DUKE ENERGY®

Jack E. Jirak
Associate General Counsel

Mailing Address:
NCRH 20 / P.O. Box 1551
Raleigh, NC 27602

o: 919.546.3257
f: 919.546.2694

jack.jirak@duke-energy.com

January 8, 2019

VIA ELECTRONIC FILING

Ms. M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Rebuttal Testimony in North Carolina Interconnection Procedures Docket Nos. E-100, Sub 101; E-7, Sub 1156; E-2, Sub 1159

Dear Ms. Jarvis:

Enclosed on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC is the Rebuttal Testimony and Exhibits of Gary Freeman, Jeff Riggins, and John Gajda in the above-referenced dockets. If you have any questions, please do not hesitate to contact me. Thank you for your assistance with this matter.

Sincerely,

Jack E. Jirak

Enclosures

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Rebuttal Testimony in North Carolina Interconnection Procedures, in Docket Nos. E-100, Sub 101; E-7, Sub 1156 and E-2, Sub 1159 has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 8th day of January, 2019.

Jack E. Jirak
Associate General Counsel
Duke Energy Corporation
NCRH 20/P.O. Box 1551
Raleigh, NC 27602-1551
(919) 546-3257
jack.jirak@duke-energy.com

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 101

In the Matter of	)	**REBUTTAL TESTIMONY OF**
Petition for Approval of Generator	)	**GARY R. FREEMAN**
Interconnection Standard	)	**ON BEHALF OF DUKE ENERGY**
	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Gary R. Freeman, and I am the General Manager of Distributed Energy Resources Compliance & Origination for Duke Energy Corporation ("Duke Energy"). My business address is 410 South Wilmington Street, Raleigh, North Carolina.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this rebuttal testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies").

Q. ARE YOU THE SAME GARY R. FREEMAN WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony provides a high-level response to certain issues raised by Public Staff and other intervenor witnesses in direct testimony pre-filed in this docket. Rebuttal testimony concurrently filed in this docket by the Companies' witnesses John W. Gajda and Jeffrey R. Riggins will respond in more detail to certain other issues and will support the Companies' proposed modifications to the North Carolina Interconnection Procedures ("NC Procedures").

My rebuttal testimony first highlights the Companies and the Public Staff's general alignment on a number of proposed modifications to the NC

Procedures, as well as the Public Staff's support of the Companies' approach to applying Good Utility Practice under the NC Procedures.

I then address criticisms lodged by certain parties in this docket and in other forums regarding the amount of time that is often required for the Companies to interconnect utility-scale solar generation projects. First and foremost, these criticisms fail to take into account the extensive evidence demonstrating the Companies' national leading successes in interconnecting distributed generation, as described extensively in my direct testimony. Secondly, such criticisms simplistically assess an incredibly complex undertaking—the study, engineering and construction required to interconnect utility-scale distributed generation—based solely on the amount of time particular projects have been in the queue, while failing to recognize the many complex factors contributing to developers' experienced "delays" in the interconnection process. I then explain that, in many cases, the amount of time that projects remain in the queue is primarily driven by factors outside the Companies' control, including the interdependency provisions of the NC Procedures and developer actions.

The Companies have and will continue to exert significant efforts to expedite the interconnection process and have invested substantial resources in doing so, which resources have led directly to the Companies' nation-leading interconnection efforts. And the Companies understand the financial impact that long interconnection wait times can have on Interconnection Customers. But those that view the long interconnection wait times as simply a product of lack of effort or administrative efficiency on the part of the Companies simply do not understand the complexity of the interconnection process or the many factors influencing the interconnection process timeline outside the Companies' control.

Finally, my testimony further describes the Companies' plans to move to full grouping studies and also responds to certain recommendations made by the Public Staff in its pre-filed direct testimony.

Q. WHAT ACTUAL CHANGES TO THE NC PROCEDURES HAVE THE COMPANIES PROPOSED IN THIS PROCEEDING?

A. The Companies' proposed changes to the NC Procedures are attached to the pre-filed rebuttal testimony of DEC/DEP witness Gajda. The proposed modifications are discussed in more detail by DEC/DEP witnesses Gajda and Riggins and are substantially similar to those modifications jointly filed by the Companies and Dominion Energy North Carolina ("DENC") in this docket on March 12, 2018. In addition, a handful of additional modifications have been identified in the interim period, as further addressed in these other witnesses' testimony.

Q. IN YOUR OPINION, IS THERE SUBSTANTIAL ALIGNMENT BETWEEN DUKE AND PUBLIC STAFF WITH RESPECT TO SUCH PROPOSED MODIFICATIONS?

A. Yes, the Companies have proposed a substantial amount of modifications to the NC Procedures. Public Staff and Duke are aligned on nearly all modifications, with a few exceptions and the Companies are committed to engage with Public Staff (as well as other intervenors) regarding potential resolution of the remaining outstanding issues.

Q. PLEASE BRIEFLY ADDRESS THE PUBLIC STAFF'S TESTIMONY REGARDING THE COMPANIES' EFFORTS TO ADMINISTER THE INTERCONNECTION PROCESS AND THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE.

A. Public Staff Witness Lucas testifies that North Carolina's "unprecedented growth of solar could only have been brought about by cooperation of the Utilities" and he notes that, despite facing significant challenges, "the Utilities appear to have made good faith efforts to interconnect DG."[1] Similar to my direct testimony, Public Staff witness Williamson highlights that North Carolina is in a unique position nationally due to the amount of utility-scale, grid-tied, intermittent, and non-dispatchable Qualified Facility ("QF") generation on its distribution system, and increasingly on its transmission system. As discussed further by DEC/DEP witness Gajda, witness Williamson expresses the Public Staff's support for the manner in which the Companies have administered the interconnection process and applied "Good Utility Practice" to safely and reliably interconnect additional generation to the Companies' systems.

[1] Public Staff Lucas Direct Testimony, at 32.

Q. PLEASE REITERATE THE COMPANIES' POSITION REGARDING ITS SUCCESS IN INTERCONNECTING PROJECTS.

A. As was discussed at length in my direct testimony, the Companies are a national leader in North Carolina with respect to the interconnection of distributed generation. By any measure, the Companies' efforts have been remarkable and at the very forefront of the nation.

And the Companies have achieved this success while continuing to ensure that system safety, reliability and power quality is maintained for all customers through the consistent implementation of non-discriminatory technical standards that have been identified as being necessary in North Carolina's "living laboratory" of utility-scale, distribution-connected solar resources. In addition, the Companies have sought, where possible within the existing construct, to allocate the costs arising from the interconnection process to Interconnection Customers.

Public Staff witness Lucas acknowledged the track record of the Companies in observing that "[e]leven years ago, North Carolina had less than one megawatt of interconnected solar capacity but now has over 3,000 megawatts."[2] As noted above, witness Lucas highlights the Companies' "good faith efforts" to interconnect third-party generation projects and to support North Carolina's unprecedented solar growth. In 2018, Duke interconnected over 450 MW of solar PV, continuing its "good faith efforts"

[2] *Id*.

to interconnect third-party solar even as the increasing penetration has made interconnection solutions more complex. Almost 400 MW of these projects were completed in the last couple of months, requiring a huge commitment from the Companies' employees needed to achieve such success under tight timelines.

Q. A NUMBER OF PARTIES CRITICIZED THE LENGTH OF TIME THAT IT TAKES DUKE TO STUDY AND INTERCONNECT PROJECTS. PLEASE RESPOND TO SUCH CRITICISM.

A. The Companies' success at interconnecting projects speaks for itself. However, it is important to also note that summarily asserting that the total amount of time a project has been in the queue is evidence that the Companies are somehow failing its obligations under the NC Procedures is almost absurdly simplistic and ignores the myriad of factors that impact an Interconnection Customer's study and processing priority and the amount of time a project will remain in the queue.

Duke has previously discussed such factors and they include but are not limited to the following: interdependency, delay in provision of information from developers, developer-requested extensions, cure periods, informal and formal disputes, developer requests for additional information, and complex engineering and construction requirements. To assist the Commission in understanding the complexity of the process, I will provide a general description of the System Impact Study ("SIS") process for distribution-connected projects. In doing so, I will also describe the fact that a substantial portion of the time required to complete the SIS is outside of the control of the Company and, furthermore, that it is the actions of the developers themselves that, in many cases, contribute to a lengthy study process for projects, which, in turn, impacts other projects in the queue.

Q. WHAT IS THE SIS AND WHAT IS ITS SIGNIFICANCE?

A. Under the NC Procedures Section 4 full study process as further discussed by DEC/DEP witness Gajda, the SIS is the initial modeling and engineering study designed to assess the impact of interconnecting the generating facility with the Companies' distribution or transmission system. The SIS process is detailed in Section 4.3 of the NC Procedures. The SIS process is then followed by the more detailed Facilities Study evaluation, which provides the Interconnection Customer a more detailed cost estimate prior to the Companies undertaking initial construction planning and drafting and delivering an Interconnection Agreement to the Interconnection Customer under Section 5.

Q. ARE THERE ASPECTS OF THE SIS TIMELINE THAT ARE OUTSIDE OF THE COMPANIES' CONTROL?

A. Yes. In fact, when considering a generic SIS study timeline, much of the timeline is comprised of discrete steps where the Companies are required to wait on developer action or response. In other words, the timeline for completion of SIS is often more influenced by the actions of the developer than by the actions of the Companies.

Furthermore, this assessment does not even consider the impact of extensions, cure periods, and formal and informal developer challenges. When a developer requests extensions, is granted cure periods or formally or informally challenges the Companies' conclusions, the portion of the SIS timeline that is outside of the Companies' control increases even further.

Q. PLEASE PROVIDE SOME EXAMPLES OF THE PORTIONS OF THE DISTRIBUTION SIS TIMELINE THAT ARE OUTSIDE OF THE COMPANIES' CONTROL.

A. The SIS process for distribution projects is comprised of a number of decisions or actions steps, and for each step, I have identified below the portion of the timeline that is outside of the Companies' control and, for purposes of this analysis, highlighted commonly requested extension periods:

[Chart on the following page]

Step	Developer Action	Time Added to SIS Process Timeline by Developer Action
Line Voltage Regulator("LVR") Review	• No developer action needed	N/A
Obtain Right of Way (if LVR impact is determined)	• Developer is required to select an LVR option and is given 15 business days. It is very common for developer to request one or more additional 15 business day extensions, leading to a total possible delay of 45 business days or more. • In those cases where a developer elects to pursue its own Right of Way, the developer is provided 30 business days. It is very common for a developer to request one or more extensions, leading to a total possible delay of 90 business days or more.	**+45 business days** (or more) **+90 business days** (or more)
Mitigation Options	• Once the volt/var study is complete, mitigation options are provided and the developer is given 15 business days to select a mitigation option. It is very common for developers to request one more extensions, leading to a total possible delay of 45 business days or more. • Once a developer selects a mitigation option, it is also necessary for the developer to provide updated documents since the project now to be studied differs from what was reflected in the Interconnection Request. Developer is given 10 business days but it is very common for a developer to request one or more extensions, leading to a total possible delay of 30 business days or more	**+45 business days** (or more) **+30 business days** (or more)
Transformer Inrush	• Developer is given 15 business days to select the type of inrush study	**+15 business days** (or more)

Step	Developer Action	Time Added to SIS Process Timeline by Developer Action
	• Developer is given 30 business days to provide transformer data. Often, corrections are needed and the developer is given 10 business days for each correct. • Developer is given 30 business days to select the inrush option.	**+30 business days** (or more) **+30 business days**
Protection Study	• No developer action needed	N/A
SIS Report Preparation	• Often developers are required to correct missing documentation and are given 10 business days to do so, with 10 business days given where a correction is needed	**+20 business days** (or more)
<u>Total Time in SIS Process Timeline Outside of the Companies' Control</u>		• **+305 business days** (for projects with LVR) which equates to **438 calendar days** • **+170 business days** (for projects without LVR impact) which equates to **237 calendar days**

Q. PLEASE SUMMARIZE THE DISTRIBUTION-CONNECTED SIS TIMELINE ABOVE.

A. As can be seen, the actions that are outside of the Companies' control for projects with LVR impacts (including common extension periods) can total as many as 305 business days, which is equivalent to approximately 445 calendar days. The actions that are outside of the Companies' control for projects without LVR impacts (including common extension periods) can total as many as 170 business days, which is equivalent to 245 calendar days.

These examples highlight how overly simplistic it is to assert that the Companies are solely at fault for developers' business challenges associated with delays in the interconnection process. In fact, in some cases, the Companies may be meeting the SIS target timeline when waiting times for Interconnection Customer decisions, for example, are excluded from the completion time requirements in. (*See* NC Procedures, Att. 7, ¶ 18) As described above, the extensive time periods that relate to developer actions can often constitute a majority of the SIS timeline for many projects.

Once again, the timeline dates specified above are generic and every project will differ. There are developers that are more timely in providing information than others and, in those cases, the portion of the timeline within developer's control is reduced. But it is also true that there are developers that are more egregious in requesting extensions, requiring cure periods and challenging the Companies' technical conclusions. Other developers may also have less technical expertise or understanding of the Companies' requirements and therefore, require more guidance from the Companies in providing appropriate documentation, etc.

Finally, as the Companies have previously described, the available capacity of the distribution and transmission system (capacity that was paid for by retail customers) is increasingly being consumed due to the high penetration levels of installed utility-scale solar across the Companies' systems, especially in DEP-East. As a result, it will become increasingly common for projects to require significant distribution or transmission system Upgrades to interconnect, the cost of which may render projects financially infeasible. DEC/DEP witness Gajda addresses this issue in greater detail in his rebuttal testimony.

The Companies' expectation (which has been borne out anecdotally by recent experience) is that developers will more frequently seek to challenge the Companies' technical conclusions and delay decisions where they perceive the available interconnection options may render their development project uneconomic. Simply put, where a developer's only viable option is withdrawal, many developers will exhaust every conceivable avenue of challenge (whether expressly provided for under the NC Procedures or not) before accepting withdrawal.

Q. HOW DOES THE ABOVE TIMELINE IMPACT THE INTERCONNECTION QUEUE?

A. Given all of the factors discussed above that are outside of the Companies' control, the timeline for completing a SIS for a distribution-connected project can easily approach a year in duration or more. Given the unparalleled volume of utility-scale solar generating facilities requesting to interconnect to the Companies distribution systems and the practical impact of the interdependency queuing process, uniquely long interconnection processing times are unsurprising. To put it in simple terms, if there are 10 projects seeking to interconnect to the same substation, the 10th project will not be studied until the Company has processed the first 8 projects. If the SIS process for a single project takes a year or more, the unavoidable reality is that the 10th project will likely remain un-studied in the queue for an extensive period of time.

Q. PLEASE DISCUSS THE INTERSECTION OF THIS SIS TIMELINE AND THE UNPARALLELED AMOUNT OF DISTRIBUTION-CONNECTED SOLAR FACILITIES IN NORTH CAROLINA.

A. Since 2011, over 1,100 utility-scale solar projects (greater than 1 MW) have sought interconnection to the Companies' distribution system, of which over 750 were between 4 and 5 MW. Of these 1,100 projects, about 400 have been connected, over 500 have either withdrawn or were canceled and over 200 are currently in the interconnection process. This amount of utility-scale distribution-connected projects is simply unparalleled in the entire country.

In many cases, these projects sought to interconnect to the same substations and distribution feeders in certain rural areas of the state. This results in many projects being designated as "interdependent" and therefore, placed "on hold" until earlier-queued projects seeking to interconnect to the same substation or distribution feeder complete the interconnection process.

As discussed above, when a later-queued project is placed on hold behind two other earlier-queued Interconnection Customers due to interdependency, such project cannot, under the terms of the NC Procedures, proceed to SIS until the earlier-queued projects are processed.

However, given that the SIS timeline can take up to a year and often longer—a substantial portion of which is not in the Companies' control—it is unsurprising that many projects would remain on hold for extended periods of time.

This outcome is not due to any failure on the part of the Companies, but, instead, has primarily resulted from the unprecedented amount of utility-scale solar projects seeking to interconnect to the Companies' distribution system. Short of eliminating significant portions of the distribution study process (which would not be in accordance with Good Utility Practice), there is simply no "silver bullet" solution to expediting the distribution study process, particularly where many such projects have sought to interconnect to the same substations and feeders.

Q. PLEASE DISCUSS HOW THE SIS PROCESS HAS EVOLVED OVER TIME.

A. As the SIS process has evolved over time, many practices have developed that have lengthened the study process. These practices include mitigation options, developer-requested extensions, cure periods, and informal information requests and challenges.

Q. PLEASE DESCRIBE THE IMPACT THAT THE MITIGATION OPTION PROCESS HAS ON THE SIS TIMELINE.

A. The mitigation option process is not contemplated by the NC Procedures, but was introduced by the Companies in late 2016 as a concession to provide alternative project size options for developers to select where the system impact of the generating facility reflected in the Interconnection Request was likely uneconomic due to the limited availability of distribution or network capacity. Rather than simply studying an Interconnection Request as submitted (which is all that is required under the NC Procedures), the Companies conduct additional analysis to provide a preliminary cost assessment of alternative project configurations. Providing such alternative options necessitates additional studies and therefore lengthens the study process and delays the study of later-queued projects. As shown above, the mitigation option evaluation and Interconnection Customer decision making process has the potential to increase the SIS timeline by 75 business days (approximately 109 calendar days), even without accounting for the impact of formal and informal disputes and information requests.

The Companies do not necessarily oppose the mitigation option process (and, in fact, have committed to provide mitigation option to certain QF standard offer projects covered under the Nameplate Settlement, as filed with the Commission on February 2, 2018), but the unavoidable result is that each additional component or practice that is layered into the SIS process will necessarily lengthen the study period and impact other projects.

Q. PLEASE DESCRIBE THE IMPACT THAT DEVELOPER-REQUESTED EXTENSIONS HAVE ON THE SIS TIMELINE.

A. As is described above, it is very common for developers to request and be granted extensions in connection with LVR options, mitigation options, transformer data provision and document correction. Such extensions prolongs the study period and can often impact other projects.

Q. PLEASE DISCUSS THE IMPACT THAT CURE PERIODS HAVE ON THE STUDY PROCESS TIMELINE.

A. The Companies have historically informally provided Interconnection Customers "cure periods" for missed deadlines in a number of circumstances during the SIS process, even though not expressly required under the NC Procedures. For example, where an Interconnection Customer fails to respond to a mitigation options communication within the timeframe specified, the Companies' assigned account manager will send a follow up communication in writing to provide the Interconnection Customer a cure opportunity before completing the SIS based upon the originally-requested size of the generating facility. These cure periods delay the interconnection process for projects and, in many cases, have an adverse impact on later-queued projects.

In the interest of expediting the overall study process, the Companies could seek to eliminate cure periods where not expressly required under the terms of the NC Procedures. However, such a practice would undoubtedly be met with strong opposition by Interconnection Customer who would object to being withdrawn for failure to adhere to the specified deadlines. Accordingly, the Companies' modifications to the NC Procedures propose to memorialize a single 10 Business Day cure period during both the Facilities Study and the System Impact study processes in the event that an Interconnection Customer fails to respond to a request of the Utility.

Q. PLEASE DISCUSS THE IMPACT OF INFORMATION REQUESTS AND INFORMAL DISPUTES ON THE SIS TIMELINE?

A. In many cases, developers seek to engage in protracted dialogue and informal discovery concerning the Companies' technical analysis or cost estimates where the developers disagree with the Companies' conclusions. While the Companies are committed to making reasonable efforts to provide information to developers concerning the Companies' study methodologies and the particular factors impacting the results of interconnection studies, the reality is that protracted engagement beyond that which is contemplated in the NC Procedures diverts substantial resources from the study efforts for other projects. In short, this type of engagement inevitably delays the interconnection process.

Q. PLEASE DESCRIBE THE IMPACT OF NOTICES OF DISPUTE.

A. Similar to the extensions and cure periods discussed above, formal notices of dispute pursuant to the NC Procedures impacts other projects and siphon resources away from the study process. The Companies are certainly not arguing that the right to file notices of dispute should be eliminated but are observing that such disputes will inevitably and unavoidably impact other projects and are yet another factor outside of the Companies' control that contribute to long queue periods. For instance, witness Riggins described in his direct testimony a particular project that refused to select a mitigation option. That same Interconnection Customer also filed a notice of dispute, which further extended the SIS process, and then was ultimately withdrawn after failing to comply with the NC Procedures. In total, the actions of the developer delayed the interconnection process at the SIS step for more than a year from the point in time that the mitigation options were delivered until the project was withdrawn.

Importantly, there were also several later-queued projects that were interdependent on the project described above, and such projects remained "on hold" throughout the entire year+ process described above. Those interdependent projects were undoubtedly frustrated that they have remained on hold for an extensive period of time. And yet, the reality is that this year+ delay was completely outside of the Companies' control.

Q. PLEASE DESCRIBE THE "CATCH-22" THE COMPANIES OFTEN FIND THEMSELVES IN WITH RESPECT TO ENGAGEMENT WITH DEVELOPERS IN THE INTERCONNECTION PROCESS.

A. When dissatisfied with the interconnection options made available by the Companies in accordance with Good Utility Practice, many developers will take every conceivable action to obtain a different outcome, which will necessarily prolong the process. While the Companies certainly understand the financial factors driving developers to take such actions, the reality is that such strategies consume utility management and engineering resources and invariably delay other projects seeking to complete the interconnection process.

The "catch-22" arises because where the Companies seeks to require particular developers to adhere to rigid timelines, it is often challenged by the particular developer. But where the Company does not strictly enforce rigid timelines, it impacts other developers who, in turn, complain about the general delays in the interconnection process.

A good example of this "catch-22" is the mitigation option process timeline. As described above, the mitigation option process prolongs the SIS timeline. Moreover, in many cases, developers have refused to select mitigation options in a timely manner. Therefore, the Companies have sought to impose reasonable deadlines for developers to respond to mitigation options. In one case, a particular developer filed a notice of dispute challenging the Companies' ability to impose a reasonable deadline on the Interconnection Customer's selection of a mitigation option. Separately, that same developer also informally complained to DEP regarding delays in studying another project owned by that developer but such delay was driven largely by an earlier-queued project owned by a separate developer that similarly refused to select a mitigation option within the prescribed timeline. In other words, developers pursue strategies to maximize opportunities for their projects but then complain when those same strategies have an adverse impact on their own projects.

Q. DISCUSS THE CHALLENGES OF CONSIDERING ONE-OFF TECHNICAL SOLUTIONS

A. In many cases, developers have requested that the Companies consider particular one-off, non-standard technical solutions in evaluating the system impacts of their proposed generating facility Interconnection Request. As discussed in greater detail by DEC/DEP witness Gajda, accommodating utility-scale generating facilities with non-standard methods shifts cost and reliability risk to the Companies' retail load customers and can become unsustainable and incompatible with the Companies' obligation to plan and operate the system in a safe and reliable manner for all customers. In general, engaging in "one-off" solutions is simply not a sustainable practice in light of the volume of pending Interconnection Requests. For the reasons I discus above, even engaging in the often-protracted discussions regarding an Interconnection Customer's desire for the Companies to restudy a custom non-standard solution to reduce the developer's Upgrade cost or to increase the capacity that can interconnect to the Companies' system at a given location can add additional significant extensions to the interconnection process.

Q. PLEASE SUMMARIZE THE COMPANIES' COMMENTS ON THE DISTRIBUTION STUDY PROCESS.

A. In summary, the distribution study process of utility-scale solar projects in North Carolina is a complex undertaking and the timeline for such process is significantly impacted by factors outside of the Companies' control.

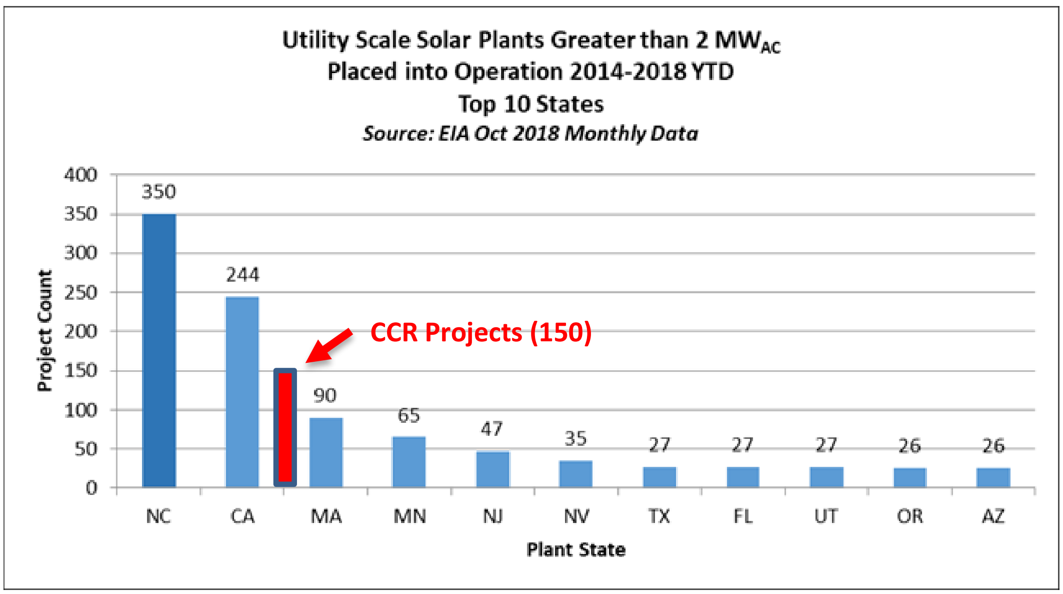
As described in the testimony of DEC/DEP witness Riggins, the Companies have exerted tremendous efforts to increase resources and improve processes to expedite the study of projects and has achieved nation-leading successes. And the Companies are not asserting that no extensions should be granted or cure periods allowed or informal exchanges of information permitted. Nor are the Companies asserting that they have, in every instance, processed every Interconnection Request in the most efficient way possible or that there are no instances in which administrative inefficiencies have contributed to delayed study processes. But it is critical that the Commission understand the extent to which current study delays and long queue wait times are substantially impacted by factors outside of the Companies' control.

Q. NCCEBA WITNESS NORQUAL SPECIFICALLY CRITICIZES THE DELAYS IN THE INTERCONNECTION PROCESS. PLEASE RESPOND.

A. An examination of some data related to CCR's development activities and the Companies' processing CCR Interconnection Requests provides a good case study of both the dramatic successes of the Companies as well as the complexities of the interconnection process.

Based on a combination of data provided by CCR and the Companies' records, the Companies have interconnected over 150 CCR- and affiliate-developed projects totaling more than 1,250 MW since 2014. To put this into perspective, this means that the Companies have processed, studied, engineered, constructed, and completed more utility-scale solar generator interconnections for a single developer—CCR—over the last 5 years ***than has been interconnected in total for every other state in the country with the exception of California***. Below, I have updated Figure 3 from my direct testimony to illustrate how the CCR projects interconnected in North Carolina compares to the top 10 utility-scale solar states in the country during the period 2014-2018.

Updated Figure 3



These facts undeniably demonstrate the Companies' significant good faith efforts to support CCR's solar generator Interconnection Request processing.

Q. DOES WITNESS NORQUAL ACKNOWLEDGE THE ASPECTS OF THE INTERCONNECTION PROCESS THAT ARE OUTSIDE OF THE CONTROL OF THE COMPANIES AS DESCRIBED ABOVE?

A. No. CCR witness Norqual fails to acknowledge the many factors impacting the interconnection process that are outside of the Companies' control. These factors have had a direct impact on the timeline for every CCR Interconnection Request.

Q. EARLIER IN YOUR TESTIMONY YOU DISCUSSED THE IMPACT OF INTERDEPENDENCY ON INTERCONNECTION TIMELINES. CAN YOU SPECIFICALLY DESCRIBE A CCR PROJECT THAT HAS EXPERIENCED INTERCONNECTION DELAYS DUE TO INTERDEPENDENCY?

A. Yes, one CCR project in DEP has been designated interdependent and "on hold" for approximately 1,450 days, or almost four years. However, the reason for this significant time in queue is that the project sought interconnection on DEP's Weatherspoon 230 kV substation behind 13 other utility-scale solar projects already in the Companies' queue. DEP has diligently sought to interconnect the earlier queued projects and as of today, six of these earlier-queued solar projects totaling approximately 26 MW have now been interconnected. But given the SIS study timeline described above (not to mention the time required to complete FSA, execute an FSA and receive payment), it is no surprise that such project has remained in the queue for an extended period. This "delay" does not reflect any fundamental flaw in the Companies' interconnection process but instead is an inevitable product of the interdependency of projects all locating in the same area and on the same circuit or substation.

Q. WHY HAVE YOU FOCUSED ON THE SIS TIMELINE FOR DISTRIBUTION-CONNECTED PROJECTS?

A. Distribution-connected projects constitute the vast majority of the utility-scale solar projects that have been interconnected (approximately 93%) and the vast majority of the utility-scale solar projects that remain in the queue (approximately 71%). Therefore, understanding the SIS timeline for distribution-connected project is critical to assessing the factors driving the current interconnection wait times.

Q. PLEASE COMMENT ON THE SIS TIMELINE FOR TRANSMISSION-CONNECTED PROJECTS.

A. As the Companies have previously explained, the amount of distribution-connected solar in North Carolina is unparalleled and these penetration levels give rise to a wide range of technical considerations and costs in connection with the interconnection. In contrast, there tends to be fewer factors impacting transmission-connected generation and where transmission network constraints arise, they tend to involve substantial expense that result in voluntary withdrawal within the established timelines. Nevertheless, there have been many instances in which developer actions have delayed the study process for transmission-connected projects and, once again, the Companies expect delays to increase as more substantial upgrades are triggered.

Q. ASIDE FROM THE SIS PROCESS, WHAT ARE THE OTHER MAJOR COMPONENTS OF THE INTERCONNECTION PROCESS?

A. The other major components of the interconnection process are the Facilities Study including the field engineering design work, the construction process, the inspection and commissioning process.

Q. PLEASE DESCRIBE HOW THOSE PROCESSES CAN ALSO BE TIME-CONSUMING.

A. The Facilities Study includes any final modeling requirements, but most importantly for distribution projects, includes the field engineering design work and development of the construction work order and more detailed cost estimates. So, for example an engineer might require several weeks to confirm existing right of way easements, obtain property owner approval for any pole line changes, obtain any new right of way, submit highway and in many cases rail road encroachment permits in addition to normal design, construction drawings, and work order estimates. For transmission projects these functions can take many months.

The construction process can be very complex, particularly in the increasingly common scenarios where projects are triggering large distribution upgrades or transmission network upgrades. For example, distribution upgrade costs in many cases have exceeded $1M and require a half year or more to complete. Transmission network upgrade costs are now being seen in the $10-$40M, and in one case will exceed $100M. The construction process can be delayed by challenges ranging from complex line outage restrictions to more mundane weather conditions. For examples, one recent distribution-connected project was delayed for months where a pole line crossing a land-owner's property could not be accessed because of rainy weather and the land-owner would not allow construction equipment on their property until his land dried out.

Q. HOW WILL HB 589 IMPACT THE INTERCONNECTION PROCESS.

A. HB 589 marked an important transition in the state's renewable procurement strategies away from standard offer contracts that incented a surging and unparalleled growth of 5 MW distribution-connected projects and towards a competitive procurement process that is expected to result in the selection of larger, transmission-connected projects.

In the long-term, from an interconnection process perspective, this transition is expected to result in more efficient interconnection practices and will tend to minimize upgrade costs by selecting projects that are located in favorable grid locations.

In simple terms, it is much easier to study and interconnect a single cost-effective 80 MW transmission-connected project identified through CPRE than it would be to study and interconnect 16 distribution-connected 5 MW projects, each of which must be carefully studied to ensure neighboring customers also interconnected to the same distribution circuits are not impacted by this large generator cycling on and off regularly.

Q. ARE THERE REMAINING CHALLENGES IN THE SHORT TERM?

A. Undoubtedly, yes. That is because there are currently approximately 224 projects greater than 1 MW seeking distribution interconnection that must be studied to support their safe and reliable interconnection. In addition, as was described in my pre-filed direct testimony, the currently interconnected generation has consumed substantial amounts of the available distribution and transmission capacity and, as a result, projects currently seeking to interconnect are increasingly triggering the need to make substantial Upgrades, including the need for major transmission network upgrades. These more significant Upgrades often require substantial engineering and construction resources, further delaying interconnection. In my direct testimony, I specifically identified a major transmission upgrade that has already been triggered and will take 3-4 years to construct and will delay the interconnection of numerous other projects located in that specific geographic area.

Once again, the delays that projects may experience due to the substantial construction projects required to further expand the Companies' network are not a product of any administrative or processing inefficiencies on the part of the Companies but instead are simply a result of the unparalleled growth of interconnected solar generation on the Companies' systems.

Given the amount of remaining distribution-connected projects that must complete the SIS timeline described above, combined with the growing congestion issues and associated construction challenges, there remain significant hurdles to the completion of the transition from North Carolina's legacy PURPA implementation to the new policy direction reflected in HB 589.

Q. WHAT IS A GROUPING STUDY?

A. A grouping study gathers multiple interconnection requests that are submitted within a defined request window into a single group or cluster. Unlike the current serial process, where interconnection requests are generally studied in sequence based on the time the interconnection request is submitted, a grouping study allows projects to be studied at the same time. To be effective, the grouping study needs to allocate upgrade costs to all projects that contribute to the need for the upgrade, and will require early financial commitments to fund these upgrades. Grouping studies are successfully being used in other parts of the country to manage high volumes of interconnection requests.

Q. PLEASE DESCRIBE THE GROUPING STUDY THAT WAS APPROVED FOR PURPOSES OF CPRE.

A. In the October 5, 2018 *Order Approving Interim Modifications to North Carolina Connection Procedures for Tranche 1 of CPRE RFP*, the

Commission approved modifications to Section 4.3.4 of the NC Procedures, amongst others, to facilitate a grouping study for the limited purposes of implementing CPRE. In this case, grouping studies will be used to establish a study "base line" for non-participating projects and then competitive participating projects are grouped to form a study "change case" to assign upgrade costs and further evaluate bids to determine the least total cost of a portfolio of projects.

Q. WHY DOES THE COMPANY BELIEVE THAT GROUPING STUDIES FOR THE ENTIRE INTERCONNECTION QUEUE WOULD BE BENEFICIAL?

A. Grouping studies will make the interconnection process more efficient from a transmission-level perspective and will allow costly transmission network upgrades to be allocated to multiple projects rather than burdening individual projects with the entire upgrade costs. Distribution-connected projects would also be included in these grouping studies, where the studies would more quickly or efficiently determine their impact on the transmission network. Network upgrade costs would also be allocated to these projects if needed, but studies to determine distribution upgrade costs most likely would remain in a sequential process, or limited/local grouping studies.

Q. WHAT OTHER UTILITIES UTILIZE GROUPING STUDIES IN THIS WAY?

A. Public Service Company of New Mexico, Midcontinent Independent System Operator, Inc. ("MISO"), Southwest Power Pool, Inc. ("SPP") and California Independent System Operator Corp. (CAISO") and other FERC jurisdictional RTOs have implemented grouping studies. On November 19, 2019, Public Service Company of Colorado ("PSCO") filed a proposal to move from a "…first-come, first served model…to a first-ready, first-served model. PSCO proposed to move to grouping studies in response to "[s]urges in the volume of new generation development" that were making it difficult to process Interconnection Requests in a timely manner. PSCO has a queue containing 23,000MW where their peak load is only 8,500MW. In its 2008 Technical Conference Order regarding Interconnection Queuing Practices, FERC suggested that grouping studies or first-ready, first-served interconnection process could speed up queue processing.

Q. PLEASE DISCUSS THE COMPANIES' SPECIFIC PLANS TO MOVE TOWARDS A FULL GROUPING STUDY, INCLUDING TARGET DATES FOR ITS ACTIONS?

A. The Companies are committed to an extensive stakeholder engagement process beginning in the first quarter of 2019 and are in the process of developing a strawman proposal that will be used as a starting point for the stakeholder process. The Companies envision an iterative process that allows for multiple meetings with stakeholders with a goal to complete the stakeholder process by late June 2019 which would result in redline changes to the State and Federal interconnection procedures. The Companies would then make a filing of the proposed changes in July 2019 to both the FERC and the NCUC. This process will also need to include South Carolina stakeholders and will likely include a filing with the South Carolina Public Service Commission since the transmission network is agnostic to state lines.

Q. IS THE GROUPING STUDY A PANACEA FOR THE CURRENT INTERCONNECTION QUEUE?

A. No. As currently contemplated, the grouping study will only assess the transmission impacts of both distribution- and transmission-connected projects, and will not assess the distribution level impacts of distribution-connected projects. As discussed above, the current interconnection queue still contains a backlog of proposed utility-scale distribution-connected projects, and there is no "quick fix" for processing such projects. Each project must undergo the distribution-level study process described above to ensure a safe and reliable interconnection

. However, assuming that the state policy reflected in HB 589 is carried forward into the future, the Companies expectation is that the majority of future procurement efforts will occur via competitive RFP processes that will most likely encourage the development of larger, transmission connected projects that can be more efficiently studied through a grouping study process.

Q. PUBLIC STAFF WITNESS LUCAS RECOMMENDS THE COMPANIES INITIATE A "STAKEHOLDER DISCUSSION FOCUSED SOLELY ON REVISITING THE PROJECT A/B PROCESS AND THE OPTIONAL GROUPING STUDY PROCESS TO DETERMINE HOW THEY MIGHT BE USED TOGETHER TO MORE EFFICIENTLY MANAGE THE LARGE NUMBER OF PROJECTS IN THE QUEUE." PLEASE RESPOND TO THE PUBLIC STAFF'S RECOMMENDATION.

A. As discussed above, the Companies believe that a grouping study will be a useful tool for expediting certain portions of the interconnection study process. The Commission should allow the Companies to implement the steps described above rather than adopting Public Staff's recommended stakeholder and reporting requirements at this time.

Q. PUBLIC STAFF WITNESS LUCAS ALSO IDENTIFIES "CONCERNS THAT RAISE SERIOUS QUESTIONS ABOUT THE FAIRNESS AND EQUITY REGARDING COST RESPONSIBILITY FOR USERS OF THE GRID, WHETHER THEY ARE DGS INJECTING ENERGY OR CONSUMERS EXTRACTING ENERGY." PLEASE RESPOND TO THESE CONCERNS.

A. The Company shares these concerns and agrees that care should be taken to assign costs to the "cost causer" and minimize the risk of cost shifting. However, the Companies also recognize that there are challenges to preventing all cost shifting and that it is nearly impossible to recover all interconnection processing costs that vary over time through fixed fees applied to a number of projects that can also vary over time. Also, post-interconnection, the Companies are seeing a growing number of customer calls dealing with, for example, net metering billing questions and questions about their solar facility performance for which there is no cost recovery mechanism for these costs other than to include in retail base rates.

Q. PUBLIC STAFF WITNESS WILLIAMSON RECOMMENDS AN INDEPENDENT REVIEW OF THE ENTIRE NORTH CAROLINA INTERCONNECTION PROCESS. PLEASE RESPOND TO SUCH RECOMMENDATION.

A. Public Staff witness Williamson is correct that the Companies remain willing to consider an "EPRI or a similar third-party to assist in studying and further developing North Carolina's Fast Track and other technical interconnection screens." Witness Gajda provides additional explanation on this proposal in his rebuttal testimony, recommending that the Companies' Technical Standards Review Group would provide an appropriate forum for such discussions with EPRI or a similar third-party. However, a third-party audit of the entire interconnection process would be an undertaking on an entirely different scale and the Companies do not believe such an enormous effort would be an appropriate or efficient use of the Companies' resources at this time, particularly as the Companies direct their efforts to implementation of a stakeholder process recommending a transition to a full grouping study. Also, many of these same resources need to remain focused on processing interconnection requests.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 101

In the Matter of	)	**REBUTTAL TESTIMONY OF**
Petition for Approval of Generator	)	**JEFFREY W. RIGGINS**
Interconnection Standard	)	**ON BEHALF OF DUKE ENERGY**
	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Jeffrey W. Riggins, P.E., Director of Standard Power Purchase Agreements ("PPAs") and Generator Interconnections for Duke Energy Corporation ("Duke Energy"). My business address is 400 South Tryon Street, Charlotte, NC 28202.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this rebuttal testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies").

Q. ARE YOU THE SAME JEFFREY W. RIGGINS WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain issues raised by the Public Staff and intervenors in their respective direct testimony pertaining to the North Carolina Interconnection Procedures ("NC Procedures"). Specifically, I will address issues raised in the testimonies of Public Staff witness Jay Lucas, Interstate Renewable Energy Council ("IREC") witness Sara Auck, and North Carolina Clean Energy Business Association ("NCCEBA") witness Christopher Norqual. My rebuttal testimony responds to and largely supports the Public Staff's recommendations regarding adding additional timeframes for utility and

Interconnection Customer action in certain sections of the NC Procedures, while opposing IREC's advocacy for the Commission to impose a "timeline enforcement mechanism" on the Companies and Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina ("DENC" and, together with the Companies, the "Utilities"). I also explain why the Companies support Public Staff's recommended additions to current queue reporting as reasonable, but oppose much of IREC's queue reporting proposals, which the Companies believe are unduly burdensome. I also respond to the Public Staff's and IREC's comments on Hosting Capacity Maps, and show that deploying a distribution system-focused HCM would likely have limited benefits to most North Carolina small Section 2 generator Interconnection Customers and would also be prohibitively expensive if the cost is fully assigned to Interconnection Customers, as recommended by the Public Staff. I also provide additional support for the Companies' proposed revisions to certain interconnection fee revisions within the NC Procedures and further address the Companies' position on the NC Procedures Section 6.2 dispute resolution process. I also address the Companies' position regarding acceptability of surety bonds as Financial Security for Interconnection Facilities. Finally, I briefly address the Public Staff's and other parties' support for proposed modifications to expedite processing of swine and poultry Interconnection Requests as well as standby generator Interconnection Requests.

Q. ARE YOU INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes. I am submitting five exhibits. Rebuttal Exhibit JWR-1 provides DEC's and DEP's most current distribution queue status report as of December 27, 2018, along with the FAQs and status definitions the Companies have posted to the Companies' renewables website. Rebuttal Exhibit JWR-2 provides an example of the free "Pre-Request Response" and "Pre-Application Report" the Companies provide to Interconnection Customers. Rebuttal Exhibit JWR-3 provides support for the Companies' revisions to the North Carolina interconnection fees. Rebuttal Exhibit JWR-4 provides the Commission certain data request responses referenced in my testimony. Last, I am submitting Rebuttal Exhibit JWR-5, which provides a form surety bond determined acceptable by the Companies' credit and risk management department. I am also co-sponsoring Rebuttal Exhibit JWG-1, which is the Companies' updated redline of the North Carolina Interconnection Procedures ("NC Procedures").

I. Utility and Interconnection Customer Response Timeframe Requirements

Q. PLEASE ADDRESS THE PUBLIC STAFF'S RECOMMENDATIONS RELATED TO UTILITY AND INTERCONNECTION CUSTOMER RESPONSE TIMEFRAME REQUIREMENTS UNDER THE NC PROCEDURES.

A. The Public Staff recommends adding more clearly defined response timelines within four sections of the NC Procedures relating to activities such as providing existing information through the Pre-Application Reports, scheduling scoping meetings, and processing refunds where an Interconnection Customer withdraws from the interconnection queue. Specifically, Public Staff witness Lucas states that the Public Staff supports incorporating the following timeframes into the NC Procedures:

- a 10 Business Day requirement in Section 1.3.3 for Utilities to provide a pre-application report;
- a 10 Business Day requirement in Section 2.2.2 for Utilities to provide reasons for failure of fast track screens;
- a 60 Business Day requirement in Section 6.3.3 for Utilities to settle up interconnection study deposits; and,
- maintaining the 10 Business Day requirement to schedule a scoping meeting in 4.2.1.

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESS LUCAS' RECOMMENDATIONS REGARDING ESTABLISHING MORE CLEAR TIMEFRAMES FOR TAKING ACTION?

A. The Companies generally agree with the Public Staff and other parties that setting clear and reasonably-achievable timeframes for action within the NC Procedures promotes transparency and is appropriate for both Utilities and Interconnection Customers to timely complete routine activities, such as providing existing information, scheduling meetings, and making payments or providing refunds. In processing Interconnection Requests, the

Companies make reasonable efforts as required by NC Procedures Section 6.1 to meet all timeframes; although, as discussed in my direct testimony and the testimony of DEC/DEP witness Freeman, certain timeframes have been challenging to meet due to the increasing complexity of processing North Carolina's unparalleled volume of utility-scale solar Interconnection Requests, as well as the fact that many aspects of the study process are outside of the Companies' control.[1] However, the Companies agree that establishing reasonable timeframes is beneficial to the overall administration of the interconnection process.

In response to Public Staff witness Lucas' specific recommendations, the Companies agree with several of the proposed modifications, but have determined that other proposals either conflict with existing provisions of the NC Procedures or are not needed as the same timeframe is already more clearly addressed in another Section of the NC Procedures. For example, the Public Staff's proposed addition of "within ten (10) business days" to Section 1.3.3 to set the timeframe by which the utility must produce the Pre-Application Report is not needed as this same 10 Business Day timeframe is already more precisely addressed in Section 1.3.1. Section 1.3.1 (as modified by the Companies' proposed NC Procedures revisions) provides: "The Utility shall provide the Pre-Application data described in Section 1.3.2 to the Interconnection Customer

[1] DEC/DEP Riggins Direct Testimony, at 6-7; DEC/DEP Freeman Rebuttal Testimony, at 7-9.

within ten (10) Business Days of receipt of the completed request form and payment of the $500~~$300~~ fee." The current Section 1.3.1 establishes "receipt of a completed request form" as the starting point for tracking the 10 Business Day timeframe. In contrast, the Public Staff's proposed addition to Section 1.3.3 does not include a clearly defined starting point and may cause confusion to the extent that it could be read to conflict with or modify the timeframe in Section 1.3.1.

The proposed addition of "within ten (10) business days" to Section 2.2.2 also conflicts with existing language of Section 2.2.1, which provides the Utility 15 Business Days to complete the initial small generator interconnection screening process. The vast majority of the Section 2 (20 kW or less inverter-based generating facilities) are residential or small commercial net-energy metering ("NEM") program customers and very rarely do the Companies determine that the Section 2 NEM generating facilities cannot be interconnected. When such circumstances arise, the Companies would follow existing Sections 2.2.1 and 2.2.2 to advise the Interconnection Customer within 15 Business Days of processing a completed Section 2 Interconnection Request and to explain why the proposed generating facility failed the initial Fast Track screening and must proceed either to Section 3.4 Supplemental Review (*see* 2.2.2.1) or to the full Section 4 Study Process (*see* 2.2.2.2).

Q. DO THE COMPANIES SUPPORT THE PUBLIC STAFF'S PROPOSED 60-BUSINESS DAY TIMEFRAME TO PROVIDE A FINAL ACCOUNTING REPORT TO A WITHDRAWN INTERCONNECTION REQUEST?

A. Yes. As Public Staff witness Lucas recognizes, the Companies often engage consultants and independent contractors to support the interconnection study process and significant time may be required for the Companies to receive and process contractor invoices before settling up interconnection deposits after any voluntary or deemed Interconnection Request withdrawal.[2] The Companies support the Public Staff's proposed 60 Business Day timeframe recommendation to settle interconnection deposits pursuant to Section 6.3.3. Notably, 60 Business Days is shorter than the 90 Business Days originally proposed by the Utilities in the prior comment proceeding. To the extent that additional time is required to complete the final accounting for a specific Interconnection Customer (such as a large and complex transmission-connected generator), the utility would adhere to the requirements of Section 6.1 to provide the Interconnection Customer an explanation of why the additional time is needed and the expected date by which the utility can deliver the final accounting. To the extent that the final accounting can be completed in less than 60 Business Days, such as where the Interconnection Customer withdraws early in the interconnection

[2] Public Staff Lucas Direct Testimony, at 29-30.

process, the Companies will issue the final accounting more expeditiously as it becomes available.

The Companies also support retaining the existing 30 calendar days from the date of issuance of the final accounting report for either the utility to make any refund required by the final accounting or for the Interconnection Customer to make any supplemental payment for the study work completed if the Interconnection Customer's cost responsibility exceeds its previous aggregate deposit payments, as described in Section 6.3.3.

Q. PLEASE RESPOND TO THE PUBLIC STAFF'S RECOMMENDATION REGARDING THE TIMING OF SECTION 4.2.1 SCOPING MEETINGS.

A. Public Staff witness Lucas recommends retaining the pre-existing ten (10) Business Day requirement in Section 4.2.1 to schedule a scoping meeting with Interconnection Customers. The Companies agree to the Public Staff's recommendation to retain the 10 Business Day requirement in Section 4.2.1, but note that preparing a more detailed "technical review," as described in my direct testimony will require additional time beyond 10 Business Days.[3] The Companies continue to believe this more robust scoping meeting could benefit Interconnection Customers by providing more detailed information regarding the feasibility of the proposed generator interconnection earlier in

[3] DEC/DEP Riggins Direct Testimony, at 25-26.

the interconnection process. Providing more detailed information earlier could also potentially help reduce the number of speculative and likely non-viable projects occupying the Companies' interconnection resources to perform complex studies only to later elect to withdraw from the queue after receiving initial study results. The Companies also believe that this enhanced scoping meeting approach can still be offered and scheduled, at the Interconnection Customer's option, "as mutually agreed to by the Parties" under Section 4.2.1. After filing direct testimony, the Public Staff indicated their support for this optional approach where the Interconnection Customer agrees to a delay in scheduling the scoping meeting to enable the Companies to prepare for an enhanced technical review.[4]

II. <u>Timeline Enforcement Mechanism</u>

Q. DID INTERVENORS RAISE CONCERNS RELATED TO CURRENT INTERCONNECTION PROCESSING TIMEFRAMES?

A. Yes. NCCEBA witness Norqual argues that interconnection delays have negatively impacted Cypress Creek Renewables' ("CCR") business.[5] IREC witness Auck also raises concerns with delays in processing Interconnection Requests.[6]

[4] Rebuttal Exhibit JWR-4, Public Staff's response to the Companies' Data Request 2-3.
[5] NCCEBA Norqual Direct Testimony, at 5-8.
[6] IREC Auck Direct Testimony, at 43-45.

Q. IREC RECOMMENDS THE COMMISSION ADOPT A TIMELINE ENFORCEMENT MECHANISM ("TEM") AS A SOLUTION TO REDUCE RECENTLY-EXPERIENCED DELAYS PROCESSING INTERCONNECTION REQUESTS. DO YOU AGREE WITH IREC'S PROPOSAL?

A. No. The Companies oppose adoption of a TEM and believe such a punitive measure is not appropriate in light of the Companies' continuing good faith and reasonable efforts to process North Carolina's unprecedented volume of utility-scale solar generator Interconnection Requests as well as the complexities of North Carolina's interconnection process, as discussed by DEC/DEP witness Freeman.

First, as stated in my direct testimony, the Companies have made significant investments in staffing, technology, and process improvements to address the delays identified by NCCEBA and IREC.[7] Further, as explained by DEC/DEP witness Freeman, the unprecedented and unparalleled number of utility-scale solar generators already interconnected by DEC and DEP validates these reasonable and good faith efforts.[8] I also explain in my direct testimony the Companies' significant efforts to staff up in order to more efficiently administer the interconnection process and to conduct studies for projects that are ready to be studied, i.e. Project A or

[7] DEC/DEP Riggins Direct Testimony, at 10-14.
[8] DEC/DEP Freeman Direct Testimony, at 7-12.

Project B Interconnection Requests.[9] Secondarily, as DEC/DEP witness Freeman discusses in his rebuttal testimony, IREC's recommendation is based on a flawed assumption that the Companies have complete control over the amount of time it takes to interconnect a project.

Q. DOES IREC'S PROPOSAL EVEN ATTEMPT TO TAKE INTO ACCOUNT THE UNIQUE COMPLEXITIES OF THE NORTH CAROLINA INTERCONNECTION LANDSCAPE OR RECOGNIZE OTHER FACTORS OUTSIDE OF THE COMPANIES' CONTROL THAT SUBSTANTIALLY LENGTHEN INTERCONNECTION PROCESSING TIME PERIODS?

A. No. The TEM described by IREC witness Auck would simply "calculate[] the total aggregate average time, in business days, that it has taken to interconnect projects…starting from the date an application is received until the date an interconnection service agreement is executed" and then penalize the Companies if they fail to meet the target on an average basis in a given year.

Such an approach absurdly assumes that the length of time from Interconnection Request submission to Interconnection Agreement ("IA") execution is completely within the Companies' control. That assumption is baseless and demonstrates a profound lack of understanding of the complexity of the interconnection process in North Carolina.

[9] DEC/DEP Riggins Direct Testimony, at 8-10.

To the contrary, DEC/DEP witness Freeman extensively describes in his rebuttal testimony the many factors affecting interconnection timelines in North Carolina that are outside of the Companies' control. One of the major factors leading to the long interconnection periods is the concept of interdependency established in Section 1.8 of the NC Procedures. Pursuant to this Commission-approved queueing process, the Companies prioritize study of Interconnection Customers whose interconnection is not impacted by other earlier-queued Interconnection Requests. Projects that are impacted by or "behind" two or more other Interconnection Requests are designated as "on hold" until earlier queued Interconnection Customers elect either to sign an IA and fund generator interconnection System Upgrades or to withdraw (*see* 1.8.3).

In many instances, numerous projects have sought interconnection to the same distribution circuit or substation, resulting in numerous projects being placed "on hold' in accordance with the NC Procedures. Under IREC's simplistic TEM proposal, the Companies could be penalized for the delays experienced by such projects even though the Companies are actually adhering to the terms of the NC Procedures.

Witness Freeman also describes the many aspects of the System Impact Study process that are outside of the Companies' control. For instance, Interconnection Customers often request multiple extensions at various stages of the interconnection process and such extensions substantially lengthen the interconnection timeline not only for the specific project requesting the extension, but also for other projects interdependent on such project. Under IREC's TEM proposal, all such extensions (along with cure periods, formal and informal disputes, failures of developers to provide correct information, delays in developer obtaining rights of way, developer requests for information) would, unjustly, lead to penalties for the Companies.

In fact, IREC's simplistic TEM proposal would actually create an incentive for the Companies to refuse to grant extensions or cure periods or allow even the slightest accommodation for Interconnection Customers. Based on the Companies' experience, any such approach would be untenable and would simply result in endless disputes with Interconnection Customers.

Q. IS IREC'S RECOMMENDED TEM REASONABLE?

No. IREC's TEM proposal completely fails to take into account the complexity of the interconnection process in North Carolina and will accomplish absolutely nothing with respect to resolving the primary drivers of the Companies' current interconnection processing challenges that DEC/DEP witness Freeman discusses in greater detail. In light of the Companies' good faith efforts and unparalleled success interconnecting utility-scale solar projects, as well as the current complexities of the interconnection process in North Carolina, imposition of a TEM would be inappropriate, unjust, and unreasonable.

Further, the Companies question the appropriateness of IREC's proposal to impose financial penalties through "positive and negative earnings adjustment" for deviations from the timeframes set forth in the NC Procedures.[10] While I am not an attorney, IREC's proposed earning adjustment mechanism appears inconsistent with North Carolina's general ratemaking framework under the Public Utilities Act under which the Commission fixes the Companies' rates until the next general rate case.

Q. DOES THE PUBLIC STAFF SUPPORT ADOPTION OF A TEM IN NORTH CAROLINA?

A. No. Public Staff witness Lucas makes clear that the Public Staff does not support adoption of a TEM. Witness Lucas testifies that "the Utilities appear to have made good faith efforts to interconnect DG" and that the "unprecedented growth of solar could only have been brought about by cooperation of the Utilities."[11]

Q. DO OTHER STATES UTILIZE A TEM IN THEIR INTERCONNECTION PROCESS?

A. Massachusetts and New York appear to be the only states to have adopted a TEM, and establishment of these TEMs were required by enabling legislation enacted in these States.[12]

---

[10] IREC Auck Direct Testimony, at 44.
[11] Public Staff Lucas Direct Testimony, at 32.
[12] Rebuttal Exhibit JWR-4, IREC's response to the Companies' Data Request 1-20.

III. Communication, Reporting, and Transparency

Q. IN YOUR DIRECT TESTIMONY, YOU EXPLAINED THE COMPANIES' EFFORTS TO IMPROVE REPORTING AND COMMUNICATION RELATED TO THE INTERCONNECTION PROCESS. PLEASE SUMMARIZE THOSE EFFORTS.

A. The Companies have added additional resources and made significant investments in new technology systems—primarily Salesforce—to better track the status of each Interconnection Request throughout the interconnection process. The Companies also voluntarily publish detailed bi-weekly DEC and DEP distribution system "Queue Snapshot" reports on its website identifying the interdependency status, operational or study status, project capacity and fuel source, as well as distribution feeder and substation name for each Interconnection Requests above 20 kW. This information is available on the Companies' website at https://www.duke-energy.com/business/products/renewables/generate-your-own/interconnection-queue. My Rebuttal Exhibit JWR-1 provides DEP's and DEC's most current distribution queue status report as of December 27, 2018, along with FAQs and status definitions that the Companies have posted to the website.

To support more efficient customer communications and reporting, the Companies are also currently expanding the use of features within Salesforce to create reminders of the Companies' milestones and developer's milestones so approaching deadlines can be proactively monitored and addressed. The Companies have also added Account Managers and Customer Account Specialists that are dedicated to managing projects and addressing inquiries from Interconnection Customers to ensure that the interconnection process moves as efficiently as reasonably possible.

Q. HAVE THE COMPANIES MADE ANY CHANGES WITH RESPECT TO PUBLISHING THEIR INTERCONNECTION QUEUES SINCE THE COMMISSION LAST APPROVED THE NC PROCEDURES IN 2015?

A. Yes. In the Commission's May 2015 Order approving the current NC Procedures, the Commission directed the Companies to file quarterly queue status and queue performance reports with the Commission in Docket No. E-100, Sub 101A. As noted above, and as commended by the Public Staff, the Companies voluntarily publish an updated Queue Snapshot report twice monthly (bi-weekly) to improve transparency into the interconnection study process and to assist Interconnection Customers in keeping informed of the status of their projects. Notably, the Companies' current voluntary queue tracking and reporting seems to already provide more information than most utilities in other states, as IREC was only able to identify a few states that are required to *or* voluntarily provide interconnection queue reporting of large generator interconnections.[13]

[13] Rebuttal Exhibit JWR-4, IREC's response the Companies' Data Request 1-18.

Looking ahead, in early 2019, the Companies plan to further enhance their published Queue Snapshot reports by providing additional granularity on the progress of System Impact Studies, which have grown in complexity since the current NC Procedures were approved in 2015. For example, the Companies recently began publishing Engineering Administrative Designations ("EAD") in their queue reports. Identifying the current EAD, such as "Voltage Flicker Mitigation Options" review, helps to provide Interconnection Customers a better understanding of which phases of the System Impacts Study process have been completed and the phases that are still underway. Rebuttal Exhibit JWR-1 shows the information currently provided in these queue reports.

Q. PLEASE SUMMARIZE THE PUBLIC STAFF'S RECOMMENDATIONS WITH RESPECT TO QUEUE REPORTING AND COMMUNICATION BETWEEN THE COMPANIES AND INTERCONNECTION CUSTOMERS THROUGHOUT THE INTERCONNECTION PROCESS.

A. Public Staff witness Lucas recognizes the Companies' efforts to communicate throughout the interconnection process and the significant improvements in the availability of information being provided to customers.[14] Public Staff witness Lucas also recommends that the Utilities evaluate and provide a detailed cost estimate of the cost of developing and

[14] Public Staff Lucas Direct Testimony, at 18.

operating an online portal to allow developers to track near real time status (within 2 Business Days of changes) of projects.

Q. DO YOU AGREE WITH THE PUBLIC STAFF'S RECOMMENDATIONS?

A. Yes. The Companies are already developing an online Interconnection Customer portal, which will allow Interconnection Customers to electronically submit Interconnection Requests and payments and will allow the Companies to share status information with Interconnection Customers. This Customer portal will pull information in "real time" from Salesforce and will be accessible to the Interconnection Customer upon logging into its Customer portal page. The Companies commit to share with the Public Staff the current plans for the online portal and to identify additional features that need to be evaluated.

Q. PLEASE RESPOND TO THE PUBLIC STAFF'S RECOMMENDATIONS WITH RESPECT TO THE ANNUAL QUEUE REPORTING TO THE COMMISSION.

A. Public Staff witness Lucas recommends modification of the generator interconnection reports filed with the Commission in Docket No. E-100, Sub 113B from annually to quarterly, and also recommends the reports include operational status and identify all FERC-jurisdictional projects.

Due to the significant increase in the number of generator interconnections since the Commission established this reporting requirement, the Companies are not opposed to increasing the frequency of reporting this information to the Commission from annually to quarterly and adding the operational status and FERC projects. The Companies already file quarterly Queue Status and Interconnection Request Performance Reports with the Commission in Docket No. E-100, Sub 101A, and the Companies are not opposed to making a quarterly filing identifying interconnected generators as requested by the Public Staff. This report will identify all projects above 20 kW requesting interconnection and their operational status as is currently posted to the Companies' website in the most recently published biweekly Queue Snapshot. For administrative efficiency, the Companies recommend adding the Public Staff's requested installed generator reporting information into the quarterly report filing currently made in Docket No. E-100, Sub 101A and separately continuing to file the small generator report annually in Docket No. E-100, Sub 113B.

