase agreements for the purchase of energy and capacity from small power producer QFs at each electrical utility's avoided cost. Therefore, the Commission, being bound by the evidence of record presented in the case, is following the General Assembly's direction to approve 10-year contract terms as reasonably balancing the over-payment risks for consumers of longer term fixed price avoided cost contracts while fully and accurately calculating DEC's and DEP's avoided costs.

**B. Proposed Avoided Cost Rates Do Not Reflect Anti-Competitive Bias Against Solar QFs**

5. The evidence in this proceeding does not support SCSBA's arguments that Duke has developed avoided cost rates that are anti-competitive or biased against future development of solar QFs. Duke made only two adjustments to its 2019 integrated resource planning inputs and assumptions in developing its avoided cost rates, both of which increase the avoided cost rates that will be paid to QFs.

6. DEC and DEP are also promoting competition in the future development of solar generation through the North Carolina Competitive Procurement of Renewable Energy Program ("CPRE Program"). Duke is currently soliciting 680 MW of new solar capacity to serve customers' energy needs through the CPRE Program. This competitive solicitation benefits consumers by requiring new solar capacity to provide dispatch rights and bid in at rates below current avoided costs. Over the next 15-year IRP planning period, Duke is also projecting adding significantly more solar capacity, up to a total

[22] See Order page 18-19

installed capacity of approximately 8,300 MW combined between DEC and DEP, to serve customers' energy needs. Therefore, solar is a significant part of DEC's and DEP's current and future generation portfolio.

7. Solar QFs do not displace the need for Duke to also plan for other types of dispatchable load-following generation, such as natural-gas fired generation.

**C. Peaker Methodology**

8. The peaker methodology as proposed by DEC and DEP is a reasonable and appropriate methodology to fully and accurately quantify DEC's and DEP's forecasted capacity and energy cost to be avoided by purchases from QFs.

**D. Avoided Energy Cost Quantification and Rate Design**

9. Duke's modeling methodology and input assumptions used to calculate DEC's and DEP's avoided energy cost rates are reasonable.

10. DEC and DEP have accurately quantified their avoided energy costs for purposes of this proceeding.

11. DEC's and DEP's proposed avoided energy rate design ensures that avoided cost rates accurately compensate QFs for the value of the energy they provide to the Companies and customers, consistent with PURPA, FERC's implementing regulations, and Act 62.

**E. Calculating Avoided Energy Rates for Large QFs**

12. To accurately quantify DEC's and DEP's avoided costs for Large QFs not eligible for the Standard Offer, it is appropriate for DEC and DEP to recognize the QF's actual energy production profile, and to incorporate the most up-to-date inputs under the

approved peaker methodology, in calculating a non-Standard Offer PPA QF's avoided energy rates.

**F. Avoided Capacity Quantification and Rate Design**

13. DEC and DEP have appropriately identified their first avoidable capacity need, as presented in the utilities' 2019 Integrated Resource Plans.

14. In applying the peaker methodology, Duke has used reasonable "peaker" cost assumptions published by the United States Energy Information Administration ("EIA") for the cost of the avoided combustion turbine unit used to quantify the projected capacity value avoided by QF purchases.

15. In applying the peaker methodology, the appropriate useful life of the avoided combustion turbine is 20 years, as recommended by Mr. Horii.

16. The performance adjustment factor capacity payment multiplier proposed by Duke is reasonable and supports Act 62's objective of placing QF generators and utility generators on equal footing in terms of reasonable allowance for unplanned outages.

17. DEC's proposed seasonal allocation weightings of 90% for winter and 10% for summer, and DEP's proposed seasonal allocation weighting of 100% for winter, should not be used in calculating DEC's and DEP's avoided capacity rates in this proceeding. Rather, the proposed seasonal allocation provided by ORS Witness Horii shall be used.

**G. Solar Integration Services Charge**

18. DEC and DEP are incurring increased intra-hour ancillary services cost to integrate variable and intermittent solar generators. It is appropriate to recover these costs from the solar generators that are causing the cost through an Integration Services Charge. The Solar Integration Services Charge ("SISC") Settlement agreed to between Duke, SCSBA, JDA, and SACE/CCL is a reasonable and appropriate resolution of the issues related to the SISC in this proceeding.

19. As set forth in the SISC Settlement, the Astrapé Study's determination that an additional 26 MW of load following reserves are required to integrate 840 MW of solar in DEC at an average cost of $1.10/MWh and that an additional 166 MW of load following reserves are required to integrate 2,950 MW of solar in DEP at an average cost of $2.39/MWh is reasonable and should be approved.

20. It is appropriate for Duke to prospectively apply the Integration Services Charge to all new uncontrolled solar generators that commit to sell and deliver power into the DEC and DEP systems. Such updated Charge approved by the Commission will be applied to commitments to sell and deliver power created after the date of the filing of such updated Charge.

21. To promote transparency, as provided for in the SISC Settlement, Duke should undertake an independent technical review of the underlying modeling, inputs, and assumptions of the Integration Services Charge prior to the next avoided cost proceeding.

22. As set forth in the SISC Settlement, it is not appropriate for Duke to impose the Integration Services Charge upon QFs or "controlled solar generators" that demonstrate that their facility is capable of operating, and contractually agree to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements incurred by the utility.

**H. Standard Offer**

23. The Standard Offer Tariff, Standard Offer PPA and Standard Offer Terms and Conditions, as modified by Duke in response to comments from the ORS and SCSBA, are commercially reasonable and should be approved for small power producer QFs up to 2 MW.

24. The Companies' requirement in the Standard Offer Tariff that QFs must deliver power within 30 months from the date of the order approving the Standard Offer Tariff is reasonable to ensure avoided cost rates paid by customers remain accurate and are not stale at the time the QF begins delivering power.

25. The Standard Offer Tariff and Standard Offer Terms and Conditions approved by the Commission in these proceedings properly apply to all existing QF Sellers, similar to the applicability of any other retail tariff offered by the Companies. The Companies' consent to material alterations to the Standard Offer PPA will not be unreasonably withheld, conditioned or delayed, and such material alterations shall apply only prospectively.

**I. Large QF PPA**

26. The Large QF PPA, as modified by Duke in response to comments and recommendations by the SCSBA, is commercially reasonable and should be the approved form of PPA for small power producer QFs that do not qualify for the Standard Offer.

27. The Companies have properly conditioned execution of the Large QF PPA on the QF executing and returning a Facilities Study Agreement to ensure the accuracy of avoided cost rates in light of modifications adopted at SCSBA's request to provide a flexible commercial operations date for QFs. However, the requirement that a QF return the Facilities Study Agreement in order to execute a Large QF PPA shall be lifted if the Companies fail to provide a System Impact Study within a year, or within an amount of time that is mutually agreeable between the buyer and seller.

28. If the Companies fail to provide a System Impact Study within one year of interconnection request (or an amount of time that is mutually agreeable between the contracting parties), then the QF shall be provided an offramp allowing it to terminate the PPA without liability if the interconnection facilities and network upgrades required for the interconnection exceed $75,000 per MW AC.

29. The Companies' three forms of performance assurance currently offered under the Large QF PPA are commercially reasonable, however the Companies shall also be required to offer a surety bond.

**J. Notice of Commitment Form**

30. The Notice of Commitment Form as proposed and modified by the Companies is reasonable and ensures that QFs make a substantial and binding

commitment to sell their output to the Companies when establishing a non-contractual legally enforceable obligation.

31. The Notice of Commitment Form provides QFs a reasonable period of time from submittal of the form to execute a PPA, and does not require the QF to execute a PPA prior to receipt of a final interconnection agreement as a condition of preserving pricing and terms and conditions established by submittal of the Form.

32. Requiring QFs to have secured all required permits and land use approvals before establishing a non-contractual legally enforceable obligation is unreasonable and is not consistent with demonstrating a substantial and binding commitment to sell power to the utilities.

33. Requiring QFs to deliver power to the utility within 365 days of executing a Notice of Commitment Form, and extending this time to account for additional time needed by the utility to complete required interconnection facilities and network upgrades, is reasonable to protect customers from paying stale and inaccurate avoided cost rates. Further, if the Companies do not provide the System Impact Study within one year of the interconnection request (or an amount of time that is mutually agreeable between the contracting parties), then the QF shall be provided an offramp allowing it to terminate the Notice of Commitment Form without liability if the interconnection facilities and network upgrades required for interconnection exceed $75,000 per MW AC.

**K. Consideration of Longer Term Fixed Price PPA Proposal**

34. Commission approval of a fixed price power purchase agreement with a duration longer than 10 years is simply not supported by the evidence in the record.

## V. EVIDENCE AND CONCLUSIONS

**A. Risks of PURPA Implementation for the Using and Consuming Public**

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 1-4**

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony, and exhibits in these Dockets, and the entire record in this proceeding.

Act 62 requires the Commission's decisions in this proceeding to, among other requirements, "strive to reduce the risk placed on the using and consuming public." S.C. Code Ann. § 58-41-20(A). The issue of what risks the Commission should consider and how the Commission should take such risks into account in meeting the requirements of the Act were the focus of considerable testimony in this proceeding.

Summary of the Evidence

Duke Witness Brown's direct testimony explained that Duke has recently gained significant experience with the over-payment risks of PURPA QF development under longer-term fixed PURPA contracts in North Carolina. From 2012 to 2017, installed solar QF capacity grew rapidly in North Carolina from approximately 77 MW to over 1,600 MW. Mr. Brown explained that these long-term fixed-price purchase obligations have continued to grow during a time of steadily declining natural gas prices, and, today, the Duke utilities have almost 4,000 MW of QF PURPA power either installed or under

contract across North Carolina and South Carolina. (Tr. Vol. 1, p. 46.13.) Mr. Brown highlighted that this surging QF growth during a period of declining avoided costs has resulted in long-term avoided cost payment obligations significantly in excess of the value that the QF power is delivering to customers, relative to the Companies' declining costs to generate electricity or to purchase alternative power. (Tr. Vol. 1, p. 46.14.) Specifically, he highlighted that DEC's and DEP's customers' current estimated financial obligation to purchase QF power is approximately $4.66 billion over the next approximately 15 years, while these contracts would have a significantly lower value of only $2.40 billion, if valued at more recent avoided cost rates. He explained that this results in a currently forecasted over-payment of approximately $2.26 billion, as compared to the Companies' current avoided cost rates. (Tr. Vol. 1, p. 46.16.)

Mr. Brown also identified the national discussion around the increasing over-payment risk of longer-term fixed price PURPA contracts, pointing to comments submitted to FERC in 2018 by the National Association of Regulatory Utilities Commissioners ("NARUC"). NARUC's comments highlighted similar experiences in Idaho and Montana to suggest that administratively forecasted avoided cost rates have dramatically overstated the actual market price of electricity. (Tr. Vol. 1, p. 46.15.)

In further describing the over-payment risk associated with longer-term QF contracts, Mr. Brown explained that, once Duke enters into a fixed price PPA with a QF, FERC has held that neither the utility nor the Commission may modify the QF's contract if changes in the Companies' avoided costs occur in the future. This effectively means that the Companies' customers are locked into paying for the QF's power at the

administratively-determined avoided cost rates for the full term of the PPA, regardless of whether market conditions change or whether the value of the QF energy and capacity decreases. He emphasized that, once the regulatory framework is set and avoided cost rates are approved in this proceeding, the Commission has little control over the amount of new QF power that will be developed in response to the price signals set in this proceeding, and ultimately the cost that customers will bear to pay for that new QF power. (Tr. Vol. 1, p.46.15, Tr. Vol. 2, p. 621.26.)

SCSBA Witness Davis argued that Duke's concerns about overpayment risk to customers from long-term fixed price PURPA contracts are overblown and unfair. He argued that Duke's calculation of the difference between the financial obligations over the life of existing QF PPAs is based upon projections of future avoided costs which have not yet been approved by the Commission and that avoided costs may increase in the future. Mr. Davis suggested that while Duke's avoided cost have recently declined, future changes in natural gas prices and other factors may result in the current overestimation of avoided costs balancing out leaving customers unharmed. (Tr. Vol. 1, p. 391.8-9.)

Witness Davis also argued that Act 62 is not explicit in describing the kinds of risks the Commission should consider, and that the SCSBA believes that the Commission should consider a broad range of cost risk considerations in this proceeding. (Tr. Vol. 1, p. 391.8.) He testified that that there are numerous risks related to the construction and operation of utility-owned generating facilities that are not present with QF PPAs entered into under PURPA. Witness Davis specifically pointed to construction cost risks, such as

the recent abandonment of Duke's Lee nuclear unit and Dominion Energy South Carolina's V.C Summer nuclear unit, as well as operating costs risks, such as changes in fuel expenses or environmental regulations that can increase the cost of operating utility owned generation in the future. (Tr. Vol. 1, p. 391.13-14.) Mr. Davis explained that these types of risk are absent from PURPA contracts because QF PPAs are performance-based, meaning small power producer QFs are only paid for the power and capacity actually delivered. (*Id*.)

JDA Witness Chilton presented arguments similar to those advanced by Mr. Davis regarding the potential risks of utility-owned generation for customers. (Tr. Vol. 1, p. 334.8.)

In rebuttal, Duke Witness Brown disagreed with SCSBA Witness Davis' suggestion that the overpayment risk of longer-term fixed price contracts would balance out leaving Duke's ratepayers, who are obligated to pay for QF power, unharmed. Witness Brown again pointed to North Carolina's recent experience where longer-term fixed avoided cost rates have already resulted in $185 million in over-payments for PURPA power delivered during 2016-2018 under long-term fixed price contracts that exceed DEC's and DEP's current cost of energy. (Tr. Vol. 2, p. 621.28.) Witness Brown also highlighted findings from the recent FERC PURPA NOPR that experience across the country has shown that over-payment and underpayments under longer-term PURPA contracts have not balanced out and customers have not been left indifferent. (Tr. Vol. 2, p. 621.29.) While the NOPR itself is not authoritative, the findings by FERC incident to the NOPR may be informative.

Finally, Witness Brown compared the greater potential for over-payment risk under the 10-year fixed price contracts required under Act 62 with the terms of PURPA mandatory purchase contracts in other southeastern states, noting that Duke has recently signed nine PPAs totaling 472 MW in North Carolina at that state's maximum five-year contract terms for administratively set PURPA rates. Mr. Brown further testified that the proposed fixed 10-year fixed avoided cost rates required under Act 62 will be the longest fixed rates offered under PURPA in the Southeast for projects larger than one MW. (Tr. Vol. 2, p. 621.25.)

Witness Brown also responded to the SCSBA's arguments about the risks of utility-owned generation versus QF purchases, explaining that the comparative risks of these two types of resources have no bearing on the calculation of DEC's and DEP's avoided costs and that such a comparison of risk profiles is entirely inapplicable to this proceeding. (Tr. Vol. 2, p. 621.30-31.) He specifically highlighted that PURPA has exempted QFs from most all aspects of State utilities regulation, including oversight of their profits, returns, and business operations, while the Commission exerts significant regulatory oversight over the construction and cost recovery of new utility-owned generation. (Tr. Vol. 2, p. 621.34.) Witness Brown pointed to the extensive certification process required for new utility generation, including new requirements established by Act 62. He then explained that once utility generation is constructed and placed into commercial operation, the utility is then subject to cost of service-based ratemaking with oversight and regulation from this Commission. This oversight ensures that costs were prudently incurred, and that any benefits or cost savings are passed on to customers. The

Commission then has ongoing regulatory oversight of Duke's recovery of plant investments providing utility service, and can review items such as depreciation rates, the cost of capital being recovered by the utility, O&M costs to be collected, as well as any additional investment necessary in the plant to provide utility service. (Tr. Vol. 2, p. 621.30-31.) Witness Brown concludes that this ongoing regulatory oversight and cost recovery framework for utility-owned generation is fundamentally different than the PURPA avoided cost framework, explaining that the risks and benefits to customers achieved through cost-of-service ratemaking are not directly comparable to the risks and benefits customers face under a PURPA avoided cost framework. (*Id.*)

In considering the relative risk of utility-owned generation, ORS Witness Lawyer testified during the hearing that utilities are not "guaranteed" a return on new capital investment, and that the ORS reviews all utility investments to ensure they are properly includible in rate base and all expenses to ensure they are reasonable and prudently incurred before they are authorized to be recovered in rates. (Tr. Vol. 2, p. 583.) He also agreed that the Commission has ongoing oversight over utilities' investments and can adjust rates to reflect changes in circumstances, such as the flow back of significant tax cuts in 2019 in response to the federal Tax Cuts and Jobs Act. (Tr. Vol. 2, p. 583.) He was not able to conclude whether the Commission had similar authority over QFs. (Tr. Vol. 2, p. 584.)

Finally, in addressing how the Commission should balance the over-payment risks of future QF contracts in South Carolina with the obligations of Act 62, Witness Brown testified during the hearing that the long-term fixed price nature of QF contracts

creates the overpayment risk. He explained this overpayment risk could be mitigated through very short term contracts at fixed avoided cost rates or long-term contracts with periodic repricing. (Tr. Vol. 2, p. 642-643.)

Commission Determination

The Commission has carefully reviewed the extensive testimony in the record as it relates to how Duke, on the one hand, and the solar industry intervenors, on the other, advocate that the Commission view the requirements of Act 62 to "strive to reduce the risk placed on the using and consuming public" in deciding the issues before the Commission in this proceeding.

The Commission initially finds that the General Assembly's directive for the Commission to strive to reduce the risks to consumers is tied to the Commission's responsibility under Act 62 to implement the avoided cost requirements of PURPA. S.C. Code Ann. § 58-41-20(A) directs the Commission to ensure that South Carolina's PURPA implementation framework remains "just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers." *See* S.C. Code Ann. § 58-41-20(A). The General Assembly's direction for the Commission to also strive to reduce the risk on the using and consuming public must be harmonized with these other PURPA implementation requirements as well as the other provisions of S.C. Code Ann. § 58-41-20. *Senate of the S.C. v. McMaster*, 425 S.C. 315, 322 (2018) ("A statute must be read as a whole and sections

which are part of the same general statutory law must be construed together and each one given effect").

In implementing these requirements, the Commission finds merit in the argument that the Commission should carefully consider the overpayment risk of administratively-forecasting avoided cost rates under longer term PURPA contracts that are increasingly uncertain and subject to future changes in the utilities' avoided costs. The Commission also finds persuasive Duke Witness Brown's testimony describing Duke's recent experience with PURPA implementation in North Carolina, as well as the similar experiences in other states across the country, as identified by NARUC.

The Commission also finds relevant the linkage of overpayment risk to longer-term avoided cost rates in light of Duke's uncontroverted testimony that the 10-year fixed avoided cost rates required under Act 62 will be the longest fixed rates offered under PURPA in the Southeast for projects larger than one MW. Thus, the Commission finds the potential overpayment risk of longer term fixed-rate contracts to be an appropriate consideration in this proceeding.

The Commission also recognizes the testimony of SCSBA Witness Davis that risks exist with the planning, construction and operation of new utility-owned generating resources. Duke has not directly disputed this testimony, but argues that risks of utility-owned generation and QF generation are not comparable and that the costs and risks of utility generation are not directly before the Commission in this proceeding to implement PURPA. Furthermore, Duke pointed out that the Commission has existing authority to appropriately address the risks of utility-owned generation outside of Act 62.

The Commission agrees that there are fundamental differences between regulation of utility investments and the fixing of avoided cost rates that make comparing the risk of utility investments under cost of service-based ratemaking with the forecasting of utility avoided cost of little probative value. For example, when a utility builds a new generating facility and places it in rate base, it does not receive forecasted avoided costs for energy and capacity like QFs under PURPA. Instead, the utility is provided only a reasonable opportunity to earn a return on its invested capital and to recover its actually-incurred expenses to meet its obligation to serve customers. The utility also recovers its capital invested over significantly longer depreciation lives for utility-owned assets, which lowers the near-term rate impact for utility projects because lower annual depreciation costs are passed directly to customers through a lower revenue requirement. As recognized by ORS Witness Lawyer, customers also receive the benefit of future reductions in the utility's cost of service, such as the recent reduction in the federal corporate income tax rate and flow back of excess deferred taxes stemming from the Federal Tax Cuts and Jobs Act of 2017. In contrast, as Duke Witness Brown explains, PURPA provides developers of QFs with a guaranteed revenue stream for the duration of the avoided cost rates approved by the Commission. (Tr. Vol. 1, p. 46.12 (citing *New York State Elec. & Gas Corp.*, 71 FERC ¶ 61,027 (1995).) This effectively means that the utility customers are locked into paying for the QF's power at the administratively determined avoided cost rates for the full term of the PPA, regardless of whether market conditions change or whether the value of the QF energy and capacity decreases or increases.

The Commission takes note of the operational risk to the system that can be presented by an influx of solar generation. Duke Witness Holeman explained, "I've worked in and around system operators for 34 years, my entire career, I know of no other generation technology that presents this type of intraday variability and intra-hour intermittency to the two system operators." (Tr. Vol. 2, p. 761.) Witness Holeman explained the challenges managed by system operators. "[In] the morning ramp-down, what we've seen, with solar and without solar, is basically a doubling of our ramping demand on the down ramp. And on the up ramp, we've seen a four times increase in the amount of ramping we have to have to meet both our load change and the solar generation change in those two hours.." (Tr. Vol. 2, p. 760.) Given that solar generation is non-dispatchable, Mr. Holeman's explanation was key in understanding the everyday challenges of QF generation. This Commission is mindful of system reliability and the system operations that must be flexible enough to address current challenges. The Commission also notes the operational risk identified by Mr. Holeman in managing QF generation.

The Commission also notes that construction of new utility-owned generation must also be supported by the utility's resource planning and certification process, which is scrutinized by the ORS and other interested parties to ensure that utility investments in new generation are needed and can cost-effectively serve customers' future energy and capacity needs. Only after obtaining a certificate to construct new generation may a utility have the right to petition the Commission in the future to recover the costs of utility investments made to serve customers. The Commission finds that SCSBA makes

a fair point that constructing new utility-owned generation creates potential risks for consumers, but it is a regulated risk overseen by this Commission under the public utilities laws and regulatory framework established by the General Assembly. In contrast, the Commission recognizes Duke Witness Brown's uncontroverted testimony that the Commission does not have a similar right to oversee QF investments and any savings from longer PPAs and lower financing costs are retained as profit by the QF developer and its investors and are not flowed through to customers. There are no limits on the amount of QF capacity that can be developed prior to the Commission's next review of Duke's avoided cost rates, such that the opportunity for QF development—and the associated cost risk for customers—is impacted only by the accuracy of the forecasted avoided rates set in this proceeding. Based upon the foregoing, the Commission finds that SCSBA's focus on the risks to customers of utility-owned generation are offset by solar generation, and as such are not directly at issue in this proceeding and will properly be assessed in other dockets, including resource planning, certificate and general rate case proceedings before this Commission.

In sum, the Commission finds that the Commission's authority and responsibility to regulate the rates and service of public utilities in South Carolina is fundamentally different than the Commission's limited oversight of QFs through its implementation of PURPA. Accordingly, the Commission finds that comparing the risks of utility-owned generation and QF generation is not reasonable or persuasive. The Commission also finds that, in the near term, the General Assembly has made the express determination through Act 62 of the appropriate balancing of risks between QFs and customers by

establishing that the avoided cost contracts to be offered to small power producer QFs shall be fixed for "a duration of ten years." *See* S.C. Code Ann. § 58-41-20(F)(1Therefore, the Commission is following the General Assembly's mandate to approve fixed 10-year contract terms[23] as reasonably balancing the over-payment risks for consumers of longer term fixed price avoided cost contracts and the General Assembly's goal of promoting renewable energy while fully and accurately calculating DEC's and DEP's avoided costs. In these current proceedings, this result appropriately meets the requirement for the Commission to strive to reduce the risks on the using and consuming public as part of its implementation of PURPA.

**B. Duke's Avoided Cost Rates Do Not Reflect Anti-Competitive Bias Against Solar QFs**

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 5-7**

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Act 62 requires the Commission to treat small power producers on a fair and equal footing with electrical utility-owned resources by, amongst other requirements, ensuring that "rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs." S.C. Code Ann. § 58-41-20(B)(1). Therefore, the Commission has a responsibility under the Act to ensure that Duke's avoided cost rates fully and accurately calculate the avoided capacity and energy costs to be avoided by

[23] See Order page 18-19

purchases from QFs and that the utilities have not unjustly and unreasonably biased the development of these rates against small power producer QFs.

Summary of the Evidence

The SCSBA has argued extensively in these proceedings that Duke's Joint Application and proposed avoided cost rates are biased against solar QFs and are impeding the competition envisioned by Act 62 between QFs and the monopoly utilities. SCSBA Witness Downey asserted that South Carolina's cost of service regulatory regime is dominated by territorial monopolies and has been slow to evolve towards a more competitive model, as contemplated by Act 62. He further stated that proper implementation of Act 62 and PURPA in South Carolina would provide businesses like Southern Current the opportunity to compete with the utilities and that customers receive the benefits of that competition. (Tr. Vol. 1, p. 401.11.)

SCSBA Witness Davis similarly argued that small power producers compete directly with utilities for market share, and that Duke, as a monopoly utility, is biased against competition from solar QFs as the utility's business model is based upon earning returns for shareholders by investing in new generation, pollution control technologies, and grid-related improvements. He testified that by keeping avoided cost rates artificially low, utilities can effectively shield themselves from competition to the benefit of shareholders and at the expense of ratepayers. (Tr. Vol. 1, p. 391.17.)

SCSBA retained Witness Burgess to evaluate Duke's quantification of DEC's and DEP's avoided capacity and energy costs. Mr. Burgess framed his recommended adjustments to Duke's calculation of avoided costs by suggesting that Duke has an

incentive to propose artificially low avoided cost rates and to impose other barriers to competitive generators, such as the integration services charge in order to increase utility investments in new generation and natural gas infrastructure, while reducing competition from solar QFs. (Tr. Vol. 1, p. 382.10.) Witness Burgess argued that Duke has made many small, but meaningful methodological choices in quantifying DEC's and DEP's avoided costs that, in the aggregate, result in avoided cost rates that are significantly biased against solar QFs. (Tr. Vol. 1, p. 382.11.) He also recommended that that the Commission should adopt avoided cost rates at the higher end of a "zone of reasonableness" as higher rates can encourage QF development and deployment and yield other benefits beyond utility avoided costs. (Tr. Vol. 1, p. 382.13.)

In rebuttal, Duke Witnesses Brown first testified that the SCSBA's arguments about promoting competition are a mischaracterization of the avoided cost framework and the purpose of the PURPA provisions of Act 62. Witness Brown explained that PURPA guarantees that the utility will purchase QF's output at Commission-approved rates and at no point does a QF need to "compete" with any other generation. (Tr. Vol. 2, p. 621.14.) He further contended that Witness Downey was also incorrect in his statement that customers will benefit from increased competition from solar QFs. Mr. Brown explained that this statement reflects a fundamental misunderstanding of the PURPA indifference principle and avoided cost framework, which are not designed to "benefit" customers but instead to leave them financially unaffected or "indifferent" to the purchase of the QF power. (Tr. Vol. 2, p. 621.15.) Witness Brown also pointed out that solar QFs do not have to compete on price or commercial terms, as those rates and

terms are administratively set by the Commission based upon the utility's projection of future avoided costs. (Tr. Vol. 2, p. 621.15-16.)

In response to the SCSBA's arguments that Duke is opposed to future competition from new solar QFs, Witness Brown pointed to the CPRE Program that Duke is undertaking pursuant to a 2017 North Carolina law supported by Duke. The CPRE Program is an independently administered competitive solicitation process designed to procure the most cost-effective utility-scale renewable energy resources across the DEC and DEP systems (whether located in North Carolina or South Carolina) at prices below the Companies' avoided costs. (Tr. Vol. 2, p. 621.17.) Witness Brown explained that Duke recently completed the "Tranche 1" CPRE solicitation, and procured approximately 550 MW of new solar capacity for 20-year fixed price contract terms at a projected savings relative to avoided cost of approximately $261 million over the 20-year term of PPA. Witness Brown also highlighted that both Southern Current and JDA successfully participated in CPRE Tranche 1, with affiliates of each of these developers winning proposals. He further testified that Duke's now-open "Tranche 2" CPRE solicitation will solicit a total of 680 MW of additional new renewable energy resources to be constructed between now and 2023. In total, Mr. Brown explained that Duke is planning to solicit up to 1,300 MW of new renewable energy capacity under the CPRE Program at rates below avoided costs over the next few years. (Tr. Vol. 2, p. 621.17-18.) Based upon this significant ongoing system-wide competitive solicitation of new solar capacity, Witness Brown contended that Duke is not attempting to shield itself from competition with solar

QFs as CPRE allows the SCSBA's members to compete directly with Duke and each other to deliver the least cost solar power to customers. (Tr. Vol. 2, p. 621. 19-20, 21.)

Duke Witness Snider also testified that SCSBA's argument that Duke is incentivized to keep avoided cost rates as low as possible, or that Duke's calculation of avoided cost in this proceeding is somehow designed to render QFs economically infeasible or to reduce competition, is false and does not reflect the realities of the capacity and energy value provided by solar QFs. (Tr. Vol. 2, p. 630.6.) Witness Snider explained that deployment of QF solar does little to offset the need for future generation because it does not provide a net dependable resource capable of meeting future capacity requirements, which occur in predominately non-daylight hours. Adding non-dispatchable QF solar has little impact on DEC's and DEP's need for future generation but rather serves as a non-firm intermittent resource that reduces fuel purchases. (Tr. Vol. 2, p. 630.6, 7.) Witness Snider also explained that Duke is financially indifferent to purchasing QF power because its cost is a fuel pass-through expense paid directly by Duke's customers in the same way natural gas or coal fuel costs are a pass through. (Tr. Vol. 2, p. 630.6.) Witness Snider provided similar testimony during the evidentiary hearing. (Tr. Vol. 2, p. 680-682.)

Duke Witness Snider also responded to SCSBA Witness Burgess's argument that Duke's avoided cost rates are biased against solar QFs. Witness Snider explained that Duke consistently uses the same system production cost models, data inputs, forward looking projections, and planning assumptions to calculate avoided costs paid to QFs that Duke uses to identify the utilities' future energy costs and timing of planned generating

resources shown in its integrated resource planning processes. (Tr. Vol. 2, p. 630.9-10.) With the exception of two discrete changes—both of which actually served to increase the avoided costs paid to QFs—Witness Snider explained that Duke's calculation of avoided cost rates paid to QFs are fully consistent with DEC's and DEP's 2019 IRPs, as recently filed with the Commission. The first adjustment was Duke's reliance on public Energy Information Association ("EIA") Combustion Turbine ("CT") cost data in developing capacity rates rather than lower cost proprietary engineering estimates of CT costs as used in the 2019 IRP. The EIA CT cost data yielded higher avoided capacity costs relative to Duke's internal CT costs assumptions. The second adjustment was to eliminate the incremental solar included in the Companies' IRPs over the 10-year avoided cost rate period in excess of installed and obligated solar. Mr. Snider explains that, because each increment of solar generation reduces the value of the next increment, the Companies' avoided cost rates would have been lower if the Companies had fully accounted for the level of future solar capacity projected in their IRPs to be installed over the next 10 years. (Tr. Vol. 2, p. 630.10-11.) Witness Snider provided similar testimony during the evidentiary hearing. (Tr. Vol. 1, p. 125-126.)

Witness Snider also pointed out that it is the solar QF development industry that has a direct and substantial interest in avoided cost rates being set as high as possible to enable the highest profits for QF developers and their investors, which are paid for by the utility's customers. Based upon this fact, he recommends the Commission carefully consider the "methodological choices" that Mr. Burgess proposes on behalf of the solar industry to artificially raise Duke's avoided cost rates. (Tr. Vol. 2, p. 630.14-15.)

During the hearing, ORS Witness Horii testified that the limited capacity value provided by solar QFs would not be able to meet the capacity need that would arise as a result of coal unit retirements. (Tr. Vol. 2, p. 549-550.) Witness Horii also found Duke's avoided energy cost calculations to be reasonable and similarly found Duke's avoided capacity cost calculations to be reasonable, except for two small changes that he recommended on behalf of ORS. (Tr. Vol. 2, p. 523-524.) Therefore, Mr. Horii did not find that Duke was biased in setting avoided costs.

During the hearing, Mr. Burgess also conceded that his advocacy for the Commission to recognize a zone of reasonableness in order to adopt higher avoided cost rates would be unprecedented. (Tr. Vol. 1, p. 416.)

During the hearing, Witness Snider testified that Duke is not trying to block solar so that Duke's affiliates can build the Atlantic Coast Pipeline or so that Duke can build other generating resources. He emphasized that Duke has over 4,000 MW of additional solar in the 2019 IRPs and the utilities need a diverse portfolio of solar and other resources to serve customers. Therefore, both incremental solar and other resources such as natural gas generation are needed to reliably serve future load growth and accomplish coal unit retirements identified in the resource plans. (Tr. Vol. 2, p. p. 728-729.)

Commission Determination

The Commission has fully considered the evidence presented by the SCSBA and other parties on this issue and does not find that Duke's avoided cost rates reflect anti-competitive bias against solar QFs. To the contrary, the record supports that Duke has applied a fair and transparent methodology (discussed further below) to quantify avoided

costs and, as testified to by Duke Witness Snider, has reasonably applied the same system production cost models, data inputs, forward looking projections and planning assumptions to calculate avoided costs paid to QFs that are used to identify the utilities' future energy costs and timing of planned generating resources in Duke's 2019 IRPs. Mr. Snider's uncontroverted testimony also shows that the two adjustments to Duke's 2019 IRP inputs and assumptions used in calculating avoided cost rates in this proceeding actually have the effect of increasing the avoided costs paid to QFs. The Commission also notes that ORS Witness Horii did not similarly allege that Duke's avoided cost rates were biased and has proposed only two adjustments, which the Commission addresses later in this Order. Thus, the Commission does not find any basis to conclude that Duke's avoided cost rates or other aspects of Duke's Joint Application in this proceeding are anti-competitive towards QFs or otherwise have the purpose or effect of impeding Act 62's directive that small power producers be treated on a fair and equal footing with electrical utility-owned resources. *See* S.C. Code Ann. § 58-41-20(B).

With regard to SCSBA's arguments that Duke has designed its avoided cost rates to impede competition between QFs and utilities, the Commission finds that these arguments cannot be reconciled with the fact that Duke is continuing to provide QFs significant opportunities to develop new solar resources through the system-wide CPRE Program. This competitive solicitation enables solar QF developers to compete directly with Duke and each other to deliver new solar projects to customers at a price below the utilities' avoided cost. The Commission also finds persuasive that both Southern Current and Johnson Development actively participated in the CPRE Tranche 1 and are eligible

for the now open Tranche 2. Finally, the Commission recognizes Duke Witness Snider's testimony that Duke's 2019 IRPs recognize the need for over 4,000 MW of additional solar. The Commission also finds Mr. Snider's testimony persuasive that Duke requires a diverse portfolio of generating resources, including both solar and natural gas resources, to serve customers' future energy needs and to accomplish the planned unit retirements identified in the Companies' IRPs. By fully and accurately quantifying Duke's avoided costs and otherwise implementing the PURPA requirements of Act 62, the Commission is providing solar QFs and all other eligible QF resources the non-discriminatory opportunity to provide this future energy and capacity to serve DEC's and DEP's customers.

The Commission also agrees with Duke Witness Brown that avoided cost rates are not market based. The objective of fixing avoided cost rates is to determine the price that leaves customers indifferent between purchasing power from traditional utility resources or from QF resources. (Tr. Vol. 2, p. 621.13 (citing *S. Cal. Edison Co*., 71 FERC ¶ 61269, 62079–80 (1995)).) Under Act 62, as well as under PURPA generally, the Commission is obligated to treat both QFs and customers fairly by fully and accurately calculating the avoided capacity and energy costs to be avoided by purchases from QFs. *See* S.C. Code Ann. § 58-41-20(B)(1); 18 C.F.R. § 292.304(a). As further addressed in this Order, the Commission finds that Duke has applied a reasonable methodology and applied acceptable data and inputs (other than the assumption incident to the expected life of combined turbine units) to fully and accurately quantify DEC's and DEP's avoided costs to be provided to QFs.

**C. Peaker Methodology**

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 8**

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony, and exhibits in these Dockets, and the entire record in this proceeding.

Act 62 directs the Commission to review and approve the methodology that the Companies use to establish avoided energy and capacity cost rates offered to QFs—including both smaller QFs eligible for the Standard Offer Tariff as well as QFs not eligible for the Standard Offer Tariff ("Large QFs")—to ensure that the electrical utility fully and accurately quantify the Companies' avoided capacity and energy costs and fairly account for costs avoided or incurred by the Companies, "including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers[.]" *See* S.C. Code Ann. §§ 58-41-20(A), 48-41-20(B)(1), (3).

Summary of the Evidence

Duke Witness Snider supports the Companies' continued use of the "peaker methodology" to quantify DEC's and DEP's avoided capacity and energy costs in these proceedings. Mr. Snider testifies that the Companies have historically applied the peaker methodology in both South Carolina and North Carolina to quantify each utility's avoided capacity and energy cost, and have consistently employed this methodology in these proceedings to meet the requirements of Act 62. Witness Snider's testimony explains how Duke applies the peaker methodology to quantify a utility's marginal capacity and energy costs based upon the avoided capacity cost of a simple cycle

combustion turbine ("CT") or "peaker" unit plus the utility's forecasted avoided system marginal energy cost. (Tr. Vol. 1, p. 58.13.) Witness Snider states that the peaker methodology provides, consistent with PURPA, an appropriate and reasonable estimate of the utility's forecasted avoided or incremental costs of alternative energy that the utility would have otherwise incurred but for the purchase from a QF facility. (*Id.*)

Witness Snider explained that the peaker methodology is widely used throughout the electric industry and accepted as a fair, reasonable, and accurate means by which to calculate avoided costs. (Tr. Vol. 1 p. 58.12.) He also pointed out that the peaker methodology was recently recognized as an acceptable method for determining a utility's avoided cost in the widely relied-upon *PURPA Title II Compliance Manual* published by the NARUC, the Edison Electric Institute, and other industry organizations in 2014. (*Id.*)

Witness Snider testified that the Companies' application of the peaker methodology appropriately captures all avoidable marginal capacity and energy costs that consumers would otherwise pay "but for" the purchase from the QF and, as such, appropriately leaves the consumer indifferent to purchasing QF generation relative to the utility generating or purchasing alternative energy from another source. (Tr. Vol. 1 p. 58.22.) Witness Snider explained that the Companies rely upon several key elements in the application of the peaker methodology to accurately align the avoided capacity cost rates that customers ultimately pay with the actual value of the capacity delivered by the QF to the utility. These elements include: (a) calculating the annual avoided capacity value of a CT; (b) determining the year in which each utility has its first avoidable capacity need; (c) determining how annual capacity payments are made to the QF

supplier; and (d) applying an appropriate Performance Adjustment Factor in calculating the avoided capacity rate to allow the QF to receive full capacity value if its forced outage rate is equivalent to that of the Companies' overall generation fleets. (*Id.*) Witness Snider specifically pointed to the Performance Adjustment Factor capacity multiplier as an adjustment to the peaker methodology that is designed to place QF resources on fair and equal footing with utility-owned resources. (Tr. Vol 1, p. 58.21, 221.)

On behalf of ORS, witness Horii agreed that the Companies' use of the peaker methodology is consistent with PURPA and widely used throughout the country to calculate avoided energy and capacity costs. (Tr. Vol. 2 at 525.10 – 525.11.) In his direct testimony, ORS Witness Horii suggested that the Companies' approach to forecasting avoided energy costs was actually based upon the Differential Revenue Requirement ("DRR") methodology. (Tr. Vol. 2 at 525.7.) However, as Witness Snider explained at the hearing, the DRR methodology is simply a "variant of the peaker" methodology, (Tr. Vol 1, p. at 122), and in any event, Witness Horii agreed that the Companies' avoided energy "calculation methodology is consistent with PURPA and the Commission's prior approval." (Tr. Vol. 2 at 525.10.) SCSBA Witness Burgess did not voice an objection to the Companies' use of the peaker methodology, acknowledging that "the general framework (i.e. the Peaker Methodology) is sound[,]" (Tr. Vol. 1 at 382.44), while alleging that certain of the input assumptions utilized by the Companies are "biased against solar QFs" as discussed separately in this Order.

Power Advisory similarly finds Duke's application of the peaker methodology to be a "reasonable methodological basis for establishing the companies avoided costs." *Power Advisory Report*, p. 19.

Commission Determination

Taking into consideration the evidence presented, the general agreement among the parties that the peaker methodology is a proper methodology by which to calculate the Companies' avoided energy and capacity costs, as well as this Commission's past acceptance of Duke's use of this methodology in prior avoided cost proceedings, the Commission hereby finds that the peaker methodology is a reasonable and appropriate methodology to fully and accurately quantify DEC's and DEP's forecasted capacity and energy cost to be avoided by purchases from QFs and is consistent with the requirements of Act 62 and PURPA.