Q. PLEASE RESPOND TO IREC'S REQUEST FOR ADDITIONAL INFORMATION TO BE INCLUDED IN QUARTERLY REPORTS.

A. IREC witness Auck recommends the Utilities continue filing quarterly performance reports, but advocates for adding significant additional granularity and reporting requirements to the current information required by the Commission. As noted, the Companies already file, and will continue filing, Queue Status and Interconnection Request Performance Reports with the Commission identifying the following intervals for all Section 4 Interconnect Requests: (i) Queue Assignment to Issuance of Interconnection Agreement; (ii) Interconnection Agreement Receipt to

Project Completion; (iii) Queue Assignment to Project Completion; and (iv) Projects interconnected by year.

While the Company supports continuing the current queue performance reporting to show the Commission progress and trends in the interconnection process, the administrative burdens and expense of expanding the quarterly performance reporting to include the voluminous and granular data in IREC witness Auck's Exhibit SBA-Direct-4 will significantly outweigh any benefit to Interconnection Customers or the overall interconnection process in North Carolina. In order to provide the granular information requested by IREC, such as maximum, mean, and median processing times for multiple steps in the study process as well as project-by-project Fast Track and supplemental review statistics, the Companies would need to dedicate additional engineering and administrative resources focused on reporting and developing metrics versus actually studying Interconnection Requests. This increase in reporting seems particularly unreasonable as it would add to the Companies' already-under-recovered costs of administering the interconnection process, which IREC is already challenging. Moreover, as described above and by DEC/DEP witness Freeman, details such as the maximum, mean, and median processing times would be inadequate without adding dozens of other burdensome reporting requirements such as tracking interdependencies and delays arising due to circumstances outside the Companies' control.

Additionally, the recommendation to provide real-time cost details for each project would require significant investment in the Companies' financial systems. As required by the NC Procedures, the Companies complete a financial review and provide a final accounting report after invoices are processed and costs are available. For the small projects that are the primary focus of IREC's testimony, costs should not be a concern since most of the Companies' costs are covered by fees rather than deposits.

Q. PLEASE RESPOND TO IREC'S REQUEST WITH RESPECT TO MONTHLY DISTRIBUTION QUEUE REPORTING.

A. IREC witness Auck also advocates that the Companies be required to publish a detailed Distribution System Interconnection Queue report on their websites "on at least a monthly basis" in a sortable spreadsheet format.[15] IREC's Exhibit SBA-Direct-3 proposes that the distribution queue report include 23 separate data fields.

As described above, DEC and DEP each already voluntarily publish public Queue Snapshot reports on its website in a downloadable format and update it twice a month; more frequently than IREC requests. Much of the data recommended in witness Auck's Exhibit SBA-Direct-3 is included in the existing queue report. Some of the information requested, however, is currently included in individual notifications to Interconnection Customers as milestones are achieved throughout the interconnection process and the

[15] IREC Auck Direct Testimony, at Exhibit SBA-Direct-3.

Companies disagree with IREC's recommendation to publicly publish this information. Specifically, detailed Interconnection Customer cost and the dates that the IA and other agreements are executed would be inappropriate to share publicly in a queue report.

Q. WHAT SPECIFIC CONCERNS WOULD THE COMPANIES HAVE WITH IMPLEMENTING IREC'S RECOMMENDATION?

A. Some of the data elements IREC witness Auck listed in Exhibit SBA-Direct-3 are already provided in the biweekly Queue Snapshot reports voluntarily published on the Companies' website. The data currently provided allows Interconnection Customers to determine the interdependency status and operational status of their Interconnection Request and to determine where their request is in queue relative to other Interconnection Requests. However, much of the information in Exhibit SBA-Direct-3, including the date, cost, and transformer data, is appropriately communicated directly to each Interconnection Customer through Pre-Request Responses, Pre-Application Reports, and emails/reports as projects proceed through the interconnection process and should not be published in the monthly queue reports. The Companies' Salesforce application currently captures the effective dates of agreements and the start and end dates of the various study and construction milestones, but does not capture the date of notifications or whether projects pass/fail screens. IREC's proposed reporting on notification dates and screen results would require additional investments to enhance the Salesforce database and significant manual effort to populate the fields after reviewing the email communications already provided to Interconnections Customers, adding additional costs to the interconnection process.

Further, IREC witness Auck seems to recommend that the Companies should be required to include small <20 kW NEM projects in its distribution system queue. The Companies already include Section 3 and Section 4 NEM projects in their Queue Snapshot reports as those projects are required to proceed through Fast Track, Supplemental, or the Section 4 Full Study process. The Companies do not, however, include the thousands of Section 2 (<20kw) projects because those requests are managed in the PowerClerk system and to date have not been subject to the Fast Track screens based on the Companies' determination that the Section 2 projects can currently interconnect safely and reliably at lower levels of penetration. These Section 2 NEM projects have historically been processed very efficiently and the administrative burden and cost associated with including them in queue reporting is unjustified.

IV. Hosting Capacity Maps

Q. PLEASE ADDRESS THE PUBLIC STAFF'S AND INTERVENORS' POSITIONS REGARDING HOSTING CAPACITY MAPS.

A. Public Staff witness Lucas states that a distribution level hosting capacity map ("HCM") would provide little benefit due to the shift towards larger, transmission-connected projects in North Carolina.[16] Public Staff witness Lucas' recommendation is to build on the grid location guidance provided for CPRE tranche 1 to "provide basic information on the transmission system and identify those areas that are at or near their hosting capacity."[17] Witness Lucas also recommends that the Companies provide the Commission and the Public Staff a detailed estimate of the cost to develop and maintain an HCM utilizing existing data and tools. The Public Staff also notes that all costs associated with HCMs should be recovered from distributed generation ("DG") developers through fees and charges.

I agree with the Public Staff that there has been a shift in Qualifying Facilities ("QF") submitting Interconnection Requests in North Carolina from distribution-connected to transmission-connected generating facilities. During calendar year 2018, the Companies received 44 new transmission-connected solar Interconnection Requests compared with just 16 distribution-connected solar Interconnection Requests greater than or equal to one MW (excluding NEM) in North Carolina. The Companies also annually receive Interconnection Requests for thousands of customer-sited net metering projects but these projects cannot change their proposed location in response to information provided through an HCM. Therefore, it appears that there would be a limited audience for a distribution level HCM in North Carolina.

[16] Public Staff Lucas Direct Testimony, at 23.
[17] Public Staff Lucas Direct Testimony, at 23.

Also, I agree that it would be in the best interest of both the Companies and the DG developers for the Companies to continue to refine the transmission grid locational guidance required by CPRE. However, input from stakeholders and additional details from the Commission and the Public Staff on the scope of any proposed changes to the grid locational guidance will be needed before a detailed estimate of the costs for such work could be developed.

Q. WHAT IS THE COMPANIES' POSITION ON IREC'S RECOMMENDATION THAT THE COMMISSION ORDER THE UTILITIES TO DEVELOP HCMs?

A. IREC witness Auck recommends that the Utilities be required to each implement a hosting capacity analysis based on proposals developed by a Commission-initiated working group. She testifies that the "ideal hosting capacity maps would include detailed hosting capacity for each node, along with substation, circuit and feeder information"[18] suggesting that "[w]ithout a hosting capacity map, customers have no information regarding the best and worst locations for new DER."[19]

I do not agree with IREC witness Auck's assertion that an HCM is the only way for customers to evaluate locations for new distributed energy resources ("DER"). As required in the NC Procedures, the Companies offer potential Interconnection Customers both a free "Pre-Request Response"

[18] IREC Auck Direct Testimony, at 38.
[19] IREC Auck Direct Testimony, at 35.

(1.2) and a more detailed "Pre-Application Report" (1.3) (examples of both are provided as Rebuttal Exhibit JWR-2). In addition, the Companies publicly post their respective interconnection queues through the biweekly Queue Snapshot reports as well as transmission grid locational guidance to inform developers of utility-scale DER regarding the number, proposed size, and general location of constrained areas on the Companies' transmission systems. Utilizing these existing resources, an Interconnection Customer can preliminarily determine the feasibility of a project before submitting an Interconnection Request.

Q. PLEASE RESPOND TO IREC WITNESS AUCK'S ASSERTION THAT DEVELOPMENT OF HCMs WOULD CREATE NUMEROUS BENEFITS IN NORTH CAROLINA.

A. Witness Auck fails to quantify the "target audience" for HCMs in North Carolina other than a reference to "smaller projects that connect to the distribution system."[20] Since a majority (>99%) of these "smaller projects" are customer-sited NEM generating facilities located on or adjacent to a retail customer's home or business, this group of customers would not materially benefit from utility investment in HCM to identify optimal locations across the utility system for siting DER. Put another way, a retail customer is not going to move its home or business a mile down the road if an HCM identifies that its premises is located on a highly saturated feeder

[20] IREC Auck Direct Testimony, at 41.

of the grid. And, again, any potential Interconnection Customer can obtain such readily available information today through either a free Pre-Request Response or by purchasing a Pre-Application Report.

Further, as stated earlier, since North Carolina enacted House Bill 589 in 2017, the Companies have recently experienced a transition away from development of distribution-connected QFs and towards larger transmission-connected solar QFs developed to compete in the competitive procurement program. Assuming this recent shift in development of utility-scale solar generation away from the Companies' distribution system continues, this also limits the audience that would benefit from an investment in HCM in North Carolina.

Q. WHAT IS THE ESTIMATED COST OF IREC'S HCM PROPOSAL?

A. IREC does not maintain information on the costs to develop and maintain hosting capacity maps and has provided no information on the projected cost for the Companies to develop its proposal.[21] Without this information there is no way for IREC to determine if HCMs are a cost-effective solution to providing grid locational guidance in North Carolina.

Q. WHAT INFORMATION DO THE COMPANIES HAVE REGARDING THE COST TO DEVELOP AN HCM?

A. Based upon public information the Company has obtained, Southern California Edison projected in 2017 that it would cost between $2-8 million

[21] Rebuttal Exhibit JWR-4, IREC's Response to the Companies' Data Request 1-19.

upfront to develop and $1-5 million a year to maintain an HCM for that utility's 4,500 circuits.[22] Recognizing Public Staff witness Lucas' position that it is appropriate to recover the costs of deploying an HCM from DG developers through fees, deployment of HCM would require a significant increase in fees to recover a cost of this scale spread across a limited audience. The effort required to develop and maintain an HCM would also compete with Supplemental Reviews and System Impact Studies for engineers experienced in interconnection studies. Therefore, the Companies continue to believe that the existing Pre-Request Response and Pre-Application Report options provided for in the NC Procedures provide Interconnection Customers reasonable access to "site specific" data. This already-available information is also generally equivalent to the data that IREC is proposing be publicized for the entire distribution system through an HCM. Importantly, the Pre-Application Report approach also directly recovers the cost from the DG developer who requested the report versus socializing the cost amongst all Interconnection Customers. Further, based on the significant drop in Interconnection Requests for distribution-connected QFs, the Companies do not believe there is sufficient justification to develop and maintain a detailed HCM for 3,900 distribution circuits

[22] California Distribution Resources Plan (R.14-08-013) Integration Capacity Analysis Working Group – Final ICA WG Report, Page 18, Table 1, *available at* https://drpwg.org/wp-content/uploads/2016/07/ICA-WG-Final-Report.pdf.

across the Carolinas, nor is there sufficient justification to independently investigate the cost of doing so.

Q. IF THE COSTS OF AN HCM ARE RECOVERED FROM DG DEVELOPERS AS THE PUBLIC STAFF RECOMMENDS, HOW MUCH WILL INTERCONNECTION-RELATED FEES INCREASE?

A. The Companies have not independently investigated the cost of developing and maintaining an HCM at this time. However, the Companies have performed some high level analysis based on the range of costs identified by Southern California Edison discussed above: approximately $2-8 million to develop the HCM and then approximately $1-5 million per year thereafter to maintain the HCM. Using the Companies' estimated 5,022 forecasted Interconnection Requests expected to be processed in 2019 (as shown in my Rebuttal Exhibit JWR-3, column 3), it would cost $398-1,593 per Interconnection Request to develop the HCM and then $199-$996 per year per Interconnection Request thereafter to maintain the HCM.

Notably, these costs would be spread across all Interconnection Requests even though the vast majority of these requests are for NEM projects that typically interconnect without issue and would not benefit from an HCM.

Q. WOULD IT BE FEASIBLE TO IMPOSE THE FULL COSTS OF DEVELOPING AND MAINTAINING AN HCM ON INTERCONNECTION CUSTOMERS?

A. No. Such a large increase in fees is unworkable in practice and IREC was unable to identify any state that has charged Interconnection Customers for the development or maintenance of an HCM.[23] Therefore, as a practical matter, the costs of developing and maintaining an HCM would have to be socialized and recovered in the Utilities' general rates.

V. Interconnection Fees

Q. THE COMPANIES HAVE PROPOSED TO INCREASE CERTAIN FEES CHARGED UNDER THE NC PROCEDURES. PLEASE ADDRESS THE PUBLIC STAFF'S AND OTHER PARTIES' POSITIONS ON THE COMPANIES' FEE PROPOSALS?

A. Public Staff witness Lucas recognizes the Commission's prior direction that DEC and DEP should not recover interconnection-related costs through the REPS Rider and should take steps to track and more fully recover interconnection-related costs through the interconnection process.[24] Mr. Lucas then states that the Public Staff has performed a limited review of the Companies' proposed modified fees but "has not audited [the proposed] interconnection fees and takes no position on them," except to reiterate the

[23] Rebuttal Exhibit JWR-4, IREC's Response to the Public Staff's Data Request 1-1(2).
[24] Public Staff Lucas Direct Testimony, at 42-43.

Public Staff's over-arching position that "costs to process interconnection requests should be borne by the Interconnection Customers and not shifted to retail customers."[25]

Dominion witness Nester supports the increased fees included in the Joint Utilities Redline filed March 12, 2018.[26]

IREC witness Auck challenges all of the Companies' proposed fee adjustments based upon IREC's general view that the Companies have been "inefficient" in their efforts to process Interconnection Requests. Ms. Auck suggests that the Companies' proposed fee increases are unreasonably large and states that the Companies have not met their burden to justify the requested fee increases. Witness Auck then compares the proposed fees to interconnection fees charged in certain other jurisdictions, and specifically takes issue with the Companies' increase in the "Change in Ownership" processing fee from $50 to $500, arguing that such a change violates the regulatory principle of gradualism and will cause "rate shock."[27]

No other party filed testimony on the reasonableness and appropriateness of either the existing or proposed fees within the NC Procedures.

[25] Public Staff Lucas Testimony, at 43-44.
[26] DENC Nester Direct Testimony, at 27.
[27] IREC Auck Direct Testimony, at 50-56.

Q. BEFORE ADDRESSING IREC'S TESTIMONY OPPOSING THE COMPANIES' PROPOSED FEE MODIFICATIONS, PLEASE COMMENT ON THE PUBLIC STAFF'S POSITION THAT ALL COSTS TO PROCESS INTERCONNECTION REQUESTS SHOULD BE BORNE BY INTERCONNECTION CUSTOMERS.

A. The Public Staff recently raised concerns in DEP's and DEC's respective 2016 and 2017 REPS Rider proceedings that the surging volume of generator interconnection requests is causing increased interconnection administration, technology, and processing costs that, absent recovery from Interconnection Customers, would be assigned to and recovered from retail customers as part of the Companies' general cost of service. As described in my direct testimony and highlighted by Public Staff witness Lucas, the Commission previously directed the Companies to track and more fully recover such interconnection-related costs from Interconnection Customers to the greatest extent possible.[28] Witness Lucas has also been clear in this proceeding that "the costs to process interconnection requests should be borne by the interconnection customers and not shifted to retail customers."[29]

[28] DEC/DEP Riggins Direct Testimony, at 18. Public Staff Lucas Direct Testimony, at 42-43. *Order Approving REPS and REPS EMF Riders and REPS Compliance*, at 19 Docket No. E-7, Sub 1106 (Aug. 16, 2016); *Order Approving REPS and REPS EMF Riders and REPS Compliance*, at 18 Docket No. E-2, Sub 1109 (Jan. 17, 2017).

[29] Public Staff Lucas Direct Testimony, at 44.

Q. ARE THE COMPANIES' PROPOSED FEES DESIGNED TO MORE FULLY RECOVER INTERCONNECTION-RELATED COSTS FROM INTERCONNECTION CUSTOMERS, AS PREVIOUSLY DIRECTED BY THE COMMISSION AND ADVOCATED FOR BY THE PUBLIC STAFF?

A. Yes. The proposed adjusted fees are designed to address the Companies' under-recovery of interconnection-related costs and to more fully recover these costs from Interconnection Customers in the future.

Q. PLEASE FURTHER DESCRIBE HOW THE COMPANIES DETERMINED THAT THE PROPOSED INCREASE TO INTERCONNECTION FEES IS NEEDED TO MORE FULLY RECOVER INTERCONNECTION COSTS INCURRED BY THE COMPANIES THAT ARE RECOVERED THROUGH FEES.

A. As discussed in some detail in my direct testimony, the Companies have followed the Commission's prior direction in DEP's and DEC's respective 2016 and 2017 REPS Rider proceedings to track the increasing direct and indirect costs that the Companies are incurring to process Interconnection Requests. In March 2017, the Companies submitted their *Interconnection Cost Allocation Procedures Report* to the Commission, detailing the procedure and "categorization" of costs that DEC and DEP planned to follow for purposes of tracking and assigning interconnection-related costs.[30] As discussed in my direct testimony, the Companies categorize direct and indirect interconnection-related costs into three separate categories, with Category 1 capturing all "Fees Recovered Work."

Costs captured in Category 1 include the Companies' direct and indirect administration, technology, and processing costs associated with fee-recovered activities under the NC Procedures. More specifically, Category 1 costs include Renewables Service Center employee and contractor labor expense along with allocations of Distributed Energy Technologies employee labor supporting the Section 2 expedited processing of certified inverter-based generators < 20 kW and Section 3 Fast Track screening process for interconnection applications < 2 MW; processing and administration for Pre-Requests and Pre-Applications; processing and administration for Changes of Control; and related technology costs that support these areas of work.

As I described in my direct testimony, the Companies experienced a significant under-recovery for Category 1 Fee-recoverable costs in both 2017 and in 2018 based upon the fees currently in place under the NC Procedures.[31]

---

[30] *Interconnection Cost Allocation Procedures Report,* Docket Nos. E-100, Sub 101; E-2, Sub 1109; and E-7, Sub 1131, at 2 (Mar. 1, 2017). In the DEP REPS Order, *supra* note 2, the Commission directed DEP to work with the Public Staff in making cost allocation refinements to interconnection-related costs and to submit a report on these efforts to the Commission no later than March 1, 2017. DEP REPS Order at Ordering Paragraph 4.

[31] DEC/DEP Riggins Direct Testimony, at 21.

Q. CAN YOU PROVIDE A DETAILED BREAKDOWN OF THE COMPANIES' 2017 AND 2018 UNDER-RECOVERY AND HOW THE PROPOSED FEES WILL ALLOW THE COMPANIES TO MORE FULLY RECOVER CATEGORY 1 FEE-RELATED COSTS IN 2019 AND FUTURE YEARS?

A. Yes. Columns 1 and 2 of Rebuttal Exhibit JWR-3 provide a breakdown of the Companies' Category 1 expenses and revenues based upon experienced volumes of fee-recovered activities during 2017 and 2018, respectively. Columns 1 and 2 then present the Companies' actually-experienced under-recovery of Category 1 costs under current fees as well as projected experience if the proposed fees were in effect during each year. For 2018, Column 2 presents a calendar year 2018 breakdown of the Companies' Category 1 work, and shows that DEC and DEP have under-recovered Category 1 expenses by approximately ($584,000) in 2018 under the current fees, while the under-recovery would have approximated ($30,000) if the Companies' proposed fees were in effect. The continuing under-recovery even under the proposed fees is based upon actually-experienced 2018 volumes of Fee-related work.

Columns 3 and 4 then project Category 1 volumes, revenues and expenses for 2019 assuming that the Companies experience an additional 10% or 20% increase in Section 2 and Section 3 Interconnection Requests in 2019. Forecasting only a limited increase in Section 2 and Section 3 Interconnection Requests is reasonable for 2019 because the new

Interconnection Request volumes will largely be driven by the Commission-approved solar rebate program, which is limited to 10,000 kW of installed capacity annually. Absent the requested adjustment to the Companies' interconnection processing and other fees, the Companies project DEC and DEP to under-recover their Category 1 interconnection-related costs by over ($550,000) in 2019.

Q. PLEASE RESPOND TO IREC'S ALLEGATION THAT THE COMMISSION SHOULD REJECT THE COMPANIES' FEE PROPOSAL ON GROUNDS THAT THE COMPANIES HAVE PRESENTED INSUFFICIENT EVIDENCE TO SUPPORT THE FEES.

A. I disagree. My direct testimony explains the Companies' procedure for tracking interconnection costs and addresses that DEC and DEP significantly under-recovered Category 1 fees-recovered work in both 2017 and 2018. My Rebuttal Exhibit JWR-3 shows in detail that DEC and DEP's North Carolina Category 1 expenses exceeded the revenues generated by fees received in 2018 to complete all fee-recovered work. IREC witness Auck's own Exhibit SBA-Direct 9 (filing Duke's Responses to Public Staff Data Request 8-2) also provides additional detail on the Companies' procedure for tracking interconnection fees and experienced under-recovery of Category 1 costs. While I appreciate IREC's persistent desire for more robust activity-by-activity tracking and reporting of interconnection fees and expenses, the Companies' cost-tracking methodology is reasonable and enables DEC and DEP to determine whether the Companies are under-recovering Category 1 fee-related expenses incurred during a given year. Based upon the experienced under-recovery of this category of costs, the Companies have then reasonably allocated these expenses amongst the categories of fees in the NC Procedures.

Q. ARE THE COMPANIES SEEKING TO PROFIT FROM THE PROPOSED FEES BY CHARGING FEES THAT EXCEED THEIR PROJECTED EXPENSES?

A. No. As recognized by Public Staff witness Lucas, the Companies have "significantly increased their staffing and been required to develop administrative, technical, and information technology processes to enable third party renewable energy facilities to interconnect" and "[w]hile they pass these costs on to the developers and customers, they do not profit from any of it."[32] I agree. The Companies are not advocating for any return on their fee-related expenses to support the interconnection process, but are simply seeking to recover their Category 1 interconnection-related costs.

Q. WOULD THE COMPANIES SUPPORT REPORTING ON ANNUALIZED VOLUMES AND FEE-RECOVERED EXPENSES IN FUTURE YEARS?

A. Yes. As my Rebuttal Exhibit JWR-3 shows, changes in volumes of Section 2 and Section 3 interconnection requests can significantly impact

[32] Public Staff Lucas Direct Testimony, at 8.

whether the Companies under-recover or fully recover Category 1 expenses in a given year. Increases or decreases in expenses to support the interconnection process can have a similar impact. To the extent the Commission wants to more closely track year-over-year changes in Section 2 and Section 3 interconnection request volumes, fee-related work, and Category 1 expenses, the Companies could file an informational report with the Commission on March 1 annually similar to my Rebuttal Exhibit JWR-3. Alternatively, to the extent that the Commission plans to again review the NC Procedures and interconnection process in 2-3 years, the Companies could report to the Public Staff and other stakeholders at that time whether actually-experienced changes in interconnection fee volumes and expenses support future adjustments to fees charged under the NC Procedures.

Q. IN OPPOSING THE COMPANIES' ADJUSTED FEES, WITNESS AUCK ALSO SUGGESTS THAT INTERCONNECTION PROCESSING IN NORTH CAROLINA HAS BEEN SLOW AND INEFFICIENT WHILE SUGGESTING THE PROPOSED FEES ARE RELATIVELY HIGH COMPARED TO OTHER STATES. HOW DO YOU RESPOND?

A. I disagree with IREC witness Auck's assertion that the Companies' interconnection processing has been unreasonably slow or inefficient. Specific to the Section 2 small generator and Section 3 Fast Track study processes, producing Pre-Application Request responses and other activities where fees are used to recover the Companies' costs, the Companies have generally been meeting the timeframes required in the NC Procedures. IREC presents no evidence to the contrary. The Companies have also been working diligently to ensure they are efficiently processing the growing number of NEM Section 2 interconnection customer requests received under the solar rebates program established in House Bill 589 and recently approved by the Commission. DEC and DEP processed a combined 4,354 of Section 2 Interconnection Requests in 2018, a significant increase from the 1,406 Section 2 Interconnection Requests processed in 2017. This significant increase was primarily due to 2018 being the first year that the solar rebates program enacted by House Bill 589 was open to participation. Again, even as volumes have increased, DEC and DEP have generally processed these small generator interconnection requests within the timeframes provided for in the NC Procedures.

Moreover, while the Companies have been challenged in meeting Section 4 study process timeframes for some large multi-megawatt solar projects, DEC and DEP should not be penalized by being forced to under-recover their Category 1 expenses including implementing the Section 2 and Section 3 smaller generator interconnection processes. Public Staff witness Lucas highlights the "cooperation of the Utilities" to support North Carolina's unprecedented solar growth and the Companies are appropriately seeking an adjustment to interconnection fees to more fully recover their costs.[33]

Q. HOW DO YOU RESPOND TO WITNESS AUCK'S ARGUMENT THAT THE COMPANIES' PROPOSED FEES ARE RELATIVELY HIGH COMPARED TO OTHER STATES?

A. First, I would note that it is nearly impossible to develop accurate comparisons of interconnection fees across states and per utility, due to differing capacity ranges, carves-outs, limiters, and policy considerations varying across each jurisdiction and utility, including whether some costs are permitted to be recovered through base rates. While the Companies do not dispute IREC's presentation in Table 4 showing relatively lower fees under the approved Interconnection Procedures in Ohio, Illinois, and Virginia compared to the fees proposed in North Carolina, fees charged under other interconnection procedures seem to more closely align with the Companies' proposed fees in North Carolina.

For example, the Companies' Pre-Application Report Fee is proposed to be $500. In comparison, California's Pre-Application fees range from $300 to $1,325[34] while New York has approved a Pre-

---

[33] Public Staff Lucas Testimony, at 32.

[34] PG&E's Pre-Application Report Request is *available at* https://www.pge.com/includes/docs/pdfs/b2b/interconnections/pre-app-request-guide.pdf. *See also* PG&E Electric Rule No. 21, *Cal. P.U.C. Sheet No.* 40278-E (effective June 8, 2017), *available at* https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf.

Application fee of $750.[35] Notably, the Pre-Application fee approved under the South Carolina Generator Interconnection Procedures is the same $500 the Companies propose to charge in North Carolina.[36]

As another example, Pennsylvania has approved interconnection processing fees of $250 plus $1/kw for Generating Facilities greater than 10 kW, or $350 plus $2/kW depending on the complexity of the interconnection.[37] To translate, Pennsylvania's fees for Generating Facilities less than 20 kW could be higher than the Companies' $200 Application Processing fee proposal for less than 20 kW-sized facilities. Additionally, the Companies' fee proposal for Generating Facilitates 20 kW to 100 kW in size is comparable to New York's fee, which similarly charges $750 for facilities falling within this size range.[38] For Generating Facilities in the > 100kW to two MW range, the Companies' are proposing a $1,000 Fast Track Application Processing Fee. This $1,000 fee proposal is lower

[35] *See* New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems, at p. 9 (Oct. 2018), *available at* http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/October%20SIR%20Appendix%20A%20-%20Final%2010-3-18.pdf.
[36] *Order Adopting Interconnection Standard and Supplemental Provisions*, SC PSC Docket No. 2015-362-E, Order No. 2016-191, Order Exhibit 1 at page 37, (April 26, 2016), *available at* https://dms.psc.sc.gov/Attachments/Order/11891e05-689d-4fe7-8816-c959480feb4e.
[37] *See* 52 PA. Pa. Code §75.38 through §75.40; *see also* PECO Net Metering/Interconnection Application Fees, *available at* https://www.peco.com/SiteCollectionDocuments/summaryoffeesrev1.pdf .
[38] *See supra* at note 28.

than similar fees in Pennsylvania,[39] Minnesota,[40] Massachusetts,[41] Utah,[42] and New Jersey[43].

Furthermore, as noted above, it is also difficult, if not impossible, to correlate the fees charged by other utilities with a determination of whether those fees actually allow the utility to fully recover its interconnection-related costs. IREC candidly noted this in response to the Public Staff, explaining that the reports that the California utilities file with the California Public Utilities Commission "may not provide a complete picture of all potential costs incurred by the utilities associated with interconnection of NEM generators" and that "IREC is unaware of any state that has done a detailed tracking of overall interconnection cost expenditures."[44] Utilities that receive only a small number of interconnection requests also may not have been required to make the significant investments in human and technology resources required to support processing thousands of interconnection requests a year. Numerous states also allow

---

[39] *See supra* at note 30.
[40] Generation Interconnection Application Fee Form, Xcel Energy Minnesota, *available at http://www.pacificorp.com/tran/ts/gip/qf/utah.html; see also* Minnesota Distributed Energy Resource Interconnection Process, Section 1.5 (issued Aug. 13, 2018), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BC0323565-0000-C93E-A016-03CA96FB9CAC%7D&documentTitle=20188-145752-03.
[41] *See* Standard Application Process, National Grid (2019), *available at* https://www9.nationalgridus.com/Masselectric/home/energyeff/4_standard-application.asp.
[42] *See* Utah Rule R746-312. Electrical Interconnection, *available at* https://rules.utah.gov/publicat/code/r746/r746-312.htm; *see also* PacificCorp, Utah, Generation Interconnection Process (2019), *available at* http://www.pacificorp.com/tran/ts/gip/qf/utah.html.
[43] *See* Building You Solar Installation, PSE&G (Dec. 19, 2018), *available at* https://nj.pseg.com/saveenergyandmoney/solarandrenewableenergy/applicationprocess.
[44] Rebuttal Exhibit JWR-4, IREC's Response to the Public Staff's Data Request 1, Topic 1.

interconnection-related costs to be subsidized through the utility's general cost of service. For example, NEM applications up to 10 kW in Florida are processed for free.[45] Overall, it is difficult to make a true "apples to apples" comparison when comparing states' interconnection fees. And given that IREC was unable to identify with any specificity the amounts recovered through base rates in other jurisdictions, IREC's proposed comparisons to other jurisdictions should not be accepted as "apples to apples" in light of the North Carolina regulatory policy directive to seek to recover all interconnection costs from Interconnection Customers.

Q. PLEASE COMMENT FURTHER ON IREC'S USE OF THE CALIFORNIA UTILITIES' INTERCONNECTION COSTS TO BENCHMARK THE COMPANIES' FEE PROPOSAL IN NORTH CAROLINA.

A. IREC witness Auck makes numerous benchmarking references to the three California utilities, Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas and Electric Company ("SDG&E") and, specifically, to their annual interconnection costs reports filed with the California Public Utilities Commission.[46]

[45] *See* Interconnection Agreement for Customer-Owned Renewable Generation Tier 1 – 10 kW or Less, Florida Power & Light Company, First Revised Sheet No. 9.050 (effective Feb. 20, 2014), *available at* https://www.fpl.com/clean-energy/pdf/net-metering-tier1.pdf.
[46] IREC Auck Direct Testimony, at 54-56, Exhibit SBA-Direct-10.

The Companies have reviewed the 2018 information-only annual reports submitted to the California Public Utilities Commission detailing annualized interconnection costs.[47] Based upon this review, I would initially note that the reported costs do not seem to include any recovery for technology costs, but do include processing and administrative costs, recovery for metering costs, as well as inspection and commissioning costs. It is also notable that there seems to be a significant disparity between the costs (or at least the subset of costs being reported) per application incurred between the three utilities. SCE's costs approximated $35 per application processed,[48] while PG&E's costs approximated $72 per application[49] and SDG&E's costs approximated $132 per application.[50] Little meaningful benchmarking can be ascertained from reviewing these costs, except to note the significant disparity seems to correlate to differences in costs reported and

[47] *See, Information-Only Advice Letter, Southern California Edison Company's Report on Net Energy Metering Interconnection Costs,* Advice 3866-E, at Attachment A, Docket U 338-E (Sept. 19, 2018); *Pacific Gas and Electric Company's Information-Only Submittal Regarding Net Energy Metering Costs,* Advice Letter 5398-E, at Attachment A, Docket U 39 E (Oct. 4, 2018); *San Diego Gas & Electric Company's Information Only Filing Regarding Net Energy Metering Costs,* Advice Letter 3273-E, at Attachment A, Table 1, Docket U902-E (Sept. 19, 2018).

[48] *Information-Only Advice Letter, Southern California Edison Company's Report on Net Energy Metering Interconnection Costs,* Advice 3866-E, at Attachment A, Docket U 338-E (Sept. 19, 2018) (to calculate cost per application, the "Total Costs" of $1,617,623 identified in Table 1 was divided by the total number of new applications, 46,819 identified below Table 1).

[49] *Pacific Gas and Electric Company's Information-Only Submittal Regarding Net Energy Metering Costs,* Advice Letter 5398-E, at Attachment A, Docket U 39 E (Oct. 4, 2018) (to calculate cost per application, the "Total," $4,641,650, from Table 1 was divided by the "Total NEM Applications," 64,756, identified above Table 1).

[50] *San Diego Gas & Electric Company's Information Only Filing Regarding Net Energy Metering Costs,* Advice Letter 3273-E, at Attachment A, Table 1, Docket U902-E (Sept. 19, 2018) (to calculate cost per application, the "Total Processing and Administration Costs," $3,158,628, was divided by the "# of New Applications." 23,929, taken both from Table 1).

differences in volumes of Interconnection Request applications processed by each utility during the prior year.

It is also notable that although the California utilities' costs and application volumes have change year-over-year since 2015, the application fees charged to all NEM applications projects ≤ 1 MW have not. Current application fees charged by PG&E, SCE and SDG&E are $145, $75 and $132, respectively. Interestingly, while PG&E reported costs of only $72 per application, the fee charged is significantly higher at $145 per application. Despite this annual reporting, it is difficult to meaningfully compare the fees charged by the California utilities to the Companies' proposed fees because they cover different types of costs, cover net metering projects only and cover only < 1 MW projects.

Q. DO THE CALIFORNIA UTILITIES' HIGHER VOLUMES OF INTERCONNECTION REQUESTS ALLOW FOR REDUCED PROCESSING COSTS?

A. Yes. Based upon my review of the California utilities 2018 reports, the volumes of NEM projects ranged from 23,929 to 64,756.[51] Even after significant growth compared to 2017 and prior years, North Carolina's 2018 volumes of < 2 MW projects was still significantly lower at 4,566. As IREC witness Auck notes, these significantly higher volumes allow the California utilities to "benefit from economies of scale."[52] This is

[51] *See supra* note 47.
[52] IREC Auck Direct Testimony, at 55.

important because a certain amount of "fixed cost" infrastructure and resources are required to support processing thousands of interconnection requests during a given period. Where the utility is processing greater volumes of applications, these costs can be spread out and reduced for each individual Interconnection Customer. Further, once the infrastructure costs are recovered, I agree with IREC that efficiencies can reduce the ongoing per application charge. Thus, the California utilities have experienced significantly higher volumes of < 1 MW projects for many years and that has allowed infrastructure and efficiencies to be built into its cost base over time. The Companies are only now starting to make the infrastructure investments to support the greater volumes of small NEM Interconnection Requests and are only now making the fixed cost investments in Salesforce and other infrastructure to support this process.

Q. IREC SPECIFICALLY ARGUES THAT INCREASING THE CHANGE OF CONTROL FEE FROM $50 TO $500 OR BY "1,000 PERCENT" IS UNREASONABLE. DO YOU AGREE?

A. No. As background, a change of control occurs when an Interconnection Customer transfers ownership of the Generating Facility or sells its ownership interest in the legal entity owning the Generation Facility, thus "changing control" of the existing legal entity that is the counter-party under the IA and responsible for operating the Generation Facility. Changes of control therefore most often occur in the context of utility-scale developers "flipping" projects to other developers.

The $50 fee currently in place has never been sufficient to allow for the recovery of the Companies' costs incurred to complete a change of control, and the increase to $500 more accurately allows the Companies' to recover their costs. Specifically, based on analysis the Companies have performed on the costs and time incurred to complete a change of control, it takes on average six hours to complete all administrative process required to document a change of control for a larger independent power producer. Additionally, if there are legal complications with the change of control, more time must and expense must be incurred. Thus, on average, the direct administrative cost of processing each change of control are at least $400. Note also that this $400 does not include technology costs in addition to supervisory time or legal costs. As another comparison, a change of control requested under a large QF generating facility power purchase agreement is $10,000, making $500, by comparison, seem extremely reasonable for processing a change of control for a standard IA.[53] Therefore, the Companies' proposed $500 fee to process a change of control is reasonable and consistent with the Commission's directive to recover costs to the greatest extent possible from Interconnection Customers.

[53] *See* Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Final *pro forma* CPRE Tranche 1 PPA, Docket Nos. E-2, Sub 1159 and E-7, Sub 1156, Attachment A at Section 24.6 (filed June 8, 2018) (approved by the NCUC's *Order Denying Joint Motion, Approving Pro Forma PPA, and Providing Other Relief,* Docket Nos. E-2, Sub 1159 and E-7, Sub 1156 on June 25, 2018).

Q. IREC ALSO ARGUES THAT RATEMAKING PRINCIPLES OF GRADUALISM SHOULD BE APPLIED TO REDUCE THE PROPOSED FEES. DO YOU AGREE THAT THIS PRINCIPLE IS APPLICABLE HERE?

A. No. From a layman's perspective, a principle of gradualism seems inapplicable in this context because an Interconnection Customer only pays an interconnection fee once. By comparison, retail customers who pay fixed charges for service on an ongoing basis. Thus, because an interconnection-related fee is only charged to an Interconnection Customer once, the principle of gradualism does not seem applicable.

Q. ARE THE COMPANIES PROPOSING TO MAKE ANY CHANGES TO ITS CHANGE OF CONTROL FEE PROPOSAL AT THIS TIME?

A. Yes. In light of the fact that the change of control administration process is more simplified for small Interconnection Customers, the Companies have bifurcated the change of control fee to retain $50 for the smallest Interconnection Customers 20 kW or less that enter into the consolidated Attachment 6 Application and IA report. The proposed $500 fee will apply to all Interconnection Customers above 20 kW that submit an Attachment 2 Interconnection Request Application Form and enter into the full Attachment 9 Interconnection Agreement.

Q. HAVE THE COMPANIES ALSO CORRECTED THE PROPOSED SECTION 2 PROCESSING FEE WITHIN ATTACHMENT 6?

A. Yes. The Duke Energy Redline filed with the Companies' direct testimony inadvertently did not modify the processing fee within Attachment 6 for Section 2 Interconnection Customers (Certified Inverter-Based Generating Facility No Larger than 20 kW) as supported on pages 23-24 of my direct testimony. This processing fee has been updated in Attachment 6 of Rebuttal Exhibit JWG-1 to accurately reflect the Companies' proposed fee of $200 as discussed in my direct testimony and further supported above.

VI. <u>Dispute Resolution</u>

Q. THE COMPANIES HAVE PROPOSED SEVERAL MODIFICATIONS TO THE DISPUTE RESOLUTION PROCESS UNDER THE NC PROCEDURES. PLEASE ADDRESS THE PUBLIC STAFF'S AND OTHER PARTIES' POSITIONS ON THE COMPANIES' MODIFICATIONS?

A. As discussed in my direct testimony and the rebuttal testimony of DEC/DEP witness Freeman, the dispute resolution process contributes to delays in the interconnection process. Such delays are exacerbated by the ambiguity in the NC Procedures regarding the associated timelines.

Public Staff witness Lucas stated that the Public Staff should continue to be involved in informal dispute resolution process, but that a third-party dispute resolution service should be another option to resolve disputes if mutually agreed by both parties.[54] To that end, Public Staff proposed certain modification to the Section 6.2 of the NC Procedures.

IREC witness Auck states that a new, "clearly defined" dispute resolution process is needed in North Carolina and should include an interconnection ombudsperson at the Commission who would help facilitate dispute resolution.[55]

DENC witness Nester believes that the existing dispute resolution process is sufficient and that IREC's proposal to add an ombudsperson is supported by little evidence.

Q. HOW DO THE COMPANIES RESPOND?

A. As stated in my direct testimony, the Companies maintain that the Public Staff's involvement, technical understanding, and perspective has been very valuable during the dispute resolution process and has allowed the Companies and Interconnection Customers to successfully resolve nearly all disputes.[56] Since submitting direct testimony, the Companies have engaged in discussions with the Public Staff regarding witness Lucas' proposal for the Companies and/or Interconnection Customers to be permitted by mutual agreement to engage a "dispute resolution service" as part of the informal dispute resolution process. The Companies are concerned that this alternative process is undefined and could also

[54] Public Staff Lucas Direct, at 37-38.
[55] IREC Auck Direct Testimony, at 46.
[56] DEC/DEP Riggins Direct Testimony, at 33.

significantly extend the timeframes for informally resolving disputes, thereby further delaying later-queued interconnection customers. The Companies also believe the Public Staff has informally facilitated the role of an "interconnection ombudsperson" in North Carolina, when needed, and no further formalization of this role is needed or appropriate at this time. The Companies plan to continue to discuss this issue with the Public Staff, but, at this time, continue to support the proposed modifications to Section 6.2 that I sponsored in my direct testimony.

VII. <u>Surety Bonds</u>

Q. HAVE THE COMPANIES PREVIOUSLY COMMITTED TO ACCEPT SURETY BONDS FROM INTERCONNECTION CUSTOMERS AS FINANCIAL SECURITY IN PARTICULAR SITUATIONS?

A. Yes. The Companies have previously committed to accept surety bonds from Interconnection Customers that contain terms that are reasonably acceptable to the Duke Energy credit and risk management ("Credit/Risk") department in the following circumstances:

- As security pursuant to NC Procedures Section 4.3.9 in the case of an executed state-jurisdictional Facilities Study Agreement with identified Network Upgrades;
- In connection with Competitive Tier Proposals (*i.e.*, Proposals that are determined by the Independent Administrator to move into Step

2 of the CPRE Evaluation Process) that are required to post "Proposal Security."

- Executed state-jurisdictional IA with identified Interconnection Facilities but no Network Upgrades when the project is participating in the CPRE evaluation process until such time as the outcome of the CPRE Tranche 1 RFP is determined.
- Executed state-jurisdictional IA with identified Interconnection Facilities and Network Upgrades that will not be completed for 3-5 years and project would not begin final design, procurement and scheduling of Interconnection Facilities construction for an extended period of time after the IA was executed.

Q. ARE THE COMPANIES WILLING TO ACCEPT SURETY BONDS FOR INTERCONNECTION FACILITIES IN SCENARIOS OTHER THAN THE SCENARIOS DESCRIBED ABOVE?

A. Yes, in those circumstances in which either DEP or DEC have previously accepted security for Interconnection Facilities or any circumstance in which there is a material lag between the execution of the IA and the date on which the Companies begin to incur costs for the Interconnection Facilities, the Companies are willing to accept surety bonds as security until such time as the Companies begin to incur costs or would otherwise require payment. For the avoidance of doubt, any surety bond must contain terms that are acceptable to the Companies' Credit/Risk Department in their sole, reasonable discretion.

Q. WHAT ARE THE PRIMARY TERMS AND CONDITIONS THAT MUST BE REFLECTED IN ANY SURETY BOND IN ORDER TO BE ACCEPTABLE TO THE COMPANIES?

A. The most crucial terms and conditions include, but are not limited to, the following:

- Must require payment to Duke in the event of the principal's failure to perform
- Payment must be made by the surety to Duke within a short period of time (*e.g.*, 10 days)
- Surety bond must be irrevocable by the Surety and noncancelable by the principal, or, alternatively, surety must be required to provide Duke prior notice of cancellation and Duke has right to demand payment if alternative security is not provided 30 days prior to cancellation
- Waiver of suretyship defenses
- North Carolina governing law and forum

A form surety bond that was provided by the Companies in connection with the CPRE RFP and contains generally acceptable terms and condition is provided as Rebuttal Exhibit JWR-5. This particular form would need to be significantly updated for use in the interconnection context.

Q. WHILE THE COMPANIES ARE WILLING TO ACCEPT SURETY BONDS FOR INTERCONNECTION FACILITIES AS DESCRIBED

ABOVE, DO THE COMPANIES AGREE THAT SURETY BONDS ARE "WIDELY ACCEPTED" IN THE UTILITY INDUSTRY AS WAS ASSERTED BY WITNESS NORQUAL?

A. No. In response to a data request, NCCEBA was able to identify only one other utility that has accepted a surety bond in the interconnection context.[57]

Q. WHY DO YOU THINK THAT IS THE CASE?

A. While I am not an expert on credit issues, I have been advised by the Duke Energy Credit/Risk department and Duke's internal legal team that surety bonds generally contain terms and conditions that provide less security than letter of credit. For instance, surety bonds generally contain more detailed pre-conditions to the assertion and payment of a claim by the non-defaulting party, which effectively provides less certainty that the Companies and its customers will be protected in the event of default. In contrast, when the Companies receive financial security in the form of letters of credit or cash pre-payment, the Companies have more unfettered rights to draw on those forms of security without the potential need for legal action to enforce its rights. In addition, surety bonds are less standardized than letters of credit, more complex and can have much greater variability of commercial terms, which would, in turn, require more in-depth, case-by-case analysis to confirm acceptability as well as, in some cases, further negotiation concerning such terms.

[57] Rebuttal Exhibit JWR-4, NCCEBA's response to the Companies' Data Request 1-15.

Finally, the Duke Energy Credit/Risk department has advised me that the assertion that the Companies have the ability to prescribe the surety bond form is generally inconsistent with our previous experience. More specifically, the Companies historically have been unable to secure any material changes in bond form language in the few instances where we determined that we would consider acceptance.

Q. WHY ARE THE COMPANIES NOW WILLING TO ACCEPT SURETY BONDS CONTAINING ACCEPTABLE TERMS AND CONDITIONS FOR INTERCONNECTION FACILITIES IN THE CIRCUMSTANCES DESCRIBED ABOVE?

A. While surety bonds will generally provide less certainty and consume more of the Companies' resource for purposes of review and negotiation, the Companies in the interest of compromise and due to the fact that the financial risk to other customers is lessened in the case of Interconnection Facilities if the security arrangement is properly structured.

Q. WITNESS NORQUAL ALSO STATES THAT "DUKE SHOULD NOT BE PERMITTED TO RETAIN THE FUNDS…OF INTERCONNECTION CUSTOMERS FOR INTERCONNECTION FACILITIES IF THE INTERCONNECTION FACILITIES ARE NOT CONSTRUCTED AND DUKE HAS NOT HAD TO INCUR ANY COSTS." TO BE CLEAR, HAS DUKE EVER RETAINED INTERCONNECTION CUSTOMER FUNDS WHERE

PARTICULAR INTERCONNECTION FACILITIES WERE ULTIMATELY NOT CONSTRUCTED?

A. No. Further, NCCEBA and CCR were also subsequently unable to identify any instances that supported the statement that the Companies ever "retained" interconnection customer's funds where Interconnection Facilities were not constructed. Instead, the statement appears to have been intended to refer to those situations in which there was some period of time between payment for the Interconnection Facilities and commencement of construction.[58]

VIII. Other Issues

Q. DID THE PUBLIC STAFF OR INTERVENOR TESTIMONY COMMENT ON ANY OTHER RECOMMENDATIONS MADE IN YOUR DIRECT TESTIMONY?

A. Yes, the Public Staff witness Lucas and North Carolina Pork Council witness Maier both agreed with the Companies' proposed revisions to Section 1.8.3.3 of the NC Procedures related to an expedited review process for swine and poultry waste to energy projects of two MW or less.[59]

Public Staff witness Lucas also supported the Companies' proposed addition of Section 1.8.3.4 of the NC Procedures related to expediting the

[58] Rebuttal Exhibit JWR-4, NCCEBA's response to the Companies' Data Request 1-17.
[59] Public Staff Lucas Direct Testimony, at 50; North Carolina Pork Council Maier Direct Testimony, at 9-10.

study process for standby generators requesting momentary parallel operation.[60]

No other parties commented on these two topics.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[60] Public Staff Lucas Direct Testimony, at 19-20.

Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC
Rebuttal Testimony of Jeffrey W. Riggins

Rebuttal Exhibit JWR-1

NC Interconnection Queue Snapshot for December 2018 as of 12/27/2018

Distribution Queue Report – Status Definitions

Interdependency Status Definitions

Approved	Final Interconnection Agreement fully executed, payments submitted, and easements obtained.
On Hold	Project is interdependent with two or more projects in the Queue.
Pending	Application has been received and application processing has been initiated.
Substation A	Interdependency status; identified by Engineering during study process, also called Project A.
Substation B	Interdependency status; identified by Engineering during study process, also called Project B.
Project Not Active	Project is withdrawn by customer or project is cancelled by Duke Energy.

Operational Status Definitions

Operational Status	**Definition**
Cancelled/Terminated	Project is cancelled by Duke Energy.
Closed	Project is closed and no longer active.
Pending	Small customer project is pending and has not been submitted (i.e. draft status in Customer Portal).
Superseded	Connected project which has been replaced by a new project.
Withdrawn	Project withdrawn by Customer.
IR Review – Pending	Interconnection Request (IR) has been received and assigned to a Smart Energy Specialist.
IR Review – In Progress	IR currently under review.
IR Review – Pending Customer Response	Incomplete IR application received; additional information requested from customer.
IR Review – Complete	IR Review complete and project ready for study.
Fast Track Study – Pending	Project moved to Fast Track Study queue; awaiting review.
Fast Track Study – In Progress	Fast Track review by study team in progress.
Fast Track Study – On Hold for Interdependency	Project will remain On Hold in Fast Track study queue until it becomes a Project A or Project B.
Fast Track Study – Pending Customer Response	Awaiting customer response for Fast Track study to continue.
Fast Track Study – Study Complete	Fast Track study complete. Ready for next step: Supplemental Review/System Impact Study/IA.
Supplemental Study – Pending	Project failed Fast Track Review and was moved to the Supplemental Review queue; awaiting review.
Supplemental Study – In Progress	Supplemental Review by study team in Progress.
Supplemental Study – On Hold for Interdependency	Project will remain On Hold in Supplemental Review study queue until it becomes a Project A or Project B.

Supplemental Study – Pending Customer Response	Awaiting Customer Response for Supplemental Review study to continue.
Supplemental Study – Study Complete	Supplemental Review study complete. Ready for next step: System Impact Study/Facility Study/IA.
System Impact Study – Pending	Project moved to the System Impact Study queue; awaiting review.
System Impact Study – In Progress	System Impact Study by study team in Progress.
System Impact Study – On Hold for Interdependency	Project will remain On Hold in System Impact Study queue until it becomes a Project A or Project B.
System Impact Study – Pending Customer Response	Awaiting customer response for System Impact Study to continue.
System Impact Study – Study Complete	System Impact Study Complete. Ready for next step: Facility Study/IA.
Facility Study – Pending	Project moved to Facility Study queue; awaiting review.
Facility Study – In Progress	Facility Study by engineering team in Progress.
Facility Study – On Hold for Interdependency	Project will remain On Hold in Facility Study queue until it becomes a Project A.
Facility Study – Pending Customer Response	Awaiting customer response for Facility Study to continue.
Facility Study – Study Complete	Facility Study complete. Ready for IA.
Construction – Pending IA/Customer Payment	Pending executed IA and/or customer payment to proceed to construction.
Construction – Pending Customer Obligation	Pending customer obligation to proceed to construction.
Construction – Under Construction / In Progress	Project has been assigned to construction.
Construction – Pending Meter Installation	Pending meter installation.
Commercial Operation – Pending	Duke construction is complete; Customer construction in not complete; not generating power.
Commercial Operation – Complete Pending Power Generation	Final preparation for commercial operation.
Commercial Operation – Power Generation In Progress	Facility has permission to operate.

Engineering Administrative Designation Definitions

Customer Call	Customer has requested a call to discuss questions related to their System Impact Study.
Customer Documentation Corrections	Duke Energy is waiting on customer to correct errors or information on the project's Interconnection Request, One Line Diagram, site map and/or specification sheets.
Customer LVR Options Selection	Duke Energy is waiting on the customer to select an LVR Preliminary Option.
Customer Mitigation Options Selection	Duke Energy is waiting on the customer to pick a Mitigation Option to move forward with the project. Duke Energy will not study all options in parallel and therefore must have a decision to progress the study.
Customer Response to Duke Energy General Inquiries	Duke Energy has submitted a question or cure letter to the customer and is awaiting a response.
Customer ROW	Duke Energy is waiting for a customer proposed path to get the project's Point of Interconnection to the substation after electing to pursue a Method S interconnection or upstream of an LVR for a Method D interconnection.
Customer Transformer Inrush Data Collection	Duke Energy is waiting for customer to return data requested detailing information necessary to complete the inrush study.
Customer Transformer Inrush Decision	Duke Energy waiting on customer to make a decision about final project design.
Duke Response to Customer Inquiry	Duke Energy is working on responding to a customer inquiry that cannot be immediately answered by the study team or requires review from other groups within Duke Energy.
Duke ROW	The project failed LVR review and the customer has requested Duke Energy to pursue ROW.
Fast Track Study	EAD does not apply projects in the Fast Track study process.
LVR Evaluation and Preliminary Options	Study team is determining whether or not the project is located downstream of an LVR. Customer will be notified via email if the project passes this screen, or will be given Preliminary Options on how to proceed due to failing the LVR screen.
Not Applicable	EAD only applies to projects that are in active System Impact Study.
Notice of Dispute/Complaint	Customer has filed a formal complaint/Notice of Dispute which is impacting the study process.
Policy	The project is on hold pending clarification of current policy or resolving technical issues related to policy. This usually requires input from various groups within Duke Energy to ensure the study team is proceeding in accordance with Good Utility Practice.
Protection Study	Study team is determining settings for protective devices and upgrades necessary to comply with protection policies.
Supplemental Study	EAD does not apply projects in the Supplemental Review study process.
Technical Review	Study team is reviewing all project documentation and preparing for project release.
Transformer Inrush/Advanced Study	Study team is determining the effect of transformer energization on the circuit.
Voltage Flicker Mitigation Options	Study team is determining the maximum size the project can interconnect based on Method of Service Guidelines and ensuring compliance with voltage and flicker standards.