**D. Avoided Energy Cost Quantification and Rate Design**

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 9-10**

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

As part of the Commission's responsibility under Act 62 to approve Duke's avoided cost methodology, the Commission must also ensure that "rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs" including the utility's energy costs to be avoided by purchases from QFs. S.C. Code Ann. § 58-41-20(B)(1),(3) SCSBA has challenged aspects of Duke's quantification of its

avoided energy rates and avoided energy rate design. In this section of the Order, the Commission first addresses Duke's quantification of avoided energy and then will address DEC's and DEP's avoided energy rate design.

Summary of the Evidence

Duke Witness Snider testified that the Companies calculate avoided energy costs under the peaker methodology by using a production cost simulation model called PROSYM. The PROSYM model analyzes the change in system production costs with and without a 100 MW block of no-cost generation (representing QF power) on an hourly basis over a 10-year period. The decrease in hourly production costs from the base case to the change case that includes the 100 MW of no-cost generation provides the marginal energy costs that can be avoided by the Companies over the 10-year avoided cost rate period. These avoided hourly energy costs are then used to calculate avoided energy rates consistent with the goal of leaving customers indifferent between QF power purchases and generation provided by the utility. (Tr. Vol. 1, p. 58.21-26.)

Duke Witness Snider testified that a number of inputs or factors in the PROSYM model drive avoided energy cost calculations over time, including load and energy forecasts, resource mix, unit characteristics, variable operation and maintenance ("VOM") costs, environmental emissions costs, reagent costs and fuel costs. He stated that although updating items such as VOM costs, environmental reagent costs, and the relative efficiency of the marginal unit with the most current information all factor into the utility's marginal cost of generation, recent changes in the commodity market price for natural gas represents the most significant change impacting the Companies' avoided

costs. He explained that this was because natural gas commodity prices represent the primary driver of the avoidable energy cost since a natural gas-fueled combined-cycle unit or combustion turbine unit is often the marginal resource, and elaborated upon recent natural gas market changes in support of his claim. (Tr. Vol. 1, p. 58.22-23.)

In response to Duke's direct testimony, SCSBA Witness Burgess testified that production cost models generally solve for the optimal unit commitment and dispatch to meet system load at least cost. (Tr. Vol. 1, p. 384.21.) However, SCSBA Witness Burgess raised four main concerns with the Companies' avoided energy cost calculations and inputs to advocate for alternative, higher avoided energy rates. He first argued that the Companies' hourly modeling results incorrectly illustrate a significant fraction of hours that have negative avoided costs, which he further argued were an "artefact" of Duke's modeling "rather than what is likely to occur in real-world operations." Specifically, he suggested that constraints built in (Duke's) model such as transmission limits, generator minimum loading levels, generator ramp rates, and so on may bear no relation to real-world conditions or the actual operation of Duke's system. Therefore, Mr. Burgess contended that Duke's avoided energy rates may be above Duke's marginal value of energy. (Tr. Vol. 1, p. 384.21-27.) He then took issue with the Companies' fuel and commodity costs, arguing that coal is often on the margin in DEC and DEP-East, while a future combined cycle gas unit is only primarily on the margin in DEP-West. In doing so, he recommended that separate regional avoided cost rates be calculated for DEP-East. Witness Burgess last argued that an avoided fuel hedge value, as well as an environmental cost adder representing coal ash costs, should be included in the

Companies' avoided energy rates to further increase the avoided cost rates paid to QF developers. (Tr. Vol. 1, p. 384.28-42.)

ORS Witness Horii testified that the method used by the Companies to calculate avoided energy costs is consistent with PURPA and the methodology previously approved by this Commission. He further testified that he had reviewed the fuel price forecasts and other variables the Companies incorporated in calculating the avoided energy costs for this proceeding. Based upon his review, Mr. Horii testified that the forecast methodologies and values utilized by DEC and DEP were consistent with market knowledge of fuel prices and generator cost forecasts available at the time of the Companies' forecasts. He further testified that the most meaningful driver of the change in the Companies' avoided energy costs from previous years is the fuel price forecast change, and that it was reasonable to expect the change in avoided energy cost calculations to track closely with the change in fuel price forecasts. In conclusion, he testified that, based upon his review, the avoided energy costs reflected in the Companies' Standard Offer tariffs were a reasonable result of the Companies' calculations, and that the Companies' calculations and methodology are consistent with PURPA and this Commission's prior approval. (Tr. Vol. 2, p. 525.7-10.)

In his rebuttal testimony, Duke Witness Snider provided support for the specific inputs included in the Companies' avoided energy cost calculation to rebut SCSBA Witness Burgess's claims. First, he explained that SCSBA Witness Burgess's concerns regarding the modeling of negative hours should be dismissed, because although Mr. Burgess's analysis accurately picks up on the negative value produced in one hour, he

fails to recognize the offsetting benefit that occurred in the prior hour when making his claim. As Witness Snider testified, the shifting of generator startup times when additional generation is added to the system occurs frequently in the production cost model as well as in the "real-world" during Duke's actual system operations. Moreover, changes in the hours that the Jocassee and Bad Creek Pumped Hydro assets pump and discharge water can also result in negative hours between the Companies' base and change case in the production cost model. Duke Witness Snider concluded by stating that discounting these negatives hours as "an artefact of Duke's modeling" when calculating the avoided energy rate would incorrectly inflate the avoided energy cost value that QFs provide to the Companies' customers. (Tr. Vol. 2, p. 630.23-26.)

Second, Witness Snider dismissed SCSBA Witness Burgess's concerns regarding the Companies' avoided fuel and commodity costs, and specifically, Mr. Burgess' argument that coal is often on the margin in DEC and DEP-East while a future combined cycle gas unit is only primarily on the margin in DEP-West. He explained that there were two issues underlying Witness Burgess's arguments: (1) Mr. Burgess misunderstood the use of the terms "marginal unit" and "marginal resource" in the context of how avoided energy costs are calculated, and (2) Mr. Burgess misunderstood that the DEP-East and DEP-West Balancing Authority Areas ("BAA") are interconnected. (Tr. Vol. 2, p. 630.26-29.) Witness Snider elaborated that "marginal resource" refers to the marginal avoidable generating units that reduced output when the 100 MW no-cost generation resource was added to the system in the change case. This definition of "marginal resource" is not synonymous with the system lambda or what is

referred to as the "marginal cost" in production cost models. Instead, system lambda represents the cost of the marginal generating unit that can increase its output to supply the next 1 MW, which Mr. Burgess failed to appreciate in making his argument. (Tr. Vol. 2, p. 630.26-29.)

In response to Witness Burgess's recommendation to fix separate avoided energy rates for DEP-East, Mr. Snider explained that DEP is responsible for operating DEP-East and DEP-West as a single Balancing Authority that comprises both the DEP-East and DEP-West BAAs. DEP commits and operates the utility's generating fleet on an integrated basis to serve load across the entire DEP Balancing Authority, meaning separate avoided energy rates for DEP-East and DEP-West would always be the same, and represented as a single avoided energy rate. (Tr. Vol. 2, p. 630-26-29.) Duke Witness Holeman similarly provided testimony supporting the fact that DEP operates DEP-East and DEP-West as a single Balancing Authority and commits and operates the utility's generating fleet on an integrated basis to serve load across the DEP BA. He testified that DEP reserves a 400 MW firm transmission path between the DEP-East and DEP-West BAAs and commits and operates the utility's generating fleet on an integrated basis to serve load across the DEP Balancing Authority. (Tr. Vol. 2, p. 758.45-46, 763.)

Third, Duke Witness Snider responded to SCSBA Witness Burgess's argument that the Companies should include a separate fuel hedge value in the Companies' avoided energy rates. He explained that SCSBA Witness Burgess failed to realize that avoided fuel costs used in the avoided energy rate calculation represent the full price of the fuel that Duke would otherwise have purchased if the Companies were to generate energy

themselves rather than purchasing fixed price QF power. He went on to explain that the objective of fixing avoided costs is to quantify the incremental cost of alternative energy that "but for the purchase from such [QF], such utility would generate or purchase from another source." Therefore, the fuel required to generate the equivalent amount of energy is the fuel being avoided. Moreover, Witness Snider explained that when prices are established in any avoided cost proceeding, they represent a price that QFs have an option to receive, while the Companies and their customers have an obligation to pay the QF at the QF's sole discretion. This arrangement essentially represents the QF owning a "Put Option" from the Companies and their customers because the QF has the right, but not the obligation, to sell its power to Duke. However, while the Companies and their customers have an economic obligation to purchase the QF power, they have no rights to deny purchase from the QF irrespective of prevailing market prices at the time of exercise. Witness Snider further testified that the Companies had not recommended a separate charge or reduction in the avoided energy rate to recognize this "put premium" to the QF. (Tr. Vol. 2, p. 630.30-31.)

Last, Witness Snider clarified that contrary to SCSBA Witness Burgess's statements, Duke had appropriately included avoided environmental costs, such as O&M costs to manage coal ash, in calculating the Companies' avoided energy rates. Specifically, Witness Snider testified that projected environmental costs associated with $NO_x$ and $SO_2$ emissions, as well as coal ash handling costs at the existing coal units were included in the production cost model when calculating avoided energy rates. (Tr. Vol. 2, p. 630.32-33.)

In conclusion, Witness Snider recommended that the Commission reject SCSBA Witness Burgess's recommendations related to the Companies' avoided energy rate calculation, and accept the Companies' avoided energy rates as a reasonable calculation of the Companies' actual avoided energy costs. (*Id.*)

On surrebuttal, SCSBA Witness Burgess maintained his original positions regarding the Companies' avoided energy rates, but stated that Duke's explanation of why there were negative hours included in the production cost model made sense conceptually. He further stated that if there were no times when the transmission limit is reached within DEP-East and DEP-West, then the avoided energy rates should be equivalent. (Tr. Vol. 2, p. 787.12.)

During the evidentiary hearing, Mr. Burgess agreed that Duke's Hearing Exhibit No. 26 confirmed that the transmission constraints across the firm transmission between DEP-East and DEP-West had been reached only three times during the last five years, none of which had occurred within the last three years. He further agreed that the transmission limit was reached between DEP-East and DEP-West for a total of only four hours within the past five years, meaning there were no transmission constraints within DEP-East and DEP-West during 99.9% of that time. (Tr. Vol. 2, p. 806.)

Commission Determination

This Commission has previously approved Duke's use of PROSYM under the peaker methodology to calculate avoided energy rates. No party to this proceeding disputes the appropriateness of Duke's utilization of the PROSYM production cost simulation model to calculate avoided energy rates. SCSBA Witness Burgess states that

"production cost models generally solve for the optimal unit commitment and dispatch to meet system load at least cost." ORS Witness Horii finds Duke's utilization of the model to be consistent with PURPA and Act 62. Therefore, it is appropriate for the Companies to continue calculating avoided energy rates under the peaker methodology utilizing the PROSYM production cost model.

In addition, the Commission finds the Companies' inputs and assumptions included in the production cost model to be reasonable and appropriate, as well as the Companies' resulting energy rate calculation. Mr. Horii, the ORS's expert consultant, reviewed the Companies' inputs and assumptions, and testified that based upon his investigation, the Companies' calculation methodology is consistent with PURPA and Commission precedent. ORS Witness Horii also testified that DEC's and DEP's avoided energy costs are a "reasonable result" of the Companies' calculations. (Tr. Vol. 2, p. 525.10.) The Commission finds merit in this testimony as well as Duke Witness Snider's testimony supporting and explaining the Companies' avoided energy rate calculations. In addition, although SCSBA took issue with the Companies' inputs and assumptions, and as explained in detail herein, Duke Witness Snider responded to each of SCSBA's claims, and SCSBA provided insufficient evidence in response to Duke's rebuttal to support its arguments that Duke's avoided energy inputs and assumptions were unreasonable. Therefore, the Commission finds and concludes that the Companies' avoided energy cost calculations, inputs, assumptions, and resulting avoided energy rates fully and accurately reflect the costs to be avoided from purchasing energy from QFs and should be approved.

Negative Avoided Energy Hours

In regard to SCSBA Witness Burgess's concerns regarding Duke's modeling of negative avoided energy hours, the Commission first notes that Mr. Burgess admitted in his rebuttal testimony that negative avoided energy hours included in Duke's model could actually represent "real-world" conditions on the Duke systems. On surrebuttal, SCSBA Witness Burgess also agreed that Duke Witness Snider's explanation as to why there were negative avoided energy hours included in the production cost model made "sense [] conceptually," and did not provide further evidence undermining Duke's explanation. Additionally, during the hearing and in response to questions from the Commission, ORS Witness Horii agreed that the inclusion of negative avoided energy costs to the production cost model could be attributable to the start costs for CTs, which aligned with Duke Witness Snider's explanation as to why negative avoided energy hours were included in the model. (Tr. Vol. 2, p. 606.) The Commission finds that SCSBA did not provide evidence supporting its contention that Duke erroneously modeled negative avoided energy hours, or refute Duke's reasoning for including negative avoided energy hours within the production cost model. While no model can completely match future conditions at the time QF energy is delivered, the Commission agrees with Duke that the operating conditions identified by SCSBA Witness Burgess are, in fact, "real world" operating constraints of Duke's generation fleet and transmission system, and are accurately represented in the model. Therefore, SCSBA's contention that Duke erroneously included negative avoided energy hours within the production cost model is rejected.

Modeling of DEP-East Marginal Cost

In response to SCSBA Witness Burgess's recommendation that the Companies be required to calculate separate avoided energy rates for DEP-East, the Commission finds persuasive Duke Witnesses Snider and Holeman's testimonies that Duke operates DEP-East and DEP-West as a single Balancing Authority. The Commission agrees with Duke that, because DEP-East and DEP-West are interconnected through firm transmission interconnects that allow integrated system dispatch of all fleet generating units in DEP-East and DEP-West to serve load in both Balancing Authority Areas, DEP's avoided energy costs reflect an avoided system cost across the full DEP Balancing Authority. Furthermore, on surrebuttal, SCSBA Witness Burgess recognized that the marginal unit to be avoided should be the same in DEP-East and DEP-West at least "the majority of the time," and also conceded that if there were no transmission constraints between DEP-East and DEP-West, then the avoided energy rate should be the same for each Balancing Authority Area. As presented in Duke's Hearing Exhibit No. 26, DEP-East and DEP-West have experienced no transmission constraints within the last three years and have had no transmission constraints 99.9% of the time within the last five years. Power Advisory similarly found that Duke's avoided energy modeling "reflects system conditions" and that "there is not an issue that needs to be remedied." *Power Advisory Report*, p. 15.

Based upon all of the evidence presented on this issue, the Commission finds and concludes that DEP's quantification of a single avoided energy rate across the DEP Balancing Authority is appropriate and should be approved in this proceeding.

Environmental Cost Inputs Issue

SCSBA Witness Burgess's rebuttal testimony alleges that the Companies' avoided energy cost calculations fail to account for certain environmental costs of marginal generating units, including coal ash costs. The Commission finds Duke Witness Snider's direct and rebuttal testimonies persuasive and unrebutted that projected environmental costs associated with NOx and $SO_2$ emissions, as well as coal ash handling costs at existing coal-fired generating units are included in Duke's production cost model for purposes of fully and accurately calculating DEC's and DEP's avoided energy rates. SCSBA has provided no evidence to refute this fact and Witness Burgess does not further disagree with Duke's inclusion of avoided environmental costs within the avoided energy rate calculation in his surrebuttal testimony. The Power Advisory Report also does not identify this critique by Mr. Burgess in its independent evaluation of Duke's avoided energy costs. Therefore, the Commission finds and concludes that Duke has appropriately included environmental costs of marginal generating units within its avoided energy rate calculations, and that these associated inputs to Duke's production cost model should be approved.

Based upon the foregoing and all evidence in the record, the Commission finds and concludes that Duke's calculation of avoided energy rates and associated inputs and assumptions are reasonable and should be approved.

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 11**

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony, and exhibits in these Dockets, and the entire record in this proceeding.

Summary of the Evidence

Duke Witness Snider described the Companies' proposed avoided energy rate design, testifying that the marginal energy rate structure includes differentiation of summer, winter, and shoulder seasons and designates nine distinct energy pricing periods to reflect the energy value of QF generation during the different timeframes. Specifically, the summer energy season is defined to include June, July, August, and September; the winter energy season is defined to include December, January, and February; and the shoulder energy season is defined to include March, April, May, October, and November. He testified that the design reflects nine energy pricing periods to reflect the energy value of QF generation during the different time frames, and that the Schedule PP rate design appropriately compensates QFs for the avoided energy value they create for customers through the incorporation of granular seasonal and hourly rate periods. (Tr. Vol. 1, p. 58.26-27.)

Duke Witness Snider further testified that the hourly energy rate periods reflect the concept of including higher priced periods, called premium peak hours, in the Companies' winter and summer seasons. He stated that these premium peak hours provide the highest rates to incent generation during these hours when the value of the energy avoided by QF power is greatest for customers. Days with premium-peak and on-

peak hours include Monday through Friday, excluding certain holidays. On-peak energy pricing has a defined set of PM hours during the summer period and both AM and PM hours during both the winter and shoulder periods. Off-peak hours within each season include all hours not otherwise defined as premium or on-peak, and include certain holidays. The hourly definitions for the nine pricing periods also vary slightly for DEC and DEP to account for the differences in each utility's load profile net of solar generation. (Tr. Vol. 1, p. 58.27-28.)

ORS Witness Horii testified that the Companies have updated the Standard Offer avoided energy rate designs by adding more hourly and seasonal granularity to more accurately reflect the hours when QFs provide energy value to the Companies. Based upon his review, Mr. Horii stated that the Companies' updates to the avoided energy rate design were a reasonable and consistent result of the Companies' utilization of the peaker methodology, and are consistent with PURPA and the Commission's prior approval. He therefore recommended no changes to the Companies' avoided energy rate design as proposed. (Tr. Vol. 2, p. 384.09-10.)

SCSBA Witness Burgess argued that the hours grouped within each pricing period, as proposed by Duke, are subjective and can be skewed to impact the prices paid to solar QFs, which are limited in the hours when they can produce electricity. In particular, he suggested that the Companies' off-peak hours are overly broad and include hours when solar generation would be available and that by grouping these hours in this manner, all of which have a lower than average cost for that season, solar QFs are being disadvantaged. Witness Burgess argued that Duke had arbitrarily selected time periods

that undervalue true daytime avoided costs, therefore biasing against daytime QF production such as solar power. (Tr. Vol. 2, p. 382.30-39.)

He further contended that in the "extreme case," avoided energy costs could even be priced on an hourly basis. He therefore suggested re-designating a certain number of these low cost of service hours into a separate pricing period so that the peak hours better coincide with solar generation operations. SCSBA Witness Burgess argued that his alternative avoided energy rate design offered distinctly more value to solar generators than the Companies' avoided energy rate design and could significantly affect solar compensation. (Tr. Vol. 1, p. 382.38-42.)

On rebuttal, Duke Witness Snider objected to SCSBA Witness Burgess's alternative avoided energy rate design as improperly focused on the specific operating characteristics of solar QFs while shifting compensation away from hours when the Companies and their customers see the most value for the energy delivered by the QF. (Tr. Vol. 1, p. 630.34.) In response to SCSBA's proposal, Witness Snider explained that the energy rate design should reflect the Companies' cost of service and system needs, as well as encourage QF generators to adjust their operation to maximize their production during hours that are most beneficial to retail customers, and therefore the system as a whole. He explained that the rate design hours must also be granular enough to provide clear price signals regarding the future value of generation to QFs, but not so specific that the defined pricing periods shift with the smallest movement in forecasted inputs. He testified that this balance is an important consideration to undertake when the rate design

will remain in effect for multiple years under a fixed-price purchased power agreement. (Tr. Vol. 2, p. 630.38-39.)

In addition, Mr. Snider testified that the rate design must also be administratively manageable to ensure accuracy in billing while minimizing potential confusion amongst QFs caused by frequent price changes. In support of the Companies' proposal, he testified that the rate design fairly balances all considerations in a manner that appropriately reflects cost causation and offers QFs the opportunity to adjust their production hours to maximize their financial benefit, in addition to being administratively manageable from a metering and billing perspective. Duke Witness Snider concluded by stating that the proposed rate design also conforms with the fundamental indifference principle of PURPA, and ensures customers are not paying more than the actual costs avoided by the utility. (Tr. Vol. 2, p. 630.39-40.)

Commission Determination

The Commission finds merit in the general approach utilized by the Companies to develop granular pricing methods for avoided energy that more accurately reflect DEC's and DEP's highest production cost hours and loads, in order to increase the likelihood that the interests of ratepayers and developers of QF generators align. In addition, the Commission agrees with Duke Witness Snider that Duke's updated rate design strikes an appropriate balance between accurate avoided cost pricing and administrative efficiency. Duke Witness Snider's testimony provides reasonable support for the Companies' avoided energy rate design as following a methodological approach to evaluate system

costs and impacts, in an effort to properly align price signals provided in the rate design with Duke's avoided energy costs.

With regard to SCSBA's proposal of an alternative rate design, the Commission finds that there is not sufficient evidence demonstrating that implementation of this additional/modified rate design proposal is appropriate for the Standard Offer or cost beneficial to Duke's customers. SCSBA's recommendation to provide additional pricing periods specific to solar QFs for the purpose of increasing a solar QF's revenue must be considered in light of the fact that the Standard Offer tariff is an optional tariff intended to be generically available to all small power producer QFs pursuant to 18 C.F.R. § 292.304(c) that are less than two megawatts in size. *See* Section 58-41-10(15). It must further be considered in light of the fact that PURPA requires non-discriminatory rates to be established for QFs, while customers should be left indifferent to the Companies' QF purchases. Further, the Commission finds that energy rate design should reflect the Companies' cost of service and system needs, as well as encourage QF generators to adjust their operations to maximize their production during hours that are most beneficial to retail customers and therefore, the system as a whole. This is supported by Act 62, which requires the Commission to treat small power producers on fair and equal footing with electrical utility-owned resources by ensuring that "rates for the purchase of energy and capacity fully and accurately reflect *the electrical utility's* avoided cost." *See* Section 58-41-20(B)(1) (emphasis added).

The Power Advisory Report identifies that Power Advisory performed independent analysis of the projected hourly avoided costs to assess the degree to which

the avoided cost energy pricing periods appear to inappropriately bias the value of energy realized by solar QFs. Power Advisory's analysis suggested that there was a "modest underpayment for solar QFs under DEC's rates and overpayment under DEP's rates." Power Advisory therefore recommended that the Commission direct the Companies to provide appropriate analytical support for their avoided cost periods in subsequent filings. *Power Advisory Report,* p. 17. The Commission notes that Power Advisory does not recommend specific modifications to DEC's and DEP's avoided energy rate design be ordered in this proceeding, and the Commission adopts Power Advisory's recommendations that the Companies should provide additional analytical support for the avoided cost rate periods in future avoided cost filings. For purposes of the avoided cost rates authorized in these proceedings, however, the Commission finds the Companies' evidence supporting DEC's and DEP's avoided energy rate design will provide a reasonable and consistent price signal to QFs, encouraging them to align their generation with the time periods that have most value to customers.

Based upon the foregoing and all evidence in the record, the Commission finds and concludes that Duke's avoided energy rate design, as presented in the Companies' Joint Application, should be approved.

**E. Calculating Avoided Energy Rates for Large QFs**

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 12**

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony, and exhibits in these Dockets, and the entire record in this proceeding.

Summary of the Evidence

In his direct testimony, Duke Witness Snider explained that the Companies plan to also use the peaker methodology to calculate avoided costs for larger, non-standard offer QFs. He testified that in using the peaker methodology for larger QFs, Duke updates the inputs used in performing the peaker methodology to most accurately reflect the costs avoided by the specific large QFs. In particular, he explained how the Companies will update projected fuel costs in the model to reflect the then-prevailing value of avoided fuel. He further explained how Duke will also use the actual load shape of the large QFs in modeling the avoided energy value as opposed to the generic baseload 100 MW generator used in the development of the Standard Offer rate. Witness Snider concluded his direct testimony by explaining how these adjustments for large QFs are consistent with PURPA and Act 62, both of which envision taking into account the actual attributes of the QF when calculating the avoided cost value created for consumers. (Tr. Vol. 1, p. 58.29-30.)

SCSBA Witness Burgess took issue with Companies' proposal to "take the specific supply characteristics or 'resource type' of the QF into account," including using a solar generation profile for solar QFs," in determining the avoided energy cost rate under the peaker methodology for non-Standard Offer PPA QFs. Witness Burgess therefore argued that, "avoided energy rates for each type of QF should be technology neutral." He also argued that the technology-specific approach for large non-Standard Offer solar QFs utilizing battery storage is inappropriate. In conclusion, he contended that Duke should treat all Standard Offer and non-Standard Offer QFs the same way

under the peaker methodology, and for both of these QFs' avoided energy cost rates to be technology neutral. (Tr. Vol. 1, p. 382.30-32.)

In response to SCSBA Witness Burgess, Duke Witness Snider first pointed out that the Companies' intent in applying a solar-specific generation profile for solar QFs is to further ensure that the avoided energy rates calculated for non-Standard Offer PPA QFs most precisely equal the Companies' avoided cost, consistent with both PURPA and Act 62. He then agreed with SCSBA Witness Burgess that a solar QF with storage operating in a controlled manner that does not reflect the generator profile of an uncontrolled intermittent solar QF should be eligible for avoided energy rates calculated using a load-profile reflecting the characteristics of the storage device utilized by the QF. However, Witness Snider reiterated that Duke supports applying a solar-specific load profile to solar non-Standard Offer PPA QFs. (Tr. Vol. 2, p. 630.34-35.)

In support of Duke's proposal, Witness Snider explained that FERC's regulations governing the rates for purchase from QFs recognize a number of factors in 18 C.F.R. § 292.304(e) relating to the supply characteristics of the QF that should be taken into account "to the extent practical" in determining avoided costs. Specific to intermittent QFs, FERC has also more recently recognized that utilities may take the QF's supply characteristics into account, including, among others, the availability of capacity, the QF's dispatchability, the QF's reliability, and the value of the QF's energy and capacity. *Windham Solar, LLC*, 157 FERC ¶ 61,134 (2016). Witness Snider explained that FERC's statements also align with Act 62's provision that avoided cost methodologies approved by the Commission "may account for differences in costs avoided based on the

geographic location and resource type" of the QF. *See* Section 58-41-20(B)(3). He additionally noted that the Commission had previously approved Dominion Energy South Carolina's proposal to calculate avoided energy rates based on a solar-specific load shape in May 2018. *Amended Order Approving Fuel Costs,* Order No. 2018-322(A) at 28, Docket No. 2018-2-E (May 2, 2018). Moreover, Witness Snider identified that other utility commissions, such as the Montana Public Service Commission, have also recently held that adopting a Standard Offer QF's avoided energy cost for QFs ineligible for the Standard Offer would be unjust and unreasonable to the utility's customers, since Larger QFs ineligible for the Standard Offer have individual and unique supply characteristics. (Tr. Vol. 2, p. 630.35-37.)

Last, Duke Witness Snider responded to SCSBA Witness Burgess's concern that Duke may include methodological choices that have not been made transparent in this proceeding when calculating non-Standard Offer PPA QF's rates, by reiterating the specific supply characteristics that Duke plans to take into account when calculating such rates for large QFs. He explained that solar QFs or solar QFs with integrated battery storage will be required to supply an hourly energy production profile that will be used in place of the flat 100 MW no-cost generation profile that is used when calculating the Standard Offer avoided energy rates. Witness Snider additionally explained that, consistent with the Companies' historic practice, the Companies will also apply the most up-to-date inputs under the peaker methodology (such as updates to the fuel prices to reflect the current market value of fuel, as well as updates to reflect any changes to the Companies' resource plan to be consistent with the most recently-filed IRPs) in order to

more accurately align the avoided cost rates paid to the QF with the value provided to customers. In conclusion, Witness Snider explained that these updates are transparent inputs to the model that can have the effect of raising the avoided cost value paid to the QF with equal likelihood as lowering the value paid to the QF. (Tr. Vol. 2, p. 630.36-37.)

Commission Determination

In Order No. 69, FERC explained that standard rates for purchase may differentiate among QF technologies on the basis of supply characteristics, while also recognizing that administrative efficiency of setting generic standardized avoided costs that do not take into account the specific characteristics of these small QFs is appropriate even if a deviation in value from true avoided costs results.

> (FERC) is aware that the supply characteristics of a particular facility may vary in value from that average rate set forth in the utility's standard rate required by this paragraph. If the Commission were to require individualized rates, however, the transaction cost associated with administration of the program would likely render the program uneconomic for this size of (QF).

Order No. 69, 45 Fed. Reg. at 12,223. In describing the avoided costs rates to be paid to larger QFs, FERC also emphasized that a QF's capacity and energy supply characteristics could be taken into account in analyzing whether the QF provided capacity value and in calculating the incremental energy value to be avoided by the QF. *Id*. at 12,224 (describing the specific capacity value considerations of wind, solar, and biomass QFs). FERC also established specific factors that could affect the rates for purchases from QFs, while emphasizing that the selection of a methodology setting avoided costs is best left to the State Commissions charged with implementing PURPA's must-purchase provisions. *Id*. at 12,226; see 18 C.F.R. § 292.304(e); *see also Windham Solar, LLC*, 157 FERC ¶

61,134, at ¶6 (2016) (recognizing that the value of avoided energy and capacity could be lower for purchases from intermittent QFs than for purchases from firm QFs). Through Section 58-41-20(B)(3), Act 62 also incorporates consideration of several of these factors as a part of South Carolina's framework for establishing avoided cost rates. Moreover, as noted by Duke Witness Snider, the Commission has previously approved Dominion Energy South Carolina's use of a solar-specific load shape in calculating avoided cost rates. *Amended Order Approving Fuel Costs,* Order No. 2018-322(A), at 28, Docket No. 2018-2-E (May 2, 2018).

The Commission finds merit in the concept underlying the recommendation of Duke Witness Snider, that Duke's quantification of avoided costs for larger QFs should recognize the characteristics of the power supplied by the QF. Considering the factors in Section 58-41-20(B)(3) and the FERC regulations in the determination of avoided cost rates ensures that the Commission-determined avoided cost methodology remains true to PURPA's directive that avoided cost rates are to be based on the costs that the utility actually avoids. Thus, the Commission recognizes that PURPA provides utilities with the ability to consider factors including the availability of capacity, the QF's dispatchability and reliability, and the value of the QFs' energy and capacity in establishing avoided cost rates for purchases from larger QFs, including solar QFs. *See* 18 C.F.R. § 292.304(e). The Commission also recognizes Duke's testimony pointing out that other utility commissions have similarly recognized that rates paid to larger QFs ineligible for the Standard Offer may take into account the specific characteristics of those QFs to most precisely calculate the utility's avoided cost. (Tr. Vol. 2, p. 630.35-37 *citing In the*

*Matter of the Petition of Crazy Mountain Wind for the Comm'n to Set Certain Terms & Conditions of Contract Between Nw. Energy & Crazy Mountain Wind, LLC.*, No. 7505C, 2017 WL 1425719, at *6 (Apr. 18, 2017)). Accordingly, the Commission concludes that this approach complies with PURPA and Act 62.

In addition, the Commission determines that the purpose of Act 62 and FERC's regulations is to ascertain more specifically what a large, non-Standard PPA solar QF's actual avoided cost rate is. SCSBA Witness Burgess's assertion that a large, non-Standard PPA solar QF should have the same production profile as a generic Standard Offer QF in calculating avoided energy rates effectively requires the standard rate to apply to all QFs, contrary to Act 62's requirement that Standard Offer rates be made available to QFs less than 2 MW in size.

Contrary to SCSBA's position, the Power Advisory Report also recognizes the improved precision of calculating avoided cost rates for large QFs at the time of the request, which "ensures that the avoided cost rate reflects current assumptions and avoids the risk of stale avoided costs, which can be more significant for a large QF." Power Advisory further recognizes that "the avoided cost rate will reflect the specific operating profile of the large QF and result in a more reliable avoided cost rate." *Power Advisory Report*, p. 18. The Commission agrees with Power Advisory and Duke that these considerations are appropriate in applying the peaker methodology to calculate avoided cost rates for QFs above 2 MW not eligible for the Standard Offer.

Based upon the foregoing and the entire record herein, the Commission finds that it is appropriate for DEC and DEP to take into account the production profile of the

facility when calculating avoided cost rates for large, non-Standard PPA QFs. The Commission further finds that it is appropriate for DEC and DEP to continue the practice of applying the most up-to-date inputs under the peaker methodology in calculating such rates for large, non-Standard PPA QFs.

**F. Avoided Capacity Quantification and Rate Design**

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 13**

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Summary of the Evidence

Duke Witness Snider's direct testimony provided support for the Companies' avoided capacity calculation. His testimony began by explaining how avoided capacity costs are calculated under the peaker methodology. Witness Snider explained that one of the key elements in the application of the peaker methodology is determining the first year in which DEC and DEP each actually have a future avoidable capacity need. (Tr. Vol. 1, p. 13-15.) He further explained that a central tenant of PURPA is that customers are not required to pay QFs for avoided capacity unless the QF is actually offsetting a capacity need of the utility. Accordingly, the annual fixed capacity costs used in the avoided capacity rate calculation includes the annual fixed capacity costs starting with the first year in which an actual avoidable capacity need exists, as determined by the utilities' most recent IRPs. (Tr. Vol. 1, p. 58.14-16.)

Duke Witness Snider testified that DEC's projection of its first avoidable capacity need occurs in 2026, while DEP's first avoidable capacity need occurs in 2020, consistent with the Companies' 2019 IRP Update filings. He testified that accounting for the timing of needed capacity accurately values the capacity being delivered by the QF, consistent with PURPA's intent for the utility to estimate the costs that, but for purchase from the QF, would have otherwise been incurred by the utility and its customers. (Tr. Vol. 1, p. 58.14-17.) Last, he explained that under the levelized Schedule PP rate design, the avoided capacity payment is levelized to allow the QF to receive an avoided capacity payment in each year of the contract, as long as an actual capacity need exists at some point within the term of the avoided cost period. Put another way, the QF will receive capacity payments during each year of the contract, in order to credit the QF for future avoided capacity, so long as the utility has an avoidable capacity need within the avoided cost period. In conclusion, Witness Snider testified that the Companies' recognition of DEC's and DEP's need for capacity in the avoided capacity cost calculation is fair to both the Companies' customers and the QF. (Tr. Vol. 1, p. 17-18.)

ORS Witness Horii supported the method used by the Companies to calculate avoided capacity costs and stated that the method was one of the generally accepted methods for calculating PURPA avoided capacity costs used throughout the United States. (Tr. Vol. 2, p. 525.11.) He then testified that the lower avoided capacity rates calculated for DEC as compared to DEP were justified. In support of his position, Mr. Horii testified that the Companies' use of the recently filed 2019 IRPs was appropriate, reasonable, and transparent. In reviewing the Companies' load and resource balance

table that DEC provided to ORS as the basis for its capacity need determination, ORS Witness Horii found that the increases of generation capacity via capacity increases or uprates in 2021 through 2024 did not require DEC to recognize avoided capacity costs in those years. (Tr. Vol. 2, p. 525.11-12.) He also agreed that although DEC's load and resource balance table identified the addition of the Lincoln combustion turbine ("CT") in 2025, DEC appropriately identified 2026 as the first year of avoided capacity cost, because the Lincoln CT has already been approved and commenced construction. Therefore, Mr. Horii explained that moving the first year of avoided capacity costs to 2025 instead of 2026 would incorrectly increase the avoided capacity payments to QFs, and recommended the Commission approve the Companies' first year of capacity needs as identified in DEC's and DEP's 2019 IRP Updates and used in calculating the Companies' avoided cost rates. (*Id.*)

In response to Duke's avoided capacity cost calculation and identified first year of need, SCSBA Witness Burgess argued that Duke's proposal was biased against QFs and underestimated capacity value in two ways. First, he argued that for DEC, Duke inappropriately assumed that each QF would provide zero capacity value from 2020 through 2026. Although he admitted that Duke's load and resource forecast do not project an internal resource need until 2026, he stated that Duke has the option to sell its excess capacity in the wholesale capacity markets and to receive commensurate compensation for doing so. (Tr. Vol. 1, p. 382.62.) He argued that the addition of QF capacity would further increase Duke's capacity position, allowing for greater off-system sales. He therefore recommended that the QF capacity provided to DEC between 2020

and 2026 be traded by DEC either bilaterally or into PJM's Reliability Pricing Model capacity market, and subsequently credited to Duke's customers, despite admitting that this capacity "may not be necessary to cover any internal capacity deficiencies." (Tr. Vol. 1, p. 382.62-65.)

Second, he argued that Duke incorrectly assumes that each QF provides zero capacity value after 2029. In support of his argument, he argued that new generation sources, such as gas peakers, have a project life of 30 years or more, and that the benefit to ratepayers of avoided capacity from QFs may extend well beyond the life of the proposed 10-year contract period. He argued that Duke's proposal limits the capacity component of QF contracts to 10 years, even though solar PV resources have a project lifetime of 20 years or more. He therefore concluded that there is "significant likelihood" that the capacity from these projects could be re-contracted at a later date. (Tr. Vol. 1, p. 384.65.) He further argued that since there would be no fuel costs, transport costs, and minimal O&M costs, the cost to re-contract these QFs would likely be very low compared to other options, providing a "meaningful option value." However, he concluded by stating that he did not recommend adjusting Duke's avoided cost methodology to reflect this option value at this time. (Tr. Vol. 1, p. 384.66.)

In response to SCSBA's first critique of the Companies' identified first year of need, Duke Witness Snider explained that from a legal perspective, utilities are not obligated to pay QFs for capacity that exceeds system needs, such as for resale in a capacity market under PURPA. In support of his contention, he stated that FERC has long held that "an avoided cost rate need not include capacity unless the QF purchase will

permit the purchasing utility to avoid building or buying future capacity…(the purchase) obligation does not require a utility to pay for capacity that it does not need." (Tr. Vol. 2, p. 630.54 (citing *City of Ketchikan*, 94 FERC ¶ 61,293 (2001) (citing *Order No. 69*, at P 30,865)).) Witness Snider further explained that FERC has also expressly stated that "there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements," as neither PURPA nor FERC's regulations require utilities to pay for the QF's capacity irrespective of the need for the capacity." *Id.* Further, he stated that FERC has more recently reiterated that "when the demand for capacity is zero, the cost for capacity may also be zero." (Tr. Vol. 2, p. 630.53-55 (citing *Hydrodynamics, Inc.,* 146 FERC ¶ 61, 193, at ¶ 35 (2014)).)

In response to SCSBA Witness Burgess's second critique, Witness Snider explained that it is prudent resource planning not to rely upon assumed future third-party owned capacity in years where no contract or other legally enforceable commitment guaranteeing delivery exists. He explained that QF owners have unfettered rights to make a business decision at the time their current PPA expires whether or not to enter into a new PURPA contract with the Companies or otherwise use (or not use) their facility in any lawful manner as they so desire. He explained that the Companies and their customers have no guarantee that the contracted facility will be physically capable of providing energy and capacity beyond the contract period for a variety of reasons. He stated that Duke's current and consistent position across numerous biennial IRP planning cycles has been to treat all wholesale purchase contracts the same and to recognize that a QF's legally enforceable commitment to provide energy and capacity extends only for the

duration of its PPA. Further, he testified that Duke's position was fully consistent with FERC's implementing regulations, and that to presume a QF had made a commitment to deliver power to utility after its initial contract term ends would be inconsistent with PURPA. Witness Snider concluded by contending that SCSBA Witness Burgess' proposal is intended to advantage existing QFs over new QFs or other capacity resources, and is therefore discriminatory towards other traditional and non-traditional utility resources, in violation of PURPA's nondiscrimination principle. (Tr. Vol. 2, p. 630.56.)

On surrebuttal, SCSBA Witness Burgess did not refute Duke Witness Snider's claim that PURPA does not require utilities to pay QFs for capacity when there is no capacity need. Instead, Mr. Burgess questioned whether DEC's 2019 IRP reflected DEC's most current planning needs and requirements, arguing that it does not reflect DEC's planned accelerated retirements of five coal plants announced in DEC's September 30, 2019 North Carolina general rate case application after the 2019 IRP Updates were filed. (Tr. Vol. 2, p. 787.7.)

On cross-examination, Duke Witness Snider addressed the fact that DEC had recently announced the accelerated retirement of five coal plants after the 2019 IRP Updates were filed. He explained first, in terms of resource planning, a utility must make a determination or, "snap a chalk line," at a certain point in time and use the most up-to-date inputs and assumptions available at that point in time in developing its integrated resource plan. Second, he explained that the planned accelerated retirement of the coal plants referenced by SCSBA Witness Burgess were subject to future regulatory determinations prior to DEC actually committing in an integrated resource plan to retire

the units, as further evidence as to why those retirements were not included in the Companies' 2019 IRP Updates. Mr. Snider specifically explained that Duke has sought authorization to adjust the depreciable lives of these plants in DEC's now-pending North Carolina general rate case and, assuming the shorter depreciable lives are approved, that DEC would reflect this change in its 2020 IRP. (Tr. Vol. 1, p. 156-157) Last, he explained that although there was a possibility that these accelerated retirements could accelerate DEC's first year of need to 2025, and therefore increase the avoided capacity rate, recognizing the accelerated retirements of these older coal units would also impact DEC's marginal cost of energy thereby having the likely overall effect of lowering DEC's overall avoided cost rates. This result would be due to the acceleration of more cost-effective and efficient generation replacing the units, which result he contended would be adverse to SCSBA's interests. (Tr. Vol. 1, p. 163-164)

During SCSBA's examination of ORS Witness Horii at the hearing, Mr. Horii testified that he was unsure solar QFs could even meet the capacity need that would arise as a result of the five coal units being retired. He explained that according to his experience, "if you retire a unit, you need to basically sort of put in a large () replacement capacity project. And, in that case, there may be no sort of avoided cost savings because you're not going to be avoiding or deferring that next capacity project because you're putting it in there to replace the massive amount of capacity that you've lost through the retirement." (Tr. Vol. 2, p. 550.) ORS Witness Horii further agreed that the retirement of these coal units could lower the Companies' proposed avoided energy rate. Last, ORS Witness Horii agreed with Duke Witness Snider's statement that it is a reasonable

approach for a utility to select a specific point in time or to "snap a chalk line" in determining its resource plan and for purposes of calculating avoided cost rates. (Tr. Vol. 2, p. 550-551.)