Duke Energy Carolinas NC Interconnection Queue Snapshot for December 2018 as of 12/27/2018

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
2018-12-05 11:36:00	12/5/2018	Substation A	Fast Track Study - In Progress	Fast Track Study	59.4	Solar	03211207	Mar-Don Dr Ret 1207
2018-11-29 12:07:00	11/29/2018	Substation A	Fast Track Study - Study Complete	Fast Track Study	43.7	Solar	01121201	Monroe Rd Ret
2018-11-27 11:28:00	11/27/2018	Substation A	Fast Track Study - In Progress	Fast Track Study	150.0	Solar	01412406	Stouts Ret 2406
2018-11-20 14:26:00	11/20/2018	Substation A	Construction - Pending IA/Customer Payment	-	52.2	Solar	14011207	Durham MN 1207
INT-2018-04930	11/16/2018	-	Construction - In Progress	-	22.3	Solar	65151204	Balsam Ret 1204
2018-11-12 20:35:00	11/12/2018	Substation A	Supplemental Study - Pending Customer Response	Supplemental Study	92.0	Solar	80751205	Brawley School Ret 1205
2018-11-01 10:21:00	11/2/2018	Substation A	Supplemental Study - In Progress	Supplemental Study	230.0	Solar	22191201	Easy St Ret 1201
NC2018-03199	10/29/2018	Substation A	Construction - Pending IA/Customer Payment	-	42.5	Solar	14152404	Brassfield Ret 2404
NC2018-03200	10/29/2018	Substation A	System Impact Study - Pending	-	10,000.0	Solar	01552401	Wallace Rd Ret 2401
NC2018-03198	10/26/2018	Substation A	Construction - Under Construction / In Progress	-	43.2	Solar	14052405	Research Triangle Ret 2405
NC2018-03196	10/25/2018	Project Not Active	Withdrawn	-	72.0	Solar	01241210	Woodlawn Tie 1210
NC2018-03197	10/25/2018	Substation A	Construction - Pending IA/Customer Payment	-	70.0	Solar	28031201	Flat Shoal Ret 1201
NC2018-03192	10/24/2018	Substation A	Construction - Pending IA/Customer Payment	-	36.0	Solar	01151210	Briar Creek Ret 1210
NC2018-03193	10/24/2018	Project Not Active	Withdrawn	-	36.0	Solar	01151210	Briar Creek Ret 1210
NC2018-03194	10/24/2018	Substation A	Fast Track Study - Study Complete	Fast Track Study	34.2	Solar	03441211	Winston Tie 1211
NC2018-03195	10/24/2018	Project Not Active	Withdrawn	-	28.0	Solar	01241210	Woodlawn Tie 1210
INT-2018-04502	10/19/2018	-	Commercial Operation - Power Generation in Progress	-	21.2	Solar	03141214	Hawthorne Rd Ret 1214
NC2018-03188	10/12/2018	Substation A	Construction - Pending IA/Customer Payment	Not Applicable	70.0	Solar	28031201	Flat Shoal Ret 1201
NC2018-03189	10/12/2018	Substation A	Construction - Pending IA/Customer Payment	Not Applicable	70.0	Solar	28031201	Flat Shoal Ret 1201
NC2018-03187	10/11/2018	Substation A	Construction - Pending IA/Customer Payment	Not Applicable	70.0	Solar	28031201	Flat Shoal Ret 1201
CPRE	10/9/2018	-	CPRE Tranche 1 Position	-	-	-	-	-
NC2018-03179	9/12/2018	Substation A	Construction - Under Construction / In Progress	-	200.0	Solar	22311201	Manchester Ret 1201
NC2018-03173	9/6/2018	Substation A	Construction - Under Construction / In Progress	-	86.0	Solar	65031201	Spartan Heights Ret 1201
NC2018-03170	8/29/2018	Substation A	Supplemental Study - Pending Customer Response	Not Applicable	30.0	Solar	01172403	Royal Ret 2403
NC2018-03168	8/27/2018	Substation A	Construction - Pending IA/Customer Payment	-	23.4	Solar	11042412	Glen Raven MN 2412
NC2018-03169	8/27/2018	Substation B	System Impact Study - Pending	-	7,000.0	Solar	10221211	Denton Ret 1211
NC2018-03166	8/9/2018	Project Not Active	Withdrawn	-	72.0	Solar	14011207	Durham MN 1207
NC2018-03165	8/2/2018	Project Not Active	Withdrawn	-	33.3	Solar	14052405	Research Triangle Ret 2405
INT-2018-03390	8/1/2018	-	Commercial Operation - Power Generation in Progress	-	20.2	Solar	14082403	Pope Rd Ret 2403
NC2018-03164	7/26/2018	Substation A	Construction - Pending IA/Customer Payment	-	30.0	Solar	21011204	Salisbury Mn 1204
NC2018-03163	7/11/2018	Substation A	Commercial Operation - Power Generation in progress	-	28.8	Solar	22311202	Manchester Ret 1202
NC2018-03161	7/9/2018	Project Not Active	Withdrawn	-	80.0	Solar	80751205	Brawley School Ret 1205
NC2018-03162	7/9/2018	Substation B	Commercial Operation - Power Generation in progress	-	72.0	Solar	03031206	Brookwood Ret 1206
NC2018-03160	7/6/2018	Substation A	Commercial Operation - Power Generation in progress	-	28.8	Solar	03031206	Brookwood Ret 1206
NC2018-03158	6/28/2018	Substation A	Commercial Operation - Power Generation in progress	-	43.2	Solar	14061209	Hope Valley Ret 1209
NC2018-03157	6/26/2018	Substation A	Construction - Pending IA/Customer Payment	-	224.0	Solar	21021208	Statesville Rd Ret 1208
NC2018-03150	6/1/2018	Substation A	Supplemental Study - In Progress	Supplemental Study	120.0	Solar	01492408	Coffey Creek Ret 2408
INT-2018-01961	5/25/2018	-	Construction - In Progress	-	22.4	Solar	01172403	Royal Ret 2403
NC2018-03139	4/26/2018	Substation B	Construction - Under Construction / In Progress	-	500.0	Solar	11202407	Whitsett Ret 2407
NC2018-03140	4/26/2018	Substation A	Fast Track Study - In Progress	Fast Track Study	1,000.0	Solar	11202407	Whitsett Ret 2407
NC2018-03141	4/26/2018	Substation B	Fast Track Study - In Progress	Fast Track Study	760.0	Solar	14242406	Genelee Ret 2406
NC2018-03136	4/25/2018	Substation A	Construction - Under Construction / In Progress	-	150.0	Solar	14242406	Genelee Ret 2406
NC2018-03137	4/25/2018	Substation B	Construction - Under Construction / In Progress	-	160.0	Solar	14242406	Genelee
NC2018-03138	4/25/2018	Substation A	Fast Track Study - In Progress	Fast Track Study	310.0	Solar	14242406	Genelee Ret 2406
NC2018-03133	4/19/2018	Substation A	Commercial Operation - Power Generation in progress	-	66.6	Solar	13241209	Third Ave Ret 1209
NC2018-03130	4/11/2018	Substation A	Commercial Operation - Power Generation in progress	-	100.0	Solar	10151210	E Thomasville Ret 1210
NC2018-03129	3/29/2018	Substation A	Fast Track Study - In Progress	Not Applicable	72.0	Solar	01612406	Pioneer Ave Ret 2406
NC2018-03128	3/28/2018	Project Not Active	Cancelled	-	1,000.0	Solar	11202409	Whitsett Ret 2409
NC2018-03125	3/27/2018	Substation A	System Impact Study - Pending	-	1,000.0	Solar	29021201	Boonville Ret 1201
NC2018-03123	3/26/2018	Substation B	System Impact Study - In Progress	Voltage Flicker Mitigation Options	1,000.0	Solar	79241202	Hartford Ave Ret 1202
NC2018-03124	3/26/2018	Substation A	Facility Study - Pending Customer Response	Not Applicable	1,000.0	Solar	21401201	Rockwell Ret 1201
NC2018-03118	3/13/2018	Substation A	Construction - Pending IA/Customer Payment	-	120.0	Solar	22281201	Speedway Ret 1201
NC2018-03119	3/13/2018	Substation A	Construction - Pending IA/Customer Payment	-	120.0	Solar	22281201	Speedway Ret 1201
NC2018-03117	3/9/2018	Substation A	Commercial Operation - Power Generation in progress	-	100.0	Solar	79031212	Lincolnton Tie 1212
NC2018-03116	3/8/2018	Substation A	Commercial Operation - Power Generation in progress	-	43.2	Solar	44010402	N Wilkesboro Ret 0402
NC2018-03113	3/1/2018	Substation A	Construction - Under Construction / In Progress	-	114.0	Solar	44071202	Cairo Ret 1202
NC2018-03110	2/19/2018	Substation A	Commercial Operation - Power Generation in progress	-	28.8	Solar	01281208	Kenilworth Ret 1208
INT-2018-00030	2/2/2018	-	Construction - In Progress	-	23.6	Solar	67311202	E Bryson Ret 1202
NC2018-03105	1/30/2018	Substation A	Commercial Operation - Power Generation in progress	Not Applicable	28.8	Solar	03051210	Buxton St Ret 1210
NC2018-03102	1/19/2018	Substation A	Commercial Operation - Power Generation in progress	-	26.6	Solar	67381203	Shortoff Ret 1203
NC2018-03100	1/18/2018	Substation A	Commercial Operation - Power Generation in progress	-	33.3	Solar	01212406	Morning Star Tie 2406
NC2018-03101	1/18/2018	Substation A	Commercial Operation - Power Generation in progress	-	40.0	Solar	01522413	Reames Rd Ret 2413
NC2018-03098	1/9/2018	Approved	Commercial Operation - Power Generation in progress	-	24.0	Solar	14082410	Pope Rd Ret 2410
NC2017-03091	12/1/2017	Substation A	Commercial Operation - Power Generation in progress	-	100.8	Solar	03051214	Buxton St Ret 1214
NC2017-03092	12/1/2017	Substation B	Commercial Operation - Power Generation in progress	-	43.2	Solar	03051214	Buxton St Ret 1214
NC2017-03090	11/30/2017	Substation A	Commercial Operation - Power Generation in progress	-	43.2	Solar	01271209	Mallard Creek Ret 1209
NC2017-03089	11/25/2017	Substation A	Commercial Operation - Power Generation in progress	-	23.4	Solar	11181203	Pleasant Grove Ret 1203
NC2017-03087	11/14/2017	Project Not Active	Withdrawn	Not Applicable	6,200.0	Biomass	72582407	Ashcraft Ave Ret 2407
NC2017-03086	11/13/2017	Project Not Active	Cancelled	-	1,000.0	Solar	44091201	Roaring River Ret 1201
NC2017-03082	11/9/2017	Project Not Active	Cancelled	-	1,000.0	Solar	44091201	Roaring River Ret 1201
NC2017-03079	11/7/2017	Project Not Active	Withdrawn	-	5,000.0	Solar	21011207	Salisbury Mn 1207
NC2017-03080	11/7/2017	Approved	Construction - Under Construction / In Progress	-	45.0	Solar	09502411	Colfax Ret 2411
INT-2017-03728	11/1/2017	-	Commercial Operation - Power Generation in Progress	-	20.1	Solar	09102410	Summerfield Ret 2410

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
NC2017-03075	10/24/2017	Approved	Commercial Operation - Power Generation in progress	-	120.0	Solar	13371205	Sweetwater Ret 1205
NC2017-03074	10/14/2017	Project Not Active	Withdrawn	-	4,000.0	Solar	13291203	Island Ford Rd Ret 1203
NC2017-03073	10/13/2017	Substation A	Supplemental Study - In Progress	Supplemental Study	300.0	Solar	14152406	Brassfield Ret 2406
NC2017-03071	10/11/2017	Substation A	System Impact Study - In Progress	Protection Study	999.0	Solar	12181207	Crump Rd Ret 1207
NC2017-03070	10/9/2017	Substation A	Construction - Under Construction / In Progress	-	500.0	Solar	19061204	Homestead Ret 1204
NC2017-03067	10/3/2017	Project Not Active	Withdrawn	-	5,000.0	Solar	16271201	Flay Ret 1201
NC2017-03066	10/2/2017	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	13131210	Propst Ret 1210
NC2017-03065	9/30/2017	Substation A	System Impact Study - In Progress	Voltage Flicker Mitigation Options	2,000.0	Solar	27091205	Meadow Green Ret 1205
NC2017-03064	9/29/2017	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	01482407	Steele Creek Ret 2407
NC2017-03032	9/17/2017	Substation A	Supplemental Study - Pending	Supplemental Study	999.0	Solar	10172407	Millis Ret 2407
NC2017-03046	9/12/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	15211201	McGinnis Crossroads Ret 1201
NC2017-03047	9/12/2017	Approved	Commercial Operation - Power Generation in progress	-	33.3	Solar	01222411	Piper Glen Ret 2411
NC2017-03041	9/2/2017	Project Not Active	Withdrawn	-	999.0	Solar	21431204	Faith Ret 1204
NC2017-03042	9/2/2017	Substation B	Facility Study - In Progress	-	999.0	Solar	21431203	Faith Ret 1203
NC2017-03035	8/26/2017	Substation A	Facility Study - In Progress	-	999.0	Solar	79241202	Hartford Ave Ret 1202
NC2017-03036	8/26/2017	Substation A	Facility Study - In Progress	-	1,108.5	Solar	21121211	Majolica Rd
NC2017-03033	8/19/2017	Substation A	System Impact Study - Pending	-	999.0	Solar	13081202	Hiddenite Ret
NC2017-03034	8/19/2017	Substation A	Facility Study - In Progress	-	999.0	Solar	13191201	Rhodhiss Ret 1201
NC2017-03027	8/10/2017	Approved	Commercial Operation - Power Generation in progress	-	72.0	Solar	01140405	N Charlotte Ret 0405
NC2017-03028	8/10/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	80081205	Cleveland Ret 1205
NC2017-03023	7/28/2017	Substation A	System Impact Study - In Progress	Voltage Flicker Mitigation Options	10,000.0	Solar	10161207	Holly Hill Ret 1207
NC2017-03024	7/28/2017	Substation B	System Impact Study - Pending	-	10,000.0	Solar	10161206	Holly Hill Ret 1206
NC2017-03025	7/28/2017	Substation B	System Impact Study - Pending	-	10,000.0	Solar	10161206	Holly Hill Ret 1206
INT-2017-02352	7/12/2017	-	Commercial Operation - Power Generation in Progress	-	21.7	Solar	01311211	Commonwealth Ret 1211
NC2017-03020-1	7/8/2017	Approved	Commercial Operation - Power Generation in progress	-	40.3	Solar	14281203	Stallings Rd Ret 1203
NC2017-03018	6/29/2017	Project Not Active	Withdrawn	-	2,760.0	Solar	14162411	Imperial Ret 2411
NC2017-03019	6/29/2017	Approved	Commercial Operation - Power Generation in progress	-	28.8	Solar	14132409	Dacian Ave Ret 2409
NC2017-03015	6/26/2017	Substation A	Supplemental Study - In Progress	Supplemental Study	900.0	Solar	79291208	Rankin Ave Ret 1208
NC2017-03006	5/25/2017	Project Not Active	Withdrawn	-	1,999.0	Solar	13031203	Catawba Ret 1203
NC2017-03005	5/24/2017	Project Not Active	Withdrawn	-	1,999.0	Solar	13031203	Catawba Ret 1203
NC2017-02999	5/18/2017	Approved	Commercial Operation - Power Generation in progress	-	184.0	Solar	09082405	Kildare Ret 2405
NC2017-03000	5/18/2017	Approved	Commercial Operation - Power Generation in progress	-	432.0	Solar	09082405	Kildare Ret 2405
NC2017-03001	5/18/2017	Substation A	Commercial Operation - Power Generation in progress	-	368.0	Solar	09082405	Kildare Ret 2405
NC2017-02995	5/3/2017	Approved	Commercial Operation - Power Generation in progress	-	51.3	Solar	19021202	Eastgate Ret 1202
NC2017-02994	5/2/2017	Approved	Commercial Operation - Power Generation in progress	-	33.1	Solar	65011205	Asheville Hwy Ret 1205
NC2017-02989	4/25/2017	Substation A	Construction - Pending IA/Customer Payment	-	750.0	Solar	14042410	Butner Ret 2410
NC2017-02990	4/25/2017	Substation B	Construction - Pending IA/Customer Payment	-	980.0	Solar	14042410	Butner Ret 2410
NC2017-02991	4/25/2017	Substation A	Construction - Pending IA/Customer Payment	-	750.0	Solar	14042410	Butner Ret 2410
NC2017-02986	3/28/2017	Approved	Commercial Operation - Power Generation in progress	-	90.0	Solar	79031208	Lincolnton Tie 1208
NC2017-02979	1/5/2017	Project Not Active	Withdrawn	-	1,999.0	Solar	09051203	Vandalia Ret 1203
NC2016-02977	12/29/2016	Project Not Active	Withdrawn	-	3,960.0	Solar	29071204	Elk Valley Ret 1204
NC2016-02974	12/27/2016	Project Not Active	Withdrawn	-	990.0	Solar	90301202	Old Fort Ret 1202
NC2016-02975	12/27/2016	Project Not Active	Withdrawn	-	5,000.0	Solar	10192408	Ragsdale Ret 2408
NC2016-02973	12/21/2016	Project Not Active	Withdrawn	-	1,980.0	Solar	90301202	Old Fort Ret 1202
NC2016-02970	12/13/2016	Project Not Active	Withdrawn	-	22.8	Solar	01311210	Commonwealth Ret 1210
NC2016-02969	12/12/2016	Project Not Active	Withdrawn	-	990.0	Solar	90391204	Carson Ret 1204
NC2016-02968	12/6/2016	Approved	Commercial Operation - Power Generation in progress	-	22.8	Solar	01311210	Commonwealth Ret 1210
NC2016-02967	12/1/2016	Project Not Active	Withdrawn	-	1,999.0	Solar	27091205	Meadow Green Ret 1205
NC2016-02963	11/30/2016	Project Not Active	Withdrawn	-	1,999.0	Solar	11031201	Gibsonville Dist 1201
NC2016-02964	11/30/2016	Project Not Active	Withdrawn	-	5,000.0	Solar	29051201	Fall Creek Ret 1201
NC2016-02959	11/21/2016	Project Not Active	Withdrawn	-	1,999.0	Solar	51061204	Madison Ret 1204
NC2016-02957	11/16/2016	Substation A	Construction - Pending IA/Customer Payment	-	1,999.0	Solar	11222405	Gilbreath Ret 2405
NC2016-02953	11/15/2016	Project Not Active	Withdrawn	-	1,980.0	Solar	90391204	Carson Ret 1204
NC2016-02951	11/14/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	11071202	Haw River Ret 1202
NC2016-02952	11/14/2016	Project Not Active	Cancelled	-	1,999.0	Solar	11151202	Saxapahaw Ret 1202
NC2016-02947	11/8/2016	Substation A	Construction - In Progress	-	286.4	Solar	21011206	Salisbury Main 1206
NC2016-02948	11/8/2016	Substation A	Facility Study - In Progress	-	2,996.0	Solar	21330408	Badin Ret
NC2016-02944	11/7/2016	Project Not Active	Withdrawn	-	2,000.0	Solar	16861201	Christopher Rd Ret 1201
NC2016-02945	11/7/2016	Substation B	System Impact Study - Pending Customer Response	Customer ROW Data Collection	4,000.0	Solar	11191202	Swepsonville Tie 1202
NC2016-02943	11/2/2016	Project Not Active	Withdrawn	-	3,000.0	Solar	21612412	West Norwood Ret 2412
NC2016-02942	11/1/2016	Project Not Active	Withdrawn	-	4,000.0	Solar	13081203	Hiddenite Ret 1203
NC2016-02937	10/31/2016	Approved	Construction - Under Construction / In Progress	-	43.0	Solar	80751205	Brawley School Ret 1205
NC2016-02939	10/31/2016	Project Not Active	Withdrawn	-	5,000.0	Solar	09102410	Summerfield Ret 2410
NC2016-02924	10/17/2016	Substation A	Construction - Pending Customer Obligation	Not Applicable	5,000.0	Solar	14042407	Butner Ret 2407
NC2016-02921	10/12/2016	Substation A	System Impact Study - In Progress	Protection Study	4,992.0	Solar	-	Baltimore Rd Ret 1202
NC2016-02922	10/12/2016	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	4,992.0	Solar	-	Baltimore Rd Ret 1202
NC2016-02916	10/3/2016	Substation A	Construction - Pending IA/Customer Payment	-	1,998.0	Solar	12181202	Crump Rd Ret 1202
NC2016-02907	9/16/2016	Project Not Active	Withdrawn	Not Applicable	8,800.0	Solar	09042412	Randolph Ave Ret
NC2016-02905	9/14/2016	Approved	Commercial Operation - Power Generation in progress	-	120.0	Solar	19051202	White Cross Ret 1202
NC2016-02904	9/13/2016	Substation A	System Impact Study - Pending Customer Response	Customer Documentation Corrections	4,999.0	Solar	22251201	Enochville Ret 1201
NC2016-02900	9/12/2016	Substation A	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	4,992.0	Solar	51061208	Madison Ret 1208
NC2016-02901	9/12/2016	Substation A	Facility Study - Pending Customer Response	Not Applicable	4,992.0	Solar	13291203	Island Ford Rd Ret 1203
NC2016-02894	9/9/2016	Substation A	Facility Study - In Progress	Not Applicable	4,752.0	Solar	03011208	Advance Ret 1208
NC2016-02895	9/9/2016	Project Not Active	Withdrawn	Not Applicable	1,999.0	Solar	17131202	Gatewood Ret 1202
NC2016-02887	9/7/2016	Substation A	System Impact Study - In Progress	Protection Study	5,000.0	Solar	10221211	Denton Ret 1211
NC2016-02881	8/31/2016	Approved	Commercial Operation - Power Generation in progress	-	200.0	Solar	44071202	Cairo Ret 1202
NC2016-02882	8/31/2016	Approved	Commercial Operation - Power Generation in progress	-	96.0	Solar	44021212	Brook St Ret 1212
NC2016-02877	8/26/2016	Project Not Active	Withdrawn	-	5,000.0	Solar	03651202	Turnersburg Ret 1202
NC2016-02865	8/24/2016	Substation A	Facility Study - In Progress	Not Applicable	3,000.0	Solar	-	Corinth Ret 1206

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
NC2016-02867	8/24/2016	Project Not Active	Withdrawn	-	1,666.0	Solar	15211201	McGinnis Crossroads Ret 1201
NC2016-02864	8/15/2016	Approved	Commercial Operation - Power Generation in progress	-	29.4	Solar	09032408	Fairfax Rd Ret 2408
NC2016-02861	8/12/2016	Substation A	Facility Study - In Progress	Not Applicable	4,592.0	Solar	80821208	Triplett Ret
NC2016-02862	8/12/2016	Substation A	Construction - Pending IA/Customer Payment	Not Applicable	3,000.0	Solar	29051201	Fall Creek Ret 1201
NC2016-02863	8/12/2016	Substation A	Supplemental Study - Study Complete	Supplemental Study	39.7	Solar	22271205	Brantley Rd Ret 1205
NC2016-02857	8/11/2016	Substation A	Facility Study - In Progress	Not Applicable	3,000.0	Solar	29041201	Cycle Ret 1201
NC2016-02858	8/11/2016	Substation A	Construction - Under Construction / In Progress	-	4,992.0	Solar	29061205	Yadkinville Ret 1205
NC2016-02851	7/26/2016	Substation B	Facility Study - In Progress	Not Applicable	4,999.0	Solar	10201202	N Gordonton Ret
NC2016-02847	7/15/2016	Substation A	Facility Study - In Progress	Not Applicable	4,992.0	Solar	03651203	Turnersburg Ret 1203
NC2016-02840	7/13/2016	Substation A	System Impact Study - Pending Customer Response	Customer Transformer Inrush Decision	5,000.0	Solar	11181202	Pleasant Grove Ret 1202
NC2016-02839	7/12/2016	Substation A	Facility Study - In Progress	Not Applicable	5,000.0	Solar	10201202	N Gordonton Ret 1202
NC2016-02829	7/1/2016	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	4,999.0	Solar	11151201	Saxapahaw Ret 1201
NC2016-02832	7/1/2016	Project Not Active	Withdrawn	-	4,000.0	Solar	11151201	Saxapahaw Ret 1201
NC2016-02834	7/1/2016	Substation A	Facility Study - In Progress	Not Applicable	3,000.0	Solar	11191204	Swepsonville Tie 1204
NC2016-02828	6/30/2016	Substation A	Facility Study - Pending Customer Response	Not Applicable	4,992.0	Solar	11151201	Saxapahaw Ret 1201
NC2016-02826	6/29/2016	Substation A	Facility Study - Pending	Not Applicable	4,992.0	Solar	29081201	Smithtown Ret 1201
NC2016-02823	6/27/2016	Substation A	System Impact Study - Pending Customer Response	Customer Documentation Corrections	4,000.0	Solar	16701204	Blanton Ret 1204
NC2016-02821	6/23/2016	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	4,999.0	Solar	11141203	Ossipee Dist 1203
NC2016-02818	6/21/2016	Substation A	Facility Study - In Progress	Not Applicable	4,992.0	Solar	29071207	Elk Valley Ret 1207
NC2016-02817	6/20/2016	Substation A	System Impact Study - In Progress	Duke ROW	4,999.0	Solar	51061203	Madison Ret 1203
CHKLIST-12047	6/14/2016	Approved	Commercial Operation - Power Generation in progress	-	120.0	Solar	14052411	Research Triangle Ret 2411
NC2016-02813	6/10/2016	Substation A	Construction - Pending IA/Customer Payment	Not Applicable	4,999.0	Solar	03191205	King Ret 1205
NC2016-02814	6/10/2016	Substation B	System Impact Study - In Progress	Protection Study	5,000.0	Solar	03071208	Clemmons Ret 1208
NC2016-02816	6/10/2016	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	5,000.0	Solar	03552402	Mocksville Main 2402
NC2016-02808	5/23/2016	Substation A	System Impact Study - In Progress	Voltage Flicker Mitigation Options	5,000.0	Solar	17031212	Wentworth Ret 1212
NC2016-02806	5/19/2016	Substation A	System Impact Study - Pending Customer Response	Customer Mitigation Options Selection	5,000.0	Solar	13051201	East Maiden Ret 1201
NC2016-02795	5/6/2016	Substation A	System Impact Study - Pending Customer Response	Customer Mitigation Options Selection	5,000.0	Solar	16201213	Lawndale Ret 1213
NC2016-02797	5/6/2016	Substation A	Construction - Pending Customer Obligation	-	5,000.0	Solar	13411201	Macedonia Ret 1201
NC2016-02791	5/2/2016	Project Not Active	Withdrawn	-	5,000.0	Solar	79241202	Hartford Ave Ret 1202
NC2016-02783	4/26/2016	Project Not Active	Withdrawn	-	5,000.0	Solar	80081205	Cleveland Ret 1205
NC2016-02777	4/18/2016	Substation A	System Impact Study - Pending Customer Response	Customer Transformer Inrush Data Collection	5,000.0	Solar	17131203	Gatewood Ret 1203
NC2016-02776	4/14/2016	Substation B	System Impact Study - Pending	-	5,000.0	Solar	09061204	Climax Ret 1204
NC2016-02773	4/7/2016	Approved	Commercial Operation - Power Generation in progress	-	36.0	Solar	09082410	Kildare Ret 2410
NC2016-00063	3/29/2016	Project Not Active	Cancelled	-	1,500.0	Diesel	03391201	Welcome Ret 1201
NC2016-00061	3/28/2016	Project Not Active	Withdrawn	-	3,668.0	Solar	16041201	Cherryville Ret 1201
NC2016-00035	3/10/2016	Substation A	Supplemental Study - Study Complete	Supplemental Study	25.0	Solar	29041201	Cycle Ret 1201
NC2016-00036	3/10/2016	Approved	Commercial Operation - Power Generation in progress	-	48.0	Solar	14082409	Pope Rd Ret 2409
NC2016-00032	3/8/2016	Approved	Commercial Operation - Complete pending power generation	-	4,996.0	Solar	11082414	Trollingwood Ret 2414
NC2016-00026	2/17/2016	Substation A	System Impact Study - In Progress	Protection Study	5,000.0	Solar	10231207	Glenola Ret 1207
NC2016-00024	2/16/2016	Substation A	Facility Study - Pending Customer Response	Not Applicable	3,000.0	Solar	65171201	Edneyville Ret 1201
CHKLIST-11960	2/12/2016	Withdrawn	Withdrawn	-	6,000.0	Biomass	79281201	Clariant Corp Char T&D 1201
NC2016-00015	2/3/2016	Approved	Commercial Operation - Power Generation in progress	-	36.0	Solar	13371210	Sweetwater Ret 1210
NC2016-00016	2/3/2016	Approved	Commercial Operation - Power Generation in progress	-	4,980.0	Solar	21011207	Salisbury Mn 1207
NC2016-00014	1/29/2016	Approved	Commercial Operation - Power Generation in progress	-	4,380.0	Solar	79271204	Peacock Tie 1204
NC2016-00012	1/20/2016	Project Not Active	Withdrawn	DET Non-Technical Policy	90.0	Solar	79031208	Lincolnton Tie 1208
NC2016-00002	1/11/2016	Approved	Commercial Operation - Power Generation in progress	-	25.0	Solar	65011201	Asheville Hwy Ret 1201
NC2016-00001	1/8/2016	Approved	Commercial Operation - Power Generation in progress	-	40.3	Solar	01212403	Morning Star Tie 2403
CHKLIST-11526	1/5/2016	Project Not Active	Withdrawn	-	26.0	Solar	16271201	Flay Ret 1201
NC2015-00062	12/29/2015	Approved	Commercial Operation - Power Generation in progress	-	360.0	Solar	01392409	Montclaire Ret 2409
NC2015-00057	12/28/2015	Approved	Commercial Operation - Power Generation in progress	-	56.0	Solar	21011204	Salisbury Main 1204
NC2015-00061	12/28/2015	Project Not Active	Cancelled	-	624.0	Solar	79261202	Belmont Tie 1202
NC2015-00056	12/22/2015	Substation A	Facility Study - Pending Customer Response	Not Applicable	1,998.0	Solar	15171203	Cleghorn SS
NC2015-00054	12/21/2015	Approved	Commercial Operation - Power Generation in progress	-	180.0	Solar	80711207	Dunbar Ret 1207
CHKLIST-11564	12/18/2015	Project Not Active	Withdrawn	-	22.8	Solar	03131203	Guthrie Ret 1203
NC2016-02936	12/18/2015	Project Not Active	Withdrawn	-	92.0	Solar	80751205	Brawley School Ret 1205
NC2015-00052	12/16/2015	Substation A	System Impact Study - Pending Customer Response	Customer Transformer Inrush Decision	4,999.0	Solar	51161202	Dan Valley Ret 1202
NC2015-00053	12/16/2015	Substation A	System Impact Study - Pending Customer Response	Customer Transformer Inrush Data Collection	4,999.0	Solar	17021201	Ruffin Ret 1201
NC2015-00058	12/16/2015	Approved	Commercial Operation - Power Generation in progress	-	60.0	Solar	09242411	Merritt Dr Ret 2411
CHKLIST-11527	12/15/2015	Approved	Commercial Operation - Power Generation in progress	-	4,750.0	Biomass	03231204	N Winston Ret 1204
NC2015-00049	12/10/2015	Project Not Active	Withdrawn	-	4,999.0	Solar	16861201	Christopher Rd Ret 1201
NC2015-00048	12/9/2015	Substation A	System Impact Study - Pending Customer Response	Not Applicable	5,000.0	Solar	13341201	Catfish Ret 1201
INT-2015-00376	12/6/2015	-	Commercial Operation - Power Generation in Progress	-	23.8	Solar	13391204	Taylorsville Tie 1204
CHKLIST-11430	12/4/2015	Project Not Active	Cancelled	-	2,000.0	Solar	21552402	Mocksville Main 2402
NC2015-00042	12/2/2015	Substation A	System Impact Study - Pending Customer Response	Customer Documentation Corrections	4,996.0	Solar	11261208	Oakwood St Ret 1208
NC2015-00038	11/18/2015	Project Not Active	Withdrawn	-	68.0	Solar	14202409	Garrett Rd Ret 2409
CHKLIST-10089	11/17/2015	Approved	Commercial Operation - Power Generation in progress	-	644.0	Solar	01522413	Reames Rd Ret 2413
CHKLIST-12114	11/17/2015	Project Not Active	Cancelled	-	44.6	Solar	01512405	Provol Ret 2405
NC2015-00029	11/9/2015	Project Not Active	Withdrawn	-	64.0	Solar	09032405	Fairfax Rd Ret 2408
NC2015-00030	11/9/2015	Project Not Active	Withdrawn	-	60.0	Solar	01432406	Eastfield Rd Ret 2406
NC2015-00028	11/5/2015	Approved	Commercial Operation - Power Generation in progress	-	28.0	Solar	14202410	Garrett Rd Ret 2410
CHKLIST-11096	10/23/2015	Approved	Commercial Operation - Power Generation in progress	-	4,990.0	Solar	79301208	Triangle Ret 1208
NC2016-00038	10/23/2015	Project Not Active	Withdrawn	-	1,998.0	Solar	72542405	Beaver Dam Ret 2405
NC2015-00027	10/19/2015	Approved	Commercial Operation - Power Generation in progress	-	24.0	Solar	11020401	N Park Dist 0401
NC2015-00025	10/16/2015	Project Not Active	Withdrawn	-	40.0	Solar	13101203	Startown Ret 1203
NC2015-00026	10/16/2015	Project Not Active	Withdrawn	-	70.0	Solar	13151202	Mt Olive Ret 1202
CHKLIST-11060	10/9/2015	Approved	Fast Track Study - Study Complete	Fast Track Study	37.4	Solar	01222409	Piper Glen Ret 2409
NC2015-00023	10/9/2015	Approved	Commercial Operation - Power Generation in progress	-	56.0	Solar	11122415	Burlington Main 2415

Duke Energy Carolinas, LLC
Duke Energy Progress, LLC

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
NC2015-00022	10/1/2015	Project Not Active	Withdrawn	Not Applicable	1,999.0	Solar	16071212	Parkway SS 1212
CHKLIST-10803	9/23/2015	Project Not Active	Withdrawn	-	1,999.0	Solar	51151202	Bryant St Ret 1202
NC2015-00018	9/16/2015	Approved	Commercial Operation - Power Generation in progress	-	360.0	Solar	01412408	Stouts Ret 2408
NC2015-00015	9/15/2015	Substation B	Facility Study - On-hold Interdependency	Not Applicable	3,000.0	Solar	28051201	Dobson Ret
NC2015-00016	9/15/2015	On Hold	System Impact Study - On-Hold Interdependency	-	4,500.0	Solar	28051202	Dobson Ret 1201
NC2015-00008	9/10/2015	Approved	Commercial Operation - Power Generation in progress	-	208.0	Solar	01421206	Kudzu Ret 1207
NC2015-00011	9/10/2015	Substation A	Facility Study - In Progress	Not Applicable	2,932.0	Solar	28051201	Dobson Ret
NC2015-00006	9/8/2015	Approved	Commercial Operation - Power Generation in progress	-	243.0	Solar	01421206	Kudzu Ret 1206
NC2015-00003	9/1/2015	Approved	Commercial Operation - Power Generation in progress	-	23.0	Solar	14121209	Green St Ret 1209
CHKLIST-10574	8/26/2015	Project Not Active	Withdrawn	-	27.0	Solar	67351202	E Sylva Ret 1202
CHKLIST-10555	8/25/2015	Approved	Commercial Operation - Power Generation in progress	-	396.0	Solar	01222404	Piper Glen Ret 2404
CHKLIST-10561	8/25/2015	Approved	Commercial Operation - Power Generation in progress	-	360.0	Solar	01271211	Mallard Creek Ret 1211
CHKLIST-10536	8/24/2015	Approved	Commercial Operation - Power Generation in progress	-	360.0	Solar	01392403	Montclaire Ret 2403
CHKLIST-10548	8/24/2015	Approved	Commercial Operation - Power Generation in progress	-	324.0	Solar	03301212	Shattalon SW STA 1212
CHKLIST-10522	8/21/2015	Approved	Commercial Operation - Power Generation in progress	-	40.0	Solar	09202403	Tarrant Rd Ret 2403
CHKLIST-10524	8/21/2015	Substation A	Facility Study - Pending	-	1,137.0	Biomass	03071210	Clemmons Ret 1210
CHKLIST-10528	8/21/2015	Approved	Commercial Operation - Power Generation in progress	-	360.0	Solar	01332412	Wilgrove Ret 2412
CHKLIST-10473	8/17/2015	Substation A	System Impact Study - Pending Customer Response	-	850.0	Solar	21071206	Julian Rd Ret 1206
CHKLIST-10451	8/14/2015	Approved	Commercial Operation - Power Generation in progress	-	72.0	Solar	79302404	Triangle Ret 2404
CHKLIST-10440	8/13/2015	Approved	Commercial Operation - Power Generation in progress	-	60.0	Solar	80872401	Glenway SS 2401
CHKLIST-10447	8/13/2015	Approved	Commercial Operation - Power Generation in progress	-	60.0	Solar	21021208	Statesville Rd Ret 1208
CHKLIST-10426	8/11/2015	Approved	Commercial Operation - Power Generation in progress	-	396.0	Solar	13401206	S Hickory Ret 1206
CHKLIST-10405	8/10/2015	Approved	Commercial Operation - Power Generation in progress	-	31.3	Solar	03221205	Mt Tabor Ret 1205
CHKLIST-10397	8/7/2015	Approved	Commercial Operation - Power Generation in progress	-	68.0	Solar	09072416	Jessuptown Ret 2416
CHKLIST-10398	8/7/2015	Approved	Commercial Operation - Power Generation in progress	-	60.0	Solar	01412406	Stouts Ret 2406
CHKLIST-10523	8/7/2015	Substation A	System Impact Study - In Progress	Voltage Flicker Mitigation Options	5,000.0	Solar	09061201	Climax Ret 1201
CHKLIST-10385	8/6/2015	Approved	Commercial Operation - Power Generation in progress	-	312.0	Solar	21091204	Long Ferry Ret 1204
CHKLIST-10387	8/6/2015	Approved	Commercial Operation - Power Generation in progress	-	60.0	Solar	10081201	N Main St Dist 1201
CHKLIST-10392	8/6/2015	Approved	Commercial Operation - Power Generation in progress	-	68.0	Solar	01302414	McAlpine Creek Ret 2414
CHKLIST-10380	8/5/2015	Approved	Commercial Operation - Power Generation in progress	-	48.0	Solar	01321209	Sunset Ret 1209
CHKLIST-10382	8/5/2015	Approved	Commercial Operation - Power Generation in progress	-	68.0	Solar	22281204	Speedway Ret 1204
CHKLIST-10360	8/4/2015	Approved	Commercial Operation - Power Generation in progress	-	800.4	Solar	17011206	Reidsville Ret 1206
CHKLIST-10201	7/30/2015	Approved	Commercial Operation - Power Generation in progress	-	302.0	Solar	13181212	Oyama Ret 1212
CHKLIST-10230	7/20/2015	Approved	Commercial Operation - Power Generation in progress	-	240.0	Solar	14152411	Brassfield Ret 2411
CHKLIST-10217	7/16/2015	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	4,800.0	Solar	17191201	Waynick Rd Ret 1201
CHKLIST-10194	7/15/2015	On Hold	System Impact Study - On-Hold Interdependency	-	2,000.0	Solar	15901202	Mooresboro Ret 1202
CHKLIST-10198	7/15/2015	Project Not Active	Withdrawn	-	2,000.0	Solar	15901202	Mooresboro Ret 1202
CHKLIST-10177	7/13/2015	Substation A	System Impact Study - In Progress	Voltage Flicker Mitigation Options	2,000.0	Solar	17191201	Waynick Rd Ret 1201
CHKLIST-10183	7/13/2015	Approved	Commercial Operation - Power Generation in progress	-	696.0	Solar	21091204	Long Ferry Ret 1204
CHKLIST-10145	7/9/2015	Approved	Commercial Operation - Power Generation in progress	-	28.0	Solar	13171205	N Hickory Ret 1205
CHKLIST-10103	7/2/2015	Approved	Commercial Operation - Power Generation in progress	-	280.0	Solar	11252408	St Marks Ret 2408
CHKLIST-10104	7/2/2015	Approved	Commercial Operation - Power Generation in progress	-	280.0	Solar	03212401	Mar-Don Dr Ret 2401
CHKLIST-10082	6/30/2015	Approved	Commercial Operation - Power Generation in progress	-	40.0	Solar	19091203	Grey Ret 1203
CHKLIST-10045	6/26/2015	Project Not Active	Cancelled	Not Applicable	350.2	Solar	01161203	Park Rd Ret 1203
CHKLIST-10047	6/26/2015	Project Not Active	Cancelled	Not Applicable	1,000.0	Solar	01492411	Coffey Creek Ret 2411
CHKLIST-9986	6/18/2015	Project Not Active	Cancelled	-	5,000.0	Solar	29051201	Fall Creek Ret 1201
CHKLIST-9968	6/17/2015	Project Not Active	Withdrawn	Not Applicable	980.0	Solar	09082406	Kildare Ret 2406
CHKLIST-9923	6/11/2015	Substation A	Construction - Under Construction / In Progress	-	6,000.0	Solar	21081204	Cleveland Ret 1204
CHKLIST-9838	6/4/2015	Approved	Commercial Operation - Power Generation in progress	-	80.0	Solar	19061209	Homestead Ret 1209
CHKLIST-9850	6/2/2015	Project Not Active	Withdrawn	-	768.0	Solar	80811202	Murdock Rd Ret 1202
CHKLIST-9734	5/20/2015	Approved	Construction - Under Construction / In Progress	-	5,000.0	Solar	10231203	Glenola Ret 1203
CHKLIST-9696	5/15/2015	Approved	Commercial Operation - Power Generation in progress	-	4,508.0	Solar	13121206	Claremont Ret 1206
CHKLIST-9654	5/12/2015	Approved	Commercial Operation - Power Generation in progress	-	1,104.0	Solar	12181202	Crump Rd Ret 1202
CHKLIST-9636	5/11/2015	Approved	Commercial Operation - Power Generation in progress	-	42.0	Solar	21010404	Salisbury Main 0404
CHKLIST-9742	5/11/2015	Project Not Active	Withdrawn	-	5,000.0	Solar	28081209	Toast Ret 1209
CHKLIST-9745	5/11/2015	Project Not Active	Withdrawn	-	4,000.0	Solar	29081201	Smithtown Ret 1201
CHKLIST-9695	5/5/2015	Approved	Commercial Operation - Power Generation in progress	-	27.0	Solar	09302408	Lake Townsend Ret 2408
CHKLIST-9703	5/4/2015	Approved	Commercial Operation - Complete pending power generation	-	5,000.0	Solar	22321202	Mt Pleasant Ret 1202
CHKLIST-9513	4/28/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	15241201	Riverstone Ret 1202
CHKLIST-9504	4/27/2015	Approved	Commercial Operation - Power Generation in progress	-	445.0	Solar	13371207	Sweetwater Ret 1207
CHKLIST-9532	4/21/2015	Project Not Active	Withdrawn	-	25.7	Solar	19011201	Cameron Ave SS 1201
CHKLIST-9357	4/10/2015	Approved	Commercial Operation - Power Generation in progress	-	1,560.0	Solar	79301206	Triangle Ret 1206
CHKLIST-9363	4/10/2015	Approved	Commercial Operation - Power Generation in progress	-	95.2	Solar	03101206	Fiddlers Creek Ret 1206
CHKLIST-9365	4/10/2015	Project Not Active	Withdrawn	Not Applicable	4,800.0	Solar	16541203	Buffalo Creek Ret 1203
CHKLIST-9313	4/2/2015	Project Not Active	Cancelled	-	4,800.0	Solar	14042409	Butner Ret 2409
CHKLIST-9286	3/31/2015	Project Not Active	Withdrawn	-	4,800.0	Solar	80811202	Murdock Rd Ret 1202
CHKLIST-9293	3/31/2015	Substation B	Construction - Pending IA/Customer Payment	-	3,500.0	Solar	09082411	Kildare Ret 2411
CHKLIST-9234	3/24/2015	Approved	Commercial Operation - Power Generation in progress	-	54.0	Solar	19011204	Cameron Ave SS 1204
CHKLIST-9218	3/20/2015	Approved	Construction - Under Construction / In Progress	-	4,998.0	Solar	21431205	Faith Ret 1205
CHKLIST-9185	3/18/2015	Substation A	Construction - Under Construction / In Progress	-	1,550.0	Biomass	09082411	Kildare Ret 2411
CHKLIST-9188	3/18/2015	Project Not Active	Withdrawn	-	4,080.0	Solar	11031201	Gibsonville Dist 1201
CHKLIST-9191	3/18/2015	Project Not Active	Withdrawn	-	5,010.0	Solar	15161202	Paradise Ret 1202
CHKLIST-9181	3/17/2015	Substation A	Construction - Under Construction / In Progress	-	1,999.0	Solar	21061210	Sumner Ret 1210
CHKLIST-9183	3/17/2015	Approved	Commercial Operation - Power Generation in progress	-	598.0	Solar	21021204	Statesville Rd Ret 1204
CHKLIST-9161	3/16/2015	Approved	Construction - Under Construction / In Progress	-	3,600.0	Solar	15161202	Paradise Ret 1202
CHKLIST-9164	3/16/2015	Substation A	System Impact Study - In Progress	Protection Study	4,998.0	Solar	15161202	Paradise Ret 1202
CHKLIST-9155	3/13/2015	Substation A	System Impact Study - In Progress	Voltage Flicker Mitigation Options	3,020.0	Solar	09082406	Kildare Ret 2406
CHKLIST-9157	3/13/2015	Substation A	System Impact Study - In Progress	Technical Review	4,998.0	Solar	03552402	Mocksville Main 2402
CHKLIST-9158	3/13/2015	Project Not Active	Withdrawn	-	4,500.0	Solar	15951202	Washburn Ret 1202

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-9159	3/13/2015	Project Not Active	Withdrawn	-	5,000.0	Solar	03071210	Clemmons Ret 1210
CHKLIST-9160	3/13/2015	Project Not Active	Withdrawn	-	2,000.0	Solar	15951202	Washburn Ret 1202
CHKLIST-9151	3/12/2015	Substation B	System Impact Study - In Progress	Voltage Flicker Mitigation Options	4,998.0	Solar	16901204	Mooresboro Ret 1204
CHKLIST-9141	3/11/2015	Project Not Active	Withdrawn	-	4,998.0	Solar	09262409	Rudd Ret 2409
CHKLIST-9134	3/10/2015	Project Not Active	Withdrawn	-	56.0	Solar	10151210	E Thomasville Ret 1210
CHKLIST-9135	3/10/2015	Project Not Active	Withdrawn	-	112.0	Solar	10151210	E Thomasville Ret 1210
CHKLIST-9101	3/4/2015	Project Not Active	Withdrawn	-	5,000.0	Solar	15901202	Mooresboro Ret 1202
CHKLIST-9112	3/4/2015	Project Not Active	Withdrawn	-	4,500.0	Solar	15951202	Washburn Ret 1202
CHKLIST-9706	3/3/2015	Project Not Active	Cancelled	-	1,990.0	Solar	72542414	Beaver Dam Ret 2414
CHKLIST-9063	3/2/2015	Project Not Active	Withdrawn	-	524.4	Solar	27091205	Meadow Green Ret 1205
CHKLIST-9065	3/2/2015	Approved	Commercial Operation - Power Generation in progress	-	2,000.0	Solar	21061208	Sumner Ret 1208
CHKLIST-9076	3/2/2015	Project Not Active	Cancelled	-	2,500.0	Solar	80081205	Cleveland Ret 1205
CHKLIST-9079	3/2/2015	Project Not Active	Withdrawn	-	5,000.0	Solar	44031206	Fairplains Ret 1206
CHKLIST-9082	3/2/2015	Project Not Active	Withdrawn	-	5,000.0	Solar	01332405	Wilgrove Ret 2405
CHKLIST-9083	3/2/2015	Substation A	System Impact Study - In Progress	Voltage Flicker Mitigation Options	4,999.0	Solar	09571202	Monticello Ret 1202
CHKLIST-9314	3/2/2015	Approved	Commercial Operation - Power Generation in progress	-	24.0	Solar	21061209	Sumner Ret 1209
CHKLIST-8997	2/23/2015	Substation A	Fast Track Study - Study Complete	Fast Track Study	312.0	Solar	14152411	Brassfield Ret 2411
CHKLIST-8907	2/6/2015	Approved	Commercial Operation - Power Generation in progress	-	75.0	Solar	79031212	Lincolnton Tie 1212
CHKLIST-8912	2/6/2015	Substation A	Facility Study - Pending	Not Applicable	2,000.0	Solar	16901204	Mooresboro Ret 1204
CHKLIST-8897	2/5/2015	Approved	Commercial Operation - Power Generation in progress	-	1,998.0	Solar	15161202	Paradise Ret 1202
CHKLIST-8881	2/2/2015	Substation A	Facility Study - Pending Customer Response	Not Applicable	4,800.0	Solar	11172405	Frieden Ret 2405
CHKLIST-8750	1/14/2015	Approved	Commercial Operation - Power Generation in progress	-	2,002.1	Solar	19051203	White Cross Ret 1203
CHKLIST-8697	1/9/2015	Project Not Active	Withdrawn	-	1,000.0	Solar	03661203	Hager Rd Ret 1203
CHKLIST-8625	12/30/2014	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	15951201	Washburn Ret 1201
CHKLIST-8608	12/26/2014	Project Not Active	Withdrawn	-	4,999.0	Solar	51061206	Madison Ret 1206
CHKLIST-8580	12/22/2014	Project Not Active	Cancelled	-	1,500.0	Solar	21071206	Julian Rd Ret 1206
CHKLIST-8342	11/19/2014	Approved	Commercial Operation - Power Generation in progress	-	84.0	Solar	21071206	Julian Rd Ret 1206
CHKLIST-8344	11/19/2014	Approved	Commercial Operation - Power Generation in progress	-	90.8	Solar	21071206	Julian Rd Ret 1206
CHKLIST-8295	11/11/2014	Pending	Pending	-	225.0	Solar	09012416	Greensboro Main 2416
CHKLIST-8208	11/5/2014	Substation A	Commercial Operation - Power Generation in progress	-	2,000.0	Solar	16861201	Christopher Rd Ret 1201
CHKLIST-8219	11/5/2014	Approved	Construction - Pending IA/Customer Payment	-	2,000.0	Solar	16701203	Blanton Ret 1203
CHKLIST-8206	11/4/2014	Approved	Commercial Operation - Power Generation in progress	-	84.0	Solar	14031210	Crest St Ret 1210
CHKLIST-8161	10/29/2014	Approved	Commercial Operation - Power Generation in progress	-	2,000.0	Solar	16061205	Bethware Ret 1205
CHKLIST-8156	10/28/2014	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	16061205	Bethware Ret 1205
CHKLIST-6067	10/6/2014	Project Not Active	Cancelled	-	1,000.0	Solar	09082406	Kildare Ret 2406
CHKLIST-6068	10/6/2014	Substation A	Fast Track Study - Study Complete	Fast Track Study	800.0	Solar	09012404	Greensboro Main 2404
CHKLIST-6050	10/2/2014	Approved	Commercial Operation - Power Generation in progress	-	157.0	Solar	21021204	Statesville Rd Ret 1204
CHKLIST-6046	10/1/2014	Approved	Commercial Operation - Power Generation in progress	-	3,480.0	Solar	29061207	Yadkinville Ret 1207
CHKLIST-6028	9/29/2014	Approved	Commercial Operation - Power Generation in progress	-	26.8	Solar	19011201	Cameron Ave SS 1201
CHKLIST-5974	9/24/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	11161202	Kimesville Ret 1202
CHKLIST-5952	9/22/2014	Pending	IR Review - Pending Customer Response	-	300.0	Solar	01161204	Park Rd Ret 1204
CHKLIST-5947	9/19/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	21401211	Rockwell Ret 1211
CHKLIST-5934	9/18/2014	Approved	Commercial Operation - Power Generation in progress	-	112.0	Solar	21071206	Julian Rd Ret 1206
CHKLIST-5922	9/16/2014	Approved	System Impact Study - Pending Customer Response	-	4,000.0	Hydroelectric	-	Browns Ford Ret 1207
CHKLIST-5851	9/11/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	17121202	Monroeton Ret 1202
CHKLIST-3964	9/8/2014	Withdrawn	Withdrawn	-	750.0	Solar	01191204	Remount Rd Ret 1204
CHKLIST-3922	9/2/2014	Project Not Active	Cancelled	-	5,000.0	Solar	09061203	Climax Ret 1203
CHKLIST-3923	9/2/2014	Approved	Commercial Operation - Power Generation in progress	-	440.0	Solar	13371207	Sweetwater Ret 1207
CHKLIST-3924	9/2/2014	Approved	Commercial Operation - Power Generation in progress	-	1,059.0	Biomass	01542402	Fisher SS 2402
CHKLIST-3905	8/26/2014	Approved	Commercial Operation - Power Generation in progress	-	4,800.0	-	80862404	Elmwood Ret 2404
CHKLIST-3870	8/15/2014	Approved	Commercial Operation - Power Generation in progress	-	25.0	Solar	19091203	Grey Ret 1203
CHKLIST-3865	8/14/2014	Approved	Commercial Operation - Power Generation in progress	-	480.0	Solar	01392409	Montclaire Ret 2409
CHKLIST-3841	8/8/2014	Approved	Commercial Operation - Power Generation in progress	-	3,500.0	Solar	14021201	Ashe St Sw Sta 1201
CHKLIST-3830	8/4/2014	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	01342408	Newell Ret 2407
CHKLIST-3822	8/1/2014	Project Not Active	Withdrawn	-	1,400.0	Biomass	13261201	Zion Church Rd Ret 1201
CHKLIST-3797	7/28/2014	Approved	Commercial Operation - Power Generation in progress	-	634.8	Solar	09252412	Denny Rd Ret 2412
CHKLIST-3801	7/28/2014	Approved	Commercial Operation - Power Generation in progress	-	1,500.0	Solar	03281204	Rural Hall Ret 1204
CHKLIST-3802	7/28/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	13351201	Longview Ret 1201
CHKLIST-3803	7/28/2014	Approved	Commercial Operation - Power Generation in progress	-	248.4	Solar	14042403	Butner Ret 2403
CHKLIST-3779	7/23/2014	Approved	Commercial Operation - Power Generation in progress	-	72.0	Solar	01291210	Bellhaven Ret 1210
CHKLIST-3771	7/22/2014	Approved	Commercial Operation - Power Generation in progress	-	3,500.0	Solar	13121211	Claremont Ret 1211
CHKLIST-3773	7/22/2014	Project Not Active	Cancelled	-	4,500.0	Solar	15171203	Cleghorn SS 1203
CHKLIST-3767	7/21/2014	Approved	Commercial Operation - Power Generation in progress	-	750.0	Solar	29061207	Yadkinville Ret 1207
CHKLIST-3742	7/16/2014	Project Not Active	Withdrawn	-	3,500.0	Solar	01721202	Davidson Ret 1202
NC2016-00059	7/11/2014	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	03011208	Advance Ret 1208
CHKLIST-3724	7/9/2014	Project Not Active	Withdrawn	-	2,000.0	Solar	11181203	Pleasant Grove Ret 1203
CHKLIST-3690	6/27/2014	Approved	Commercial Operation - Power Generation in progress	-	33.9	Solar	01522402	Reames Rd Ret 2402
CHKLIST-3670	6/18/2014	Approved	Commercial Operation - Power Generation in progress	-	258.0	Solar	09092405	Friendship Ret 2405
CHKLIST-3615	6/4/2014	Project Not Active	Cancelled	-	278.4	Solar	67291201	E Andrews Ret 1201
CHKLIST-3608	6/2/2014	Approved	Commercial Operation - Power Generation in progress	-	255.0	Solar	01361204	Bancroft Ret 1204
CHKLIST-3603	5/30/2014	Pending	Pending	-	42.8	Solar	09042405	Randolph Ave Ret 2405
CHKLIST-3554	5/14/2014	Approved	Commercial Operation - Power Generation in progress	-	72.1	Solar	11172408	Frieden Ret 2408
CHKLIST-3546	5/13/2014	Approved	Commercial Operation - Power Generation in progress	-	101.2	Solar	14251202	Ellerbee Ret 1202
CHKLIST-3541	5/9/2014	Approved	Commercial Operation - Power Generation in progress	-	1,000.0	Solar	14152411	Brassfield Ret 2411
CHKLIST-3527	5/7/2014	Project Not Active	Withdrawn	-	216.0	Solar	01361204	Bancroft Ret 1204
CHKLIST-3485	4/22/2014	Approved	Commercial Operation - Power Generation in progress	-	55.2	Solar	14132410	Dacian Ave Ret 2410
CHKLIST-3460	4/11/2014	Substation A	System Impact Study - Pending	-	5,000.0	Solar	01342406	Newell Ret 2406
CHKLIST-3448	4/2/2014	Approved	Commercial Operation - Power Generation in progress	-	36.0	Solar	01252405	Arrowood Ret 2405
CHKLIST-3436	3/28/2014	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	13431201	Pinch Gut Creek Ret 1201

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-3432	3/26/2014	Approved	Commercial Operation - Power Generation in progress	-	336.0	Solar	03552401	Mocksville Main 2401
CHKLIST-3428	3/25/2014	Project Not Active	Cancelled	-	1,981.0	Solar	65171203	Edneyville Ret 1203
CHKLIST-3429	3/25/2014	Project Not Active	Cancelled	-	1,981.0	Solar	15211201	McGinnis Crossroads Ret 1201
CHKLIST-3430	3/25/2014	Project Not Active	Cancelled	-	1,981.0	Solar	72042402	Van Wyck Ret 2402
CHKLIST-3389	2/27/2014	Pending	System Impact Study - In Progress	-	5,000.0	Solar	-	-
CHKLIST-3391	2/27/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	29021202	Boonville Ret 1202
CHKLIST-3379	2/21/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	72542414	Beaver Dam Ret 2414
CHKLIST-3381	2/21/2014	Project Not Active	Cancelled	-	4,000.0	Solar	51040401	Stoneville Ret 0401
CHKLIST-3382	2/21/2014	Project Not Active	Cancelled	-	4,998.0	Solar	80862404	Elmwood Ret 2404
CHKLIST-3363	2/11/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	72582409	Ashcraft Ave Ret 2409
CHKLIST-3365	2/11/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	13081202	Hiddenite Ret 1202
CHKLIST-3353	2/4/2014	Approved	Commercial Operation - Power Generation in progress	-	27.0	Solar	03211208	Mar-Don Dr Ret 1208
CHKLIST-3345	1/31/2014	Approved	Commercial Operation - Complete pending power generation	-	5,000.0	Solar	11172408	Frieden Ret 2408
CHKLIST-3350	1/31/2014	Project Not Active	Cancelled	-	2,000.0	Solar	16201213	Lawndale Ret 1213
CHKLIST-3332	1/23/2014	Project Not Active	Withdrawn	-	5,890.0	Solar	16651203	Belwood Ret 1203
CHKLIST-3308	1/9/2014	-	Commercial Operation - Power Generation in progress	-	1,900.0	Biomass	-	Rankin Ave Ret 1205
CHKLIST-3306	1/3/2014	Approved	Commercial Operation - Power Generation in progress	-	260.0	Solar	80811202	Murdock Rd Ret 1202
CHKLIST-3301	12/30/2013	Approved	Commercial Operation - Power Generation in progress	-	3,000.0	Solar	14052412	Research Triangle Ret 2412
CHKLIST-3303	12/30/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	13151201	Pinch Gut Creek Ret 1203
CHKLIST-3285	12/23/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	72582408	Ashcraft Ave Ret 2408
CHKLIST-3257	12/6/2013	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	01512407	Provol Ret 2407
CHKLIST-3231	11/26/2013	Project Not Active	Cancelled	-	4,950.0	Solar	21361207	Locust Ret 1207
CHKLIST-3215	11/22/2013	Project Not Active	Withdrawn	-	3,500.0	Solar	29021201	Boonville Ret 1201
CHKLIST-3205	11/19/2013	Approved	Commercial Operation - Power Generation in progress	-	22.8	Solar	03211208	Mar-Don Dr Ret 1208
CHKLIST-3197	11/15/2013	Project Not Active	Cancelled	-	4,998.0	Solar	72552408	Mini Ranch Ret 2408
CHKLIST-3192	11/14/2013	Project Not Active	Cancelled	-	4,998.0	Solar	13191201	Rhodhiss Ret 1201
CHKLIST-3193	11/14/2013	Approved	Commercial Operation - Power Generation in progress	-	4,995.0	Solar	21091208	Long Ferry Ret 1208
CHKLIST-3196	11/14/2013	Project Not Active	Cancelled	-	115.0	Solar	01121212	Monroe Rd Ret 1212
CHKLIST-3183	11/12/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	72511201	Monroe Main 1201
CHKLIST-3178	11/11/2013	Pending	Pending	-	60.0	Solar	09252412	Denny Rd Ret 2412
CHKLIST-3164	11/6/2013	Approved	Commercial Operation - Power Generation in progress	-	36.0	Solar	09242411	Merritt Dr Ret 2411
CHKLIST-3156	11/4/2013	Approved	Commercial Operation - Power Generation in progress	-	63.0	Solar	44031204	Fairplains Ret 1204
CHKLIST-3157	11/4/2013	Project Not Active	Cancelled	-	4,998.0	Solar	21361206	Locust Ret 1206
CHKLIST-3105	10/18/2013	Approved	Commercial Operation - Power Generation in progress	-	170.0	Solar	01522407	Reames Rd Ret 2407
CHKLIST-3095	10/15/2013	Approved	Commercial Operation - Power Generation in progress	-	40.0	Solar	03171206	Kernersville Ret 1206
CHKLIST-3055	10/2/2013	Project Not Active	Withdrawn	-	45.0	Solar	65011204	Asheville Hwy Ret 1204
CHKLIST-3057	10/2/2013	Approved	Commercial Operation - Power Generation in progress	-	27.6	Solar	14071207	Horton Rd Ret 1207
CHKLIST-3052	10/1/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	10121210	Randleman Rd Ret 1210
CHKLIST-3030	9/27/2013	Project Not Active	Cancelled	-	4,998.0	Solar	51081201	Prestonville Ret 1201
CHKLIST-3031	9/27/2013	Approved	Commercial Operation - Power Generation in progress	-	3,000.0	Solar	29021201	Boonville Ret 1201
CHKLIST-3032	9/27/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	21121212	Majolica Rd Ret 1212
CHKLIST-3033	9/27/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	03081203	Ebert Rd Ret 1203
CHKLIST-3034	9/27/2013	Project Not Active	Cancelled	-	4,998.0	Solar	22321202	Mt Pleasant Ret 1202
CHKLIST-3035	9/27/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	79251203	Acrerock Tie 1203
CHKLIST-3036	9/27/2013	Project Not Active	Cancelled	-	4,998.0	Solar	03351206	Tysinger Rd Ret 1206
CHKLIST-3037	9/27/2013	Project Not Active	Withdrawn	-	4,998.0	Solar	72042402	Van Wyck Ret 2402
CHKLIST-3038	9/27/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	21372406	Richfield Ret 2406
CHKLIST-3039	9/27/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	80862404	Elmwood Ret 2404
CHKLIST-3040	9/27/2013	Project Not Active	Cancelled	-	4,998.0	Solar	21061210	Sumner Ret 1210
CHKLIST-3041	9/27/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	01552401	Wallace Rd Ret 2401
CHKLIST-3023	9/23/2013	Project Not Active	Cancelled	-	24.0	Solar	14021203	Ashe St Sw Sta 1203
CHKLIST-3021	9/19/2013	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	79131201	N Stanley Ret 1201
CHKLIST-3022	9/19/2013	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	16801211	Patterson Springs Ret 1211
CHKLIST-3006	9/11/2013	Project Not Active	Cancelled	-	4,998.0	Solar	21481205	China Grove Ret 1205
CHKLIST-3007	9/11/2013	Project Not Active	Withdrawn	-	4,998.0	Solar	03651202	Turnersburg Ret 1202
CHKLIST-2984	8/23/2013	Project Not Active	Cancelled	-	4,500.0	Solar	13031205	Catawba Ret 1205
CHKLIST-2985	8/23/2013	Project Not Active	Withdrawn	-	4,500.0	Solar	10121205	Randleman Rd Ret 1205
CHKLIST-2979	8/21/2013	Project Not Active	Withdrawn	-	2,000.0	Solar	90201210	Glenwood Ret 1210
CHKLIST-2968	8/15/2013	Approved	Commercial Operation - Power Generation in progress	-	225.0	Solar	01141201	N Charlotte Ret 1201
CHKLIST-2953	8/9/2013	Project Not Active	Cancelled	-	4,950.0	Solar	17141206	Williamsburg Ret 1206
CHKLIST-2954	8/9/2013	Project Not Active	Withdrawn	-	4,950.0	Solar	51061206	Madison Ret 1206
CHKLIST-2951	8/8/2013	Approved	Commercial Operation - Power Generation in progress	-	250.0	Solar	80711207	Dunbar Ret 1207
CHKLIST-2948	8/7/2013	Project Not Active	Withdrawn	-	4,950.0	Solar	51061208	Madison Ret 1208
CHKLIST-2935	7/29/2013	Approved	Commercial Operation - Power Generation in progress	-	700.0	Biomass	27091205	Meadow Green Ret 1205
CHKLIST-2931	7/26/2013	Approved	Commercial Operation - Power Generation in progress	-	750.0	Solar	09252404	Denny Rd Ret 2404
CHKLIST-2927	7/25/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	16271202	Flay Ret 1202
CHKLIST-2904	7/17/2013	Project Not Active	Cancelled	-	5,000.0	Solar	21112402	Linwood SS 2402
CHKLIST-2905	7/17/2013	Project Not Active	Cancelled	-	3,500.0	Solar	13121211	Claremont Ret 1211
CHKLIST-2906	7/17/2013	Project Not Active	Withdrawn	Not Applicable	4,000.0	Solar	27111211	Ridgeview Ret 1211
CHKLIST-2907	7/17/2013	Approved	Commercial Operation - Power Generation in progress	-	3,000.0	Solar	11261204	Oakwood St Ret 1204
CHKLIST-2908	7/17/2013	Approved	Commercial Operation - Power Generation in progress	-	2,000.0	Solar	16861202	Christopher Rd Ret 1202
CHKLIST-2909	7/17/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	17121202	Monroeton Ret 1202
CHKLIST-2910	7/17/2013	Project Not Active	Cancelled	-	5,000.0	Solar	16861201	Christopher Rd Ret 1201
CHKLIST-2891	7/3/2013	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	29041201	Cycle Ret 1201
CHKLIST-2885	7/1/2013	Approved	Commercial Operation - Power Generation in progress	-	5,200.0	Biomass	01361203	Bancroft Ret 1203
CHKLIST-2868	6/20/2013	Approved	Commercial Operation - Power Generation in progress	-	4,875.0	Solar	16801212	Patterson Springs Ret 1212
CHKLIST-2859	6/14/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	09111201	Kimesville Ret 1201
CHKLIST-2856	6/13/2013	Approved	Commercial Operation - Power Generation in progress	-	1,890.0	Solar	79361203	Crowders Creek Ret 1203
CHKLIST-2857	6/13/2013	Approved	Commercial Operation - Power Generation in progress	-	1,990.0	Solar	16301201	S Shelby SS 1201

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-2847	6/8/2013	Approved	Commercial Operation - Power Generation in progress	-	400.0	Biomass	65121205	Mills River Ret 1205
CHKLIST-2841	6/6/2013	Project Not Active	Cancelled	-	21.1	Solar	67131204	Depot St Ret 1204
CHKLIST-2842	6/6/2013	Project Not Active	Withdrawn	-	3,000.0	Solar	11261204	Oakwood St Ret 1204
CHKLIST-2844	6/6/2013	Project Not Active	Withdrawn	-	500.0	Solar	13121211	Claremont Ret 1211
CHKLIST-2831	5/30/2013	Approved	Commercial Operation - Power Generation in progress	-	1,990.0	Solar	16701203	Blanton Ret 1203
CHKLIST-2822	5/28/2013	Project Not Active	Cancelled	-	4,500.0	Solar	09082410	Kildare Ret 2410
CHKLIST-2823	5/28/2013	Project Not Active	Cancelled	-	4,500.0	Solar	21112402	Linwood SS 2402
CHKLIST-2824	5/28/2013	Project Not Active	Cancelled	-	4,500.0	Solar	80821208	Triplett Ret 1208
CHKLIST-2825	5/28/2013	Project Not Active	Withdrawn	-	4,500.0	Solar	03231210	N Winston Ret 1210
CHKLIST-2826	5/28/2013	Approved	Commercial Operation - Power Generation in progress	-	4,500.0	Solar	13191201	Rhodhiss Ret 1201
CHKLIST-2827	5/28/2013	Approved	Commercial Operation - Power Generation in progress	-	4,500.0	Solar	11241201	Efland Ret 1201
CHKLIST-2814	5/22/2013	Approved	Commercial Operation - Power Generation in progress	-	35.0	Solar	01241212	Woodlawn Tie 1212
CHKLIST-2803	5/20/2013	Project Not Active	Cancelled	-	3,000.0	Solar	51601205	Ogburn Dist 1205
CHKLIST-2804	5/20/2013	Project Not Active	Withdrawn	-	4,000.0	Solar	13121211	Claremont Ret 1211
CHKLIST-2805	5/20/2013	Project Not Active	Cancelled	-	5,000.0	Solar	27091205	Meadow Green Ret 1205
CHKLIST-2806	5/20/2013	Project Not Active	Cancelled	-	5,000.0	Solar	15171203	Cleghorn SS 1203
CHKLIST-2807	5/20/2013	Project Not Active	Withdrawn	-	4,000.0	Solar	11261206	Oakwood St Ret 1206
CHKLIST-2808	5/20/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	17011210	Reidsville Ret 1210
CHKLIST-2809	5/20/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	13431203	Pinch Gut Creek Ret 1203
CHKLIST-2801	5/17/2013	Approved	Commercial Operation - Power Generation in progress	-	2,000.0	Solar	21081203	Cleveland Ret 1203
CHKLIST-2787	5/14/2013	Project Not Active	Cancelled	-	2,500.0	Solar	16901205	Mooresboro Ret 1205
CHKLIST-2788	5/14/2013	Approved	Commercial Operation - Power Generation in progress	-	2,500.0	Solar	16061207	Bethware Ret 1207
CHKLIST-2789	5/14/2013	Project Not Active	Cancelled	-	2,500.0	Solar	16651203	Belwood Ret 1203
CHKLIST-2790	5/14/2013	Project Not Active	Cancelled	-	2,500.0	Solar	16861202	Christopher Rd Ret 1202
CHKLIST-2791	5/14/2013	Approved	Commercial Operation - Power Generation in progress	-	2,000.0	Solar	13351202	Longview Ret 1202
CHKLIST-2784	5/13/2013	Project Not Active	Cancelled	-	2,500.0	Solar	15241203	Riverstone Ret 1203
CHKLIST-2785	5/13/2013	Pending	Pending	-	1,589.3	Solar	65021201	Big Willow Ret 1201
CHKLIST-2780	5/9/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	13381201	Old Mtn Rd Ret 1201
CHKLIST-2781	5/9/2013	Project Not Active	Withdrawn	-	2,500.0	Solar	15951203	Washburn Ret 1203
CHKLIST-2764	5/2/2013	Project Not Active	Cancelled	-	2,714.0	Solar	67083403	Nantahala Hydro 3403
CHKLIST-2439	4/3/2013	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	01241212	Woodlawn Tie 1212
CHKLIST-2419	3/20/2013	Approved	Commercial Operation - Power Generation in progress	-	600.0	Solar	65121205	Mills River Ret 1205
CHKLIST-2420	3/20/2013	Project Not Active	Cancelled	-	4,500.0	Solar	17121201	Monroeton Ret 1201
CHKLIST-2406	3/19/2013	Project Not Active	Cancelled	-	2,000.0	Solar	13101203	Startown Ret 1203
CHKLIST-2407	3/19/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	21061210	Sumner Ret 1210
CHKLIST-2408	3/19/2013	Project Not Active	Withdrawn	-	4,000.0	Solar	03372402	Walnut Cove Tie 2402
CHKLIST-2409	3/19/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	17141205	Williamsburg Ret 1205
CHKLIST-2410	3/19/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	17141206	Williamsburg Ret 1206
CHKLIST-2411	3/19/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	17141205	Williamsburg Ret 1205
CHKLIST-2415	3/19/2013	Project Not Active	Withdrawn	-	4,950.0	Solar	11261205	Oakwood St Ret 1205
CHKLIST-2418	3/19/2013	Project Not Active	Withdrawn	-	4,500.0	Solar	51601205	Ogburn Dist 1205
CHKLIST-2399	3/18/2013	Project Not Active	Withdrawn	-	4,000.0	Solar	17141205	Williamsburg Ret 1205
CHKLIST-2400	3/18/2013	Project Not Active	Withdrawn	-	4,000.0	Solar	14102401	Eno Ret 2401
CHKLIST-2401	3/18/2013	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	60351202	Grassy Pond Ret 1202
CHKLIST-2402	3/18/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	13151201	Mt Olive Ret 1201
CHKLIST-2403	3/18/2013	Project Not Active	Withdrawn	-	2,000.0	Solar	13431201	Pinch Gut Creek Ret 1201
CHKLIST-2404	3/18/2013	Project Not Active	Cancelled	-	5,000.0	Solar	17011210	Reidsville Ret 1210
CHKLIST-2382	2/26/2013	Project Not Active	Cancelled	-	2,500.0	Solar	15171203	Cleghorn SS 1203
CHKLIST-2384	2/26/2013	Approved	Commercial Operation - Power Generation in progress	-	1,989.0	Solar	15951203	Washburn Ret 1203
CHKLIST-2385	2/26/2013	Project Not Active	Cancelled	-	2,500.0	Solar	15211201	McGinnis Crossroads Ret 1201
CHKLIST-2386	2/26/2013	Approved	Commercial Operation - Power Generation in progress	-	1,981.0	Solar	65171204	Edneyville Ret 1204
CHKLIST-2387	2/26/2013	Project Not Active	Cancelled	-	2,500.0	Solar	15211201	McGinnis Crossroads Ret 1201
CHKLIST-1025	2/21/2013	Approved	Commercial Operation - Power Generation in progress	-	790.0	Solar	01271206	Mallard Creek Ret 1206
CHKLIST-2363	2/11/2013	Project Not Active	Withdrawn	-	4,950.0	Solar	29061205	Yadkinville Ret 1205
CHKLIST-2364	2/11/2013	Project Not Active	Withdrawn	-	4,500.0	Solar	29081201	Smithtown Ret 1201
CHKLIST-2365	2/11/2013	Project Not Active	Withdrawn	-	4,500.0	Solar	17131203	Gatewood Ret 1203
CHKLIST-2366	2/11/2013	Project Not Active	Withdrawn	-	4,500.0	Solar	09262403	Rudd Ret 2403
CHKLIST-2367	2/11/2013	Project Not Active	Withdrawn	-	4,500.0	Solar	79041204	North Lincoln Ret 1204
CHKLIST-2347	2/5/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	27091205	Meadow Green Ret 1205
CHKLIST-2348	2/5/2013	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	03372401	Walnut Cove Tie 2401
CHKLIST-2349	2/5/2013	Project Not Active	Withdrawn	-	4,000.0	Solar	15241202	Riverstone Ret 1202
CHKLIST-2350	2/5/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	16701202	Blanton Ret 1202
CHKLIST-2351	2/5/2013	Project Not Active	Cancelled	-	5,000.0	Solar	17191202	Waynick Rd Ret 1202
CHKLIST-2352	2/5/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	16651202	Belwood Ret 1202
CHKLIST-2353	2/5/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	13181206	Oyama Ret 1206
CHKLIST-2354	2/5/2013	Project Not Active	Cancelled	-	4,000.0	Solar	17191201	Waynick Rd Ret 1201
CHKLIST-2355	2/5/2013	Project Not Active	Cancelled	-	5,000.0	Solar	11172405	Frieden Ret 2405
CHKLIST-2356	2/5/2013	Project Not Active	Withdrawn	-	3,000.0	Solar	22321201	Mt Pleasant Ret 1201
CHKLIST-2357	2/5/2013	Project Not Active	Withdrawn	-	2,000.0	Solar	13341201	Catfish Ret 1201
CHKLIST-2358	2/5/2013	Project Not Active	Cancelled	-	5,000.0	Solar	09262403	Rudd Ret 2403
CHKLIST-2329	1/21/2013	Project Not Active	Cancelled	-	1,000.0	Solar	09252404	Denny Rd Ret 2404
CHKLIST-2319	1/16/2013	Approved	Commercial Operation - Power Generation in progress	-	1,600.0	Biomass	79291205	Rankin Ave Ret 1205
CHKLIST-2320	1/16/2013	Project Not Active	Cancelled	-	4,500.0	Solar	13341201	Catfish Ret 1201
CHKLIST-2321	1/16/2013	Project Not Active	Cancelled	-	4,500.0	Solar	79221202	Webbs Chapel Ret 1202
CHKLIST-2307	1/11/2013	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	21401211	Rockwell Ret 1211
CHKLIST-2308	1/11/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	15151203	Avondale Ret 1203
CHKLIST-2309	1/11/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	15261206	Hudlow Ret 1206
CHKLIST-2310	1/11/2013	Project Not Active	Cancelled	-	5,000.0	Solar	15171203	Cleghorn SS 1203
CHKLIST-2311	1/11/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	13341204	Catfish Ret 1204

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-2312	1/11/2013	Project Not Active	Withdrawn	-	3,000.0	Solar	15241202	Riverstone Ret 1202
CHKLIST-2313	1/11/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	14142410	Fairntosh Ret 2410
CHKLIST-2248	12/4/2012	Approved	Commercial Operation - Power Generation in progress	-	3,000.0	Solar	15171203	Cleghorn SS 1203
CHKLIST-2249	12/4/2012	Project Not Active	Withdrawn	-	3,000.0	Solar	14042410	Butner Ret 2410
CHKLIST-2250	12/4/2012	Project Not Active	Withdrawn	-	4,000.0	Solar	13121212	Claremont Ret 1212
CHKLIST-2224	11/21/2012	Project Not Active	Cancelled	-	5,000.0	Solar	17191201	Waynick Rd Ret 1201
CHKLIST-2222	11/20/2012	Project Not Active	Withdrawn	-	4,950.0	Solar	17121202	Monroeton Ret 1202
CHKLIST-2217	11/19/2012	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	17011202	Reidsville Ret 1202
CHKLIST-2218	11/19/2012	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	13101203	Startown Ret 1203
CHKLIST-2210	11/14/2012	Approved	Commercial Operation - Power Generation in progress	-	95.0	Solar	65201205	Naples Ret 1205
CHKLIST-2198	11/5/2012	Approved	Commercial Operation - Power Generation in progress	-	108.0	Solar	09032404	Fairfax Rd Ret 2404
CHKLIST-2199	11/5/2012	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	11042410	Glen Raven Main 2410
CHKLIST-2186	11/1/2012	Approved	Commercial Operation - Power Generation in progress	-	52.0	Solar	10172412	Millis Ret 2412
CHKLIST-2177	10/29/2012	Approved	Commercial Operation - Power Generation in progress	-	1,500.0	Solar	80731201	Deerfield Ret 1201
CHKLIST-2161	10/23/2012	Approved	Commercial Operation - Power Generation in progress	-	3,000.0	Solar	16701204	Blanton Ret 1204
CHKLIST-2162	10/23/2012	Project Not Active	Cancelled	-	5,000.0	Solar	16901204	Mooresboro Ret 1204
CHKLIST-2163	10/23/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	11071203	Haw River Ret 1203
CHKLIST-2164	10/23/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	11151201	Saxapahaw Ret 1201
CHKLIST-1131	10/15/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	03552402	Mocksville Main 2402
CHKLIST-1132	10/15/2012	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	21311208	Oakboro Ret 1208
CHKLIST-1126	10/12/2012	Approved	Commercial Operation - Power Generation in progress	-	3,500.0	Solar	79361203	Crowders Creek Ret 1203
CHKLIST-1114	10/8/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	16901204	Mooresboro Ret 1204
CHKLIST-1115	10/8/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	15171203	Cleghorn SS 1203
CHKLIST-1116	10/8/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	13261202	Zion Church Rd Ret 1202
CHKLIST-1117	10/8/2012	Project Not Active	Cancelled	-	3,000.0	Solar	15151202	Avondale Ret 1202
CHKLIST-1097	10/4/2012	Approved	Commercial Operation - Power Generation in progress	-	82.0	Solar	21011209	Salisbury Main 1209
CHKLIST-1107	10/4/2012	Approved	Commercial Operation - Power Generation in progress	-	3,480.0	Solar	21431207	Faith Ret 1207
CHKLIST-1090	10/1/2012	Project Not Active	Cancelled	-	1,000.0	Solar	03241208	Oak Ridge Ret 1208
CHKLIST-1086	9/28/2012	Project Not Active	Cancelled	-	2,800.0	Biomass	79291210	Rankin Ave Ret 1210
CHKLIST-1072	9/25/2012	Project Not Active	Cancelled	-	95.0	Solar	65201206	Naples Ret 1206
CHKLIST-1074	9/25/2012	Project Not Active	Withdrawn	-	3,670.0	Solar	15241203	Riverstone Ret 1203
CHKLIST-0967	9/19/2012	Project Not Active	Cancelled	-	1,475.0	Biomass	01241206	Woodlawn Tie 1206
CHKLIST-1050	9/12/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	11191202	Swepsonville Tie 1202
CHKLIST-1051	9/12/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	09111201	Kimesville Ret 1201
CHKLIST-1052	9/12/2012	Approved	Commercial Operation - Power Generation in progress	-	4,500.0	Solar	16901204	Mooresboro Ret 1204
CHKLIST-1043	9/5/2012	Approved	Commercial Operation - Power Generation in progress	-	1,996.4	Solar	65171204	Edneyville Ret 1204
CHKLIST-1012	8/14/2012	Approved	Commercial Operation - Power Generation in progress	-	260.8	Solar	01241210	Woodlawn Tie 1210
CHKLIST-1007	8/9/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	60351202	Grassy Pond Ret 1202
CHKLIST-1003	8/7/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	16071212	Parkway SS 1212
CHKLIST-0983	7/23/2012	Approved	Commercial Operation - Power Generation in progress	-	3,000.0	Solar	11151201	Saxapahaw Ret 1201
CHKLIST-0984	7/23/2012	Approved	Commercial Operation - Power Generation in progress	-	3,000.0	Solar	11181203	Pleasant Grove Ret 1203
CHKLIST-0985	7/23/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	16901204	Mooresboro Ret 1204
CHKLIST-0955	6/27/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	09061203	Climax Ret 1203
CHKLIST-0956	6/27/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	09411208	Tabernacle Church Ret 1208
CHKLIST-0957	6/27/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	11031201	Gibsonville Dist 1201
CHKLIST-0944	6/22/2012	Approved	Construction - Pending IA/Customer Payment	-	1,996.4	Solar	15241202	Riverstone Ret 1202
CHKLIST-0945	6/22/2012	Project Not Active	Withdrawn	-	1,996.4	Solar	15241203	Riverstone Ret 1203
CHKLIST-0946	6/22/2012	Project Not Active	Withdrawn	-	1,996.4	Solar	15901202	Mooresboro Ret 1202
CHKLIST-0947	6/22/2012	Approved	Commercial Operation - Power Generation in progress	-	1,996.4	Solar	15901202	Mooresboro Ret 1202
CHKLIST-0948	6/22/2012	Project Not Active	Withdrawn	-	1,996.4	Solar	15951203	Washburn Ret 1203
CHKLIST-0949	6/22/2012	Project Not Active	Withdrawn	-	1,996.4	Solar	15211201	McGinnis Crossroads Ret 1201
CHKLIST-0922	6/12/2012	Approved	Commercial Operation - Power Generation in progress	-	52.5	Solar	01281205	Kenilworth Ret 1205
CHKLIST-0918	6/8/2012	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	17191202	Waynick Rd Ret 1202
CHKLIST-0910	6/5/2012	Approved	Commercial Operation - Power Generation in progress	-	112.0	Solar	14192410	Ellis Rd Ret 2410
CHKLIST-0904	6/4/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	16271202	Flay Ret 1202
CHKLIST-0894	5/29/2012	Approved	Commercial Operation - Power Generation in progress	-	40.9	Solar	11172408	Frieden Ret 2408
CHKLIST-10869	5/11/2012	Approved	Commercial Operation - Power Generation in progress	-	600.0	Hydroelectric	16911201	Stice Shoals Tie 1201
CHKLIST-0871	5/7/2012	Project Not Active	Withdrawn	-	1,996.4	Solar	65171203	Edneyville Ret 1203
CHKLIST-0872	5/7/2012	Project Not Active	Cancelled	-	1,500.0	Solar	65171202	Edneyville Ret 1202
CHKLIST-0873	5/7/2012	Project Not Active	Withdrawn	-	1,996.4	Solar	65171202	Edneyville Ret 1202
CHKLIST-0858	5/2/2012	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	11172405	Frieden Ret 2405
CHKLIST-0859	5/2/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	09791202	Pleasant Garden Ret 1202
CHKLIST-0854	5/1/2012	Approved	Commercial Operation - Power Generation in progress	-	3,000.0	Solar	11172406	Frieden Ret 2406
CHKLIST-0856	5/1/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	09052404	Vandalia Ret 2404
CHKLIST-0857	5/1/2012	Project Not Active	Withdrawn	-	4,000.0	Solar	09411208	Tabernacle Church Ret 1208
CHKLIST-0844	4/26/2012	Project Not Active	Withdrawn	-	135.0	Solar	01141201	N Charlotte Ret 1201
CHKLIST-0845	4/26/2012	Project Not Active	Withdrawn	-	500.0	Solar	01061205	Hickory Grove Ret 1205
CHKLIST-0835	4/20/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	11161203	Kimesville Ret 1203
CHKLIST-0833	4/19/2012	Approved	Commercial Operation - Power Generation in progress	-	135.0	Solar	16071209	Parkway SS 1209
CHKLIST-0832	4/18/2012	Project Not Active	Withdrawn	-	3,200.0	Biomass	22281201	Speedway Ret 1201
CHKLIST-0776	4/17/2012	Approved	Commercial Operation - Pending	-	33.0	Wind	14011207	Durham Main 1207
CHKLIST-0830	4/16/2012	Project Not Active	Withdrawn	-	2,000.0	Solar	09061204	Climax Ret 1204
CHKLIST-0823	4/10/2012	Project Not Active	Cancelled	-	70.0	Biomass	15121203	Oakland Rd Ret 1203
CHKLIST-0815	4/3/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	13261201	Zion Church Rd Ret 1201
CHKLIST-0816	4/3/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	17021203	Ruffin Ret 1203
CHKLIST-0817	4/3/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	79041204	North Lincoln Ret 1204
CHKLIST-0818	4/3/2012	Approved	Commercial Operation - Power Generation in progress	-	100.0	Solar	01492406	Coffey Creek Ret 2406
CHKLIST-0803	3/28/2012	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	72542413	Beaver Dam Ret 2413
CHKLIST-0797	3/20/2012	Project Not Active	Cancelled	-	1,500.0	Solar	15241203	Riverstone Ret 1203

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-0788	3/12/2012	Approved	Commercial Operation - Power Generation in progress	-	20.4	Solar	11172408	Frieden Ret 2408
CHKLIST-0782	3/6/2012	Approved	Commercial Operation - Power Generation in progress	-	800.0	Biomass	51061204	Madison Ret 1204
CHKLIST-0768	2/28/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	16801211	Patterson Springs Ret 1211
CHKLIST-0769	2/28/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	16271202	Flay Ret 1202
CHKLIST-0759	2/13/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	19051202	White Cross Ret 1202
CHKLIST-0746	2/7/2012	Approved	Commercial Operation - Power Generation in progress	-	3,500.0	Solar	28061204	Bannertown Tie 1204
CHKLIST-0738	1/24/2012	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	16521201	Waco Ret 1201
CHKLIST-0739	1/24/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	03552402	Mocksville Main 2402
CHKLIST-0711	12/20/2011	Substation A	Fast Track Study - Study Complete	Fast Track Study	100.0	Solar	09042406	Randolph Ave Ret 2406
CHKLIST-0712	12/20/2011	Project Not Active	Withdrawn	-	45.0	Solar	09252412	Denny Rd Ret 2412
CHKLIST-0713	12/20/2011	Pending	Pending	-	150.0	Solar	09252412	Denny Rd Ret 2412
CHKLIST-0703	12/8/2011	Project Not Active	Withdrawn	-	4,800.0	Biomass	22261202	Roberta Rd Ret 1202
CHKLIST-0695	11/28/2011	Approved	Commercial Operation - Power Generation in progress	-	70.0	Biomass	44061213	Browns Ford Ret 1213
CHKLIST-0682	11/18/2011	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	14011207	Durham Main 1207
CHKLIST-0672	11/17/2011	Project Not Active	Cancelled	-	90.0	Solar	17011206	Reidsville Ret 1206
CHKLIST-0673	11/17/2011	Approved	Commercial Operation - Power Generation in progress	-	50.0	Solar	09042405	Randolph Ave Ret 2405
CHKLIST-0654	11/10/2011	Approved	Commercial Operation - Power Generation in progress	-	24.0	Solar	13071202	Glen Alpine Ret 1202
CHKLIST-0655	11/10/2011	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	16651202	Belwood Ret 1202
CHKLIST-0643	11/7/2011	Approved	Commercial Operation - Power Generation in progress	-	72.0	Solar	09262403	Rudd Ret 2403
CHKLIST-0645	11/7/2011	Approved	Commercial Operation - Power Generation in progress	-	94.1	Solar	01721201	Davidson Ret 1201
CHKLIST-0624	10/28/2011	Project Not Active	Cancelled	-	75.0	Solar	79031212	Lincolnton Tie 1212
CHKLIST-0626	10/28/2011	Approved	Commercial Operation - Power Generation in progress	-	175.0	Solar	09502412	Colfax Ret 2412
CHKLIST-0605	10/26/2011	Project Not Active	Cancelled	-	100.0	Solar	09052404	Vandalia Ret 2404
CHKLIST-0606	10/17/2011	Approved	Commercial Operation - Power Generation in progress	-	1,500.0	Solar	10251204	Fair Grove Ret 1204
CHKLIST-0604	10/13/2011	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	13341201	Catfish Ret 1201
CHKLIST-0593	10/7/2011	Approved	Commercial Operation - Power Generation in progress	-	83.7	Solar	10151210	E Thomasville Ret 1210
CHKLIST-0571	9/15/2011	Approved	Commercial Operation - Power Generation in progress	-	1,600.0	Biomass	28061207	Bannertown Tie 1207
CHKLIST-0548	8/22/2011	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	09032407	Fairfax Rd Ret 2407
CHKLIST-0526	8/9/2011	Project Not Active	Cancelled	-	21.0	Solar	80731202	Deerfield Ret 1202
CHKLIST-0519	8/2/2011	Approved	Commercial Operation - Power Generation in progress	-	1,059.0	Biomass	19061204	Homestead Ret 1204
CHKLIST-0434	6/1/2011	Approved	Commercial Operation - Power Generation in progress	-	28.8	Solar	10042412	Linden St Sw Sta 2412
CHKLIST-0395	5/10/2011	Project Not Active	Cancelled	-	1,900.0	Solar	90201210	Glenwood Ret 1210
CHKLIST-0379	4/28/2011	Approved	Commercial Operation - Power Generation in progress	-	169.0	Solar	17010402	Reidsville Ret 0402
CHKLIST-0382	4/26/2011	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	16071209	Parkway SS 1209
CHKLIST-0401	4/19/2011	Approved	Commercial Operation - Power Generation in progress	-	4,500.0	Solar	22191202	Easy St Ret 1202
CHKLIST-0375	4/4/2011	Project Not Active	Cancelled	-	300.0	-	13261201	Zion Church Rd Ret 1201
CHKLIST-0393	3/23/2011	Approved	Commercial Operation - Power Generation in progress	-	49.0	Solar	01061214	Hickory Grove Ret 1214
CHKLIST-0396	3/23/2011	Approved	Commercial Operation - Power Generation in progress	-	135.0	Solar	13181206	Oyama Ret 1206
CHKLIST-0400	3/23/2011	Approved	Commercial Operation - Power Generation in progress	-	27.4	Solar	01071205	Lakewood Ret 1205
CHKLIST-0182	3/9/2011	Approved	Commercial Operation - Power Generation in progress	-	100.0	Solar	14162411	Imperial Ret 2411
CHKLIST-0399	2/25/2011	Approved	Commercial Operation - Power Generation in progress	-	221.8	Solar	11082413	Trollingwood Ret 2413
CHKLIST-0394	2/8/2011	Approved	Commercial Operation - Power Generation in progress	-	60.0	Solar	80711206	Dunbar Ret 1206
CHKLIST-0072	11/22/2010	Approved	Commercial Operation - Power Generation in progress	-	101.2	Solar	14251202	Ellerbee Ret 1202
CHKLIST-0003	10/26/2010	Approved	Commercial Operation - Power Generation in progress	-	1,000.0	Solar	28061207	Bannertown Tie 1207
CHKLIST-0186	10/19/2010	Approved	Commercial Operation - Power Generation in progress	-	200.0	Solar	14192406	Ellis Rd Ret 2406
CHKLIST-0047	10/4/2010	Project Not Active	Cancelled	-	2,000.0	Solar	01332411	Wilgrove Ret 2411
CHKLIST-0049	10/4/2010	Project Not Active	Cancelled	-	1,000.0	Solar	01342407	Newell Ret 2407
CHKLIST-0075	7/20/2010	Approved	Commercial Operation - Power Generation in progress	-	28.0	Solar	14192410	Ellis Rd Ret 2410
CHKLIST-0180	7/9/2010	Approved	Commercial Operation - Power Generation in progress	-	250.0	Solar	01351210	Little Rock Ret 1210
CHKLIST-0184	5/21/2010	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	11252408	St Marks Ret 2408
CHKLIST-0290	4/9/2010	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	01492405	Coffey Creek Ret 2405
CHKLIST-0200	11/23/2009	Approved	Commercial Operation - Power Generation in progress	-	1,600.0	Biomass	10161206	Holly Hill Ret 1206
CHKLIST-0208	11/12/2009	Approved	Commercial Operation - Power Generation in progress	-	135.0	Solar	14182402	Treyburn Ret 2402
CHKLIST-0169	10/22/2009	Approved	Commercial Operation - Power Generation in progress	-	150.0	Solar	21010405	Salisbury Main 0405
CHKLIST-0240	10/19/2009	Approved	Commercial Operation - Power Generation in progress	-	440.0	Hydroelectric	11091201	Hopedale Dist 1201
CHKLIST-0039	9/28/2009	Approved	Commercial Operation - Power Generation in progress	-	24.0	Solar	09082406	Kildare Ret 2406
CHKLIST-0161	9/15/2009	Approved	Commercial Operation - Power Generation in progress	-	27.5	Solar	01041207	Elizabeth Ave Ret 1207
CHKLIST-0035	9/10/2009	Approved	Commercial Operation - Power Generation in progress	-	35.5	Solar	09042407	Randolph Ave Ret 2407
CHKLIST-0210	4/20/2009	Approved	Commercial Operation - Power Generation in progress	-	11,500.0	Biomass	22281202	Speedway Ret 1202
CHKLIST-0212	4/20/2009	Approved	Commercial Operation - Power Generation in progress	-	5,300.0	Biomass	22281202	Speedway Ret 1202
CHKLIST-0033	3/5/2009	Approved	Commercial Operation - Power Generation in progress	-	21.4	Solar	09102406	Summerfield Ret 2406
CHKLIST-0252	8/25/2008	Approved	Commercial Operation - Power Generation in progress	-	51.0	Solar	14192410	Ellis Rd Ret 2410
CHKLIST-0128	8/11/2008	Approved	Commercial Operation - Power Generation in progress	-	2,400.0	Biomass	03111201	Goodwill Church Rd Ret 1201
CHKLIST-0193	12/17/2007	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	01212406	Morning Star Tie 2406
CHKLIST-0198	9/29/2006	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	14162411	Imperial Ret 2411
CHKLIST-0187	1/1/1900	Project Not Active	Cancelled	-	1,000.0	Biomass	19061204	Homestead Ret 1204
CHKLIST-3048	1/1/1900	Project Not Active	Cancelled	-	1,238.0	Solar	09252411	Denny Rd Ret 2411
CHKLIST-3692	1/1/1900	Project Not Active	Withdrawn	-	4,950.0	Solar	11181202	Pleasant Grove Ret 1202
-	1/1/1900	-	Cancelled	-	30.8	Solar	01212406	-
-	1/1/1900	-	Withdrawn	-	36.3	Solar	01222411	Piper Glen Ret
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	240.0	Hydroelectric	11172405	Frieden Ret 2405
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	325.0	Hydroelectric	15151202	Avondale Ret 1202
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	365.0	Hydroelectric	13411202	Macedonia Ret 1202
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	500.0	Hydroelectric	27100402	Leaksville Ret 0402
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	750.0	Hydroelectric	79091201	High Shoals Ret 1201
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	820.0	Hydroelectric	79051201	Harden Ret 1201
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	951.0	Hydroelectric	51061205	Madison Ret 1205
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	1,275.0	Hydroelectric	51050401	Mayodan Ret 0401
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	1,500.0	Hydroelectric	03552402	Mocksville Main 2402

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	1,500.0	Hydroelectric	11151201	Saxapahaw Ret 1201
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	1,600.0	Hydroelectric	15151202	Avondale Ret 1202
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	1,800.0	Hydroelectric	79091201	High Shoals Ret 1201
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	3,180.0	Biomass	14091206	Oxford Rd Ret 1206
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	3,600.0	Hydroelectric	15201203	Lake Lure Ret 1203
-	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Biomass	13261201	Zion Church Rd Ret 1201
-	1/1/1900	Cancelled	Cancelled	-	10,000.0	Solar	-	-
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	40.5	Solar	-	-
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	46.1	Solar	01482405	Steele Creek Ret 2405
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	60.2	Solar	79121204	McAdenville Jct Tie 1204
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	70.6	Solar	65011210	Asheville Hwy Ret 1210
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	93.1	Solar	14162403	Imperial Ret 2403
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	95.8	Solar	01291210	Bellhaven Ret 1210
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	136.9	Solar	79221201	Webbs Chapel Ret 1201
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	153.3	Solar	19031206	James St Ret 1206
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	228.7	Solar	09502410	Colfax Ret 2410
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	260.0	Solar	03432407	Willard Rd Ret 2407
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	304.3	Solar	21081203	Cleveland Ret 1203
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	330.3	Solar	10042405	Linden St Sw Sta 2405
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	448.9	Solar	01492408	Coffey Creek Ret 2408
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	452.2	Solar	01321206	Sunset Ret 1206
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	871.3	Solar	80831202	Marshall Ret 1202
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	925.1	Solar	21121210	Majolica Rd Ret 1210
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	1,009.0	Solar	79291208	Rankin Ave Ret 1208
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	1,042.0	Solar	09502410	Colfax Ret 2410
-	1/1/1900	-	Commercial Operation - Complete pending power generation	-	1,847.5	Solar	01421206	Kudzu Ret 1206
-	1/1/1900	-	IR Review - In Progress	-	22.8	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	23.0	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	28.0	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	30.0	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	36.0	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	36.0	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	43.2	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	50.0	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	60.0	-	-	-
-	1/1/1900	-	IR Review - Pending	-	36.0	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	25.5	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	26.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	28.8	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	28.8	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	28.8	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	28.8	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	33.3	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	33.3	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	34.5	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	40.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	40.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	48.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	52.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	52.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	52.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	61.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	61.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	61.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	61.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	66.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	66.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	66.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	66.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	66.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	66.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	72.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	72.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	72.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	72.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	72.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	72.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	73.3	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	75.6	Solar	-	-

Duke Energy Carolinas, LLC
Duke Energy Progress, LLC

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
-	1/1/1900	-	IR Review - Pending Customer Response	-	95.4	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	100.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	100.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	100.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	110.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	115.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	201.3	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	299.7	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	323.0	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	496.0	Solar	-	-
-	1/1/1900	Project Not Active	Cancelled	-	26.0	-	-	-
-	1/1/1900	Project Not Active	Cancelled	-	1,000.0	Diesel	03141215	Hawthorne Rd Ret 1215
-	1/1/1900	Project Not Active	Cancelled	-	1,990.0	Solar	11082410	Trollingwood Ret 2410
-	1/1/1900	Project Not Active	Withdrawn	-	23.4	Solar	11181203	Pleasant Grove Ret 1203
-	1/1/1900	Project Not Active	Withdrawn	-	100.0	Solar	14162411	Imperial Ret 2411
-	1/1/1900	Project Not Active	Withdrawn	-	230.0	Solar	22191201	Easy St. Ret
-	1/1/1900	Project Not Active	Withdrawn	-	3,500.0	Solar	79091201	High Shoals Ret 1201

Disclaimer: Please note this queue report is updated twice a month. Information is accurate as of the date listed in the title of this report. Please contact DERContracts@duke-energy.com if you have questions about the status of your project.

DUKE ENERGY.

Duke Energy Progress NC Interconnection Queue Snapshot for December 2018 as of 12/27/2018

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
2018-11-06 09:23:00	11/7/2018	Substation A	Construction - Under Construction / In Progress	-	23.4	Solar	T4600B01	CARY 230KV
NC2018-03191	10/16/2018	Substation A	Construction - Pending Customer Obligation	-	34.5	Solar	T0371B02	BEAVERDAM 115KV
NC2018-03190	10/15/2018	Substation B	Supplemental Study - Pending Customer Response	Supplemental Study	50.0	Solar	T4595B01	CARALEIGH 230KV
CPRE	10/9/2018	-	CPRE Tranche 1 Position	-	-	-	-	-
NC2018-03184	9/28/2018	Substation A	Commercial Operation - Power Generation in progress	-	22.9	Solar	T0745B12	REYNOLDS 115kV
NC2018-03181	9/17/2018	Substation A	Supplemental Study - Study Complete	Supplemental Study	23.0	Solar	T4603B11	GREEN LEVEL 230KV
NC2018-03182	9/17/2018	Substation B	Supplemental Study - Pending Customer Response	Supplemental Study	21.4	Solar	T4603B11	GREEN LEVEL 230KV
NC2018-03180	9/15/2018	Substation A	Supplemental Study - Study Complete	Supplemental Study	86.6	Solar	T5126B13	RALEIGH YONKERS ROAD 115KV
INT-2018-04069	9/12/2018	-	Commercial Operation - Power Generation in Progress	-	21.1	Solar	T0750B11	Oteen 115kV
NC2018-03178	9/12/2018	Substation A	Construction - Pending Customer Obligation	-	67.6	Solar	T5131B01	RALEIGH NORTHSIDE 115KV
NC2018-03177	9/11/2018	Substation A	System Impact Study - In Progress	Voltage Flicker Mitigation Options	5,000.0	Solar	T4610B12	CARY TRENTON ROAD 230KV
NC2018-03172	9/5/2018	Substation A	Supplemental Study - Pending Customer Response	Supplemental Study	40.0	Solar	T4240B01	MOREHEAD 115KV
NC2018-03171	8/31/2018	Substation A	Construction - Pending Customer Obligation	-	96.0	Solar	T0870B02	WEAVERVILLE 115KV
INT-2018-00381	8/22/2018	-	Construction - Pending Meter Installation	-	25.9	Solar	03451203	Biscoe 115Kv
NC2018-03167	8/22/2018	Substation A	Supplemental Study - Pending Customer Response	Supplemental Study	100.0	Solar	T4595B01	CARALEIGH 230KV
NC2018-03156	6/22/2018	Substation A	Construction - Under Construction / In Progress	-	100.0	Solar	T5970B07	SELMA 230KV
NC2018-03155	6/21/2018	Substation A	Construction - Pending Customer Obligation	-	25.0	Solar	T4500B13	ARCHER LODGE 230KV
NC2018-03151	6/14/2018	Project Not Active	Withdrawn	-	1,000.0	Solar	T1360B03	MT. GILEAD 115KV
NC2018-03152	6/14/2018	Project Not Active	Withdrawn	-	1,000.0	Solar	T1360B03	MT. GILEAD 115KV
NC2018-03153	6/14/2018	Project Not Active	Withdrawn	-	1,000.0	Solar	T1360B02	MT. GILEAD 115KV
NC2018-03154	6/14/2018	Project Not Active	Withdrawn	-	1,000.0	Solar	T1360B02	MT. GILEAD 115KV
INT-2018-02011	5/30/2018	-	Commercial Operation - Power Generation in Progress	-	24.2	Solar	T1700B11	West End 230Kv
NC2018-03148	5/23/2018	Project Not Active	Cancelled	-	1,000.0	Solar	T1428B01	ROCKINGHAM-ABERDEEN ROAD
NC2018-03149	5/23/2018	Substation A	Commercial Operation - Power Generation in progress	-	43.2	Solar	T5005B07	MORDECAI 115KV
NC2018-03146	5/10/2018	Substation B	Construction - Pending	-	278.0	Solar	T4276B02	RHEMS 230KV
NC2018-03147	5/10/2018	Substation B	Interconnection Agreement - In Progress	-	370.0	Solar	T4276B02	RHEMS 230KV
NC2018-03135	4/24/2018	On Hold	Fast Track Study - On-Hold Interdependency	Fast Track Study	1,000.0	Solar	T5860B04	LILLINGTON 115KV
NC2018-03134	4/23/2018	Substation B	Commercial Operation - Power Generation in progress	-	28.8	Solar	T6455B01	MASONBORO 230KV
NC2018-03132	4/13/2018	On Hold	System Impact Study - On-Hold Interdependency	-	1,000.0	Solar	T5660B05	DUNN 230KV
NC2018-03127	3/28/2018	Substation B	System Impact Study - Pending Customer Response	Customer Transformer Inrush Data Collection	1,000.0	Solar	T5660B01	DUNN 230KV
NC2018-03126	3/27/2018	Approved	Commercial Operation - Power Generation in progress	-	22.1	Solar	T6455B01	MASONBORO 230KV
NC2018-03115	3/7/2018	Project Not Active	Withdrawn	Not Applicable	2,000.0	Solar	T5660B05	DUNN 230KV
NC2018-03112	3/1/2018	Substation A	Commercial Operation - Power Generation in progress	-	28.8	Solar	T0515B02	EMMA 115KV
NC2018-03111-1	2/28/2018	Substation A	Construction - Pending IA/Customer Payment	-	28.8	Solar	T4210B12	JACKSONVILLE CITY 115KV
NC2018-03104	1/24/2018	Substation A	Commercial Operation - Power Generation in progress	-	37.8	Solar	T5660B05	DUNN 230KV
NC2018-03103	1/23/2018	Substation A	Facility Study - Pending	Not Applicable	3,000.0	Solar	T5895B01	MT. OLIVE INDUSTRIAL115KV
NC2018-03096	1/11/2018	Substation A	System Impact Study - Pending Customer Response	Customer Transformer Inrush Data Collection	6,201.0	Solar	T2200B23	LAURINBURG 230KV
NC2018-03099	1/10/2018	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	T5136B04	RALEIGH OAKDALE 230KV
NC2018-03097	1/9/2018	Approved	Commercial Operation - Power Generation in progress	-	24.0	Solar	T5314B11	GARNER TRYON HILLS 115KV
NC2017-03094	12/15/2017	Project Not Active	Withdrawn	-	49.0	Solar	T0515B03	EMMA 115KV
NC2017-03093	12/8/2017	Approved	Commercial Operation - Power Generation in progress	-	22.8	Solar	T0340B16	WEST ASHEVILLE 115KV
NC2017-03088	11/18/2017	Substation B	System Impact Study - In Progress	Transformer Inrush/Advanced Study	2,000.0	Solar	T0965B03	ASHEBORO NORTH 115KV
NC2017-03085	11/13/2017	Substation A	System Impact Study - In Progress	Transformer Inrush/Advanced Study	5,000.0	Battery	T0510B22	ELK MOUNTAIN 115KV
NC2017-03083	11/10/2017	Substation A	System Impact Study - In Progress	Protection Study	2,000.0	Solar	T4222B01	KINGS BLUFF 115KV
NC2017-03081	11/9/2017	Substation A	System Impact Study - In Progress	Transformer Inrush/Advanced Study	5,000.0	Solar	T0510B11	ELK MOUNTAIN 115KV
NC2017-03078	11/2/2017	Substation B	Facility Study - Pending	-	999.0	Solar	T1610B04	TROY 115KV
NC2017-03077	10/27/2017	Substation B	Supplemental Study - Study Complete	Supplemental Study	950.0	Solar	T4610B13	CARY TRENTON ROAD 230KV
NC2017-03076	10/25/2017	Project Not Active	Withdrawn	Not Applicable	11,000.0	Solar	T1360B02	MT. GILEAD 115KV
NC2017-03068	10/3/2017	Substation A	System Impact Study - Pending Customer Response	Not Applicable	999.0	Solar	T1428B01	ROCKINGHAM ABERDEEN ROAD 230KV
NC2017-03059	9/28/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T2520B02	ST. PAULS 115KV
NC2017-03060	9/28/2017	Project Not Active	Cancelled	-	1,000.0	Solar	T2475B02	SHANNON 115KV
NC2017-03061	9/28/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T2475B02	SHANNON 115KV
NC2017-03062	9/28/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T4319B02	GLOBAL TRANSPARK 115KV
NC2017-03063	9/28/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T4319B01	GLOBAL TRANSPARK 115KV
NC2017-03057	9/22/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T4319B02	GLOBAL TRANSPARK 115KV
NC2017-03058	9/22/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T2475B02	SHANNON 115KV
NC2017-03056	9/21/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T2520B02	ST. PAULS 115KV
NC2017-03052	9/15/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T2475B02	SHANNON 115KV
NC2017-03053	9/15/2017	On Hold	Fast Track Study - On-Hold Interdependency	Fast Track Study	1,000.0	Solar	T4170B02	GRIFTON 115KV
NC2017-03054	9/15/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T2280B23	RAEFORD 115KV
NC2017-03055	9/15/2017	On Hold	Fast Track Study - On-Hold Interdependency	Fast Track Study	1,000.0	Solar	T6045B13	SAMARIA 115KV
NC2017-03049	9/14/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T5085B04	OXFORD SOUTH 230KV
NC2017-03050	9/14/2017	Substation A	Fast Track Study - On-Hold Interdependency	Fast Track Study	1,000.0	Solar	T6045B13	SAMARIA 115KV
NC2017-03051	9/14/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T5085B04	OXFORD SOUTH 230KV
NC2017-03048	9/13/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T2280B23	RAEFORD 115KV
NC2017-03044	9/11/2017	On Hold	Fast Track Study - On-Hold Interdependency	Fast Track Study	1,000.0	Solar	T4170B01	GRIFTON 115KV
NC2017-03043	9/9/2017	Substation A	Fast Track Study - Study Complete	Fast Track Study	36.6	Solar	T0322B03	ASHEVILLE BENT CREEK 115KV
NC2017-03039	9/2/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T4271B01	NEWPORT 115 KV
NC2017-03040	9/2/2017	On Hold	Fast Track Study - On-Hold Interdependency	Fast Track Study	1,000.0	Solar	T4930B02	LOUISBURG 115KV
NC2017-03037	8/31/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T1980B04	FAIRMONT 115KV
NC2017-03038	8/31/2017	Project Not Active	Withdrawn	-	1,000.0	Solar	T5302B02	STALLINGS CROSSROADS 115KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
INT-2017-02740	8/10/2017	-	Commercial Operation - Power Generation in Progress	-	23.4	Solar	T1530B03	Siler City 115 Kv
NC2017-03021	7/18/2017	Substation A	Facility Study - Pending Customer Response	Not Applicable	1,426.0	Natural Gas	T0750B16	OTEEN 115KV
NC2017-03012	6/14/2017	Substation A	Supplemental Study - Study Complete	Supplemental Study	110.0	Solar	T0515B02	EMMA 115KV
NC2017-03010	5/27/2017	Substation A	Supplemental Study - Study Complete	Supplemental Study	36.0	Solar	T4610B12	Cary Trenton Rd 230KV
NC2017-03003	5/23/2017	Project Not Active	Withdrawn	-	22.8	Solar	T1530B03	SILER CITY 115KV
NC2017-02998	5/11/2017	Substation A	Facility Study - Pending	Not Applicable	2,000.0	Solar	T1330B04	LIBERTY 115KV
NC2017-02997	5/10/2017	Project Not Active	Withdrawn	Not Applicable	6,200.0	Biomass	T1670B01	WADESBORO 230KV
NC2017-02996	5/8/2017	Project Not Active	Withdrawn	-	500.0	Solar	T1330B04	LIBERTY 115KV
NC2017-02993	4/28/2017	Project Not Active	Withdrawn	-	500.0	Solar	T6215B01	CHADBOURN 115KV
NC2017-02992	4/26/2017	Project Not Active	Withdrawn	Not Applicable	10,000.0	Solar	T5230B01	ROXBORO SOUTH 230KV
NC2017-02988	4/10/2017	Substation A	Facility Study - In Progress	Not Applicable	8,800.0	Battery	T0764B03	ASHEVILLE ROCK HILL 115KV
NC2017-02987	4/7/2017	Substation A	Facility Study - Pending	Not Applicable	6,361.0	Solar	T0670B01	MARSHALL 115KV
NC2017-02984	1/27/2017	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4360B03	SWANSBORO 230KV
NC2017-02985	1/27/2017	Approved	Commercial Operation - Power Generation in progress	-	96.0	Solar	T6720B06	WILMINGTON WINTER PARK 230KV
NC2017-02983	1/25/2017	Project Not Active	Withdrawn	Not Applicable	10,000.0	Solar	T5240B13	ROXBORO #2 115KV
NC2017-02982	1/16/2017	Project Not Active	Withdrawn	Not Applicable	4,995.0	Solar	T4725B05	GARNER PANTHER BRANCH 230KV
NC2016-02965	11/30/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,950.0	Solar	T4285B01	ROSE HILL 230KV
NC2016-02961	11/22/2016	Approved	Construction - Under Construction / In Progress	-	4,998.0	Solar	T6446B22	LELAND INDUSTRIAL 115KV
NC2016-02962	11/22/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5230B02	ROXBORO SOUTH 230KV
NC2016-02960	11/21/2016	Substation A	Facility Study - Pending	Not Applicable	5,000.0	Solar	T5240B10	ROXBORO 115KV
NC2016-02958	11/17/2016	Approved	Commercial Operation - Power Generation in progress	-	27.7	Solar	T4603B12	GREEN LEVEL 230KV
NC2016-02955	11/16/2016	Substation A	Facility Study - In Progress	Not Applicable	1,980.0	Solar	T5660B01	DUNN 230KV
NC2016-02956	11/16/2016	Project Not Active	Withdrawn	-	990.0	Solar	T5240B13	ROXBORO 115KV
NC2016-02954	11/15/2016	Substation A	System Impact Study - In Progress	Protection Study	5,000.0	Solar	T2210B02	LUMBERTON #2 115KV
NC2016-02950	11/11/2016	Substation B	System Impact Study - Pending Customer Response	Not Applicable	3,000.0	Solar	T5504B02	BUIES CREEK 230KV
NC2016-02946	11/8/2016	Approved	Construction - Under Construction / In Progress	Not Applicable	4,836.0	Solar	T6446B11	LELAND INDUSTRIAL 115KV
NC2016-02949	11/8/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5660B01	DUNN 230KV
NC2016-02971	11/7/2016	On Hold	Fast Track Study - On-Hold Interdependency	Fast Track Study	499.5	Solar	T4785B03	HENDERSON EAST 230KV
NC2016-02938	10/31/2016	Substation B	System Impact Study - In Progress	Voltage Flicker Mitigation Options	2,000.0	Solar	T5921B02	NEWTON GROVE 230KV
NC2016-02941	10/31/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4074B01	BRIDGETON 115KV
NC2016-02935	10/27/2016	Substation B	System Impact Study - Pending Customer Response	Customer ROW Data Collection	5,000.0	Solar	T1672B03	WADESBORO-BOWMAN SCHOOL 230KV
NC2016-02932	10/25/2016	Project Not Active	Withdrawn	-	960.0	Solar	T0840B03	VANDERBILT #1 115KV
NC2016-02931	10/24/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	2,000.0	Solar	T0965B01	ASHEBORO NORTH 115KV
NC2016-02930	10/21/2016	Project Not Active	Withdrawn	Not Applicable	4,989.0	Solar	T2440B03	SANFORD HORNER BLVD. 230KV
NC2016-02923	10/17/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,992.0	Solar	T4230B04	KINSTON 115KV
NC2016-02925	10/17/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,992.0	Solar	T4230B04	KINSTON 115KV
NC2016-02926	10/17/2016	Substation A	Construction - Pending IA/Customer Payment	Not Applicable	4,992.0	Solar	T4276B01	RHEMS 230KV
NC2016-02927	10/17/2016	Substation A	Facility Study - Pending	Not Applicable	4,992.0	Solar	T5921B01	NEWTON GROVE 230KV
NC2016-02928	10/17/2016	Substation A	Facility Study - Pending	Not Applicable	4,992.0	Solar	T1672B03	WADESBORO-BOWMAN SCHOOL 230KV
NC2016-02929	10/17/2016	Substation A	Facility Study - In Progress	Not Applicable	5,000.0	Solar	T6160B02	BURGAW 115KV
NC2016-02919	10/5/2016	Approved	Commercial Operation - Power Generation in progress	-	52.2	Solar	T5125B03	RALEIGH HOMESTEAD 230KV
NC2016-02917	10/4/2016	Substation A	Facility Study - Pending	Not Applicable	4,992.0	Solar	T2580B02	VANDER 115KV
NC2016-02918	10/4/2016	Approved	Commercial Operation - Power Generation in progress	-	413.0	Solar	T5125B03	RALEIGH HOMESTEAD 230KV
NC2016-02914	9/22/2016	Substation A	Facility Study - In Progress	Not Applicable	4,560.0	Solar	T5504B02	BUIES CREEK 230KV
NC2016-02910	9/21/2016	Substation A	Construction - Under Construction / In Progress	Not Applicable	4,992.0	Solar	T6160B02	BURGAW 115KV
NC2016-02911	9/21/2016	Approved	Construction - Under Construction / In Progress	Not Applicable	5,000.0	Solar	T5921B01	NEWTON GROVE 230KV
NC2016-02912	9/21/2016	Approved	Construction - Under Construction / In Progress	Not Applicable	5,000.0	Solar	T0965B05	ASHEBORO NORTH 115KV
NC2016-02913	9/21/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,992.0	Solar	T4360B02	SWANSBORO 230KV
NC2016-02908	9/16/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,992.0	Solar	T4108B03	CATHERINE LAKE 230KV
NC2016-02906	9/15/2016	Approved	Construction - Under Construction / In Progress	Not Applicable	4,730.0	Solar	T5450B03	BAILEY 230KV
NC2016-02903	9/13/2016	Substation B	Facility Study - In Progress	Not Applicable	4,992.0	Solar	T4360B02	SWANSBORO 230KV
NC2016-02897	9/12/2016	Substation B	System Impact Study - Pending Customer Response	Customer LVR Options Selection	4,992.0	Solar	T1670B01	WADESBORO 230KV
NC2016-02898	9/12/2016	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	5,000.0	Solar	T5860B03	LILLINGTON 115KV
NC2016-02902	9/12/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,992.0	Solar	T2080B01	HOPE MILLS CHURCH ST. 115KV
NC2016-02893	9/9/2016	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T1190B01	HAMLET 230KV
NC2016-02896	9/9/2016	Substation B	System Impact Study - In Progress	Voltage Flicker Mitigation Options	4,992.0	Solar	T5890B03	MT. OLIVE 115KV
NC2016-02888	9/7/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,992.0	Solar	T6250B01	DELCO 115KV
NC2016-02889	9/7/2016	Approved	Construction - Under Construction / In Progress	Not Applicable	1,998.0	Solar	T2247B02	PEMBROKE 115KV
NC2016-02890	9/7/2016	Substation A	System Impact Study - In Progress	Transformer Inrush/Advanced Study	4,416.0	Solar	T1765B01	BEARD 115KV
NC2016-02891	9/7/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,992.0	Solar	T4255B01	NEW BERN WEST 230KV
NC2016-02892	9/7/2016	Substation A	System Impact Study - In Progress	Technical Review	4,992.0	Solar	T4150B03	FARMVILLE 230KV
NC2016-02884	9/6/2016	Substation B	Facility Study - In Progress	Not Applicable	4,992.0	Solar	T4255B03	NEW BERN WEST 230KV
NC2016-02885	9/6/2016	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	4,992.0	Solar	T2080B01	HOPE MILLS CHURCH ST. 115KV
NC2016-02886	9/6/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,992.0	Solar	T4255B03	NEW BERN WEST 230KV
NC2016-02883	9/2/2016	Substation A	System Impact Study - In Progress	Protection Study	2,400.0	Solar	T5740B02	FREMONT 115KV
-	9/2/2016	Project Not Active	Cancelled	-	1,750.0	Biomass	T1530B02	SILER CITY 115KV
NC2016-02880	8/30/2016	Approved	Construction - Under Construction / In Progress	Not Applicable	5,000.0	Solar	T5085B02	OXFORD SOUTH 230KV
NC2016-02878	8/29/2016	Approved	Construction - Under Construction / In Progress	Not Applicable	1,998.0	Solar	T5240B15	ROXBORO 115KV
NC2016-02879	8/29/2016	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T4930B02	LOUISBURG 115KV
NC2016-02871	8/25/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T4360B01	SWANSBORO 230KV
NC2016-02872	8/25/2016	Substation B	Facility Study - Pending Customer Response	Not Applicable	5,000.0	Solar	T4500B19	ARCHER LODGE 230KV
NC2016-02873	8/25/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5465B05	BELFAST 115KV
NC2016-02866	8/24/2016	Approved	Construction - Under Construction / In Progress	Not Applicable	5,000.0	Solar	T1330B03	LIBERTY 115KV
NC2016-02868	8/24/2016	Substation A	System Impact Study - Pending Customer Response	Customer Documentation Corrections	5,000.0	Solar	T5235B02	ROXBORO BOWMANTOWN ROAD 230KV
NC2016-02869	8/24/2016	Substation B	System Impact Study - Pending Customer Response	Customer Transformer Inrush Decision	5,000.0	Solar	T1140B01	ELLERBE 230KV
NC2016-02870	8/24/2016	Substation A	System Impact Study - Pending Customer Response	Customer ROW for LVR	5,000.0	Solar	T2080B01	HOPE MILLS CHURCH ST. 115KV
Project 14941	8/22/2016	Project Not Active	Cancelled	-	4,992.0	Solar	T4136B11	DOVER 230KV
NC2016-02859	8/12/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4700B11	FRANKLINTON 115KV
NC2016-02860	8/12/2016	Substation A	Construction - Pending IA/Customer Payment	Not Applicable	1,999.0	Solar	T4500B19	ARCHER LODGE 230KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
NC2016-02856	8/10/2016	Substation A	System Impact Study - Pending Customer Response	Customer ROW for LVR	5,000.0	Solar	T2444B02	SANFORD DEEP RIVER 230KV
NC2016-02855	8/8/2016	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	5,000.0	Solar	T5580B02	CLINTON FERRELL ST. 115KV
NC2016-02850	8/4/2016	Substation B	System Impact Study - In Progress	Voltage Flicker Mitigation Options	5,000.0	Solar	T5230B03	ROXBORO SOUTH 230KV
NC2016-02854	8/4/2016	Substation A	Construction - Pending Customer Obligation	-	150.0	Solar	T2141B06	Jonesboro 230kV
NC2016-02853	8/3/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5427B01	ANGIER 230KV
NC2016-02852	7/26/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T2225B01	MONCURE 115KV
NC2016-02849	7/25/2016	Substation A	Facility Study - Pending	Not Applicable	5,000.0	Solar	T2200B24	LAURINBURG 230KV
NC2016-02848	7/19/2016	Project Not Active	Withdrawn	-	350.0	Solar	T5230B02	ROXBORO SOUTH 230KV
NC2016-02844	7/15/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,590.0	Solar	T6386B12	VISTA 115KV
NC2016-02845	7/15/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T5465B01	BELFAST 115KV
NC2016-02846	7/15/2016	Substation B	System Impact Study - In Progress	Voltage Flicker Mitigation Options	4,992.0	Solar	T4108B02	CATHERINE LAKE 230KV
NC2016-02843	7/14/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5900B01	NASHVILLE 115KV
NC2016-02841	7/13/2016	Substation A	Construction - Under Construction / In Progress	Not Applicable	4,400.0	Solar	T5378B02	WENDELL 230KV
NC2016-02842	7/13/2016	Project Not Active	Withdrawn	Not Applicable	4,000.0	Solar	T6675B11	WHITEVILLE SOUTHEAST REGIONAL PARK 115KV
NC2016-02837	7/7/2016	Project Not Active	Withdrawn	Not Applicable	4,000.0	Solar	T4255B01	NEW BERN WEST 230KV
NC2016-02838	7/7/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,999.0	Solar	T4410B13	WALLACE 115KV
NC2016-02835	7/5/2016	Project Not Active	Withdrawn	Not Applicable	4,000.0	Solar	T4255B01	NEW BERN WEST 230KV
NC2016-02831	7/1/2016	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T5754B02	GOLDSBORO LANGSTON 115KV
NC2016-02833	7/1/2016	Approved	Construction - Under Construction / In Progress	Not Applicable	4,992.0	Solar	T2141B07	JONESBORO 230KV
NC2016-02827	6/30/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4233B02	LAKE WACCAMAW 115KV
NC2016-02824	6/29/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	2,200.0	Solar	T1672B03	WADESBORO-BOWMAN SCHOOL 230KV
NC2016-02825	6/29/2016	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T4230B03	KINSTON 115KV
NC2016-02822	6/24/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,032.0	Solar	T4050B02	BAYBORO 230KV
NC2016-02819	6/22/2016	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	5,000.0	Solar	T6250B02	DELCO 115KV
NC2016-02820	6/22/2016	Approved	Construction - Under Construction / In Progress	Not Applicable	5,000.0	Solar	T6360B02	GARLAND 230KV
NC2016-02815	6/10/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5480B02	BENSON 230KV
NC2016-02812	6/9/2016	Substation A	Facility Study - Pending	Not Applicable	5,000.0	Solar	T5890B03	MT. OLIVE 115KV
CHKLIST-11261	6/7/2016	Approved	Commercial Operation - Power Generation in progress	-	84.0	Solar	T0510B11	ELK MOUNTAIN 115KV
NC2016-02811	6/7/2016	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T2190B01	LAURINBURG CITY 230KV
NC2016-02810	5/27/2016	Substation B	Facility Study - Pending	Not Applicable	4,996.0	Solar	T6330B01	ELIZABETHTOWN 115KV
NC2016-02809	5/24/2016	Substation A	Facility Study - Pending	Not Applicable	5,000.0	Solar	T1670B01	WADESBORO 230KV
NC2016-02807	5/20/2016	Approved	Commercial Operation - Complete pending power generation	Not Applicable	350.0	Biomass	T4285B01	ROSE HILL 230KV
NC2016-02805	5/18/2016	Substation A	System Impact Study - On-Hold Interdependency	-	2,000.0	Solar	T5754B02	GOLDSBORO LANGSTON 115KV
NC2016-00029	5/16/2016	Project Not Active	Withdrawn	Not Applicable	4,990.0	Solar	T2280B23	RAEFORD 115KV
NC2016-02804	5/16/2016	Substation A	System Impact Study - Pending Customer Response	Customer ROW for LVR	5,000.0	Solar	T5580B05	CLINTON FERRELL ST. 115KV
NC2016-02803	5/13/2016	Substation B	System Impact Study - Pending Customer Response	Customer Transformer Inrush Decision	5,000.0	Solar	T4410B12	WALLACE 115KV
NC2016-02800	5/11/2016	Project Not Active	Withdrawn	-	5,000.0	Solar	T4050B02	BAYBORO 230KV
NC2016-02801	5/11/2016	Substation A	Facility Study - In Progress	Not Applicable	5,000.0	Solar	T4360B03	SWANSBORO 230KV
NC2016-02798	5/9/2016	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T6670B02	WHITEVILLE 115KV
NC2016-02799	5/9/2016	Project Not Active	Withdrawn	-	5,000.0	Solar	T5888B02	MT. OLIVE WEST 115KV
NC2016-02796	5/6/2016	Substation A	System Impact Study - Pending Customer Response	Not Applicable	5,000.0	Solar	T6675B11	WHITEVILLE SOUTHEAST REGIONAL PARK 115KV
NC2016-02793	5/4/2016	Substation B	System Impact Study - Pending Customer Response	Customer Transformer Inrush Decision	5,000.0	Solar	T4915B01	LITTLETON 115KV
NC2016-02794	5/4/2016	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T5754B01	GOLDSBORO LANGSTON 115KV
NC2016-02792	5/2/2016	Substation B	System Impact Study - In Progress	Transformer Inrush/Advanced Study	5,000.0	Solar	T4285B02	ROSE HILL 230KV
NC2016-02790	4/28/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T4360B03	SWANSBORO 230KV
NC2016-02786	4/27/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T1670B01	WADESBORO 230KV
NC2016-02787	4/27/2016	Substation B	System Impact Study - Pending Customer Response	Customer Documentation Corrections	5,000.0	Solar	T4050B02	BAYBORO 230KV
NC2016-02788	4/27/2016	Substation A	System Impact Study - Pending Customer Response	Not Applicable	5,000.0	Solar	T4915B01	LITTLETON 115KV
NC2016-02789	4/27/2016	On Hold	System Impact Study - On-Hold Interdependency	-	1,998.0	Solar	T6670B02	WHITEVILLE 115KV
NC2016-02781	4/26/2016	Project Not Active	Withdrawn	Not Applicable	4,989.0	Solar	T4108B03	CATHERINE LAKE 230KV
NC2016-02782	4/26/2016	Project Not Active	Withdrawn	-	1,980.0	Solar	T6630B02	TABOR CITY 115KV
NC2016-02784	4/26/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T1330B04	LIBERTY 115KV
NC2016-02785	4/26/2016	Project Not Active	Withdrawn	-	5,000.0	Solar	T5888B02	MT. OLIVE WEST 115KV
NC2016-02780	4/25/2016	Substation B	System Impact Study - Pending Customer Response	Not Applicable	5,000.0	Solar	T1700B15	WEST END 230KV
NC2016-00408	4/20/2016	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T5480B03	BENSON 230KV
NC2016-02778	4/20/2016	Substation B	Facility Study - Pending	Not Applicable	5,000.0	Solar	T6630B01	TABOR CITY 115KV
NC2016-02775	4/7/2016	Substation A	Facility Study - Pending Customer Response	Not Applicable	5,000.0	Solar	T4050B02	BAYBORO 230KV
NC2016-02771	4/6/2016	Substation A	Facility Study - Pending Customer Response	Not Applicable	1,000.0	Solar	T1610B02	TROY 115KV
NC2016-00057	3/22/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,950.0	Solar	T4130B04	CHOCOWINITY 230KV
NC2016-00054	3/21/2016	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T5360B01	WARRENTON 115KV
Project 12279	3/21/2016	Project Not Active	Cancelled	-	1,999.0	Solar	T5970B17	SELMA 230KV
NC2015-00028-1	3/18/2016	Substation A	Facility Study - Pending	Not Applicable	4,998.0	Solar	T4930B02	LOUISBURG 115KV
NC2016-00049	3/17/2016	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	5,000.0	Solar	T5360B01	WARRENTON 115KV
NC2016-00050	3/17/2016	Substation A	System Impact Study - Pending Customer Response	Customer LVR Options Selection	5,000.0	Solar	T5090B02	OXFORD NORTH 230KV
NC2016-00041	3/16/2016	Substation A	Facility Study - Pending Customer Response	Not Applicable	5,000.0	Solar	T6330B02	ELIZABETHTOWN 115KV
NC2016-00044	3/16/2016	Approved	Commercial Operation - Power Generation in progress	-	60.0	Solar	T5005B05	MORDECAI 115KV
NC2016-00046	3/16/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T4050B02	BAYBORO 230KV
NC2016-00047	3/15/2016	On Hold	System Impact Study - On-Hold Interdependency	-	4,999.0	Solar	T5912B06	NEW HOPE 115KV
NC2016-00039	3/10/2016	Approved	Commercial Operation - Power Generation in progress	-	48.0	Solar	T5005B05	MORDECAI 115KV
NC2016-00034	3/9/2016	Project Not Active	Withdrawn	-	60.0	Solar	T1440B26	ROCKINGHAM 230KV
NC2016-00031	3/8/2016	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T5600B03	ROSEBORO 115KV
NC2016-00033	3/8/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T6330B01	ELIZABETHTOWN 115KV
NC2016-00030	3/2/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T4276B03	RHEMS 230KV
NC2016-00028	2/26/2016	Substation A	Facility Study - Pending	Not Applicable	4,998.0	Solar	T2475B02	SHANNON 115KV
NC2016-00027	2/24/2016	Project Not Active	Withdrawn	-	1,980.0	Solar	T6630B02	TABOR CITY 115KV
NC2016-00023	2/16/2016	Substation A	System Impact Study - In Progress	Voltage Flicker Mitigation Options	5,000.0	Solar	T5860B03	LILLINGTON 115KV
NC2016-00025	2/16/2016	Substation A	System Impact Study - Pending Customer Response	Not Applicable	4,998.0	Solar	T4108B01	CATHERINE LAKE 230KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
NC2016-00021	2/10/2016	Substation A	Facility Study - In Progress	Not Applicable	5,000.0	Solar	T5570B02	CLINTON NORTH 115KV
NC2016-00019	2/8/2016	Project Not Active	Withdrawn	Not Applicable	1,980.0	Solar	T4319B02	GLOBAL TRANSPARK 115KV
NC2016-00020	2/8/2016	Project Not Active	Withdrawn	-	1,980.0	Solar	T4108B03	CATHERINE LAKE 230KV
NC2016-00017	2/5/2016	Project Not Active	Cancelled	-	22.8	Solar	T0690B02	ARDEN 115KV
NC2016-00018	2/5/2016	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	5,000.0	Solar	T4170B02	GRIFTON 115KV
NC2016-00011	1/20/2016	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T1230B01	ROBBINS 115KV
NC2016-00009	1/15/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4230B04	KINSTON 115KV
NC2016-00007	1/14/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T2475B02	SHANNON 115KV
NC2016-00008	1/14/2016	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T4230B04	KINSTON 115KV
NC2016-00010	1/14/2016	Substation A	Facility Study - Pending Customer Response	Not Applicable	5,000.0	Solar	T2280B23	RAEFORD 115KV
NC2016-00013	1/14/2016	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4230B04	KINSTON 115KV
CHKLIST-11702	1/11/2016	Project Not Active	Cancelled	-	1,999.0	Solar	T6160B01	BURGAW 115KV
CHKLIST-11698	1/8/2016	Project Not Active	Withdrawn	-	1,999.0	Solar	T6630B02	TABOR CITY 115KV
NC2015-00064	1/6/2016	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	5,000.0	Solar	T5912B06	NEW HOPE 115KV
NC2015-00063	12/29/2015	Approved	Commercial Operation - Power Generation in progress	-	28.0	Solar	T4610B12	CARY TRENTON ROAD 230KV
NC2015-00059	12/28/2015	Project Not Active	Withdrawn	-	4,980.0	Solar	T1230B01	ROBBINS 115KV
NC2015-00060	12/28/2015	Project Not Active	Withdrawn	Not Applicable	4,980.0	Solar	T1530B01	SILER CITY 115KV
NC2015-00055	12/22/2015	Substation B	System Impact Study - In Progress	Protection Study	4,996.0	Solar	T5480B02	BENSON 230KV
NC2016-00004	12/18/2015	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T5754B01	GOLDSBORO LANGSTON 115KV
NC2016-00005	12/17/2015	Substation A	System Impact Study - In Progress	Protection Study	5,000.0	Solar	T4410B10	WALLACE 115kV
NC2016-00006	12/17/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T6090B10	ZEBULON 115KV
NC2015-00051	12/15/2015	Project Not Active	Withdrawn	-	4,996.0	Solar	T5912B06	NEW HOPE 115KV
INT-2015-00372	12/10/2015	-	Commercial Operation - Power Generation in Progress	-	20.8	Solar	T6455B06	MASONBORO 230KV
NC2015-00050	12/10/2015	Project Not Active	Withdrawn	Not Applicable	3,667.0	Solar	T4930B02	LOUISBURG 115KV
NC2015-00047	12/9/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	1,998.0	Solar	T0900B01	ABERDEEN 115KV
NC2016-00003	12/4/2015	Approved	Construction - Under Construction / In Progress	-	4,200.0	Biomass	T5740B03	FREMONT 115KV
NC2015-00043	12/3/2015	On Hold	System Impact Study - On-Hold Interdependency	-	4,000.0	Solar	T6670B02	WHITEVILLE 115KV
NC2015-00044	11/24/2015	Substation B	System Impact Study - In Progress	Protection Study	4,200.0	Solar	T4930B02	LOUISBURG 115KV
CHKLIST-7263	11/20/2015	Approved	Commercial Operation - Power Generation in progress	-	150.0	Biomass	T5580B02	CLINTON FERRELL ST. 115KV
NC2015-00040	11/20/2015	Substation A	Facility Study - In Progress	Not Applicable	4,990.0	Solar	T5752B13	ROSEWOOD 115KV
NC2015-00041	11/20/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	1,990.0	Solar	T5490B01	BEULAVILLE 115KV
NC2015-00036	11/18/2015	Approved	Construction - Under Construction / In Progress	Not Applicable	5,000.0	Solar	T5235B02	ROXBORO BOWMANTOWN ROAD 230KV
NC2015-00037	11/18/2015	Project Not Active	Withdrawn	-	72.0	Solar	T4686B12	FALLS 230KV
NC2015-00039	11/18/2015	Project Not Active	Withdrawn	-	68.0	Solar	T5000B45	MILBURNIE 230KV
NC2015-00033	11/17/2015	Substation A	Facility Study - In Progress	Not Applicable	5,000.0	Solar	T1360B02	MT. GILEAD 115KV
NC2015-00034	11/17/2015	Approved	Commercial Operation - Power Generation in progress	-	1,965.4	Solar	T2432B05	SANFORD GARDEN STREET 230KV
NC2015-00035	11/17/2015	Substation A	Facility Study - Pending Customer Response	Not Applicable	1,998.0	Solar	T4285B02	ROSE HILL 230KV
NC2015-00031	11/16/2015	On Hold	System Impact Study - On-Hold Interdependency	-	4,998.0	Solar	T6670B02	WHITEVILLE 115KV
NC2015-00032	11/16/2015	Substation B	System Impact Study - Pending Customer Response	Customer Documentation Corrections	1,998.0	Solar	T4136B11	DOVER 230KV
NC2016-00042	11/4/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	1,666.0	Solar	T5670B22	EDMONDSON 230KV
NC2015-00041-1	11/3/2015	Substation A	System Impact Study - Pending Customer Response	Customer Mitigation Options Selection	5,000.0	Solar	T4170B01	GRIFTON 115KV
NC2015-00046	10/30/2015	Project Not Active	Withdrawn	Not Applicable	5,550.0	Solar	T1050B01	CARTHAGE 115KV
NC2015-00024	10/13/2015	Approved	Commercial Operation - Power Generation in progress	-	28.0	Solar	T5000B42	MILBURNIE 230KV
NC2015-00019	9/30/2015	Substation A	Facility Study - Pending Customer Response	Not Applicable	5,000.0	Solar	T5600B03	ROSEBORO 115KV
NC2015-00020	9/30/2015	Substation B	System Impact Study - In Progress	Protection Study	5,000.0	Solar	T5600B03	ROSEBORO 115KV
NC2015-00017	9/15/2015	Approved	Commercial Operation - Power Generation in progress	-	70.7	Solar	T4530B05	APEX 230KV
NC2015-00012	9/14/2015	Approved	Construction - Under Construction / In Progress	-	73.4	Solar	T6041B01	SPRING HOPE 115KV
NC2015-00013	9/14/2015	Approved	Construction - Under Construction / In Progress	-	138.2	Solar	T6041B01	SPRING HOPE 115KV
NC2015-00014	9/14/2015	Substation B	Facility Study - Pending	Not Applicable	5,000.0	Solar	T2190B02	LAURINBURG CITY 230KV
NC2015-00009	9/10/2015	Substation B	System Impact Study - In Progress	Voltage Flicker Mitigation Options	1,999.0	Solar	T6670B03	WHITEVILLE 115KV
NC2015-00010	9/10/2015	On Hold	System Impact Study - On-Hold Interdependency	-	4,998.0	Solar	T5770B01	GRANTHAM 230KV
CHKLIST-10667	9/9/2015	On Hold	System Impact Study - On-Hold Interdependency	-	20,000.0	Solar	T5650B20	ERWIN 230KV
NC2015-00005	9/8/2015	Project Not Active	Withdrawn	Not Applicable	1,999.0	Solar	T6670B02	WHITEVILLE 115KV
NC2015-00007	9/8/2015	Approved	Commercial Operation - Power Generation in progress	-	45.0	Solar	T0340B11	WEST ASHEVILLE 115KV
NC2015-00002	9/1/2015	Project Not Active	Cancelled	-	1,980.0	Solar	T4210B13	JACKSONVILLE CITY 115KV
CHKLIST-10605	8/31/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,995.0	Solar	T1700B12	WEST END 230KV
CHKLIST-10607	8/31/2015	Substation A	Facility Study - In Progress	Not Applicable	4,996.0	Solar	T1700B13	WEST END 230KV
CHKLIST-10596	8/28/2015	Approved	Interconnection Agreement - In Progress	-	45.0	Solar	T4600B04	CARY 230KV
CHKLIST-10585	8/27/2015	Substation A	Facility Study - Pending	Not Applicable	5,000.0	Solar	T1140B01	ELLERBE 230KV
CHKLIST-10588	8/27/2015	Approved	Commercial Operation - Power Generation in progress	-	160.0	Solar	T2249B04	PINEHURST 115KV
CHKLIST-10577	8/26/2015	Approved	Commercial Operation - Power Generation in progress	-	110.0	Solar	T0764B03	ASHEVILLE ROCK HILL 115KV
CHKLIST-10579	8/26/2015	Project Not Active	Withdrawn	-	1,999.0	Solar	T4170B01	GRIFTON 115KV
CHKLIST-10368	8/25/2015	Project Not Active	Withdrawn	-	48.2	Solar	T1520B01	SEAGROVE 115KV
CHKLIST-10559	8/25/2015	Approved	Commercial Operation - Power Generation in progress	-	360.0	Solar	T5912B02	NEW HOPE 115KV
CHKLIST-10534	8/24/2015	Substation A	System Impact Study - In Progress	Protection Study	5,000.0	Solar	T6670B02	WHITEVILLE 115KV
CHKLIST-10538	8/24/2015	Project Not Active	Withdrawn	-	4,800.0	Solar	T6670B02	WHITEVILLE 115KV
CHKLIST-10542	8/24/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T6630B02	TABOR CITY 115KV
CHKLIST-10544	8/24/2015	Substation A	Facility Study - Pending	Not Applicable	2,200.0	Solar	T6630B02	TABOR CITY 115KV
CHKLIST-10545	8/24/2015	Approved	Commercial Operation - Power Generation in progress	-	324.0	Solar	T4604B13	AMBERLY 230KV
CHKLIST-10547	8/24/2015	Project Not Active	Withdrawn	-	30.0	Diesel	T0784B13	AVERY CREEK 115KV
CHKLIST-10553	8/24/2015	Approved	Commercial Operation - Power Generation in progress	-	360.0	Solar	T4910B22	RALEIGH LEESVILLE ROAD 230KV
CHKLIST-10507	8/20/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	1,610.0	Biomass	T5580B01	CLINTON FERRELL ST. 115KV
CHKLIST-10493	8/17/2015	Substation A	Facility Study - Pending	Not Applicable	4,998.0	Solar	T2190B02	LAURINBURG CITY 230KV
CHKLIST-10412	8/10/2015	Approved	Commercial Operation - Power Generation in progress	-	396.0	Solar	T0690B01	ARDEN 115KV
CHKLIST-10390	8/6/2015	Approved	Commercial Operation - Power Generation in progress	-	360.0	Solar	T6320B07	WILMINGTON EAST 230KV
CHKLIST-10394	8/6/2015	Approved	Commercial Operation - Power Generation in progress	-	396.0	Solar	T5111B23	CARY PINEY PLAINS 230KV
CHKLIST-10362	8/4/2015	Substation A	Facility Study - In Progress	Not Applicable	2,000.0	Solar	T5732B03	FOUR OAKS 230KV
CHKLIST-10338	8/3/2015	Approved	Commercial Operation - Power Generation in progress	-	152.0	Solar	T4790B25	HENDERSON 230KV
CHKLIST-10340	8/3/2015	Approved	Commercial Operation - Power Generation in progress	-	50.4	Solar	T4790B18	HENDERSON 230KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-10604	8/3/2015	Approved	Commercial Operation - Power Generation in progress	-	81.0	Solar	T6205B13	CASTLE HAYNE 230KV
CHKLIST-10312	7/29/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,990.0	Solar	T2190B01	LAURINBURG CITY 230KV
CHKLIST-10361	7/28/2015	Substation B	Facility Study - Pending	Not Applicable	4,998.0	Solar	T1190B04	HAMLET 230KV
CHKLIST-10576	7/28/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T5670B02	EDMONDSON 230KV
CHKLIST-10278	7/27/2015	Approved	Commercial Operation - Power Generation in progress	-	64.0	Solar	T5111B22	CARY PINEY PLAINS 230KV
CHKLIST-10280	7/27/2015	Approved	Commercial Operation - Power Generation in progress	-	64.0	Solar	T5111B22	CARY PINEY PLAINS 230KV
CHKLIST-10298	7/24/2015	Project Not Active	Withdrawn	-	5,000.0	Solar	T5375B02	GOLDSBORO WEIL 115KV
CHKLIST-10260	7/22/2015	Project Not Active	Cancelled	-	4,995.0	Solar	T5360B04	WARRENTON 115KV
NC2015-00001	7/22/2015	Project Not Active	Withdrawn	-	5,000.0	Solar	T4410B11	WALLACE 115KV
CHKLIST-10222	7/17/2015	Substation A	Facility Study - In Progress	Not Applicable	1,999.0	Solar	T2141B05	JONESBORO 230KV
CHKLIST-10225	7/17/2015	Project Not Active	Cancelled	Not Applicable	4,800.0	Solar	T6041B01	SPRING HOPE 115KV
CHKLIST-10197	7/15/2015	Project Not Active	Cancelled	-	27.0	Solar	T0371B03	BEAVERDAM 115KV
CHKLIST-10070	6/30/2015	Approved	Commercial Operation - Power Generation in progress	-	420.0	Solar	T4796B11	HOLLY SPRINGS INDUSTRIAL 230KV
CHKLIST-10071	6/30/2015	Approved	Commercial Operation - Power Generation in progress	-	392.0	Solar	T0750B05	OTEEN 115KV
CHKLIST-10073	6/30/2015	Project Not Active	Cancelled	-	392.0	Solar	T4273B06	JACKSONVILLE NORTHWOODS 115KV
CHKLIST-10074	6/30/2015	Approved	Commercial Operation - Power Generation in progress	-	392.0	Solar	T4602B02	CARY EVANS ROAD 230KV
CHKLIST-10076	6/30/2015	Approved	Commercial Operation - Power Generation in progress	-	532.0	Solar	T5119B22	RALEIGH BRIER CREEK 230KV
CHKLIST-10049	6/26/2015	Approved	Commercial Operation - Power Generation in progress	-	255.2	Solar	T5770B01	GRANTHAM 230KV
CHKLIST-10050	6/26/2015	Approved	Commercial Operation - Power Generation in progress	-	185.6	Solar	T5770B01	GRANTHAM 230KV
CHKLIST-9994	6/22/2015	Substation A	IR Review - Pending Customer Response	-	812.0	Solar	T0362B02	BARNARDSVILLE 115KV
CHKLIST-9971	6/17/2015	Substation A	Facility Study - In Progress	Not Applicable	1,998.0	Solar	T5480B01	BENSON 230KV
CHKLIST-9953	6/15/2015	Project Not Active	Cancelled	-	40.0	Solar	T6320B07	WILMINGTON EAST 230KV
CHKLIST-9955	6/15/2015	Project Not Active	Cancelled	-	40.0	Solar	T6471B12	MURRAYSVILLE 230KV
CHKLIST-9922	6/11/2015	Approved	Construction - Under Construction / In Progress	Not Applicable	5,000.0	Solar	T5570B02	CLINTON NORTH 115KV
CHKLIST-9895	6/8/2015	Project Not Active	Withdrawn	-	2,400.0	Solar	T4720B04	GARNER 115KV
CHKLIST-9876	6/4/2015	Approved	Commercial Operation - Power Generation in progress	-	36.0	Solar	T4600B01	CARY 230KV
CHKLIST-9832	6/1/2015	Project Not Active	Withdrawn	-	1,999.0	Solar	T5085B02	OXFORD SOUTH 230KV
CHKLIST-9721	5/19/2015	Approved	Commercial Operation - Power Generation in progress	-	51.0	Solar	T5126B13	RALEIGH YONKERS ROAD 115KV
CHKLIST-9727	5/19/2015	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T5385B04	WILSON MILLS 230KV
CHKLIST-9708	5/18/2015	Project Not Active	Withdrawn	Not Applicable	4,250.0	Solar	T4770B03	HENDERSON NORTH 115KV
CHKLIST-9664	5/13/2015	Approved	Commercial Operation - Power Generation in progress	-	40.0	Solar	T0781B01	SKYLAND 115KV
CHKLIST-9837	5/13/2015	Approved	Commercial Operation - Power Generation in progress	-	1,000.0	Solar	T2210B02	LUMBERTON 115KV
CHKLIST-9842	5/13/2015	Approved	Commercial Operation - Power Generation in progress	-	1,000.0	Solar	T2210B02	LUMBERTON 115KV
CHKLIST-9601	5/6/2015	Approved	Commercial Operation - Power Generation in progress	-	40.0	Solar	T4595B04	CARALEIGH 230KV
CHKLIST-9516	4/28/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T5752B12	ROSEWOOD 115KV
CHKLIST-9505	4/27/2015	Substation A	System Impact Study - Pending Customer Response	Customer Mitigation Options Selection	4,999.0	Solar	T1980B03	FAIRMONT 115KV
CHKLIST-7915	4/25/2015	Approved	Commercial Operation - Power Generation in progress	-	1,980.0	Solar	T6040B13	CASTALIA 230KV
CHKLIST-9476	4/23/2015	Approved	Commercial Operation - Power Generation in progress	-	45.0	Solar	T0371B03	BEAVERDAM 115KV
CHKLIST-9479	4/23/2015	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T5385B03	WILSON MILLS 230KV
CHKLIST-9482	4/23/2015	Approved	Commercial Operation - Power Generation in progress	-	180.0	Solar	T4595B04	CARALEIGH 230KV
CHKLIST-9435	4/21/2015	Project Not Active	Withdrawn	-	9,996.0	Solar	T6670B02	WHITEVILLE 115KV
CHKLIST-9451	4/21/2015	Substation A	Construction - Pending IA/Customer Payment	-	800.0	Diesel	T5888B01	MT. OLIVE WEST 115KV
CHKLIST-9425	4/20/2015	Project Not Active	Withdrawn	-	9,996.0	Solar	T6630B02	TABOR CITY 115KV
CHKLIST-9649	4/20/2015	Approved	Commercial Operation - Power Generation in progress	-	68.0	Solar	T4595B05	CARALEIGH 230KV
CHKLIST-9415	4/17/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5090B01	OXFORD NORTH 230KV
CHKLIST-9402	4/15/2015	Substation B	System Impact Study - In Progress	Voltage Flicker Mitigation Options	5,000.0	Solar	T5770B01	GRANTHAM 230KV
CHKLIST-9385	4/14/2015	Project Not Active	Cancelled	-	4,998.0	Solar	T2141B05	JONESBORO 230KV
CHKLIST-9531	4/13/2015	Project Not Active	Withdrawn	-	4,500.0	Solar	T5401B01	YOUNGSVILLE 115KV
CHKLIST-9355	4/10/2015	Approved	Construction - Under Construction / In Progress	Not Applicable	4,340.0	Solar	T5480B02	BENSON 230KV
CHKLIST-9359	4/10/2015	Project Not Active	Withdrawn	Not Applicable	4,999.0	Solar	T6215B02	CHADBOURN 115KV
CHKLIST-9349	4/9/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T6220B01	CLARKTON 115KV
CHKLIST-9311	4/2/2015	Project Not Active	Cancelled	-	1,999.0	Solar	T5670B03	EDMONDSON 230KV
CHKLIST-9315	4/2/2015	Project Not Active	Cancelled	-	5,040.0	Solar	T2631B04	WEATHERSPOON 230KV
CHKLIST-9294	3/31/2015	Project Not Active	Withdrawn	-	4,999.0	Solar	T5360B03	WARRENTON 115KV
CHKLIST-9261	3/26/2015	On Hold	Fast Track Study - On-Hold Interdependency	Fast Track Study	1,999.0	Solar	T5385B01	WILSON MILLS 230KV
CHKLIST-9214	3/20/2015	Approved	Commercial Operation - Power Generation in progress	-	1,998.0	Solar	T5240B14	ROXBORO 115KV
CHKLIST-9211	3/19/2015	Substation A	System Impact Study - In Progress	Transformer Inrush/Advanced Study	4,990.0	Solar	T1850B02	CANDOR 115KV
CHKLIST-9195	3/18/2015	Project Not Active	Withdrawn	-	5,040.0	Solar	T4555B01	BAHAMA 230KV
CHKLIST-9196	3/18/2015	Substation A	System Impact Study - In Progress	Protection Study	3,920.0	Solar	T2181B05	LAUREL HILL 230KV
CHKLIST-9198	3/18/2015	Project Not Active	Withdrawn	Not Applicable	4,999.0	Solar	T1980B01	FAIRMONT 115KV
CHKLIST-9162	3/16/2015	Project Not Active	Withdrawn	Not Applicable	5,001.0	Solar	T1980B03	FAIRMONT 115KV
CHKLIST-9153	3/13/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T6670B03	WHITEVILLE 115KV
CHKLIST-9156	3/13/2015	Substation B	System Impact Study - Pending	-	2,000.0	Solar	T5754B01	GOLDSBORO LANGSTON 115KV
CHKLIST-9139	3/11/2015	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	1,998.0	Solar	T4230B04	KINSTON 115KV
CHKLIST-9130	3/10/2015	Project Not Active	Cancelled	-	1,000.0	Solar	T6215B02	CHADBOURN 115KV
CHKLIST-9088	3/3/2015	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T5360B02	WARRENTON 115KV
CHKLIST-9062	3/2/2015	Substation A	Facility Study - In Progress	Not Applicable	1,999.0	Solar	T5385B01	WILSON MILLS 230KV
CHKLIST-9064	3/2/2015	Project Not Active	Withdrawn	-	2,000.0	Solar	T5302B03	STALLINGS CROSSROADS 115KV
CHKLIST-9066	3/2/2015	Project Not Active	Withdrawn	-	2,000.0	Solar	T5302B03	STALLINGS CROSSROADS 115KV
CHKLIST-9070	3/2/2015	Substation B	Facility Study - In Progress	Not Applicable	1,980.0	Solar	T5385B01	WILSON MILLS 230KV
CHKLIST-9073	3/2/2015	On Hold	Fast Track Study - On-Hold Interdependency	Fast Track Study	1,999.0	Solar	T5385B02	WILSON MILLS 230KV
CHKLIST-9074	3/2/2015	Project Not Active	Withdrawn	-	2,000.0	Solar	T5970B06	SELMA 230KV
CHKLIST-9048	3/1/2015	Project Not Active	Withdrawn	-	999.5	Solar	T2282B01	RAEFORD SOUTH 115KV
CHKLIST-9049	3/1/2015	Project Not Active	Withdrawn	-	1,998.9	Solar	T2215B01	MAXTON 115KV
CHKLIST-9050	3/1/2015	Project Not Active	Cancelled	-	1,999.0	Solar	T1980B01	FAIRMONT 115KV
CHKLIST-9051	3/1/2015	Project Not Active	Cancelled	-	1,000.0	Solar	T2247B02	PEMBROKE 115KV
CHKLIST-9052	3/1/2015	Project Not Active	Withdrawn	Not Applicable	999.5	Solar	T2580B02	VANDER 115KV
CHKLIST-9053	3/1/2015	Project Not Active	Cancelled	-	18,330.0	Solar	T5888B03	MT. OLIVE WEST 115KV
CHKLIST-9054	3/1/2015	Substation B	System Impact Study - Pending Customer Response	Customer LVR Options Selection	4,999.0	Solar	T5650B22	ERWIN 230KV