Commission Determination

The Commission finds that DEC and DEP have appropriately identified their first avoidable capacity needs, as presented in their 2019 IRP Updates. ORS's expert Witness Horii testified that the Companies' use of the recently filed 2019 IRPs was appropriate, reasonable, and transparent, and the Commission finds merit in his testimony. Moreover, in regard to DEC's recently announced plans to accelerate retirement of certain coal units, the Commission finds that for purposes of this proceeding, it is reasonable not to consider those retirements in determining the DEC's first year of capacity for several reasons. As evidenced by Duke Witness Snider, it is necessary for the utilities to "snap a line in chalk" at some point in time for purposes of resource planning and calculating the Companies' avoided cost rates. ORS's expert Witness Horii agrees, and testified that this is a reasonable approach. Moreover, as also testified to by Duke Witness Snider, these five coal units have yet to receive the necessary regulatory approvals to be included in DEC's IRP as "committed" to these earlier retirement dates.

SCSBA's argument in support of including the prospective earlier retirement of the five coal units in DEC's calculation of avoided capacity costs was based upon the premise that including these retirements would accelerate the Companies' first year of capacity need, thereby increasing the avoided capacity rates approved in this proceeding to be paid to QF. However, Duke Witness Snider testified that consideration of the

accelerated retirement of these five coal plants would not only affect the Companies' avoided capacity rate, but also the system production cost of energy used to quantify the avoided energy rate. He explained that most likely, the aggregate effect of accounting for these accelerated coal unit retirements would be an overall decrease in the Companies' avoided cost rates, based on the likelihood that retiring older coal units would drive down the avoided energy rate more so than any increase in avoided capacity. ORS's expert Witness Horii agreed that Duke Witness Snider's contention was plausible, and SCSBA provided no evidence suggesting otherwise.

The Commission also recognizes and appreciates Power Advisory's recommendation that DEC be required to adjust forward its first year of capacity need to 2025 to reflect the likelihood that these accelerated coal unit retirements become part of the DEC's resource plans. *Power Advisory Report*, p. 21. However, as discussed above, the Commission finds that it is appropriate and necessary to "snap a chalk line" in developing inputs and assumptions for calculating avoided cost rates, that the loss in avoided energy payments may more than offset the gain in avoided capacity payments to QFs by recognizing the accelerated unit retirement date assumptions, that the acceleration in unit retirement dates is subject to future regulatory determinations prior to DEC actually committing in an integrated resource plan to retire the units, and that if shorter depreciable lives are approved, that DEC will appropriately reflect this change in its 2020 IRP.

Based upon all of the evidence on this issue, the Commission finds and concludes that DEC's identified first capacity need in 2026 and DEP's identified first capacity need

in 2020 are reasonable and appropriate for purposes of calculating avoided costs in this proceeding.

In regard to SCSBA's proposal to require the Companies to assume excess QF capacity can be sold into a wholesale capacity market prior to DEC's first year of capacity need in 2026, the Commission finds and concludes that such a requirement would be inconsistent with PURPA and contrary to FERC precedent. As cited to by Duke Witness Snider, FERC has held that "an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity…(the purchase) obligation does not require a utility to pay for capacity that it does not need." (Tr. Vol. 2, p. 630.54 (citing *City of Ketchikan*, 94 FERC ¶ 61,293 (2001) (citing *Order No. 69*, at P 30,865)).) FERC has also stated that "there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements," as neither PURPA nor FERC's regulations require utilities to pay for the QF's capacity irrespective of the need for the capacity." *Id.* FERC also reiterated in the *Hydronamics* decision cited by Duke Witness Snider that "when the demand for capacity is zero, the cost for capacity may also be zero." (Tr. Vol. 2, p. 630.54 *citing Hydrodynamics, Inc.,* 146 FERC ¶ 61, 193, at ¶ 35 (2014).) PURPA therefore does not force a utility and its customers to pay for capacity that it otherwise does not need to serve customers. SCSBA Witness Burgess testified in his surrebuttal testimony that "he [does not] disagree with this position. (Tr. Vol. 2, p. 787.20.) The Power Advisory Report also generally accepts Duke's position on this issue. *Power Advisory Report*, p. 21. Therefore, the Commission agrees with Duke and the ORS that

customers should not be required to pay solar QFs for capacity prior to the first year in which it is needed to serve system load and SCSBA's seemingly abandoned argument on this issue is rejected.

Based upon the foregoing and the entire record herein, the Commission finds the Companies' reliance upon the 2019 IRP Updates reasonable, and the resulting identified first years of need for DEC and DEP reasonable and appropriate as well.

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 14-16**

The evidence in support of these findings of fact are found in the verified Joint Application, pleadings, testimony and exhibits in theses Dockets, and the entire record in this proceeding.

Summary of the Evidence

ORS Witness Horii and SCSBA Witness Burgess each challenged certain aspects of Duke Witness Snider's calculation of avoided capacity cost under the peaker methodology. Duke Witness Snider testified that DEC and DEP each calculated their respective avoided capacity cost based on the cost of constructing new "peaker" combustion turbine ("CT") capacity. Duke relied upon publicly available CT cost data from the United States Energy Information Administration ("EIA"), which reflected the cost to build a single CT unit at a greenfield site. Duke then adjusted the EIA CT costs to recognize the economies of scale associated with shared land, buildings, roads, security, gas interconnection and other infrastructure for a 4-unit CT site, which Witness Snider testified aligned with the Companies' practice to build multiple units at a new site. (Tr. Vol. 1, p. 58.14-5.)

Issues Raised by ORS Witness Horii

Witness Horii recommended DEC make two changes to the avoided capacity cost calculations: 1) Increase the Fixed Charge Rate for a combustion turbine ("CT"); and 2) Correct the allocation of capacity costs to seasons and time of day.

Life of a CT

According to witness Horii, DEC and DEP used a 35-year economic life for the CT, rather than a 20-year economic life, to determine the proper Fixed Charge Rate then used to determine avoided capacity costs. A 20-year life for a CT is commonly used in jurisdictions like California for their electricity avoided costs, PJM for their Cost of New Entry report, and by the highly regarded Lazards Levelized Cost of Energy Analysis report. Tr. p. 525.13, II. 13-17. According to witness Horii, the Companies' use of a 35-year economic life for avoided capacity costs is not appropriate because the Companies failed to include appropriate fixed operating and maintenance ("FOM") costs as part of the total fixed costs for a CT. Tr. 528.2, I. 18 to 528.3, I. I. It is via the inclusion of expensive overhaul work, such as major maintenance, that a CT's life could be extended from twenty (20) to thirty-five (35) years. Tr. p. 528.3, II. 4-5. By using an overly long life in the Fixed Charge Rate calculation, DEC and DEP are spreading the capital-related costs of the CT over an excessive number of years and artificially lowering the estimate of costs that would need to be collected in each year for the CT owner. Tr. p. 525.13, I. 17, p. 525.15, I. 1-2.

According to witness Horii, the Companies inappropriately included major maintenance FOM costs associated with the 35-year life of a CT in the modeling of

avoided energy costs. Tr. p. 528.3, II. 14-17, p. 528.4, II. 1-4. Witness Horii testified that the Companies improperly minimize (or nearly eliminate) the cost of major maintenance because of the way they calculate avoided energy costs. Tr. p. 528.4, II. 10-11. The Companies model major maintenance costs in PROSYM as an additional start cost for the CT. Tr. p. 528.4, II. 11-12. Witness Horii testified that on its face, this could be viewed as reasonable, however, avoided energy costs are calculated as the difference in operating costs between 1) a base case and 2) a change case that includes 100 MW of free generation. Tr. p. 528.4, II. 12-15. Both the base case and the change case would have substantial major maintenance costs, but almost none of these costs translate to avoided energy costs because they mostly cancel out when calculating the change in costs between the two cases. Tr. p. 528.4, II. 15-18.

Witness Horii's analysis corrected the CT life to twenty (20) years in DEC's and DEP's annualization tool provided by the Companies. Tr. p. 525.14. For DEC, the CT Fixed Charge Rate increases from 7.635% per year to 9.831% per year, which increases the avoided capacity cost by 29%. Tr. p. 525.14, II. 3-5. For DEP, the Fixed Charge Rate increases from 7.189% per year to 9.394% per year, which increases the avoided capacity cost by 30.7%. Tr. p. 525.18, II. 2- 4. To further substantiate witness Horii's recommendation, he correctly calculated a 35-year CT avoided capacity cost for DEC and DEP and compared them to his previously calculated 20-year CT avoided capacity costs and the results were nearly identical. Tr. p. 528.6, II. 8-12. According to witness Horii, including the higher costs of major maintenance in the forecast of FOM costs and a 35-year economic life, results in avoided capacity costs that are 1% lower than his

recommendation for DEC and 2% lower than his recommendation for DEP. Tr. p. 528.6, II. 12- 15. Witness Snider testified that he agrees with witness Horii that other jurisdictions and other studies use varying economic life assumptions. Tr. p. 630.51, II. 9-10. However, since consumers in South Carolina pay for both traditional generation and PURPA QF generation, he asserts it is reasonable that the assumption of useable economic life should be the same in either case. Tr. p. 630.51, II. 10-15. Since the 35-year useful life assumption used in the development of capacity rates in this case is consistent with the Company's IRP, Mr. Snider argues it is appropriate to utilize this same assumption for avoided cost purposes. Tr. p. 630.51, II. 16-19.

Witness Snider testified that the FOM cost is included in the calculation of the annual capacity cost and includes labor, office and administration, training, contract labor, safety, building and ground maintenance, communication, and laboratory expenses. Tr. p. 630.52, II. 6-9. The variable O&M ("VOM") cost is modeled in PROSYM and includes routine maintenance, makeup water, water treatment, water disposal, and other consumables, excluding fuel. Tr. p. 630.52, II. 9- 11. In addition, the major maintenance cost assumes third-party maintenance based on the recommended maintenance schedule set forth by the original equipment manufacturer to meet the 35-year useful life of the CT. Tr. p. 630.52, II. 11-14. The major maintenance cost is modeled separately from VOM and is included in PROSYM as a start cost for CTs. Tr. p. 630.52, II. 14-16. Thus, the capital and FOM costs are included in the annual capacity cost in developing the avoided capacity rates paid to QFs, and VOM and major maintenance costs are captured

in the PROSYM production cost model and reflected in the avoided energy rates. Tr. p. 630.52, II. 16-19.

Issues Raised by SCSBA Witness Burgess and Duke's Response

SCSBA Witness Burgess argued that Duke's avoided CT unit cost was potentially biased against QFs and recommended a number of adjustments to Duke's avoided CT unit costs, each of which had the effect of increasing Duke's avoided capacity cost. (Tr. Vol. 1, p. 382.55-56.)

First, while Mr. Burgess found that the EIA's cost estimate for the F-Frame CT unit ($677/kW) represented a reasonable estimate, he argued that this type of unit does not necessarily correspond to the cost of the peaking unit that Duke would ultimately select to meet future peak demand or provide other services. (Tr. Vol. 1, p. 382.56, 58.) He argued that the increasing challenges of integrating solar into the Duke system may cause Duke to install more flexible peaking units that can better respond to the variable output of solar generation. Witness Burgess, therefore, recommended a significantly higher cost aeroderivative CT unit be taken into consideration, pointing out that an increasing number of more flexible aeroderivative CT units are being built in PJM. (*Id.*) He argued that consideration should be given to Dominion Energy Virginia's 2018 IRP estimate of the cost of an aeroderivative CT unit cost ($1,680/kW), and specifically recommended the Commission adopt a capital cost assumption of $1,178, representing the midpoint of the EIA F-Frame unit estimate, as relied upon by Duke, and the Dominion Energy Virginia aeroderivative CT unit estimate. (Tr. Vol. 1, p. 382.58.) Witness Burgess also opposed Duke's economies of scale adjustment, suggesting that

constructing multiple CT units is not representative of what Duke is likely to build in the near term to satisfy its peaking needs. (Tr. Vol. 1, p. 382.58.)

Witness Burgess also argued that Duke's failure to include significant transmission system upgrade costs in the avoided CT cost estimate was not reasonable. Witness Burgess pointed to Xcel Energy Minnesota's 2016-2030 upper Midwest Resource Plan as estimating the capital cost of transmission associated with a new peaker (CT unit) to be $152/kW. Mr. Burgess did not adopt the Xcel Minnesota's Midwest IRP value, however, instead arguing that including $120/kW in transmission upgrade costs in Duke's avoided capacity cost calculation would be "more conservative." (Tr. Vol. 1, p. 382.60.)

In total, Mr. Burgess recommended that Duke's avoided CT costs be increased by 104%. (Tr. Vol. 1, p. 382.60.)[24]

In rebuttal, Duke Witness Snider responded that Mr. Burgess's recommendation to take the cost of an aeroderivative CT unit into consideration was unreasonable and that Duke opposed Mr. Burgess's recommendation to use the midpoint cost of the advanced F-Frame CT unit and the aeroderivative CT unit as arbitrary and inappropriate for a number of reasons. Witness Snider first highlighted that DEC and DEP both have numerous F-Frame CT units installed on their systems today and that Duke's 2019 IRPs show that DEC and DEP are both planning to build numerous F-class CT units in the future. (Tr. Vol. 2, p. 630.41-43.) He further testified that neither DEC nor DEP are

[24] SCSBA designated this percentage figure as confidential because it was derived from confidential CT cost information provided by Duke. Duke does not believe this figure needs to be confidential and Duke witness Snider filed it publicly in his rebuttal testimony. (Tr. Vol. 2, p. 630.49.) Duke agrees to its inclusion in the Commission's final Order as public information.

currently projecting the need to build aeroderivative CT units. (Tr. Vol. 2, p. 630.43.) Witness Snider also pointed out that reliance on a higher cost aeroderivative CT unit is also not consistent with the peaker methodology, which is designed to quantify the cost of building the least cost peaker unit to provide incremental capacity and the system marginal cost of energy as reflecting the utility's full avoided cost. (Tr. Vol. 2, p. 630.44-45.) Witness Snider also explained that Mr. Burgess's rationale that Duke may need to install more expensive aero-derivative CT units in the future to manage the intermittent output of must-take solar generators does not justify paying solar QFs higher capacity value. He explained that if Duke were to identify the need to install more expensive aero-derivative CT units, then the cost causer would be the solar providers, and the incremental cost of constructing aero-derivative CTs versus F-class CTs should be paid by the solar providers, and not paid for by customers to the solar providers. (*Id.*) Witness Snider also pointed out that Dominion Energy Virginia ultimately did not even include the aero-derivative CT in its final IRP and also did not recognize this type of unit as a proxy for the cost of capacity avoidable by the QF. (Tr. Vol. 2, p. 630.42, 45.)

Specific to Mr. Burgess's opposition to the economies of scale adjustment, Mr. Snider reiterated that the adjustment is fully consistent with Duke's practice of building multiple CT units at each power station. Mr. Snider further explained the reasonableness of Duke's approach by noting that Duke did not include any economies of scope adjustments despite the fact that Duke's IRPs also reflect Duke's plans to construct between two and eight CTs during a given year. (Tr. Vol. 2, p. 630.42, 45.) Witness Snider also identified that Duke provided extensive information to Mr. Burgess regarding

the Companies' practices in response to SCSBA Interrogatory 3-9, which was introduced as Exhibit 5 during the hearing. (Tr. Vol. 2, p. 243-246.) Hearing Exhibit 5 validated Mr. Snider's position that eight of Duke's 11 power stations have four or more CTs and that Duke's consistent practice is to plan to build four or more generating units at a new greenfield power station site in order to create economies of scale. Therefore, Mr. Snider affirmed the economies of scale adjustment was appropriate. (*Id.*)

In response to Mr. Burgess's recommendation to incorporate transmission system network upgrade costs into the cost of the avoided CT unit, Mr. Snider explained that the EIA CT cost estimate appropriately included the interconnection costs of physically connecting the generation source to the transmission system. Interconnection costs are appropriately included because they are real costs that will be avoided when avoiding the construction of a new CT, and because the QF is fully responsible for the interconnection costs associated with its own facility. (Tr. Vol. 2, p. 630.48.) In contrast, he explained that the network system upgrade costs proposed to be included by Witness Burgess were not appropriate as these significant transmission system costs may not be required to construct a CT and would also not be avoided by purchasing power from the QF. Witness Snider further explained that the concept of paying avoided transmission system upgrade costs to the QF generator would imply that the addition of non-firm generation on the system has deferred the need for system upgrades, which is not the case. (Tr. Vol. 2, p. 630.48-49.)

Duke Witness Snider concluded that SCSBA Witness Burgess's recommendation to increase the avoided capital cost assumptions for both DEC and DEP by 104% would

more than double the capacity payments made by Duke's customers to solar QF providers in excess of the equivalent capacity cost that would otherwise have been incurred if the capacity would have been provided by the utility. Duke opposed this higher capacity cost as a subsidy to the benefit of the QF developer, asserting that would violate the fundamental indifference principle of PURPA and Act 62. (Tr. Vol. 2, p. 630.49.)

During the evidentiary hearing, Mr. Burgess conceded that the Commission should recognize the CT units that Duke actually plans to build on its system, which is the F-Frame unit relied upon by Duke in calculating the avoided capacity cost. (Tr. Vol. 1, p. 430.) Witness Burgess further conceded that his proposed adjustment to include the cost of significant transmission upgrades was a judgment call and not based upon any analysis. (Tr. Vol. 1, p. 434.) He was also unaware of whether Xcel Energy's avoided cost rates included the same transmission network upgrade costs that Witness Burgess proposed to include for Duke and conceded that Dominion's significantly smaller $10.75/kW "transmission cost" could be comparable to Duke's inclusion of interconnection facilities cost. (Tr. Vol. 1, p. 433-434.)

Commission Determination

We agree with ORS witness Horii that use of a 20-year useful life for avoided capacity costs is most appropriate. Witnesses Snider and Horii agree major maintenance costs must be included in the calculation of the Companies' avoided costs; however, witness Horii argues the Companies inappropriately account for them. By including major maintenance costs in calculating avoided energy in both the base and change cases, the

Companies "essentially make those costs disappear," discounting the impact that major maintenance has on the avoided cost. See Tr. p. 528.4, II. 1-9; p. 605, I. 11 top. 606, I. 6. Witness Snider argues thirty-five (35) years should be used because it is consistent with the useful life contained in the Companies' IRPs. Witness Horii does not contest that thirty-five (35) years may be used, but asserts that if 35 years is used as the life of the CT, major maintenance must be appropriately included. Furthermore, witness Horii conducted an analysis that included major maintenance in the FOM and the results were nearly identical to those calculated initially using a 20-year useful life of the CT. Duke's analyses, by failing to include the major maintenance FOM in their calculation of avoided capacity costs, underestimate the full fixed cost of a CT. The Commission finds that it is not necessary for the useful life of the CT, when calculating avoided costs, to match the useful life of a CT the Companies assume in their IRPs. Additionally, the Commission finds that the Companies' method of including FOM inappropriately discounts the impact of major maintenance on the calculation of avoided costs. Tr. p. 528.3 to 528.6 As a result, the Commission finds the preponderance of the evidence in the record supports the position put forth by ORS witness Horii as just and reasonable.

The Commission rejects SCSBA Witness Burgess's recommendations to significantly increase the avoided CT capital cost assumptions relied upon by DEC and DEP to calculate the avoided capacity costs. The Commission initially notes that the Power Advisory Report accepted Duke's proposed CT cost assumptions and rejected each of Mr. Burgess's recommendations to increase the avoided CT cost. *Power Advisory Report*, p. 19-20. The Commission finds that Duke has reasonably supported its

use of the F-Frame CT in developing the avoided capacity costs under the peaker methodology. There is simply no basis to conclude that DEC or DEP are planning to construct aero-derivative CTs in the current 15-year planning period. Even if Duke were planning to construct such resources in the future, the Commission agrees with Duke and Power Advisory that the increased costs of constructing aero-derivative CTs would be caused by the intermittency and volatility of solar. It would therefore be inappropriate to pay solar generators based upon the higher capital cost of the aero-derivative CT in order to provide the capabilities needed to manage the operational challenges that intermittent and uncontrolled must take energy would be causing.

The Commission also finds that the record clearly supports Duke's proposed economies of scale adjustment both in terms of Duke's existing fleet as well as Duke's plans to install multiple new CTs in the future.

Finally, the Commission finds that Duke has reasonably included the facilities costs of interconnecting the CT unit to Duke's transmission system, and agrees with Duke and Power Advisory that including significant transmission system network upgrades is inappropriate in setting this generic avoided capacity cost value.

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 17**

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Summary of the Evidence

Witness Horii recommended that DEC correct the allocation of capacity costs to seasons and time of day. According to witness Horii, avoided costs should be calculated based on current conditions, but DEC's analysis reflects solar penetration levels too far into the future to reflect actual system capacity needs in 2020. Tr. p. 525.14, II. 6-16.) While DEC correctly allocates the capacity costs based on the relative Loss of Load Expectation ("LOLE") in each time period, DEC incorrectly uses LOLEs based on an expected 3,500 MW of solar penetration on the DEC system, rather than the current levels of solar penetration of 840 MW. Id. According to witness Horii, 3,500 MW of solar penetration, "Tranche 4" in the analysis nomenclature, is the highest level of solar penetration evaluated and reflects solar penetration levels far in exceedance of current levels. See Tr. 525.14, II. 10-12. Witness Horii testified this was problematic because the timing of the need for capacity when there are 840 MW of solar on the DEC system is not the same as the timing of the need for capacity when there are 3,500 MW of solar on the system; installed solar generation shifts the need for system capacity increasingly away from hours when that solar is generating. Tr. p. 525.1411. 8-21. Witness Horii testified that avoided costs should be calculated based on current conditions. See Tr. p. 528.7, II. 19-20; see also Tr. p. 525.16. Specifically, Act 62 states "[e]ach electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility ...." Witness Horii testified "Tranche 4" represents an amount of future solar that has not yet committed to a contract price for power and that if avoided cost rates are calculated correctly, they would reflect the cost conditions that

exist at the time any contracts are signed. Tr. p. 528.8, II. 2-9. Witness Horii testified overpayment would only occur if one group of solar QFs were paid based on a cost higher than actual avoided cost levels. See Tr. 528.8, II. 8-11.

According to witness Horii, with the higher level of solar generation, the need for system capacity shifts away from hours when the already installed solar is generating until, at some point, the amount and timing of the capacity credits may economically preclude solar from being added --- but that only means that the next tranche of solar is not cost effective. Tr. p. 525.15, II. 21-22. The prior tranches are still providing value via their reduction in their peak that helped shift the new peak to later hours. See Tr. 525.15, I. I top. 525.16, I. 2. Witness Horii testified that when looking at the avoided costs of new QFs in 2020 (the timeframe of the projects affected by the rates decided in these dockets), it is important to reflect cost changes relative to current conditions. Tr. p. 525.16, II. 5-7. Because these avoided capacity costs will be used to calculate compensation for solar in 2020, it is appropriate to use LOLEs that are based on current solar penetration levels. Tr. p. 525.16, II. 7-9.

In his surrebuttal, Mr. Horii updated his recommendation to reflect that the "Existing plus Transition" scenario-which takes into account projects with signed interconnection agreements and PPAs-is the appropriate measure of "current conditions" on the basis that nearly 100% of projects with signed interconnection agreements and PPA's have resulted in completed in-service projects over the past three years. See Tr. p. 528.9, II. 3-7.

Witness Horii also testified that DEP incorrectly allocated the seasonal and time of day capacity allocation factors. See Tr. p. 525.17, I. 16 top. 525.18, I. 12. According to witness Horii, correcting the seasonal and time of day capacity allocation factors for DEP to reflect the "Existing plus Transition"" amount of solar penetration instead of the overly high "Tranche 4" results in a very small change in the capacity allocation factors. Tr. p. 525.18, II. 5-7. The summer peak allocation would change from DEP's proposed 0% to 1%, and the winter morning peak share would drop from 70% to 69%. Tr. p. 525.18, II. 8-9. The winter evening on-peak allocation would remain the same. See Tr. p. 525.17, I. 16 top. 525.18, I. 12. Witness Snider testified Duke used the "Tranche 4" level of solar identified in the Astrape Solar Capacity Value study to determine the seasonal allocation factors used in this case. Tr. p. 630.58, II. 6-15. According to witness Snider, at the time the Solar Capacity Value study was conducted, the Companies' projection of total solar mandated by N.C. HB 589[25] and solar included in Act 236 corresponded to the "Tranche 4" level of solar in the study, which reflected 3,500 MW of cumulative solar for DEC and 3,585 MW for DEP. Tr. p. 630.59, II. 18- 21. While the exact timing and amounts of transition and incremental solar additions may change over time, the Companies assert that it is reasonable to assume the cumulative mandated levels of solar

[25] North Carolina Session Law 2017-192, House Bill 589 ("N.C. HB 589") established the Competitive Procurement of Renewable Energy ("CPRE") Program solicitation process, which calls for the addition of 2,660 MW of competitively procured renewable resources across the Duke Energy Balancing Authority Areas over a 45-month period. Tr. p. 630.59, II. 6- 10. The total CPRE target of 2,660 MW via competitive solicitations will vary based on the amount of "Transition" MW at the end of the 45-month period, which N.C. HB 589 expected to total 3,500 MW. Tr. p. 630.59, II. 10-12. If the aggregate capacity of the Transition MW exceeds 3,500 MW, the competitive procurement volume of 2,660 MW will be reduced by the excess amount. Tr. p. 630.59, II. 13-14. N.C. HB 589 also allows for up to 600 MW of renewable energy procurement programs for large customers such as military installations and universities, as well as a community solar program. Tr. p. 630.59, II. 14-17.

under Tranche 4 for purposes of calculating the Standard Offer avoided cost rates. Tr. p. 630.59, II. 21-23, p. 630.60, II. 1-2. According to witness Snider, on July 10, 2018, Duke issued a request for bids for the first Tranche of CPRE, requesting 600 MW in DEC and 80 MW in DEP. Tr. p. 630.60, 11. 4-5. Of the total number of projects selected by the independent administrator, a total of 13 projects signed PPAs. Tr. p. 630.60, 11. 5-6. Ten of the projects will be located in North Carolina and three projects will be located in South Carolina. Tr. p. 630.60, 11. 6-8. As explained by Duke Witness George Brown, the Companies plan to issue a request for bids for the second Tranche of CPRE (680 MW) in October 2019 to be constructed by 2023. Tr. p. 630.60, 11. 8-10; see also Tr. p. 621.17, I. 19 top. 621.18, 1. 1.

SCSBA Witness Burgess argued that the Companies' seasonal allocation of capacity value was "incorrect and "biased against solar QFs" and Mr. Burgess instead contended that the Companies should shift capacity payment hours from Winter AM to Summer PM hours. In support of his claim, Mr. Burgess criticized some of the assumptions in the Solar Capacity Value Study including the underlying load forecasts, differences in the availability of demand response in winter and summer months, and characterization of neighboring utility capacity support. Mr. Burgess also listed seasonal variations in assumptions for forced outage rates and planned maintenance as a biased assumption, but failed to expand on his concerns with that issue. (Tr. Vol. 1, p. 382.49-54.)

Specific to the Companies' underlying load forecasts, SCSBA Witness Burgess argued that the Solar Capacity Value study does not properly take into consideration how

load and the resulting allocations might shift over time. In regard to the Companies' demand response programs, SCSBA witness Burgess argued that Duke incorrectly assumes only half of the demand response resources available in summer are available in winter. Although, he stated that "this may be a reasonable assumption based on current demand response contracts and availability, a more concerted effort by Duke to target and mitigate extreme winter peak events could shift the balance of these resources towards winter and the resulting seasonal allocation towards summer." (Tr. Vol. 1, p. 382.49.) He further stated that he could not determine the hypothetical impact additional winter demand response resources would have on the seasonal allocation results by arguing that Duke did not provide him the necessary information to fully evaluate his hypothetical alternative demand response scenario. (Tr. Vol. 1, p. 382.50.) In regard to utility "neighbor" assistance, Witness Burgess argued that DEC and DEP are neighbors to several summer peaking utilities that may have available resources to contribute to winter peaking needs, and that greater summer capacity allocation may be artificially limited in Duke's modeling due to assumed transmission constraints. Last, SCSBA Witness Burgess argued that, based upon his review of historical load data for DEC and DEP, the seasonal allocations do not make sense. He therefore recommended a different seasonal allocation from Duke's proposal, specifically that DEP's seasonal allocation reflect a 77% summer and 23% winter allocation, and DEC's seasonal allocation reflect a 82% summer and 18% winter seasonal allocation. (Tr. Vol. 1, p. 382.51-52.)

SACE/CCL Witness Wilson's testimony provided general critique of the Companies' 2016 Resource Adequacy study and 2018 Solar Capacity Value study,

documented in Exhibit B to his testimony. He argued that his Exhibit B shows that the risk of very high loads under extreme cold was significantly overstated in the 2016 Resource Adequacy study, primarily due to what he considered to be the faulty approach Astrapé Consulting used to extrapolate the relationship between temperature and load to very low temperatures. He argued that winter resource adequacy risk was also overstated due to the demand response and operating reserve assumptions applicable to winter peak conditions. Moreover, he argued that both winter and summer risk were further overstated due to the economic load forecast uncertainty assumptions, which greatly overstate the risk of large and unexpected increases in peak load. He also contended that the Companies' approach to estimating seasonal, monthly and hourly resource adequacy risk, seasonal capacity values of solar resources, and recommended reserve margins will be highly sensitive to various assumptions that can change dramatically over just a few years. SACE/CCL Witness Wilson recommended that the Companies' seasonal allocation be rejected, but failed to propose any alternative seasonal allocations. (Tr. Vol. 2, p. 495.1-7.)

In response to SCSBA's first argument that the Companies should shift capacity payment hours from Winter AM to Summer PM, Duke Witness Snider testified that such a shift in capacity payment hours would unfairly benefit solar QFs at the expense of the Companies' customers and be in violation of PURPA's indifference principle. Witness Snider then rejected SCSBA Witness Burgess's claims regarding the reasonableness of the Companies' Solar Capacity Value study, explaining first, in regard to load forecasts, that the Companies' best estimate of the value of incremental QF solar capacity is

reflected and validated by the Solar Capacity Value study's results. Mr. Burgess's argument, on the other hand, requests the Companies to make arbitrary assumptions of potential future changes to seasonal capacity needs in order to benefit solar QFs, which would additionally send improper price signals to QFs regarding the timing and need for QF capacity and energy. Mr. Snider testified that accepting Mr. Burgess's proposal would be both unreasonable and inappropriate. (Tr. Vol. 2, p. 630.64-73.)

Regarding SCSBA Witness Burgess's arguments concerning the Companies' demand response programs, Witness Snider first explained that the study requested by Mr. Burgess was for the Companies to run a hypothetical scenario assuming winter demand response had somehow increased to the same level as summer demand response, which is simply not the case. Duke therefore declined to run the hypothetical assumption assuming untrue facts regarding the Companies' demand response program capabilities. In support of this assertion, Witness Snider explained that Duke's actual program experience has evidenced that winter residential demand response program "potential" is more difficult to achieve than summer potential and listed several specific reasons. For instance, most winter demand response programs require in-home customer appointments, whereas summer demand response programs do not. He therefore concluded that it is not appropriate to pre-assume an unreasonable amount of winter demand response can be achieved, as advocated for by SCSBA, or hypothetical winter demand response impact on avoided cost rates at this point in time. For the same above-explained reasons, Witness Snider also rejected SACE/CCL Witness Wilson's similar critique of the Companies' winter demand response. (Tr. Vol. 2, p. 630.69-73.)

Duke Witness Snider also responded to SCSBA's criticisms regarding neighbor assistance, stating that these critiques were inaccurate and explaining that the Solar Capacity Value study included comprehensive modeling of the load, resources, and transmission capability of neighboring utilities. Last, he responded to SCSBA's arguments related to Mr. Burgess's review of historical load data for DEC and DEP. Although SCSBA had not yet responded to a data request requesting Mr. Burgess' exact calculations, Witness Snider testified that he most likely failed to account for the impact of must-take solar output in his analysis, and incorrectly included an extremely broad number of hours. Therefore, he believed SCSBA Witness Burgess's review of the data was incorrect. In sum, Mr. Snider rebutted SCSBA's critiques of the Companies' seasonal allocation and rejected their alternative, and incorrectly calculated seasonal allocation. (Tr. Vol. 2, p. 630.72-73.)

In response to SACE/CCL Witness Wilson, Duke Witness Snider testified first, that Witness Wilson's testimony relied heavily upon his past assessment of the Companies' 2016 Resource Adequacy study and 2018 Solar Capacity Value study. He explained that since 2016, the Companies, Astrapé, and the NC Public Staff have worked to resolve outstanding concerns related to the 2016 Resource Adequacy study. Specifically, Witness Snider testified that concerns related to the correlation of load and extreme cold temperatures were already previously resolved with the NC Public Staff. Regarding SACE/CCL Witness Wilson's concerns with the Companies' operating reserves assumption, Witness Snider testified that Mr. Wilson was incorrect in his assertion and that Duke had already previously demonstrated that Mr. Wilson's assertion

was incorrect in several North Carolina proceedings. He further testified that adopting Wilson's recommendations related to economic load forecast would only serve to lower the reserve margin requirement but would not have any impact on the allocation of LOLE or the Companies' rate design. If anything, a lower reserve margin could push out the date of the first capacity need for each utility, an outcome that would increase reliability risk and reduce capacity payments for QFs. Last, Witness Snider disagreed with Mr. Wilson's conclusion that the Companies should strive for price signals that are likely to remain reasonably stable as conditions change. In conclusion, Mr. Snider noted that Mr. Wilson had not proposed an alternative seasonal allocation, and recommended the Commission reject his critiques regarding the Companies' proposal. (Tr. Vol. 2, p. 630.70-79.)

SCSBA Witness Burgess's surrebuttal testimony stated that he agreed with Duke's critiques of his initial historical load analysis included in his rebuttal testimony, though with qualifications. He stated that to address the issues in his analysis identified by Duke, he would first update his analysis to reflect net load (rather than just load) by adjusting the historical load profiles to account for must-take solar output. To address the second issue—that he incorrectly included an extremely broad number of hours by using the top 5% of load hours—he testified that he adjusted the number of hours in his seasonal allocation proposal to reflect a narrower band of top load hours. Mr. Burgess then proposed a new seasonal allocation based upon an updated historical load analysis integrating the two aforementioned changes. His updated seasonal allocation proposed a 58% summer and 42% winter allocation for DEC and a 4% summer and 96% winter

allocation for DEP. In addition, he argued that Duke should provide SCSBA a hypothetical analysis assuming Duke's winter demand response was higher, stating that the purpose of this hypothetical analysis is simply intended as a sensitivity case to see what the effect would be on the Companies' seasonal allocation. (Tr. Vol. 2, p. 782.22-24.)

Commission Determination

We agree with ORS witness Horii that avoided costs should be calculated based on current conditions. Witness Horii testified 'Tranche 4" represents an amount of future solar that is not yet committed to a contract price for power and that if avoided cost rates are calculated correctly, they would reflect the cost conditions that exist at the time any contracts are signed. The "Existing plus Transition" scenario appropriately accounts for "current conditions." See Tr. 528.9, 11. 1-12. In contrast, the projected solar generation that the Companies ask us to rely on has neither signed contracts nor fixed prices. See Tr. p. 528.9, I. 7-12. Act 62 states "[e]ach electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility ...." Mr. Horii's proposal to rely on "current conditions" for the purpose of estimating the seasonal capacity value of the next group of solar resources accomplishes this objective. Further, this Commission is prohibited from making a decision based on speculation or surmise. The Companies' recommendation would require us to venture down this path. This Commission cannot make a decision based on an assumption that unreasonably deflates the value of avoided cost. As a result, the Commission finds the preponderance

of the evidence in the record supports a finding consistent with ORS witness Horii's position on this issue and his position is just and reasonable.

**G. Solar Integration Services Charge**

**EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-22**

The evidence in support of these findings of fact are found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Summary of the Evidence

ORS's Position:

Witness Horii testified that integrating renewable generation creates additional costs for utilities. Tr. p. 525.18 - p. 525.19. According to witness Horii, E3 conducted extensive work in California and Hawaii where renewable generation comprises a large portion of generation resources. Tr. p. 525.19. In its modeling, E3 has seen that increasing amounts of solar and wind generation can require additional ramping capability and reserves to meet both the intermittent nature of solar and wind generation and the diurnal ramping characteristics of solar generation. Tr. p. 525.19. The cost impact can include higher start-up costs, fuel costs, and O&M costs resulting from resources operating at levels below their maximum efficiency to allow upward headroom to ramp up output. Costs can also increase for additional generation plants required to provide additional flexible capacity. Tr. p. 525.19. ORS Witness Horii testified he believed the Companies' analysis to be an acceptable approach to estimating the solar integration costs. Tr. p. 525.19. However, witness Horii did have two observations about

the Companies' analysis that he shared with the Commission: 1) the results of the Study may indicate higher solar integration costs than would be required if the Companies sought to minimize those integration costs; and 2) the Companies' proposal to use average integration costs that update annually. Tr. p. 525.19. According to witness Horii, integration costs could potentially be reduced in the following ways: 1) if additional operating reserve requirements were dynamically linked to solar output levels and the varying risk of solar output reductions; 2) employing improved solar output forecast methods to reduce the forecast error between expected and actual solar output; and 3) employing pre-curtailment of solar to reduce the cost to address solar over forecast error. Tr. p. 525.20.

Regarding the Companies' proposal to use average integration services charge instead of actual integration services charge, witness Horii testified that this practice would dampen the price signal and socialize the higher cost over both new and existing solar resources. Tr. p. 525.22. According to witness Horii, this would encourage the over-installation of solar beyond 2020 because the new solar entering the market would be subsidized by existing solar and would not be subject to the full cost of integrating onto the Companies' electric systems. Tr. p. 525.22.

Witness Horii recommended the Companies' solar integration services charges of $1.10/MWh for DEC and $2.39/MWh for DEP be approved, but these charges be adopted as upper limits for solar integration service charges for contracts signed under the Standard Offers proposed by the Companies. Tr. p. 525.23. Additionally, witness Horii recommended the Companies should conduct additional integration studies, and if

lower incremental integration services charges were to be adopted for future offers, the integration services charges for this vintage of Standard Offer contracts be updated to reflect those lower values starting with the effective date of the new offers. Tr. p. 525.23. According to witness Horii, the Companies should be required to update their analysis for future changes to their Standard Offers after conducting technical workshops where Duke receives input from the solar community and other stakeholders. Tr. p. 525.24. Witness Horii recommended areas of agreement and disagreement be documented in a formal stakeholder process report to be submitted to the Commission along with the integration study. Tr. p. 525.24.

DEC's and DEP's Position:

According to witness Snider, Act 62 requires Duke to account for costs avoided or incurred

by the utility, including ancillary service costs provided by or consumed by small power producers such as solar QFs. Tr. p. 55. It explains how the companies require additional ancillary services due to the integration of intermittent solar QF power, and as such, have proposed a solar integration service charge to appropriately assign cost to solar generators. Tr. p. 55. Witness Snider also introduces the Astrape study relied upon to calculate the level of additional ancillary requirements and the cost of these additional ancillaries. Tr. p. 55. According to witness Snider, if the costs of additional ancillary requirements are not ascribed to the QF, then customers would unfairly be obligated to pay these increased costs through the fuel clause. Tr. p. 56. Additionally, witness Snider

testified that the companies will directly pass through savings from QFs paying the integration charge to customers in future fuel proceedings. Tr. p. 56.

Regarding the Agreement, witness Snider testified the Companies support the terms of the stipulation, and he believes the stipulation represents a fair, reasonable, and full resolution of all the issues in this proceeding regarding the integration services charge. Tr. p. 56, II. 19-23. Witness Snider also testified that his testimony should not be construed as advocating any position that is contrary to the terms of the stipulation. Tr. p. 56 - 57. According to witness Wintermantel, who works with Astrape Consulting, Astrape was retained by Duke in late 2017 to analyze and quantify the ancillary service impact of integrating existing and future solar generation for the companies. Tr. p. 300. This study was concluded in the fall of 2018 and is being relied upon by Duke witness Glen Snider to support the integration services charge presented in the companies' avoided cost filing. Tr. p. 300.