Duke Energy Carolinas, LLC
Duke Energy Progress, LLC

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-9055	3/1/2015	Substation A	Construction - Under Construction / In Progress	Not Applicable	3,400.0	Solar	T5890B03	MT. OLIVE 115KV
CHKLIST-9056	3/1/2015	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1330B04	LIBERTY 115KV
CHKLIST-9057	3/1/2015	Project Not Active	Cancelled	-	4,800.0	Solar	T2631B04	WEATHERSPOON 230KV
CHKLIST-9058	3/1/2015	Project Not Active	Withdrawn	-	4,800.0	Solar	T5860B01	LILLINGTON 115KV
CHKLIST-9059	3/1/2015	Project Not Active	Cancelled	-	4,800.0	Solar	T2631B03	WEATHERSPOON 230KV
CHKLIST-9060	3/1/2015	Project Not Active	Withdrawn	-	4,800.0	Solar	T5860B01	LILLINGTON 115KV
CHKLIST-9061	3/1/2015	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T2631B01	WEATHERSPOON 230KV
CHKLIST-9046	2/27/2015	Project Not Active	Cancelled	Not Applicable	1,998.0	Solar	T5090B01	OXFORD NORTH 230KV
CHKLIST-9024	2/25/2015	Substation A	System Impact Study - Pending Customer Response	Customer LVR Options Selection	2,000.0	Solar	T5754B01	GOLDSBORO LANGSTON 115KV
CHKLIST-9025	2/25/2015	On Hold	System Impact Study - On-Hold Interdependency	-	2,000.0	Solar	T5360B02	WARRENTON 115KV
CHKLIST-9026	2/25/2015	Substation A	System Impact Study - Pending Customer Response	Customer ROW for LVR	4,998.0	Solar	T5230B03	ROXBORO SOUTH 230KV
CHKLIST-9027	2/25/2015	Project Not Active	Withdrawn	-	5,010.0	Solar	T5935B03	PRINCETON 115KV
CHKLIST-9028	2/25/2015	Substation A	Construction - Pending IA/Customer Payment	Not Applicable	5,000.0	Solar	T4255B01	NEW BERN WEST 230KV
CHKLIST-9031	2/25/2015	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	T0372B05	BILTMORE 115KV
CHKLIST-8987	2/20/2015	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T2631B03	WEATHERSPOON 230KV
CHKLIST-8978	2/19/2015	On Hold	Fast Track Study - On-Hold Interdependency	Fast Track Study	1,998.0	Solar	T4785B02	HENDERSON EAST 230KV
NC2015-00004	2/19/2015	Substation B	Fast Track Study - Study Complete	Fast Track Study	2,000.0	Solar	T1980B04	FAIRMONT 115KV
CHKLIST-8929	2/9/2015	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T5660B01	DUNN 230KV
CHKLIST-8932	2/9/2015	Project Not Active	Cancelled	-	4,998.0	Solar	T2335B02	ROWLAND 230KV
CHKLIST-8905	2/6/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4785B06	HENDERSON EAST 230KV
CHKLIST-8906	2/6/2015	Substation A	System Impact Study - Pending Customer Response	Not Applicable	4,000.0	Solar	T4770B01	HENDERSON NORTH 115KV
CHKLIST-8908	2/6/2015	Substation A	System Impact Study - In Progress	Voltage Flicker Mitigation Options	5,000.0	Solar	T5900B02	NASHVILLE 115KV
CHKLIST-8909	2/6/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T4276B02	RHEMS 230KV
CHKLIST-8910	2/6/2015	Substation A	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T5427B03	ANGIER 230KV
CHKLIST-8911	2/6/2015	Approved	Commercial Operation - Power Generation in progress	-	4,995.0	Solar	T2247B02	PEMBROKE 115KV
CHKLIST-8893	2/4/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,550.0	Solar	T1810B01	BLADENBORO 115KV
CHKLIST-8883	2/3/2015	Substation A	Facility Study - Pending	-	1,999.0	Solar	T5650B20	ERWIN 230KV
CHKLIST-8873	2/2/2015	Project Not Active	Cancelled	-	4,800.0	Solar	T4230B04	KINSTON 115KV
CHKLIST-8874	2/2/2015	Project Not Active	Cancelled	-	1,000.0	Solar	T4319B01	GLOBAL TRANSPARK 115KV
CHKLIST-8848	1/29/2015	Project Not Active	Cancelled	Not Applicable	2,000.0	Solar	T4410B11	WALLACE 115KV
CHKLIST-8849	1/29/2015	Project Not Active	Withdrawn	Not Applicable	2,000.0	Solar	T4320B01	SNOW HILL 115KV
CHKLIST-8857	1/29/2015	On Hold	Fast Track Study - On-Hold Interdependency	Fast Track Study	2,000.0	Solar	T6040B13	CASTALIA 230KV
NC2016-02127	1/29/2015	Project Not Active	Withdrawn	Not Applicable	2,000.0	Solar	T5580B02	CLINTON FERRELL ST. 115KV
CHKLIST-8836	1/27/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T6040B12	CASTALIA 230KV
CHKLIST-8819	1/26/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5935B03	PRINCETON 115KV
CHKLIST-8820	1/26/2015	Substation A	System Impact Study - Pending Customer Response	Customer LVR Options Selection	3,000.0	Solar	T5912B01	NEW HOPE 115KV
CHKLIST-8821	1/26/2015	On Hold	System Impact Study - On-Hold Interdependency	-	5,000.0	Solar	T6045B12	SAMARIA 115KV
CHKLIST-8822	1/26/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5900B01	NASHVILLE 115KV
CHKLIST-8823	1/26/2015	Project Not Active	Withdrawn	Not Applicable	3,000.0	Solar	T4785B01	HENDERSON EAST 230KV
CHKLIST-8827	1/26/2015	Project Not Active	Cancelled	Not Applicable	5,000.0	Solar	T5970B07	SELMA 230KV
CHKLIST-8808	1/23/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5900B02	NASHVILLE 115KV
CHKLIST-8801	1/22/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4785B06	HENDERSON EAST 230KV
CHKLIST-8802	1/22/2015	Substation A	System Impact Study - Pending Customer Response	Customer Documentation Corrections	5,000.0	Solar	T5770B03	GRANTHAM 230KV
CHKLIST-8803	1/22/2015	Substation B	System Impact Study - In Progress	Voltage Flicker Mitigation Options	5,000.0	Solar	T6040B12	CASTALIA 230KV
CHKLIST-8794	1/21/2015	Project Not Active	Cancelled	Not Applicable	5,000.0	Solar	T5754B01	GOLDSBORO LANGSTON 115KV
CHKLIST-8798	1/21/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5302B02	STALLINGS CROSSROADS 115KV
CHKLIST-8781	1/20/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4770B03	HENDERSON NORTH 115KV
CHKLIST-8782	1/20/2015	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	5,000.0	Solar	T5360B03	WARRENTON 115KV
CHKLIST-8788	1/20/2015	Approved	Commercial Operation - Power Generation in progress	-	34.2	Solar	T5125B03	RALEIGH HOMESTEAD 230KV
CHKLIST-8791	1/20/2015	Project Not Active	Withdrawn	-	4,800.0	Solar	T1230B01	ROBBINS 115KV
CHKLIST-8767	1/19/2015	Substation A	Construction - Pending IA/Customer Payment	Not Applicable	4,000.0	Solar	T5360B04	WARRENTON 115KV
CHKLIST-8770	1/19/2015	Project Not Active	Withdrawn	-	5,000.0	Solar	T4770B03	HENDERSON NORTH 115KV
CHKLIST-8777	1/19/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4770B05	HENDERSON NORTH 115KV
CHKLIST-8756	1/16/2015	Project Not Active	Withdrawn	-	1,999.0	Solar	T1980B03	FAIRMONT 115KV
CHKLIST-8757	1/16/2015	Project Not Active	Withdrawn	-	1,999.0	Solar	T1980B03	FAIRMONT 115KV
CHKLIST-8754	1/15/2015	Project Not Active	Cancelled	-	1,999.0	Solar	T2580B01	VANDER 115KV
CHKLIST-8755	1/15/2015	Project Not Active	Cancelled	-	1,999.0	Solar	T2580B01	VANDER 115KV
CHKLIST-8751	1/14/2015	Project Not Active	Withdrawn	-	1,990.0	Solar	T1980B03	FAIRMONT 115KV
CHKLIST-8717	1/12/2015	Substation A	System Impact Study - Pending Customer Response	Not Applicable	4,000.0	Solar	T6250B02	DELCO 115KV
CHKLIST-8718	1/12/2015	Project Not Active	Withdrawn	-	5,000.0	Solar	T4074B01	BRIDGETON 115KV
CHKLIST-8719	1/12/2015	Substation A	System Impact Study - Pending Customer Response	Customer ROW Data Collection	3,500.0	Solar	T5360B03	WARRENTON 115KV
CHKLIST-8720	1/12/2015	Substation A	Construction - Pending IA/Customer Payment	Not Applicable	5,000.0	Solar	T6040B12	CASTALIA 230KV
CHKLIST-8722	1/12/2015	Project Not Active	Withdrawn	-	5,000.0	Solar	T1330B04	LIBERTY 115KV
CHKLIST-8693	1/9/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,500.0	Solar	T6250B02	DELCO 115KV
CHKLIST-8694	1/9/2015	Project Not Active	Cancelled	-	4,500.0	Solar	T4930B02	LOUISBURG 115KV
CHKLIST-8672	1/7/2015	Project Not Active	Withdrawn	-	4,800.0	Solar	T2631B03	WEATHERSPOON 230KV
CHKLIST-8673	1/7/2015	Approved	Construction - Pending Customer Obligation	-	4,973.0	Solar	T1530B04	SILER CITY 115KV
CHKLIST-8674	1/7/2015	Project Not Active	Cancelled	-	4,800.0	Solar	T1530B04	SILER CITY 115KV
CHKLIST-8675	1/7/2015	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T4410B11	WALLACE 115KV
CHKLIST-8677	1/7/2015	Project Not Active	Cancelled	Not Applicable	4,999.0	Solar	T5090B02	OXFORD NORTH 230KV
CHKLIST-8679	1/7/2015	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5935B03	PRINCETON 115KV
CHKLIST-8681	1/7/2015	Approved	Construction - Under Construction / In Progress	Not Applicable	5,000.0	Solar	T2280B23	RAEFORD 115KV
CHKLIST-8688	1/7/2015	Project Not Active	Withdrawn	-	2,302.0	Solar	T0990B02	BISCOE 115KV
CHKLIST-8689	1/7/2015	Project Not Active	Withdrawn	-	2,302.0	Solar	T0990B02	BISCOE 115KV
CHKLIST-8665	1/6/2015	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T2444B22	SANFORD DEEP RIVER 230KV
CHKLIST-8668	1/6/2015	On Hold	System Impact Study - On-Hold Interdependency	-	4,998.0	Solar	T4785B02	HENDERSON EAST 230KV
CHKLIST-8669	1/6/2015	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T4410B11	WALLACE 115KV
CHKLIST-8670	1/6/2015	Project Not Active	Cancelled	-	4,998.0	Solar	T1530B01	SILER CITY 115KV
CHKLIST-8656	1/5/2015	Project Not Active	Cancelled	-	10,000.0	Solar	T4255B01	NEW BERN WEST 230KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-8657	1/5/2015	Substation A	System Impact Study - Pending Customer Response	Not Applicable	5,000.0	Solar	T4230B02	KINSTON 115KV
CHKLIST-8658	1/5/2015	Substation A	System Impact Study - Pending Customer Response	Customer Documentation Corrections	5,000.0	Solar	T4785B06	HENDERSON EAST 230KV
CHKLIST-8659	1/5/2015	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	5,000.0	Solar	T4785B06	HENDERSON EAST 230KV
CHKLIST-8660	1/5/2015	Project Not Active	Withdrawn	-	2,000.0	Solar	T5465B02	BELFAST 115KV
CHKLIST-8626	12/30/2014	On Hold	System Impact Study - On-Hold Interdependency	-	4,999.0	Solar	T2631B03	WEATHERSPOON 230KV
CHKLIST-8627	12/30/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,938.0	Solar	T1440B28	ROCKINGHAM 230KV
CHKLIST-8611	12/29/2014	Substation A	Facility Study - In Progress	Not Applicable	4,998.0	Solar	T1190B04	HAMLET 230KV
CHKLIST-8624	12/29/2014	Substation A	System Impact Study - In Progress	Voltage Flicker Mitigation Options	4,999.0	Solar	T2215B02	MAXTON 115KV
CHKLIST-8586	12/23/2014	On Hold	System Impact Study - On-Hold Interdependency	-	4,998.0	Solar	T2631B03	WEATHERSPOON 230KV
CHKLIST-8567	12/22/2014	Project Not Active	Cancelled	-	4,800.0	Solar	T4700B11	FRANKLINTON 115KV
CHKLIST-8568	12/22/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T2631B04	WEATHERSPOON 230KV
CHKLIST-8569	12/22/2014	Project Not Active	Cancelled	-	4,800.0	Solar	T2631B01	WEATHERSPOON 230KV
CHKLIST-8570	12/22/2014	Project Not Active	Withdrawn	-	2,400.0	Solar	T5240B15	ROXBORO 115KV
CHKLIST-8571	12/22/2014	Project Not Active	Withdrawn	-	4,800.0	Solar	T2631B01	WEATHERSPOON 230KV
CHKLIST-8572	12/22/2014	Project Not Active	Cancelled	-	4,800.0	Solar	T1980B01	FAIRMONT 115KV
CHKLIST-8575	12/22/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T5900B01	NASHVILLE 115KV
CHKLIST-8576	12/22/2014	Approved	Construction - Under Construction / In Progress	Not Applicable	5,000.0	Solar	T2250B02	PITTSBORO 230KV
CHKLIST-8541	12/19/2014	Project Not Active	Cancelled	-	20,000.0	Solar	T4074B02	BRIDGETON 115KV
CHKLIST-8828	12/19/2014	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T5302B03	STALLINGS CROSSROADS 115KV
CHKLIST-8525	12/18/2014	Project Not Active	Withdrawn	-	1,998.0	Solar	T6045B13	SAMARIA 115KV
CHKLIST-8527	12/18/2014	Project Not Active	Cancelled	-	4,800.0	Solar	T1550B05	SOUTHERN PINES 115KV
CHKLIST-8475	12/15/2014	Project Not Active	Cancelled	-	4,800.0	Solar	T5230B03	ROXBORO SOUTH 230KV
CHKLIST-8476	12/15/2014	Project Not Active	Cancelled	-	4,800.0	Solar	T1050B02	CARTHAGE 115KV
CHKLIST-8480	12/15/2014	Substation B	System Impact Study - In Progress	LVR Evaluation and Preliminary Options	4,999.0	Solar	T2631B01	WEATHERSPOON 230KV
CHKLIST-8484	12/15/2014	Substation A	Facility Study - Pending Customer Response	Not Applicable	4,998.0	Solar	T5935B01	PRINCETON 115KV
CHKLIST-8458	12/11/2014	Project Not Active	Withdrawn	-	2,000.0	Solar	T2631B01	WEATHERSPOON 230KV
CHKLIST-8444	12/9/2014	Approved	Commercial Operation - Power Generation in progress	-	250.0	Solar	T0750B16	OTEEN 115KV
CHKLIST-8437	12/8/2014	Project Not Active	Cancelled	-	5,000.0	Solar	T1330B03	LIBERTY 115KV
CHKLIST-8429	12/4/2014	Approved	Construction - Pending Customer Obligation	-	5,000.0	Solar	T4150B03	FARMVILLE 230KV
CHKLIST-8400	12/2/2014	Project Not Active	Withdrawn	-	2,000.0	Solar	T4500B11	ARCHER LODGE 230KV
CHKLIST-8401	12/2/2014	Project Not Active	Withdrawn	-	2,000.0	Solar	T5970B06	SELMA 230KV
CHKLIST-8402	12/2/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	1,999.0	Solar	T5385B02	WILSON MILLS 230KV
CHKLIST-8403	12/2/2014	Project Not Active	Withdrawn	-	2,000.0	Solar	T5385B01	WILSON MILLS 230KV
CHKLIST-8404	12/2/2014	Project Not Active	Withdrawn	-	2,000.0	Solar	T4500B13	ARCHER LODGE 230KV
CHKLIST-8405	12/2/2014	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T5385B01	WILSON MILLS 230KV
CHKLIST-8406	12/2/2014	Project Not Active	Withdrawn	-	2,000.0	Solar	T5970B06	SELMA 230KV
CHKLIST-8407	12/2/2014	Project Not Active	Withdrawn	-	2,000.0	Solar	T5970B07	SELMA 230KV
CHKLIST-8408	12/2/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	1,999.0	Solar	T5385B02	WILSON MILLS 230KV
CHKLIST-8409	12/2/2014	Project Not Active	Cancelled	-	2,000.0	Solar	T5385B02	WILSON MILLS 230KV
CHKLIST-8373	11/24/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T2631B03	WEATHERSPOON 230KV
CHKLIST-8348	11/20/2014	Approved	Commercial Operation - Power Generation in progress	-	96.0	Solar	T4530B05	APEX 230KV
CHKLIST-8237	11/6/2014	Substation A	Interconnection Agreement - In Progress	Not Applicable	5,000.0	Solar	T4136B12	DOVER 230KV
CHKLIST-8078	10/26/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4770B01	HENDERSON NORTH 115KV
CHKLIST-8138	10/22/2014	Project Not Active	Cancelled	-	2,000.0	Solar	T1980B04	FAIRMONT 115KV
CHKLIST-8139	10/22/2014	Project Not Active	Cancelled	-	5,000.0	Solar	T1980B03	FAIRMONT 115KV
CHKLIST-8140	10/22/2014	Substation A	System Impact Study - Pending Customer Response	Customer LVR Options Selection	5,000.0	Solar	T2631B01	WEATHERSPOON 230KV
CHKLIST-8141	10/22/2014	Project Not Active	Cancelled	-	4,800.0	Solar	T1550B02	SOUTHERN PINES 115KV
CHKLIST-8136	10/21/2014	Project Not Active	Cancelled	-	4,998.0	Solar	T5970B08	SELMA 230KV
CHKLIST-8137	10/21/2014	Approved	Commercial Operation - Power Generation in progress	-	4,973.0	Solar	T6045B13	SAMARIA 115KV
CHKLIST-8517	10/20/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2181B01	LAUREL HILL 230KV
CHKLIST-8135	10/17/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T1612B11	TROY BURNETTE 115KV
CHKLIST-8134	10/8/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T2631B01	WEATHERSPOON 230KV
CHKLIST-8133	9/30/2014	Approved	Commercial Operation - Power Generation in progress	-	1,990.0	Solar	T5670B22	EDMONDSON 230KV
CHKLIST-8132	9/29/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,999.0	Solar	T1980B04	FAIRMONT 115KV
NC2015-00021	9/25/2014	Substation A	Facility Study - Pending	-	479.0	Solar	T0840B03	VANDERBILT 115KV
CHKLIST-8127	9/24/2014	Project Not Active	Cancelled	-	4,999.0	Solar	T0990B02	BISCOE 115KV
CHKLIST-8128	9/24/2014	Project Not Active	Cancelled	-	5,000.0	Solar	T1670B01	WADESBORO 230KV
CHKLIST-8123	9/23/2014	Approved	Commercial Operation - Power Generation in progress	-	176.0	Solar	T6041B01	SPRING HOPE 115KV
CHKLIST-8124	9/23/2014	Approved	Commercial Operation - Power Generation in progress	-	85.0	Solar	T6041B01	SPRING HOPE 115KV
CHKLIST-8125	9/23/2014	Approved	Commercial Operation - Power Generation in progress	-	93.0	Solar	T6041B01	SPRING HOPE 115KV
CHKLIST-8126	9/23/2014	Substation A	System Impact Study - Pending Customer Response	Not Applicable	4,998.0	Solar	T5390B02	YANCEYVILLE 230KV
CHKLIST-8122	9/18/2014	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T2250B01	PITTSBORO 230KV
CHKLIST-5917	9/16/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T5090B02	OXFORD NORTH 230KV
CHKLIST-8120	9/16/2014	Project Not Active	Withdrawn	-	5,280.0	Solar	T2250B01	PITTSBORO 230KV
CHKLIST-8121	9/16/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,747.0	Solar	T2250B01	PITTSBORO 230KV
CHKLIST-8093	9/15/2014	Project Not Active	Cancelled	-	5,000.0	Solar	T1530B01	SILER CITY 115KV
CHKLIST-8094	9/15/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1612B12	TROY BURNETTE 115KV
CHKLIST-8095	9/15/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4785B02	HENDERSON EAST 230KV
CHKLIST-8096	9/15/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1530B05	SILER CITY 115KV
CHKLIST-8097	9/15/2014	Substation A	Facility Study - In Progress	Not Applicable	4,990.0	Solar	T6045B12	SAMARIA 115KV
CHKLIST-8098	9/15/2014	Substation B	Facility Study - Pending	Not Applicable	4,998.0	Solar	T6045B12	SAMARIA 115KV
CHKLIST-8099	9/15/2014	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T2141B05	JONESBORO 230KV
CHKLIST-8100	9/15/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T6045B12	SAMARIA 115KV
CHKLIST-8101	9/15/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T5360B01	WARRENTON 115KV
CHKLIST-8102	9/15/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T5650B20	ERWIN 230KV
CHKLIST-8103	9/15/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T5650B20	ERWIN 230KV
CHKLIST-8104	9/15/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T5860B02	LILLINGTON 115KV
CHKLIST-8105	9/15/2014	Substation A	Construction - Pending IA/Customer Payment	Not Applicable	4,466.0	Solar	T1520B01	SEAGROVE 115KV
CHKLIST-8106	9/15/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,498.0	Solar	T1530B01	SILER CITY 115KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-8107	9/15/2014	Project Not Active	Withdrawn	-	2,000.0	Solar	T1980B01	FAIRMONT 115KV
CHKLIST-8108	9/15/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T4770B05	HENDERSON NORTH 115KV
CHKLIST-8109	9/15/2014	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T1850B02	CANDOR 115KV
CHKLIST-8111	9/15/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T4720B04	GARNER 115KV
CHKLIST-8112	9/15/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T2320B01	RED SPRINGS 115KV
CHKLIST-8113	9/15/2014	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4785B06	HENDERSON EAST 230KV
CHKLIST-8114	9/15/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T5360B01	WARRENTON 115KV
CHKLIST-8115	9/15/2014	Project Not Active	Cancelled	-	5,000.0	Solar	T4770B05	HENDERSON NORTH 115KV
CHKLIST-8116	9/15/2014	Project Not Active	Withdrawn	-	2,000.0	Solar	T2215B02	MAXTON 115KV
CHKLIST-8117	9/15/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T2200B24	LAURINBURG 230KV
CHKLIST-8118	9/15/2014	Approved	Construction - Under Construction / In Progress	Not Applicable	4,998.0	Solar	T5360B01	WARRENTON 115KV
CHKLIST-8119	9/15/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T4130B03	CHOCOWINITY 230KV
CHKLIST-8086	9/12/2014	Project Not Active	Cancelled	-	4,800.0	Solar	T5240B11	ROXBORO 115KV
CHKLIST-8087	9/12/2014	Project Not Active	Cancelled	-	4,800.0	Solar	T5240B11	ROXBORO 115KV
CHKLIST-8088	9/12/2014	Project Not Active	Cancelled	-	5,000.0	Solar	T2282B02	RAEFORD SOUTH 115KV
CHKLIST-8089	9/12/2014	Project Not Active	Withdrawn	-	2,000.0	Solar	T6045B12	SAMARIA 115KV
CHKLIST-8090	9/12/2014	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T2444B21	SANFORD DEEP RIVER 230KV
CHKLIST-8091	9/12/2014	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T4170B01	GRIFTON 115KV
CHKLIST-8092	9/12/2014	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T4136B11	DOVER 230KV
CHKLIST-8084	9/11/2014	Approved	Commercial Operation - Power Generation in progress	-	134.4	Solar	T0390B01	CANDLER 115KV
CHKLIST-8085	9/11/2014	Project Not Active	Cancelled	-	5,908.8	Solar	T5480B01	BENSON 230KV
CHKLIST-8083	9/10/2014	Approved	Commercial Operation - Power Generation in progress	-	630.0	Solar	T6070B01	WARSAW 230KV
CHKLIST-8079	9/8/2014	Project Not Active	Withdrawn	-	3,376.8	Solar	T5911B01	NEW HILL 230KV
CHKLIST-8080	9/8/2014	Approved	Commercial Operation - Power Generation in progress	-	96.0	Solar	T0340B17	WEST ASHEVILLE 115KV
CHKLIST-8081	9/8/2014	Project Not Active	Withdrawn	Not Applicable	3,000.0	Solar	T5860B01	LILLINGTON 115KV
CHKLIST-8082	9/8/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5085B04	OXFORD SOUTH 230KV
CHKLIST-8010	8/20/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T2520B02	ST. PAULS 115KV
CHKLIST-8001	8/14/2014	Project Not Active	Withdrawn	-	4,999.0	Solar	T5450B03	BAILEY 230KV
CHKLIST-8002	8/14/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T2215B02	MAXTON 115KV
CHKLIST-8003	8/14/2014	Project Not Active	Cancelled	-	756.0	Solar	T0350B01	BALDWIN 115KV
CHKLIST-8004	8/14/2014	Project Not Active	Withdrawn	-	3,998.0	Solar	T5650B21	ERWIN 230KV
CHKLIST-8005	8/14/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T5090B04	OXFORD NORTH 230KV
CHKLIST-8006	8/14/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T5090B04	OXFORD NORTH 230KV
CHKLIST-8007	8/14/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T5935B02	PRINCETON 115KV
CHKLIST-8008	8/14/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T5935B02	PRINCETON 115KV
CHKLIST-8009	8/14/2014	Project Not Active	Cancelled	-	4,998.0	Solar	T5935B02	PRINCETON 115KV
CHKLIST-7993	8/12/2014	Project Not Active	Cancelled	-	4,998.0	Solar	T1550B05	SOUTHERN PINES 115KV
CHKLIST-7994	8/12/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T1550B05	SOUTHERN PINES 115KV
CHKLIST-7995	8/12/2014	Project Not Active	Cancelled	-	4,998.0	Solar	T5090B02	OXFORD NORTH 230KV
CHKLIST-7996	8/12/2014	Project Not Active	Cancelled	-	4,998.0	Solar	T5090B02	OXFORD NORTH 230KV
CHKLIST-7997	8/12/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T5504B02	BUIES CREEK 230KV
CHKLIST-7998	8/12/2014	Project Not Active	Cancelled	-	3,500.0	Solar	T4720B04	GARNER 115KV
CHKLIST-7999	8/12/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T4320B02	SNOW HILL 115KV
CHKLIST-8000	8/12/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T4320B02	SNOW HILL 115KV
CHKLIST-7984	7/29/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5490B01	BEULAVILLE 115KV
CHKLIST-7985	7/29/2014	Approved	Commercial Operation - Power Generation in progress	-	53.0	Solar	T6446B22	LELAND INDUSTRIAL 115KV
CHKLIST-7986	7/29/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T2520B01	ST. PAULS 115KV
CHKLIST-7987	7/29/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T2520B01	ST. PAULS 115KV
CHKLIST-7988	7/29/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T2520B01	ST. PAULS 115KV
CHKLIST-7989	7/29/2014	Project Not Active	Withdrawn	Not Applicable	5,500.0	Solar	T5385B04	WILSON MILLS 230KV
CHKLIST-7990	7/29/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T5860B01	LILLINGTON 115KV
CHKLIST-7991	7/29/2014	Project Not Active	Withdrawn	Not Applicable	4,999.0	Solar	T5570B03	CLINTON NORTH 115KV
CHKLIST-7992	7/29/2014	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T1610B03	TROY 115KV
CHKLIST-7981	7/28/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T4136B12	DOVER 230KV
CHKLIST-7982	7/28/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T4130B04	CHOCOWINITY 230KV
CHKLIST-7983	7/28/2014	Project Not Active	Withdrawn	-	4,950.0	Solar	T2335B02	ROWLAND 230KV
CHKLIST-7976	7/21/2014	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T1980B04	FAIRMONT 115KV
CHKLIST-7977	7/21/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T2320B01	RED SPRINGS 115KV
CHKLIST-7978	7/21/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T2320B02	RED SPRINGS 115KV
CHKLIST-7974	7/18/2014	Approved	Commercial Operation - Power Generation in progress	-	4,995.0	Solar	T2190B02	LAURINBURG CITY 230KV
CHKLIST-7975	7/18/2014	Project Not Active	Cancelled	-	3,998.0	Solar	T2181B05	LAUREL HILL 230KV
CHKLIST-7979	7/16/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T2320B01	RED SPRINGS 115KV
CHKLIST-7969	7/10/2014	Project Not Active	Withdrawn	-	4,950.0	Solar	T6070B04	WARSAW 230KV
CHKLIST-7970	7/10/2014	Project Not Active	Withdrawn	-	4,950.0	Solar	T1672B03	WADESBORO-BOWMAN SCHOOL 230KV
CHKLIST-7971	7/10/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T4785B04	HENDERSON EAST 230KV
CHKLIST-7972	7/10/2014	Approved	Commercial Operation - Power Generation in progress	-	1,980.0	Solar	T5900B05	NASHVILLE 115KV
CHKLIST-7973	7/10/2014	Approved	Commercial Operation - Power Generation in progress	-	4,995.0	Solar	T4319B02	GLOBAL TRANSPARK 115KV
CHKLIST-7966	7/9/2014	Project Not Active	Cancelled	-	680.0	Solar	-	N/A
CHKLIST-7967	7/9/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,890.0	Solar	T1850B02	CANDOR 115KV
CHKLIST-7968	7/9/2014	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T0960B11	ASHEBORO EAST 115KV
CHKLIST-7962	6/30/2014	Project Not Active	Cancelled	-	5,000.0	Solar	T4930B02	LOUISBURG 115KV
CHKLIST-7963	6/30/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T6160B01	BURGAW 115KV
CHKLIST-7964	6/30/2014	Project Not Active	Withdrawn	-	4,999.0	Solar	T5450B03	BAILEY 230KV
CHKLIST-7965	6/30/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T6045B13	SAMARIA 115KV
CHKLIST-7942	6/29/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5450B03	BAILEY 230KV
CHKLIST-7961	6/27/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T5970B07	SELMA 230KV
CHKLIST-7957	6/20/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4930B02	LOUISBURG 115KV
CHKLIST-7958	6/20/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4930B03	LOUISBURG 115KV
CHKLIST-7959	6/20/2014	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T6070B02	WARSAW 230KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-7951	6/17/2014	Project Not Active	Cancelled	-	5,000.0	Solar	T5385B02	WILSON MILLS 230KV
CHKLIST-7952	6/17/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4276B02	RHEMS 230KV
CHKLIST-7953	6/17/2014	Approved	Construction - Under Construction / In Progress	Not Applicable	5,000.0	Solar	T4285B02	ROSE HILL 230KV
CHKLIST-7954	6/17/2014	Project Not Active	Withdrawn	Not Applicable	4,500.0	Solar	T5830B03	LAGRANGE 115KV
CHKLIST-7955	6/17/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T2280B05	RAEFORD 115KV
CHKLIST-7956	6/17/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T6250B01	DELCO 115KV
CHKLIST-7948	6/12/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2432B01	SANFORD GARDEN STREET 230KV
CHKLIST-7949	6/12/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2432B02	SANFORD GARDEN STREET 230KV
CHKLIST-7950	6/12/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2432B03	SANFORD GARDEN STREET 230KV
CHKLIST-7946	6/9/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5465B05	BELFAST 115KV
CHKLIST-7947	6/9/2014	Project Not Active	Cancelled	-	4,995.0	Solar	T6630B01	TABOR CITY 115KV
CHKLIST-7943	6/6/2014	Project Not Active	Cancelled	Not Applicable	5,000.0	Solar	T5888B03	MT. OLIVE WEST 115KV
CHKLIST-7944	6/6/2014	Approved	Construction - Pending Meter Installation	-	65.0	Solar	T5314B13	GARNER TRYON HILLS 115KV
CHKLIST-7945	6/6/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1550B05	LAKEVIEW 115KV
CHKLIST-7941	6/4/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2190B01	LAURINBURG CITY 230KV
CHKLIST-7938	5/30/2014	Project Not Active	Cancelled	-	4,950.0	Solar	T6360B02	GARLAND 230KV
CHKLIST-7939	5/30/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,950.0	Solar	T5580B05	CLINTON FERRELL ST. 115KV
CHKLIST-7940	5/30/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T5690B02	ERWIN MILLS 115KV
CHKLIST-7935	5/28/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T1530B03	SILER CITY 115KV
CHKLIST-7936	5/28/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T6160B01	BURGAW 115KV
CHKLIST-7937	5/28/2014	Project Not Active	Withdrawn	-	4,950.0	Solar	T5580B02	CLINTON FERRELL ST. 115KV
CHKLIST-7930	5/23/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T5302B03	STALLINGS CROSSROADS 115KV
CHKLIST-7931	5/23/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2631B01	WEATHERSPOON 230KV
CHKLIST-7932	5/23/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5830B01	LAGRANGE 115KV
CHKLIST-7933	5/23/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5970B07	SELMA 230KV
CHKLIST-7934	5/23/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5732B03	FOUR OAKS 230KV
CHKLIST-7927	5/16/2014	Approved	Commercial Operation - Power Generation in progress	-	24.0	Solar	T0510B21	ELK MOUNTAIN 115KV
CHKLIST-7923	5/14/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	3,400.0	Solar	T5749B01	GODWIN 115KV
CHKLIST-7924	5/14/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5085B02	OXFORD SOUTH 230KV
CHKLIST-7925	5/14/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5090B04	OXFORD NORTH 230KV
CHKLIST-7926	5/14/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4770B01	HENDERSON NORTH 115KV
CHKLIST-7770	5/5/2014	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T4074B02	BRIDGETON 115KV
CHKLIST-7922	5/1/2014	Project Not Active	Withdrawn	-	1,981.0	Solar	T6040B13	CASTALIA 230KV
CHKLIST-7918	4/29/2014	Approved	Construction - Under Construction / In Progress	Not Applicable	5,000.0	Solar	T2181B05	LAUREL HILL 230KV
CHKLIST-7919	4/29/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5302B01	STALLINGS CROSSROADS 115KV
CHKLIST-7920	4/29/2014	Approved	Commercial Operation - Power Generation in progress	-	134.0	Solar	T5116B03	RALEIGH DURHAM AIRPORT 230KV
CHKLIST-7916	4/25/2014	Project Not Active	Cancelled	-	1,981.0	Solar	T5830B01	LAGRANGE 115KV
CHKLIST-7917	4/25/2014	Approved	Commercial Operation - Power Generation in progress	-	4,995.0	Solar	T5570B03	CLINTON NORTH 115KV
CHKLIST-7902	4/23/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5732B03	FOUR OAKS 230KV
CHKLIST-7914	4/22/2014	Project Not Active	Withdrawn	-	4,800.0	Solar	T4230B02	KINSTON 115KV
CHKLIST-7912	4/17/2014	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T5490B01	BEULAVILLE 115KV
CHKLIST-7910	4/16/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T5490B01	BEULAVILLE 115KV
CHKLIST-7911	4/16/2014	Project Not Active	Cancelled	-	10,000.0	Solar	T4785B02	HENDERSON EAST 230KV
CHKLIST-7909	4/11/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T6360B02	GARLAND 230KV
CHKLIST-7904	4/8/2014	Project Not Active	Cancelled	-	500.0	Solar	T5749B01	GODWIN 115KV
CHKLIST-7905	4/8/2014	Approved	Commercial Operation - Power Generation in progress	-	1,981.0	Solar	T6040B13	CASTALIA 230KV
CHKLIST-7906	4/8/2014	Approved	Commercial Operation - Power Generation in progress	-	58.0	Solar	T6205B11	CASTLE HAYNE 230KV
CHKLIST-7907	4/8/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T4770B05	HENDERSON NORTH 115KV
CHKLIST-7908	4/8/2014	Approved	Commercial Operation - Power Generation in progress	-	4,800.0	Solar	T6330B01	ELIZABETHTOWN 115KV
CHKLIST-7903	4/7/2014	Project Not Active	Withdrawn	Not Applicable	5,000.0	Solar	T4225B01	KORNEGAY 115KV
CHKLIST-7901	4/3/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5749B01	GODWIN 115KV
CHKLIST-7900	4/1/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1520B01	SEAGROVE 115KV
CHKLIST-7793	3/27/2014	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T1980B01	FAIRMONT 115KV
CHKLIST-7897	3/27/2014	Approved	Commercial Operation - Power Generation in progress	-	100.0	Biomass	T4285B01	ROSE HILL 230KV
CHKLIST-7898	3/27/2014	Approved	Commercial Operation - Power Generation in progress	-	4,995.0	Solar	T2247B02	PEMBROKE 115KV
CHKLIST-7899	3/27/2014	Project Not Active	Withdrawn	-	1,981.0	Solar	T2580B01	VANDER 115KV
CHKLIST-7895	3/20/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T4285B02	ROSE HILL 230KV
CHKLIST-7896	3/20/2014	Project Not Active	Cancelled	-	4,998.0	Solar	T6330B01	ELIZABETHTOWN 115KV
CHKLIST-7893	3/19/2014	Project Not Active	Withdrawn	-	1,000.0	Solar	T5770B01	GRANTHAM 230KV
CHKLIST-7890	3/13/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T5090B01	OXFORD NORTH 230KV
CHKLIST-7891	3/13/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T1530B01	SILER CITY 115KV
CHKLIST-7888	3/10/2014	Project Not Active	Withdrawn	-	5,000.0	Solar	T5600B01	ROSEBORO 115KV
CHKLIST-7889	3/10/2014	Project Not Active	Cancelled	Not Applicable	5,000.0	Solar	T5888B03	MT. OLIVE WEST 115KV
CHKLIST-7886	3/3/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T5888B03	MT. OLIVE WEST 115KV
CHKLIST-7887	3/3/2014	Project Not Active	Cancelled	-	4,998.0	Solar	T6070B04	WARSAW 230KV
CHKLIST-7884	2/27/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5732B02	FOUR OAKS 230KV
CHKLIST-7885	2/27/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5749B01	GODWIN 115KV
CHKLIST-7879	2/25/2014	Project Not Active	Withdrawn	-	4,320.0	Biomass	T6070B04	WARSAW 230KV
CHKLIST-7881	2/25/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2200B23	LAURINBURG 230KV
CHKLIST-7882	2/25/2014	Approved	Commercial Operation - Power Generation in progress	-	4,500.0	Solar	T4255B03	NEW BERN WEST 230KV
CHKLIST-7883	2/25/2014	Approved	Commercial Operation - Power Generation in progress	-	4,500.0	Solar	T4130B03	CHOCOWINITY 230KV
CHKLIST-7880	2/21/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4170B02	GRIFTON 115KV
CHKLIST-7874	2/20/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	5,000.0	Solar	T5490B02	BEULAVILLE 115KV
CHKLIST-7875	2/20/2014	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T6220B01	CLARKTON 115KV
CHKLIST-7876	2/20/2014	Project Not Active	Cancelled	-	4,883.0	Solar	T5490B01	BEULAVILLE 115KV
CHKLIST-7877	2/20/2014	Project Not Active	Cancelled	-	1,998.0	Solar	T5888B01	MT. OLIVE WEST 115KV
CHKLIST-7878	2/20/2014	Project Not Active	Withdrawn	-	4,230.0	Biomass	T5570B02	CLINTON NORTH 115KV
CHKLIST-7872	2/19/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T6040B12	CASTALIA 230KV
CHKLIST-7873	2/19/2014	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T5749B01	GODWIN 115KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-7865	2/10/2014	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T2475B01	SHANNON 115KV
CHKLIST-7866	2/10/2014	Project Not Active	Withdrawn	-	1,981.0	Solar	T1980B04	FAIRMONT 115KV
CHKLIST-7867	2/10/2014	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T2215B02	MAXTON 115KV
CHKLIST-7869	2/10/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5860B01	LILLINGTON 115KV
CHKLIST-7870	2/10/2014	Approved	Commercial Operation - Power Generation in progress	-	4,995.0	Solar	T4770B04	HENDERSON NORTH 115KV
CHKLIST-7871	2/10/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T4285B02	ROSE HILL 230KV
CHKLIST-7864	2/4/2014	Project Not Active	Cancelled	-	1,900.0	Solar	T0791B04	SPRUCE PINE 115KV
CHKLIST-7862	1/27/2014	Project Not Active	Withdrawn	-	1,981.0	Solar	T1670B01	WADESBORO 230KV
CHKLIST-7863	1/27/2014	Approved	Commercial Operation - Power Generation in progress	-	1,981.0	Solar	T4225B02	KORNEGAY 115KV
CHKLIST-7861	1/24/2014	Project Not Active	Cancelled	-	5,000.0	Solar	T4770B05	HENDERSON NORTH 115KV
CHKLIST-7858	1/23/2014	Project Not Active	Cancelled	-	2,572.0	Solar	-	N/A
CHKLIST-7859	1/23/2014	Project Not Active	Cancelled	-	6,000.0	Solar	T2475B02	SHANNON 115KV
CHKLIST-7860	1/23/2014	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,998.0	Solar	T5740B02	FREMONT 115KV
CHKLIST-7854	1/17/2014	Project Not Active	Withdrawn	-	4,998.0	Solar	T5754B01	GOLDSBORO LANGSTON 115KV
CHKLIST-7855	1/17/2014	Approved	Construction - Pending Customer Obligation	-	39.0	Solar	T4610B13	CARY TRENTON ROAD 230KV
CHKLIST-7856	1/17/2014	Approved	Commercial Operation - Power Generation in progress	-	150.0	Solar	T5119B13	RALEIGH BRIER CREEK 230KV
CHKLIST-7857	1/17/2014	Project Not Active	Cancelled	-	2,572.0	Solar	T1670B01	WADESBORO 230KV
CHKLIST-7851	1/2/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5754B01	GOLDSBORO LANGSTON 115KV
CHKLIST-7852	1/2/2014	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T6070B03	WARSAW 230KV
CHKLIST-7853	1/2/2014	Project Not Active	Withdrawn	-	4,950.0	Solar	T1428B01	ROCKINGHAM-ABERDEEN ROAD 230KV
CHKLIST-7850	12/30/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5090B02	OXFORD NORTH 230KV
CHKLIST-7847	12/19/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1670B01	WADESBORO 230KV
CHKLIST-7848	12/19/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T5830B02	LAGRANGE 115KV
CHKLIST-7849	12/19/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T5480B03	BENSON 230KV
CHKLIST-7843	12/18/2013	Project Not Active	Cancelled	-	4,998.0	Solar	T6041B02	SPRING HOPE 115KV
CHKLIST-7844	12/18/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T4136B12	DOVER 230KV
CHKLIST-7845	12/18/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1700B15	WEST END 230KV
CHKLIST-7846	12/18/2013	Project Not Active	Withdrawn	-	4,998.0	Solar	T5240B12	ROXBORO 115KV
CHKLIST-7841	12/6/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5302B03	STALLINGS CROSSROADS 115KV
CHKLIST-7842	12/6/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4130B04	CHOCOWINITY 230KV
CHKLIST-7829	11/27/2013	Project Not Active	Withdrawn	-	4,998.0	Solar	T1190B01	HAMLET 230KV
CHKLIST-7831	11/27/2013	Project Not Active	Cancelled	-	4,998.0	Solar	T2475B01	SHANNON 115KV
CHKLIST-7832	11/27/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T1530B01	SILER CITY 115KV
CHKLIST-7833	11/27/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T4136B12	DOVER 230KV
CHKLIST-7834	11/27/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T2475B02	SHANNON 115KV
CHKLIST-7836	11/27/2013	Project Not Active	Cancelled	-	5,000.0	Solar	T2217B01	MAXTON AIRPORT 115KV
CHKLIST-7837	11/27/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4785B03	HENDERSON EAST 230KV
CHKLIST-7838	11/27/2013	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T5888B03	MT. OLIVE WEST 115KV
CHKLIST-7839	11/27/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T1672B03	WADESBORO-BOWMAN SCHOOL 230KV
CHKLIST-7840	11/26/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T1670B02	WADESBORO 230KV
CHKLIST-7828	11/24/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T5890B01	MT. OLIVE 115KV
CHKLIST-7830	11/21/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4225B01	KORNEGAY 115KV
CHKLIST-7826	11/12/2013	Approved	Commercial Operation - Power Generation in progress	-	300.0	Solar	T4276B02	RHEMS 230KV
CHKLIST-7825	11/8/2013	Project Not Active	Cancelled	-	1,980.0	Solar	T6360B02	GARLAND 230KV
CHKLIST-7822	10/30/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T5888B03	MT. OLIVE WEST 115KV
CHKLIST-7823	10/30/2013	Approved	Commercial Operation - Power Generation in progress	-	4,998.0	Solar	T2520B02	ST. PAULS 115KV
CHKLIST-7820	10/18/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5770B01	GRANTHAM 230KV
CHKLIST-7821	10/18/2013	Project Not Active	Cancelled	-	4,999.0	Solar	T1440B25	ROCKINGHAM 230KV
CHKLIST-7819	10/16/2013	Project Not Active	Withdrawn	Not Applicable	16,000.0	Solar	T1765B01	BEARD 115KV
CHKLIST-7818	10/15/2013	Project Not Active	Cancelled	-	4,000.0	Biomass	T5740B03	FREMONT 115KV
CHKLIST-7817	10/11/2013	Approved	Commercial Operation - Power Generation in progress	-	1,980.0	Solar	T5921B01	NEWTON GROVE 230KV
CHKLIST-7824	10/8/2013	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T2200B23	LAURINBURG 230KV
CHKLIST-7808	10/7/2013	Approved	Commercial Operation - Power Generation in progress	-	46.0	Solar	T4325B03	WILMINGTON SUNSET PARK 115KV
CHKLIST-7809	10/7/2013	Project Not Active	Withdrawn	-	4,998.0	Solar	T4230B02	KINSTON 115KV
CHKLIST-7810	10/7/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5935B02	PRINCETON 115KV
CHKLIST-7811	10/7/2013	Approved	Commercial Operation - Power Generation in progress	-	3,500.0	Solar	T5360B03	WARRENTON 115KV
CHKLIST-7812	10/7/2013	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T4770B05	HENDERSON NORTH 115KV
CHKLIST-7813	10/7/2013	Approved	Commercial Operation - Power Generation in progress	-	45.0	Solar	T4990B37	METHOD 230KV
CHKLIST-7806	10/4/2013	Approved	Commercial Operation - Power Generation in progress	-	43.0	Solar	T5136B04	RALEIGH OAKDALE 230KV
CHKLIST-7807	10/4/2013	Project Not Active	Cancelled	-	19,990.0	Solar	T5650B20	ERWIN 230KV
CHKLIST-7804	9/30/2013	Project Not Active	Cancelled	-	4,999.0	Solar	T5680B01	ELM CITY 115KV
CHKLIST-7803	9/27/2013	Approved	Commercial Operation - Power Generation in progress	-	48.0	Solar	T4930B03	LOUISBURG 115KV
CHKLIST-7800	9/24/2013	Project Not Active	Withdrawn	-	4,999.0	Solar	T4930B02	LOUISBURG 115KV
CHKLIST-7801	9/24/2013	Approved	Commercial Operation - Power Generation in progress	-	552.0	Solar	T4602B04	CARY EVANS ROAD 230KV
CHKLIST-7802	9/24/2013	Project Not Active	Withdrawn	-	3,020.0	Biomass	T2217B02	MAXTON AIRPORT 115KV
CHKLIST-7797	9/20/2013	Project Not Active	Cancelled	-	137.0	Solar	T5970B08	SELMA 230KV
CHKLIST-7798	9/20/2013	Approved	Commercial Operation - Power Generation in progress	-	75.0	Solar	T5970B08	SELMA 230KV
CHKLIST-7799	9/20/2013	Approved	Commercial Operation - Power Generation in progress	-	123.0	Solar	T5970B08	SELMA 230KV
CHKLIST-7796	9/18/2013	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T4233B02	LAKE WACCAMAW 115KV
CHKLIST-7795	9/12/2013	Project Not Active	Withdrawn	Not Applicable	4,500.0	Solar	T2217B02	MAXTON AIRPORT 115KV
CHKLIST-7794	9/5/2013	Project Not Active	Withdrawn	-	2,000.0	Solar	T5900B05	NASHVILLE 115KV
CHKLIST-7790	9/4/2013	Project Not Active	Cancelled	-	4,950.0	Solar	-	N/A
CHKLIST-7791	9/4/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T5390B02	YANCEYVILLE 230KV
CHKLIST-7792	9/4/2013	Project Not Active	Cancelled	-	4,950.0	Solar	T4630B13	DUNCAN 230KV
CHKLIST-7789	8/28/2013	Project Not Active	Cancelled	-	4,950.0	Solar	T1810B01	BLADENBORO 115KV
CHKLIST-7786	8/26/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5390B04	YANCEYVILLE 230KV
CHKLIST-7787	8/26/2013	Approved	Commercial Operation - Power Generation in progress	Not Applicable	4,995.0	Solar	T5740B03	FREMONT 115KV
CHKLIST-7788	8/26/2013	Project Not Active	Withdrawn	-	2,000.0	Solar	T5921B02	NEWTON GROVE 230KV
CHKLIST-7785	8/22/2013	Project Not Active	Cancelled	-	31.4	Solar	-	N/A

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-7784	8/14/2013	Approved	Commercial Operation - Power Generation in progress	-	4,800.0	Solar	T4225B01	KORNEGAY 115KV
CHKLIST-7783	8/9/2013	Project Not Active	Withdrawn	-	4,999.0	Solar	T6350B01	FAIR BLUFF 115KV
CHKLIST-7778	8/2/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T6350B01	FAIR BLUFF 115KV
CHKLIST-7779	8/2/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T5480B04	BENSON 230KV
CHKLIST-7780	8/2/2013	Project Not Active	Withdrawn	-	10,000.0	Solar	T4230B02	KINSTON 115KV
CHKLIST-7781	8/2/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T6041B03	SPRING HOPE 115KV
CHKLIST-7775	7/31/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4915B01	LITTLETON 115KV
CHKLIST-7776	7/31/2013	Approved	Commercial Operation - Power Generation in progress	-	3,000.0	Solar	T5360B03	WARRENTON 115KV
CHKLIST-7777	7/31/2013	Project Not Active	Cancelled	-	5,000.0	Solar	T5390B04	YANCEYVILLE 230KV
CHKLIST-7771	7/25/2013	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	T1765B01	BEARD 115KV
CHKLIST-7772	7/25/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5302B02	STALLINGS CROSSROADS 115KV
CHKLIST-7773	7/25/2013	Project Not Active	Cancelled	-	5,000.0	Solar	T5650B20	ERWIN 230KV
CHKLIST-7774	7/25/2013	Project Not Active	Cancelled	-	4,000.0	Solar	T4255B05	NEW BERN WEST 230KV
CHKLIST-7768	7/24/2013	Project Not Active	Cancelled	-	5,000.0	Solar	-	N/A
CHKLIST-7769	7/24/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4785B06	HENDERSON EAST 230KV
CHKLIST-7764	7/9/2013	Approved	Commercial Operation - Power Generation in progress	-	19,800.0	Solar	T2217B01	MAXTON AIRPORT 115KV
CHKLIST-7765	7/9/2013	Approved	Commercial Operation - Power Generation in progress	-	100.0	Solar	T6310B20	EAGLE ISLAND 115KV
CHKLIST-7766	7/9/2013	Approved	Commercial Operation - Power Generation in progress	-	1,600.0	Solar	T6310B20	EAGLE ISLAND 115KV
CHKLIST-7767	7/9/2013	Approved	System Impact Study - Pending Customer Response	-	1,500.0	Solar	T4108B03	CATHERINE LAKE 230KV
CHKLIST-7762	7/3/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T4319B02	GLOBAL TRANSPARK 115KV
CHKLIST-7763	7/3/2013	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T1190B01	HAMLET 230KV
CHKLIST-7782	7/1/2013	Approved	Commercial Operation - Power Generation in progress	-	10,000.0	Solar	T5450B03	BAILEY 230KV
CHKLIST-7760	6/26/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T1850B01	CANDOR 115KV
CHKLIST-7761	6/26/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T4710B04	FUQUAY 230KV
CHKLIST-1100	6/24/2013	Approved	Commercial Operation - Power Generation in progress	-	375.0	Solar	T5314B11	CARALEIGH 230KV
CHKLIST-7756	6/14/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4225B01	KORNEGAY 115KV
CHKLIST-7757	6/14/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4130B03	CHOCOWINITY 230KV
CHKLIST-7758	6/14/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2580B01	VANDER 115KV
CHKLIST-7759	6/14/2013	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T5090B01	OXFORD NORTH 230KV
CHKLIST-7755	6/7/2013	Approved	Commercial Operation - Power Generation in progress	-	792.0	Hydroelectric	T1610B03	TROY 115KV
CHKLIST-7753	6/5/2013	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T4170B01	GRIFTON 115KV
CHKLIST-7754	6/5/2013	Project Not Active	Withdrawn	-	15,300.0	Solar	T4130B01	CHOCOWINITY 230KV
CHKLIST-7751	5/31/2013	Approved	Commercial Operation - Power Generation in progress	-	1,000.0	Solar	T5122B03	RALEIGH BLUE RIDGE 230KV
CHKLIST-7750	5/14/2013	Project Not Active	Cancelled	-	2,000.0	Solar	T6041B03	SPRING HOPE 115KV
CHKLIST-7745	5/10/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T6041B01	SPRING HOPE 115KV
CHKLIST-7746	5/10/2013	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	T5480B01	BENSON 230KV
CHKLIST-7747	5/10/2013	Project Not Active	Cancelled	-	5,000.0	Solar	T5732B01	FOUR OAKS 230KV
CHKLIST-7748	5/10/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T6045B12	SAMARIA 115KV
CHKLIST-7749	5/10/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5935B03	PRINCETON 115KV
CHKLIST-7736	5/6/2013	Project Not Active	Withdrawn	-	1,000.0	Solar	T2225B01	MONCURE 115KV
CHKLIST-7737	5/6/2013	Project Not Active	Cancelled	-	5,000.0	Solar	T5385B04	WILSON MILLS 230KV
CHKLIST-7738	5/6/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T5732B02	FOUR OAKS 230KV
CHKLIST-7739	5/6/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T5480B03	BENSON 230KV
CHKLIST-7740	5/6/2013	Project Not Active	Cancelled	-	5,000.0	Solar	T5970B08	SELMA 230KV
CHKLIST-7741	5/6/2013	Project Not Active	Cancelled	-	5,000.0	Solar	T5480B02	BENSON 230KV
CHKLIST-7742	5/6/2013	Substation A	Facility Study - In Progress	Not Applicable	13,450.0	Solar	T6041B03	SPRING HOPE 115KV
CHKLIST-7744	5/6/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5680B01	ELM CITY 115KV
CHKLIST-7734	4/29/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1430B01	ROCKINGHAM WEST 115KV
CHKLIST-7735	4/29/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4320B01	SNOW HILL 115KV
CHKLIST-7733	4/26/2013	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	T2247B01	PEMBROKE 115KV
CHKLIST-7752	4/21/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1810B02	BLADENBORO 115KV
CHKLIST-7730	4/16/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4255B01	NEW BERN WEST 230KV
CHKLIST-7731	4/16/2013	Project Not Active	Withdrawn	-	2,000.0	Solar	T5378B03	WENDELL 230KV
CHKLIST-7732	4/16/2013	Approved	Commercial Operation - Power Generation in progress	-	48.0	Solar	T2250B03	PITTSBORO 230KV
CHKLIST-7724	4/13/2013	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	T5640B02	CLAYTON 115KV
CHKLIST-7723	4/12/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T5385B04	WILSON MILLS 230KV
CHKLIST-7725	4/12/2013	Project Not Active	Withdrawn	-	3,000.0	Solar	T6205B12	CASTLE HAYNE 230KV
CHKLIST-7726	4/12/2013	Project Not Active	Withdrawn	-	2,000.0	Solar	T4850B01	KNIGHTDALE 115KV
CHKLIST-7727	4/12/2013	Project Not Active	Withdrawn	-	3,000.0	Solar	T5385B02	WILSON MILLS 230KV
CHKLIST-7728	4/12/2013	Project Not Active	Cancelled	-	3,000.0	Solar	T5385B02	WILSON MILLS 230KV
CHKLIST-7729	4/12/2013	Project Not Active	Cancelled	-	5,000.0	Solar	T5970B07	SELMA 230KV
CHKLIST-7716	4/8/2013	Project Not Active	Cancelled	-	1,990.0	Solar	T1190B01	HAMLET 230KV
CHKLIST-7717	4/8/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5970B07	SELMA 230KV
CHKLIST-7718	4/8/2013	Project Not Active	Cancelled	-	5,000.0	Solar	T5385B02	WILSON MILLS 230KV
CHKLIST-7719	4/8/2013	Project Not Active	Withdrawn	-	3,000.0	Solar	T5385B02	WILSON MILLS 230KV
CHKLIST-7720	4/8/2013	Project Not Active	Cancelled	-	4,000.0	Solar	T5970B07	SELMA 230KV
CHKLIST-7721	4/8/2013	Project Not Active	Cancelled	-	4,000.0	Solar	T4500B13	ARCHER LODGE 230KV
CHKLIST-7722	4/8/2013	Project Not Active	Cancelled	-	2,000.0	Solar	-	N/A
CHKLIST-7709	3/28/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T5912B03	NEW HOPE 115KV
CHKLIST-7710	3/28/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T6670B04	WHITEVILLE 115KV
CHKLIST-7711	3/28/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T5912B05	NEW HOPE 115KV
CHKLIST-7712	3/28/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T5912B03	NEW HOPE 115KV
CHKLIST-7713	3/28/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T4426B11	WAKE TECH 230KV
CHKLIST-7715	3/28/2013	Approved	Commercial Operation - Power Generation in progress	-	15,000.0	Solar	T4130B02	CHOCOWINITY 230KV
CHKLIST-7705	3/22/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T5650B20	ERWIN 230KV
CHKLIST-7706	3/22/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T6350B01	FAIR BLUFF 115KV
CHKLIST-7707	3/22/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T2631B01	WEATHERSPOON 230KV
CHKLIST-7708	3/22/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T0990B03	BISCOE 115KV
CHKLIST-7704	3/15/2013	Project Not Active	Cancelled	-	4,975.0	Solar	T5390B04	YANCEYVILLE 230KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-7702	3/1/2013	Project Not Active	Withdrawn	-	325.0	Biomass	T1850B01	CANDOR 115KV
CHKLIST-7703	3/1/2013	Project Not Active	Cancelled	-	20,000.0	Solar	T4130B02	CHOCOWINITY 230KV
CHKLIST-7700	2/28/2013	Approved	Commercial Operation - Power Generation in progress	-	1,000.0	Solar	T0350B01	BALDWIN 115KV
CHKLIST-7701	2/28/2013	Project Not Active	Cancelled	-	1,600.0	Solar	T5732B03	FOUR OAKS 230KV
CHKLIST-7697	2/26/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T6220B01	CLARKTON 115KV
CHKLIST-7698	2/26/2013	Project Not Active	Withdrawn	-	2,000.0	Solar	T5900B05	NASHVILLE 115KV
CHKLIST-7696	2/22/2013	Approved	Commercial Operation - Power Generation in progress	-	4,872.0	Solar	T5921B02	NEWTON GROVE 230KV
CHKLIST-7695	2/19/2013	Approved	Commercial Operation - Power Generation in progress	-	1,980.0	Solar	T5600B03	ROSEBORO 115KV
CHKLIST-7692	2/18/2013	Approved	Commercial Operation - Power Generation in progress	-	4,320.0	Solar	T2631B04	WEATHERSPOON 230KV
CHKLIST-7690	2/13/2013	Approved	Commercial Operation - Power Generation in progress	-	452.8	Solar	T5116B03	RALEIGH DURHAM AIRPORT 230KV
CHKLIST-7691	2/13/2013	Project Not Active	Withdrawn	-	4,320.0	Solar	T6070B01	WARSAW 230KV
CHKLIST-7686	2/9/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1672B01	WADESBORO-BOWMAN SCHOOL 230KV
CHKLIST-7687	2/9/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T5450B03	BAILEY 230KV
CHKLIST-7688	2/9/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T4170B01	GRIFTON 115KV
CHKLIST-7689	2/9/2013	Approved	Commercial Operation - Power Generation in progress	-	3,000.0	Solar	T4785B03	HENDERSON EAST 230KV
CHKLIST-7684	2/8/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T6041B03	SPRING HOPE 115KV
CHKLIST-7685	2/8/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T2181B05	LAUREL HILL 230KV
CHKLIST-7680	2/7/2013	Project Not Active	Withdrawn	-	2,000.0	Solar	T5480B04	BENSON 230KV
CHKLIST-7681	2/7/2013	Approved	Commercial Operation - Power Generation in progress	-	4,400.0	Solar	T5427B02	ANGIER 230KV
CHKLIST-7682	2/7/2013	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T2631B03	WEATHERSPOON 230KV
CHKLIST-7683	2/7/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T6040B12	CASTALIA 230KV
CHKLIST-7694	2/6/2013	Approved	Commercial Operation - Power Generation in progress	-	20,000.0	Solar	T0990B02	BISCOE 115KV
CHKLIST-7677	1/30/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1850B01	CANDOR 115KV
CHKLIST-7678	1/30/2013	Approved	Commercial Operation - Power Generation in progress	-	4,500.0	Solar	T6070B01	WARSAW 230KV
CHKLIST-7679	1/30/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T1850B01	CANDOR 115KV
CHKLIST-7675	1/29/2013	Approved	Commercial Operation - Power Generation in progress	-	2,500.0	Solar	T4730B12	GARNER WHITE OAK 230KV
CHKLIST-7676	1/29/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T5600B01	ROSEBORO 115KV
CHKLIST-7661	1/23/2013	Project Not Active	Cancelled	-	1,200.0	Hydroelectric	T1610B03	TROY 115KV
CHKLIST-7663	1/23/2013	Project Not Active	Withdrawn	-	2,000.0	Solar	T5935B01	PRINCETON 115KV
CHKLIST-7665	1/23/2013	Approved	Commercial Operation - Power Generation in progress	-	1,990.0	Solar	T4320B01	SNOW HILL 115KV
CHKLIST-7666	1/23/2013	Project Not Active	Cancelled	-	1,000.0	Solar	T0510B22	ELK MOUNTAIN 115KV
CHKLIST-7667	1/23/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5830B03	LAGRANGE 115KV
CHKLIST-7668	1/23/2013	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T6070B02	WARSAW 230KV
CHKLIST-7669	1/23/2013	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T5360B02	WARRENTON 115KV
CHKLIST-7670	1/23/2013	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	Solar	T2320B02	RED SPRINGS 115KV
CHKLIST-7671	1/23/2013	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T1810B02	BLADENBORO 115KV
CHKLIST-7672	1/23/2013	Approved	Commercial Operation - Power Generation in progress	-	1,980.0	Solar	T5600B01	ROSEBORO 115KV
CHKLIST-7673	1/23/2013	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T5090B02	OXFORD NORTH 230KV
CHKLIST-7674	1/23/2013	Project Not Active	Withdrawn	-	5,000.0	Solar	T5732B03	FOUR OAKS 230KV
CHKLIST-7664	1/21/2013	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T5302B02	STALLINGS CROSSROADS 115KV
CHKLIST-7662	1/8/2013	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T5302B01	STALLINGS CROSSROADS 115KV
CHKLIST-7660	1/7/2013	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T4320B02	SNOW HILL 115KV
CHKLIST-7658	12/6/2012	Project Not Active	Withdrawn	-	2,000.0	Solar	T4320B01	SNOW HILL 115KV
CHKLIST-7659	12/5/2012	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T4319B01	GLOBAL TRANSPARK 115KV
CHKLIST-7656	12/3/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T6070B01	WARSAW 230KV
CHKLIST-7657	11/30/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T6350B01	FAIR BLUFF 115KV
CHKLIST-7653	11/29/2012	Approved	Commercial Operation - Power Generation in progress	-	4,999.0	Solar	T5888B01	MT. OLIVE WEST 115KV
CHKLIST-7654	11/28/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T6215B02	CHADBOURN 115KV
CHKLIST-7655	11/28/2012	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T5754B01	GOLDSBORO LANGSTON 115KV
CHKLIST-7650	11/26/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2200B22	LAURINBURG 230KV
CHKLIST-7651	11/26/2012	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T1140B01	ELLERBE 230KV
CHKLIST-7652	11/21/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5770B01	GRANTHAM 230KV
CHKLIST-7648	11/14/2012	Approved	Commercial Operation - Power Generation in progress	-	30.0	Solar	T0375B03	BLACK MOUNTAIN 115KV
CHKLIST-7649	11/14/2012	Project Not Active	Withdrawn	-	1,600.0	Solar	T5921B01	NEWTON GROVE 230KV
CHKLIST-7647	11/12/2012	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T6070B01	WARSAW 230KV
CHKLIST-7644	11/5/2012	Project Not Active	Cancelled	-	1,976.0	Solar	T5888B01	MT. OLIVE WEST 115KV
CHKLIST-7641	11/2/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5890B01	MT. OLIVE 115KV
CHKLIST-7642	11/2/2012	Project Not Active	Withdrawn	-	2,000.0	Solar	T5490B01	BEULAVILLE 115KV
CHKLIST-7643	11/2/2012	Project Not Active	Cancelled	-	2,000.0	Solar	T6041B03	SPRING HOPE 115KV
CHKLIST-7645	11/2/2012	Approved	Commercial Operation - Power Generation in progress	-	4,320.0	Solar	T1980B03	FAIRMONT 115KV
CHKLIST-7646	11/2/2012	Approved	Commercial Operation - Power Generation in progress	-	200.0	Solar	T5085B01	OXFORD SOUTH 230KV
CHKLIST-7636	10/26/2012	Project Not Active	Withdrawn	-	440.0	Solar	T0784B13	AVERY CREEK 115KV
CHKLIST-7637	10/26/2012	Approved	Commercial Operation - Power Generation in progress	-	1,900.0	Solar	T6070B04	WARSAW 230KV
CHKLIST-7638	10/26/2012	Project Not Active	Cancelled	-	1,900.0	Solar	T6090B10	ZEBULON 115KV
CHKLIST-7639	10/26/2012	Project Not Active	Cancelled	-	2,000.0	Solar	T0375B02	BLACK MOUNTAIN 115KV
CHKLIST-7640	10/26/2012	Project Not Active	Withdrawn	-	2,000.0	Solar	T5570B03	CLINTON NORTH 115KV
CHKLIST-7633	10/24/2012	Project Not Active	Cancelled	-	20,000.0	Solar	T2320B01	RED SPRINGS 115KV
CHKLIST-7634	10/24/2012	Project Not Active	Cancelled	-	20,000.0	Solar	T5360B03	WARRENTON 115KV
CHKLIST-7635	10/24/2012	Project Not Active	Cancelled	-	20,000.0	Solar	T1810B01	BLADENBORO 115KV
CHKLIST-7630	10/19/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2335B02	ROWLAND 230KV
CHKLIST-7626	10/18/2012	Project Not Active	Cancelled	-	5,000.0	Solar	-	N/A
CHKLIST-7628	10/18/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5465B03	BELFAST 115KV
CHKLIST-7629	10/18/2012	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T5240B15	ROXBORO 115KV
CHKLIST-7631	10/18/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2282B02	RAEFORD SOUTH 115KV
CHKLIST-7632	10/17/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T6215B01	CHADBOURN 115KV
CHKLIST-7618	10/8/2012	Project Not Active	Cancelled	-	50.0	Solar	T6470B05	WILMINGTON OGDEN 230KV
CHKLIST-7619	10/8/2012	Approved	Commercial Operation - Power Generation in progress	-	257.0	Solar	T6090B05	ZEBULON 115KV
CHKLIST-7620	10/8/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T5970B08	SELMA 230KV
CHKLIST-7621	10/8/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T1980B03	FAIRMONT 115KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-7624	10/8/2012	Project Not Active	Withdrawn	-	1,976.0	Solar	T5570B03	CLINTON NORTH 115KV
CHKLIST-7622	10/5/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T0990B03	BISCOE 115KV
CHKLIST-7627	10/3/2012	Approved	Commercial Operation - Power Generation in progress	-	4,990.0	Solar	T4785B06	HENDERSON EAST 230KV
CHKLIST-7623	10/1/2012	Approved	Commercial Operation - Power Generation in progress	-	4,990.0	Solar	T5360B02	WARRENTON 115KV
CHKLIST-7617	9/20/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T2181B05	LAUREL HILL 230KV
CHKLIST-7293	9/13/2012	Project Not Active	Cancelled	-	1,500.0	Solar	T0340B11	WEST ASHEVILLE 115KV
CHKLIST-7615	9/13/2012	Approved	Commercial Operation - Power Generation in progress	-	1,500.0	Solar	T0340B11	WEST ASHEVILLE 115KV
CHKLIST-7616	9/13/2012	Project Not Active	Cancelled	-	3,000.0	Solar	-	N/A
CHKLIST-7609	9/7/2012	Approved	Commercial Operation - Power Generation in progress	-	385.0	Solar	T4710B02	FUQUAY 230KV
CHKLIST-7611	9/7/2012	Project Not Active	Cancelled	-	1,700.0	Solar	T0665B11	LEICESTER 115KV
CHKLIST-7612	9/7/2012	Project Not Active	Cancelled	-	1,999.0	Solar	T5888B03	MT. OLIVE WEST 115KV
CHKLIST-7613	9/7/2012	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T5888B03	MT. OLIVE WEST 115KV
CHKLIST-7614	9/7/2012	Approved	Commercial Operation - Power Generation in progress	-	1,900.0	Solar	T6070B02	WARSAW 230KV
CHKLIST-7608	8/27/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	T2520B02	ST. PAULS 115KV
CHKLIST-7607	8/22/2012	Approved	Commercial Operation - Power Generation in progress	-	43.0	Solar	T5000B42	MILBURNIE 230KV
CHKLIST-7597	8/15/2012	Approved	Commercial Operation - Power Generation in progress	-	1,980.0	Solar	T5888B01	MT. OLIVE WEST 115KV
CHKLIST-7386	8/1/2012	Approved	Commercial Operation - Power Generation in progress	-	407.0	Solar	T5642B12	CLAYTON INDUSTRIAL 115KV
CHKLIST-7605	7/30/2012	Approved	Commercial Operation - Power Generation in progress	-	3,800.0	Solar	T6215B01	CHADBOURN 115KV
CHKLIST-7606	7/30/2012	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T4785B06	HENDERSON EAST 230KV
CHKLIST-7590	7/24/2012	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T5490B01	BEULAVILLE 115KV
CHKLIST-7599	7/19/2012	Approved	Commercial Operation - Power Generation in progress	-	350.0	Diesel	T6382B02	WILMINGTON RIVER ROAD 115KV
CHKLIST-7600	7/19/2012	Approved	Commercial Operation - Power Generation in progress	-	400.0	Diesel	T6470B05	WILMINGTON OGDEN 230KV
CHKLIST-7601	7/19/2012	Approved	Commercial Operation - Power Generation in progress	-	400.0	Diesel	T6160B02	BURGAW 115KV
CHKLIST-7602	7/19/2012	Approved	Commercial Operation - Power Generation in progress	-	400.0	Diesel	T4074B01	BRIDGETON 115KV
CHKLIST-7603	7/19/2012	Approved	Commercial Operation - Power Generation in progress	-	400.0	Diesel	T4035B02	ATLANTIC BEACH 115KV
CHKLIST-7596	7/16/2012	Project Not Active	Cancelled	-	5,000.0	Solar	T5375B01	GOLDSBORO WEIL 115KV
CHKLIST-7598	7/16/2012	Project Not Active	Cancelled	-	47.0	Solar	T4930B03	LOUISBURG 115KV
CHKLIST-7591	6/27/2012	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T5830B02	LAGRANGE 115KV
CHKLIST-7593	6/27/2012	Approved	Commercial Operation - Power Generation in progress	-	1,300.0	Solar	T0400B13	CANTON 115KV
CHKLIST-7594	6/27/2012	Approved	Commercial Operation - Power Generation in progress	-	1,753.0	Biomass	T4108B03	CATHERINE LAKE 230KV
CHKLIST-7595	6/27/2012	Project Not Active	Cancelled	-	250.0	Solar	T6630B02	TABOR CITY 115KV
CHKLIST-7592	6/25/2012	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T6070B01	WARSAW 230KV
CHKLIST-7387	6/19/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	T2520B02	ST. PAULS 115KV
CHKLIST-7587	6/19/2012	Project Not Active	Cancelled	-	333.0	Solar	T4070B06	BEAUFORT 115KV
CHKLIST-7588	6/19/2012	Approved	Commercial Operation - Power Generation in progress	-	308.0	Solar	T5314B11	CARALEIGH 230KV
CHKLIST-7586	6/18/2012	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T4320B02	SNOW HILL 115KV
CHKLIST-7378	6/8/2012	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T5888B02	MT. OLIVE WEST 115KV
CHKLIST-7380	6/8/2012	Project Not Active	Withdrawn	-	2,000.0	Solar	T5900B05	NASHVILLE 115KV
CHKLIST-7381	6/8/2012	Approved	Commercial Operation - Power Generation in progress	-	2,400.0	Solar	T5230B02	ROXBORO SOUTH 230KV
CHKLIST-7382	6/8/2012	Project Not Active	Cancelled	-	266.0	Solar	T0750B16	OTEEN 115KV
CHKLIST-7383	6/8/2012	Project Not Active	Cancelled	-	1,950.0	Solar	T5360B01	WARRENTON 115KV
CHKLIST-7385	6/8/2012	Project Not Active	Cancelled	-	4,975.0	Solar	T4233B02	LAKE WACCAMAW 115KV
CHKLIST-7384	6/7/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4170B02	GRIFTON 115KV
CHKLIST-7374	6/4/2012	Project Not Active	Cancelled	-	780.0	Solar	T6310B20	EAGLE ISLAND 115KV
CHKLIST-7375	6/4/2012	Project Not Active	Cancelled	-	500.0	Solar	T0350B01	BALDWIN 115KV
CHKLIST-7377	6/4/2012	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T5680B01	ELM CITY 115KV
CHKLIST-7371	6/1/2012	Approved	Commercial Operation - Power Generation in progress	-	1,000.0	Solar	T5314B11	GARNER TRYON HILLS 115KV
CHKLIST-7372	5/30/2012	Approved	Commercial Operation - Power Generation in progress	-	565.0	Solar	T5314B11	CARALEIGH 230KV
CHKLIST-7373	5/30/2012	Approved	Commercial Operation - Power Generation in progress	-	204.0	Solar	T5160B10	RALEIGH 115KV
CHKLIST-7379	5/23/2012	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T4074B02	BRIDGETON 115KV
CHKLIST-7376	5/22/2012	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T5390B04	YANCEYVILLE 230KV
CHKLIST-7366	5/14/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	T4276B02	RHEMS 230KV
CHKLIST-7368	5/14/2012	Project Not Active	Cancelled	-	2,000.0	Solar	T2432B01	SANFORD GARDEN STREET 230KV
CHKLIST-7369	5/14/2012	Project Not Active	Withdrawn	-	4,975.0	Solar	T5375B02	GOLDSBORO WEIL 115KV
CHKLIST-7370	5/14/2012	Project Not Active	Cancelled	-	1,950.0	Solar	T5385B04	WILSON MILLS 230KV
CHKLIST-7355	5/9/2012	Approved	Commercial Operation - Power Generation in progress	-	3,500.0	Solar	T1980B01	FAIRMONT 115KV
CHKLIST-7357	5/9/2012	Approved	Commercial Operation - Power Generation in progress	-	32.0	Solar	T4595B05	CARALEIGH 230KV
CHKLIST-7358	5/9/2012	Approved	Commercial Operation - Power Generation in progress	-	2,000.0	Solar	T1025B01	BYNUM 230KV
CHKLIST-7359	5/9/2012	Project Not Active	Cancelled	-	5,000.0	Solar	T4276B02	RHEMS 230KV
CHKLIST-7361	5/9/2012	Approved	Commercial Operation - Power Generation in progress	-	125.0	Solar	T4785B02	HENDERSON EAST 230KV
CHKLIST-7363	5/9/2012	Project Not Active	Cancelled	-	5,000.0	Solar	T6670B02	WHITEVILLE 115KV
CHKLIST-7365	5/9/2012	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T5235B02	ROXBORO BOWMANTOWN ROAD 230KV
CHKLIST-7367	5/9/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4555B01	BAHAMA 230KV
CHKLIST-7348	5/2/2012	Approved	Commercial Operation - Power Generation in progress	-	1,990.0	Solar	T0665B11	LEICESTER 115KV
CHKLIST-7349	5/2/2012	Project Not Active	Cancelled	-	2,000.0	Solar	T0350B01	BALDWIN 115KV
CHKLIST-7351	5/2/2012	Project Not Active	Cancelled	-	500.0	Solar	T4501B03	AUBURN 230KV
CHKLIST-7352	5/2/2012	Approved	Commercial Operation - Power Generation in progress	-	1,990.0	Solar	T6070B04	WARSAW 230KV
CHKLIST-7354	5/2/2012	Project Not Active	Withdrawn	-	5,000.0	Solar	T5860B01	LILLINGTON 115KV
CHKLIST-7356	4/26/2012	Approved	Commercial Operation - Power Generation in progress	-	3,600.0	Solar	T2215B02	MAXTON 115KV
CHKLIST-7360	4/20/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T6675B11	WHITEVILLE SOUTHEAST REGIONAL PARK 115KV
CHKLIST-7364	4/20/2012	Approved	Commercial Operation - Power Generation in progress	-	424.0	Solar	T0350B01	BALDWIN 115KV
CHKLIST-7346	4/18/2012	Approved	Commercial Operation - Power Generation in progress	-	600.0	Diesel	T6466B03	WILMINGTON NINTH AND ORANGE 230KV
CHKLIST-7347	4/18/2012	Approved	Commercial Operation - Power Generation in progress	-	600.0	Diesel	T2082B02	HOPE MILLS ROCKFISH ROAD 230KV
CHKLIST-7341	4/17/2012	Project Not Active	Cancelled	-	500.0	Solar	T1520B02	SEAGROVE 115KV
CHKLIST-7342	4/17/2012	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Solar	T6045B12	SAMARIA 115KV
CHKLIST-7343	4/17/2012	Project Not Active	Cancelled	-	3,000.0	Solar	T1025B02	BYNUM 230KV
CHKLIST-7340	4/16/2012	Approved	Commercial Operation - Power Generation in progress	-	1,900.0	Solar	T4285B02	ROSE HILL 230KV
CHKLIST-7345	4/8/2012	Approved	Commercial Operation - Power Generation in progress	-	383.0	Solar	T5360B03	WARRENTON 115KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-7339	3/16/2012	Approved	Commercial Operation - Power Generation in progress	-	1,990.0	Solar	T4410B11	WALLACE 115KV
CHKLIST-7334	3/15/2012	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T1190B01	HAMLET 230KV
CHKLIST-7335	3/15/2012	Project Not Active	Cancelled	-	5,000.0	Solar	T1530B02	SILER CITY 115KV
CHKLIST-7336	3/15/2012	Approved	Commercial Operation - Power Generation in progress	-	383.0	Solar	T6310B20	EAGLE ISLAND 115KV
CHKLIST-7337	3/13/2012	Approved	Commercial Operation - Power Generation in progress	-	2,000.0	Solar	T5302B02	STALLINGS CROSSROADS 115KV
CHKLIST-7338	3/13/2012	Approved	Commercial Operation - Power Generation in progress	-	1,999.0	Solar	T5480B04	BENSON 230KV
CHKLIST-7344	3/2/2012	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T5360B01	WARRENTON 115KV
CHKLIST-7328	2/29/2012	Project Not Active	Withdrawn	-	500.0	Solar	T4210B12	ACKSONVILLE CITY 115KV
CHKLIST-7330	2/29/2012	Project Not Active	Cancelled	-	400.0	Solar	T4319B02	GLOBAL TRANSPARK 115KV
CHKLIST-7331	2/29/2012	Approved	Commercial Operation - Power Generation in progress	-	120.0	Biomass	T4285B01	ROSE HILL 230KV
CHKLIST-7332	2/29/2012	Project Not Active	Withdrawn	-	500.0	Other	T4710B02	FUQUAY 230KV
CHKLIST-7296	2/23/2012	Approved	Commercial Operation - Power Generation in progress	-	21.0	Solar	T0700B01	MONTE VISTA 115KV
CHKLIST-7325	2/10/2012	Approved	Commercial Operation - Power Generation in progress	-	2,750.0	Solar	T5090B02	OXFORD NORTH 230KV
CHKLIST-7327	2/10/2012	Project Not Active	Cancelled	-	402.0	Solar	T1810B01	BLADENBORO 115KV
CHKLIST-7319	2/3/2012	Project Not Active	Cancelled	-	5,000.0	Solar	T2190B01	LAURINBURG CITY 230KV
CHKLIST-7320	2/3/2012	Approved	Commercial Operation - Power Generation in progress	-	190.0	Solar	T4600B02	CARY 230KV
CHKLIST-7321	2/3/2012	Project Not Active	Cancelled	-	500.0	Solar	T0350B02	BALDWIN 115KV
CHKLIST-7322	2/3/2012	Approved	Commercial Operation - Power Generation in progress	-	42.0	Solar	T0362B02	BARNARDSVILLE 115KV
CHKLIST-7323	2/3/2012	Project Not Active	Cancelled	-	125.0	Solar	T5168B01	RALEIGH WORTHDALE 230KV
CHKLIST-7324	2/3/2012	Project Not Active	Cancelled	-	700.0	Solar	T0791B04	SPRUCE PINE 115KV
CHKLIST-7318	1/30/2012	Approved	Commercial Operation - Power Generation in progress	-	5,000.0	Solar	T4710B04	FUQUAY 230KV
CHKLIST-7313	1/13/2012	Project Not Active	Cancelled	-	500.0	Solar	T5108B04	PINE LAKE 230KV
CHKLIST-7316	1/13/2012	Project Not Active	Cancelled	-	300.0	Solar	T6160B01	BURGAW 115KV
CHKLIST-7317	1/13/2012	Approved	Commercial Operation - Power Generation in progress	-	2,000.0	Solar	T2200B22	LAURINBURG 230KV
CHKLIST-7314	1/3/2012	Approved	Commercial Operation - Power Generation in progress	-	400.0	Solar	T5131B09	RALEIGH NORTHSIDE 115KV
CHKLIST-7294	12/19/2011	Approved	Commercial Operation - Power Generation in progress	-	1,500.0	Solar	T4866B01	FUQUAY BELLS LAKE 230KV
CHKLIST-7292	12/5/2011	Approved	Commercial Operation - Power Generation in progress	-	1,000.0	Solar	T5230B02	ROXBORO SOUTH 230KV
CHKLIST-7275	11/5/2011	Approved	Commercial Operation - Power Generation in progress	-	77.0	Solar	T0651B01	LAKE JUNALUSKA 115KV
CHKLIST-7287	10/27/2011	Approved	Commercial Operation - Power Generation in progress	-	800.0	Solar	T0665B11	LEICESTER 115KV
CHKLIST-7288	10/27/2011	Approved	Commercial Operation - Power Generation in progress	-	800.0	Solar	T0665B11	LEICESTER 115KV
CHKLIST-7311	10/18/2011	Approved	Commercial Operation - Power Generation in progress	-	7,300.0	Biomass	T4795B03	HOLLY SPRINGS 230KV
CHKLIST-7285	10/10/2011	Approved	Commercial Operation - Power Generation in progress	-	340.0	Solar	T0965B01	ASHEBORO NORTH 115KV
CHKLIST-7284	10/7/2011	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T2520B02	ST. PAULS 115KV
CHKLIST-7279	10/4/2011	Approved	Commercial Operation - Power Generation in progress	-	1,000.0	Solar	T1025B03	BYNUM 230KV
CHKLIST-7280	10/4/2011	Approved	Commercial Operation - Power Generation in progress	-	39.0	Solar	T5000B44	MILBURNIE 230KV
CHKLIST-7282	10/4/2011	Approved	Commercial Operation - Power Generation in progress	-	160.0	Solar	T0781B03	SKYLAND 115KV
CHKLIST-7283	10/4/2011	Approved	Commercial Operation - Power Generation in progress	-	1,200.0	Solar	T6041B03	SPRING HOPE 115KV
CHKLIST-7210	9/30/2011	Approved	Commercial Operation - Power Generation in progress	-	520.0	Solar	T5230B02	ROXBORO SOUTH 230KV
CHKLIST-7277	9/13/2011	Approved	Commercial Operation - Power Generation in progress	-	500.0	Solar	T0965B04	ASHEBORO NORTH 115KV
CHKLIST-7276	9/9/2011	Approved	Commercial Operation - Power Generation in progress	-	25.0	Solar	T2440B03	SANFORD HORNER BLVD. 230KV
CHKLIST-7271	8/26/2011	Approved	Commercial Operation - Power Generation in progress	-	158.0	Solar	T5085B01	OXFORD SOUTH 230KV
CHKLIST-7270	8/9/2011	Approved	Commercial Operation - Power Generation in progress	-	798.0	Solar	T5732B03	FOUR OAKS 230KV
CHKLIST-7269	8/8/2011	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T2335B01	ROWLAND 230KV
CHKLIST-7272	8/8/2011	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T2475B02	SHANNON 115KV
CHKLIST-7273	8/8/2011	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T2215B02	MAXTON 115KV
CHKLIST-7274	8/8/2011	Approved	Commercial Operation - Power Generation in progress	-	4,975.0	Solar	T2282B03	RAEFORD SOUTH 115KV
CHKLIST-7265	8/4/2011	Approved	Commercial Operation - Power Generation in progress	-	410.0	Solar	T4710B02	FUQUAY 230KV
CHKLIST-7268	8/4/2011	Approved	Commercial Operation - Power Generation in progress	-	79.0	Solar	T5116B03	RALEIGH DURHAM AIRPORT 230KV
CHKLIST-7267	8/3/2011	Approved	Commercial Operation - Power Generation in progress	-	1,040.0	Solar	T4501B03	AUBURN 230KV
CHKLIST-7261	6/22/2011	Approved	Commercial Operation - Power Generation in progress	-	81.0	Solar	T2250B01	PITTSBORO 230KV
CHKLIST-7264	6/22/2011	Approved	Commercial Operation - Power Generation in progress	-	1,050.0	Solar	T4730B12	GARNER WHITE OAK 230KV
CHKLIST-7259	6/7/2011	Approved	Commercial Operation - Power Generation in progress	-	1,760.0	Biomass	T5732B02	FOUR OAKS 230KV
CHKLIST-7258	6/2/2011	Approved	Commercial Operation - Power Generation in progress	-	250.0	Other	T2444B03	SANFORD DEEP RIVER 230KV
CHKLIST-7260	5/18/2011	Approved	Commercial Operation - Power Generation in progress	-	977.9	Solar	T4255B03	NEW BERN WEST 230KV
CHKLIST-7257	5/12/2011	Approved	Commercial Operation - Power Generation in progress	-	160.0	Solar	T4723B11	GARNER I-40 230KV
CHKLIST-7256	5/10/2011	Approved	Commercial Operation - Power Generation in progress	-	2,000.0	Solar	T2200B22	LAURINBURG 230KV
CHKLIST-7255	3/16/2011	Approved	Commercial Operation - Power Generation in progress	-	384.0	Solar	T5360B04	WARRENTON 115KV
CHKLIST-7254	2/28/2011	Project Not Active	Cancelled	-	1,000.0	Solar	T5230B02	ROXBORO SOUTH 230KV
CHKLIST-7253	2/17/2011	Approved	Commercial Operation - Power Generation in progress	-	193.0	Solar	T2200B23	LAURINBURG 230KV
CHKLIST-7252	1/26/2011	Approved	Commercial Operation - Power Generation in progress	-	385.0	Solar	T4596B23	RALEIGH HARRINGTON STREET 115KV
CHKLIST-7251	12/21/2010	Approved	Commercial Operation - Power Generation in progress	-	72.0	Solar	T4610B13	CARY TRENTON ROAD 230KV
CHKLIST-7244	11/22/2010	Approved	Commercial Operation - Power Generation in progress	-	350.0	Diesel	T4795B22	HOLLY SPRINGS 230KV
CHKLIST-7245	11/22/2010	Approved	Commercial Operation - Power Generation in progress	-	350.0	Diesel	T2082B02	HOPE MILLS ROCKFISH ROAD 230KV
CHKLIST-7246	11/22/2010	Approved	Commercial Operation - Power Generation in progress	-	350.0	Diesel	T5165B01	LEESVILLE WOOD VALLEY 230KV
CHKLIST-7247	11/22/2010	Approved	Commercial Operation - Power Generation in progress	-	34.0	Solar	T0781B01	SKYLAND 115KV
CHKLIST-7248	11/22/2010	Approved	Commercial Operation - Power Generation in progress	-	22.5	Solar	T0371B02	BEAVERDAM 115KV
CHKLIST-7249	11/22/2010	Approved	Commercial Operation - Power Generation in progress	-	22.5	Solar	T0371B02	BEAVERDAM 115KV
CHKLIST-7250	11/22/2010	Approved	Commercial Operation - Power Generation in progress	-	193.0	Solar	T0340B11	WEST ASHEVILLE 115KV
CHKLIST-7233	11/10/2010	Approved	Commercial Operation - Power Generation in progress	-	23.0	Solar	T5311B05	RALEIGH TIMBERLAKE 115KV
CHKLIST-7243	11/1/2010	Approved	Commercial Operation - Power Generation in progress	-	24.0	Solar	T4725B03	GARNER PANTHER BRANCH 230KV
CHKLIST-7241	10/14/2010	Approved	Commercial Operation - Power Generation in progress	-	57.0	Solar	T4595B01	CARALEIGH 230KV
CHKLIST-7242	10/14/2010	Approved	Commercial Operation - Power Generation in progress	-	73.0	Solar	T4595B01	CARALEIGH 230KV
CHKLIST-7239	9/14/2010	Approved	Commercial Operation - Power Generation in progress	-	875.0	Diesel	T4240B01	MOREHEAD 115KV
CHKLIST-7240	9/14/2010	Approved	Commercial Operation - Power Generation in progress	-	750.0	Diesel	T6455B12	MASONBORO 230KV
CHKLIST-7235	8/30/2010	Approved	Commercial Operation - Power Generation in progress	-	515.0	Solar	T5120B02	RALEIGH EAST STREET 230KV
CHKLIST-7236	8/26/2010	Approved	Commercial Operation - Power Generation in progress	-	438.0	Diesel	T4500B12	ARCHER LODGE 230KV
CHKLIST-7232	8/25/2010	Approved	Commercial Operation - Power Generation in progress	-	193.0	Solar	T0870B03	WEAVERVILLE 115KV
CHKLIST-7237	8/17/2010	Approved	Commercial Operation - Power Generation in progress	-	438.0	Diesel	T5010B01	MORRISVILLE 230KV
CHKLIST-7238	8/17/2010	Approved	Commercial Operation - Power Generation in progress	-	438.0	Diesel	T1550B01	SOUTHERN PINES 115KV

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
CHKLIST-7231	7/27/2010	Approved	Commercial Operation - Power Generation in progress	-	66.0	Solar	T0784B12	AVERY CREEK 115KV
CHKLIST-7230	7/21/2010	Approved	Commercial Operation - Power Generation in progress	-	100.0	Solar	T4785B02	HENDERSON EAST 230KV
CHKLIST-7229	6/12/2010	Approved	Commercial Operation - Power Generation in progress	-	40.0	Solar	T0810B06	SWANNANOA 115KV
CHKLIST-7228	6/10/2010	Approved	Commercial Operation - Power Generation in progress	-	400.0	Solar	T4796B11	HOLLY SPRINGS INDUSTRIAL 230KV
CHKLIST-7225	5/26/2010	Approved	Commercial Operation - Power Generation in progress	-	3,180.0	Biomass	T5770B01	GRANTHAM 230KV
CHKLIST-7226	5/10/2010	Approved	Commercial Operation - Power Generation in progress	-	192.5	Solar	T4230B04	KINSTON 115KV
CHKLIST-7234	5/6/2010	Approved	Commercial Operation - Power Generation in progress	-	350.0	Hydroelectric	T6041B02	SPRING HOPE 115KV
CHKLIST-7194	4/20/2010	Approved	Commercial Operation - Power Generation in progress	-	675.0	Hydroelectric	T1390B03	RAMSEUR 115KV
CHKLIST-7216	2/16/2010	Approved	Commercial Operation - Power Generation in progress	-	500.0	Diesel	T4990B36	METHOD 230KV
CHKLIST-7218	2/16/2010	Approved	Commercial Operation - Power Generation in progress	-	200.0	Solar	T5060B02	NEUSE 115KV
CHKLIST-7223	1/22/2010	Approved	Commercial Operation - Power Generation in progress	-	22.3	Solar	T5890B01	MT. OLIVE 115KV
CHKLIST-7217	1/21/2010	Approved	Commercial Operation - Power Generation in progress	-	192.5	Solar	T4600B02	CARY 230KV
CHKLIST-7213	10/23/2009	Approved	Commercial Operation - Power Generation in progress	-	440.0	Solar	-	ATLANTIC BEACH 115KV
CHKLIST-7215	9/24/2009	Approved	Commercial Operation - Power Generation in progress	-	23.0	Solar	T0784B13	AVERY CREEK 115KV
CHKLIST-7211	9/11/2009	Approved	Commercial Operation - Power Generation in progress	-	4,400.0	Hydroelectric	T2225B02	MONCURE 115KV
CHKLIST-7197	6/29/2009	Approved	Commercial Operation - Power Generation in progress	-	2,500.0	Hydroelectric	T0510B22	ELK MOUNTAIN 115KV
CHKLIST-7190	1/26/2009	Approved	Commercial Operation - Power Generation in progress	-	500.0	Hydroelectric	T1025B02	BYNUM 230KV
CHKLIST-7206	12/9/2008	Approved	Commercial Operation - Power Generation in progress	-	800.0	Solar	T4610B12	CARY TRENTON ROAD 230KV
CHKLIST-7209	11/13/2008	Approved	Commercial Operation - Power Generation in progress	-	50.0	Solar	T5314B12	GARNER TRYON HILLS 115KV
CHKLIST-7208	8/29/2008	Approved	Commercial Operation - Power Generation in progress	-	1,562.0	Diesel	T2141B03	JONESBORO 230KV
CHKLIST-7207	8/25/2008	Approved	Commercial Operation - Power Generation in progress	-	60.0	Solar	T0340B11	WEST ASHEVILLE 115KV
CHKLIST-7195	7/24/2008	Approved	Commercial Operation - Power Generation in progress	-	550.0	Hydroelectric	T1390B04	RAMSEUR 115KV
CHKLIST-7205	7/10/2008	Approved	Commercial Operation - Power Generation in progress	-	1,000.0	Solar	T6310B20	EAGLE ISLAND 115KV
CHKLIST-7202	7/8/2008	Approved	Commercial Operation - Power Generation in progress	-	4,000.0	Biomass	T4255B05	NEW BERN WEST 230KV
CHKLIST-7188	4/7/2008	Approved	Commercial Operation - Power Generation in progress	-	800.0	Hydroelectric	-	N/A
CHKLIST-7224	3/15/2008	Approved	Commercial Operation - Power Generation in progress	-	1,200.0	Solar	T4610B12	CARY TRENTON ROAD 230KV
CHKLIST-7189	1/13/2008	Approved	Commercial Operation - Power Generation in progress	-	600.0	Hydroelectric	T5940B25	ROCKY MOUNT 230KV
CHKLIST-7204	9/7/2007	Approved	Commercial Operation - Power Generation in progress	-	44.0	Solar	T0515B01	EMMA 115KV
CHKLIST-7196	7/18/2007	Approved	Commercial Operation - Power Generation in progress	-	1,500.0	Hydroelectric	T2225B01	MONCURE 115KV
CHKLIST-7203	4/4/2006	Approved	Commercial Operation - Power Generation in progress	-	40.0	Solar	T4610B12	CARY TRENTON ROAD 230KV
CHKLIST-7201	3/8/2006	Approved	Cancelled	-	983.0	Biomass	T0510B11	ELK MOUNTAIN 115KV
CHKLIST-1103	1/1/1900	Project Not Active	Cancelled	-	250.0	Solar	T6630B02	TABOR CITY 115KV
CHKLIST-1105	1/1/1900	Project Not Active	Cancelled	-	2,000.0	Solar	T5375B02	GOLDSBORO WEIL 115KV
CHKLIST-1106	1/1/1900	Project Not Active	Cancelled	-	2,000.0	Solar	T5888B01	MT. OLIVE WEST 115KV
CHKLIST-7191	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	235.0	Hydroelectric	T2440B05	SANFORD HORNER BLVD. 230KV
CHKLIST-7192	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	600.0	Hydroelectric	-	N/A
CHKLIST-7193	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	400.0	Hydroelectric	T0965B05	ASHEBORO NORTH 115KV
CHKLIST-7198	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	80.0	Hydroelectric	-	N/A
CHKLIST-7200	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	990.0	Hydroelectric	T1610B03	TROY 115KV
CHKLIST-7298	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	4,950.0	-	T2444B22	SANFORD DEEP RIVER 230KV
CHKLIST-7299	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	10,000.0	-	T4050B02	Bayboro 230KV
CHKLIST-7303	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	1,000.0	Hydroelectric	T0362B02	BARNARDSVILLE 115KV
CHKLIST-7307	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	1,415.0	Biomass	T0665B22	LEICESTER 115KV
CHKLIST-8643	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	24.0	Solar	T4595B01	CARALEIGH 230KV
CHKLIST-8644	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	60.0	Solar	T4325B02	WILMINGTON SUNSET PARK 115KV
CHKLIST-8645	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	24.0	Solar	T4325B02	WILMINGTON SUNSET PARK 115KV
CHKLIST-8646	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	77.0	Solar	T2250B02	PITTSBORO 230KV
CHKLIST-8647	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	273.0	Solar	T5116B05	RALEIGH DURHAM AIRPORT 230KV
CHKLIST-8648	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	40.0	Solar	T6470B05	WILMINGTON OGDEN 230KV
NC2017-03077	1/1/1900	Project Not Active	Withdrawn	-	1,000.0	Solar	T4610B13	CARY TRENTON ROAD 230KV
-	1/1/1900	-	IR Review - In Progress	-	21.0	Solar	T4600B02	WEST CHATHAM STREET 23KV
-	1/1/1900	-	IR Review - In Progress	-	24.0	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	28.8	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	49.4	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	50.0	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	52.2	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	100.0	-	-	-
-	1/1/1900	-	IR Review - In Progress	-	100.0	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	23.1	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	28.8	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	28.8	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	30.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	43.2	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	52.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	-	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	57.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	61.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	61.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	61.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	61.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	61.2	Solar	-	-

Project Queue Number	Queue Number Issue Date	IR Interdependency Status	Operational Status	Engineering Administrative Designation	Capacity kW (AC)	Energy Source Type	Feeder Number	Substation Name
-	1/1/1900	-	IR Review - Pending Customer Response	-	61.2	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	66.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	66.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	66.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	66.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	72.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	72.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	72.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	72.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	72.0	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	75.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	75.6	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	86.4	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	99.7	Solar	-	-
-	1/1/1900	-	IR Review - Pending Customer Response	-	100.0	Solar	-	-
-	1/1/1900	-	-	-	96.0	Solar	-	-
-	1/1/1900	Project Not Active	Cancelled	-	800.0	Biomass	-	-
-	1/1/1900	Project Not Active	Cancelled	-	3,500.0	Solar	T4730B12	GARNER WHITE OAK 230KV
-	1/1/1900	Project Not Active	Cancelled	-	6,400.0	Biomass	T1670B01	WADESBORO 230KV
-	1/1/1900	Project Not Active	Cancelled	-	6,400.0	Biomass	T5921B02	Newton Grove 230kV
-	1/1/1900	Project Not Active	Cancelled	-	11,000.0	Solar	-	-
-	1/1/1900	Project Not Active	Withdrawn	-	23.4	Solar	-	-
Project 12942	1/1/1900	Approved	Commercial Operation - Power Generation in progress	-	9,000.0	Biomass	T5600B01	ROSEBORO 115KV

Disclaimer: Please note this queue report is updated twice a month. Information is accurate as of the date listed in the title of this report. Please contact DERContracts@duke-energy.com if you have questions about the status of your project.