The main premise of the ancillary service study is to assess the integration cost impact of adding different penetrations of solar generation while ensuring that system reliability is the same before and after the additional solar is added. Tr. p. 33, 11. 24-25, p. 301. The study determines the amount of load following reserves that are required to maintain the same level of reliability when adding various amounts of solar penetration and then also calculates the cost of these additional reserves to develop the integration charge. Tr. p. 301. According to witness Winteremantel's testimony, Duke supports the terms of the Agreement. Tr. p. 299, l. 7. He believes the Agreement represents a fair, reasonable, and full resolution of all issues in this proceeding regarding the integration

services charge. Tr. p. 299, 11. 8-11. Witness Wintermantel also testified that his testimony should not be construed as advocating for any position that is contrary to the terms of the Agreement. Tr. p. 299, 11. 11-13. According to witness Wintermantel, the Agreement adopts the results of the Astrape study for the existing plus transition solar penetration level for DEC and DEP. Tr. p. 299, 11. 17-19. At the existing plus transition solar penetration level for DEC, the study showed that an additional 26 megawatts of load following reserves were required to integrate 840 megawatts of solar. Tr. p. 299, 11. 20-24. The cost of these 26 megawatts of load following reserves translates into an ancillary service cost impact of $1.10 per megawatt-hour. Tr. p. 299, 11. 24-25, p. 300, 1-2. For DEP, the study identified that 166 megawatts of additional load following reserves were required in order to integrate 2,950 megawatts of solar generation. Tr. p. 300, 11. 3-6. For DEP, this resulted in an ancillary service cost impact of $2.39 per megawatt-hour. Tr. p. 300, 11. 6-8.

Company witness Wheeler testified that Duke supports the terms of the stipulation, and that he believes the stipulation represents a fair, reasonable, and full resolution of all issues in this proceeding regarding the integration services charge. Tr. p. 258, 11. 14-18. Additionally, witness Wheeler testified that his testimony should not be construed as advocating any position that is contrary to the terms of the stipulation. Tr. p. 258, II. 18-21.

SACE/CCL's Position

Brendan Kirby, a Licensed Professional Engineer with a BS in electrical engineering from Lehigh University and an MS in electrical engineering, power option,

from Carnegie-Mellon University, testified on behalf of CCL and SACE. Tr. p. 457, II. 3-7. Witness Kirby commented on Duke Energy's proposed SISC and the ancillary services study, prepared by Astrape Consulting in support of the SISC. Tr. p. 458, IL 7-11. Specifically, his testimony critiqued aspects of the ancillary service-study methodology and discussed how certain assumptions and mythological choices in the study led to the cost of solar integration being overstated. Tr. p. 458, II. 11-15. Witness Kirby also testified that SACE and CCL support the terms of the settlement stipulation and believe it represents a fair and reasonable and full resolution of all issues in this proceeding regarding the SISC. Tr. p. 458, IL 18-21. Furthermore, witness Kirby testified that his testimony should not be construed as advocating for a position that is contrary to the terms of the stipulation at this time. Tr. p. 458, IL 21-24.

Finally, witness Kirby testified that he supported an independent technical review of the integration charge methodology as set forth in the stipulation. Tr. p. 458, I. 25, p. 459, II. 1-2.

SBA's Position

Ed Burgess, Senior Director at Strategen Consulting, testified on behalf of SBA. Tr. p. 373, I. 16. In witness Burgess' direct testimony he testified to a number of concerns he had with the Companies' SISC including: 1) his belief that it is premature to impose the SISC on solar QFs until the true costs of integration can be more accurately quantified through an independent analysis as contemplated by Act 62; his contention that the analytical model used by Duke contained fundamental flaws; the lack of evidence in South Carolina that the integration costs projected by Duke will materialize

soon; his contention that the Companies' proposal was one-sided and incomplete; and his concern that the form of the SISC model was linked to a hypothetical model, rather than real-world costs. Tr. p. 382.70, IL 10-18, p. 382.71, IL 1-9.

However, subsequent to the filing of the Agreement, witness Burgess testified that the SBA supports the terms of the Agreement, and he believes the Agreement represents a fair and reasonable resolution of all issues in this proceeding regarding the SISC. Tr. p. 378, II. 7-11. Additionally, he testified that his testimony should not be construed as advocating for any position that is contrary to the terms of the stipulation. Tr. p. 378, II. 12-14.

Partial Settlement Agreement

On October 21, 2019, an Agreement that purports to resolve issues related to the Companies' SISC was filed with the Commission. The signatories to the Agreement were: the Companies, SBA, SACE/CCL, and JDA. ORS did not object to the Agreement. According to the Agreement, the

> ... solar integration services charges (SISC) of $1.10/MWh (DEC) and $2.39/MWh (DEP) are reasonable, for purposes of this proceeding, for solar small power producers that enter into a PPA or establish a Legally Enforceable Obligation prior to the effective date of avoided cost calculations and methodologies filed in the next DEC/DEP avoided cost proceeding conducted by the SC Public Service Commission.

Additionally,

> The Astrape Study used to calculate the SISC presents novel and complex issues that warrant further consideration. Duke shall submit the study methodology and inputs to an independent technical review and include the results of that review and any revisions in its initial filing in the next avoided cost proceeding. To the maximum extent practicable the independent review of the study methodology shall take into consideration the South Carolina Integration Study called for by S.C. Code Ann. § 58-

> 37-60. This process shall be subject to Commission oversight and comment from interested stakeholders.

No party objected to the introduction of the Agreement.

Commission Determination

In enacting Act 62, the South Carolina General Assembly directed this Commission to consider ancillary services avoided or incurred by the electrical utility in the methodology used in establishing avoided cost rates. *See* Section 58-41-20(B)(3). Duke's Joint Application presented the Integration Services Charge as responsive to Act 62's directives and as necessary and appropriate to recognize the costs that Duke is now incurring to integrate solar generators into the DEC and DEP Balancing Authorities and to more accurately and appropriately value the energy and capacity provided by solar QFs eligible for Schedule PP. ORS Witness Horii provided similar testimony based upon his experience that utilities in other parts of the country are incurring increased additional ancillary services costs due to the integration of intermittent solar resources. The Commission finds the testimony provided by Duke Witnesses Snider and Wintermantel, as well as the results of the Astrapé Ancillary Services Study and Mr. Horii's testimony, provide persuasive evidence that Duke is incurring increased ancillary services costs to integrate increasing penetrations of intermittent "must-take" solar QFs. Therefore, as an initial matter, the Commission finds and concludes that establishing a solar Integration Services Charge is necessary and appropriate under the directives of Act 62 and in order to accurately quantify the costs being avoided by purchasing power from solar generators being installed on the DEC and DEP systems.

Turning to the quantification and application of an integration services charge, the Commission gives substantial weight to the testimony of SCSBA, SACE/CCL and Duke witnesses regarding the issues addressed in the SISC Settlement, which generally supports Duke's initial proposal to establish the Integration Services Charge as outlined in Duke's Joint Application. Specifically, the SISC Settlement supports applying a SISC of $1.10/MWh in DEC and $2.39/MWh in DEP as reasonable for solar small power producers that enter into a PPA or establish a Legally Enforceable Obligation prior to the effective date of avoided cost calculations and methodologies filed in the Companies' next avoided cost proceeding. The SISC Settlement further provides that these charges should not be subject to adjustment during the PPA, and that the SISC will only apply on a prospective basis, thereby balancing the interest of solar generator owners and customers. In this regard, the Commission gives substantial weight to ORS's non-objection to the SISC Settlement entered into between the Settling Parties resolving the otherwise-controverted issue of integration costs in these proceedings.

The SISC Settlement also provides that Duke cannot impose the SISC on a solar QF that is a "controlled solar generator," and that Duke must file with the Commission by November 18, 2019, for review and comment, proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the SISC. The Commission finds these provisions reasonable.

In addition, the Commission finds the provision that Duke shall submit the study methodology and inputs to an independent technical review and include the results of that review and any revisions in its initial filing in the next avoided cost proceeding

reasonable, and finds that this provision appropriately addresses concerns raised by Mr. Horii regarding updating the integration charges.

The Commission concludes that the SISC Settlement is the product of the "give-and-take" of settlement negotiations between Duke, SCSBA and SACE/CCL in an effort to appropriately balance the Settling Parties' interests in reasonably and accurately quantifying the increased ancillary services costs being incurred by Duke and customers as a result of the growing solar generation being installed on the DEC and DEP systems. The Commission also recognizes Power Advisory's findings that this Settlement presents a reasonable accommodation among the parties regarding the contentious issues surrounding variable resource integration charges. *Power Advisory Report*, at 30. Further, as stated by Duke during the hearing, the terms of the SISC Settlement are also consistent with the NC Utilities Commission's *October 17, 2019 Supplemental Notice of Decision*, and which this Commission has taken judicial notice of such Decision in these proceedings. (Tr. Vol. 1, p. 10-11, 15.) The Commission finds that the SISC Settlement strikes a fair balance between the interests of the Companies, the solar generators that will be subject to the Integration Services Charge and customers. The Commission has fully evaluated the provisions of the SISC Settlement and concludes, in the exercise of its independent judgment that the provisions of the SISC Settlement are just and reasonable to all parties to this proceeding in light of the evidence presented and serve the public interest. The Commission also finds that Duke has adhered to Act 62's directives in establishing the solar Integration Services Charge as described in the SISC Settlement. Based upon the foregoing and entire evidence in this proceeding, the Commission hereby

approves the terms of SISC Settlement and application of solar Integration Services Charge to Schedule PP as defined therein.

**H. Standard Offer**

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 23-25**

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Act 62 establishes that the Commission shall approve a Standard Offer tariff and support terms and conditions to be available to small power producer QFs that are 2 MW or smaller. S.C. Code Ann. § 58-41-20(A), S.C. Code Ann. § 8-41-10(15). Act 62 requires that power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by FERC implementing PURPA. S.C. Code Ann. § 58-41-20(B)(2).

Summary of the Evidence

The Companies propose for Commission approval the Companies' Standard Offer, which includes the Companies' respective Schedule PP (SC) Purchased Power tariffs ("Standard Offer Tariff" or "Schedule PP"), Terms and Conditions for the Purchase of Electric Power ("Standard Offer Terms and Conditions" or "Terms and Conditions"), and Standard Offer power purchase agreement ("Standard Offer PPA") available to all qualifying cogenerators and small power production QFs up to 2 MW in size. These documents memorialize the contractual relationship between the Companies and smaller QFs up to 2 MW selling power to the Companies under the Standard Offer.

The Commission most recently approved the Companies' Standard Offer contracting documents in Order No. 2016-349, issued on May 12, 2016.

Standard Offer Tariff

As described by Witness Wheeler, the Standard Offer Tariff sets forth the Companies' avoided cost rates and contract terms available to Standard Offer QFs desiring to sell energy and capacity to DEC and DEP under PURPA. (Tr. Vol. 1, p. 260.7.) The Companies' Standard Offer Tariffs provide eligible QFs with variable, 5-year, and 10-year, fixed term options. Witness Wheeler testified that the effective date of the Standard Offer Tariff should be November 30, 2018, because this is the date on which the previously-effective Standard Offer Tariff expired. (Tr. Vol. 1, p. 260.9.) Witness Wheeler explained that establishing the effective date any later date than November 30, 2018, would result in the absence of long-term fixed avoided cost rate credits pursuant to which new Standard Offer QFs could sell power to the Companies pursuant to PURPA as of November 30, 2018. (Tr. Vol. 1, p. 260.9.)

Standard Offer PPA: Standard Offer Terms and Conditions

The Standard Offer PPA is the pro forma PPA that the Companies use to contract with QFs eligible for the Standard Offer for the purchase of energy and capacity under PURPA. The Terms and Conditions are incorporated into the Standard Offer PPA by reference (see Section 2 of the PPA) and set forth the contractual obligations of both the QF and the Companies as necessary to administer Schedule PP and the Standard Offer PPA in a fair and consistent manner.

As Witness Wheeler testified at the evidentiary hearing, of the issues originally in contention between the Companies and SBA with regard to the Standard Offer PPA and Terms and Conditions, only several issues remained unresolved as of the date of the hearing. (Tr. Vol. 1, p. 257-258.)

SBA Witness Levitas agreed to Duke's provisions in the Standard Offer PPA and Standard Offer Terms and Conditions that address when a QF Seller can make modifications to a Standard Offer QF project selling power to the Companies but believes that those revisions to the Standard Offer PPA and Standard Offer Terms and Conditions should only be applied on a going-forward basis. Witness Wheeler addressed this issue at the hearing, explaining that such an interpretation would contradict longstanding existing language in the rate update section of Schedule PP in Provision 1(b) of the Terms and Conditions. (Tr. Vol. 1, p. 267.) However, regarding prospective application, Levitas opined that contractual relationships must continue to be governed by the PPAs and terms and conditions that are currently in place. (Tr. Vol. 1, p. 324.12) Even so, Levitas noted that Duke would not be precluded from taking a position as to what the current language of those existing PPAs provides or how it should be interpreted. (Tr. Vol. 1, p. 324.12 – 324.13.)

Commission Determination

Standard Offer Tariff

As explained below, the Commission adopts the Standard Offer Tariff proposed by the Companies in Witness Wheeler Direct DEC Exhibit 2 and Witness Wheeler Direct DEP Exhibit 2, with the revised Storage Protocols, as agreed to by SBA and the

Companies, with modifications as proposed by SBA witness Levitas and Power Advisory. The Commission finds that the Standard Offer Tariff as modified is commercially reasonable and consistent with regulations and orders promulgated by FERC implementing PURPA, as required by Act 62.

The first provision remaining unresolved is the requirement for a QF to begin delivering power within 30 months from the date of the order approving the Tariff (and which may be extended under limited circumstances set forth in the Tariff). Witness Wheeler's testimony explained that this provision was added to both the Standard Offer PPA and Standard Offer Tariff in 2016 to require QFs to complete construction and begin delivery of generation in a timely manner. (Tr. Vol. 1, p. 262.10.) Witness Wheeler explained that without this requirement, a QF can enter into a Standard Offer PPA and wait an indefinite period of time before beginning to sell power to the Companies, and that this would hypothetically allow a QF to enter into a Standard Offer PPA in 2019 and begin selling its output to the Companies in 2025, for a period ending in 2035, at rates set in 2019. (Tr. Vol. 1, p. 262.10.)

However, in hearing testimony, Mr. Levitas states:

> For the standard offer, in my direct testimony, as you heard earlier, I recommended removing the requirement in the Duke proposed PPA that a QF be placed in service within 30 months of the Commission's approval of the standard offer tariff. In my surrebuttal testimony, I state that SBA doesn't object to this outside in-service date provided it is linked to the interconnection facilities and network upgrades in-service date, as Duke has agreed to with respect to Large QF PPAs. So there's a COD deadline under contract that is extended based on interconnection delays. I'm suggesting the same thing apply with respect to the Standard Offer PPA.

(Tr. Vol. 1, p. 318.) The Commission also acknowledges Power Advisory's opinion that QFs should be provided extensions on their in-service date for any delays associated with interconnection facilities and network upgrades. Power Advisory Report states at p. 45-46 of its Report:

> Customers need reasonable protections to avoid "stale" rates and completion of the project in a timely manner. However, Mr. Wheeler does not address Mr. Levitas' issue of the lengthy interconnection process. Since the in-service date of the interconnection facilities and network upgrades for the QF is out of the QF's hands, it's only fair that the QF be given day-for-day extensions on its in-service date for any delays attributable to the in-service date of these interconnection facilities. Duke has already agreed to this for the Large QF PPA. There is no reason why this shouldn't also be the case for the Standard Offer and Duke itself offers no reason. In fact, Mr. Brown of Duke acknowledges in hearing testimony that the QF should not be responsible for delays in interconnection:
>
> Q. So who bears the risk that the project will fall behind schedule, the QF or the ratepayer?
>
> A (BROWN) Generally speaking, I would say -- it depends if it's because of something that the utility is doing on our side, we're unable to connect it, I would say the QF is not responsible for that.

Currently, Duke provides extensions to the QF if the QF's construction is nearly complete and they demonstrate good faith effort to completing their project in a timely manner but does not address the issue of completing their own network upgrade construction in a timely fashion. Accordingly, we believe that the better practice is to adopt the 30-month in-service date following avoided cost rate approval, but to link that period to the interconnection facilities and network in-service date. We would note that Duke has agreed to this provision with respect to Large QF PPAs. We agree with Power Advisory that since the in-service date of the interconnection facilities and network

upgrades for the QF is out of the QF's hands, it's only fair that the QF be given day-for-day extensions on its in-service date for any delays attributable to the in-service date of these interconnection facilities. Duke has already agreed to this for the Large QF PPA. There is no reason why this should not also be the case for the Standard Offer and Duke itself offers no reason.

Standard Offer PPA: Standard Offer Terms and Conditions

The Commission finds the Standard Offer PPA and Standard Offer Terms and Conditions, as described in Witness Wheeler's rebuttal testimony, as modified by the testimony of witness Levitas and the Power Advisory Report are commercially reasonable and consistent with regulations and orders promulgated by FERC implementing PURPA, as required by Act 62. The Commission agrees with Witness Wheeler that changes to the Standard Offer Tariff and Terms and Conditions, with the exception of changes to the levelized rates, have historically applied retroactively to QFs with existing PPAs. However, the Commission acknowledges and finds credible Power Advisory's opinion that changing contract terms retroactively can be problematic in ensuring lender and developer certainty. We believe that lender and developer certainty must prevail over historic retroactive application of changes to the Standard Offer Tariff and Terms and Conditions. Accordingly, such changes shall apply prospectively only.

Further, with regard to "material alterations," witness Levitas testified as follows:

> In the interest of further narrowing the matters in dispute in this proceeding, and as part of a comprehensive resolution of issues relating to the PPAs and the NOC form, SCSBA is willing to accept Duke's position on these issues subject to two modifications. First Duke's Terms and Conditions need to provide that Duke's consent to requested material

> alterations will not be unreasonably withheld, conditioned or delayed. Duke has agreed to a similar condition in its Large QF PPAs.

(Tr. Vol. 1, pp. 11-12.) The other modification is prospective application of changes, as discussed above.

**I. In addition to approving prospective application of changes, we also approve the principle that Duke's consent to material alterations will not be unreasonably withheld, conditioned or delayed. To hold otherwise would interfere with the party's ability to fairly negotiate changes in PPAs. Duke has already agreed to a similar condition in its Large QF PPAs. We agree that the provision is also reasonably applied to Standard Offer PPAs. Large QF PPA**

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 26-29**

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

Summary of the Evidence

The Large QF PPA is the standard form PPA that the Companies propose to use to contract with small power producer QFs greater than 2 MW in size and not eligible for the Standard Offer ("Large QF") that commit to sell and deliver energy and capacity to the Companies. The Commission's authority to review and approve the terms and conditions of contracts between QFs and electric utilities is not new. *See* S.C. Code Ann. § 58-3-140 and S.C. Code Ann. Regs. 103-303. However, Act 62 now expressly requires the Commission to review and approve one or more standard form PPAs for use by small

power production facilities not eligible for the Standard Offer. S.C. Code Ann. § 58-41-20(A). The Act provides that such form PPAs should not be determinative of the avoided cost price and length (or "term") of the power purchase agreement but requires utilities' form PPAs to contain certain commercial terms and conditions, including, but not limited to, provisions addressing force majeure, indemnification, choice of venue, and confidentiality. *Id.* Consistent with PURPA, Act 62 also provides utilities and QFs the freedom to enter into PPAs with terms that differ from the Commission-approved form PPA. *See* S.C. Code Ann. § 58-41-20(A) (such PPAs must be filed with the Commission pursuant to S.C. Code Ann. § 58-41-20(D)). Act 62 also generally requires that all PPAs be commercially reasonable and consistent with regulations and orders promulgated by FERC implementing PURPA. S.C. Code Ann. § 58-41-20(B)(2).

Duke Witness Johnson testified that the proposed Large QF PPA is a comprehensive power purchase agreement providing for the exclusive purchase and sale of 100% of the output of energy and capacity from a QF facility on a fixed price, fixed term basis. (Tr. Vol. 1, p. 282.24.) Further, he stated, the PPA is substantially similar to the form of PPA that the Companies have used to contract with large QF facilities (including numerous large solar QF facilities) over the past several years. *Id.*

ORS Witnesses Horii testified that the Companies' Large QF PPA is commercially reasonable and conforms to applicable PURPA and FERC guidelines. (Tr. Vol. 2, p. 525.26.) SBA Witness Levitas identified several areas of concern with the Large QF PPA in his direct testimony; however, Duke witness Johnson testified at the

evidentiary hearing that only a few of the issues originally in contention between the Companies and SBA were unresolved as of the date of the hearing. (Tr. Vol. 1, p. 275.)

Methodology for Calculating Liquidated Damages

With regard to the methodology for calculating liquidated damages, at the evidentiary hearing, SBA Witness Levitas testified that SBA was agreeable to accepting the calculation of liquidated damages as proposed in Duke Witness Johnson's rebuttal testimony, which represents a capacity-based calculation of liquidated damages. (Tr. Vol. 1, p. 284.9.) Under this methodology, liquidated damages within the Large QF PPA would be calculated as follows:

> For Facilities with Nameplate Capacity Rating up to 15 MW: the default Liquidated Damages shall be equal to the average annual estimated capacity payment under this Agreement over the Term; for PPAs with Nameplate Capacity > 15 MW the default Liquidated Damages shall be equal to: for the first 15 MW (the average annual estimated capacity payments under this Agreement over the Term) + $10,000 per MW for any nameplate capacity above 15 MW.

(Tr. Vol. 1, p. 284.9)

Alternate Eligibility Criteria for QF Sellers to Enter into PPA

Additionally, an outstanding issue existed as of the date of the hearing with regard to the criteria that QF Sellers must satisfy before entering into the Large QF PPA. In Duke Witness Johnson's rebuttal testimony, in response to certain suggestions by Duke Witness Levitas, the Companies revised the eligibility for the Large QF PPA to require that a QF Seller must have executed and returned a Facilities Study Agreement to the Companies pursuant to the South Carolina Generator Interconnection Procedures ("SCGIP").

(Tr. Vol. 1, pp. 284.11-284.12.) Witness Levitas' testimony advocated for the Companies to adopt an alternate eligibility criteria for QF Sellers in the event that a QF has not received a Facilities Study Agreement within one year of becoming an Interconnection Customer. (Tr. Vol. 1, p. 322.28.) Witness Levitas testified that such protection for QF Sellers is necessary given the Companies' lengthy interconnection process. *Id.* In response, Witness Johnson testified that QF Sellers should not be allowed to enter into a PPA prior to receiving a System Impact Study Report. He explained that the QF would not have any insights into the cost of its required interconnection facilities and system upgrades, and, therefore, would not be to the point in the development process of knowing whether the generating facility is commercially viable or not. (Tr. Vol. 1, p. 284.30.)

In hearing testimony, Mr. Johnson states:

> The issue has to do with when a QF can enter into a PPA. As described in my rebuttal testimony, we believe it is appropriate for a QF to enter into a PPA after it sends a Facilities Study Agreement (FSA) back to the utility. At this point in time, the QF has insight into its interconnection and system upgrade costs and can evaluate the commercial viability of the project. In order to accommodate Witness Levitas' request to create a flexible commercial operation date, adding this provision was also important to Duke to ensure QFs are not prematurely entering into PPAs as a result of this added flexibility. Witness Levitas advocates that a QF should be able to enter into a PPA once it has been an interconnection customer for one year; however, as I describe in my rebuttal testimony, without knowing interconnection costs and an estimate of time frame to achieve COD, the QF facility is not to the point in the development process of knowing whether the generating facility is commercially viable.

(Tr. Vol.

In hearing testimony, Mr. Levitas quotes from his surrebuttal testimony, and points out that Mr. Johnson has not adequately addressed his proposal that the QF be able

to form a LEO or execute a PPA within one year of filing its interconnection request. Otherwise, Mr. Levitas asserts that Duke is in a position to frustrate or control the QF.

Levitas' surrebuttal testimony states:

> …as Witness Johnson observes, deferring LEO/contract formation until the FSA has been signed provides both the developer and the utility with a better sense of project viability and moves the establishment of the contract price to a point closer to commercial operation. However, Witness Johnson fails to recognize the purpose served by my proposal that, in the alternative, the QF be able to form a LEO or execute a PPA within one year of filing its interconnection request if the utility has not completed the System Impact Study (or using Duke's proposal, if it has not yet been presented with a Facilities Study Agreement to execute). In the absence of such an alternative, the utility could potentially control and frustrate the QF's LEO formation, which has been expressly prohibited by FERC and reaffirmed in the NOPR. As I pointed out in my direct testimony, the North Carolina Utilities Commission, with Duke's consent, has adopted exactly this sort of approach. In sum, I am comfortable with Duke's proposed requirement that a signed FSA be a condition of LEO formation or PPA execution, provided that there is an alternative eligibility criterion based on time from the interconnection request. I continue to believe that one year is a reasonable interval given the time frames set forth under the Interconnection Procedures, but if Duke believes the one-year time frame I proposed is unreasonable in some circumstances, SCSBA would be willing to discuss alternatives.

(Tr. Vol. 1, p. 324.10.)

Power Advisory opines that Mr. Johnson has not addressed Mr. Levitas' point that the utility can potentially control or frustrate the QF if the QF has not received a System Impact Study within one year from the time of Interconnection Request, since the QF will not know its interconnection costs, albeit preliminary, before LEO formation. In the extreme case, if Duke were to delay delivery of the System Impact Study (SIS) for an indefinite period, then the QF would never be able to sign a PPA with the knowledge of what its interconnection costs would be. Controlling or frustrating the QF to form a LEO

is prohibited by FERC. Power Advisory agrees that Duke should be required to provide a System Impact Study within a timely manner to the QF from the time of Interconnection Request.

We agree with Power Advisory's reasoning, and adopt Mr. Levitas' point that the requirement that the QF execute and return a Facilities Study Agreement (FSA) in order to sign a PPA should be lifted, if a System Impact Study is not provided to the QF in a timely manner (whether that time frame is one year or a period of time that is mutually agreeable to the buyer and seller). If the SIS is not provided in a timely manner, then the requirement that the QF execute and return a Facilities Study Agreement (FSA) in order to sign a PPA should be lifted.

While Mr. Johnson argues that an FSA is required to demonstrate commercial viability, it is nonetheless more important that the utility not be permitted to control or frustrate QF development through unreasonable delays in interconnection. If Duke were to deliver SISs in a timely manner then this would be a moot point – Duke would achieve its stated goal of only having projects that are commercially viable and the QF community would achieve its stated goal of not being unfairly delayed.

Termination of PPA for Interconnection Costs

Witness Levitas proposed in his surrebuttal testimony that QFs should be able to terminate a PPA without incurring liquidated damages if the costs of interconnection exceed $75,000 per megawatt. In support of his proposal, Witness Levitas stated that many binding contractual relationships include conditions precedent that allow a party to terminate the contract under limited circumstances. He further stated that his

recommended provision is necessary where the utility fails to complete the System Impact Study in a timely fashion, and the QF is allowed to form a LEO or enter into a PPA.

Mr. Levitas provided Direct Testimony as follows:

> I think that the PPA should include a right of Seller to terminate the PPA without liability if the interconnection facilities and network upgrades required for the facility to be interconnected to Duke's system exceed $75,000 per MW per AC. Given the QFs' total lack of control over and visibility into Duke's interconnection costs, and the extremely high interconnection costs that have been quoted to many QFs, it is reasonable to provide this limited off-ramp from the obligations.

(Tr. Vol. 1., p. 322.19.) (Another issue is that significant liquidated damages could also result if a QF terminates a PPA without an approved reason.)

Witness Johnson first asserts in rebuttal testimony that the QF could walk away from its binding commitment with no liability if Levitas' proposal is adopted. (Tr. Vol. 1, p. 284.41.) Second, Johnson states that Levitas gives no basis for his $75,000 MW AC proposal. *Id.* Mr. Levitas agrees that the offramp proposal could be removed if the System Impact Study is completed within one year from the time of the interconnection request. (Tr. Vol. 1, p. 324.5.) This is a longer period than the one provided by this Commission's Interconnection Procedures. *Id.* Witness Levitas further testified that that Dominion has agreed to the provision of allowing the QF to terminate their PPA without penalty if interconnection costs exceed $75,000/MW-AC. (Tr. Vol. 1, p. 324.4.)

Power Advisory asserts that witness Johnson does not address Mr. Levitas' point that the timeliness of the System Impact Study would make the offramp for high interconnection costs a moot point. Experience elsewhere indicates that interconnection

costs tend to increase with higher penetration rates of such resources. The risk to the QF of entering into a PPA and then facing either interconnection costs that make the project unviable or significant liquidated damages because of termination is unreasonable. Power Advisory at 49. As a result, Power Advisory believes that Duke should either: (1) provide the System Impact Study within 1 year of interconnection request (or an amount of time that is mutually agreeable between the buyer and seller) or (2) allow an offramp to the QF. Dominion has accepted the offramp provision. *Id.*

Power Advisory further asserts that Duke maintains a similar stance on this issue as it did for the issue pertaining to the FSA being a requirement for a QF to enter into a PPA. Again, the issue is moot if Duke is able to process System Impact Studies in a timely manner. If Duke can process the SIS in a timely manner, both sides will have achieved their stated goals: Duke's of not wanting to allow QFs the offramp for expensive interconnection costs, and the QF community's of not wanting to enter into a PPA and potentially face interconnection costs that could make a project unviable. Power Advisory at 50.

We agree with the reasoning of Power Advisory. If Duke can process System Impact Studies in a timely manner, then the issue is moot. However, we hold that if Duke does not provide the System Impact Study within one (1) year of an interconnection request (or within an amount of time that is mutually agreeable to the contracting parties), then the QF should be provided with an offramp, allowing it to terminate the PPA without liability if the interconnection facilities and network upgrades required for interconnection exceed $75,000 per MW AC.

Surety Bond as Performance Assurance

The final remaining item with regard to the Large QF PPA is Witness Levitas' proposal that Duke allow the use of surety bonds as a form of performance assurance. (Tr. Vol. 1, p. 324.5.) Duke Witness Johnson addressed this issue at the hearing, testifying that Duke has never allowed a surety bond in any previous PPA and that Duke already considered this issue when developing the PPA for CPRE. (Tr. Vol. 1, pp. 279-280.) He further testified that Duke does not believe it would be a permissible form of performance assurance because a surety bond, when compared to other forms of security, is more difficult to collect on. (Tr. Vol. 1, pp. 288-289.) Duke Witness Wheeler also testified at the hearing that Duke decided to move away from allowing surety bonds several years ago because the Companies found that in some cases, the QF did not renew the surety bond for the life of the contract. (Tr. Vol. 1, p. 289.)

In surrebuttal testimony, Mr. Levitas reiterates that Duke does not allow the use of surety bonds as a permissible form of performance assurance. (Tr. Vol. 1, p. 324.5.) In contrast, Dominion's proposed PPAs do allow for the use of surety bonds and include a commercially reasonable form bond for this purpose. *Id.* Mr. Levitas recommends Duke doing so as well. *Id.*

In hearing testimony, Mr. Johnson offers two reasons as to why Duke doesn't offer surety bonds as a form of performance assurance: (1) feedback from the seller community while developing the CPRE Tranche 1 PPA and (2) Duke has never allowed a surety bond in any previous PPA. (Tr. Vol. 1, pp. 279-280.)

In cross-examination, Mr. Johnson says that surety bonds are harder to collect on than cash but does not offer a reason as to why Dominion would offer a surety bond as an eligible form of performance assurance, indicating that this is not his area of expertise. (Tr. Vol. 1, pp. 279-280.) Whereas Duke offers three forms of performance assurance – cash, letter of credit and a guarantee – Dominion offers the same three, but also offers surety bonds.

In further cross-examination, as stated above, Mr. Wheeler indicates that Duke made a determination several years ago to drop surety bonds as a form of performance assurance because they found that in some cases, the QF didn't renew the surety bond for the life of the contract. (Tr. Vol. 1, p. 289.)

Although Power Advisory asserts that cash, letter of credit and a guarantee are sufficient for performance assurance (Power Advisory at 51), we disagree. The only reasons presented by Duke in testimony against using surety bonds as performance assurance were that a surety bond is harder to collect on, and that the QF did not renew the surety bond for the life of the contract in some cases. We do not think these are sufficient reasons to reject the use of a surety bond as performance assurance. Certainly, Duke could address the issue of renewal and require that QFs obtain a surety bond that would remain in effect for the life of a contract, if the QF chose this form of performance assurance. Second, Duke could research collectability on any surety bond offered by a QF as performance assurance, although Duke may not unreasonably refuse to accept any surety bond which meets all legal requirements. Further, we would note that Dominion offers surety bonds as a form of performance assurance, along with cash, letter of credit,

and a guarantee. Accordingly, we hold that surety bonds are a permissible performance assurance method, and Duke shall offer them for performance assurance to requesting QFs.

**J. Notice of Commitment Form**

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 30-33**

The evidence in support of these findings of fact is found in the verified Joint Application, pleadings, testimony, and exhibits in these Dockets, and the entire record in this proceeding.

Section 58-41-20(D) of the Act provides that small power producer QFs (as defined in the Act) shall have the right to sell their electric output to an electric utility by executing and delivering to the utility a Commission-approved "notice of commitment to sell form." By delivering a Notice of Commitment Form ("Form"), the Act prescribes that the small power producer is committing to sell its output (a) at the avoided cost rates, and

(b) pursuant to the PPA terms in effect at the time it submits the Form to the utility. The Act does not specify each element of the Form required to establish the QF's "commitment to sell," but makes clear that the Form must provide the small power producer a "reasonable period of time" from submittal of the Form to execute a PPA with the utility. The Act also prohibits a utility from requiring a small power producer to execute a PPA prior to receiving "a final interconnection agreement from the electrical utility" as a condition to "preserving the pricing and terms and conditions established by its submittal of the form to execute a [PPA]." S.C. Code Ann. § 58-41-20(D).

Underlying Act 62's directive to establish a "notice of commitment to sell" form is the concept of a "legally enforceable obligation," which has been established by FERC's regulations implementing PURPA. FERC's regulations specify that a QF can choose to sell its output to the utility on an uncommitted and "as available" basis or the QF can choose to sell its output pursuant to a "legally enforceable obligation," ("LEO") whereby the QF commits to deliver energy and capacity to the utility over a specified term. See 18 C.F.R. § 292.304(d). Where the QF chooses to sell its power pursuant to a LEO, PURPA requires that rates paid to the QF be fixed at the utility's avoided costs calculated at the time the LEO is established or, at the QF's option, at the time the power is delivered. *Id.* FERC has recognized that a LEO may be established by the QF and the utility executing a mutually-binding contract, such as a PPA. However, when a utility refuses to sign a contract, the QF may petition this Commission to recognize the creation of a non-contractual LEO. The parties to this proceeding agree that the South Carolina legislature intended this Notice of Commitment Form to serve as the "non-contractual LEO" that FERC's regulations describe, while the PPAs themselves serve as the "contractual LEO." The parties also agree that the Notice of Commitment Form is a novel concept and that only North Carolina has established such a mechanism to create a non-contractual LEO.

The purpose of the non-contractual LEO, as FERC set forth in Order No. 69, is "to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility." *Final Rule Regarding the Implementation of Section 210 of the*

*Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 (1980) ("Order No. 69"). As FERC confirmed in its recent Notice of Proposed Rulemaking, FERC's PURPA regulations do not specify when or how a LEO is established, and FERC has not identified specific criteria that states must follow in determining when a LEO is established. PURPA NOPR, at ¶ 134. However, FERC's orders have provided general guidance that "a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations." JD Wind 1, LLC, 129 FERC ¶ 61,148 at P25 (2009) (emphasis added). FERC has also recently made clear that "the establishment of a legally enforceable obligation turns on the QF's commitment, and not the utility's actions." FLS Energy, Inc., 157 FERC ¶ 61,211 at P 24 (Dec. 15, 2016) (emphasis in original).

Summary of the Evidence

As described by Duke Witness Johnson, the Companies' Notice of Commitment Form has been developed to identify the QF "Seller" making the commitment to sell and to then require the QF to certify that it is actually making a commitment substantial enough to establish a binding LEO. (Tr. Vol. 1, p. 282.14.)

ORS Witness Horii found the Companies' Notice of Commitment Form to be consistent with PURPA and FERC's implementing regulations. (Tr. Vol. 2, p. 525.25.) SBA Witness Levitas identifies several areas of concern with the Notice of Commitment Form in his direct testimony, the majority of which have been addressed by Duke Witness Johnson's rebuttal testimony and exhibits. Witness Johnson testified at the

evidentiary hearing that only a few of the issues originally in contention between the Companies and SBA were unresolved as of the date of the hearing. (Tr. Vol. 1, p. 275.)

Duke Changes in Rebuttal Testimony

Duke witness Johnson proposed certain changes to the Notice of Commitment Form in his rebuttal testimony. First, the witness proposed adding the following language: "Seller has received a System Impact Study Report and has returned the signed Facilities Study Agreement to the Company." Duke generally agrees with Witness Levitas that completing the System Impact Study under the South Carolina Generator Interconnection Procedures provides the QF developer at least preliminary information regarding the cost and timing to achieve COD ("Commercial Operations Date") if the QF elects to proceed with the project. (Tr. Vol. 1, pp. 284.20-284.21.) Thus, incorporating this requirement into the Notice of Commitment Form would provide some indicia of commercial viability, which the Companies' support. *Id.*

However, given Witness Levitas' comments regarding conditioning a LEO on an action by the utility (i.e., delivering the System Impact Study Report), the Companies believe it would be more appropriate to instead require the QF to have submitted a signed Facilities Study Agreement to the utility. (Tr. Vol. 1., pp. 284.23-284.24.) The Facilities Study Agreement is delivered at the same time a completed System Impact Study Report is issued by the utility and is required to commence the next step in the interconnection process. *Id.* While still not a binding commitment of any sort, a QF that has executed and returned the Facilities Study Agreement to the utility has completed a meaningful

step toward developing the project. *Id.* Accordingly, Duke proposes modifying the Notice of Commitment Form to incorporate this requirement. *Id.*

We approve this addition. Clearly, this removes concerns about provision of the System Impact Study Report to the QF, since the language presupposes receipt of the System Impact Study Report by the QF. The QF may then return the Facilities Study Agreement to the Company after having the benefit of reviewing the System Impact Study Report. Failure to provide the System Impact Study Report to the QF within a prescribed time may affect the QF's provision of a Facilities Study Agreement, however, as addressed infra in this Order.

Cure Language

Second, "cure" language is proposed to be added to the Notice of Commitment Form, as per the suggestion of SBA witness Levitas. The language is as follows: "(b) ceases to have control of the Project Site; (c) ceases to be certified as a QF with FERC and any such deficiency, in items (a)-(c) above, has not been cured within ten (10) business days." (Tr. Vol. 1, pg. 322.29.) Under the proposal, the Notice of Commitment Form would automatically terminate if the QF ceases to have control of the Project Site, the QF ceases to be an interconnection customer of the Company, or the QF ceases to be certified as a QF with FERC. Witness Levitas also recommends that the QF should have 10 business days to cure any noncompliance with these conditions. *Id.* The Companies do not oppose this modification. (Tr. Vol. 1, p. 284.35.)

Elimination of "Damages" Section of the Notice of Commitment Form

With regard to the "damages" section of the Notice of Commitment Form, witness Johnson proposes complete elimination of the "damages" clause, despite witness Levitas' proposal to modify the clause into a section on "liquidated damages." (Tr. Vol. 1, p. 284.37.) Section 8 of the Companies' Notice of Commitment Form initially proposed a provision to make the Companies whole if the QF Seller defaults or breaches any representation or warranties made in the Notice of Commitment Form. *Id.* SBA Witness Levitas proposes to delete the Companies' "make whole" damages provision and, instead, to incorporate his proposed LD provision, which Johnson discusses in his Rebuttal Testimony. *Id.*

The Companies have carefully considered Mr. Levitas' proposal to include liquidated damages in the Notice of Commitment Form, but are rejecting it and, at this time, believe that it is more appropriate to eliminate proposed Section 8 from the Notice of Commitment Form altogether. *Id.* The reason for this elimination is that the Companies are not relying upon QF capacity that is subject only to a Notice of Commitment Form (i.e., prior to the QF executing a PPA) as "committed capacity" for IRP planning purposes. (Tr. Vol. 1, p. 284.38.) This is in large part due to the Companies' experience in North Carolina that speculative QFs do not perceive the non-contractual LEO as a binding commitment and have often walked away from their non-contractual LEO prior to executing a PPA. *Id.* Once the QF executes a PPA, however, Duke relies upon the QF to deliver its full capacity and energy output by a specified delivery date and for a specified term. *Id.* Thus, once the QF makes this binding contractual commitment,

liquidated damages are appropriate because Duke is harmed by the QF's failure to deliver the committed capacity and energy over the term of the PPA. *Id.*

Accordingly, based upon the Companies' current resource planning perspective of the validity of non-contractual LEOs, the Companies are proposing not to include any damages provisions in the Notice of Commitment Form. *Id.* Further, the limited duration of the LEO allowed under the Notice of Commitment Form is also an important consideration supporting Duke's updated proposal not to include a damages provision. (Tr. Vol. 1, p. 284.39.)

Because of all of the policy reasons stated above, we approve the Companies' proposal to eliminate the "damages" section of the Notice of Commitment Form and reject the SBA proposal to convert the "damages" section to "liquidated damages."

Required Permits and Land Use Approvals

With regard to other issues in contention on the Notice of Commitment Form, the first is whether the Companies may condition eligibility for the Notice of Commitment Form on the requirement that a QF must have secured all required permits and land use approvals. SBA witness Levitas objects to Duke's requirement that QFs obtain permits and land-use approvals prior to establishing a LEO. (Tr. Vol. 1, p. 322.25.) The witness asserts that obtaining environmental permits and land-use approvals can be an expensive and time-consuming process, sometimes costing in the hundreds of thousands of dollars. *Id.* Levitas states that it is unreasonable to expect a QF to incur these expenses until it has secured a price for its output so that it can in turn secure financing for the project. *Id.*

The Standard offer PPA is silent on this subject, according to the witness, while the large QF PPA expressly contemplates that permits will be obtained after PPA execution. *Id.* Levitas discerns no logic in what he characterizes as an onerous requirement. *Id.* We agree with witness Levitas that obtaining permits and land-use approvals prior to establishing a LEO is unreasonable, since this process is clearly expensive and time-consuming, and would come at a time that the QF has not secured a price for its output, and the QF would therefore lack financing. Further, such a requirement does not appear in the Standard Offer PPA, while the large QF PPA specifically states that permits will be obtained after PPA execution. We recognize Mr. Johnson's opposing view, however, requiring a QF to obtain permits and land-use approvals prior to establishing a LEO clearly lacks logic. We therefore reject the proposed requirement.

365 Day Commercial Operation

Another remaining issue in contention is whether the Companies may require the QF to achieve commercial operation within 365 days of executing the Notice of Commitment Form. SBA witness Levitas objected to Duke's requirement that a facility be placed in service within 365 days of Commitment Form submittal in his Direct Testimony. (Tr. Vol. 1, p. 322.25-322.26.) Levitas testified that QFs must be able to secure pricing before they can incur major development expenses, secure financing, and construct the project. *Id.* While many QFs can complete the development cycle within a year, larger and more complex QFs may not be able to do so.

The witness asserts that Duke's interconnection study and construction process in South Carolina has been taking on the order of three years. *Id.* According to the witness, Duke's proposed 365-day in-service requirement is tantamount to saying that no QF could ever form a non-contractual LEO that it could comply with, in that a QF often has no idea how long it will take to achieve interconnection, and therefore commercial operation. *Id.* Levitas asserts that it would be completely unreasonable to require a QF to predict when it will be 365 days or less from commercial operation. *Id.*

Duke's expressed concern is that delays between LEO formation and facility COD have the potential to allow QFs to lock in "stale" rates to the detriment of ratepayers.

(Tr. Vol. 1, pp. 322.27-322.38.) Levitas states that, as with utility generation investments, it is necessary for developers to have price certainty. (Tr. Vol. 1, p. 322.28.)

At a reasonable point in the development cycle, which, in his opinion, is particularly important given PURPA's goal of promoting QF development, Levitas notes that there will always be a need to balance that requirement against an understandable goal of having rates be as current as possible. *Id.* The bottom line, according to the witness, is that QFs must be allowed to secure pricing with enough lead time to develop their projects and to allow the utility to interconnect.

The witness agrees with Duke that a QF should not be able to lock in rates indefinitely. (Tr. Vo1. 1, p. 322.37.) Given the time it takes to develop and build the project, Levitas believes that the Commission should start by establishing a presumptive

time in which a utility should be able to complete interconnection studies and the construction of required interconnection facilities and network upgrades. *Id.*

Duke witness Johnson in Rebuttal testimony generally disagrees with Levitas' Direct Testimony, however. According to Johnson, Duke generally agrees with witness Levitas that completing the System Impact Study under the South Carolina Generator Interconnection Procedures provides the QF developer at least preliminary information regarding the cost and timing to achieve COD if the QF elects to proceed with the project. (Tr. Vol. 1, p. 284.32.) Thus, incorporating this requirement into the Notice of Commitment Form would provide some indicia of commercial viability, which the Companies' support. *Id.* However, given Witness Levitas' earlier comments regarding conditioning a LEO on an action by the utility (i.e., delivering the System Impact Study Report), the Companies believe it would be more appropriate to instead require the QF to have submitted a signed Facilities Study Agreement to the utility. *Id.* The Facilities Study Agreement is delivered at the same time a completed System Impact Study Report is issued by the utility and is required to commence the next step in the interconnection process. (Tr. Vol. 1, pp. 284.32-284.33.) While still not a binding commitment of any sort, a QF that has executed and returned the Facilities Study Agreement to the utility has completed a meaningful step toward developing the project, according to witness Johnson. *Id.*

Levitas surrebuttal testimony states that SCSBA is prepared to withdraw its objection to that requirement if the deadline is extended to account for additional time required for the utility to complete required Interconnection Facilities and Network

Upgrades. (Tr. Vol. 1, p. 324.8.) Given the substantial delays that can occur at any time in the interconnection process (up to and including completion of work under an Interconnection Agreement), which are outside the control of the QF, Levitas states that there is almost no point at which a QF can be certain that it will be able to achieve commercial operation within 365 days, unless allowances are made for possible interconnection delays. *Id.* The witness notes that the DESC Notice of Commitment form contains such a provision. *Id.* Further, as Witness Johnson points out, this relief from an in-service deadline based on interconnection timing has been incorporated by Duke into its Large QF PPAs. *Id.* Levitas asserts that, just as there is no reason that a QF should be prevented from executing a PPA because of the utility's interconnection schedule, it similarly should not be prevented from forming a non-contractual LEO for that reason. (Tr. Vol. 1, pp. 324.8-324.9.)

However, Levitas asserts that there are some benefits to a requirement that the QF submit an FSA as a condition to forming a LEO. As Witness Johnson observes, deferring LEO/contract formation until the FSA has been signed provides both the developer and the utility with a better sense of project viability and moves the establishment of the contract price to a point closer to commercial operation. (Tr. Vol. 1, p. 324.10.) However, Levitas asserts that Witness Johnson fails to recognize the purpose served by his proposal that, in the alternative, the QF be able to form a LEO or execute a PPA within one year of filing its interconnection request if the utility has not completed the System Impact Study (or using Duke's proposal, if it has not yet been presented with a Facilities Study Agreement to execute). *Id.* In the absence of such an alternative,

according to Levitas, the utility could potentially control and frustrate the QF's LEO formation. *Id.* The North Carolina Utilities Commission, with Duke's consent, has adopted exactly this sort of approach, according to the witness. *Id.* In sum, Levitas states that he is comfortable with Duke's proposed requirement that a signed FSA be a condition of LEO formation or PPA execution, provided that there is an alternative eligibility criterion based on time from the interconnection request. *Id.* Levitas continues to believe that one year is a reasonable interval given the time frames set forth under the Interconnection Procedures, but if Duke believes the one-year time frame proposed is unreasonable in some circumstances, SCSBA would be willing to discuss alternatives. *Id.*

Power Advisory also addresses this issue at pages 55-56. It notes that Mr. Johnson does not address Mr. Levitas' proposal to remove his objection if the deadline is extended to account for additional time needed by the utility to complete required interconnection facilities and network upgrades except to say that the QF could opt to enter into a Large QF PPA where that provision exists. Power Advisory at 55. However, Power Advisory asserts that this does not help the QF if it feels the utility is refusing to enter into a PPA (which is why it would need to go the LEO route in the first place). *Id.*

As in the case of the 30-month in-service requirement following rates selection for the Standard Offer, Power Advisory opines that the Commission must balance the goal of the utility to keep the timelines relatively short, while also allowing the QF a legitimate chance to meet its deadlines. *Id.*

In conducting additional research on in-service requirements following LEO formation, Power Advisory has found that there are other states where the allowable time is longer than 365 days from LEO formation. *Id.* The two most recent rulings were in Washington State (June 2019) and Oregon (August 2016). *Id.* Thus, while Duke has identified three states with relatively short deadlines, other states have longer deadlines. *See* Washington Administrative Code (WAC) 480-106-050, Section 4, and Oregon Standard Power Purchase Agreement (New QF), approved by the Public Utility Commission of Oregon, effective August 11, 2016, Section 2.3.

This Commission notes that there appears to be at least some consensus in the testimony of Duke and SBA, i.e. with regard to the reasonability of the QF signing an FSA as a condition to forming a LEO. However, this Commission recognizes SBA's difficulty with this requirement in the absence of the provision of a System Impact Study Report from the Companies. The Commission recognizes the value of retaining the 365 day in-service requirement for certainty of commercial operation after commitment, but also recognizes that this period may be subject to interconnection delays. Accordingly, we adopt the 365 day in-service requirement following the Notice of Commitment form, but we hereby provide that the deadline may be extended to account for additional time needed by the utility to complete required interconnection facilities and network upgrades. This requirement is similar to the one adopted for Duke's Large QF PPA term.

Offramp from Notice of Commitment When Upgrades Exceed $75,000

One additional point of disagreement has to do with the SBA proposal that an offramp be provided from the Notice of Commitment Form when Interconnection

Facilities and Network Upgrades exceed $75,000 per MW AC. This issue is similar to the one presented with regard to an offramp from PPAs under similar circumstances. This Commission believes the matter should be treated in a manner similar to our decision with regard to an offramp for PPAs under those similar circumstances. If Duke does not provide the System Impact Study within one year of an interconnection request (or an amount of time that is mutually agreeable between the contracting parties), then the QF should be provided an Offramp allowing it to terminate a Notice of Commitment without liability if the interconnection facilities and network upgrades required for interconnection exceed $75,000 per MW AC. *See* Power Advisory at 56.

We would note that Duke witness Johnson opposes such an Offramp, stating that, under these circumstances, a QF would be absolved of its LEO commitment, and would be able to walk away without liability. (Tr. Vol. 1, p. 284.42.) SBA witness Levitas states that he believes that a QF should be able to walk away from a Notice of Commitment based on interconnection costs, even though in many cases those costs will be known by the time the form is executed. (Tr. Vol. 1, p. 324.10.) On balance, we believe that a reiteration of our position regarding an offramp from a PPA is reasonable with regard to an offramp from the Notice of Commitment Form under similar circumstances, and we so hold, based on the same policy considerations. Essentially, if Duke does not provide the System Impact Study within one year of the interconnection request (or an amount of time that is mutually agreeable between the contracting parties), then the QF should be provided an offramp allowing it to terminate its Notice of

Commitment without liability if the interconnection facilities and network upgrade`s required for interconnection exceed $75,000 per MW AC.

**K. Consideration of Longer Term Fixed Price PPA Proposal**

**EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 34**

The evidence in support of this finding of fact is found in the verified Joint Application, pleadings, testimony and exhibits in these Dockets, and the entire record in this proceeding.

As recognized earlier in this Order, the General Assembly has mandated that Duke must initially offer to purchase power from small power producer QFs pursuant to fixed price PURPA PPAs with commercially reasonable terms and a duration of ten years. Duke has met this requirement by submitting DEC's and DEP's Standard Offer Schedule PPs for QFs up to 2 MW and the Large QF form of PPA for small power producers 2 MW to 80 MW that are not eligible for the Standard Offer. Act 62 also provides that the Commission "may . . . approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including but not limited to, a reduction in the contract price relative to the ten year avoided cost." *See* S.C. Code. Ann. § 58-41-20(F)(1).

Summary of the Evidence

Recognizing that the obligation to offer fixed price PPAs for durations longer than 10 years is an option provided to intervenors under Act 62, Duke's Joint Application and direct testimony did not present such a proposal. However, Duke did address the

overpayment risk of longer-term fixed price contracts. Duke Witness Brown testified that primary components that contribute to the over-payment risk for customers under PURPA are: (1) avoided cost rates, (2) length of contract, and (3) the volume of contracts. He explained that the Companies' recent experience has been that paying above-market avoided cost prices over a long period of time for an unprecedented number of QF contracts resulted in the current $2.26 billion overpayment obligation based upon DEC's and DEP's existing PURPA obligations. Because the volume of contracts the Companies must enter into under PURPA are unpredictable and because Act 62 mandates that the Companies must offer long-term ten-year contracts[26] for significant QF capacity until the 20 percent thresholds set in Act 62 are reached, Mr. Brown testified that it is imperative that the Commission ensure avoided cost rates are accurately calculated. (Tr. Vol. 1, p. 46.16.) The Commission has more fully addressed Duke's testimony on this issue as well as the Commission's determination that such risks are an important consideration in reducing the risk on the using and consuming public earlier in this Order and will not summarize that testimony and the Commission's findings again here.

Johnson Development Witness Chilton testified to her perspective on the financing needs of QFs and the contract terms that Johnson Development recommends should be offered to small power producer QFs. Ms. Chilton contended that PURPA and Act 62's requirements that QF generation must be allowed to compete on even terms with the utility's other generation resources, both present and projected, implicitly requires

[26] See Order pages 18-19

that the QF be able to obtain regularly-available, market-rate financing for the costs of developing, building, and operating their projects. (Tr. Vol. 1, p. 334.4). She explained that based upon her experience only a limited number of QFs have been able to find financing for short term or low price PPAs. (Tr. Vol. 1, p. 334.4-5.) She further contended that the longer the contract term, accompanied by a reasonable avoided cost-based purchase price, the more mainstream capital will be available for QF development. Ms. Chilton argued that while PURPA and FERC regulations defer to state Commissions to direct PPA terms, Act 62 recommends ten-year term as a starting point, but does not limit PPAs to ten years. (Tr. Vol. 1, p. 334.4-5.) To support Commission consideration of longer contract terms, Johnson Development Witness Chilton points to Duke's recent participation in the North Carolina CPRE Program where Ms. Chilton argues Duke "seized 45% of all PPAs awarded" and pointed to the Companies' unregulated affiliate, Duke Energy Renewables, recent participation in Georgia competitive solicitation. The contract term offered under the North Carolina CPRE Program is 20 years, while the contract term for the Georgia Power competitive solicitation is 35 years. Ms. Chilton also recognized that Act 62 requires the Commission to consider decrements to avoided cost for PPA terms of longer duration, and recommended the Commission set the tenor of length of PPA contracts at a minimum of 15 and in some cases 20 years with "appropriate statutory conditions" as required by in S.C. Code Ann. § 58-41-23 20(F)(1), to facilitate the opportunity to obtain financing for a majority of QFs in South Carolina. (Tr. Vol. 1, p. 334.8, 9-10.)

Witness Chilton further commented on Duke's avoided cost practices since 2017 of offering five-year PPA terms to large QFs above the 2 MW standard offer eligibility threshold. She testified that Duke does not provide any indication that they intend to offer PPAs of longer duration, and further suggested that Duke's low proposed avoided cost rates further justify the need for longer PPA tenor to make QFs financeable. (Tr. Vol. 1, p. 334.10.)

In rebuttal, Duke Witness Brown responds to Johnson Development Witness Chilton's testimony regarding ensuring QFs have access to regularly-available, market-rate financing and her advocacy for fixed price PPA terms of 15 years or longer. Witness Brown first explains that neither FERC's regulations, FERC Orders implementing PURPA, nor Act 62 prescribes that avoided cost rates and terms offered to QFs must enable their project sponsors to obtain "regularly available market rate financing." (Tr. Vol. 2, p. 621.35.) Witness Brown also comments that Ms. Chilton fails to recognize that there are differences in the financing that would be "regularly available" for sophisticated versus unsophisticated QF developers, for smaller QFs versus larger QFs, or for solar QFs versus other types of QF technologies, and that numerous factors including a QF developer's balance sheet, management team experience and creditworthiness, as well as available tax incentives, and project- and avoided cost-specific considerations including price, contract tenor, the cost of capital, and the risk of the investment, among others, all come into play in determining whether an investment can attract debt and/or equity capital. (Tr. Vol. 2, p. 621.35-36.)

Witness Brown also explained that the limited guidance from FERC addressing the issue of QF financing arose in the context of Connecticut's implementation of PURPA, where the Connecticut Commission had approved the utility offering QFs only a real time energy rate, which FERC found was not consistent with a QF's right to commit to deliver power pursuant to a legally enforceable obligation based upon a forecasted avoided cost rate. Brown explained that in 2016, FERC stated that the term of a legally enforceable obligation should be "long enough to allow QFs reasonable opportunities to attract capital from potential investors," while also clearly reiterating that FERC's regulations do not specify any particular number of years for such legally enforceable obligations, meaning that the term and structure of forecasted avoided cost rates is left to the discretion of the implementing State Commission. (Tr. Vol. 2, p. 621.36 *citing Windham Solar, LLC*, 157 FERC ¶ 61,134 at ¶ 8 (2016).) He also noted that Duke has recently signed nine PPAs totaling 472 MW in North Carolina at that State's maximum five (5) year contract terms. This suggests that developers do not need longer than 10-year contracts to be able to finance projects. (Tr. Vol. 2, p. 621.25.) Witness Brown also highlighted FERC's findings in the recent PURPA NOPR that assessing the financing needs of the QF industry would also be changing as technology costs continue to decline. The FERC specifically pointed to Energy Information Administration data showing that the overnight capital cost to construct fixed tilt solar photovoltaic generation declined 67 percent between 2013 and 2017. (Tr. Vol. 2, p. 621.34.) In summary, Witness Brown reiterated that there is no basis to conclude that PURPA requires all QFs to be able to obtain regularly available market rate financing, as suggested by Ms. Chilton, nor is the

Commission required to undertake efforts to determine what avoided cost rates, terms and conditions would be "financeable" for QFs.

Witness Brown then explained that if the Commission were to attempt to set avoided cost rates based upon what creates an easily financed rate for developers, this would very clearly violate PURPA and Act 62. (Tr. Vol. 2, p. 621.37.) He also pointed out that the Commission cannot truly know what is required for QFs to obtain financing—or the level of profit sought by QF developers—because PURPA largely exempts QFs from Commission oversight of their profits and business operations so that neither the Companies, the ORS, nor the Commission has any clear insight into a QF developer's business or the level of profit deemed "reasonable" to attract equity capital. (Tr. Vol. 2, p. 621.38.) He also noted recent findings by the North Carolina Utilities Commission that a QF has no limit on, and the Commission has no right to review, the amount of debt QFs may use for financing, the return on equity, or the overall rate of return achieved by QF investors. (Tr. Vol. 2, p. 621.38 *citing Order Establishing Standard Rates and Contract Terms for Qualifying Facilities,* at 35, N.C.U.C. Docket No. E-100, Sub 148 (Oct. 11, 2017).) Accordingly, Witness Brown argued that the Commission should reject JDA Witness Chilton's recommendation that the Commission investigate the avoided cost rates and terms that would allow QFs to obtain regularly available market rate financing. (*Id.)*

In response to Witness Chilton's testimony recommending the Commission require the Companies to adopt avoided cost rates for fixed terms of 15 years or longer under PURPA, Duke Witness Brown explained that Duke does not support offering

longer term fixed price PPAs in excess of 10 years unless the price is determined pursuant to a competitive procurement framework. He explained the North Carolina CPRE Program and Georgia Power Company's Renewable Energy Development Initiative—each of which have recently competitively solicited 20-year and 35-year fixed price PPAs, respectively—cited by Witness Chilton actually validate Duke's position that there is a less risky and more cost-effective way to procure new solar capacity for customers. These independently-administered competitive solicitation processes approved in North Carolina and Georgia ensure that only the most cost-effective projects are selected, thereby reducing the risk of overpayment and providing ratepayer protection. (Tr. Vol. 2, p. 621.24.) Brown testified that the fact that the Companies' projects won proposals in these independently administered competitive solicitations simply means that Duke's project proposals, along with other winning third-party proposals, delivered the most value for customers at the lowest cost. (Tr. Vol. 2, p. 621.24-25.)

Witness Brown also testified that offering administratively-determined fixed price contracts any longer than necessary to comply with Act 62 significantly increases the overpayment risk for customers and, therefore, would be inconsistent with Act 62's directives that the Commission's PURPA implementation decisions should reduce the risk on the using and consuming public who are obligated to pay for QF purchases. Moreover, Witness Brown argued that Johnson Development Witness Chilton does not propose any "appropriate statutory conditions," that would result in longer-term fixed price contracts mitigating the overpayment risk to customers. (Tr. Vol. 2, p. 621.23.)

In addition to offering the 10-year fixed price PPA option required to comply with Act 62, Witness Brown pointed out that South Carolina projects can also compete in the North Carolina CPRE Program and that both Southern Current and Johnson Development-affiliated solar projects had already successfully participated in Tranche 1 of the CPRE Program. (Tr. Vol. 2, p. 621.20-21.) Witness Brown also highlighted that the 10-year fixed price contracts required to comply with Act 62 will be the longest fixed-price PURPA PPA rates offered in the Southeast for projects larger than one MW. He also noted that Duke has recently signed nine PPAs totaling 472 MW in North Carolina at that State's maximum five-year contract terms. (Tr. Vol. 2, p. 621.25.)

In surrebuttal, Johnson Development Witness Chilton reiterated her prior testimony that PPA terms longer than 10 years, while not mandated by Act 62, are expressly encouraged by the Act as a means of promoting renewable energy development in South Carolina. She also argued the Commission should not take into consideration other Southeastern states' less favorable PURPA regimes because they have had less robust PURPA outcomes. (Tr. Vol. 1, p. 336.4.) Finally, Witness Chilton responded to Duke Witness Brown's testimony that Johnson Development had failed to put forward a PPA with decrement to the 10-year avoided costs as required by Act 62, testifying that she was leaving open the possibility to offer additional testimony as necessary and purporting to "expressly preserve" Johnson Development's right in this docket, future proceedings, and in PPA negotiations to propose various methods of complying with the Act 62 requirements for longer term contracts. (Tr. Vol. 1, p. 336.5.)

During the hearing, Johnson Development Witness Chilton agreed that a decrement to the 10-year avoided cost rate is required in order for the Commission to adopt a fixed price contract for a term longer than 10 years. (Tr. Vol. 1, p. 344.) However, in response to questions from Commissioner Belser, she was unable to identify any specific proposal that Johnson Development supported to comply with the statutory requirements for the Commission to consider a longer-term fixed price PPA. (Tr. Vol. 2, p. 355.) She also identified that the Commission would not be able to eliminate all risk of uncertainty up or down for the ratepayer in considering proposals for longer-term fixed-price contracts. (Tr. Vol. 2, p. 361.) Witness Chilton also explained that a "financing party is looking at a number of different factors and at each factor is looking for certainty: certainty in the price, certainty in the length, and certainty in the other types of terms that are involved in the contract. And so the greater the certainty, the more accessibility of the financing." However, she also noted that interest rates do not necessarily improve for longer contracts, admitting under cross examination that it is the investor or "equity holder" that primarily benefits from the longer term of the contract, not necessarily the issuer of debt. (Tr. Vol. 1, p. 344, 348.)

During the hearing, SCSBA Witness Levitas identified conceptual proposals that he believed could mitigate the risk to ratepayers of longer-term contracts. He commented that the PPA pricing could be adjusted after the initial 10-year contract term subject to a floor and a ceiling, similar to a hedge arrangement, which would limit future increases or decreases in the PPA price paid to the QF; however, Mr. Levitas could not point specifically to whether such a contract structure had been adopted in another state or

whether it was compliant with Act 62. (Tr. Vol. 2, p. 358-359.) He also commented that a longer-term PPA could be structured based upon PPA pricing below the full projected avoided cost over the contract term, pointing out that the Michigan Consumers Energy 10-year term PPA is calculated based upon a five-year escalating avoided cost projection that is then fixed for years 6 through 10. He explained this proposal would reduce the risk for customers by compressing the pricing over a shorter-term period and reduce the risk for the QF by fixing the rate over the term, so it is not fluctuating during the term of the contract. (Tr. Vol. 2, p. 359-360.)

During the hearing, in response to questions from Vice Chairman Williams regarding potential "doomsday scenarios" of overpayment risk for ratepayers, Duke Witness Snider pointed out the recent declining cost of solar technology over time would not benefit customers if higher avoided cost rates are fixed for longer terms contracts. (Tr. Vol. 1, p. 201-202.) He explained that the further you go out into the future, the greater the risk, meaning that longer contract tenors exacerbates the overpayment risk for customers. (Tr. Vol. 1, p. 205-206.) Witness Snider therefore advocated that the question for the Commission was how to ensure that the State is procuring the right volume of solar energy at the right pace at the right price, and suggested that a competitive procurement with set volumetric targets helps to mitigate the risk for customers as compared to no volumetric limits and an administratively determined price under PURPA. (Tr. Vol. 1, p. 206.) Duke Witness Brown also responded that if the State is interested in procuring solar energy, then it should be procured at the lowest possible cost of solar energy. (Tr. Vol. 1, p. 203-204.)

Commission Determination

As addressed earlier in this Order, Act 62 requires Duke to offer to enter into 10-year fixed price PPAs with South Carolina small power producer QFs, based upon the avoided cost rates and contracts approved by this Commission, up to the point the initial 20 percent of South Carolina retail peak threshold prescribed by S.C. Code. Ann. § 58-41-20(F)(2) is met.[27] For the avoidance of doubt, this requirement includes offering 10-year fixed price PPAs to QFs up to 2 MW eligible for the Standard Offer as well as large QFs up to 80 MW eligible for Duke's Large QF Form PPA. Johnson Development Witness Chilton notes that, prior to Act 62's enactment, Duke offered larger QFs negotiated fixed-price PPAs for a term of only five years. (Tr. Vol. 1, p. 334.10.) The Commission understands from Witness Brown's testimony that Duke's policy of limiting larger QF PURPA contracts to five-year terms was consistent with the maximum PURPA contract terms that is allowed by law in North Carolina. (Tr. Vol. 2, p. 621.25.) Consistent with S.C. Code Ann. § 58-41-20(F)(1), Duke Witness Brown's testimony during the hearing indicates that Duke fully understands the requirements of Act 62 to offer all South Carolina small power producer QFs commercially reasonable fixed price PURPA PPAs, as approved by the Commission, "for a duration of ten years" up to the 20 percent of South Carolina retail peak threshold. (Tr. Vol. 2, p. 688-689.) [28]

The more controversial issue under S.C. Code Ann. § 58-41-20(F)(1) and (F)(2) is whether the Commission should, in its discretion, approve a fixed price PPA in this

[27] See Order pages 18-19
[28] Id.

proceeding with a duration longer than 10 years. In balancing the interest of the QF industry and the risks to ratepayers of longer term fixed price contracts, the General Assembly expressly prescribed in Act 62 that any such longer-term fixed price PPA option approved by the Commission, "must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including but not limited to, a reduction in the contract price relative to the ten year avoided cost." *See* S.C. Code Ann. § 58-41-20(F)(1). The General Assembly further directed that any such longer term PPA option "shall be based on the avoided cost rates and methodologies as determined by the commission" in these proceedings and granted the Commission the authority to "determine any other necessary terms and conditions deemed to be in the best interest of the ratepayers." *Id.*

The Commission concludes that no intervening party to these proceedings elected to put into evidence a proposal that conforms to the mandates of S.C. Code Ann. § 58-41-20(F)(1). Act 62 was passed into law on May 16, 2019, establishing the opportunity for intervenors to put forward PPA proposals that would meet the statutory conditions to justify Commission approval of an optional longer-term fixed price PPA exceeding 10 years. Both Johnson Development and SCSBA filed direct testimony on September 11, 2019, and subsequently filed surrebuttal testimony on October 11, 2019, with Johnson Development Witness Chilton recognizing in both direct and rebuttal testimony that "appropriate statutory conditions" were required for the Commission to approve an alternative longer-term fixed price PPA proposal. At the hearing, Witness Chilton expressly declined to offer a proposal on behalf of Johnson Development when asked by

the Commission, while SCSBA Witness Levitas put forward multiple high-level conceptual proposals of potential longer-term fixed price PPA structures. (Tr. Vol. 2, p. 355, 358-360.) Johnson Development and SCSBA have not explained why they elected not to timely present proposed "additional terms, conditions, and/or rate structures" for consideration by Duke, ORS, and other customer intervenors who will be obligated to pay for the QF power contracted for by Duke under the avoided cost rates and fixed price PPAs approved by the Commission in these proceedings.

Commission Order No. 2019-128-H established that it would not be appropriate for Johnson Development and SCSBA to offer new evidence after the hearing, but, over Duke's objection, accepted that it would be "permissible to include proposals that are <u>based on the evidence and testimony in the record of the case</u> in proposed orders." (emphasis in original). The Commission finds that Johnson Development and SCSBA have generally attempted to comply with this directive, but their proposal still effectively attempts to present new evidence in the form of the proposed modified terms, conditions, and/or rate structures that they advocate the Commission approve as part of a longer-term fixed price PPA option. Duke, ORS, and other parties have had no opportunity to review, cross-examine, and provide evidence to the Commission on this proposal and would be prejudiced if the Commission approved the alternative PPA proposal based upon the current record in these proceedings. The Commission also has not had the benefit of receiving ORS' and Duke's perspectives on whether the Commission should impose "other necessary terms and conditions deemed to be in the best interest of the ratepayers" as provided for in the S.C. Code. Ann. § 58-41-20(F)(1). The Commission also finds that

Johnson Development's and SCSBA's proposal is deficient under the statute as it fails to properly be based upon "a reduction in the contract price relative to the ten year avoided cost" as expressly required by S.C. Code Ann. § 58-41-20(F)(1). Because any determination by the Commission to approve contracts with a duration of longer than ten years must be predicated on specific proposals from intervenors that comply with S.C. Code Ann. § 58-41-20(F)(1) and are entered into the evidentiary record during the course of this proceeding, the Commission declines to approve the proposals from Johnson Development and SCSBA.

In sum, the Commission has carefully reviewed this issue under the standards and requirements prescribed by the General Assembly in S.C. Code Ann. § 58-41-20(F)(1) and finds that no proposal from intervenors has been entered into evidence this proceeding that complies with the statute. Duke is required by Act 62 to offer all small power producer QFs up to 80 MW a 10-year fixed price PPA based upon the avoided cost rates and contract documents approved by the Commission in this Order. South Carolina solar QFs may also elect to compete in the now-open CPRE Program Tranche 2 for a 20-year fixed price PPA if the QF is the most cost-effective option for customers. Moreover, the Commission has begun the process of establishing a South Carolina Competitive Procurement Program, as authorized by Act 62. The process for creating such programs is occurring in Docket No. 2019-364-E.

The Commission also notes that S.C. Code Ann. § 58-41-20(A) provides electrical utilities and small power producers the right to mutually agree to enter into PPAs with terms that differ from the commission approved form(s); however, those terms

will not be dictated as just and reasonable and mandatory for all QFs in these proceedings. JDA and SCSBA members are free to bring their proposals as part of those PPA negotiations, and they may also timely bring forward proposals that meet the subsection (F)(1) requirements in future avoided costs/PURPA implementation proceedings initiated by the Commission under S.C. Code Ann. § 58-41-20(A).

## VI. ORDERING PARAGRAPHS

NOW, THEREFORE, IT IS HEREBY ORDERED THAT:

1. Based upon the Joint Application, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission hereby adopts each and every finding of fact enumerated herein. The Commission's conclusions of law are fully stated above.

2. Any motions not expressly ruled upon herein are denied.

3. The avoided capacity and energy costs for DEC approved in this proceeding are:

*10-Year Avoided Capacity Rates – Distribution (20 Year CT, $/kWh)*

| Summer On-Peak | Winter AM On-Peak | Winter PM On-Peak |
|---|---|---|
| 0.0330 | 0.0394 | 0.0131 |

*10-Year Avoided Energy Rates ($/kWh)*

| Summer PM Premium Peak | Summer PM On-Peak | Summer Off-Peak |
|---|---|---|
| 0.0458 | 0.0448 | 0.0260 |

| Winter AM Premium Peak | Winter AM On-Peak | Winter PM On-Peak |
|---|---|---|
| 0.0504 | 0.0461 | 0.0415 |

| Winter Off-Peak | Shoulder On-Peak | Shoulder Off-Peak |
|---|---|---|
| 0.0270 | 0.0339 | 0.0228 |

4. The avoided capacity and energy costs for DEP approved in this proceeding are:

*10-Year Avoided Capacity Rates – Distribution (20 Year CT, $/kWh)*

| Rate | Summer On-Peak | Winter AM On-Peak | Winter PM On-Peak |
|---|---|---|---|
| Variable | 0.0029 | 0.1369 | 0.0595 |
| 5-Year Fixed | 0.0030 | 0.1395 | 0.0607 |
| 10-Year Fixed | 0.0030 | 0.1437 | 0.0625 |

*10-Year Avoided Energy Rates ($/kWh)*

| Summer PM Premium Peak | Summer PM On-Peak | Summer Off-Peak |
|---|---|---|
| 0.0330 | 0.0311 | 0.0268 |

| Winter AM Premium Peak | Winter AM On-Peak | Winter PM On-Peak |
|---|---|---|
| 0.0358 | 0.0354 | 0.0342 |

| Winter Off-Peak | Shoulder On-Peak | Shoulder Off-Peak |
|---|---|---|
| 0.0275 | 0.0298 | 0.0226 |

5. Within 15 days of the date of this Order, DEC and DEP shall each file final avoided cost rates, Standard Offer tariffs, Schedule PP PPAs and terms and conditions, form contract power purchase agreements for Large QFs, and Notice of Commitment to Sell forms consistent with the requirements of this Order.

6. The Standard Offer tariffs shall become effective November 30, 2018, and shall remain in effect until the date that the Commission approves updated avoided cost rates in a subsequent proceeding.

7. On or before November 18, 2019, Duke shall file proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the SISC, as contemplated by the SISC Stipulation approved herein.

BY ORDER OF THE COMMISSION:

Comer H. "Randy" Randall, Chairman

ATTEST:

Jocelyn Boyd, Chief Clerk/Executive Director

## Docket Nos. 2019-185-E and 2019-186-E

# Independent Third Party Consultant Final Report Pursuant to South Carolina Act 62

## Prepared for:

## Public Service Commission of South Carolina

November 1, 2019

***Submitted by:***

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# Executive Summary

## Introduction

On May 16, 2019, the Governor of South Carolina signed into law the South Carolina Energy Freedom Act (Act 62), which addresses the state's implementation of parts of the Public Utility Regulatory Policies Act (PURPA). There were many elements to PURPA. Section 210 pertained to a new class of generators identified as qualifying facilities (QFs) and an obligation on investor-owned electric utilities to purchase power from QFs at the utilities' avoided costs, which are the incremental cost to the utility of generating or purchasing this power. These elements of PURPA, along with obligations by South Carolina electric utilities to provide a standard offer under which they would purchase power from small power producer QFs, are a major focus of Act 62.

Act 62 directs the Public Service Commission of South Carolina (Commission) to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section."[1]

Under the standard offer provisions of Act 62, electric utilities are required to implement a Standard Offer Purchased Power Tariff, a Power Purchase Agreement (PPA), and Terms and Conditions that are available to small power producers that are 2 MW or smaller. The main areas of review and analysis are avoided costs; variable integration charges and appropriate PPA terms and conditions. Each is reviewed below.

## Avoided Costs

The Companies stressed the risk of overpayment from long-term PPAs based on avoided costs, noting that the 4,000 MWs of solar QF PPAs under contract represent an overpayment of about $2.26 billion at current avoided costs, a figure that intervenors say was overstated. Other parties indicated that overpayment risk is mitigated going forward since avoided costs will be updated every two years. Intervenors also said that ratepayers don't bear the risk of cost overruns with QFs, unlike with utility owned generation.

Parties discussed whether avoided costs might go up or down in the future thus either benefiting or harming ratepayers given the long-term contracts with QFs at a fixed price based on these avoided costs. The primary factor of future avoided costs was identified as natural gas prices, with intervenors saying gas prices are likely to increase substantially.

[1] Act 62. Section 58-41-20. (A)

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**Avoided Energy Costs**

The Companies use the peaker methodology to estimate avoided costs, which is a widely accepted industry standard.

Areas of investigation with respect to the Companies' avoided energy costs included the following:

- Negative Avoided Energy Costs
- Coal Unit Retirements
- DEP East and DEP West Integration
- Selection of Avoided Cost Periods

**Avoided Capacity Costs**

Areas of investigation regarding the Companies' avoided capacity cost estimates in our report included the following:

- Assessment of Avoided Capital Cost Methodology
- Capital Cost of a New Peaker
- Capacity Value Timing, where we recommend an advancement of the first year of need for additional capacity given recently announced coal unit retirements.
- Weighting of Peak Periods, where we recommend increasing the weight given to the summer peak period.

**Solar Integration Services Charge (SISC)**

The Companies' proposed SISC and the methodology employed to develop it were the subject of considerable dispute among the parties. However, prior to the commencement of the hearings, various parties submitted a partial settlement agreement covering the SISC. The agreed upon charges were $1.10/MWh for DEC and $2.39/MWh for DEP.

**PPA and NOC Terms and Conditions**

Power Advisory discussed the concept of commercial reasonableness as it relates to the Power Purchase Agreements and Notice of Commitment to Sell Forms. We also discussed the implications of a 10-year contract term identified in Act 62.

In the course of this proceeding, the two sides (namely the Companies and SBA) came to agreement on many matters which Power Advisory found to be fair and reasonable. The matters that were unresolved were as follows:

Standard Offer PPA issues not resolved include:

- Material alterations - retroactive vs. prospective

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- 30-month in-service date following rates approval

Large QF PPA issues not resolved include:

- Facilities Study Agreement (FSA) a condition of signing a Large QF PPA
- Offramp should interconnection facilities and network upgrades exceed $75,000/MW-AC
- Surety Bonds as a permissible form of performance assurance

Notice of Commitment (NOC) to Sell Form issues not resolved include:

- All required permits and land-use approvals a condition of LEO formation
- 365 day in-service requirement following LEO formation
- Offramp should interconnection facilities and network upgrades exceed $75,000/MW-AC

For each of these issues, Power Advisory provided a summary of the positions of both sides and provided its independent opinion to the Commission based on the evidence provided.

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# 1. INTRODUCTION

On May 16, 2019, the Governor of South Carolina signed into law the South Carolina Energy Freedom Act (Act 62), which addresses the state's implementation of parts of the Public Utility Regulatory Policies Act (PURPA). PURPA was originally enacted by the US Congress in 1978.[2] There were many elements to PURPA. Section 210 pertained to a new class of generators identified as qualifying facilities (QFs) and an obligation on investor-owned electric utilities to purchase power from QFs at the utilities' avoided costs, which are the incremental cost to the utility of generating or purchasing this power. (See discussion in Chapter 2.) These elements of PURPA, along with obligations by South Carolina electric utilities to provide a standard offer under which they would purchase power from small power producer QFs, are a major focus of Act 62. QFs include small power producers that utilize renewable energy to generate electricity and are 80 MW or smaller as well as cogeneration facilities.

Act 62 directs the Public Service Commission of South Carolina (Commission) to "open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section."[3]

Under the standard offer provisions of Act 62, electric utilities are required to implement a Standard Offer Purchased Power Tariff, a Power Purchase Agreement (PPA), and Terms and Conditions that are available to small power producers that are 2 MW or smaller. Standard offers are employed to recognize that small projects are less able than large projects to bear the costs associated with negotiating a PPA and ascertaining the terms and conditions under which the local electric utility would be willing to purchase power.

Act 62 applies to all utilities that are regulated by the Commission, except that electric utilities serving less than 100,000 customers are exempt from the renewable energy programs outlined in Chapter 41 of the Act. As such, the Act applies to Duke Energy Carolinas, LLC (DEC) and Duke Energy Progress, LLC (DEP), collectively the "Companies" or "Duke"; and Dominion Energy South Carolina, Inc. (DESC). Pursuant to Act 62 the Commission opened three dockets for the three

---

[2] On September 19, 2019, FERC issued a Notice of Proposed Rulemaking on Qualifying Facility Rates and Requirements and Implementation Issues Under PURPA (NOPR), which proposes to scale back some of the requirements of PURPA. FERC characterizes the intent of the NOPR to "rebalance the benefits and obligations of the Commission's PURPA Regulations in light of the changes in circumstances since the PURPA Regulations were promulgated in 1980." (para 4.) Power Advisory notes that the Commission's actions in these dockets are in response to Act 62, but that Section 58-41-10 (B) does specify that "implementing this chapter, the commission shall treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that: …power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA."

This is only a notice of proposed rulemaking, which should not be interpreted as the promulgation of final regulations.

[3] Act 62. Section 58-41-20. (A)

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utilities to which the Act applies, for DESC Docket No. 2019-184-E, DEC Docket No. 2019-185-E, and DEP Docket No. 2019-186-E.

With respect to implementing the Act, the Commission is directed:

> "to address all renewable energy issues in a fair and balanced manner, considering the costs and benefits to all customers of all programs and tariffs that relate to renewable energy and energy storage, both as part of the utility's power system and as direct investments by customers for their own energy needs and renewable goals. The commission also is directed to ensure that the revenue recovery, cost allocation, and rate design of utilities that it regulates are just and reasonable and properly reflect changes in the industry as a whole, the benefits of customer renewable energy, energy efficiency, and demand response, as well as any utility or state specific impacts unique to South Carolina which are brought about by the consequences of this act."[4]

The Act requires Commission decisions to reflect a careful balancing of interests:

> "Any decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public."