Frequently Asked Questions

Large Distribution Interconnections (≥20 kW)

This FAQ provides general information; please consult the applicable state commission and FERC procedures for detailed guidance (which govern in the event of any conflict between such procedures and this general information).

1. **What is the overall interconnection process and who can I contact to get help?**
The interconnection process is defined by state utility commission or FERC-approved procedures. These procedures provide governing standards that an Interconnection Customer must follow in order to connect a Generating Facility to a utility's system. The applicable set of procedures is determined by the nature and location of the Generating Facility.

Your contact for support depends on what phase of the interconnection process your request is in. Please note that all project lifecycles are subject to change based on the specifics of each project. Once your project moves past the "Review" phase, you will be given specific contact information for the person assigned to your project in each of the different phases.

The chart below identifies the appropriate point of contact based on status of your project.

Distribution Project Lifecycle			
1. REVIEW	**2. STUDY**	**3. CONSTRUCTION**	**4. POST PROJECT**
Renewable Service Center (RSC)	**Customer Account Specialist (CAS)**	**Contract Analyst/Account Manager**	**Contract Management Group**
- Pre-Request (NC Only) - Pre-Application - Interconnection Request - 3-Day Letter - 10-Day Letter	- Fast Track - Supplemental Review - System Impact Study - Customer Options Meeting - Scoping Meeting	- Facility Study - Construction Planning Meeting - Interconnection Agreement - Standard Purchase Power Agreement - Permission to Operate	- Negotiated Purchase Power Agreement - REC only Agreement - Contracts Database - Billing - Post Commercial Operations
REVIEW covers new IRs and any body of work related to being processed once a project has been submitted	*STUDY covers any body of work being processed while a project is in the study phase*	*CONSTRUCTION covers any body of work being done once a project is out of the study phase through the facility receiving their permission to operate*	*POST PROJECT covers any body of work being done after the project is generating power, including but not limited to contract management*

Renewable Service Center (RSC) – CustomerOwnedGeneration@duke-energy.com or 866.233.2290
Customer Account Specialist (CAS) – DERContracts@duke-energy.com
Contract Analyst/Account Manager – DERContracts@duke-energy.com
Contract Management – DERContracts@duke-energy.com

2. **What is the difference between a Pre-Request and a Pre-Application, and why should I get one?**
Both Pre-Requests and Pre-Applications are non-binding requests to provide information for a proposed project or specific site. Responses provided by Duke Energy to these requests do not confer any rights to an Interconnection Customer and the customer must still submit and meet Interconnection Request requirements to apply to interconnect and obtain a Queue Number.

Pre-Request: Per state jurisdictional procedures, a Pre-Request is only available for North Carolina projects. The Pre-Request Response provides the Interconnection Customer with high-level electric system information including the number of phases, distance to substation, distance to three-phase conductor, MVA rating of the substation transformer, as well as existing and queued generation on the same substation. There is no fee associated with a Pre-Request.

Pre-Applications: A Pre-Application is available for North Carolina and South Carolina projects. The Pre-Application Report provides the same information as the Pre-Request as well as existing substation, capacity, voltage, and other infrastructure information, which can be helpful in analyzing the viability of a proposed project or site. In comparison to a Pre-Request, the Pre-Application is more formal and offers more detailed information to help an Interconnection Customer determine if a proposed project is feasible. Pre-Applications require a fee of $300 for a North Carolina project, or $500 for a South Carolina project.

Please contact the Renewable Service Center at CustomerOwnedGeneration@duke-energy.com or 866.233.2290, if you have questions about Pre-Requests or Pre-Applications.

3. **How can I use the Queue Report published online?**
Queue Reports are updated twice a month and published to the company's website. If you have issues retrieving the correct Queue Report, check to make sure you have chosen the correct jurisdiction and state when navigating the website, as each jurisdiction (Duke Energy Carolinas/Progress) and state (NC/SC) has its own queue report. You can select your jurisdiction by clicking the state name on the upper left corner of the website.

Once you have navigated to the appropriate Queue Report, find your project's Queue Number. The best way to utilize the Queue Report is to electronically filter and sort the information using Substation Name and Queue Number Issue Date. This will narrow the report to show which projects are vying for space on the same substation as your project. Engineering Administrative Designations (EAD) are published for each project and can be used to understand what part of the System Impact Study each project is in. EADs are not applicable to the Fast Track and Supplemental Review processes. On the same webpage as the Queue Report, there is a link to Status Definitions which defines what each status means.

4. **What is Interdependency and what is the difference between Interdependency Statuses – Project A, Project B and On Hold?**
Both the state and FERC interconnection procedures require Duke Energy to study all Interconnection Requests based on the order in which requests enter the Queue. This is often referred to as a serial queue study process. Under North Carolina and South Carolina state procedures, projects are deemed to be interdependent where an upgrade or the interconnection facilities necessary for the Generating Facility are impacted by another Generating Facility. Interdependency Status is assigned after the Interconnection Request is deemed complete and is used to indicate interdependence of projects in the queue.

Project A is assigned to a project that is not impacted by any earlier-queued Interconnection Request (for example, a project that is first in line for a particular substation and has no other identified interdependencies).

Project B indicates the project is interdependent with only one earlier-queued Interconnection Request (for example, a project that is second in line for a particular substation and has no other identified interdependencies).

On Hold indicates the project is interdependent with two or more earlier-queued Interconnection Requests (for example, a project that is third in line for a particular substation or has other identified interdependencies).

5. **Why hasn't my project's Interdependency Status changed?**
   Each project/substation pairing creates a unique situation, so there is no single answer for this question. The status cannot be changed until the interconnection requests of all earlier-queued interdependent Interconnection Requests have been resolved. This process can take an extended period of time depending on the number of interdependent projects and the complexity of such projects. For instance, timelines can become extended when inquiries arise from the Project A/B due to the need for technical clarifications, selection of mitigation options, identification of rights of way, dispute, etc. It is best to contact your Customer Account Specialist by emailing DERContracts@duke-energy.com if you have questions about the status of a project.

6. **When will my project's System Impact Study be complete?**
   Study completion dates depend on your project's Interdependency and Operational Status. Once a project's Interdependency Status becomes "Project A" or "Project B," use the EAD published in the Queue Report to understand what part of the System Impact Study your project currently is in. When the project reaches the EAD of "Protection Study" a Customer Account Specialist should be able to provide you with an estimated completion date. Interconnection Requests that have been designated as "On Hold" are not permitted to proceed with the study process until they become a "Project B". For this reason, there is no specific timeline by which projects in "On Hold" status will be released for study.

Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC
Rebuttal Testimony of Jeffrey W. Riggins

Rebuttal Exhibit JWR-2

Examples of Pre-Request Results and Pre-Application Response

Example of Pre-Request Results:

Good Morning,

Based on the current information and records I have in front of me right now, here is the pre-request information for your requested site. This is subject to change any time after today.

Circuit ID	T6446B22
Substation Name	LELAND INDUSTRIAL 115KV
Substation Capacity (MVA)	15
Circuit Voltage (KV)	22.86
Distance from IPP to substation (mi)	1.76
Distance from IPP to nearest 3-PH conductor (mi)	0.01
Distance from IPP to nearest heavy 3-PH conductor (mi)	0.73

Customers on substation (queue and existing)		
Queue #	**MW**	**Feeder ID**
CHKLIST-7985	0.053	T6446B22
NC2016-02946	4.998	T6446B11
NC2016-02961	4.998	T6446B22

Customers on feeder (queue and existing)		
Queue #	**MW**	**Feeder ID**
CHKLIST-7985	0.053	T6446B22
NC2016-02961	4.998	T6446B22

Thank you,

Duke Energy Progress

Example of Pre-Application Response:

Pre-Application Response Information

Below are the 13 points listed in the Pre-Application report section of the NC State Jurisdictional Interconnection Standard Section 1.3.2. (May 15, 2015)

Project Name: Deleted
Circuit ID: T0781B01
Size: Deleted
Substation Name: Skyland 115KV

Based on the current information and records we have in front of us right now, here is the pre-Application information for your requested site (this is subject to change any time after today):

	Information	
1.3.2.1	Total capacity (in MVA) of substation/area bus, bank or circuit based on nominal or operating ratings likely to serve the proposed Point of Interconnection.	30
1.3.2.2	Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection.	0.234
1.3.2.3	Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Interconnection.	0
1.3.2.4	Substation nominal distribution voltage and/or transmission nominal voltage if applicable. (in KV)	115
1.3.2.5	Nominal distribution circuit voltage at the proposed Point of Interconnection. (in KV)	22.86
1.3.2.6	Approximate circuit distance between the proposed Point of Interconnection and the substation. (in Miles)	6.695
1.3.2.7	Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load and absolute minimum load, when available.	Peak Load: 15,086.8 kW Low Load: 2,541.2 kW
1.3.2.8	Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.	(1)x"Fuse_30A" (1)x"V_Reg_100A_13.2" (1)x"Switch_1200A" (1)x"Recloser_4E_140" (5)x"Switch_600A" (1)x"Recloser_OVR_360" (1)x"V_Reg_200A" (1)x"Recloser_GWVIPERS_800" (1)xFCB

1.3.2.9	Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.	Single Phase 2.39mi to Three Phase
1.3.2.10	Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation. (in Amps)	70A 92.5A 120A 320A 360A 320A
1.3.2.11	Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.	Radial Supply
1.3.2.12	Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.	LG Short Circuit @ POI: 1195A
1.3.2.13	Other information regarding an Affected System the Utility deems relevant to the Interconnection Customer.	N/A

Thank you,

Duke Energy Progress

Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC
Rebuttal Testimony of Jeffrey W. Riggins

Rebuttal Exhibit JWR-3

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
2017/2018 Actual and 2019 Pro Forma Category 1 Volumes and Expenses for NC Interconnections Fees

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC

2017/2018 Actual and 2019 Pro Forma Category 1 Volumes and Expenses for NC Interconnections Fees

	Column 1 [1]			Column 2 [2]			Column 3 [3]			Column 4 [4]		
	Actual 2017 Volumes & Expenses w/Current & Proposed Fees			Actual 2018 Volumes With Annualized November Expenses w/Current & Proposed Fees			Projected 2019 Volumes @ 10% Increases Over 2018 Volumes w/Current & Proposed Fees			Projected 2019 Volumes @ 20% Increases Over 2018 Volumes w/Current & Proposed Fees		
	Volumes	Revenue @ Current Fees	Revenue @ Proposed Fees	Volumes	Revenue @ Current Fees	Revenue @ Proposed Fees	Volumes	Revenue @ Current Fees	Revenue @ Proposed Fees	Volumes	Revenue @ Current Fees	Revenue @ Proposed Fees
Pre-Requests	59	$0	$0	119	$0	$0	131	$0	$0	143	$0	$0
Pre-Applications	32	$9,600	$16,000	15	$4,500	$7,500	17	$4,950	$8,250	18	$5,400	$9,000
≤ 20 kW	1,406	$140,600	$281,200	4,354	$435,400	$870,800	4,789	$478,940	$957,880	5,225	$522,480	$1,044,960
≤ 100kW	34	$8,500	$25,500	172	$43,000	$129,000	189	$47,300	$141,900	206	$51,600	$154,800
≤ 2 MW	63	$31,500	$63,000	40	$20,000	$40,000	44	$22,000	$44,000	48	$24,000	$48,000
Changes of Control:												
≤ 20 kW	110	$5,500	$5,500	110	$5,500	$5,500	121	$6,050	$6,050	132	$6,600	$6,600
> 1 MW	9	$450	$4,500	21	$1,050	$10,500	23	$1,155	$11,550	25	$1,260	$12,600
Total Revenue	**1,713**	**$196,150**	**$395,700**	**4,831**	**$509,450**	**$1,063,300**	**5,314**	**$560,395**	**$1,169,630**	**5,797**	**$611,340**	**$1,275,960**
Employee & Contractor Expenses		**$760,565**			**$835,446**			**$877,218**			**$877,218**	
PowerClerk		**$148,000**			**$148,000**			**$125,800**			**$125,800**	
Salesforce Allocation		**$159,259**			**$109,628**			**$160,000**			**$160,000**	
Total Estimated Expenses		**$1,067,824**			**$1,093,074**			**$1,163,018**			**$1,163,018**	
Net (Under)/Over-Recovery		**-$871,674**	**-$672,124**		**-$583,624**	**-$29,774**		**-$602,623**	**$6,612**		**-$551,678**	**$112,942**

1 - Duke Energy implemented a new labor charging methodology in November/December 2017. Volumes for Changes of Control < 20 kW are estimated. Other volumes are actuals per PowerClerk and Salesforce systems.

2 - Duke Energy is still in the process of closing financial records for 2018. Expenses are annualized based on November year to date charges. Volumes are actuals per PowerClerk and Salesforce systems.

3 - View of 2019 with projected volumes increasing 10% over 2018 volumes. Expenses are projected to increase by 5%. PowerClerk expenses are reduced by 15% as ≤ 20 kW projects transition to Salesforce. Correspondingly, Salesforce expenses are projected to increase.

4 - View of 2019 with projected volumes increasing 20% over 2018 volumes with all other assumptions from footnote 3 the same.

Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC
Rebuttal Testimony of Jeffrey W. Riggins

Rebuttal Exhibit JWR-5

Form Surety Bond Determined Acceptable by the Companies

SURETY BOND – COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY

COLLATERAL SECURITY PAYABLE UPON DEMAND

* * * * *

PRINCIPAL / BIDDER *(Legal Name and Business Address)*

SURETY *(Legal Name and Business Address)*	***CONTRACT NO.***	***CONTRACT DATE***
OBLIGEE [Duke Energy Carolinas, LLC][Duke Energy Progress, LLC] ---- *add address* -----	***SURETY BOND EFFECTIVE DATE*** ***Is this the issue date?***	
PROPOSAL SECURITY AMOUNT	***PENAL SUM OF BOND***	

KNOW ALL PERSONS BY THESE PRESENTS THAT: PRINCIPAL (herein, "Bidder") and SURETY are held and firmly bound to [Duke Energy Carolinas, LLC] [Duke Energy Progress, LLC] ("Duke Energy"), a limited liability company organized and existing under the laws of the state of North Carolina, its successors and assigns in the amount of $[*insert Bond Amount*] ("Proposal Security Amount"), for the payment of which the Bidder and Surety, their heirs, executors, administrators, successors and assigns are hereby jointly and severally bound.

WHEREAS, Bidder has submitted a bid proposal into Duke Energy's Request for Proposals for the Competitive Procurement of Renewable Energy ("RFP"), which was issued by Duke Energy on [___________];

WHEREAS, Duke Energy has selected Bidder's proposal (the "Bid") for further evaluation in Step 2 of the RFP process (such evaluation referred to herein as the "Step 2 Evaluation Process") pursuant to the RFP;

WHEREAS, Bidder and Surety acknowledge that the RFP process will be delayed and Duke Energy will be harmed if Bidder withdraws the Bid, or if the Bid is selected as a Bid for the Step 2 Evaluation Process and the Bidder does not execute the RENEWABLE POWER PURCHASE AGREEMENT or the ASSET PURCHASE AND SALE AGREEMENT (as applicable, the "Agreement") associated with the RFP as requested by Duke Energy and/or fails to provide Performance Assurance as required under and as defined in the Agreement; and

WHEREAS, Bidder desires to furnish this Bond pursuant to the requirement in Section III of the RFP to provide Proposal Security for a bid selected to continue forward into the Step 2 Evaluation Process;

NOW THEREFORE, the condition of this obligation is such that if (i) Duke Energy or the Independent Administrator acting on its behalf notifies Bidder that the Bid has been eliminated from consideration in the RFP, or (ii) Duke Energy subsequently selects the Proposal as a winning Proposal under the RFP and Bidder has executed the Agreement and posted Performance Assurance as required in such Agreement, then this obligation will be null and void; otherwise it will remain in full force and effect, subject to the following additional conditions:

1. Capitalized terms undefined herein will take the meaning or definition provided in the RFP or where indicated, the Agreement. In the event of any conflict between this Bond and the RFP, the terms of this Bond will control.

2. If Bidder withdraws the Bid, or if Duke Energy selects the Bid as a winning Proposal and the Bidder does not execute the Agreement with Duke Energy for the Bid within 60 days of the closing of the RFP or fails to meet the creditworthiness requirements or to post performance security as required under the Agreement within 5 business days of the execution of the Agreement, then Duke Energy will issue a demand for payment of the Proposal Security Amount to the Surety ("Demand for Payment").

3. Surety will, not later than ten (10) days after delivery of a Demand for Payment to the Surety at the address provided below, pay the Proposal Security Amount to Duke Energy. Surety's obligation for payment of the Proposal Security Amount will be deemed established regardless of the underlying causes for Bidder's withdrawal of the Bid and irrespective of any other circumstance whatsoever that might otherwise constitute a legal or equitable discharge or defense of the Surety.

4. Bidder and Surety acknowledge that the Proposal Security Amount represents a fair and reasonable pre-estimation of the damages due to Duke Energy under the circumstances existing as of the Surety Bond Effective Date and that such amount represents a reasonable estimate of Duke Energy's losses in the event of (i) Bidder's withdrawal of the Bid following its selection for further evaluation in the Step 2 Evaluation Process, or (ii) Bidder's failure to execute the Agreement with Duke Energy for the Bid if selected as a winning Proposal or failure to provide Performance Assurance as required under the Agreement. The Proposal Security Amount will not be deemed a penalty, and the Bidder and Surety hereby waive and forfeit any right to contest the reasonableness or validity of the liquidated Proposal Security Amount. Duke Energy's right to recover the Proposal Security Amount will in no way limit its entitlement to other non-monetary remedies to which Duke Energy may be entitled pursuant to the terms of the RFP, the Bond, or applicable law.

5. It is hereby agreed that this obligation is effective beginning on the Surety Bond Effective Date, above, provided that, if this Bond remains in effect after one (1) year following the Surety Bond Effective Date, Bidder may cancel this Bond after such one (1) year period by giving Duke Energy at least forty-five (45) days prior written notice of the cancellation date. Such cancellation notice will be sent by certified mail or by overnight courier with tracking service to:

   {Add notice info}

   with copy to
   [Duke Energy Carolinas, LLC] [Duke Energy Progress, LLC]
   Attn: Credit Risk Manager
   550 South Tryon Street (DEC40C)
   Charlotte, NC 28202

Any obligations of the Bidder prior to any such cancellation will survive such cancellation and continue to be a liability of the Surety until paid in full by the Bidder.

This Bond is irrevocable by Surety.

6. Within thirty (30) days following the date of any notice of cancellation of this Bond that is provided to Duke Energy under Paragraph 6, Bidder will provide to Duke Energy a replacement Bond that satisfies the requirements of Section III of the RFP in the amount of the Performance Security required for the pre-COD period. Bidder's failure to provide such replacement Bond in the required timeframe will constitute a default under this Bond and will entitle Duke Energy to issue a Demand for Payment to the Surety for the payment of the Proposal Security Amount.

7. The Surety's liability is limited to the Proposal Security Amount ("Penal Sum of Bond"), unless suit must be brought for enforcement of the within obligations and in which case the Surety will also be liable for all costs in connection therewith, interest and reasonable attorneys' fees, including costs of and fees for appeals.

8. Failure of the Surety to pay the Proposal Security Amount within ten (10) days of Demand for Payment will constitute default of the Surety's obligation under the Bond and Duke Energy will be entitled to enforce against the Surety any remedy available to it.

9. Surety, for value received, hereby stipulates and agrees that no change, modification, omission, addition or change in or to the RFP or the Agreement, and no action or failure to act by Duke Energy will in any way affect the Surety's obligation on this Bond; and Surety hereby waives notice of any and all such modifications, omissions, alterations, and additions to the terms of the RFP or the Agreement.

10. If any part or provision of this Bond will be declared unenforceable or invalid by a court of competent jurisdiction, such determination in no way will affect the validity or enforceability of the other parts or provisions of this Bond.

11. The undersigned Surety and Bidder are held and firmly bound for the payment of all legal costs, including reasonable attorney's fees, incurred in all or any actions or proceedings taken to enforce this Bond or the obligations created herein, or payment of any award of judgment rendered against the undersigned Surety. Nothing contained herein will be construed to obligate Duke Energy to pay any fees or expenses incurred in connection with the issuance of this Bond.

12. All disputes relating to the execution, interpretation, construction, performance, or enforcement of the Bond and the rights and obligations thereto will be governed by the laws of, and resolved in the State and Federal courts in North Carolina. The rights and remedies of Duke Energy herein are cumulative and in addition to any and all rights and remedies that may be provided by law or equity.

13. The undersigned Surety agent(s) represent that he/she is a true and lawful attorney-in-fact for the Surety and authorized to bind the Surety hereto and to affix the Surety's corporate seal hereunder, as evidenced by the attached power of attorney.

IN WITNESS WHEREOF, this instrument is SIGNED AND SEALED this _____ day of_______________, 20__.

PRINCIPAL/BIDDER:

For Bidder: _________________________

Signature: _________________________

(SEAL)

Name and Title: _________________________

Address: _________________________

____

____

SURETY:

Attorney in Fact: _________________________

Signature: _________________________

(SEAL)

Name and Title: _________________________

Address: _________________________

____

____

AFFIDAVIT AND ACKNOWLEDGEMENT OF ATTORNEY-IN-FACT

STATE OF _____________

COUNTY OF ___________

I hereby certify that I am the attorney-in-fact of ______________________, a [*insert entity type*], which is the surety in the foregoing bond, and that I am authorized to execute on the above Surety's behalf the foregoing bond pursuant to the Power of Attorney dated ____________ and attached hereto, and on behalf of the Surety, acknowledge the foregoing bond before me as the above Surety's act and deed.

Given under my hand this _____ day of ____________.

____
ATTORNEY-IN-FACT

____
PRINT NAME

(NOTARY SEAL)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 101

In the Matter of	)	**REBUTTAL TESTIMONY OF**
Petition for Approval of Generator	)	**JOHN W. GAJDA**
Interconnection Standard	)	**ON BEHALF OF DUKE ENERGY**
	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John W. Gajda. My business address is 3401 Hillsborough Street, Raleigh, North Carolina.

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

A. I am employed on a Developmental Assignment for Duke Energy Corporation ("Duke Energy"), which is a type of "Special Projects" designation, working in the System Operations group. I am submitting this rebuttal testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, "the Companies").

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I submitted direct testimony in this proceeding on behalf of the Companies on December 19, 2018.

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

A. The purpose of my rebuttal testimony is to address several issues raised in the direct testimony of the Public Staff and certain other intervenors and to provide support for the Companies' proposed revisions to the North Carolina Interconnection Procedures ("NC Procedures"). Specifically, I agree with Public Staff witness Williamson's position on Good Utility Practice, and elaborate on how the Companies' application of Good Utility Practice is in alignment with the Public Staff's expectations of the

Companies' and Dominion Energy North Carolina's ("DENC" and collectively, the "Utilities") responsibility under the NC Procedures. I also respond to the Public Staff's statement that utility flexibility is necessary to most appropriately and efficiently implement Good Utility Practice over time, and rebut the solar advocate intervenors' claims otherwise. Next, I rebut North Carolina Sustainable Energy Association ("NCSEA") witness Paul Brucke and Interstate Renewable Energy Council ("IREC") witness Brian Lydic's proposal to require the Technical Standards Review Group to be changed from a discussion-based forum to a formal proceeding. I then rebut IREC witness Sarah Auck's proposals to significantly overhaul the current Fast Track and Supplemental Review processes by explaining how the current Section 2 and Section 3 processes are working effectively at this time and are tailored to North Carolina's interconnection landscape.

I also respond to NCSEA witness Brucke and NCCEBA witness Christopher Norqual's statements regarding the Companies' perspective and definition of "material modification" as it relates to energy storage, and also explain the Companies' position and acceptance of software controls in determining the maximum output of a generating facility under the NC Procedures Redline. Finally, I explain why the Companies do not support Public Staff witness Williamson's proposal for an independent review of the entire NC Procedures at this time, due to the current ongoing NC Procedures review and the Companies' plans to focus on queue reform and a transition to full grouping studies.

Q. ARE YOU INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes. I am submitting four exhibits. JWG Rebuttal Exhibit 1 is the Companies' updated redline of the NC Procedures. JWG Rebuttal Exhibit 2 is the Companies' Distributed Energy Resource Method of Service Guidelines (the "MOS Guidelines"). JWG Rebuttal Exhibit 3 provides detail on the Companies' publicly available "Carolinas TSRG Updates" website. Last, I am submitting JWG Rebuttal Exhibit 4, which provides the Commission certain data request responses referenced in my testimony.

I. Good Utility Practice

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S POSITION REGARDING GOOD UTILITY PRACTICE.

A. Public Staff witness Williamson states that it is the Utilities' responsibility to maintain and operate the electric grid in a safe and reliable manner, and emphasizes that Good Utility Practice must include flexibility for changes over time. Expanding on the issue of flexibility, Public Staff witness Williamson details how North Carolina's unique interconnection landscape has "the potential to create operational challenges that must be managed in both the short- and long-term."[1] Based on this unique interconnection landscape, Public Staff witness Williamson contends that short-term "fixes" may be necessary prior to any formal NCIP revisions, and therefore "a

[1] Public Staff Williamson Direct Testimony, at 5.

degree of flexibility should be at the discretion of the Utilities" in applying Good Utility Practice.

In conclusion, Public Staff witness Williamson states that the Utilities are responsible for determining the practices, methods and acts necessary to meet the rules and standards established by the relevant regulatory bodies, and that the Utilities' application of this Good Utility Practice must retain some level of flexibility.

Q. DOES THE PUBLIC STAFF'S POSITION ON GOOD UTILITY PRACTICE ALIGN WITH THE COMPANIES' POSITION?

A. Yes. Based on my reading of Public Staff witness Williamson's testimony, the Public Staff is aligned with Companies' position on Good Utility Practice. Public Staff witness Williamson explains that the Utilities are responsible for determining the practices, methods, and acts necessary to establish Good Utility Practice, consistent with rules and standards established by this Commission and other regulatory agencies such as the Federal Energy Regulatory Commission ("FERC") and the North American Electric Reliability Corporation ("NERC").[2] However, it is important to distinguish that the relevant regulatory bodies mentioned by the Public Staff as overseeing the Utilities do not directly establish Good Utility Practice; rather, the Companies establish and maintain their engineering guidelines and technical standards in such a way as to assure compliance with the rules

[2] *Id.*

and standards established by the Commission and other relevant regulatory bodies. As I discuss in my direct testimony, since the Companies are completely responsible for ensuring power quality and reliability, the Companies seek to maintain flexibility within the Good Utility Practice construct so as to continually optimize power quality, reliability, and economic considerations for its customers.[3]

Q. DO YOU AGREE WITH THE PUBLIC STAFF'S VIEW THAT THE GOOD UTILITY PRACTICE STANDARD SHOULD BOTH PROMOTE ALIGNMENT WITH PRACTICES OF THE OVERALL UTILITY INDUSTRY WHILE ALSO ALLOWING FLEXIBILITY FOR THE COMPANIES TO APPLY REASONABLE JUDGMENT TO MEET NEW OR EMERGING CHALLENGES?

A. Yes. Public Staff witness Williamson states that the Utilities' application of Good Utility Practice should be consistent with the practices, methods and acts engaged in, or approved by, a significant portion of the electric industry, while also recognizing the need for flexibility to exercise reasonable judgement "to the extent the Utilities identify new or emerging challenges or issues that may impact safety and reliability concerns."[4]

I agree with witness Williamson's statements. The Companies, like most utilities, continuously assess the alignment of their practices and

---

[3] DEC/DEP Gajda Direct Testimony, at 24.
[4] Public Staff Williamson Direct Testimony, at 5.

experiences with those of their peers through many venues that facilitate shared practices and utility monitoring. For example, many of the Companies' engineers actively participate in committees within organizations such as the NESC (National Electrical Safety Code), IEEE (Institute of Electrical and Electronics Engineers), Southeastern Electric Exchange, and North American Transmission Forum, to name a few.

However, in order to carry out its mission of delivering safe, reliable, and economic electricity to its customers, the Companies must also be permitted to carry out, with confidence, independent technical design and judgment activities within its own engineering workforce. To this end, the Companies deliberately and consistently hire, for particular key positions, only degreed engineers from ABET (Accreditation Board for Engineering and Technology) accredited institutions. Furthermore, the Companies have an established practice within the Transmission and Distribution departments of requiring Professional Engineering licensure prior to promotion to Senior Engineer, Lead Engineer, or Principal Engineer. Specific to implementing Good Utility Practice within the generator interconnection process, these rigorous standards for advancement promote reasonable judgement and good business practices, grounded in achieving the Companies' overall mission to provide safe, reliable, and economic delivery of electricity.

II. <u>Application and Transparency of Good Utility Practice</u>

Q. DOES THE PUBLIC STAFF SUPPORT THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE AS REFLECTED IN THE MOS GUIDELINES?

A. Yes. As background, the MOS Guidelines were developed in order to consider the impacts associated with the Companies' long term planning obligations, so that the Companies could provide reasonable and non-discriminatory access to their distribution systems, while also ensuring this was done in a scalable and sustainable manner. I also discussed the MOS Guidelines in some detail in my direct testimony.[5]

Public Staff witness Williamson states that the Public Staff supports the Companies' application of Good Utility Practice as reflected in the MOS Guidelines. He specifically states that "the MOS [Guidelines] are reasonable guidelines for the Duke Utilities to apply in meeting their obligation to provide safe, reliable electric service to the using and consuming public."[6] For the Commission's reference, I have attached the Companies' MOS Guidelines as JWG Rebuttal Exhibit 2.

Q. DOES THE PUBLIC STAFF CHALLENGE ANY ASPECT OF THE COMPANIES' TECHNICAL STANDARDS AS INCONSISTENT WITH GOOD UTILITY PRACTICE?

---

[5] DEC/DEP Gajda Direct Testimony, at 49.
[6] Public Staff Williamson Direct Testimony, at 15.

A. No. The Public Staff did not challenge any aspect of the Companies current interconnection practices as being inconsistent with Good Utility Practice.[7]

Q. DO ANY PARTIES DISAGREE WITH THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE AND RESULTING TECHNICAL STANDARDS?

A. While the Public Staff generally supports the Companies' MOS Guidelines and application of Good Utility Practice, witnesses testifying on behalf of NCSEA, NCCEBA, and IREC—the solar industry advocates —generally oppose the Companies' technical standards and requirements. These solar industry advocates specifically contend that the Companies' MOS Guidelines are "overly restrictive" and "not typical" of other utilities around the country.[8]

Q. BASED UPON YOUR EXPERIENCE, WAS IT EXPECTED THAT THESE SOLAR INDUSTRY ADVOCATES MAY DISAGREE WITH THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE AND THE COMPANIES' DEVELOPMENT OF THE MOS GUIDELINES?

A. Yes. The Companies understand that the concerns of a developer in any particular instance are generally focused on the specific generating facility

---

[7] Public Staff Williamson Direct Testimony, at 15.
[8] NCSEA Brucke Direct Testimony, at 11.

for which they are seeking interconnection, and that developers do not carry the obligations of utility service to the using and consuming public.

In my direct testimony, I explained how the Companies' and these solar advocates have differing views on the appropriate allocation of engineering and technical risk, as well as the proper assignment of costs to mitigate those risks, between the Interconnection Customer Generating Facility owner and the Utilities and existing and future retail customers.[9] Public Staff witness Lucas similarly describes the potential for divergence between the interests of the using and consuming public versus interconnection developers.[10]

This difference in perspective between the solar industry and the Companies is analogous to the tension between a city or town imposing setbacks, permitting and other zoning requirements on a homebuilder that could physically locate 10 homes on a piece of property but is limited to seven to avoid adversely impacting the surrounding community. While more dense development may in some cases be physically feasible, the short-term and longer-term risks and burdens of doing so—such as increased water runoff and impacts to already-funded roads, schools and other infrastructure paid for by the general citizenry—would be assigned to existing neighbors and other citizens. This concern becomes even more

---

[9] DEC/DEP Gajda Direct Testimony, at 55.
[10] Public Staff Lucas Direct Testimony, at 6.

pronounced when a development boom occurs and the pace of development risks outpacing local zoning and planning. This is not to suggest that homebuilders or solar developers are "bad actors" in any way; however, their interests in developing and interconnecting the largest home development or solar project at the least cost may not align with the interests of the using and consuming public that has funded the infrastructure which they are seeking to use.

Q. DO YOU HAVE ANY OTHER COMMENTS THAT THE COMMISSION SHOULD TAKE INTO CONSIDERATION WHEN EVALUATING THESE SOLAR ADVOCATES' CLAIMS THAT THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE IS ATYPICAL OR OVERLY RESTRICTIVE?

A. Yes. As the Companies have repeatedly stated, with no known challenges to the contrary, we are in a "living laboratory" here in North Carolina, due to the unparalleled penetration of uncontrolled utility-scale generation resources both in operation and in the queue. Assertions that some of the Companies' application of Good Utility Practice do not have parallels in other states are not surprising, since no other states are experiencing the penetration levels of these specific types of resources. Utilities which are not undergoing anything like North Carolina's solar QF development boom, or do not have aggressive renewable penetration mandates in place, may not have begun to consider potential impacts to their system planning obligations. It is for this precise reason that the NC Procedures specifically contemplate that a particular practice may constitute Good Utility Practice even where the practice is not widely applied in the industry.

The Companies are dually responsible for planning and operating the distribution system while also managing the parallel operation of North Carolina's unique, and increasing, penetration of DER. Therefore, Good Utility Practice must absolutely carry with it considerations for scalability and sustainable practices, if the Companies are to continue to provide to the using and consuming public over the long term, "…reliable utility service at reasonable prices within the framework of state and federal law."[11]

Q. DO YOU AGREE WITH THESE SOLAR ADVOCATE INTERVENORS' THAT THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE, AND SPECIFICALLY THEIR DEVELOPMENT OF THE MOS GUIDELINES IS ATYPICAL OR OVERLY RESTRICTIVE?

A. No. Even recognizing North Carolina's unique utility-scale solar development experience, other utilities have established guidelines and technical standards similar to the Companies' MOS Guidelines. NCSEA witness Brucke states that "…Duke's Method of Service Guidelines are not typical…"[12] The Companies note however, that both PEPCO (PEPCO Holdings, which includes Atlantic City Electric in New Jersey, Delmarva

[11] Public Staff Lucas Direct Testimony, at 6.
[12] NCSEA Brucke Direct Testimony, at 11.

Power in Delaware, and Potomac Electric Power in Washington, D.C.)[13] and Arizona Public Service[14] have established guidelines like individual and aggregate DER capacity limits for generators, that are similar to Section 2 of the Companies' MOS. Therefore, the Companies' application of Good Utility Practice and its development of the MOS is not "atypical." Further, while NCSEA witness Brucke argues that the Companies' limit of aggregate DER on a substation as detailed in section 2.1.2 of the MOS is "overly restrictive," PEPCO has a similar limit established which appears to be more conservative than the Companies' limit. Additionally, Dominion Energy North Carolina limits aggregate DER capacity connected to substation transformers to a value similar to the Companies.

Q. PLEASE EXPAND ON THE COMPANIES' APPLICATION OF GOOD UTILITY PRACTICE AND THE MOS GUIDELINES BY PROVIDING AN EXAMPLE OF HOW THE MOS GUIDELINES HELP THE COMPANIES MAINTAIN THEIR LONG-TERM PLANNING OBLIGATIONS TO PROVIDE RELIABLE AND COST EFFECTIVE ELECTRIC SERVICE TO THEIR CUSTOMERS.

A. Consider this example, which relates to the Companies' technical policy related to Line Voltage Regulators ("LVRs"), as is detailed in section 3.2 of

[13] PEPCO's guidelines are *available at* https://www.pepco.com/MyAccount/MyService/Pages/MD/CriteriaSummary.aspx.

[14] Arizona Public Service's guidelines are *available at* https://www.aps.com/library/solar%20renewables/InterconnectReq.pdf.

the MOS. The first sentence in section 3.2 states "…DEC and DEP have identified that interconnection of uncontrolled utility-scale generation resources with no dependable capacity, at locations beyond LVRs and in high quantities across an entire system, is not consistent with Good Utility Practice." In this policy, the Companies recognize that locating generating facilities in the first zone of voltage regulation, closest to a substation, is more scalable and sustainable than locating facilities further down circuits beyond LVRs. This is because current distribution voltage regulation technology is largely designed for typical distribution loads, which are characterized by voltage drop and by limited volatility of demand. In contrast, multi-MW, distribution-connected independent generating facilities are characterized by voltage rise and by, in most cases, significant volatility of generation output–enough to cause adverse impacts to customers and the regulation equipment itself. This is somewhat manageable in the first zone of regulation, but the impacts of voltage rise and generation output changes become significantly less manageable beyond the first zone of regulation. No power system designer would ever think of a second zone of voltage regulation—many miles from the substation—as a preferred place to site a generating facility. And, even if a specific solution can be designed for a generating facility located beyond an LVR, the solution is not representative of a scalable and sustainable solution, due to the longer-term impacts to distribution planning that would occur absent the MOS Guidelines and the resulting increased costs to retail customers. In the paper "Maintaining Long Rural Feeders with Large Interconnected Distributed Generation,"[15] the author details how special regulator settings were used to interconnect a 9 MW landfill gas generator which was located beyond an LVR. This referenced project was actually interconnected in DEP in approximately 2010. While the initial solution, which involved complex analysis and special regulator settings, was successful, changes in circuit loads only two years after the initial interconnection caused the solution to become obsolete. A new study performed to consider the new retail load indicated that the regulator settings could not be adjusted to accommodate the 9 MW generator and the new 2 MW load simultaneously. The solution was to construct a mile of 3 phase line to support interconnection of the new 2 MW load customer. Importantly, the cost of this local distribution upgrade project was borne by DEP's retail customers. Public Staff witness Lucas describes in his direct testimony more background as to how and why this situation can occur.[16]

NERC also published a report in February 2017, "Distributed Energy Resources – Connection Modeling and Reliability Considerations," in which the authors discuss some of the challenges to long-term planning, and specifically how the "T-D interface" is becoming more crucial.[17] The

[15] Keary R. Dosier, *Maintaining Long Rural Feeders with Large Interconnected Distributed Generation*, 2014 IEEE Rural Electric Power Conference (REPC) (May 18-21, 2014), *available at* https://ieeexplore.ieee.org/document/6842197 .

[u] Public Staff Lucas Direct Testimony, at 45.

[17] North American Electric Reliability Corporation, *Distribute Energy Resources – Connection, Modeling and Reliability Considerations* (Feb. 2017), *available at*

Companies' careful considerations of long-term planning, one of the main functions of an electric utility, led to the creation of the MOS.

Q. DOES YOUR EXAMPLE REBUT CONTENTIONS MADE BY THE SOLAR ADVOCATES STATING THAT THE COMPANIES' IMPLEMENTATION OF GOOD UTILITY PRACTICE TO DEVELOP THE MOS GUIDELINES WAS UNREASONABLE?

A. Yes. NCSEA witness Brucke contends that "Duke has indicated that interconnection beyond a line voltage regulator is technically feasible if they reconfigure line voltage regulator settings."[18] As an initial matter, the Companies acknowledge that not only is it technically feasible for a specific generator interconnection to reconfigure the LVR settings, but also that the Companies have, years prior to the development of the MOS Guidelines, physically designed this type of interconnection solution for generator interconnection customers several times. The Companies also acknowledge that this practice has been utilized by other utilities in the past. However, recognizing that the Companies now have an unparalleled number of utility-scale generating facilities interconnected to their distribution systems, the Companies determined that this practice is not scalable nor sustainable in high quantities across an entire system for a number of reasons. For example, this practice limits the effective management of distribution

https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.

[18] NCSEA Brucke Direct Testimony, at 7.

circuit switching, increasing its complexity to a level not supported at high numbers by Duke Energy's Distribution Control Center and also not supported by the Distribution Management System currently in place.

Q. ARE THERE ANY ADDITIONAL EXAMPLES YOU CAN PROVIDE THAT MAY REBUT CONTENTIONS MADE BY THE SOLAR ADVOCATES THAT THE COMPANIES' DECISION TO DEVELOP THE MOS GUIDELINES WAS UNREASONABLE?

A. Yes. To touch on one additional item as an example, NCSEA witness Brucke states in his testimony that the Companies' prohibition of double-circuiting "…is not reasonable," [19] as is detailed in section 3.2.4 of the MOS Guidelines. Similar to the prior LVR example explained above, the Companies determined in mid-2016 that allowing "partial double circuits" to support utility-scale generator interconnection was not a scalable nor sustainable practice, as it would lead to many scenarios where certain load growth patterns could no longer be cost effectively served, thereby again pushing undetermined future costs to retail customers.

These instances provide examples of how consideration of scalability and sustainability can impact the application of Good Utility Practice, and how individual generator Interconnection Customers and third-party developers may not understand or appreciate the longer term obligations the Companies have to maintain a highly reliable and cost-

---

[19] NCSEA Brucke Direct Testimony, at 10.

effective system for the using and consuming public. Further, these examples illustrate the importance of the Companies' need for flexibility to implement Good Utility Practice over time, to efficiently and timely respond to changes in the Companies' power system and in the electric industry as a whole.

Q. HOW DO THE COMPANIES RESPOND TO STATEMENTS THAT THE DEC OR DEP HAVE DENIED INTERCONNECTION FOR SOME INTERCONNECTION REQUESTS?

A. To my knowledge, the Companies have never "denied interconnection outright" as suggested by Witness Brucke.[20] To do so would be inconsistent with how the Companies have interpreted the interconnection-related obligation arising under PURPA, as discussed in section 1 of the MOS Guidelines. Of particular importance, the second paragraph of the MOS Guidelines states:

> DEC and DEP consider all necessary system upgrades to the general electrical system that are required in order to provide distributed energy resources (DER) reasonable and non-discriminatory access to the DEC and DEP distribution systems, the primary purpose of which is to serve existing and future retail customers. As firm retail electric providers, DEC and DEP seek to interconnect DER in a manner that allows each resource to operate within its contractual

---

[20] NCSEA Brucke Direct Testimony, at 6.

parameters without negatively impacting existing utility customers' quality of service or cost of service. DEC and DEP are not, however, obligated under the NCIP or SCGIP to make modifications that are, or reasonably could be determined to be, detrimental to the operation of its system or detrimental to DEC's and DEP's public service obligations as regulated public utilities or retail electric service providers."[21]

Q. CAN YOU PROVIDE ANY EXAMPLES ILLUSTRATING WHY A DISTRIBUTION SYSTEM INTERCONNECTION MAY BE DETERMINED TECHNICALLY INFEASIBLE, AS OPPOSED TO "DENIED" BY THE COMPANIES?

A. Yes. A common reason for infeasibility is that there are already one or more five (5) MW generating facilities connected to the circuit or substation, meaning the circuit or substation cannot support more power injection (additional MWs).

The reason the circuit or substation cannot support additional MWs of generation may be as simple as excessive voltage rise, or due to other more complex factors. Because voltage rise is caused by the interaction of local generation against the impedance of the entire utility system, a common solution to this locational infeasibility could be to simply reconductor the distribution conductor to a larger conductor. However, if

[21] *See* Rebuttal Exhibit JWG-2, Section 1.

the distribution conductor is already the largest standard conductor size in use by the Companies, and no changes at the substation benefit the voltage issue, then the interconnection will be infeasible due to the specific interconnection location being "DER saturated." Notably, these DER saturated areas are becoming increasingly common in North Carolina's unique interconnection landscape due to the increasing levels of utility-scale solar penetration.

Q. CAN YOU PLEASE EXPAND ON YOUR EXAMPLE AND HOW "DER SATURATION" CAN AFFECT THE FEASIBILITY OF A PROPOSED INTERCONNECTION?

A. Yes. To expand on my example, under a scenario where significant DER interconnects to the point of "saturation," the Companies must still determine what other options may be available for the Interconnection Customer to connect. However, where the local distribution infrastructure is saturated, there are no further upgrades available to be completed to allow for an additional interconnection to existing distribution system infrastructure. Therefore, the Companies may determine that construction of a new distribution substation (sometimes called a "T/D substation" or a "retail substation") is the only option functionally available for the Interconnection Customer to interconnect in that specific location.

The Companies are fully aware of the substantial cost difference between distribution work (such as reconductoring) and construction of a new T/D substation. Reconductoring for a mile or two, when feasible, may cost several hundred thousand dollars, while the cost of constructing a new substation might exceed $5 million. The Companies are further aware that this very large cost difference may impact the project's financials, and thus overall project feasibility. However, while the Companies have always sought to identify the simplest and most reasonable interconnection solution, at the least cost, consistent with Good Utility Practice, the Companies' conclusions will not be altered simply because the outcome is not financially viable for a particular Interconnection Customer.

Q. LOOKING TO YOUR EXAMPLE, ARE YOU STATING THAT NCSEA WITNESS BRUCKE'S ASSERTION THAT THE COMPANIES' ARE DENYING INTERCONNECTION "OUTRIGHT" IS INSTEAD RELATED TO INTERCONNECTION COSTS?

A. Yes. The Companies asked NCSEA witness Brucke via a data request to explain and support this allegation. NCSEA witness Brucke responded that DEC and DEP have always proposed mitigation options but that he "has seen many instances where the mitigation options are financially impractical. For example, if a project is not allowed to interconnect to a distribution feeder as requested, Duke may propose that a new substation be built, and the project connect to the transmission system, which generally would not be financially feasible for a typical 5 MW project."[22]

[22] *See* Rebuttal Exhibit JWG-4 NCSEA Response to Duke Data Request 2-18.

Q. HOW DO YOU RESPOND?

A. The fact that there are no financially feasible interconnection options for a particular project does not constitute "outright" denial of interconnection. Instead, in such cases, it is the unavoidable outcome of the Companies' application of Good Utility Practice in a consistent and non-discriminatory manner. It is the utility's responsibility under the NC Procedures to evaluate the impacts of the proposed generating facility on the distribution and transmission system and to identify any Upgrades required to implement a safe and reliable interconnection (*see* Section 4.3.3 and Attachment 7 System Impact Study Agreement, Section 10, 12). As I highlight above, the Companies' MOS Guidelines establish that the standard for reviewing a proposed generator interconnection is to ensure that the Interconnection Customer will be responsible for any Upgrades required to enable interconnection and parallel operation of the generator "without negatively impacting existing utility customers' quality of service or cost of service." As penetrations increase, more expensive Upgrades such as new T/D substations will be required to interconnect additional generation to already-saturated circuits and substations in certain areas of the Companies' systems. Nonetheless, the Companies commit to providing each Interconnection Customer a technically feasible option for a safe and reliable interconnection at the lowest cost possible, consistent with Good Utility Practice.[23]

Q. PLEASE DESCRIBE THE PUBLIC STAFF'S RECOMMENDATIONS FOR IMPROVING THE PROCESS OF COMMUNICATING NEW CRITERIA MODIFICATIONS FROM THE UTILTIY TO THE INTERCONNECTION CUSTOMERS.

A. Public Staff witness Williamson recommends that in the event of a new screen, study, technical standard, or major modification of technical methodology being developed by the Utilities in their application of the NC Procedures, that the Utilities should be required to: (1) file the new technical standard with the Commission in this docket for information purposes only, (2) immediately post the information on the utility's website, and (3) present the topic for discussion at the next TSRG stakeholder meeting.[24]

Public Staff witness Williamson's further recommends that the Utilities should also inform the Commission of any potential queue impacts, including impacts to (1) Interconnection Request processing time, (2) project withdrawals, (3) and increased interconnection costs to be incurred by Applicants, if known.[25] While the Companies understand and agree with the transparency objective underlying witness Williamson's

---

[23] I note that Interconnection Requests for locations close to substations, and on circuits and substations which have not been "DER saturated," still generally allow very straightforward interconnections and are less impacted by the MOS Guidelines.
[24] Public Staff Williamson Direct Testimony, at 24.
[25] *Id.*

recommendation and are always supportive of Interconnection Customers having as much information as reasonably possible, the Companies would be unable to meaningfully comply with these further recommendations.

More specifically, the Companies believe that anticipating and fully addressing and identifying any possible "queue impacts" is infeasible in that it would require the Companies' to use time and engineering resources in making mere hypotheticals and projections concerning the business decisions of third party Interconnection Customers. This is because the Companies will likely not have clear visibility into whether affected project(s) will be more likely to withdraw from the queue due to a new technical standard, and because it will be difficult to quantify if a modification to a technical standard will cause "delays in Interconnection Request processing time." Whether the new standard will result in "increased costs" for most or all Interconnection Customers will also likely be challenging to determine unless the new technical standard or requirement uniformly specifies a particular "solution," such as installing a particular piece of equipment, that will apply to all Interconnection Customers uniformly. Thus, due to the many uncertainties identified above, any projected potential queue impacts would be of little value (particular relative to the amount of resources likely required to conduct the assessment) and could even lead to greater frustration amongst Interconnection Customers when such projections are determined not to be accurate in general or with respect to particular projects.

Q. TO CLARIFY, DO THE COMPANIES' OTHERWISE AGREE TO IMPLEMENT THE PUBLIC STAFF'S RECOMMENDATIONS RELATING TO FILING SUCH REVISIONS?

A. Yes. The Companies' agree to 1) file any significant new screens, studies, or major modification in their application of the NC Procedures with the Commission in this docket for informational purposes only; 2) post information on the utility's website regarding the new screen, study, or modification to the NC Procedures; and 3) present the topic for discussion at the next TSRG stakeholder meeting.

III. Technical Standards Review Group

Q. CAN YOU DISCUSS THE TSRG AND WHETHER THE COMPANIES ARE CONFIDENT THAT THIS STRUCTURE WILL PROVIDE GREATER TRANSPARENCY AND PROMOTE MUTUAL UNDERSTANDING BETWEEN THE COMPANIES AND INTERCONNECTION CUSTOMERS?

A. Yes. Since the TSRG's implementation in early 2018, there have been several meetings held per its intended quarterly meeting frequency, with discussion focused on new interconnection-related developments or planned revisions to the Companies' existing technical standards. The Companies believe the TSRG to be a success, as it has already fostered increased communications and transparency between the Companies' and its Interconnection Customers since the TSRG's inception. Additionally, Public Staff witness Williamson expresses support for the TSRG, stating "the TSRG stakeholder meetings should continue in their current format on at least a quarterly basis for the foreseeable future."[26] Therefore, and as stated above, the Companies and Public Staff both foresee the TSRG as a key tool in communicating new or changing technical standards amongst interested stakeholders.

Q. HOW DO THE COMPANIES' RESPOND TO CERTAIN SOLAR ADVOCATES' CLAIMS THAT THE TSRG HAS BEEN LESS THAN SUCCESSFUL?

A. The Companies disagree that the TSRG has been anything less than successful. Specifically, NCSEA witness Brucke claims that "no changes to any Duke policy or standard have been implemented," since the TSRG was established.[27] This statement assumes that the TSRG is only successful when it results in changes and the Companies do not agree with this assertion. Furthermore, the TSRG is a new creation and therefore it is unrealistic to expect that it will have resulted in significant changes in such a short period of time. To quote the Public Staff, "the TSRG has been beneficial to participants even though it is still in its infancy."[28]

In comparison to the solar advocate interveners, the Public Staff, as evidenced by the above statement, is encouraged by what they have witnessed to-date through their active participation in the TSRG. If one

---

[26] Public Staff Williamson Direct Testimony, at 22.
[27] NCSEA Brucke Direct Testimony, at 13.
[28] Public Staff Williamson Direct Testimony, at 22.

reviews the detailed agendas and minutes, which are made publicly available at https://www.duke-energy.com/business/products/renewables/generate-your-own/tsrg and included in my Rebuttal Exhibit JWG-3, one can see the vast breadth and depth of technical issues being raised and discussed at the meetings. Further, much of the Companies' time during these initial meetings has been appropriately spent on educating non-utility TSRG members on the basis and reasons for current practices, systems, processes and procedures—many of which have existed long before the introduction of utility-scale DER.

Q. HAVE THE COMPANIES IMPLEMENTED ANY PROCEDURES RELATED TO THE TSRG AND INCREASING TECHNICAL OVERSIGHT AND UTILITY ACCOUNTABILITY AND CAN YOU PROVIDE ANY EXAMPLES?

A. Yes. The Companies started keeping a detailed action item log and are tracking and following up on discussion items brought to the Companies' attention by interested stakeholders through the TSRG. For example, at the April 2018 meeting, developers asked questions about Salesforce and Powerclerk, and the Companies responded by agreeing to put the issues on the agenda for the July meeting. At the July meeting, the Companies presented information on the status of Salesforce and Powerclerk, in response to these stakeholders' requests. Similarly, at the July meeting, there were many questions raised about voltage management and DSDR and at the October meeting, the Companies provided a summary of how nominal voltage and DSDR are related, and then posted information on the TSRG website under the "meeting three" documents list concerning the same. This action item log, and resulting follow-up communications, shows how the Companies' are taking the TSRG itself, and resulting communications and discussion, seriously in increasing transparency and coordination between the Companies and interested industry stakeholders.

Q. WERE THERE ANY RECOMMENDATIONS MADE BY INTERVENORS RELATING TO THE TSRG'S FUTURE IMPLEMENTATION?

A. Yes. The Companies, the Public Staff, and IREC all support continued implementation of quarterly TSRG meetings. Additionally, IREC witness Lydic recommends that in the future, all TSRG meetings "be publicly noticed and its agenda and meeting minutes be filed in a docket or otherwise publicly posted."[29] The Companies note that the TSRG's meetings already have been and continue to be posted publicly at https://www.duke-energy.com/business/products/renewables/generate-your-own/tsrg, with agendas co-developed by the Companies and the interested stakeholders. Minutes and presentations from each meeting are additionally posted to the Companies' interconnection webpages.

Last, NCSEA and IREC recommend that the current form of the TSRG change to allow for Commission oversight, and discuss a process by

[29] IREC Lydic Direct Testimony, at 23.

which consensus and/or Commission approval would be required for changes to interconnection technical standards.[30]

Q. HOW DO THE COMPANIES' RESPOND TO IREC AND NCSEA'S RECOMMENDATION THAT THE TSRG BE SUBJECT TO COMMISSION OVERSIGHT?

A. The Companies' disagree with IREC and NCSEA that the TSRG should be subject to Commission oversight. In response, I first note that both the Companies and the Public Staff agree that "Duke Energy retains the right to make the final decision on all technical standards or evolving [Good Utility Practice] revisions, subject to Commission review as part of its general regulatory power and the dispute resolution process defined in the NCIP."[31] This approach mirrors the Massachusetts TSRG, on which the Companies' TSRG was based (and which was cited by IREC as a model). The Massachusetts governing documents state that:

> "The members of the TSRG understand and agree that the Utilities have the final decision over which Technical Standards, both common and Utility-specific, to employ for the purposes of interconnecting DG facilities to their respective distribution systems

[30] IREC Lydic Direct Testimony, at 23; NCSEA Brucke Direct Testimony, at 13.
[31] Public Staff Williamson Direct Testimony, at 23.

> and ultimate control over any Utility-specific and common Technical Standards Manuals they develop."[32]

Thus, other, similar TSRGs do not require Commission oversight.

Further, although the Companies do not dispute the Commission's regulatory powers, to allow Commission oversight of the TSRG would, in essence, give stakeholders a unique ability to assert power over the Companies' internal planning and operating standards. This, in turn, would force the Companies to "re-optimize" power quality, reliability, and economic considerations for retail customers "around" whatever technical standards have been put in place for these solar QF developer stakeholders. Stated another way, today the Companies are free to continually make informed alterations and modifications to their utility system (*i.e.*, provide continual optimization), as long as the cost and quality of service continues to be maintained or improved, given other uncontrolled external constraints. If consensus and/or direct Commission approval were to be required for changes to interconnection technical standards through the TSRG (not including the NC Procedures), the TSRG stakeholders (interconnecting solar QF developers) would be provided first right to alter the Companies' internal practices, and at the cost of retail customers. Therefore, these recommendations should be rejected.

---

[32] Massachusetts Technical Standards Review Group Final By Laws, *Technical Standards Review Group Guidelines*, at 1, https://drive.google.com/file/d/0B836U49Yrh_QYW5vNGlTR2xrMUk/view.

In conclusion, the Companies believe that the TSRG is a truly valuable and necessary forum in today's emerging world of interconnecting and operating in parallel with growing levels of distributed generation. The Companies also believe that nothing in the current environment changes the effective role of the Commission's long-held oversight and regulatory authority over quality of service and cost of service, and that the Companies, as do all utilities, continue to operate effectively in a mode of continual internal optimization to meet the needs of their retail customers.

IV. IEEE 1547

Q. CAN YOU PROVIDE THE COMPANIES' PERSPECTIVE ON IEEE 1547?

A. Yes. IEEE 1547-2018 represented significant changes to the earlier 2003 version. The new 1547 Standard, titled "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," is not a procedural standard, although it does provide "requirements relevant to the performance, operation, testing, safety, and maintenance of the interconnection." As detailed by Public Staff witness Williamson, "it is not a standard that the Utilities are bound to follow but is a standard that provides guidance on incorporating DER onto the grid."[33]

[33] Public Staff Williamson Direct Testimony, at 17.

Q. CAN YOU PLEASE EXPAND ON THE STATEMENT MADE BY THE PUBLIC STAFF IN REGARDS TO THE IEEE 1547 NOT BEING A STANDARD THE UTILTIIES ARE BOUND TO FOLLOW?

A. Yes. Public Staff witness Williamson's comment is a key point to keep in mind when discussing the IEEE 1547 standard. IEEE 1547 contains the phrase "DER shall…" about eighty-six (86) times, while the phrase "Area EPS shall…" is never included.[34] The import of this DER-focused standard is significant as it allows for utility-specific implementation of Good Utility Practice and does not impose exact requirements, which the Companies' (or any utility) must specifically implement from the IEEE 1547 standard.

However, to keep in line with new developments in the DER industry and to recognize evolving Good Utility Practice, the Companies are studying the new IEEE 1547 standard and working on determining if and when some of the standard's provisions may be appropriate to adopt. Therefore, if and when this becomes the case, the standard will be available for the Companies to utilize in assuring that DER follow all standard designs as called for in the IEE 1547. Until that time, the Companies agree with IREC[35] in that the TSRG is and will be an appropriate forum for

---

[34] Note that "Area EPS" refers to the Area Electric Power system, a term meant to refer to the utility.

[35] IREC witness Lydic argues that the TSRG is the appropriate forum for considering smart inverters and the IEEE 1547 standard. IREC Lydic Direct Testimony, at 31-32.

consideration and implementation of the IEEE 1547-2018 Standard, as its use will require coordination with, and action by, North Carolina interconnection developers.[36]

V. Fast Track and Supplemental Review

Q. PLEASE SUMMARIZE IREC'S POSITIONS AS IT RELATES TO FAST TRACK AND SUPPLMENTAL REVIEW.

A. Throughout this proceeding, IREC has placed great emphasis on changing the Fast Track and Supplemental Review process, and raised issues relating to both processes.

Specifically, IREC took positions on:

- the Companies' definition of line section as it applies to Fast Track screen 3.2.1.2;
- changing the Fast Track Eligibility for interconnections on 5 kV circuits, in any location, from 100 kW to 500 kW;
- screening for projects 20 kW and less;
- Supplemental Review screens; and,
- screening criteria for penetration of net-metered DER on a substation transformer.

[36] Notably, questions surrounding "smart inverters" are part and parcel of 1547-2018's scope, and will be taken up in a forum such as the TSRG.