Further guidance regarding how the interests of QFs will be protected and balanced with customers' interests flows from the direction to:

> "treat small power producers on a fair and equal footing with electrical utility owned resources by ensuring that:
>
> (1) rates for the purchase of energy and capacity fully and accurately reflect the electrical utility's avoided costs;
>
> (2) power purchase agreements, including terms and conditions, are commercially reasonable and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA; and
>
> (3) each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy,

[4] Act 62. Section 58-41-05.

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capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment."

Act 62 also authorizes the commission "to employ, through contract or otherwise, third party consultants and experts in carrying out its duties under this section, including, but not limited to, evaluating avoided cost rates, methodologies, terms, calculations, and conditions under this section."[5] Power Advisory LLC (Power Advisory) was engaged by the Commission on September 3rd to serve as the independent third-party consultant in the three dockets filed pursuant to Act 62. This is Power Advisory's report to the Commission outlining our findings from the review of the materials filed by the parties and the hearings before the Commission regarding DEC and DEP in Docket Nos. 2019-185-E and 2019-186-E.

## 1.1 Relevant Experience of Power Advisory

Power Advisory is a management consulting firm focused on the North American electricity sector. The lead consultant on this project and Power Advisory President, John Dalton, has over thirty years of experience as a senior electricity market analyst and policy consultant. John has testified in over 25 proceedings before state and provincial regulatory commissions; advised jurisdictions on the design of renewable energy procurement frameworks including standard offer programs; and has extensive experience overseeing and reviewing quantitative analyses including avoided cost estimates, electricity price forecasts, generation technology cost estimates and production cost modeling.

Recent Power Advisory consulting assignments related to the mandate of South Carolina Act 62 include drafting and review of Power Purchase Agreements for renewable energy resources including variable output resources such as solar; assessing renewable technology costs; evaluating the requirements to integrate variable output renewable energy resources and reviewing utility avoided costs. Power Advisory has overseen the development, reviewed the implementation, and advised on changes to renewable energy procurement programs in Alberta, British Columbia, Massachusetts, New York, Nova Scotia, Ontario, Rhode Island and Vermont. For some of these projects, Power Advisory was responsible for drafting the Power Purchase Agreement. While serving as the Nova Scotia Renewable Energy Administrator, Power Advisory drafted the PPA which was accepted by the Utility and Review Board. Relevant to the consideration of variable energy integration charges, Power Advisory prepared a report for the Government of Canada on the integration of variable output renewable energy sources focusing on the importance of essential reliability services. Power Advisory team members have a long history of running and overseeing the specification of production cost models (and reviewing the results of these models) such as the Companies used to develop their avoided cost estimates.

[5] Act 62. Section 58-41-20. (H)

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## 1.2 Power Advisory Review and Participation in Proceeding

As indicated, Power Advisory was engaged by the Commission on September 3, 2019. Hearings in these proceedings began on October 21st after the parties submitted Direct, Rebuttal and Surrebuttal Testimony. Power Advisory issued interrogatories and requests for production of documents to the Companies, reviewed the interrogatory responses and documents provided by the parties as well as reviewed the filed Direct, Rebuttal and Surrebuttal Testimony and monitored the hearings. Given the schedule in this proceeding which requires a Commission decision by November 16th, we were requested by the Commission to issue a final report on or before November 4th to provide the parties an opportunity to comment on the report.

Act 62 specifies that "the qualified independent third party's duty will be to the commission. Any conclusions based on the evidence in the record and included in the report are intended to be used by the commission along with all other evidence submitted during the proceeding, to inform its ultimate decision setting the avoided costs for each electrical utility."[6] We have sought to follow this direction and ensure that our conclusions are based on the evidence in the record. We note that the schedule for this proceeding was compressed and this is the first opportunity for us to present our findings. Where necessary and appropriate we rely on our expertise in the electricity sector to evaluate and analyze the findings and information presented by the parties.

## 1.3 Contents of the Report

Our report is organized along the primary areas of focus of Act 62. Following this introduction is our review of the definition of avoided costs, a discussion of potential risks from avoided cost-based rates, a review of the avoided cost methodology proposed and the resulting avoided cost estimates and response to major issues regarding these avoided cost estimates identified by parties to this proceeding. The next chapter reviews the Companies' proposed Solar Integration Services Charges, the methodology that was used to develop these charges and the partial settlement agreement entered into by various parties. Chapter 4 reviews various terms and conditions that are disputed by the parties pertaining to the power purchase agreements and notice of commitment to sell forms.

Act 62 provides that "The independent third party shall also include in the report a statement assessing the level of cooperation received from the utility during the development of the report and whether there were any material information requests that were not adequately fulfilled by the electrical utility."[7] Power Advisory notes that the Companies provided a high level of cooperation and were responsive to Power Advisory requests.

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[6] Act 62. Section 58-41-20. (I)

[7] Act 62. Section 58-41-20. (H)

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# 2. STANDARD OFFER AND AVOIDED COST METHODOLOGIES

## 2.1 Defining Avoided Costs

Act 62 defines "avoided cost" as "the incremental costs 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".[8] As Duke Witness Snider notes, this is "precisely the same definition prescribed by the Federal Energy Regulatory Commission's ("FERC") implementing regulations."[9]

The Act also directs that:

> "each electrical utility's avoided cost methodology fairly accounts for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment."[10]

## 2.2 Perspective on Avoided Cost Risks

DEC/DEP highlight the risks posed by establishing avoided costs that in hindsight overstate these incremental energy and capacity costs.

In his Direct Testimony, Duke Witness George V. Brown notes the "over-payment risk" associated with allowing QFs to lock in long-term administratively-determined avoided costs has been part of a broader national conversation regarding PURPA implementation, with the National Association of Regulatory Utilities Commissioners ("NARUC") recently advocating in a letter to FERC that calculating avoided costs should "move away from the use of administratively determined avoided costs to their measurement through competitive solicitations or market clearing prices."[11] He then notes that the "the avoided cost rates paid to QFs in substantially all of the PPAs associated with the almost 4,000 MW of solar QF power is now in excess of the Companies' current avoided cost."[12] This overpayment represents about $2.26 billion at the

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[8] 16. U.S.C. Section 824a-3(b); (d).

[9] Duke Snider Direct, p. 5.

[10] Act 62. Section 58-41-20 (B) (3).

[11] Duke Brown Direct, p. 12-13.
National Association of Regulatory Utility Commissioners December 18, 2017 Letter to Federal Energy Regulatory Commission, Re: Public Utility Regulatory Policies Act of 1978 Regulatory Reform, at 2, accessible at: https://www.naruc.org/about-naruc/press-releases/naruc-pushes-for-purpa-reform-in-letterto- ferc/

[12] Duke Brown Direct, p. 16, line 7.

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Companies' current avoided costs, or about 48% of the financial obligation represented by these PPAs.[13]

SBA argued and Power Advisory concurs that this calculation of the overpayment overstates the reduction in value of the energy and capacity provided by these QFs because the addition of this 4,000 MW of QF power contributes to the reduction in avoided costs.[14] Specifically, the value of avoided capacity for DEC has been reduced from about $6.68/MWh to $0.83/MWh in large part because these solar QF additions have changed when the system peak is likely to occur and the resulting peak load reductions provided by solar QFs.[15] The Companies noted that this is the nature of any resource: the more you add, the less it's worth.[16] Ultimately, the Companies asserted that a small part of the roughly $30/MWh decline in avoided costs that they cite is attributable to the impact of additional solar in reducing the avoided costs attributable to solar.[17]

Mr. Snider notes that "there are three primary components that contribute to the overpayment risk for customers under PURPA: (1) avoided cost rates, (2) length of contract, and (3) the volume of contracts."[18] Power Advisory notes that the avoided costs proposed by DEP and DEC in Dockets 2019-185-E and 2019-186-E are significantly less than those that contributed to this above market cost that the Companies raise as an example of overpayment risk. As discussed further below, the relatively low level of current avoided cost rates mitigate future over-payment risks. Conversely, Mr. Burgess and Mr. Davis assert that there are risks and uncertainties associated with the utilities' avoided cost estimates and available resource options that also need to be considered and weighed. Mr. Burgess asserts that there are risks of "cost overruns of large traditional resource procurements"[19] and "stranded costs for 20- to 40-year capital-intensive traditional infrastructure investments".[20] Mr. Burgess argues that thermal plants had larger and more often experienced cost overruns than solar projects. Whereas Mr. Burgess notes that with PURPA-based contracts ratepayers don't bear any cost overrun risk.[21] Power Advisory notes that new projects built by the Companies will likely be built under the traditional regulatory construct where prudently incurred

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[13] The Companies acknowledge that these avoided costs have not been approved by the Commission. Hearing Vol. 1, p. 59, lines 12-15 (Duke Brown).

[14] Hearing Vol. 1, p. 57, lines 3-7 (Duke Snider).

[15] Ibid., p. 66 lines 7-9.

[16] Ibid., p. 70 lines 21-24.

[17] Ibid., p. 71, lines 8-14.

[18] Duke Snider Direct, p.16, lines 11-13.

[19] SBA Burgess Direct, p.13, lines 20-21.

[20] Ibid., p. 14, lines 17-18.

[21] Ibid., p. 17, lines 8-9.

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costs can be recovered from customers. This can result in customers paying higher project costs than the utility estimate, which presumably would not be embedded in the utilities' avoided costs projections. Conversely, if the project's construction cost is less than the estimate these savings would be shared by customers. However, an important difference with respect to QFs is that their cost recovery is based on avoided costs that would be fixed for the contract term. However, risks can increase with increases in the volume of purchases.

Power Advisory notes that the risks of the utilities' projections of avoided costs significantly overstating actual avoided costs over the terms of any power purchase agreements entered into by QFs are mitigated by the direction in the Act that fixed price obligations be based on a 10-year avoided cost determination.[22,23] Another mitigant to the risk of avoided costs significantly overstating actual avoided costs are relatively low natural gas prices, with the average cost of ten-year forward natural gas declining about 25 percent between 2015 and 2019.[24] **Figure 1** shows the decline in natural gas prices from 2015 to 2019. In his Direct Testimony, Mr. Snider notes that for DEP and DEC "natural gas commodity prices represent the primary driver of the avoidable energy cost since a natural gas-fueled combined-cycle unit or combustion turbine unit is often the marginal resource."[25]

Yet another mitigant to the risk of avoided costs significantly overstating actual avoided costs is the fact that avoided costs are to be updated every two years pursuant to the Act and that the Commission could open a proceeding to update avoided costs prior to this if deemed necessary.[26] While this doesn't affect the risks posed by any PPAs awarded through the standard offer program prior to the reset, it does limit the risk going forward. Such a re-evaluation of avoided costs every two years is consistent with best practice.

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[22] Electrical utilities, subject to approval of the commission, shall offer to enter into fixed price power purchase agreements with small power producers for the purchase of energy and capacity at avoided cost, with commercially reasonable terms and a duration of ten years. Section 58-41-20. (F) (1) This issue is discussed further below.

[23] The Act does indicate that the "commission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including but not limited to, a reduction in the contract price relative to the ten year avoided cost." Section 58-41-20. (F) (1)

[24] Hearing, Vol 1, p. 47, lines 14-16 (Duke Snider)

[25] Duke Snider Direct, p. 24.

[26] Hearing, Vol 1, p. 179, lines 11-21 (Duke Brown)

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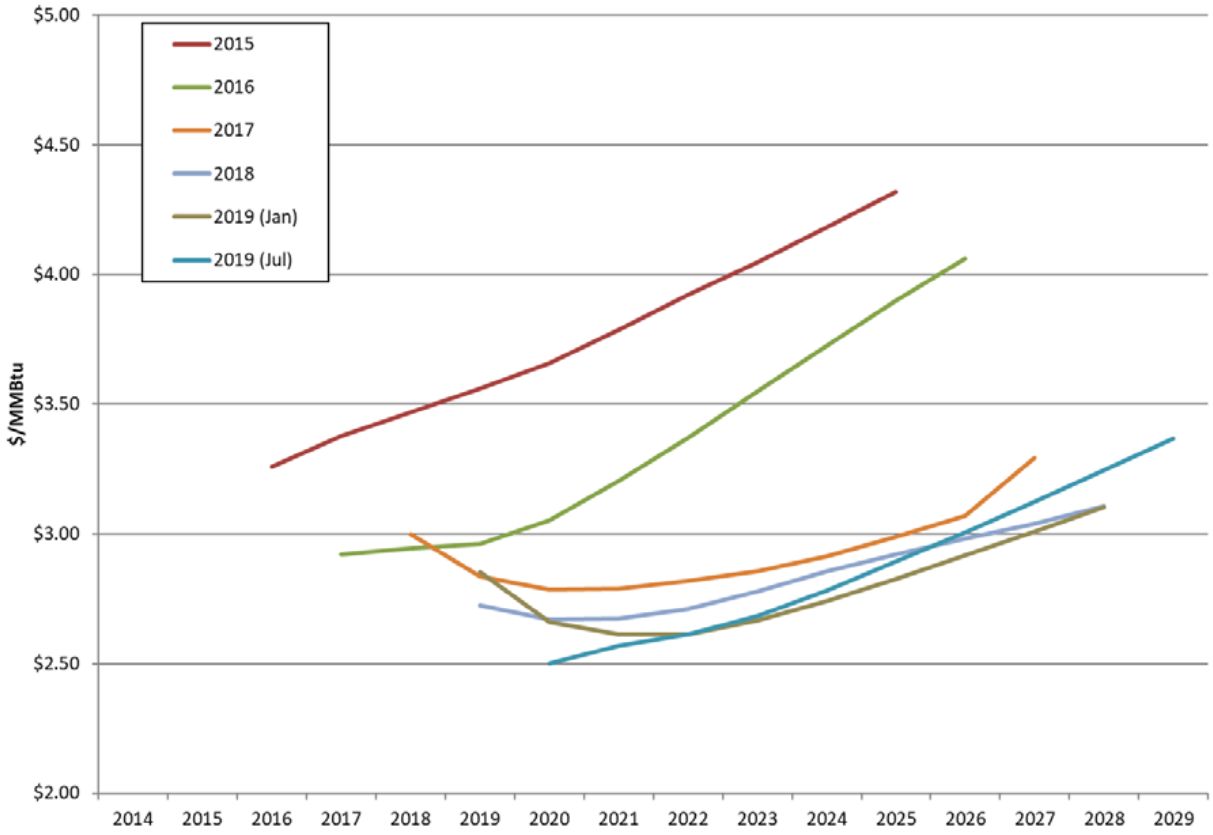
**Figure 1: 10-Year Forward Market Natural Gas Prices (Period 2015 to July 2019)[27]**




## 2.3 Rate Impacts

The Companies have pointed out the overpayment risks and the resulting rate impacts from avoided cost projections that prove to be higher than actual avoided costs incurred. The magnitude of these risks was the subject of considerable discussion and dispute among the parties. With the Companies pointing out past experience which has resulted in significant overpayments to QFs and the SBA and JDA noting that the avoided cost estimates that are the subject of this proceeding are considerably below previous estimates and that this reduces the risks of avoided costs that prove to be too high. In general, there was some agreement among the intervenors that accurate avoided cost projections avoid this overpayment risk and any resulting adverse rate impacts over the long-term because the avoided costs paid to QFs would

[27] Duke Snider Direct, p. 24.

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by definition reflect the utilities' cost to generate or purchase this power.[28,29] Forecasts are inevitability wrong so that actual realized avoided costs will be either higher or lower than the projections.

An important determinant of this avoided cost risk are future natural gas prices and the degree to which they depart from the values reflected in the Companies' filed avoided cost projections. As indicated in Figure 1 above, there was general agreement that natural gas prices are at what some parties characterized as historic lows. This caused some parties, including Office of Regulatory Staff witness Mr. Horii, to argue that there's a greater risk of higher natural gas prices and ultimately higher avoided costs than a risk of lower natural gas prices and lower avoided costs.[30] Ms. Chilton argued that the potential benefits of locking in lower QF purchase prices now is greater than the potential risk.[31]

## 2.4 Transparency of Avoided Cost Filing

Act 62 specifies that "Each electrical utility's avoided cost filing must be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission."[32] In this section, Power Advisory assesses the transparency of DEC and DEP's avoided cost filing. We note that the language in this section of the Act references the utility's avoided cost filing. DEC and DEP included as a confidential exhibit in the Direct Testimony of Glen A. Snider "supporting calculations used to derive the avoided energy and avoided capacity rates." While improvements can be made in subsequent biennial avoided cost filings, Power Advisory believes that DEC and DEP's avoided cost filing and subsequent responses to data requests and requests for production of documents resulted in an avoided cost filing that was reasonably transparent.

In his Rebuttal Testimony, Mr. Horii testifying on behalf of the Office of Regulatory Staff noted "The Companies provided data responses and supporting information to their filings that allowed me to conduct my analysis, assess the reasonableness of their proposals, and develop recommendations regarding the implementation of Act 62."[33] He also noted that "While I was able

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[28] With avoided costs levelized over ten years, there can be some rate impacts initially as the fixed rate paid to the QF may be higher than the actual avoided cost in the initial years of the PPA. Over the life of the PPA with accurate avoided cost projects there would be offsetting savings in the later years in the contract term.

[29] Hearing Vol 2, p. 89 (ORS Horii) and ORS Horii Surrebuttal, p.8.

[30] Hearing Vol 2, p. 92-93, lines 19-14 (ORS Horii).

[31] Hearing, Vol 1, p. 354, lines 20-21 (JDA Chilton).

[32] Act 62. Section 58 41 30 (J)

[33] ORS Horii Surrebuttal, p. 5, lines 4-6.

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to do a quick assessment and identify clear issues with some of the Companies' assumptions, future proceedings would benefit from a more expanded period of time allowed for testimony and rebuttal testimonies."[34] Power Advisory concurs with Mr. Horii's comments regarding the schedule.

In his Surrebuttal Testimony, Mr. Burgess recommends that Duke provide additional transparency regarding the following assumptions: (1) Detailed descriptions of must-run and cycling restrictions and the rationale for including these; (2) Hourly data on when must-run units are operating; (3) Hourly data on pumped hydro dispatch in the base case and change case; and (4) Hourly data on the timing of individual unit starts.[35] Given the significant proportion of hours with negative avoided costs such information would enhance the transparency of the Companies' avoided cost filing.

## 2.5 Avoided Energy Cost Estimates

The Companies use the peaker methodology to estimate avoided costs, which is a widely accepted industry standard approach to quantifying avoided costs.[36,37] As Mr. Snider notes in his Direct Testimony "[t]his approach assumes…the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal…energy costs that a utility avoids by purchasing power from a QF."[38] The Companies used a production cost simulation model (PROSYM) to estimate the hourly avoided energy costs of a fixed block of 100 MW that was assumed to be available throughout the year. The model is specified to reflect the Companies' generation resources including capacity ratings, outage rates, physical constraints (e.g., start times) and variable operating costs (i.e., fuel, environmental costs and variable operations and maintenance expenses). Hourly customer demand is also reflected, with the model dispatching generating units to meet hourly customer load at least cost. The Companies' noted that the "avoided energy and capacity costs are calculated using largely the same data inputs and assumptions presented in DEC's and DEP's 2019 IRPs."[39]

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[34] ORS Horii Direct, p. 5, lines 10-13.

[35] SBA Burgess Surrebuttal, p. 13, lines 16-20.

[36] Mr. Horii characterizes the methodology as a Differential Revenue Requirement (DRR) methodology (ORS Horii Direct, p. 7.). Mr. Snider indicated that the DRR methodology is just a variant of the peaker methodology (Hearing Vol 1, p. 117, lines 10-11.).

[37] Hearing Vol 1, p. 45, lines 22-23 (Duke Snider).

[38] Duke Snider Direct, p. 10.

[39] Duke Snider Rebuttal, p. 9-10, lines 20-1.

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To project avoided energy costs the model is run for both a "Base Case" and a "Change Case", which reflects the addition of a 100 MW generator available in all hours. The difference in the hourly energy cost between the Base Case and the Change Case is the hourly avoided energy cost. The Companies then aggregated these hourly avoided energy cost values into nine energy price periods in each year from 2020 to 2029, with these annual values levelized to produce 10-year levelized avoided energy cost estimates, which are adjusted for losses recognizing the assumed interconnection voltage of the QF on the Companies' system, incremental working capital requirements and applicable excise taxes. The nine energy pricing periods are summer premium-peak, on-peak, and off-peak; winter premium-peak, on-peak (AM and PM), and off-peak; and shoulder-season on-peak and off-peak.

Mr. Burgess offers a number of criticisms of the Companies' avoided energy cost estimates, a number of which Power Advisory believes warrant consideration and further discussion.[40] First of all, a significant portion of the hourly avoided energy costs are negative, particularly during periods when solar projects are likely to be operating. Second, the pricing periods that they have employed appear to inappropriately reduce the avoided energy cost rates during hours when solar resources are available. Each of these issues is discussed in turn.

### *2.5.1 Negative Avoided Energy Costs*

In response to the SBA First Set of Interrogatories (2.b.) as well as other similar data requests, the Companies provided detailed summary spreadsheets of the hourly avoided cost modeling results of the difference between the Base and Change Case for both DEC and DEP. A review of these spreadsheets indicates that during a significant proportion of hours the estimated hourly marginal cost values are negative. In his Direct Testimony, Mr. Burgess indicates that for DEC 16% of the avoided cost hours calculated for 2019 through 2029 were negative and 10% for DEP.[41] Importantly for solar resources, Mr. Burgess notes that during the "summer peak periods, when both demand is high and solar resources are most available, the number of hours with negative avoided costs is as high as 20% or more for both DEC and DEP (See Figure 2).[42] Mr. Burgess

[40] In his Direct Testimony, Mr. Horii when asked if he recommended any changes to the Companies' avoided energy cost calculations or resulting rates stated: "No. Based on my review, the avoided energy costs reflected by the Companies in the Standard Offer tariffs are a reasonable result of the Companies' calculations." (ORS Horii Direct, p.10, lines 9-10). In his Surrebuttal Testimony, Mr. Horii disagrees with one element of Duke's modeling (major maintenance costs), but acknowledges the impact of this is negligible (p.4-6).

[41] SBA Burgess Direct, p. 22.

[42] Ibid.

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estimates that the presence of these negative values results in a 30% reduction in total avoided costs (and corresponding QF revenues) for DEC and a 28% reduction for DEP.[43]

**Figure 2. Burgess Estimate of DEP Percent of Summer Weekday Hours when Avoided Costs are Negative[44]**

In their Rebuttal Testimony, the Companies responded to Mr. Burgess' criticism and seek to explain the incidence of negative avoided costs.

> "Negative avoided costs occur for a variety of reasons when QF energy is added to the system. For example, the inclusion of no-cost QF energy can shift combustion turbine ("CT") starts from one hour to the next, thereby creating an instance where a start cost is avoided in one hour but the cost is then incurred in the next hour. The addition of no-cost QF energy creates conditions that can lead to negative avoided costs in some hours that are seen in both the model, as well as on the actual Duke system."[45]

> "any time a generating unit is added to a resource stack, particularly a generator that acts like a baseload resource (such as a 100 MW no-cost resource) the timing of unit commitment and dispatch of the entire resource stack can change. In a security constrained unit commitment and dispatch model, the no-cost resource will impact the dispatch of a variety of units which can lead to changes in operating parameters such as the timing of unit starts, pump hours at pumped hydro storage facilities, and the timing

[43] Ibid.

[44] SBA Burgess Direct, p. 25.

[45] Duke Snider Rebuttal, p. 20 lines 10-17.

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> of ramps of conventional generators. The shifting of unit starts and pump hours at the hydro storage facilities account for the majority of negative avoided cost hours."[46]
>
> "Over this time period, 16% of all hours in DEC contained "negative" avoided cost hours, while 10% of all hours in DEP contained "negative" avoided cost hours. The Companies then looked at the number of hours where either conventional unit start costs or a pumped hydro pump costs were incurred in the change case and not in the base case. In DEC, unit start and pumped hydro pump changes correlated with negative avoided cost hours 88% of the time. In DEP, unit start and pumped hydro pump changes correlated with negative avoided cost hours 80% of the time."[47]

Clearly, these negative values significantly affect the avoided costs available to solar QFs. To the degree that these negative avoided cost values are reasonable reflections of system costs stemming from operating constraints, then Power Advisory asked the Companies if avoided costs could be increased by constraining down QF generation in some hours. The Companies responded:

> "It would not be possible to execute this strategy as solar curtailment would not reduce the "negative costs" referred to in the prior response. For instance, in the case of a CT start that was presented in Duke Witness Snider's rebuttal testimony, the reason that a negative avoided cost hour was incurred was not because there was an additional start, but rather the start was shifted out in time."[48]

On the other hand in response to a question from Vice Chair Williams, the Companies' Vice President of the System Planning and Operations Department, Mr. Holeman agreed that there are times when the Companies elect to decommit a generating unit given levels of solar output and then have to shortly thereafter start a unit and that this need to start a unit (e.g., a CT) could be avoided by dispatching down solar generation.[49] Power Advisory also notes that the Companies laud the operating flexibility provided by the North Carolina Competitive Procurement of Renewable Energy (CPRE) and cite this as a significant benefit relative to the lack of flexibility associated with PURPA-QFs. Power Advisory believes that there are potential savings from such operating flexibility that could benefit customers and QFs and make it easier to operate the Companies system, which have not been adequately acknowledged.

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[46] DEC/DEP Response to Power Advisory Second Set of Interrogatories, #2-1 (a).

[47] Ibid., #2-1 (b).

[48] Ibid., #2-2.

[49] Hearing Vol 1, p. 316-319 (Duke Holeman).

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### *2.5.2 Coal Unit Retirements*

In late September Duke announced that it was accelerating the retirement dates of several coal-fired units including two coal-fired Allen Steam Units (Units 4 & 5) with a rated capacity of about 526 MW, which are now scheduled to retire in 2024 and Cliffside Unit 5 (540 MW), which is now scheduled to retire in 2026.[50] Mr. Snider acknowledged that these retirements could advance DEC's need for additional capacity to 2025, but indicated that this would have a relatively modest impact on avoided capacity rates for DEC.[51] Furthermore, he argued that there would be a corresponding change in avoided energy costs from the introduction of a new more efficient natural gas unit.[52] Mr. Burgess took an alternative perspective and asserted

> "the fact that these coal units are online in the first place means that they push down the remaining portion of the generation supply curve. This in turn will affect which gas generation unit is backed down due to the addition of a QF (relative to a scenario where the coal unit was not online). Put differently, if the must-run coal units were not included, the marginal gas unit that is displaced would more likely be a higher-cost, less-efficient gas unit. In that case, the avoided cost may be higher than what is currently modeled."[53]

Power Advisory also notes that the high proportion of hours with negative avoided energy costs could also be contributing to the presence of these relatively inflexible coal units that are being retired and with their retirement, the proportion of these avoided energy costs will be reduced. Power Advisory was unable to establish what the likely impact on avoided energy costs of these coal unit retirements would be. However, we recommend that for future avoided cost filings the Commission direct utility companies to base their avoided cost analyses on best available information that reflects anticipated unit retirements.

### *2.5.3 DEP East and DEP West Integration*

Mr. Burgess also expressed concern with respect to how the Companies avoided cost analysis established avoided costs for DEP given the presence of two separate balancing areas (BAAs).[54] The Companies clarified that "DEP-East and DEP-West BAAs operate as a single DEP NERC Balancing Authority, and are interconnected through firm transmission interconnects that allow integrated system dispatch of all fleet generating units in DEP-East and DEP-West to serve load

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[50] Hearing Vol 1, p. 147, lines 11, 15, p. 148, lines 8, 12 (Duke Snider).

[51] Ibid., p. 151, line 19.

[52] Ibid., p. 151, lines 23-24.

[53] SBA Burgess Surrebuttal, p. 12, lines 17 -24.

[54] SBA Burgess Direct, p. 68 lines 6-11 and p.69 lines 1-8.

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in both DEP-West and DEP-East."[55] Furthermore, in response to a Power Advisory Interrogatory the Companies noted that "the DEP Balancing Authority Areas ("BAAs"), namely DEP West and DEP East, are interconnected through firm transmission that allows energy to flow from East to West and vice versa. In the production cost model, because of this firm transmission interconnection, when 100 MW of no-cost generation is added to the model, both DEP BAAs interact to re-optimize generation from the base case. As both BAAs are interconnected, the production cost delta is applied across the total DEP system."[56]

Importantly, DEP system operators commit and dispatch resources in DEP East and DEP West collectively to meet the collective load of the two BAAs. They do not independently commit and dispatch resources in each of the two BAAs. Finally, the Companies noted that "During three (3) instances over the last five (5) years, none within the past three (3) years, the transfer of energy has been constrained between DEP East and DEP West for a total four hours…less than 0.01% during the last five (5) years."[57] At the Hearing, Mr. Burgess argued that in markets relatively few hours of congestion can result in very high energy prices.[58] Power Advisory notes that Mr. Burgess' argument applies to competitive electricity markets with locational marginal prices where competitive generators can capitalize on transmission congestion to realize higher prices and resulting revenues and doesn't apply to a regulated electric utility where systems costs are based on directly incurred marginal operating costs. Based on the limited number of hours when there is congestion and the costing constructs used in a regulated electricity system, Power Advisory believes that there is not an issue that needs to be remedied, recognizing that in this instance the Companies modeling reflects system conditions.

### *2.5.4 Selection of Avoided Cost Periods*

As discussed, the Companies have proposed nine energy pricing periods for the avoided energy costs. In response to a Power Advisory data request regarding why it is appropriate to establish distinct pricing periods, the Companies noted that:

> "the time-of-use rate design proposed by the Companies is applicable to all QFs, not just solar generators, and reflects the value of energy during each rating period. The proposed design was developed in response to a North Carolina Utilities Commission ("NCUC") requirement to offer more granular rates that better aligned with the actual cost of generation during each period…The rate design considerations … address forecasted cost,

[55] Duke Snider Rebuttal, p. 27-28.

[56] DEC/DEP Response to Power Advisory Second Set of Interrogatories, #2-4.

[57] Ibid.

[58] SBA Burgess Hearing Vol, p. 346-347.

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future changes in Company load characteristics, and administrative concerns to be certain the design could be efficiently implemented and provide appropriate price signals over the entirety of a levelized contract term."[59]

The Companies assert that "the avoided energy payment rate designs provide sufficient seasonal and hourly granularity and appropriate price signals and incentives for QFs to maximize output during times when energy has the most value to the Companies and their customers."[60] In his Direct Testimony, Mr. Burgess asserted that "the arbitrary selection of time periods undervalues the true daytime avoided cost, therefore biasing against daytime QF production such as solar power. A different selection of pricing periods would more accurately reflect avoided cost [sic] and could significantly affect solar compensation."[61] In response to this critical assessment of these periods by Mr. Burgess, Mr. Snider argues, "the energy rate design should reflect the Companies' cost of service and system needs, as well as encourage QF generators to adjust their operation to maximize their production during hours that are most beneficial to retail customers and therefore, the system as a whole."[62]

Power Advisory notes that the vast majority of QFs that are likely to avail themselves of these avoided costs are non-dispatchable solar projects and are not able to adjust their operation to follow the price signals sent. The construction of these periods is important and the establishment of broad periods that are composed of hours with significantly varying prices can adversely affect the economic efficiency of these periods as discussed further below. As basic principle, electricity rates should be designed to reflect costs, to promote efficiency in the use or production of electricity and equity across customers or suppliers. These periods and the associated avoided costs for DEC and DEP are shown in **Figure 3** below. The Companies suggest that this is just an interest of solar QFs and imply that because the design of these cost periods may only affect one resource that such a concern isn't valid. Power Advisory notes that the vast majority of the resources that are to avail themselves of these avoided cost rates are solar QFs and that any bias to these resources warrants further consideration.

Furthermore, when asked whether avoided energy cost rates that varied by hour would be more appropriate the Companies noted "an hourly design using forecast energy data would yield different rates in each hour, but would fail to reflect real-world dynamics that cause actual cost to substantially differ from the ten-year weather normal forecast used to calculate rates in this proceeding. For example, in any given hour the system load response to abnormal weather and generation plant availability may cause a shift in the relative value of a particular hour. So while

[59] DEC/DEP Response to Power Advisory Second Set of Interrogatories, #2-3.

[60] Duke Snider Direct, p. 29.

[61] SBA Burgess Direct, p. 39.

[62] Duke Snider Rebuttal, p. 39.

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the nine energy price periods outlined in this filing provide reasonable price signals between the identified periods, going to a more granular hourly forecast would not necessarily produce a better price signal."[63]

**Figure 3: DEC & DEP Proposed Avoided Cost Periods and Rates[64]**

| Energy Rates | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Independent Energy Price Blocks | 1.Summer Premium Peak (PM) | | 2.Summer On-Peak (PM) | | 3.Summer Off-Peak | | 4. Winter Premium Peak (AM) | | 5.Winter On-Peak (AM) | | 6.Winter On-Peak (PM) | | 7.Winter Off-Peak | | 8.Shoulder On-Peak | | 9.Shoulder Off-Peak | |
| Company | DEC | DEP | DEC | DEP | DEC | DEP | DEC | DEP | DEC | DEP | DEC | DEP | DEC | DEP | DEC | DEP | DEC | DEP |
| 10-Yr Rate (cents/KWH) | 4.58 | 3.30 | 4.48 | 3.11 | 2.60 | 2.68 | 5.04 | 3.58 | 4.61 | 3.54 | 4.15 | 3.42 | 2.70 | 2.75 | 3.39 | 2.98 | 2.28 | 2.26 |

| DEC Energy Hour Ending | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Summer (Jun-Sep) | 3.Off | | | | | | | | | | | | 2.On (PM) | | | | 1.Premium | | | | 2.On (PM) | | 3.Off | |
| Winter (Dec-Feb) | 7.Off | | | | | 5.On | 4.Premium | | | 5.On | 7.Off | | | | | | | 6.On (PM) | | | | | 7.Off | |
| Shoulder (Remaining) | 9.Off | | | | | | 8.On | | | | 9.Off | | | | | | 8.On | | | | | | | 9.Off |

| DEP Energy Hour Ending | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Summer (Jun-Sep) | 3.Off | | | | | | | | | | | | | 2.On (PM) | | | 1.Premium | | | | 2.On | | 3.Off | |
| Winter (Dec-Feb) | 7.Off | | | | 5.On (AM) | | 4.Premium | | | 5.On (AM) | | 7.Off | | | | | | | 6.On (PM) | | | | 7.Off | |
| Shoulder (Remaining) | 9.Off | | | | | | 8.On | | | | 9.Off | | | | | | | 8.On | | | | | | 9.Off |

Power Advisory performed some independent analysis of the projected hourly avoided costs to assess the degree to which the avoided cost energy pricing periods appear to inappropriately bias the value of energy realized by solar QFs. Such bias can occur if price levels within a pricing period vary significantly and a specific technology (e.g., solar) has a disproportionate share of its output in a portion of the pricing period with a higher or lower value. Specifically, solar projects produce only during daylight hours. If avoided costs are generally forecast to be higher during daylight hours, but the pricing period is composed of both some lower value nighttime hours and some higher value daylight hours, then these pricing periods would undervalue the solar QF's output and not properly reflect the value of this output to customers. This analysis suggested that there was a modest underpayment for solar QFs under DEC's rates and overpayment under DEP's rates. We recommend that the Commission direct the Companies to provide appropriate analytical support for their avoided cost periods in subsequent filings.

## 2.6 Large QF Avoided Cost Summary

### Duke's Position

For large (greater than 2 MW) non-standard offer QFs, Duke plans to use the same peaker methodology. However, the inputs to the modelling are only discussed theoretically as the Companies plans to use most-recent available values at the time of performing the modelling. For

[63] DEC and DEP Response to Power Advisory Second Set of Interrogatories, No. 4.

[64] Duke Snider Direct, p. 27 Figure 3.

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example, fuel costs will be updated to reflect the then-prevailing value of avoided fuel and the actual production profile of the large QF will be modelled.

**Intervenor Comments**

SBA witness Burgess in his Direct testimony, critiqued Duke's proposal for the development of avoided cost rates for non-standard offer QFs larger than 2 MW.[65] The peaker methodology adds a hypothetical 100 MW of no-cost generation to the utilities' generation fleet as reflected in the base case. This method makes no distinction between resource types. On the other hand, the proposed non-standard QF approach will take the specific supply characteristics into account and will include solar generation profile for solar QFs. Mr. Burgess argues that the estimation of avoided cost rates should be kept consistent across all QF contracts. Burgess claimed the methodological changes in the non-standard offer calculation are not transparent.[66]

**Power Advisory Opinion**

Duke is proposing to calculate the avoided cost rate for the large QF at the time of request. As such there isn't an opportunity to review these avoided costs. However, calculating the rate at the time of the request, ensures that the avoided cost rate reflects current assumptions and avoids the risk of stale avoided costs, which can be more significant for a large QF. Furthermore, the avoided cost rate will reflect the specific operating profile of the large QF and result in a more reliable avoided cost rate.

## 2.7 Avoided Capacity Cost Estimates

### *2.7.1 Assessment of Avoided Capital Cost Methodology*

DEC and DEP have used the peaker methodology to estimate the avoided capacity cost. As Mr. Snider notes in his Direct Testimony "This approach assumes that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a simple-cycle combustion turbine ("CT") generating unit (a "peaker") plus the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF."[67] Mr. Snider notes that the Companies have consistently used the peaker methodology to forecast avoided energy and capacity costs and that the methodology has widespread acceptance.

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[65] SBA Burgess Direct Amended, p. 29-31.

[66] Ibid.

[67] Duke Snider Direct, p. 10.

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As noted in Mr. Snider's Direct Testimony, the peaker methodology implicitly assumes that peakers or simple-cycle combustion turbines represent ideal form of generation addition to meet future capacity needs. DEC & DEP's most recent Integrated Resource Plans (IRP) indicate that the most immediate utility sponsored capacity additions will be combined cycle gas turbines (CCGTs) and CTs.[68] For the ten-year term of the Companies' avoided cost forecast, DEP's IRP proposes the development of a 1,341 MW CCGT in 2025 and an additional 1,341 MW CCGT in 2027, with 470 MW of CTs in 2028 and 1,880 MW in 2029. DEC's IRP specifies a 470 MW CT in 2026 and a 1,341 MW CCGT in 2028.

DEP's most immediate capacity need is addressed by two CCGTs, suggesting that these are a better fit, with the incremental capital cost of the CCGT offset by additional energy savings produced by the CCGT's lower heat rate. DEC's most immediate capacity need is addressed by a CT, with a larger CCGT added two years later. Given the Companies' proposed resource additions, Power Advisory believes that the peaker methodology is reasonable methodological basis for establishing the companies avoided costs. Mr. Burgess concurs and notes that "the general framework (i.e., the Peaker Methodology) is sound."[69]

Mr. Burgess offers several criticisms of the Companies avoided capital cost estimates including: (1) the assumed capital cost of a new peaker are understated by the assumed technology type, economies of scale, and associated fixed costs; and (2) the timing of assumed capacity value from a QF understates this value.

### *2.7.2 Capital Cost of a New Peaker*

Mr. Burgess recommends that an aeroderivative peaker be used as the basis for DEP/DEC's avoided capacity cost estimate. He argues that such a peaker is more likely to be representative than the type of resource that Duke adds for its avoided capital cost analysis (i.e., a lower capital cost frame unit). This may be true, but it doesn't mean that an aeroderivative peaker is the appropriate avoided cost benchmark. Mr. Burgess suggests that such an aeroderivative peaker maybe preferred by DEP/DEC because of its greater operating flexibility including quick start and ramping capability, both of which are valuable given higher solar penetration rates in their service territories. We note that these services represent additional value offered by this technology, value that is attributable to their ability to provide the associated ancillary services. We believe that this value should be deducted from the cost of these units. These are services that a QF solar unit isn't likely to be contracted to provide. Therefore, it would not be appropriate to base the solar resources' capacity payment on the aeroderivative peaker's capital cost because it isn't providing

[68] DEP/DEC, "Integrated Resource Plan Update Report 2019," September 2019

[69] SBA Burgess Direct, p. 44.

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the same service.[70] Alternatively, the Companies may elect to install such an aeroderivative peaker for this incremental value, which could in turn be recovered by a solar integration charge.

In his Rebuttal Testimony, Mr. Snider makes a related argument. "I do agree with Mr. Burgess that aero-derivative CTs could be a future way for the Companies to manage the intermittent output of must-take solar generators. In that event, however, the cost causer for the more expensive aero-derivative CT would be the solar providers themselves and thus, the incremental cost of constructing aero-derivative CTs versus F-class CTs should be paid by the solar providers and not paid for by customers to the solar providers."[71] In essence, Mr. Snider is arguing that the incremental cost of an aero-derivative CT versus a F-class CT would be a proxy for the SISC. Power Advisory agrees with the Companies.

In his Direct Testimony Mr. Snider notes "the Companies adjusted the EIA data to reflect the economies of scale associated with land, buildings, roads, security, gas interconnection and other infrastructure for a 4-unit CT site."[72] Mr. Burgess also critiques the Companies' capital cost estimate given that it reflects a $70/kW credit for economies of scale offered by a four-unit CT. The Companies responded that eight of their eleven sites with CTs have four or more CTs so its economies of scale adjustment is appropriate and reflects the ability to share infrastructure among multiple CTs, which reduces the CT's unit costs ($/kW).[73] Power Advisory agrees with the Companies.

Mr. Burgess also argues that the Companies should include the costs of transmission upgrades necessary to interconnect the CT to its transmission network.[74] Mr. Snider noted that "[s]ometimes a utility's construction of new generation facilities will require transmission upgrades, but not all new generation additions require such upgrades."[75] Power Advisory notes that avoiding transmission upgrades can be an important driver of the location of new utility resources and as a result believes that adding such a cost is likely to be speculative and inappropriate without additional evidence that such network upgrades are likely.

### *2.7.3 Capacity Value Timing*

Mr. Burgess also asserts the Companies underestimated the capacity value in terms of timing. The Companies effectively acknowledged this with respect to DEC given the recently announced retirements of Allen Units 4 & 5 and Cliffside 5, which would advance DEC's need for additional

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[70] Power Advisory acknowledges that Mr. Burgess does assert that solar projects can provide a number of the services that more traditional resources that provide reserves offer.

[71] Duke Snider Rebuttal, p. 44.

[72] Duke Snider Direct, p. 15, lines 2-5.

[73] Duke Snider Hearing, Volume 1, p. 241 lines 12-15.

[74] SBA Burgess Direct, p. 58-59.

[75] Duke Snider Rebuttal, p. 48 lines 8-10.

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capacity to 2025. As discussed earlier, the Companies argue that there would be a more than offsetting reduction in avoided energy costs, which they suggest makes an adjustment of avoided capacity costs for DEC inappropriate or unnecessary. Power Advisory doesn't agree that this is necessarily the case given that inflexible higher cost coal units could reduce avoid energy costs when operating at minimum load to ensure their availability in other periods. Therefore, we recommend that DEC's avoided capacity cost be adjusted to reflect a one-year acceleration of the year in which capacity is required to 2025.

With respect to DEC, it assumes no capacity value prior to 2026, the first year of anticipated need and assumes no capacity value after 2029 for either Company. Mr. Burgess asserts that DEC QFs can provide capacity prior to 2026 and by so doing enable DEC to make additional sales of surplus capacity and therefore, this capacity value should be considered based on its market value. In his Rebuttal Testimony, Mr. Snider argues that:

> "From a legal perspective, utilities are not obligated to pay QFs for capacity that exceeds system needs, such as for resale in a capacity market under PURPA. FERC has long held that 'an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity…[the purchase] obligation does not require a utility to pay for capacity that it does not need.'[76] FERC has also expressly stated that 'there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements," as neither PURPA nor FERC's regulations require utilities to pay for the QF's capacity irrespective of the need for the capacity.'"[77]

With respect to the second issue of no assumed capacity value after 2029, the analysis and valuation period is through 2029. While the Companies my realize additional value at the end of the contract term this is by no means certain. Mr. Snider argues that "at the time their current PPA expires whether or not to establish a new legally enforceable obligation ("LEO") and contractually commit to deliver their full output, including capacity, to the utility, whether to cease operations after their current contract expires, or whether to otherwise use their facility in any lawful manner they so desire, based on the current economic, regulatory, and market circumstances existing at the time their current PPA expires."[78] Power Advisory believes that reflecting capacity value after 2029 in the avoided capital cost estimates would violate the direction in Act 62 to "reduce the risk placed on the using and consuming public."

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[76] City of Ketchikan, 94 FERC ¶ 61,293 (2001) ("Ketchikan") citing Order No. 69, FERC Stats. & Regs., Preambles 1977-1981, P30,128 at 30,865.

[77] Ibid.

[78] Duke Snider Rebuttal, p. 56.

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### *2.7.4 Weighting of Peak Periods*

Duke utilized an analysis performed by Astrapé Consulting that assessed the Loss of Load Expectation (LOLE) on a seasonal basis to set a seasonal weighting for avoided capacity. As stated in Witness Snider's direct testimony:

> "Seasonal allocation places capacity value into the appropriate season of the year that drives the Companies' reliability need for new capacity resource additions. For DEC and DEP, seasonal allocation is now heavily weighted to winter based on the impact of summer versus winter loss of load risk, which has been driven by the volatility in winter peak demand, as well as the growing penetration of solar resources and its associated impact on summer versus winter reserves. As presented in detail in the Solar Capacity Value study conducted by Astrapé Consulting and described in the Companies' 2018 IRPs, 100% of DEP's loss of load risk occurs in the winter and approximately 90% of DEC's loss of load risk occurs in the winter.16 Thus, DEP's filed rates in this proceeding pay all of its annual capacity value in the winter while DEC's new rates pay 90% of its annual capacity value in the winter and the remaining 10% in the summer period." [79]

As stated in Duke's evidence above, DEC and DEP are now primarily winter peaking for two main reasons: the growing penetration of solar capacity and volatility in winter peak demand. However, intervenors disagreed with Duke's position for several reasons.

ORS Witness Horii's concern is that Duke's analysis undervalues solar capacity because Duke is effectively assuming future solar capacity that is not yet contracted and is impacting the value of current solar capacity. In essence, Mr. Horii suggests the avoided costs put forth are calculated reasonably, but the assumption of how much solar capacity on the system is incorrect and as a result the avoided capacity value of solar resources is under-stated. As outlined in Mr. Horii's Direct Testimony:

> "DEC correctly allocates the capacity costs based on the relative Loss of Load Expectation ("LOLE") in each time period. However, DEC uses LOLEs based on 3,500 megawatts ("MW") of solar penetration on the DEC system. 3,500 MW of solar penetration is "Tranche 4" in the analysis nomenclature which is the highest level of solar penetration evaluated, and reflects solar penetration levels far in exceedance of current levels. DEC's allocations of avoided capacity costs to season and time of day, therefore reflect capacity needs too far into the future, rather than reflect what system capacity needs would be in 2020 when there are only approximately 840 MW (Company witness Snider direct testimony, page 35) of solar on the system.

[79] Duke, Snider Direct, p. 19.

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> This is problematic because the timing of the need for capacity when there are 840 MW of solar on the DEC system is not the same as the timing of the need for capacity when there are 3,500 MW of solar on the system. With the higher level of solar generation, the need for system capacity shifts away from hours when the already installed solar is generating."[80]

Duke disputes this characterization on the basis that the solar capacity projections used in their analysis can be reasonably expected to occur as they are largely mandated by North Carolina law, specifically NC HB 589.

> "North Carolina Session Law 2017-192, House Bill 589 ("N.C. HB 589") established the Competitive Procurement of Renewable Energy ("CPRE") Program competitive solicitation process, which calls for the addition of 2,660 MW of competitively procured renewable resources across the Duke Energy Balancing Authority Areas over a 45-month period. The total CPRE target of 2,660 MW via annual competitive solicitations will vary based on the amount of "Transition" MW at the end of the 45-month period, which N.C. HB 589 expected to total 3,500 MW. If the aggregate capacity of the Transition MW exceeds 3,500 MW, the competitive procurement volume of 2,660 MW will be reduced by the excess amount. N.C. HB 589 also allows for up to 600 MW of renewable energy procurement programs for large customers such as military installations and universities, as well as a community solar program.
>
> At the time that the Solar Capacity Value study was being conducted, the Companies' projection of total solar mandated by N.C. HB 589 and solar included in SC Act 236 corresponded to the "Tranche 4" level of solar in the study, which reflected 3,500 MW of cumulative solar for DEC and 3,585 MW for DEP. While the exact timing and amounts of transition and incremental solar additions may change over time, the Companies believe that it is reasonable to assume the cumulative mandated levels of solar under Tranche 4 for purposes of calculating the standard offer avoided cost rates."[81]

Mr. Snider suggests that the Tranche 4 level of solar capacity is the correct one to avoid double counting and over-payment.[82] Mr. Horii updated ORS' view in his Surrebuttal Testimony, but maintained the key point that avoided capacity costs should be set based on current conditions. He also suggests there is no overpayment risk by basing avoided costs on current conditions.

> "The total "Tranche 4" MW of renewable generation contemplated in the Competitive Procurement of Renewable Energy ("CPRE") Program is mandated by North Carolina law (HB589) to be integrated by a certain date in the future. However, avoided costs should be calculated based on current conditions. Specifically, Act 62 states "[e]ach electrical

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[80] ORS Horii Direct, p. 14.

[81] Duke Snider Rebuttal, pp. 59-60.

[82] Duke Snider Rebuttal, p. 63.

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> utility or incurred by the electrical utility…". "Tranche 4" represents an amount of future solar that has not yet committed to a contract price for power. As such, there is no overpayment risk because future solar will be evaluated based on avoided cost rates that exist at that time in the future. To be sure, if the future solar were paid based on higher avoided costs from the past, there would be an overpayment risk, but that risk would have nothing to do with the Qualifying Facilities' ("QF") solar.
>
> If avoided cost rates are calculated correctly, as I propose, they would reflect the cost conditions that exist at the time any contracts are signed. Overpayment would only occur if one group of solar QFs were paid based on a cost higher than actual avoided cost levels."[83]

Based on an updated understanding of current conditions, Mr. Horii suggested in his Surrebuttal Testimony that Tranche 1 solar capacity assumptions are the most appropriate.

> "In my direct testimony I recommended seasonal allocation factors based on the Loss of Load Expectation ("LOLE") from the Companies' "Existing Plus Transition" solar penetration case. With the signed CPRE contracts, solar penetration is comparable to the "Tranche 1" case, and I now recommend seasonal allocation factors based on the "Tranche 1" case. Using the same method described in my direct testimony, I calculated updated allocation factors shown below in Table 3 compared to DEC's proposed values and those I recommended in my direct testimony."
>
> Table 3 now shows Horii's view that DEC's capacity values should be weighted 30% to summer and 70% to winter.[84] DEP's capacity values, based on Horii's analysis, are weighted 99% winter and 1% summer, and did not change in his Surrebuttal Evidence.[85]

SBA Witness Burgess also disagreed with Duke's weighting on the basis of a number of concerns with Duke's modeling approach and assumptions.[86] In order to address these concerns, Mr. Burgess proposed that the seasonal capacity allocation be developed based on historical load patterns. "I recommend that the seasonal allocation that reflects this historical pattern as shown in the table above. I believe this is a simple and transparent approach and is an accurate representation of when Duke's historical peak loads have occurred. Additionally, this avoids any potential influence from opaque modeling approaches and associated inputs." [87]

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[83] ORS Horii Surrebuttal, pp. 7-8.

[84] ORS Horii Surrebuttal p. 10.

[85] ORS Horii Surrebuttal p. 11 and ORS Horii Direct, p. 18 for the 1% capacity value.

[86] SBA Burgess Direct, pp. 47-48.

[87] SBA Burgess Direct, p. 53.

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Duke disputed this approach, primarily on the basis that it only considered load and did not consider the impact of non-dispatchable solar generation.

> "SBA Witness Burgess and SACE/CCL Witness Wilson point out that DEC and DEP experience significant summer demands. However, as previously discussed, summer peaks occur in late afternoon hours when solar has significantly greater energy contributions as compared to dark winter mornings where very little – if any – solar is available at the time of peak. Thus, in the summer peak, loads net of solar output are reduced relative to winter peak loads net of solar. With the significant penetration of solar resources in recent years, the Companies no longer serve load, but rather serve load net of must-take solar output. It is the load net of solar that has an impact on summer versus winter reserves and LOLE values, and represents the actual net load that the remainder of the Companies' resources must satisfy. SBA Witness Burgess appears to completely ignore this fact in his analysis."

Mr. Burgess acknowledged Duke's concern in his Surrebuttal testimony, and developed revised summer/winter weightings based on the load shape approach he advocates as an alternative to the Duke approach. Mr. Burgess also addressed Duke's concern that his analysis relied on an excessive number of hours, and restricted his approach to the top 0.1% of peak net load hours, as compared to the top 10% of gross load hours in his original approach.[88] Based on this revised approach, Mr. Burgess estimates DEP as 96% winter and 4% summer, and DEC as 42% winter and 58% summer.

SACE/CCL Witness Wilson also identified concerns with Duke's analysis that the capacity need in the winter was over-stated relative to the summer need. In particular, Mr. Wilson suggested that Duke's resource adequacy studies exaggerated the increase in load due to low winter temperatures, as well as the peak winter demand response and operating reserve assumptions.[89]

With respect to the concern that the risk of winter peak loads is over-stated, Mr. Wilson provides evidence that the linear regression approach used by Duke is overly simplistic and exaggerates the load response to extreme temperatures.[90] Mr. Wilson outlines his view that the relationship between low temperatures and increased load weakens at very low temperatures largely because the demand induced by the low temperatures has already largely occurred.[91]

> "Through discovery, the Companies provided data showing the scenarios (weather year, day, hour, load forecast error assumption), that led to lost load in the 2016 RA Studies. For DEP, using all years, the RA Study has 86% of the expected load loss hours in winter; if only weather data 1997 and later is used, 75% of the load loss hours are in summer and only

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[88] SBA, Burgess Surrebuttal, p. 21.

[89] SACE/CCL Wilson Direct, p. 28.

[90] SACE/CCL Wilson Direct, pp. 32 Figure JFW-1 for example illustrates that at extremely low temperatures Duke's approach potentially over-estimates load by over 1,000 MW.

[91] SACE/CCL Wilson Direct, pp. 31, paragraph 20.

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> 25% are in winter. For DEC, 69% of the expected load loss hours are in winter in the RA Study; but if only weather since 1997 is modeled, 92% of the load loss hours are in summer, 8% are in winter. This data shows that in the RA Studies, the vast majority of the hours with load loss result from scenarios based on those instances of extreme cold from the 1980s and 1990s, and the overstated loads associated with them due to the flawed regressions. While including more rather than less historical weather data is preferred, excluding the 1982-1996 data quantifies how the flawed regressions have skewed the results and overstated winter resource adequacy risk. The data strongly suggest that if the regressions were corrected, the resource adequacy risk would still be weighted toward summer on both systems."[92]

Duke disagreed with Mr. Wilson's assessment, and noted that this issue has been examined and Duke has largely addressed concerns with the impact of extreme weather.

> "Load uncertainty due to extreme temperatures is a significant driver of LOLE and can be challenging to capture since there are few instances in recent history to correlate load with extreme temperatures. Based on results of some additional sensitivities requested by the NC Public Staff, the NC Public Staff was satisfied that the approach taken to capture the correlation of load and extreme weather was reasonable."[93]

In Surrebuttal Testimony, Mr. Wilson stated that the response of demand to extreme weather events was not covered in the Joint Report issued. Specifically, Mr. Wilson noted:

> "This [why NC Public Staff was satisfied] is not known; while the NC Public Staff's section of the Joint Report discusses other issues in some detail, with regard to this issue, NC Public Staff simply stated (p. 2), "After meeting with the Company, the Public Staff was satisfied that this approach was reasonable." NC Public Staff did not state why it dropped this issue. The Companies' section of the Joint Report was also silent on this issue.
>
> The December 2017 Presentation, however, addressed this issue over twelve slides, at pp. 9-20. In particular, this presentation included a sensitivity analysis that suggested this issue had only a modest impact on reserve margins (0.3%; p. 14). Perhaps NC Public Staff was swayed by this sensitivity analysis."[94]

**Power Advisory Assessment**

Power Advisory agrees with Mr. Horii that avoided costs should be calculated based on current solar levels, rather than expected future solar levels even where these are based on a legislated policy commitment. In effect, the avoided capacity cost of solar added to the system today should

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[92] SACE/CCL, Wilson Direct, pp. 35-36

[93] Duke, Snider Rebuttal, pp. 75-76.

[94] SACE/CCL, Wilson Surrebuttal, p. 6.

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be based on the amount of solar on the system today. Future additions would be based on the avoided cost at the time they are added, which would reflect the then current levels of avoided costs. This ensures there is no risk of overpayment. As such, Power Advisory believes that the capacity weightings proposed by Mr. Horii in his Surrebuttal Testimony are reasonable and that the Companies should be directed to update their avoided capacity cost rates to reflect these weightings.

Power Advisory notes that Mr. Wilson's evidence is compelling that Duke's approach to modeling the impact of extreme temperatures is problematic. However, Mr. Wilson's evidence does not suggest specific changes to be made to the summer vs. winter capacity ratings without further analysis. Power Advisory also notes that while the impact on required reserve margins of 0.3% noted by Mr. Wilson is not a material concern, this does not mean that the impact on the weighting of capacity value between summer and winter seasons is also immaterial.

Power Advisory believes the LOLE studies used by Duke are an appropriate methodology to assess the seasonal contribution of capacity. As such, the seasonal estimates put forth by Mr. Burgess using a simpler methodology should not be adopted, but represent a reasonable check on the LOLE modeling.

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# 3. SOLAR INTEGRATION CHARGES

## 3.1 Companies' Proposal

The Companies propose a Solar Integration Services Charge (SISC) based on an estimate of the average ancillary service cost of integrating variable solar generation. The Companies engaged Astrapé Consulting (Astrapé') to conduct a Solar Ancillary Service Study to analyze and quantify the ancillary service impact of integrating existing and future solar generation on both the DEC and DEP systems. Astrapé employed its proprietary Strategic Energy & Risk Valuation Model (SERVM) to conduct this Solar Ancillary Service Study. SERVM is used to estimate the required increase in regulating reserves and contingency reserves on the DEP and DEC systems to comply with mandatory North American Electric Reliability Corporation (NERC) resource and demand balancing (BAL) reliability standards.

The Companies' witness Nick Wintermantel explains that "The NERC BAL standards are minimum reliability requirements, so additional online reserves (frequently referred to as load following reserves) must also be carried due to net load uncertainty and intra hour volatility as well as the need to respond to unplanned generator outages. The more uncertain and volatile net load becomes, the more load following reserves are required to maintain the balance between resources and demand and thus, compliance with NERC BAL Reliability Standards in real-time."[95]

Astrapé developed a special metric to estimate the required increase in regulating reserves and contingency reserves from increases in solar energy on the DEP and DEC systems. Specifically, Astrapé created a Loss of Load Expectation (LOLE) based on its estimate of the number of loss of load events due to system flexibility constraints, calculated in events per year ($LOLE_{FLEX}$). Wintermantel characterizes this reliability metric in terms of "there was enough capacity installed on the system but not enough flexibility to meet the net load ramps caused by solar generation, or startup times prevented a unit coming online fast enough to meet the unanticipated ramps."[96]

Astrapé used SERVM to estimate the increase in regulating reserves and contingency reserves costs for an "Existing plus Transition" scenario which reflects 2020 solar installations of 840 MW and 2,950 MW in DEC and DEP and "represents the solar penetration the Companies expect to be installed on the DEC and DEP systems by 2020."[97]

Mr. Wintermantel explains: "SERVM commits resources to meet expected hourly net load and then randomly selects (or draws) from the intra hour historical datasets for load and solar separately

[95] Duke Wintermantel Direct, p. 6.

[96] Duke Wintermantel Direct, p. 15.

[97] Duke Snider Direct, p. 36.

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based on similar conditions. In other words, to simulate a peak load hour, SERVM randomly selects five-minute volatility data from the set of peak load hours in the historical intra hour load dataset. The selected five-minute volatility data for that hour is then applied to a perfectly smooth net load profile causing five-minute deviations. The conventional fleet is then forced to serve the net load with volatility. [98] In essence, these five-minute deviations must be balanced by the available generation fleet or a violation is recorded.

Based on this analysis, the Companies are proposing Solar Integration Service Charges of $1.10/MWh for DEC and $2.39/MWh for DEP.

## 3.2 Solar Integration Services Charge Settlement

The Companies' proposed SISC and the methodology employed to develop it were the subject of considerable dispute among the parties. Prior to the commencement of the hearings, various parties submitted a partial settlement agreement covering the SISC.[99]

The North Carolina Utilities Commission (NCUC) issued a supplemental notice of decision on October 17, 2019, in the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018. The decision addressed issues relating to DEC/DEP's proposed SISC. The issues addressed in the decision are some of the same as those being considered by the Commission in this proceeding. The highlights from the NCUC's directive are described below.

- All parties in the proceeding agree that DEC and DEP incur additional costs to integrate "Existing plus Transition" level solar QF facilities. It was also agreed that the quantification of near-term projected capacity represented by "Existing plus transitional" for DEC and DEP as 840 MW and 2950 MW is accepted as reasonable.
- Astrapé study's determinations that an additional 26 MW of load following reserves are required to integrate 840 MW of solar QFs in DEC, at an average cost of $1.10/MWh, and that an additional 166 MW of load following reserves are required to integrate 2,950 MW of solar QFs in DEP, at an average cost of $2.39/MWh, are reasonable for use in this proceeding.
- It is also accepted that DEC and DEP incur additional ancillary services costs and will account for these when calculating costs and benefits resulting from purchases of energy and capacity from solar QFs.
- Duke will also be required to calculate non-SISC rates available to controlled solar generators.

[98] Duke Snider Direct, p. 12.

[99] The parties included DEC/DEP, SBA, JDA and SACE/CCL.

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With the issuance of this supplemental decision that pertained to a study that was also submitted in this proceeding the parties entered into settlement negotiations. The resulting settlement agreement is summarized below.

1. DEC and DEP's quantification of near-term project capacity reflected by "Existing plus Transition" solar QF's to be installed, namely 840 MW and 2,950 MW, is reasonable.

2. For the purposes of this proceeding, the SISC of $1.10/MWh and $2.39/MWh for DEC and DEP are reasonable. This applies to small solar power producers that enter into PPAs or any Legally Enforceable Obligation before the effective date of avoided cost calculations filed in the next DEC / DEP avoided cost proceeding before the Commission. These charges will not be subject to any adjustment during the term of the PPA.

3. The SISC cannot be imposed on a "controlled solar generator". This refers to any solar QF that is capable and agrees to operate in a manner that materially reduces or eliminates the need for additional ancillary services incurred by Duke. This includes but is not limited to solar with battery storage. Duke is required to submit to the Commission, the guidelines to establish controlled solar generator by November 18, 2019.

4. The Astrapé study used to calculate the SISC warrants further review. Duke will submit all inputs and methodology of the Astrapé study for an independent technical review. The results of the review are to be filed in the next avoided cost filing by Duke for Commission review and interested parties to comment on.

5. Duke will submit revised Standard Offer and Large QF PPAs reflecting the stipulations of this settlement within 15 days of the Commission's final order approving the SISC.

Power Advisory accepts this settlement agreement as a reasonable accommodation among the parties regarding the contentious issues surrounding variable resource integration charges.

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# 4. FORM CONTRACT POWER PURCHASE AGREEMENTS, COMMITMENT TO SELL FORMS, AND OTHER RELATED TERMS AND CONDITIONS

## 4.1 Background on Commercially Reasonable Terms and Conditions

Act 62 specifies that the Commission should treat QFs on a fair and equal basis with electric utility-owned resources while protecting ratepayer interests. The relevant sections of the Act as it relates to this chapter of the report include the following (emphasis added):

- "Within such proceeding the commission shall approve one or more standard form power purchase agreements for use for qualifying small power production facilities not eligible for the standard offer. Such power purchase agreements shall contain provisions, including, but not limited to, **provisions for force majeure, indemnification, choice of venue, and confidentiality provisions** and other such terms, but shall not be determinative of price or length of the power purchase agreement. The commission may approve multiple form power purchase agreements to accommodate various generation technologies and other project specific characteristics."[100]

- "A small power producer shall have the right to sell the output of its facility to the electrical utility at the avoided cost rates and pursuant to the power purchase agreement then in effect by delivering an executed notice of commitment to sell form to the electrical utility. The commission shall approve a standard notice of commitment to sell form to be used for this purpose that provides the small power producer a reasonable period of time from its submittal of the form to execute a power purchase agreement. **In no event**, however, **shall the small power producer**, as a condition of preserving the pricing and terms and conditions established by its submittal of an executed commitment to sell form to the electrical utility, **be required to execute a power purchase agreement prior to receipt of a final interconnection agreement from the electrical utility**."[101]

- "Any decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public."[102]

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[100] Act 62. Section 58 41 10. (A)

[101] Act 62. Section 58 41 10. (D)

[102] Act 62. Section 58-41-20. (A)

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- "In implementing this chapter, the commission shall treat small power producers on a fair and equal footing with electrical utility-owned resources by ensuring that power purchase agreements, including terms and conditions, are **commercially reasonable** and consistent with regulations and orders promulgated by the Federal Energy Regulatory Commission implementing PURPA."[103]

- "In establishing standard offer and form contract power purchase agreements, the commission shall consider whether such power purchase agreements should prohibit any of the following: (a) **termination of the power purchase agreement**, **collection of damages from small power producers**, or commencement of the term of a power purchase agreement prior to commercial operation, if delays in achieving commercial operation of the small power producer's facility are due to the electrical utility's interconnection delays"[104]

- "The commission is expressly directed to consider the potential benefits of terms with a longer duration [than 10 years] **to promote the state's policy of encouraging renewable energy**."[105]

In this chapter, we examine terms and conditions of the Standard Offer PPA, the Large QF PPA and the Notice of Commitment to Sell Form, and consider their commercial reasonableness.

As specified by Act 62 a critical standard for assessing the reasonableness of the terms and conditions is the degree to which they are commercially reasonable. In the most basic sense commercially reasonable means terms and conditions that are consistent with concepts of good faith and fair dealing. For a PPA this requires a balancing of various principles and concepts including: (1) the terms and conditions should conform to industry norms and what is typical, with good comparables being other PURPA PPAs; (2) result in an appropriate alignment of risk, with risks best managed by those who have control over them; (3) the terms and conditions should not unduly impair the ability of the QF to secure financing. For example, if there is an unreasonable risk of termination of the PPA that cannot be adequately mitigated by the QF, or financial penalties that would imperil the ability to cover debt service, without a reasonable opportunity to remedy, or other significant risks related to the cash flows, the project would be in jeopardy of not securing financing; and (4) the terms and conditions should be reasonable from the perspective of

[103] Act 62. Section 58-41-20. (B) (2)

[104] Act 62. Section 58-41-20. (E) (3) (a)

[105] Act 62. Section 58-41-20. (F) (2)

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ratepayers and reflect the objective in the Act to reduce the risk placed on the using and consuming public.[106]

In our comments below, we have attempted to strike a reasonable balance between treating QFs on a fair and reasonable basis and protecting ratepayer interests, while striving to reduce the risk placed on the using and consuming public.

### *4.1.1 Implications of 10-year PPA Contract Length in South Carolina*

**Introduction**

As discussed, Act 62 represents a delicate balancing of the interests of the "consuming public" and the interests of QFs, while "striving to reduce the risk placed on the using and consuming public." However, as various parties pointed out the Act was passed unanimously in the South Carolina House and Senate. Given the effort devoted to drafting this legislation it would appear that there was an expectation by legislators that the Act would engender a response beyond the filings by various electric utilities. Nonetheless, Act 62 by no means establishes ensuring QF project development as a threshold. However, we expect that the Commission would be interested in understanding the implications of the proposed avoided costs on the resulting opportunities for QF development in South Carolina, recognizing that the Act provides:

> "Electrical utilities, subject to approval of the commission, shall offer to enter into fixed price power purchase agreements with small power producers for the purchase of energy and capacity at avoided cost, with commercially reasonable terms and a duration of ten years. The commission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, which must contain additional terms, conditions, and/or rate structures as proposed by intervening parties and approved by the commission, including but not limited to, a reduction in the contract price relative to the ten year avoided cost."[107]

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[106] Reflecting the balancing of these principles and the appropriate risk allocation, the QF is ultimately responsible for project construction and operation and the terms and conditions should provide proper incentives to ensure that these responsibilities are discharged in a manner the project provides the value that the utility has contracted for."the Scheduled Commercial Operation Date shall be no more than three years from the date the Effective Date."
PacificPower "Oregon Standard Power Purchase Agreement (New QF)", approved by the Public Utility Commission of Oregon, effective August 11, 2016, Section 2.3.
https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Power_Purchase_Agreement_for_New_Firm_QF_And_Intermittent_Resource_with_MAG.pdf

[107] Section 58-41-10. (F)(1)

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**Discussion**

Contract length was an important issue in this proceeding, with a number of intervenors arguing that contract lengths longer than 10-years were essential if QFs were to secure regularly-available market-rate financing, under the term employed by Johnson Development Associates, Inc. Witness Ms. Chilton. In discovery, Duke's questions centered on the basis for an obligation for QFs to obtain regularly-available market-rate financing and a standard of commercially reasonable access to capital in these dockets. In response, JDA highlighted the FERC precedent of *Windham Solar LLC and Allco Finance Limited*, 157 F.E.R.C. P61,134, ¶ 8, which states that PURPA contract term lengths "should be long enough to allow QFs reasonable opportunities to attract capital from potential investors" as well as Act 62. As JDA notes, the Act specifically allows the Commission to approve contracts beyond 10-years and asks it to consider such longer durations.[108]

At the heart of whether the 10-year contract term is sufficient or not to enable financing under reasonable terms is the contract price. As contract length shortens, the required PPA price to secure conventional financing increases owing to the riskiness of the cash flows in the post-PPA period. This relationship is illustrated in

Figure **4**. The figure contains PPA pricing for 30-year, 20-year and 10-year PPAs. In late 2017, through competitive bid, Georgia Power contracted for 510 MWs of solar in Georgia with an average price of $36/MWh for 30-year contracts.[109] Eighteen months later, in 2019, Duke contracted for 550 MWs of solar projects in North Carolina (CPRE Tranche 1) for an average price of $38/MWh for 20-year contracts.[110] Owing to the increased riskiness of the cash flows in the post-PPA term, the $/MWh price for a 10-year PURPA contract in South Carolina would need to exceed the $38/MWh figure. The problem is that the currently proposed avoided cost rates for the Companies are expected to be about $30/MWh, well below these figures.[111] Thus, without longer contract length, the solar industry would not be able to finance PURPA projects in South Carolina because they would not be economical. While the bar on the right shows a required PPA price to secure financing, Power Advisory has not calculated that price so the top part of the bar is illustrative only.

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[108] S.C. Code Ann § 58-41-20(F)(2)

"Act No. 62 of 2019 states that the "[C]omission may also approve commercially reasonable fixed price power purchase agreements with a duration longer than ten years, …"5 and "The [C]omission is expressly directed to consider the potential benefits of terms with a longer duration to promote the state's policy of encouraging renewable energy."

[109] Georgia Power, "Georgia Power renewable growth to continue throughout 2018: 970 MW of solar capacity online today, 510 MW of new solar contracts recently awarded" March 13, 2018 https://southerncompany.mediaroom.com/2018-03-13-Georgia-Power-renewable-growth-to-continue-throughout-2018

[110] Hearing Vol 2, p. 181 lines 9-13 (Duke Brown).

[111] Ibid.

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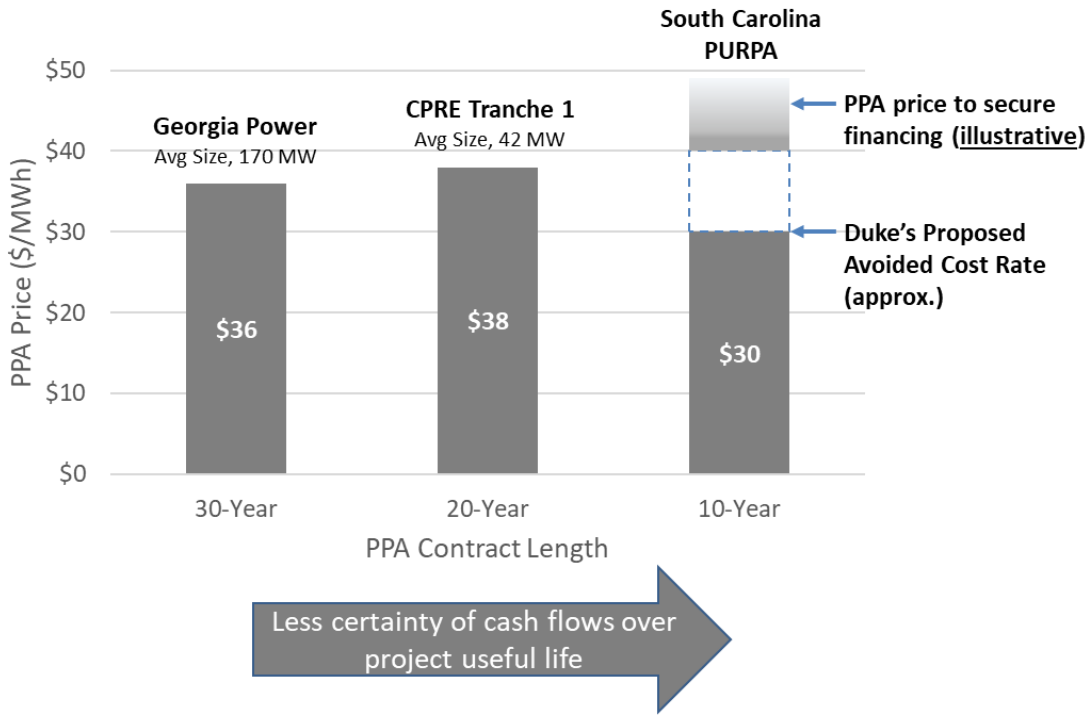
**Figure 4. PPA Price ($/MWh) vs. Contract Length (Years)[112]**




It's also important to note two things that could drive required PPA prices in South Carolina higher than these other benchmarks:

- The Investment Tax Credit (ITC) declines from 30% in 2019 to 26% in 2020, to 22% in 2021 to 10% in 2022, thus eroding solar economics over time (and drives required PPA prices higher).
- The comparable PPA rates for 30 year and 20 year have average project sizes of 170 MWs and 42 MWs, respectively. These sizes are much higher than the average South Carolina PURPA projects. Thus, project economics would be worse.

Two other investor concerns related to the 10-year contract length include the following:[113]

- It is hard to forecast the avoided cost of a given utility to understand what the pricing will be 10 years from now.

[112] Power Advisory.

[113] Norton Rose Fulbright, Project Finance NewsWire, August 2019, p.2, column 2, paragraph 4; accessible at: https://www.projectfinance.law/newswire-archive/august-2019/

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- There is regulatory risk in terms of whether there will still be a utility purchase obligation 10 years from now.

This is in contrast to an organized power market such as PJM, ISO-NE or ERCOT where there is a liquid market for electricity in the post-PPA term and far more confidence in the price forecasts. In addition, a hedge product can be used to put a floor under the electricity prices. As a result, shorter term PPAs are possible in these organized markets. By contrast, the risks in South Carolina in the post-PPA period are much harder to mitigate.

#### *4.1.2 Risk Mitigation*

One opportunity that would mitigate the risk to the investors in the post-PPA period would be to have some sort of upper and lower price bounds. This concept was raised by Mr. Levitas in his hearing testimony.[114] However, it would defeat the purpose of ensuring up to date rates for the ratepayers as the rates and guaranteed price range might not overlap.

**Intervenor Proposals for Terms and Conditions for Longer PPA Lengths**

It is important to note that the Intervenors were planning to propose terms and conditions for longer PPA lengths, however, Power Advisory did not receive these prior to submission of this report.

#### *4.1.3 Comparison with PURPA contract lengths in other states*

Power Advisory reviewed contract lengths in some of the most prominent PURPA states, where the market for PURPA projects has been the greatest over the past 10 years in megawatts (Figure 5). The average contract length of 15 states as shown in the figure is currently 14.1 years, down from 15.5 years when taking into account regulatory actions over the past few years. The current contract lengths ranged from 2 to 25 years, with a median of 15 years.

[114] Hearing Vol 1, p. 347 (SBA Levitas).

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**Figure 5. PURPA Contract Length by State Sorted Longest to Shortest [115]**

| State | Current Term (Years) | Date Effective | Increase/Decrease | Previous Term (Years) |
|---|---|---|---|---|
| Montana | 25 | Apr-19 | Retained same | 25 |
| Vermont | 25 | | Same | 25 |
| Oregon | 20 | Mar-16 | Retained same | 20 |
| Wyoming | 20 | Jun-16 | Retained same | 20 |
| New Mexico | 20 | | Same | 20 |
| Michigan | 20 | | Same | 20 |
| Utah | 15 | Jan-16 | Decrease | 20 |
| Washington | 12 | Jun-19 | Increase | 5 |
| Connecticut | 12 | | Same | 12 |
| North Carolina | 10 | Oct-17 | Decrease | 15 |
| South Carolina | 10 | May-19 | Retained same | 10 |
| California | 10 | | Same | 10 |
| Mississippi | 5 | | Same | 5 |
| Georgia | 5 | | Same | 5 |
| Idaho | 2 | Aug-15 | Decrease | 20 |
| **Average** | **14.1** | | | **15.5** |

The most significant change in contract length over the past few years occurred in Idaho, the third largest PURPA market over the last 10 years in megawatt additions, according to data from EIA.[116] In August 2015, at the request of the utility, the Idaho Public Service Commission reduced the PURPA contract length from 20 years to 2 years.[117] That made it the shortest PURPA PPA contract

[115] Power Advisory, based on various regulatory filings, Standard Offer PPAs and associated documents

[116] Data are from the US Energy Information Administration (EIA), EIA-860 database https://www.eia.gov/electricity/data/eia860/

[117] Idaho Public Utilities Commission, "Idaho commission reduces contract length for some PURPA projects to two years" Case No. IPC-E-15-01, AVU-E-15-01, PAC-E-15-0, August 19, 2015. https://puc.idaho.gov/press/150820_PURPAfinal_files.pdf

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length in the US and remains that way to this day. Although the QF was eligible for continual renewal of its contract every two years at then-current avoided costs, this effectively turned the project into a merchant plant, which had relatively little long-term revenue certainty. Since this ruling, no new QF projects of greater than 1 MW have become operational in Idaho according to data from EIA. In the wake of this change, several other utilities have requested their regulator reduce contract lengths to shorter durations. Some of the results of those requests are as follows:

- In Utah, the utility requested a reduction from 20 to 2 years, but the Public Service Commission decided to reduce it more moderately, from 20 to 15 years.[118]
- In Wyoming, several utilities asked its regulator to reduce the PURPA contract length from 20 years to 3 years but was denied.[119]

On the flip side, in June 2019, Washington State increased its contract length from 5 years to 12-15 years.[120]

### *4.1.4 Summary of Witnesses Commenting on PPA and NOC Documents*

The main witnesses for the PPA and NOC form terms and conditions were Mr. Levitas for SBA and Mr. Wheeler (Standard Offer PPA) and Mr. Johnson (Large QF PPA and NOC form) for Duke. In addition, there were other witnesses who touched on issues related to PPAs and NOCs but did not make proposed markups to the documents. These witnesses are:

- Jon Downey, Southern Current, representing SBA
- Hamilton Davis, Southern Current, representing SBA
- Brian Horii, E3, representing ORS
- Robert Lawyer, representing ORS

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[118] Public Service Commission of Utah, "In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities – Docket No.15-035-53 Order" Issued January 7, 2016 https://pscdocs.utah.gov/electric/15docs/1503553/2712701503553o.pdf

[119] "25. The Commission denies RMP's Application for authority to amend Schedules 37 and 38 to reduce the contract term of its PURPA PPAs with QFs from 20 years to three years. The Commission concludes that RMP failed to meet its burden to demonstrate that the proposed modification of the Wyoming PPA contracts is reasonable, will solve an alleged system-wide problem, and is in the public interest of Wyoming ratepayers."

Public Service Commission of Wyoming, "In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities," Docket No. 20000-481-EA-15 (Record No. 14220), June 23, 2016.

Similar decisions reached by the Wyoming PSC for the other utilities, notably PacifiCorp.

[120] Washington State Legislature, Chapter 480-106-050
https://apps.leg.wa.gov/wac/default.aspx?cite=480-106&full=true

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- Rebecca Chilton, representing Johnson Development Associates, Inc.
- George Brown, Duke

### *4.1.5 Summary of Issues*

Duke and SBA each provided direct, rebuttal (Duke) and surrebuttal (SBA) testimony as it relates to the Standard Offer PPA, Large QF PPA and Notice of Commitment (NOC) to Sell Form. They provided oral testimony at a hearing held before the Commission October 21-22, 2019. SBA also provided testimony in the Dominion hearing held Oct 14-15, 2019 during which Duke's terms and conditions were cited on occasion.

#### *4.1.5.1 Resolved Issues*

The parties have come to a negotiated agreement on several issues originally cited in Mr. Levitas' Direct Testimony as warranting revision. This is viewed by Power Advisory as evidence that these negotiated terms are fair and reasonable. These included the following organized by the document to which they refer.

**Standard Offer PPA**

Requests accepted by SBA:

- Agreed to Material Alterations subject to two conditions: (1) Duke's consent to requested material alterations will not be unreasonably withheld, conditioned or delayed and (2) changes are made prospectively not retroactively.

Requests accepted by Duke:

- Accepted the first condition above (but not the second one)
- At the request of ORS, agreed to remove "estimated annual energy production" from its definition of Existing Capacity which was included in Material Alterations. A number of other points were negotiated between SBA and Duke as a result of the inclusion of this term (estimated annual energy production) but became a moot point after Duke agreed to remove it.
- Agreed to adopt a modification to Duke's Storage Protocol whereby the QF is required to levelize the output of the overall Facility (solar plus storage) over the Capacity Hours, thereby avoiding the need for curtailment.

**Large QF PPA**

Requests accepted by SBA:

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- Accepted proposal for liquidated damages equal to the average annual estimated capacity payments under the Agreement over the Term for up to 15 MW and $10,000/MW-AC thereafter.

Requests accepted by Duke:

- Agreed to adopt a modification to Duke's Storage Protocol whereby the QF is required to levelize the output of the overall Facility (solar plus storage) over the Capacity Hours, thereby avoiding the need for curtailment.
- Agreed to replace PPA termination for failure to comply with confidentiality or publicity provisions of the PPA with liquidated damages but maintaining all legal remedies available as need be.
- Agreed to enter into a new or modified PPA agreement that is consistent with the Commission's Order.
- Agreed to allow force majeure as a reason to extend the COD Milestone Date.
- Agreed to set the COD Milestone Date at 90 days after the Interconnection Facilities and System Upgrades In-Service Date and allow for day-to-day extensions to account for any delays not caused by the Seller QF.

**Notice of Commitment (NOC) to Sell Form**

Requests accepted by Duke:

- Agreed to provide 10 Business Day cure period for Section 6.iii of the form (related to PPA termination for missing COD date, ceasing to have site control, or ceasing to be certified as a QF with FERC)
- Agreed that remove Section 8 ("8. Seller will make the Company whole for any damages or expenses arising from Seller's breach of any warranty, representation, or covenant in this Notice of Commitment.

A summary of the issues that have not been resolved are shown below. These unresolved matters are reviewed in the next sections of this chapter along with Power Advisory's recommendations for resolution.

#### *4.1.5.2 Issues Not Resolved*

**Standard Offer PPA** issues not resolved include:

- Material alterations – retroactive vs. prospective
- 30-month in-service date following rates approval

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**Large QF PPA** issues not resolved include:

- Facilities Study Agreement (FSA) a condition of signing a Large QF PPA
- Offramp should interconnection facilities and network upgrades exceed $75,000/MW-AC
- Surety Bonds as a permissible form of performance assurance

**Notice of Commitment (NOC) to Sell Form** issues not resolved include:

- All required permits and land-use approvals a condition of LEO formation
- 365 day in-service requirement following LEO formation
- Offramp should interconnection facilities and network upgrades exceed $75,000/MW-AC

## 4.2 Standard Offer PPA (≤ 2 MW)

### *4.2.1 Material Alterations – Retroactive vs. Prospective*

Duke seeks to clarify that they may discontinue purchases from the QF and/or terminate a QF's PPA in the event that there is a material alteration.[121]

In his rebuttal testimony, Mr. Wheeler defines Material Alteration as follows:

> "Material Alteration" as used in this Agreement shall mean a modification to the Facility which renders the Facility description specified in this Agreement inaccurate in any material sense as determined by Company in a commercially reasonable manner including, without limitation,
>
> (i) the addition of a Storage Resource;
>
> (ii) a modification which results in an increase to the Contract Capacity, Nameplate Capacity (in AC or DC), or generating capacity (or similar term used in the Agreement) (the "Existing Capacity"), or
>
> (iii) a modification which results in a decrease to the Existing Capacity by more than five (5) percent. Notwithstanding the foregoing, the repair or replacement of equipment at the Facility (including solar panels) with like-kind equipment, which does not increase Existing Capacity or decrease the Existing Capacity by more than five percent (5%), shall not be considered a Material Alteration."[122]

[121] Duke Wheeler Direct, p.21.

[122] Duke Wheeler Rebuttal, p.7.

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Thus, absent any necessary repair and replacement that doesn't affect the DC or AC rating by +/-5%, which is allowable, any increase in the facility's DC or AC rating, or any decrease in the facility's DC or AC rating by more than 5% requires the consent of Duke. Also, consent is required for the addition of a Storage Resource. If consent is not given, the QF's PPA would be terminated and they would be able to enter into a new PPA with the then-current avoided cost rate.

Mr. Wheeler argues against the QF being allowed to violate the +0/-5% tolerance during the development process saying that by the time a PPA is executed that the general parameters of the facility should be known. If circumstances cause significant material changes to the facility, the PPA should be subject to review."[123]

Initially, Mr. Levitas argues against a QF having to get Duke's consent for any Material Alterations. However, in his surrebuttal testimony he accepts Duke's position on these issues subject to two modifications as follows:

> "[1] Duke's Terms and Conditions need to provide that Duke's consent to requested material alterations will not be unreasonably withheld, conditioned or delayed. Duke has agreed to a similar condition in its Large QF PPAs.
>
> [2] The proposed terms and conditions must be applied only prospectively to new PPAs and not be made applicable to existing PPAs. (It is not clear whether Duke is asking the Commission to modify existing PPAs to incorporate its proposed new terms and conditions, but doing so would be highly problematic for existing QFs and their financing parties and of questionable legality.)"[124]

In hearing testimony, Mr. Wheeler says that Duke agrees to Mr. Levitas' first condition, but not the second. Duke intends on modifying the terms and conditions for <u>all existing and future</u> Standard Offer PPAs. Mr. Wheeler comments:

> "Mr. Levitas states the terms and conditions should only be applied prospectively to the new PPAs. I disagree with Mr. Levitas since it contradicts existing long-standing language in the rate update section of Schedule PP in Provision 1(B) of the terms and conditions. This language was repeated to be clear that all provisions of the company tariffs are subject to review and revision by the Commission and, upon approval, would apply to all Standard Offer QF purchases. The only exception that's identified in this language is that any levelized rates will not change during the contract term offered to the QF, the price certainty necessary to secure financing."[125]

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[123] Duke Wheeler Rebuttal, p. 19.

[124] SBA Levitas Surrebuttal, p. 11.

[125] Hearing Vol 1, p. 262 (Duke Wheeler).

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In hearing testimony, Mr. Levitas objected to Mr. Wheeler's suggestion of revising all Standard Offer PPAs with the new terms and conditions stating, indicating it would be terrible public policy, and if that is Duke's position, then he would object to the Material Alterations clause in its entirety:

> "The second condition on our willingness to agree to these very extensive changes is that they must be applied only prospectively to new PPAs, and not be made applicable retroactively to existing PPAs. Mr. Wheeler pointed out, in his sur-surrebuttal, if you will, that you have adopted language in the past that does provide that, when you approve changes to the standard offer forms, that they may be made applicable retroactively, so that -- that language does exist, but that doesn't obligate you to make them applicable retroactively, and I would submit to you that, where you have many contracts that are in place today based on the -- the laws and -- and the terms of these conditions that were in effect at the time, to adopt this kind of wholesale change to a document, and then incorporate that -- all of that -- those changes retroactively to existing contractual relationships is terrible public policy. And, while -- as I said, we don't oppose these types of changes being made going forward, if your view was that we're -- if we make them going forward, we're also going to make them retroactively, and our position would be don't make them at all."[126]

<u>Power Advisory Opinion</u>

The Commission will have to decide on balancing Duke's goal which is to apply the new terms and conditions retroactively to all existing Standard Offer QF contracts with SBA's goal of only applying them to new PPAs. Though it doesn't obligate the Commission to do so, there is a provision in the existing Standard Offer that allows for revision of the existing contracts. Provision 1(b) reads as follows:

> **"**Application of Terms and Conditions and Schedules - All Purchase Agreements in effect at the effective date of this tariff or that may be entered into in the future, are made expressly subject to these Terms and Conditions, and subject to all applicable Schedules as specified in the Purchase Power Agreement, and any changes therein, substitutions thereof, or additions thereto lawfully made, provided no change may be made in rates or in essential terms and conditions of this contract except by agreement of the parties to this contract or by order of the state regulatory authority having jurisdiction (hereinafter "Commission")."[127]

The clause "…provided no change may be made in rates or in essential terms and conditions of this contract…" would seem to indicate that there is protection for the seller.

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[126] Hearing Vol 1, p. 311-312 (SBA Levitas).

[127] Duke Energy Carolinas Schedule PPA Terms and Conditions, effective July 1, 2016, Provision 1(b) https://etariff.psc.sc.gov/Attachments/tariffFile/492cc0bb-7d8c-437e-b9d9-b8ad65eab2cf

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The problem with changing contract terms and conditions retroactively is that it can have a chilling effect on existing and future financing, as the lender community, which requires certainty, doesn't know what to expect in the way of changes down the road once it agrees to financing. It's not only the lender community but the developer community as well.

Two things are not clear:

1. Whether Duke would identify existing operating projects that have made changes in the past that are now deemed Material Alterations and as a result, terminate the PPA. Power Advisory believes that if the Commission does allow Duke to adopt these terms and conditions retroactively, then Duke's ability to terminate should only be on Material Alterations made in the *future*, not the past.

2. Whether Duke is referring to the Material Alteration terms/conditions only or <u>all</u> terms/conditions that are being revised in the Standard Offer as part of this proceeding.

From a commercial reasonableness standpoint, Power Advisory would argue that making changes to the terms and conditions of a contract retroactively is not commercially reasonable as it sets a potentially dangerous precedent. Rather, they should only be applied prospectively to new PPAs.

#### *4.2.2 30-month In-service Date Following Rates Approval*

Mr. Levitas recommends removing the following paragraph that terminates the PPA after 30 months following the date of the order initially approving the rates selection:

> "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 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. 1.4 above. This date may be extended by upon mutual agreement by both parties."[128]

Mr. Levitas says that the 30 month rule has been a problem in North Carolina. In North Carolina, there have been long waits for interconnection. On one occasion, Duke voluntarily agreed to extend eligibility for the rates and on another it was directed to do so by the North Carolina General Assembly. A similar situation has occurred in South Carolina, where many projects that established LEOs under the prior standard offer rate schedule were not able to begin deliveries of

[128] SBA Levitas Direct, Levitas-1 Section 3: Initial Delivery Date.

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power within 30 months after those rates were approved, solely because of interconnection delays.[129]

In rebuttal testimony, Mr. Wheeler says that this provision was adopted in 2016 so as to avoid QFs getting "stale" rates. Hypothetically, this would allow a QF to enter into a Standard Offer PPA in 2019 and begin selling its output to the Companies in 2025, for a period ending in 2035, at rates set in 2019. This would be unjust.[130]

Duke says that if the QF is unable to get the current avoided cost tariff, they can always get the next one.

In hearing testimony, Mr. Wheeler states:

> "Mr. Levitas' proposal would significantly extend the length of the time that can pass after QFs lock into avoided cost rates until they begin delivering power to the grid. Moreover, the language in the tariff currently provides QFs an extension if they aren't delivering power within the 30 months but their construction is nearly complete and they demonstrate a good-faith effort to complete their project in a timely manner."[131]

In hearing testimony, Mr. Levitas states:

> "For the standard offer, in my direct testimony, as you heard earlier, I recommended removing the requirement in the Duke proposed PPA that a QF be placed in service within 30 months of the Commission's approval of the standard offer tariff. In my surrebuttal testimony, I state that SBA doesn't object to this outside in-service date provided it is linked to the interconnection facilities and network upgrades in-service date, as Duke has agreed to with respect to Large QF PPAs. So there's a COD deadline under contract that is extended based on interconnection delays. I'm suggesting the same thing apply with respect to the Standard Offer PPA."[132]

<u>Power Advisory Opinion:</u>

Customers need reasonable protections to avoid "stale" rates and completion of the project in a timely manner. However, Mr. Wheeler does not address Mr. Levitas' issue of the lengthy interconnection process. Since the in-service date of the interconnection facilities and network upgrades for the QF is out of the QF's hands, it's only fair that the QF be given day-for-day extensions on its in-service date for any delays attributable to the in-service date of these interconnection facilities. Duke has already agreed to this for the Large QF PPA. There is no reason why this shouldn't also be the case for the Standard Offer and Duke itself offers no reason. In fact,

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[129] SBA Levitas Direct, p. 28-29.

[130] Duke Wheeler Rebuttal, p. 10.

[131] Hearing Vol 1, p. 258-259 (Duke Wheeler).

[132] Hearing Vol 1, p. 309-310 (SBA Levitas).

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Mr. Brown of Duke acknowledges in hearing testimony that the QF should not be responsible for delays in interconnection:

> "Q. So who bears the risk that the project will fall behind schedule, the QF or the ratepayer?
>
> A (BROWN) Generally speaking, I would say -- it depends if it's because of something that the utility is doing on our side, we're unable to connect it, I would say the QF is not responsible for that."[133]

Currently, Duke provides extensions to the QF if the QF's construction is nearly complete and they demonstrate good faith effort to completing their project in a timely manner but does not address the issue of completing their own network upgrade construction in a timely fashion.

## 4.3 Large QF PPA (>2 MW)

### *4.3.1 Facilities Study Agreement (FSA) a Condition of Signing Large QF PPA*

In his rebuttal testimony, Mr. Johnson says that Duke will require the QF to have returned a Facilities Study Agreement before signing a PPA which will demonstrate commercial viability of their project. This is in response to agreeing to extend the COD deadline due to interconnection delays. Specifically, Mr. Johnson states:

> "To ensure QFs are not prematurely entering into PPAs as a result of this added flexibility to the COD Milestone [referring to extensions due to interconnection delays], the Companies have also revised the Large QF PPA to require that, in order to enter into the Large QF PPA, a QF must have executed and returned the Facilities Study Agreement to the Companies under the South Carolina Generator Interconnection Procedures."[134]

In hearing testimony, Mr. Johnson states:

> "The issue has to do with when a QF can enter into a PPA. As described in my rebuttal testimony, we believe it is appropriate for a QF to enter into a PPA after it sends a Facilities Study Agreement (FSA) back to the utility. At this point in time, the QF has insight into its interconnection and system upgrade costs and can evaluate the commercial viability of the project. In order to accommodate Witness Levitas' request to create a flexible commercial operation date, adding this provision was also important to Duke to ensure QFs are not prematurely entering into PPAs as a result of this added flexibility. Witness Levitas advocates that a QF should be able to enter into a PPA once it has been an

[133] Hearing Vol 2, p. 215 (Duke Brown)

[134] Duke Johnson Rebuttal, p. 11.

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> interconnection customer for one year; however, as I describe in my rebuttal testimony, without knowing interconnection costs and an estimate of time frame to achieve COD, the QF facility is not to the point in the development process of knowing whether the generating facility is commercially viable."[135]

In hearing testimony, Mr. Levitas quotes from his surrebuttal testimony. He points out that Mr. Johnson has not adequately addressed his proposal that the QF be able to form a LEO or execute a PPA within one year of filing its interconnection request. Otherwise, Duke is in a position to frustrate or control the QF. His surrebuttal testimony states:

> "…as Witness Johnson observes, deferring LEO/contract formation until the FSA has been signed provides both the developer and the utility with a better sense of project viability and moves the establishment of the contract price to a point closer to commercial operation. However, Witness Johnson fails to recognize the purpose served by my proposal that, in the alternative, the QF be able to form a LEO or execute a PPA within one year of filing its interconnection request if the utility has not completed the System Impact Study (or using Duke's proposal, if it has not yet been presented with a Facilities Study Agreement to execute). In the absence of such an alternative, the utility could potentially control and frustrate the QF's LEO formation, which has been expressly prohibited by FERC and reaffirmed in the NOPR. As I pointed out in my direct testimony, the North Carolina Utilities Commission, with Duke's consent, has adopted exactly this sort of approach. In sum, I am comfortable with Duke's proposed requirement that a signed FSA be a condition of LEO formation or PPA execution, provided that there is an alternative eligibility criterion based on time from the interconnection request. I continue to believe that one year is a reasonable interval given the time frames set forth under the Interconnection Procedures, but if Duke believes the one-year time frame I proposed is unreasonable in some circumstances, SCSBA would be willing to discuss alternatives."[136]

<u>Power Advisory Opinion</u>

Mr. Johnson has not addressed Mr. Levitas' point that the utility can potentially control or frustrate the QF if the QF has not received a System Impact Study within one year from the time of Interconnection Request since the QF will not know its interconnection costs, albeit preliminary, before LEO formation. In the extreme case, if Duke were to delay delivery of the System Impact Study (SIS) for an indefinite period, then the QF would never be able to sign a PPA with the knowledge of what its interconnection costs would be. Controlling or frustrating the QF to form a LEO is prohibited by FERC.[137] Power Advisory agrees that Duke should be required to provide a System Impact Study within a timely manner to the QF from the time of Interconnection Request

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[135] Hearing Vol 1, p. 267-268 (SBA Levitas).

[136] SBA Levitas Surrebuttal, p. 9.

[137] See paragraph 23 in the Montana ruling: 157 FERC ¶ 61,211, Docket No. EL7-5-000 https://www.ferc.gov/whats-new/comm-meet/2016/121516/E-7.pdf

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(whether that time frame is one year or a period of time that is mutually agreeable to the buyer and seller). If the SIS is not provided in a timely manner, then the requirement that the QF execute and return a Facilities Study Agreement (FSA) in order to sign a PPA should be lifted.

While Mr. Johnson argues that an FSA is required to demonstrate commercial viability, it's nonetheless more important that the utility not be permitted to control or frustrate QF development through unreasonable delays in interconnection. If Duke were to deliver SISs in a timely manner then this would be a moot point – Duke would achieve its stated goal of only having projects that are commercially viable and the QF community would achieve its stated goal of not being unfairly delayed.

#### *4.3.2 Offramp Should Interconnection Facilities & Network Upgrades Exceed $75,000/MW*

In direct testimony, Mr. Levitas expresses SBA's point of view as follows:

> "I think that the PPA should include a right of Seller to terminate the PPA without liability if the interconnection facilities and network upgrades required for the facility to be interconnected to Duke's system exceed $75,000 per MW per AC. Given the QFs' total lack of control over and visibility into Duke's interconnection costs, and the extremely high interconnection costs that have been quoted to many QFs, it is reasonable to provide this limited off-ramp from the obligations."[138]

In rebuttal testimony, Mr. Johnson does not agree with SBA's proposal to be able to walk away from a commitment if system upgrade costs exceed $75,000 per MW AC. First, it allows the QF to make a binding commitment to sell that it could walk away without any liability. Second, Mr. Levitas doesn't give any basis for the $75,000 / MW AC figure.

> "When considered together, the result seems to be that if the QF's System Impact Study Report estimates interconnection costs in excess of $75,000 per MW of the Facility's Nameplate Capacity, the QF could elect to enter into a Notice of Commitment knowing at the time it purportedly made a binding commitment to sell that it could walk away without any liability."
>
> "Mr. Levitas also provides no basis for this arbitrary $75,000/MW threshold for the costs of interconnection facilities and system upgrades, which will be increasingly exceeded as more and more generators interconnect to the grid. While I am not an expert on the interconnection process, it is my understanding that it is increasingly routine for a two (2) MW generator to exceed $150,000 in total interconnection facilities and system Upgrades and for transmission connected generators 20 MW to 50 MW to exceed the $1.5 million

[138] SBA Levitas Direct, p. 19.

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> to $3.75 million in interconnection facilities and system Upgrades. Because a QF exceeding these thresholds would essentially be absolved from its LEO commitment and allowed to walk away without liability, Duke does not support this proposal."[139]

In his surrebuttal testimony, Mr. Levitas agrees to remove the offramp as long as the System Impact Study is completed within a year from the time of interconnection request. Mr. Levitas says:

> "…the utilities have the ability to take my proposed condition precedent out of play by completing the System Impact Study within a year, which is much longer than the time provided for in the Commission's interconnection procedures."[140]

In hearing testimony, Mr. Johnson reiterates his point:

> "The issue has to do with whether the QF should be allowed to terminate the PPA, because its interconnection costs are more than $75,000 per megawatt. My rebuttal testimony explains that this is an unnecessary provision, because under Duke's proposal, the QF would already know its interconnection costs before entering into a PPA. But, more importantly, this option would not provide for a binding commitment by a QF, as it could terminate their PPA without penalty."[141]

> In hearing testimony, Mr. Levitas summarizes his direct and surrebuttal testimony and adds that Dominion has agreed to the provision of allowing the QF to terminate their PPA without penalty if interconnection costs exceed $75,000/MW-AC.[142]

<u>Power Advisory Opinion</u>

Mr. Johnson does not address Mr. Levitas' point that the timeliness of the System Impact Study would make the offramp for high interconnection costs a moot point. Experience elsewhere indicates that interconnection costs tend to increase with higher penetration rates of such resources. The risk to the QF of entering into a PPA and then facing either interconnection costs that make the project unviable or significant liquidated damages because of termination is unreasonable.

As a result, Power Advisory believes that Duke should either: (1) provide the System Impact Study within 1 year of interconnection request (or an amount of time that is mutually agreeable between the buyer and seller) or (2) allow an offramp to the QF. Dominion has accepted the offramp provision.

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[139] Duke Johnson Rebuttal, p. 41.

[140] SBA Levitas Surrebuttal, p. 4.

[141] Hearing Vol 1, p. 268 (Duke Johnson).

[142] Hearing Vol 1, p. 306-307 (SBA Levitas).

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Duke maintains a similar stance on this issue as it did for the issue pertaining to the FSA being a requirement for a QF to enter into a PPA. Again, the issue is moot if Duke is able to process System Impact Studies in a timely manner. If Duke can process the SIS in a timely manner, both sides will have achieved their stated goals: Duke's of not wanting to allow QFs the offramp for expensive interconnection costs, and the QF community's of not wanting to enter into a PPA and potentially face interconnection costs that could make a project unviable.

#### *4.3.3 Surety Bonds as a Permissible form of Performance Assurance*

In surrebuttal testimony, Mr. Levitas states that Duke does not allow the use of surety bonds as a permissible form of performance assurance. In contrast, Dominion's proposed PPAs do allow for the use of surety bonds and include a commercially reasonable form bond for this purpose. Mr. Levitas recommends Duke doing so as well.[143]

In hearing testimony, Mr. Johnson offers two reasons as to why Duke doesn't offer surety bonds as a form of performance assurance: (1) feedback from the seller community while developing the CPRE Tranche 1 PPA and (2) Duke has never allowed a surety bond in any previous PPA.

> "Mr. Levitas suggests through surrebuttal that Duke should allow the use of a surety bond as a permissible form of performance assurance. The company's considered comments from the solar community on this issue when developing the PPA that was used for CPRE, and do not believe that a surety bond would be a permissible form of performance assurance. Duke has never allowed a surety bond in any previous PPA and Mr. Levitas offers no reason why this is reasonable."[144]

In cross-examination, Mr. Johnson says that surety bonds are harder to collect on than cash, but does not offer a reason as to why Dominion would offer a surety bond as an eligible form of performance assurance, indicating that this is not his area of expertise. Whereas Duke offers three forms of performance assurance – cash, letter of credit and a guarantee – Dominion offers the same three, but also offers surety bonds.[145]

In further cross-examination, Mr. Wheeler indicates that Duke made a determination several years ago to drop surety bonds as a form of performance assurance because they found that in some cases, the QF didn't renew the surety bond for the life of the contract.[146]

<u>Power Advisory Opinion</u>

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[143] SBA Levitas Surrebuttal, p. 4.

[144] Hearing Vol 1, p. 278 (Duke Johnson).

[145] Hearing Vol 1, p. 281-282 (Duke Johnson).

[146] Hearing Vol 1, p. 283-284 (Duke Wheeler).

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Power Advisory believes that Duke should be able to determine the appropriate security for performance assurance. They already allow three options including cash, letter of credit and a guarantee which we believe is enough. Duke looked at this issue several years ago and made a determination that surety bonds posed more risks than the other options.

## 4.4 Notice of Commitment to Sell Form

### *4.4.1 All Required Permits and Land-use Approvals a Condition of LEO Formation*

In his direct testimony, Mr. Johnson proposes that the QF must first secure all required permits and land use approvals before LEO formation as a means of showing project viability and refers to similar requirements in Montana and Minnesota.

In his direct testimony, Mr. Levitas objects to the fact that a pre-condition of LEO formation is that the QF has to first secure all required permits and land-use approvals. Mr. Levitas indicates that obtaining environment permits and land-use approvals can be an expensive and time consuming process, sometimes costing in the hundreds of thousands of dollars. It is unreasonable to expect a QF to incur these expenses until it has secured a price for its output so that it can in turn secure financing for the project.[147]

Mr. Levitas goes on to say that the Standard Offer PPA is silent on this topic and that for the Large QF PPA, it expressly states that permits are obtained <u>after</u> the PPA is signed. So there is no reason for LEO formation to be more onerous than the PPA.

In his rebuttal testimony, Mr. Johnson's main points are: [148]

- In order to show commercial viability and financial commitment to construct a QF generator, the QF must have site control
- This dictates that the QF must have necessary environmental permits or other zoning approvals
- QFs have the option of entering into a Large QF PPA if they would like to have the in-service date extended for delays in interconnection, but does not offer the same for LEO formation
- There should be no legal impediment to the QF constructing the project at the time it commits to sell and deliver the output under the Notice of Commitment Form
- Minnesota and Montana have similar requirements:

  > "As I mentioned briefly in my Direct Testimony, both Montana and Minnesota have explicitly found that obtaining site permits are an appropriate prerequisite for determining

[147] SBA Levitas Direct, p. 25.

[148] Duke Johnson Rebuttal, p. 34-35.

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> the date a LEO is established. In Montana, the Public Service Commission, through its PURPA-implementing administrative rules, instructs that a LEO is established when a QF "has obtained and provided to the purchasing utility written documents confirming control of the site for the length of the asserted legally enforceable obligation and permission to construct the qualifying facility that establish, at a minimum . . . (ii) proof of all required land use approvals and environmental permits necessary to construct and operate the facility." Likewise, the Minnesota Public Utilities Commission ("Minnesota PUC") has many times considered the existence of site permits, or lack thereof, as evidence relevant to the establishment of a LEO."

In his surrebuttal testimony, Mr. Levitas re-states that it is not reasonable to require QFs to obtain all environmental permits and land use approvals without having firm pricing and that Duke has never made such requirements a pre-condition for a PPA.[149]

At the hearing, Mr. Johnson states:

> "The issue that's still in contention is the requirement that a QF must secure all environmental permits and land-use approvals, in order to execute the Notice of Commitment Form. I believe that this is a reasonable requirement that demonstrates a commitment by the QF to develop the project and sell power to the utility." [150]

At hearing testimony, Mr. Levitas states:

> "I explained in my direct testimony why it is not reasonable to require QFs to obtain all environmental permits and land use approvals without having firm pricing and note in my surrebuttal testimony that Duke has never made such requirements a pre-condition of executing a PPA, and does not propose to do so in this proceeding." [151]

<u>Power Advisory Opinion</u>:

Both sides make good points. Duke only wants viable projects to form LEOs and identifies other states (Minnesota and Montana) that similarly require permits before LEO formation. Mr. Levitas indicates the costly nature to the QF of obtaining all permits without even knowing its avoided cost rate. He also identifies the contradiction that Duke has never required permits in advance of signing a Large QF PPA.

While Mr. Johnson referred to Minnesota and Montana as two states that require permits prior to LEO formation, Power Advisory also found states that did not have this requirement. For example,

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[149] SBA Levitas Surrebuttal, p. 10.

[150] Hearing Vol 1, p. 271 (Duke Johnson).

[151] Hearing Vol 1, p. 309 (SBA Levitas).

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in Washington, the published Contracting Procedures only require a description of and anticipated timeline for acquiring any outstanding permits but do require the permits themselves. The requirement is described as follows:

> "List of acquired and outstanding Qualifying Facility permits, including a description of the status and timeline for acquisition of any outstanding permits."[152]

This is a lower bar than actually requiring that all permits be in hand.

Power Advisory believes that since SBA has agreed to the 365 day in-service date requirement (conditional on obtaining a System Impact Study (below)), that QFs be allowed to secure permits after formation of a LEO, so as to balance the two issues. As in the case of Washington, a list of the acquired and outstanding permits could be required to be outlined.

This makes it consistent with the Large QF PPAs which do not require permits be obtained before execution. The QF already has to meet the requirement of being in service within 365 days or risk termination and resulting liquidated damages. This requirement alone will motivate QFs to move forward with viable projects only.

### *4.4.2 365 Day In-service Requirement Following LEO Formation*

In Duke's direct testimony, they require that the QF place its facility in service within 365 days of executing the Notice of Commitment (NOC) form.

In his direct testimony, Mr. Levitas objects to this requirement. Mr. Levitas says this would impose "unreasonable obstacles" to LEO formation which is in violation of FERC precedent. It's unreasonable because the interconnection and the construction process in South Carolina is currently taking 3 years. Smaller, less complicated QFs may be able to achieve COD within 365 days, but larger complicated ones cannot since their timelines are longer.

Specifically, Mr. Levitas says:

> "QFs must be able to secure pricing before they can incur major development expenses, secure financing, and construct the project. While many QFs can complete the development cycle within a year, larger and more complex QFs may not be able to do so.
>
> But more significantly, Duke's interconnection study and construction process in South Carolina has been taking on the order of three years. So Duke's proposed 365-day in service requirement is tantamount to saying that no QF could ever form a non-contractual LEO that it could comply with. Even more problematic is the fact that there is no point in

[152] Avista, "Schedule 62 Appendix A - Contracting Procedures", pursuant to WAC 480-106-030(2). https://www.myavista.com/-/media/myavista/content-documents/our-rates-and-tariffs/wa/rate-requests/schedule-62-filing.pdf?la=en

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> the interconnection process at which a QF has any guarantee that it will achieve interconnection by a specific date, since Duke views the deadlines under the SCGIP and even in Interconnection Agreements as essentially unenforceable. In fact, a QF often has no idea how long it will take to achieve interconnection, and therefore commercial operation. It would be completely unreasonable to require a QF to predict when it will be 365 days or less from commercial operation."[153]

In his surrebuttal testimony, Mr. Johnson responds to SBA by saying that 365 days is not too onerous and makes the following main points: [154]

- QFs should not be able to lock into avoided cost rates indefinitely
- The QF is making a binding commitment to construct the Facility and achieve commercial operation when it submits the Notice of Commitment Form and establishes a LEO
- Duke suggests that execution of a Large QF PPA would alleviate much of Mr. Levitas' concerns regarding failure to achieve COD since Duke has accepted Mr. Levitas' proposal to set the COD Milestone at 90 days after the Interconnection Facilities and System Upgrades In-Service Date and allow for day-to-day extensions to account for any delays not caused by the Seller QF
- QFs by definition take risks and the risk that the QF doesn't achieve COD is one risk that it is taking
- Idaho, New Mexico and Texas are three examples of where the in-service date requirement is 365 days or less following formation of a LEO

In his surrebuttal testimony, Mr. Levitas is willing to withdraw its objection to the 365 day in-service requirement if the COD deadline is extended to account for additional time required for the utility to complete required Interconnection Facilities and Network Upgrades.[155]

At the hearing, Mr. Johnson states:

> "As described in my testimony, it's reasonable to require a QF to deliver power within 365 days after executing a Notice of Commitment Form. To ensure that QFs are not locking into prices or into rates for an extended period of time, and then requiring customers to pay for those stale rates on those purchases. My testimony points out that the 365-day period is less stringent than the requirements in other states like Texas and New Mexico."[156]

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[153] SBA Levitas Direct, p. 26.

[154] Duke Johnson Surrebuttal, p. 23-29.

[155] SBA Levitas Surrebuttal, p. 7-8.

[156] Hearing Vol 1, p. 270-271 (Duke Johnson).

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At the hearing, Mr. Levitas states:

> "In my direct testimony, I objected to Duke's requirement that the QF be capable of being placed in service within 365 days as a condition of LEO formation using the NOC form. However, in my surrebuttal testimony, I state that SCSBA is prepared to withdraw that objection if the deadline is extended to account for additional time needed by the utility to complete required interconnection facilities and network upgrades. I note that the DESC NOC form contains such a provision. I would also note that this is similar to Duke's Large QF PPA term which extends COD based on interconnection delays." [157]

Power Advisory Opinion:

Mr. Johnson doesn't address Mr. Levitas' proposal to remove his objection if the deadline is extended to account for additional time needed by the utility to complete required interconnection facilities and network upgrades except to say that the QF could opt to enter into a Large QF PPA where that provision exists. However, that doesn't help the QF if it feels the utility is refusing to enter into a PPA (which is why it would need to go the LEO route in the first place).

As in the case of the 30-month in-service requirement following rates selection for the Standard Offer, the Commission must balance the goal of the utility to keep the timelines relatively short, while also allowing the QF a legitimate chance to meet its deadlines.

In conducting additional research on in-service requirements following LEO formation, Power Advisory has found that there are other states where the allowable time is longer than 365 days from LEO formation. The two most recent rulings were in Washington State (June 2019)[158] and Oregon (August 2016).[159] Thus, while Duke has identified three states with relatively short deadlines, other states have longer deadlines. Thus, while Duke has identified three states with relatively short deadlines, other states have longer deadlines.

In sum, Power Advisory believes that the QF should be required to be in-service within 365 days of forming the LEO but that the COD date should be extended to 90 days following completion of the utility upgrade work. Thus, the utility must bear some of the responsibility to ensure that the timeline is reasonable. Otherwise, in the extreme case, it would be possible for them to simply delay the upgrades until the QF can no longer meet its deadline.

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[157] Hearing Vol 1, p. 308 (SBA Levitas).

[158] Washington Administrative Code (WAC) 480-106-050, Section 4. https://apps.leg.wa.gov/wac/default.aspx?cite=480-106&full=true

[159] Oregon Standard Power Purchase Agreement (New QF), approved by the Public Utility Commission of Oregon, effective August 11, 2016, Section 2.3. https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Power_Purchase_Agreement_for_New_Firm_QF_And_Intermittent_Resource_with_MAG.pdf

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#### *4.4.3 Offramp Should Interconnection Facilities & Network Upgrades Exceed $75,000/MW*

This is similar to Section 4.3.2 and Power Advisory believes it should be dealt with the same way.

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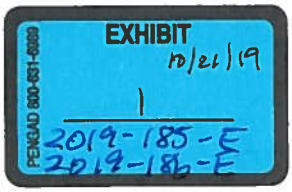


STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

Docket No. 2019-185-E
Docket No. 2019-186-E

October 21, 2019

| | | |
|---|---|---|
| South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) - S.C. Code Ann. Section 58-41-20(A) | ) | **PARTIAL SETTLEMENT AGREEMENT** |
| South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Progress, LLC's Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, Carolinas, LLC's and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) - S.C. Code Ann. Section 58-41-20(A) | ) | |

This Partial Settlement Agreement ("Settlement Agreement") is made by and among the signatory parties (collectively known as "the Parties").

WHEREAS, pursuant to S.C. Code Ann. § 58-41-20, the South Carolina Public Service Commission ("Commission") is required to open a docket for the purpose of establishing each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement this section; and is required to approve each electrical utility's standard offer, avoided cost methodologies, form contract power purchase agreements, commitment to sell forms, and any other terms or conditions necessary to implement that statutory provision; and

WHEREAS the commission opened the above-referenced dockets for purposes of implementing these statutory provisions with respect to DEC and DEP; and

WHEREAS the Parties to this Settlement each participated as Parties in the above-referenced dockets; and

WHEREAS In the interest of compromise the Parties reached settlement of certain issues in the case that the parties believe is just, fair, and reasonable, and

WHEREAS issues not agreed to herein remain in dispute;

AS SUCH, the Parties entered into this Partial Settlement as follows:

## A. STIPULATION OF SETTLEMENT AGREEMENT, TESTIMONY, AND WAIVER OF CROSS-EXAMINATION

Through the testimony and exhibits presented to the Commission in this proceeding, the Settling Parties represent that certain issues between them in this case have been settled in accordance with the terms and conditions contained in this Settlement Agreement, which is just, fair, reasonable and in the public interest. The terms of the Settlement Agreement are summarized as follows:

1. DEC and DEP's quantification of the near-term projected capacity represented by "Existing plus Transition" solar QFs to be installed on the DEC and DEP systems, 840 MW and 2,950 MW, respectively, is reasonable for use in this proceeding.

2. That solar integration services charges (SISC) of $1.10/MWh (DEC) and $2.39/MWh (DEP) are reasonable, for purposes of this proceeding, for solar small power producers that enter into a PPA or establish a Legally Enforceable Obligation prior to the effective date of avoided cost calculations and methodologies filed in the next DEC / DEP avoided cost proceeding conducted by the SC Public Service Commission. These charges shall not be subject to adjustment during the term of the PPA. The SISC in the foregoing amounts should apply prospectively only to projects subject to the avoided cost methodologies and contractual terms and conditions established in this proceeding, and shall not apply to the rates established in prior avoided cost proceedings; nor shall it be binding with respect to any subsequent avoided cost proceeding.

3. Duke cannot impose the SISC on a solar QF that is a "controlled solar generator," meaning, generally, any solar QF that demonstrates that its facility is capable of operating, and contractually agrees to operate, in a manner that materially reduces or eliminates the need for additional ancillary service requirements incurred by the utility, including but not limited to QFs equipped with battery storage. Duke must to file with the Commission by November 18, 2019, for review and comment, proposed guidelines for QFs to become "controlled solar generators" and thereby avoid the SISC.

4. The Astrapé Study used to calculate the SISC presents novel and complex issues that warrant further consideration. Duke shall submit the study methodology and inputs to an independent technical review and include the results of that review and any revisions in its initial

filing in the next avoided cost proceeding. To the maximum extent practicable the independent review of the study methodology shall take into consideration the South Carolina Integration Study called for by S.C. Code Ann. § 58-37-60. This process shall be subject to Commission oversight and comment from interested stakeholders. The parties agree that undertaking the work associated with the independent technical review is reasonable and appropriate to effectuate Act 62 compliance.

5. Within 15 days of the Commission's final Order approving the SISC, unless otherwise directed by the Commission, and as agreed to in this Stipulation, Duke shall file revised Standard Offer and Large QF purchase power agreements and terms and conditions, in redline and clean versions, that comply with the contract terms and conditions specified in this Stipulation.

6. To the extent the Companies propose to impose the SISC for any other programs or contexts in South Carolina, the Commission will separately consider the appropriateness and applicability of the SISC in the proceedings to consider and review those programs.

7. The parties agree to waive cross-examination of the following witnesses. With respect to only those issues specifically addressed herein, the Parties agree that no other evidence will be offered in the proceeding by the Parties other than the Testimony of the following witnesses and exhibits and this Settlement Agreement, unless the additional evidence is to support this Settlement Agreement. The Parties also reserve the right to engage in cross or redirect examination of witnesses as necessary to respond to issues raised by the examination of their witnesses, if any, by non-Parties or by late-filed testimony by non-Parties. Notwithstanding any of the foregoing, the Parties may make any witness available for questioning on any issue by the Commission.

**Duke witnesses:**

1. Nick Wintermantel
2. Samuel Holeman
3. Glen Snider (only as to issues addressed in this Settlement Agreement)
4. Steve Wheeler (only as to issues addressed in this Settlement Agreement)

**CCL / SACE witness:**

1. Brendan Kirby

**SBA witness:**

1. Ed Burgess (only as to issues addressed in this Settlement Agreement)

**ORS witness:**

1. Brian Horii (only as to issues addressed in this Settlement Agreement)

## B. REMAINING TERMS AND CONDITIONS

1. The Parties agree that this Settlement Agreement is reasonable, in the public interest and in accordance with law and regulatory policy.

2. Further, ORS is charged with the duty to represent the public interest of South Carolina pursuant to S.C. Code Ann. § 58-4-10(B). The Parties agree to advocate that the Commission accept and approve this Settlement Agreement in its entirety as a fair, reasonable and full resolution of the issues specifically referenced herein, and to take no action inconsistent with its adoption by the Commission.

3. The Parties further agree to cooperate in good faith with one another in recommending to the Commission that this Settlement Agreement be accepted and approved by the Commission in its entirety.

4. This Settlement Agreement is binding on the Parties only, and only as to the issues specifically addressed herein. It creates no rights in third parties nor are there third-party beneficiaries to it; nor does it bind any Party with respect to any issue in this docket not specifically

referenced herein. Only Parties who are signatories may make any claim under this Settlement Agreement.

5. The Parties agree that signing this Settlement Agreement (a) will not constrain, inhibit, impair, waive, or prejudice their arguments or positions held in future or collateral proceedings; (b) will not constitute a precedent or evidence of acceptable practice in future proceedings; and (c) will not limit the relief, rates, recovery or rates of return that any Party may seek or advocate in any future proceeding.

6. If the Commission declines to approve this Settlement Agreement in its entirety, then any Party may withdraw from the Settlement Agreement without penalty or obligation within three (3) days of receiving notice of the decision, by providing written notice of withdrawal via electronic mail to all parties in that time period.

7. This Settlement Agreement shall be effective upon execution by the Parties and shall be interpreted according to South Carolina law.

8. This Settlement Agreement contains the complete agreement of the Parties. This Settlement Agreement shall bind and inure to the benefit of each of the signatories hereto and their representatives, predecessors, successors, assigns, agents, shareholders, officers, directors (in their individual and representative capacities), subsidiaries, affiliates, parent corporations, if any, joint ventures, heirs, executors, administrators, trustees, and attorneys.

9. The above terms and conditions fully represent the agreement of the Parties hereto. Therefore, each Party acknowledges its consent and agreement to this Settlement Agreement, by affixing its signature or by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the agreement. Facsimile signatures and email signatures shall be

as effective as original signatures to bind any Party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Settlement Agreement. The Parties agree that in the event any Party should fail to indicate its consent to this Settlement Agreement and the terms contained herein, then this Settlement Agreement shall be null and void and will not be binding on any Party.

**[SIGNATURES TO FOLLOW ON SEPARATE PAGES]**

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Heather Shirley Smith

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/s/ James H. Goldin

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