Q. DO YOU AGREE WITH IREC THAT BOTH THE FAST TRACK AND SUPPLEMENTAL REVIEW PROCESSES NEED TO BE REVIEWED AND CHANGED?

A. No. The Companies have seen few issues with the overall Section 3 Fast Track process, and move the majority of Fast Track projects through the queue with relative ease, as compared to the more significant and time-consuming technical and queue challenges related to multi-MW solar farms. Therefore, the Companies believe that both the overall Section 3 Fast Track and Supplemental Review processes are working efficiently at this time and do not need a complete overhaul.

Q. CAN YOU EXPLAIN THE COMPANIES' APPROACH TO EVALUATION OF FAST TRACK SCREEN 3.2.1.2 AND WHY IT DIFFERS FROM IREC'S POSITION?

A. Yes. First, however, I would note that the Public Staff supports the Companies' overall approach to the Fast Track screening process as a whole, including its interpretation of the term "line section" as it evaluates the Fast Track screening criteria.

As background to the Companies' application of Fast Track Screen 3.2.1.2, the Companies developed their interpretation of "line section" using the term "automatic sectionalizing device" as it is classically used in the utility industry. Specifically, the Companies interpret this to apply to a device which is capable of automatically sectionalizing (separating) a section of the distribution system, quickly and without local or remote human intervention. The capability is typically necessary due to a fault, and would include feeder circuit breakers, reclosers, sectionalizers, and fuses. To clarify, there is nothing electrically different about one circuit zone which consists of a transformer fuse, transformer, and several secondary services, as compared with another circuit zone consisting of mile-long fused tap line containing many service transformers and services. As Public Staff witness Williamson stated in support of the Companies' application of this section, "the Utilities are reasonable in using a conservative approach that will results in a higher degree of grid safety and reliability."[37]

In contrast to the Companies' application of this screen, IREC states that the Companies' approach to the 15% peak load screen, and interpretation of "line section" as the zone defined by a service transformer fuse, is too narrow. IREC therefore recommends that the definition of line section include a larger section of the distribution circuit.

In support of their argument, IREC cites a paper titled, "Evaluation of Alternatives to the FERC SGIP Screens for PV Interconnection Studies," to justifying its recommendation for a different definition of line section. However, this paper states that "…Automatic sectionalizing devices may include feeder breakers, line automatic sectionalizing switches, and possibly fuses as well." Therefore, this paper acknowledges that a fuse is an automatic sectionalizing device, and therefore also supports the

[37] Public Staff Williamson Direct Testimony, at 13.

Companies' current definition and application of line section within NC Procedures section 3.2.1.2.

The Companies agree with Public Staff witness Williamson that a "…screen should not be arbitrarily adjusted on the sole premise of allowing more projects to pass the screen and be interconnected."[38] The Companies therefore contend that IREC's recommendations should be rejected, as Fast Track section 3.2.1.2 and the current definition of "line section" as applied by the Companies is reasonable and being applied in an efficient manner. All of the above considered, the Companies do however agree with Public Staff witness Williamson that it would be appropriate to address the Companies' application of "line section" within the Section 3.2.12 technical screen during a future meeting of the TSRG, though only so as to increase transparency as to the Companies' interpretation of that term.

Q. HOW DO THE COMPANIES RESPOND TO IREC'S POSITION THAT THE FAST TRACK PROCESS IS NOT WORKING, NOTING HIGH PERCENTAGE SCREEN FAILURE RATES?

A. Most of the screen "failures" are related to the 15% peak load screen, discussed above. As noted in my direct testimony, during the 2017 Stakeholder Process, the Companies shared how the majority of Interconnection Requests proposing to interconnect to the Companies' systems under Fast Track initially fail the Fast Track screens, but are then

---

[38] *Id.*

successfully evaluated for interconnection through Supplemental Review. Interconnection Customers processed through the Section 3 process are passing Supplemental Review without the Companies identifying a need for full Section 4 study at a rate of approximate 97 percent.

IREC suggested the initial Fast Track screen failures are evidence that the Companies are not applying the Fast Track screens appropriately. However, as I explain in direct testimony, similar logic would lead one to conclude that since the vast majority of college students fail to attain a grade point average in excess of 3.75, university professors must be designing their tests to be too difficult. The Companies maintain that the focus should be on the time for overall processing of Interconnection Requests of certain sizes, regardless of the exact processing mechanism, while technical screens and evaluations should be handled appropriately.

Q. WHY DO THE COMPANIES NOT SUPPORT CHANGING FAST TRACK ELIGIBILITY FOR INTERCONNECTIONS ON 5 KV CLASS CIRCUITS, IN ANY LOCATION, FROM 100 KW TO 500 KW?

A. I would first note that the Public Staff supports the Companies' position to not change Fast Track Eligibility for interconnections on 5 kV class circuits located anywhere on the circuit from 100 kW to 500 kW. Since existing Section 3.1 Fast Track Eligibility Table already establishes an eligibility value of 500 kW for sites within 2.5 miles of the substation, the Eligibility value under question is primarily for facilities further than 2.5 miles from the substation. The reason why the Companies do not support this change in eligibility is primarily based upon physics, which explains why the change is completely unnecessary. As background, most of the Companies' 4160 volt circuit backbones are less than 2.5 miles in length, making an interconnection at a location further than 2.5 miles from the substation exceedingly rare. Hence, the screen value goes mostly unused if eligibility is increased.

As a comparison of distribution circuits: if one assumes 480 amperes of current flow (approximate capacity for a distribution circuit), one would calculate an equivalent voltage drop for a 23 kV feeder of 9 miles in length, a 12 kV feeder 5 miles in length, and a 4.16 kV feeder 1.6 miles in length. As a point of reference, the standard feeder design in DEP, designed in the 1960s, called for the optimum length of a 23 kV circuit to be 9 miles, and the optimum length for a 12 kV circuit to be 5.5 miles, making the point that these are typical feeder lengths even today. Therefore, one should expect few 4.16 kV circuits to be in excess of 2.5 miles in length. In fact, a query of DEC's 4.16 kV circuits across North Carolina and South Carolina estimates 85% of the circuits to be less than 3 miles in length.

Furthermore, a closer inspection of the Fast Track Eligibility table in section 3.1 reveals that it clearly utilizes, as a primary component, the concept of stiffness ratio, and does so appropriately based on the description of stiffness ratio in IEEE 1547.7. Specifically, IEEE 1547.7 describes weak or insufficiently stiff locations on a power system indicative of "…a greater potential to affect system voltage, power quality, and system protection schemes," therefore providing the conceptual basis for deriving appropriate values in the Fast Track Eligibility Table.

As an example, if one were to construct a Fast Track Eligibility Table strictly upon a single stiffness ratio value, and choose a ratio of 60 as the criteria of Fast Track eligibility, the following table would result, based on common parameters of the DEC and DEP systems:

Line Voltage	Interconnection at 3.0 electrical miles from substation	Interconnection at 0.5 miles from substation
4.16 kV	≤ 141 kW	≤ 656 kW
12.5 kV	≤ 0.87 MW	≤ 1.90 MW
24 kV	≤ 1.65 MW	≤ 2.30 MW

Compare this to the actual Fast Track Eligibility table in section 3.1 of the NC Procedures:

Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline and ≤ 2.5 Electrical Circuit Miles from Substation
< 5 kV	≤ 100 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW	≤ 2 MW
≥ 15 kV and < 35 kV	≤ 2 MW	≤ 2 MW

The similarities of the tables are striking. In comparing these tables, one can see how Interconnection Requests for generating facilities well over 100 kW, up to 500 kW, in locations greater than 2.5 miles from the substation, on 5 kV circuits, will not only be exceedingly rare, but when they occur, have great potential for system reliability impacts that require upgrades and which should be studied in the Section 4 study process.

Although IREC witness Auck believes that IREC's eligibility proposal is now a "…*de facto* national standard…"[39] and points to the state of Ohio—where Duke Energy Ohio[40] operates—adopting a 500 kVA threshold for this screen, the Companies assert that this change has virtually no positive effect to the processing of interconnection requests, and will be rarely, if ever used. Additionally, in the Companies' opinion, compliance with a supposed "…*de facto* national standard…" is insufficient as a singular justification when the engineering and physics behind the screen involved do not offer support.

Q. WILL THE COMPANIES PLEASE CLARIFY THEIR PRACTICES FOR SCREENING PROJECTS 20 KW AND LESS?

A. Yes. First, I would like to make a clarification concerning recent filings and data requests made by the Companies which referenced the use of a "Demand Table" in its evaluation of projects ≤ 20 kW. To be clear, the Companies use this "Demand Table" to confirm compliance with the NEM tariffs in DEC and DEP, not to evaluate interconnection impacts. The NEM

[39] IREC Auck Direct Testimony, at 19.
[40] The Companies note that to their knowledge, Duke Energy Ohio did not support this eligibility change before the Public Utilities Commission of Ohio.

tariffs in DEC and DEP require that the capacity of the generating facility must not exceed the Customer's estimated maximum annual kilowatt demand, and the "Demand Table" is composed of estimated kW demand levels based on attributes of the customer's home. The data in the "Demand Table" is sourced from the Company's design information, which it uses to size service transformers, secondary service cables, and other electrical equipment. Therefore, the "Demand Table" is not specifically germane to the discussions around interconnection impact evaluation.

Turning to the actual screening of Interconnection Requests ≤ 20 kW in size, to-date the Companies validate that the Interconnection Customer is utilizing equipment which is UL1741 listed for its <20 kW project. Notably, having proper UL1741 equipment is the most important safety and operational aspect for these sized interconnections. The Companies have not, however, performed Section 3 Fast Track screening for all 4,000+ Section 2 Interconnection Requests. Previously, the Companies evaluated the Section 3 screens and concluded, in conjunction with their knowledge and experience of small inverter-based facilities, that no safety risks and little to no operational risks would occur if initial Section 3 Fast Track screening was not completed. Instead, the Companies' evaluation concluded that application of the Section 3 screen to such small projects would rather result in a laborious process with little to no benefit to Interconnection Customers or to the protection of power quality and reliability on the system.

Q. WHY DO THE COMPANIES NOT SUPPORT SIGNIFICANT CHANGES TO THE SUPPLEMENTAL REVIEW PROCESS?

A. The current Supplemental Review process provides valuable flexibility for both the Utility and the Interconnection Customer. Additionally, the Companies have utilized the Supplemental Review process with much success; when a project fails to pass one or more Fast Track screens, the project most often proceeds to Supplemental Review where it is then successfully evaluated. In many cases, Fast Track-eligible projects require additional technical evaluation but do not need to undergo the Section 4 study process to ensure they can be safely and reliably interconnected. However, larger projects or locations with more complexity may be referred to the Section 4 study process to assure that circuit impacts of interconnecting the proposed Generating Facility are well-understood before proceeding to an Interconnection Agreement.

While IREC claims that the Companies' use of discretion "provides a ripe opportunity for the appearance of, or actual, discriminatory treatment of projects,"[41] the Companies initially note IREC witness Auck's testimony that they are legally prohibited from exercising discriminatory treatment of projects, and second, even question why or to what end they would engage in such discriminatory treatment. From the Companies' perspective, there

[41] IREC Auck Direct Testimony, at 17.

appears to be no obvious incentive to do so, and the Companies therefore reject IREC's unsupported contention.

Q. WHY DO THE COMPANIES NOT SUPPORT IREC'S PROPOSAL FOR THE IMPLEMENTATION OF ADDITIONAL SCREENS WITHIN THE SUPPLEMENTAL REVIEW PROCESS?

A. The Companies' do not support IREC's proposal for a set of three prescriptive Supplemental Review screens in lieu of the current, more flexible approach the Companies advocate to continue to implement. The Companies first reject IREC's proposal because the addition of standardized screens to the Supplemental Review process implies that there is a complete and uniform understanding of every possible future design of DER and how it might connect to the distribution system. Secondly, IREC's proposal assumes that distribution systems in North Carolina are 100% equivalent to distribution systems elsewhere. Neither premise is correct.

Rather than adopting new screens within the Supplemental Review process, the Companies instead would support further evaluation of the Fast Track process screens, taking into account the specifics of the distribution systems involved, as well as industry developments. The Companies' recently formed TSRG can provide a forum to evaluate whether a more well-defined Supplemental Review process would create benefits over the current flexible Supplemental Review process that exists today.

Further, although IREC contends that these Supplemental Review screens will increase efficiency—seemingly because customers know what to expect and can assess earlier on whether their project would pass screens—the Companies' evaluation of these proposed screens shows the opposite conclusion; acceptance of these additional screens would in fact decrease efficiency. As detailed in my direct testimony, a few of IREC's proposed screens mirror the Companies' current Supplemental Review process, while others do not provide much value to Interconnection Customers at all, meaning these screens would only further delay an Interconnection Customer's processing through the queue.

Further, the Companies in their experience find that the relative small cost of a Fast Track review and Supplemental Review, in comparison to the cost of the project, incentivizes Interconnection Customers to complete the study and interconnection process as swiftly as possible, in order to be aware of the final outcome and any related costs of their proposed project, prior to fully committing to construction and final operation. Thus, the Companies' current study process, is developed organically to only address the items which need to be studied for a safe and reliable interconnection and nothing further. In conclusion, the Supplemental Review process as it exists provides the Companies more latitude to continually improve and optimize the evaluation process, a concept which comes natural to a utility in almost everything it does, and provides benefit to all Interconnection Customers.

Q. CAN YOU PROVIDE ANY EXAMPLES OF HOW THE FLEXIBILTIY OF THE CURRENT SUPPLEMENTAL REVIEW PROCESS HAS IMPROVED NORTH CAROLINA'S INTERCONNECTION PROCESS?

A. Yes. The Companies note how IREC witness Lydic questions the Companies' use of a 10% screen in which the aggregate amount of net-metered DER on a substation is calculated to see if it is below 10% of the substation transformer capacity, within Supplemental Review. This is actually a great example of the Companies' organically developing flexible evaluation methods to move projects through the queue as swiftly as possible, while also making sure certain impacts are not missed.

Specifically, this 10% screen was developed so that the Companies could flag growing penetration of net-metered DER on substations, and perform additional study if needed. It was created with the knowledge that conservatively, the minimum load experienced by most all transformer banks would be at least 10% of the bank's rating. This screen also has allowed most net-metered projects to move quickly through evaluation as this screen was satisfied.

In using and developing flexible evaluation methods, the Companies are utilizing internal engineering talent to identify what is needed specifically on the Companies' systems, with the Companies assuming any and all risk which may come with improper technical evaluations. In any case, the Companies' more "personalized" evaluation is better than evaluation through a set of screens handed down from elsewhere and not taking into account specifics of the Companies' systems.

Further, since the Companies are completely responsible for reliability and power quality on their systems, the Companies are best able to process interconnection requests with flexibility in its evaluation processes. The risk of such processes being too lenient or liberal are taken on by the Companies, while the risk of such processes being too conservative or restrictive are addressed by offering full transparency of its methodologies and availability for discussion through the TSRG. Finally, the reason to maintain these processes as flexible and not lock them down is that this is a dynamic and changing area of study. Handling these issues within the TSRG rather than specifically in a regulatory document is more efficient for all stakeholders and presents no disadvantages for stakeholders.

VI. Material Modification

Q. PLEASE ADDRESS THE COMPANIES' POSITION ON MATERIAL MODIFICATIONS, ESPECIALLY WITH RESPECT TO ENERGY STORAGE.

A. NCSEA witness Brucke and NCCEBA witness Norqual both testify that an Interconnection Customer should be able to add energy storage to an Interconnection Request already in the queue. As background, during Working Group #2 in the 2017 Stakeholder Process, language was agreed upon which called for the ability to make changes to the DC system configuration of a facility, without them being considered "indicia of a material modification." In addition, the Interconnection Request form was revised to call for hourly production profile information. Both of these changes can be seen in the final markup of the NC Procedures as compiled by Advanced Energy and filed with the Commission by the Public Staff in August of 2017. As explained throughout the 2017 Stakeholder Process, the Companies' concerns are with modeling accuracy and system impacts of battery storage, and assuring that what is being studied actually matches the reality of the generating facility's impact to the system, especially where otherwise material changes are subsequently made to the facility design.

Despite this seemingly unassailable perspective, NCCEBA witness Norqual questions the Companies' addition of a phrase in the NC Procedures Redline, as filed with my direct testimony. Specifically, the following section 1.5.2.5 reads as follows, with the additional text submitted by the Companies underlined:

> 1.5.2.5 A change in the DC system configuration to include additional equipment that does not impact the Maximum Generating Capacity, daily production profile or the proposed AC configuration of the Generating Facility including: DC optimizers, DC-DC converters, DC charge controllers, static VAR compensators, power plant controllers, and energy storage devices such that the output is delivered during the same periods <u>and with the same profile</u> considered during the System Impact Study.

The Companies realized after the conclusion of Working Group #2 that the 1.5.2.5 language likely left open for interpretation whether an Interconnection Customer could generate at the originally requested full output at any time between sunrise and sunset, the assumed operating hours of a solar farm. The assessment of exactly what hours of the day, and to what levels, of energy storage production might be a permissible modification, without performing additional study, would be subjective at best. Without being able to perform proper studies to re-assess the impacts of the modified generator + storage output, the Companies risk inadvertent discriminatory treatment across Interconnection Customers. Study complexity is growing, not diminishing, and an uncontrolled storage device could be in a charge state, discharge state, or neutral state at any time. Any study must be able to account for what will truly happen in reality.

Therefore, the Companies added the words "and with the same profile" to the Advanced Energy redline simply out of an abundance of caution. This was necessary because operation at full requested output early or late in the day, for example, when studies have been assuming solar output has been very low, cannot be supported by original study assumptions. Although this should be well understood, the Companies believe the clarifying language is necessary to ensure system safety and reliability.

Additionally, I note that it is true that the NC Procedures allow for some changes to the DC configuration without concern for production profile, such as DC/AC ratio increases. These DC/AC ratios are known to impact early and late day ramping, a growing concern of its own, though the Companies manage the concern through requirements or other mitigation if system ramping becomes sufficiently impacted. However, the addition of energy storage is not analogous to a DC/AC ratio increase. The Companies expect modeling to become more complex in the future, and without assurances the original profile can be maintained with the addition of battery storage, the Companies must consider profile changes as "material" when and where they do impact study assumptions.

VII. Software Controls

Q. PLEASE ADDRESS THE COMPANIES' POSITION ON THE REVISED NCIP SECTION 6.10.2, WITH RESPECT TO SOFTWARE CONTROLS.

A. Yes. IREC witness Lydic, claims that the phrase "mutually agreed upon" as included in Section 6.10.2, presents concern in that it could allow the Utilities to limit controls to only physical controls. Importantly, the Companies already rely upon software-based controls, for example when inverters in solar farms are programmed with appropriate "Pmax" (maximum real power output) settings to assure that the sum total of inverter output does not exceed the contract capacity. Conversely, solar farms utilize power plant controllers (which are programmable devices and have attributes of software-based controls) to control output as well. Therefore, the phrase "mutually agreed upon" should not present problems for

Interconnection Customers looking to use software controls to manage power export. However, the Companies note that proper output controls are extremely important as they control impacts to retail customers on distribution circuits, and on the transmission system for transmission interconnected generating facilities. Therefore, the Companies will continue to review and agree upon appropriate export controls proposed by Interconnection Customers.

VIII. Completion of an Independent Review of the NC Procedures

Q. WHAT IS THE COMPANIES' POSITION ON THE PUBLIC STAFF'S RECOMMENDATION FOR AN INDEPENDENT REVIEW OF THE NC PROCEDURES?

A. The Companies do not support a full independent review of the NC Procedures. A full independent review would likely consume significant time in 2019, and is broader than the Companies would support as reasonable and beneficial based upon the recently-completed 2017 Stakeholder Process and the Commission's review of the NC Procedures review that is already underway. As discussed in greater detail by DEC/DEP witness Freeman, significant work will already be required in 2019 to transition the study process for larger generators from the current serial process to a cluster study approach. Requiring the same Duke Energy team to also coordinate a separate independent review of the full NC Procedures in parallel (on top of their actual "day jobs" of administering the interconnection process) would be nearly impossible and potentially delay or impair the implementation of needed queue reforms. This is especially the case if the Public Staff is contemplating "significant stakeholder input" into the independent review process. At a minimum, the Companies would request that such a study be delayed until after the grouping study stakeholder process is concluded.

While the Public Staff appears to assert that independent review of the entire interconnection procedures is "common,"[42] Public Staff only cites to one analogous example, New York's independent review. The Companies have reviewed the EPRI report on the New York interconnection standards, and note that New York's review was part of that state's overarching "Reforming the Energy Vision" process. Notably, New York's then-existing interconnection standards only applied to generators up to 2 MW, meaning New York's interconnection procedures and pre-existing landscape was in a much different place than North Carolina's today. Additionally, although the Companies tried to find the cost of EPRI completing its assessment and developing this 100+ page report for New York, we have been unable to do so and also note that the cost of such a review is a concern. The Companies are not aware of any other state having undertaken a third-party review on such an enormous scale.

As I explain in my direct testimony, the Companies continue to support a more narrowly-focused independent review or consultation with

[42] Public Staff Williamson Direct Testimony, at 27.

ERPI on the Fast Track and Supplemental Review process.[43] This could be implemented through the TSRG, with industry participation and feedback provided through the TSRG. However, a "full NC Procedures review" with stakeholder input would be unduly burdensome to implement at this time, would impair the Companies' ability to perform other functions (including efforts to implement a full grouping study), would likely be costly, and should therefore be rejected or at least postponed by the Commission.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[43] DEC/DEP Gajda Direct Testimony, at 36.

Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC
Rebuttal Testimony of John W. Gajda

Rebuttal Exhibit JWG-1

Updated Duke Energy Redline

NORTH CAROLINA

INTERCONNECTION PROCEDURES, FORMS, AND AGREEMENTS

For State-Jurisdictional Generator Interconnections

DUKE ENERGY SPONSORED REVISIONS

Effective
~~5~~XX/XX~~15~~/~~2015~~XX
XX

Docket No. E-100, Sub 101

TABLE OF CONTENTS

Page No.

Section 1. General Requirements……1

1.1 Applicability……1
1.2 Pre-Request Response……3
1.3 Pre-Application Report……3
1.4 Interconnection Request……6
1.5 Modification of the Interconnection Request……7
1.6 Site Control……9
1.7 Queue Number……10
1.8 Interdependent Projects……10
1.9 Interconnection Requests Submitted Prior to the Effective Date of these Procedures……12

Section 2. Optional 20 kW Inverter Process for Certified Inverter-Based Generating Facilities No Larger than 20 kW……13

2.1 Applicability……13
2.2 Interconnection Request……13
2.3 Certificate of Completion……14
2.4 Contact Information……15
2.5 Ownership Information……15
2.6 UL 1741 Listed……15

Section 3. Optional Fast Track Process for Certified Generating Facilities……15

3.1 Applicability……15
3.2 Initial Review……16
3.3 Customer Options Meeting……20
3.4 Supplemental Review……21

Section 4. Study Process……22

4.1 Applicability……22
4.2 Scoping Meeting……22
4.3 System Impact Studies……23
4.4 Facilities Study……24

Section 5. Interconnection Agreement and Scheduling……25

5.1 Construction Planning Meeting……25
5.2 ~~Final~~ Interconnection Agreement……26
5.3 Interconnection Construction……26

TABLE OF CONTENTS

Section 6. Provisions that Apply to All Interconnection Requests 27

6.1 Reasonable Efforts 27
6.2 Disputes 27
6.3 Withdrawal of An Interconnection Request 27
6.4 Interconnection Metering 28
6.5 Commissioning 28
6.6 Confidentiality 28
6.7 Comparability 29
6.8 Record Retention 29
6.9 Coordination with Affected Systems 29
6.10 Capacity of the Generating Facility 30
6.11 Sale of an Existing or Proposed Generation Facility 30
6.12 Isolating or Disconnecting the Generating Facility 31
6.13 Limitation of Liability 31
6.14 Indemnification 32
6.15 Insurance 32
6.16 Disconnect Switch 33
6.17 Certification Codes and Standards 33
6.18 Certification of Generator Equipment Packages 33

Attachment 1 – Glossary of Terms

Attachment 2 – Interconnection Request Application Form

Attachment 3 – Pre-Application Report Form

Attachment 4 – Certification Codes and Standards

Attachment 5 – Certification of Generator Equipment Packages

Attachment 6 – Interconnection Request, Certificate of Completion, and Terms and Conditions for Certified Inverter-Based Generating Facilities No Larger than 20 kW

Attachment 7 – System Impact Study Agreement

Attachment 8 – Facilities Study Agreement

Attachment 9 – Interconnection Agreement

Section 1. General Requirements

1.1 Applicability

1.1.1 This Standard contains the requirements, in addition to applicable tariffs and service regulations, for the interconnection and parallel operation of Generating Facilities with Utility Systems in North Carolina. These procedures apply to Generating Facilities that are interconnecting to Utility Systems in North Carolina where the Interconnection Customer is not selling the output of its Generating Facility to an entity other than the Utility to which it is interconnecting.

Interconnection Requests for new Generating Facilities shall be submitted to the Utility for approval at the final design stage and prior to the beginning of construction.

The submission of a written request for a Section 1.2 Pre-Request Response and/or Section 1.3 Pre-Application Report is encouraged to identify potential interconnection issues unforeseen by the Interconnection Customer.

Revised Interconnection Requests for equipment or design changes should be submitted pursuant to Section 1.5.

Notification by the Interconnection Customer to the Utility of change of ownership or change in control should be submitted pursuant to Section 6.11.

1.1.1.1 A request to interconnect a certified inverter-based Generating Facility no larger than 20 kW shall be evaluated under the Section 2, 20 kW Inverter Process. (See Attachments 4 and 5 for certification criteria.)

1.1.1.2 A request to interconnect a certified Generating Facility no larger than the capacity specified in Section 3.1 shall be evaluated under the Section 3 Fast Track Process. (See Attachments 4 and 5 for certification criteria.)

1.1.1.3 A request to interconnect a Generating Facility larger than the capacity stated in Section 3.1, or a Generating Facility that does not qualify for or pass the Fast Track Process or qualify for the 20 kW Inverter Process, shall be evaluated under the Section 4 Study Process. Interconnection Customers that qualify for Section 2 or Section 3 may also choose to proceed directly to Section 4 if they believe Section 4 review is likely to be necessary.

1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of these procedures.

1.1.3 The 201~~7~~8~~5~~ revisions to the Commission's interconnection standard shall not apply to Generating Facilities ~~already interconnected~~ having a fully executed Interconnection Agreement as of the effective date of the 201~~57~~8 revisions to this Standard, unless the Interconnection Customer proposes a Material Modification, transfers ownership of the Generating Facility, or application of the 201~~7~~8~~5~~ revisions to the Commission's interconnection standard are agreed to in writing by the Utility and the Interconnection Customer. This Standard shall apply if the Interconnection Customer does not have a fully executed Interconnection Agreement for ~~has not actually interconnected~~ the Generating Facility as of the effective date of the 201~~57~~8 revisions. Revised fees and new deposits will ~~only~~ apply to new Interconnection Requests and future transactions involving existing Interconnection Requests occurring after the effective date of the 201~~7~~8 revisions to this Standard ~~involving existing projects in the interconnection queue, such as a Change In Control.~~

Any Interconnection Customer that has not executed an interconnection agreement with the Utility prior to the effective date of the ~~2015~~ 2018 revisions to this Standard shall have ~~30 Calendar Days~~45 Business Days following the later of the effective date of the Standards or the posted date of notice in writing from the Utility to ~~demonstrate site control pursuant to Section 1.6, and to post the deposit outlined in Section 1.4~~make prepayment or provide Financial Security in a form reasonably acceptable to the Utility for any Network Upgrades identified in the Interconnection Customer's System Impact Study Report as required by Section 4.3.9 of the Procedures.

~~Any Interconnection Customer that has executed an interconnection agreement with the Utility prior to the effective date of this Standard but the Utility has not actually interconnected the Generating Facility, shall have 60 Calendar Days to submit Upgrade and Interconnection Facility payments (or Financial Security acceptable to the Utility for Interconnection Facilities only) required pursuant to Section 5.2. Any amounts previously paid by the Interconnection Customer at the time deposit or payment is due under this Section shall be credited towards the deposit amount or other payment required under this Section.~~

~~1.1.4 Prior to submitting its Interconnection Request, the Interconnection Customer may ask the Utility's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The Utility shall respond within 10 Business Days.~~

~~1~~1.1.~~5~~4 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. All Utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.1.~~6~~5 References in these procedures to Interconnection Agreement are to the North Carolina Interconnection Agreement. (See Attachment 9.)

1.2 Pre-Request Response

1.2.1 The Utility shall designate an employee or office from which information on the application process can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the Utility's Internet web site.

1.2.2 The Interconnection Customer may request a Pre-Request Response by providing the Utility details of a potential project in writing, including site address, grid coordinates, project size, project developer name, and proposed Point of Interconnection.

Electric system information provided to the Interconnection Customer should include number of phases and voltage of closest circuit, distance to existing source, distance to substation, and other information and/or materials useful to an understanding of an interconnection at a particular point on the Utility's System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The Utility shall comply with reasonable requests for such information in a timely manner, not to exceed ten (10) Business Days. The Pre-Request Response produced by the Utility is non-binding and does not confer any rights. The Interconnection Customer must still meet the Section 1.4 requirements to apply to interconnect to the Utility's system and to obtain a Queue Number. Any one developer shall have no more than five (5) requests for Pre-Request Responses in the Pre-Request Response queue at one time.

1.3 Pre-Application Report

1.3.1 In addition to, or instead of, requesting an informal Pre-Request Response, an Interconnection Customer may submit a formal written Pre-Application Report request form (see Attachment 3) along with a non-refundable fee of $500~~$300~~ for a Pre-Application Report on a proposed project at a specific site. The Utility shall provide the Pre-Application data described in Section 1.3.2 to the Interconnection Customer within ten (10) Business Days of receipt of the completed request form and payment of the $500~~$300~~ fee. The Pre-Application Report produced by the Utility is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Utility's system and to obtain a Queue Number. The written Pre-Application Report request form shall include the information in Sections 1.3.1.1 through 1.3.1.8 below to clearly and sufficiently identify the location of the proposed Point of Interconnection. Any one developer shall have no more than five (5) requests for Pre-Application Reports in the Pre-Application Report queue at one time.

1.3.1.1 Project contact information, including name, address, phone number, and email address.

1.3.1.2 Project location (street address, location map with nearby cross streets and town, grid coordinates of anticipated Point of~~O~~ ~~I~~Interconnection, etc.).

1.3.1.3 Meter number, pole number, location map or other equivalent information identifying proposed Point of Interconnection, if available.

1.3.1.4 Generator or Storage Type (e.g., solar, wind, combined heat and power, battery, etc.)

1.3.1.5 Size (alternating current kW, and for storage kWh).

1.3.1.6 Single or three phase generator configuration.

1.3.1.7 Stand-alone generator (no onsite load, not including station service – Yes or No?)

1.3.1.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

1.3.2. Using the information provided by the Interconnection Customer in the Pre-Application Report request form in Section 1.3.1, the Utility shall identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. This selection by the Utility does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional Pre-Application Reports if information about multiple Points of Interconnection is requested. Subject to Section 1.3.3, the Pre-Application Report shall include the following information:

1.3.2.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.

1.3.2.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection.

1.3.2.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Interconnection.

1.3.2.4 Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

1.3.2.5 Nominal distribution circuit voltage at the proposed Point of Interconnection.

1.3.2.6 Approximate circuit distance between the proposed Point of Interconnection and the substation.

1.3.2.7 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load and absolute minimum load, when available.

1.3.2.8 Number, location, and rating of protective devices, and number, location, and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.

1.3.2.9 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

1.3.2.10 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

1.3.2.11 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

1.3.2.12 Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

1.3.2.13 Other information regarding an Affected System the Utility deems relevant to the Interconnection Customer.

1.3.3 The Pre-Application Report need only include existing data. A Pre-Application Report request does not obligate the Utility to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the Utility cannot complete all or some of the Pre-Application Report due to lack of available data, the Utility shall provide the Interconnection Customer with a Pre-Application Report that includes the data that is readily available. Notwithstanding any of the provisions of this section, the Utility shall, in good faith, include data in the Pre-Application Report that represents the best available information at the time of reporting. Further, the total capacity provided in Section 1.3.2.1 does not indicate that an interconnection of aggregate generation up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the Pre-Application Report may become outdated at the time of the submission of the complete Interconnection Request.

1.4 Interconnection Request

1.4.1 The Interconnection Customer shall submit its Interconnection Request to the Utility, and the Utility shall notify the Interconnection Customer confirming receipt of the Interconnection Request within three (3) Business Days of receiving the Interconnection Request.

The Interconnection Request Application Form shall be date- and time-stamped upon receipt of the following:

1.4.1.1 A substantially complete Interconnection Request Application Form contained in Attachment 2 submitted by a valid legal entity registered with the North Carolina Secretary of State, and signed by the Interconnection Customer.

1.4.1.2 The applicable fee or Interconnection Request Deposit. The applicable fee is specified in the Interconnection Request Application Form and applies to a certified inverter-based Generating Facility no larger than 20 kW reviewed under Section 2 and to any certified Generating Facility no larger than the capacity specified in Section 3.1 to be evaluated under the Section 3 Fast Track Process.

For all Generating Facilities that do not qualify for the 20 kW Inverter Process or the Fast Track Process, fail the Fast Track and Supplemental Review Process under Section 3.0 and are to be evaluated under the Section 4 Study Process, an Interconnection Request Deposit is required. The Interconnection Request Deposit shall equal $20,000 plus one dollar ($1.00) per kWac of capacity specified in the Interconnection Request Application Form, not to exceed an aggregate Interconnection Request Deposit of $100,000. The Interconnection Request Deposit is intended to cover the Utility's reasonably anticipated costs including overheads for conducting the System Impact

Study and the Facilities Study. Such deposit shall, however, be applicable towards the cost of all studies, Upgrades and Interconnection Facilities including overheads.~~.~~

1.4.1.3 A Site Control Verification letter (sample included within Attachment 2).

1.4.1.4 A site plan indicating the location of the project, the property lines and the desired Point of Interconnection.

1.4.1.5 An electrical one-line diagram for the Generating Facility.

1.4.1.6 Inverter specification sheets for the Interconnection Customer's equipment that will be utilized.

1.4.2 The original date- and time-stamp applied to the Interconnection Request Application Form shall be accepted as the qualifying date- and time-stamp for the purposes of establishing Queue Position and any timetable in these procedures.

1.4.3 The Utility shall notify the Interconnection Customer in writing within ten (10) Business Days of the receipt of the Interconnection Request Application Form as to whether the Form and initial supporting documentation specified in Sections 1.4.1.1 through 1.4.1.6 are complete or incomplete. An Interconnection Request will be deemed complete upon submission of the listed information in Section 1.4.1 to the Utility.

1.4.4 If the Interconnection Request Application Form and/or the initial supporting documentation or any other information requested by the Utility is incomplete, the Utility shall provide, along with notice that the information is incomplete, a written list detailing all information that must be provided. The Interconnection Customer will have ten (10) Business Days after receipt of the notice to submit the listed information. If the Interconnection Customer does not provide the listed information or a written request for an extension of time, not to exceed ten (10) additional Business Days, within the deadline, the Interconnection Request will be deemed withdrawn.

1.5 Modification of the Interconnection Request

~~"Material Modification" means a modification to machine data or equipment configuration or to the interconnection site of the Generating Facility that has a material impact on the cost, timing or design of any Interconnection Facilities or Upgrades or that may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers, which includes any required study revisions resulting from the modification. The Utility shall allow for modifications submitted before the execution of a System Impact Study Agreement which do not change the nature of the interconnection request, as determined by the Utility. Material~~

~~Modifications include certain project revisions as defined in Section 1.5.1 Material Modifications include project revisions proposed at any time after receiving notification by the Utility of a complete Interconnection Request pursuant to Section 1.4.3 that 1) alters the size or output characteristics of theGenerating Facility from its Utility-approved Interconnection Request submission; or 2) may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers.~~

~~1.5.1 Indicia of a Material Modification, include, but are not limited to:~~

~~1.5.1.1 A change in Point of Interconnection (POI) to a new location, unless the change in a POI is on the same circuit less than two (2) structures away from the original location, on the same side of any prior connections to the circuit, and the new POI is within the same protection zone as the original locationA change in Point of Interconnection (POI) to a new location, unless the change in a POI is on the same circuit less than two (2) poles away from the original location, and the new POI is within the same protection zone as the original location;~~

~~1.5.1.2 A change or replacement of generating equipment such as generator(s), inverter(s), transformers, relaying, controls, etc. that is not a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;~~

~~1.5.1.3 A change from certified to non-certified devices ("certified" means certified by an OSHA recognized Nationally Recognized Test Laboratory (NRTL), to relevant UL and IEEE standards, authorized to perform tests to such standards);~~

~~1.5.1.4 A change of transformer connection(s) or grounding from that originally proposed;~~

~~1.5.1.5 A change to certified inverters with different specifications or different inverter control specifications or set-up than originally proposed;~~

~~1.5.1.6 An increase of the AC output of a Generating Facility; or~~

~~1.5.1.6 A change reducing the AC output of the generating facility by more than 10%.~~

"Material Modification" means a modification to machine data or equipment configuration or to the interconnection site of the Generating Facility that has a material impact on the cost, timing or design of any Interconnection Facilities or Upgrades or that may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers. Material Modifications include certain project revisions as defined in Section 1.5.1.

1.5.1(a) Indicia of a Material Modification before the System Impact Study Agreement has been ~~fully~~ executed ~~begun~~by the Interconnection Customer include only:

1.5.1.1 A change in Point of Interconnection (POI) to a new location, unless the change in a POI is on the same circuit less than two (2) poles away from the original location, and the new POI is within the same protection zone as the original location;

~~1.5.1.2 A change or replacement of generating equipment such as generator(s), inverter(s), transformers, relaying, controls, etc. that is not a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;~~

1.5.1.2~~3~~ A change from certified to non-certified devices ("certified" means certified by an OSHA recognized Nationally Recognized Test Laboratory (NRTL), to relevant UL and IEEE standards, authorized to perform tests to such standards);

~~1.5.1.4 A change of transformer connection(s) or grounding from that originally proposed;~~

~~1.5.1.5 A change to certified inverters with different specifications or different inverter control specifications or set-up than originally proposed;~~

1.5.1.3~~6~~ An increase of the Maximum Generating Capacity of a Generating Facility; or

1.5.1.4~~6~~ A change reducing the AC output of the generating facility by more than 10%.

1.5.1(b) Indicia of a Material Modification after the System Impact Study Agreement has been ~~fully~~ executed by the Interconnection Customer include, but are not limited to:

1.5.1.1 A change in Point of Interconnection (POI) to a new location, unless the change in a POI is on the same circuit less than two (2) poles away from the original location, and the new POI is within the same protection zone as the original location;

1.5.1.2 A change or replacement of generating equipment such as generator(s), inverter(s), transformers, relaying, controls, etc. that is not a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;

1.5.1.3 A change from certified to non-certified devices ("certified" means certified by an OSHA recognized Nationally Recognized Test Laboratory (NRTL), to relevant UL and IEEE standards, authorized to perform tests to such standards);

1.5.1.4 A change of transformer connection(s) or grounding from that originally proposed;

1.5.1.5 A change to certified inverters with different specifications or different inverter control specifications or set-up than originally proposed;

1.5.1.6 An increase of the Maximum Generating Capacity of a Generating Facility; or

1.5.1.6 A change reducing the Maximum Generating Capacity of the generating facility by more than 10%.

1.5.2 The following are not indicia of a Material Modification at any time:

1.5.2.1 A change in ownership of a Generating Facility; the new owner, however, will be required to execute a new Interconnection Agreement and Study agreement(s) for any Study which has not been completed and the Report issued by the Utility.

1.5.2.2 A change or replacement of generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. that is a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;

1.5.2.3 An increase in the DC/AC ratio that does not increase the maximum AC output capability of the generating facility;

1.5.2.4 A decrease in the DC/AC ratio that does not reduce the AC output capability of the generating facility by more than 10%.

1.5.2.5 A change in the DC system configuration to include additional equipment that does not impact the Maximum Generating Capacity, daily production profile or the proposed AC configuration of the Generating Facility including: DC optimizers, DC-DC converters, DC charge controllers, ~~static VAR compensators,~~ power plant controllers, and energy storage devices such that the output is delivered during the same periods and with the same profile considered during the System Impact Study.

1.5.3 To the extent Interconnection Customer proposes to modify any information provided in the Interconnection Request deemed complete by the Utility, the Interconnection Customer shall submit any such modifications to the Utility in writing. If the Utility determines that the proposed modification(s) constitutes a Material Modification, the Utility shall notify the Interconnection Customer in writing within ten (10) Business Days that the modification is a Material Modification and the Interconnection Request shall be withdrawn from the Queue unless the Interconnection Customer withdraws the proposed Material Modification within 15 Calendar Days of receipt of the Utility's written notification. If the modification is determined by the Utility not to be a Material Modification, then the Utility shall notify the Interconnection Customer in writing that the modification has been accepted and that the Interconnection Customer shall retain its Queue Number. Any dispute as to the Utility's determination that a modification constitutes a Material Modification- shall proceed in accordance with Section 6.2 below.

1.5.4 Modification Inquiry

1.5.4.1 Prior to making any modification, the Interconnection Customer may first submit an informal modification inquiry in writing that requests the Utility to evaluate whether such modification to the original or most recent Interconnection Request is a Material Modification. The Interconnection Customer shall provide specific details on all changes that are to be considered by the Utility.

1.5.4.2 In response to Interconnection Customer's informal request, if the Utility evaluates the proposed modification(s) and determines that the changes are not Material Modifications, the Utility shall inform the Interconnection Customer in writing within ten (10) Business Days. If the Interconnection Customer wishes to proceed with the proposed modification(s), the Interconnection Customer shall submit a revised Interconnection Request Application Form that reflects the approved modifications.

1.6 Site Control

Documentation of site control shall be submitted to the utility with the Interconnection Request using the sample site control verification form included in the Interconnection Request in Attachment 3.

Site control may be demonstrated through:

1. Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility;

2. An option to purchase or acquire a leasehold site for such purpose; or

3. An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

Should Interconnection Customer's site control lapse at any point in time prior to interconnection and such lapse is brought to the attention of Utility, the Utility shall notify the Interconnection Customer in writing of the alleged lapse in site control. The Interconnection Customer shall have ten (10) Business Days from the posted date on the notice from the Utility to cure and submit documentation of re-established site control, where failure to cure the lapse will result in the Interconnection Request being deemed withdrawn.

1.7 Queue Number

1.7.1 The Utility shall assign a Queue Number pursuant to Section 1.4.2. Subject to an Interconnection Customer's election to participate in an optional Utility-sponsored System Impact Grouping Study, as described in Section 4.3.4, the Queue Number of each Interconnection Request shall be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. Subject to Sections 1.7.3, 1.8 and Section 4.3.4, the Queue Number of each Interconnection Request shall also determine the order in which each Interconnection Request is studied.

1.7.2 Subject to the provisions of Sections 1.4, 1.5, and 1.6, Generating Facilities shall retain the Queue Number assigned to their initial Interconnection Request throughout the review process, including where moving through the processes covered by Sections 2, 3, and 4.

<u>1.7.3</u> <u>A Queue Number established for purposes of administering a Competitive Resource Solicitation under Section 4.3.4 shall not be subject to the Interdependency provisions of Section 1.8. Any Interconnection Customer that elects to participate in the System Impact Grouping Study and is selected through the Competitive Resource Solicitation shall complete the Section 4 Study process based upon the Queue Position</u> designated to administer the Competitive Resource Solicitation and the Interconnection Customer's cost responsibility shall be determined based upon the terms of the Competitive Resource Solicitation. <u>Any Interconnection Customer that elects to participate in the System Impact Grouping Study</u> established in Section 4.3.4 <u>but is not selected through the Competitive Resource Solicitation shall</u> be deemed subordinate to the designated Competitive Resource Solicitation Queue Number or an Interconnection Customer that has completed System Impact Study and committed to Upgrades under Section 4.3.9, but shall maintain its original Queue Position for purposes of determining cost responsibility for Upgrades in relation to (i) other Interconnection Customers that elected to participate in the System Impact Grouping Study, but were not selected through the Competitive Resource Solicitation; and (ii) projects that were assigned a Queue Number after the

date on which the Queue Number was designated by the Utility to administer the System Impact Grouping Study.

1.8 Interdependent Projects

"Interdependent Customer" (or "Project"), "Project A" ~~and~~, "Project B", and "Project C" are defined in the ~~g~~Glossary of ~~t~~Terms (see Attachment 1).

1.8.1 Upon an Interconnection Customer's submission of a Section 1.4 Interconnection Request for the Section 3 Fast Track Process or Section 4 Study Process, the Utility shall review the Interconnection Request and make a preliminary determination whether any known Interdependency exists between the Interconnection Customer's proposed Generating Facility and any other Interconnection Customer with a lower Queue Number. Any preliminary determination by the Utility that the Generating Facility does not create an Interdependency will result in the Interconnection Request being preliminarily designated as a Project A and the Utility shall proceed immediately to either the Section 3 Fast Track Process or the Section 4 Study process, as applicable. The Utility shall advise the Interconnection Customer in writing or at the Section 4.2 ~~Scoping~~ scoping ~~Meeting~~meeting, if requested by the Interconnection Customer, regarding its preliminary determination of whether Interdependency would be created by the Generating Facility. A Generating Facility designated and reviewed for system impacts as a Project A may still be determined to create an Interdependency and may be designated by the Utility as an Interdependent Project during the Section 4.3 System Impact Study Process. Once the System Impact Study report is issued by the Utility designated a Generating Facility as a Project A for purposes of the Section 4.4 Facilities Study, the Interconnection Request shall retain this designation without change.

1.8.2 If the Utility determines that ~~that~~ the Interconnection Customer's proposed Generating Facility is Interdependent with one (1) other Interconnection Request with a lower Queue Number, the Utility shall notify the Interconnection Customer in writing or at the Section 4.2 ~~Scoping~~ scoping ~~Meeting~~ meeting that the Interconnection Request is designated as a Project B.

1.8.2.1 Following the Section 4.2 ~~Scoping~~ scoping ~~Meeting~~ meeting and execution of the System Impact Study Agreement, the Project B shall proceed to the Section 4.3 Study process. Project B shall receive a System Impact Study report that assumes the interdependent Project A Interconnect Request with the lower Queue Number completes construction and interconnection and another System Impact Study report that assumes the interdependent Project A Interconnect Request with the lower Queue Number is not constructed and is withdrawn.

1.8.2.2 The Utility shall not proceed to a Project B Facilities Study until after the Project B Interconnection Customer returns a signed Facilities Study Agreement to the Utility and the Utility has issued the Section 4.4.4 Facilities Study report for the Interdependent Project A. The Project B Interconnection Customer shall then have the option of whether to proceed with a Facility Study, or wait until the Interdependent Project A executes a ~~Final~~ Interconnection Agreement and makes payment for any required Upgrade, Interconnection Facilities, and other charges under Section 5.2. If the Project B Interconnection Customer with a signed Facilities Study Agreement prior to Interdependent Project A committing to Section 5 construction, the Project B's Facility Study shall assume that the interdependent Project A Interconnection Request with the lower Queue Number completes construction and interconnection. If Project A is later cancelled prior to the Project A Interconnection Customer making payment for the required Upgrade, the Utility will revise the Project B Facility Study at Project B Interconnection Customer's expense. If Project B Interconnection Customer chooses to wait to request the Project B Facility Study, Project B is not required to adhere to the timeline in Section 4.4.1 until Project A has signed an Interconnection Agreement and paid the payment charge specified in Section 5.2.4 of these Interconnection Procedures or withdrawn.

1.8.3 If the Utility determines ~~that~~ that the Interconnection Customer's proposed Generating Facility is Interdependent with more than one (1) other Interconnection Request with lower Queue Numbers, the Utility shall make a preliminary determination and notify the Interconnection Customer in writing or at the Section 4.2 scoping meeting, if requested by the Interconnection Customer describing generally the number and type of Interdependencies of Interconnection Requests with lower Queue Numbers.

1.8.3.1 Except as provided in Section 1.8.3.3 below, ~~T~~the Utility shall not study a project if it is interdependent with more than one project, each of which has a lower Queue Number. The utility will study a project when interdependency with only one lower Queue Number project exists. The removal of interdependency with multiple projects may be the result of
1) upgrades to the Utility System which eliminate the cause of the interdependency, 2) withdrawal of interdependent project(s) with lower Queue Numbers, or 3) a lower Queue Number project signing an Interconnection Agreement and making payments required in Section 5.2.4.

1.8.3.2 Within five (5) Business Days of an Interconnection Request becoming a Project B Interconnection Request that is Interdependent with only one (1) other Interconnection Request with a lower Queue Number, the Utility shall notify the

Interconnection Customer in writing~~schedule the Section 4.2 Scoping~~ ~~scoping~~ ~~Meeting~~ ~~meeting.~~ and provide the new Project B an executable System Impact Study Agreement. Upon being designated by the Utility as a Project B, the Interconnection Customer may request a Section 4.2 scoping meeting on or before the date that the System Impact Study Agreement must be returned to the utility pursuant to Section 4.2.1. The new Project B ~~the~~ Interconnection Customer's Queue Number will be used to determine the order in which the Interconnection Request is studied under section 4.3 relative to all other Interconnection Requests.

1.8.3.3 When an Interconnection Customer is proposing to interconnect a Small Animal Waste Facility and that facility is interdependent with more than one project, each of which has a lower Queue Number, the utility shall designate the Small Animal Waste Facility for expedited Section 4 study ahead of other interdependent Interconnection Customers that have not commenced the Section 4 study process pursuant to Section 1.8.3.1, as either (i) Project B, if the project with the next lowest Queue number to Project A has not completed the Section 4.2 Scoping Meeting or executed a System Impact Study Agreement; or (ii) Project C, if a Project B has already been designated by the Utility, completed the Section 4.2 Scoping Meeting, ~~and~~or executed a System Impact Study Agreement. Upon being designated by the Utility as a Project C, the Small Animal Waste Facility shall be the next facility to become a Project B, regardless of whether ~~a project~~another interdependent Interconnection Request with a lower Queue Number exists ~~for that interconnection location~~. Notwithstanding Section 1.7.1, a Small Animal Waste Facility will ~~take on the payment obligations~~be responsible for Interconnection Facilities and any Upgrades -arising from its ~~new~~designated Project B or Project C position in the Queue as provided for in this Section~~-such that if upgrades are needed, the upgrade obligations will be those of the Small Animal Waste Facility~~.

1.8.3.4 When an Interconnection Customer is proposing to interconnect a Standby Generation Facility with zero export requested, the Utility shall designate the Standby Generation Facility for expedited Section 4 study as a Project A and also ahead of all other Section 4 studies currently underway in the Utility study queue, unless there are other Standby Generation Facilities currently under study, in which case such Standby Generation Facilities shall be studied in their own queue order. Notwithstanding Section 1.7.1, a Standby Generation Facility will be responsible for Interconnection Facilities and any Upgrades arising from its designated Project A position in the Queue as provided for in this section.

1.9 Interconnection Requests Submitted Prior to the Effective Date of these Procedures

Other than as set forth in Section 1.1.3, nothing in this Standard affects an Interconnection Customer's Queue Number assigned before the effective date of these procedures. Interconnection Requests which have received a System Impact Study report as of the effective date of these procedures that did not identify any interdependency with another project shall be deemed a Project A. Any Interconnection Requests for which the Utility has not completed the System Impact Study and issued a System Impact Study report to the Interconnection Customer as of the effective date of these procedures shall be reviewed for Interdependency pursuant to Section 1.8.

~~Should an Interconnection Customer fail to comply with Section 1.1.3 following receipt of written notice specifying how the Interconnection Customer failed to comply and the expiration of an opportunity to cure by the close of business on the tenth (10th) Business Day following the posted date of such notice to cure, such Interconnection Customer will lose its Queue Number and such Interconnection Request shall be deemed withdrawn.~~

Section 2. Optional 20 kW Inverter Process for Certified Inverter-Based Generating Facilities No Larger than 20 kW

2.1 Applicability

The 20 kW Inverter Process is available to an Interconnection Customer proposing to interconnect its inverter-based Generating Facility with the Utility's System if the Generating Facility is no larger than 20 kW and if the Interconnection Customer's proposed Generating Facility meets the codes, standards, and certification requirements of Attachments 4 and 5 of these procedures, or the Utility has reviewed the design or tested the proposed Generating Facility and is satisfied that it is safe to operate.

The Utility may require the Interconnection Customer to install a manual load-break disconnect switch or safety switch as a clear visible indication of switch position between the Utility System and the Interconnection Customer. When the installation of the switch is not otherwise required (e.g. National Electric Code, state or local building code) and is deemed necessary by the Utility for certified, inverter-based generators no larger than 10 kW, the Utility shall reimburse the Interconnection Customer for the reasonable cost of installing a switch that meets the Utility's specifications (see also Section 6.16).

2.2 Interconnection Request

The Interconnection Customer shall complete the Interconnection Request Application Form for a certified inverter-based Generating Facility no larger than

20 kW in the form provided in Attachment 6 and submit it to the Utility, together with the non-refundable processing fee specified in the Interconnection Request Application Form and the documentation required pursuant to Section 1.4.1.

2.2.1 The Utility shall verify that the Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process. (See Section 3.2.1.) The Utility has 15 Business Days to complete this process. Unless the Utility determines and demonstrates that the Generating Facility cannot be interconnected safely and reliably, the Utility shall approve the Interconnection Request upon fulfillment of all requirements in Section 1.4 and return the Interconnection Request Application Form to the Interconnection Customer.

2.2.1.2 If the proposed interconnection passes the screens but the Utility determines that minor Utility construction is required to interconnect the Generating Facility to the Utility's system, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer a non-binding good faith estimate of the cost of interconnection along with the Interconnection Request Application Form within 15 Business Days after the determination.

2.2.1.3 If the proposed interconnection passes the screens, but the costs of interconnection including System Upgrades and Interconnection Facilities cannot be determined without further study or review, the Utility will notify the Interconnection Customer that the Utility will need to complete a Facilities Study under Section 4.4 to determine the necessary costs of interconnection and will charge the~~.~~ actual cost of the Facilities Study to the Interconnection Customer.

2.2.2 Screens failure: Despite the failure of one or more screens, the Utility, at its sole option, may approve the interconnection provided such approval is consistent with safety and reliability. If the Utility cannot determine that the Generating Facility may be interconnected consistent with safety, reliability, and power quality standards, the Utility shall provide the Interconnection Customer with detailed information on the reasons for failure in writing. In addition, the Utility shall either:

2.2.2.1 Notify the Interconnection Customer in writing that the Utility is continuing to evaluate the Generating Facility under Section 3.4 Supplemental Review if the Utility concludes that the Supplemental Review might determine that the Generating Facility could continue to qualify for interconnection pursuant to Fast Track: or

2.2.2.2 Offer to continue evaluating the Interconnection Request under the Section 4 Study Process.

2.3 Certificate of Completion

2.3.1 After installation of the Generating Facility, the Interconnection Customer shall submit the Certificate of Completion in the form provided in Attachment 6 to the Utility. Prior to parallel operation, the Utility may inspect the Generating Facility for compliance with standards including a witness test and the scheduling of an appropriate metering replacement, if necessary.

2.3.2 The Utility shall notify the Interconnection Customer in writing that interconnection of the Generating Facility is authorized. If the witness test is not satisfactory, the Utility has the right to disconnect the Generating Facility. The Interconnection Customer has no right to operate in parallel with the Utility until a witness test has been performed, or previously waived on the Interconnection Request. The Utility is obligated to complete this witness test within ten (10) Business Days of the receipt of the Certificate of Completion. If the Utility does not inspect within ten (10) Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

2.3.3 Interconnection and parallel operation of the Generating Facility is subject to the Terms and Conditions stated in Attachment 6 of these procedures.

2.4 Contact Information

The Interconnection Customer must provide its contact information. If another entity is responsible for interfacing with the Utility, that contact information must also be provided on the Interconnection Request Application Form.

2.5 Ownership Information

The Interconnection Customer shall provide the legal name(s) of the owner(s) of the Generating Facility.

2.6 UL 1741 Listed

The Underwriters' Laboratories (UL) 1741 standard (Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources) addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a nationally recognized testing laboratory that verifies compliance with UL 1741. This "listing" is then marked on the equipment and supporting documentation.

Section 3. Optional Fast Track Process for Certified Generating Facilities

3.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Generating Facility with the Utility's System if the Generating Facility's capacity does not exceed the size limits identified in the table below. Generating Facilities below these limits are eligible for Fast Track review. However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Generating Facility will pass the Fast Track screens in Section 3.2 below or the Supplemental Review screens in Section 3.4 below.

Fast Track eligibility is determined based upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. ~~All~~ Generating Facilities connecting to lines greater or equal to 35 kilovolt (kV) are ineligible for the Fast Track Process regardless of size, unless mutually agreed to in writing between the Interconnection Customer and the Utility. ~~For inverter-based systems,~~ Only certified inverter-based systems are eligible for the Fast Track Process and the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based Generating Facilities located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds set forth in the table below. In addition to the size threshold, the Interconnection Customer's proposed Generating Facility must ~~meets~~meet the codes, standards, and certification requirements of Attachments 4 and 5 of these procedures, or the Utility has to have reviewed the design or tested the proposed Generating Facility and be satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems[1]		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline[2] and ≤ 2.5 Electrical Circuit Miles from Substation[3]
< 5 kV	≤ 100 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 1 MW	≤ 2 MW
≥ 15 kV and < 35 kV	≤ 2 MW	≤ 2 MW

[1] Must be an UL certified inverter.

[2] For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

[3] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report pursuant to section 1.2.

3.1.1 The Interconnection Customer may elect in the Interconnection Request Application Form to proceed directly to the Supplemental Review, in order to minimize overall processing time in the event ~~of any Fast Track screen failures~~the Utility deems Supplemental Review is appropriate. This is accomplished by selecting both the Fast Track and Supplemental Review options on the Interconnection Request Application Form and paying the applicable Fast Track fee and Supplemental Review deposit~~fee~~

3.2 Initial Review

Within 15 Business Days after the Utility notifies the Interconnection Customer it has received a complete Interconnection Request pursuant to Section 1.4 and the Utility has preliminarily determined that the Interconnection Request is not interdependent with more than one Interconnection Request with lower Queue Numbers under Section 1.8, the Utility shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Utility's determinations under the screens.

3.2.1 Screens

3.2.1.1 The proposed Generating Facility's Point of Interconnection must be on a portion of the Utility's Distribution System.

3.2.1.2 For interconnection of a proposed Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Utility’s System connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

3.2.1.3 For interconnection of a proposed Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Generating Facility, on the circuit shall not exceed 90% of the circuit and/or bank minimum load at the substation.

~~3.2.1.4 All synchronous and induction machines must be connected to a distribution circuit where the local minimum load to generation ratio on the circuit line segment is larger than 3 to 1. A 3-1 load to generation ratio screen utilizes actual recorded data that is sufficient to establish the minimum threshold.~~

3.2.1.4~~5~~ For interconnection of a proposed Generating Facility to the load side of spot network protectors, the proposed Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW.

3.2.1.5~~6~~ The proposed Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

3.2.1.6~~7~~ The proposed Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

3.2.1.7~~8~~ Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service to be provided to the Interconnection Customer, including line configuration and the transformer connection for the purpose of limiting the potential for creating over-voltages on the Utility's System due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	**Type of Interconnection to Primary Distribution Line**	**Result/Criteria**
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass Screen
Three-phase, four wire	Effectively-grounded three-phase or single phase, line-to-neutral	Pass Screen

3.2.1.8~~9~~ If the proposed Generating Facility is to be interconnected on a single-phase shared secondary, the aggregate Generating Facility capacity on the shared secondary, including the proposed Generating Facility, shall not exceed 65% of the transformer nameplate rating.

3.2.1.9~~10~~ If the proposed Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

3.2.1.10~~1~~ The Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

3.2.2 Screen Results

3.2.2.1 If the proposed interconnection passes the screens and requires no construction by the Utility on its own System, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer an executable Interconnection Agreement within ten (10) Business Days after the determination.

3.2.2.2 If the proposed interconnection passes the screens and the Utility is able to determine without further study or review that only minor Utility construction is required to interconnect the Generating Facility to the Utility's system, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer a non-binding good faith estimate of the cost of interconnection along with an executable Interconnection Agreement within 15 Business Days after the determination.

3.2.2.3 If the proposed interconnection passes the screens, but the costs of interconnection including System Upgrades and Interconnection Facilities cannot be determined without further study or review, the Utility will notify the Interconnection Customer that the Utility will need to complete a Facilities Study under Section 4.4 to determine the necessary costs of interconnection.

3.2.2.4 If the proposed interconnection fails the screens, but the Utility determines that the Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, and requires no construction by the Utility on its own System, the Interconnection Request shall be approved and the Utility shall provide the Interconnection Customer an executable Interconnection Agreement within ten (10) Business Days after the determination.

3.2.2.5 If the proposed interconnection fails the screens, but the Utility determines that the Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards and the Utility is able to determine without further study or review that only minor Utility construction is required to interconnect with the Generating Facility, the Interconnection Request shall be approved and the Utility will provide the Interconnection Customer a non-binding good faith estimate of the cost of interconnection along with an executable Interconnection Agreement within 15 Business Days after the determination.

3.2.2.6 If the proposed interconnection fails the screens, and the Utility does not or cannot determine from the initial review that the

Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Utility shall provide the Interconnection Customer with the opportunity to attend a customer options meeting as described in Section 3.3 below.

3.3 Customer Options Meeting

If the Utility determines the Interconnection Request cannot be approved without (1) minor modifications at minimal cost, (2) a supplemental study or other additional studies or actions, or (3) incurring significant cost to address safety, reliability, or power quality problems, the Utility shall notify the Interconnection Customer of that determination within five (5) Business Days after the determination, and upon request provide copies of ~~all~~ data and analyses underlying its conclusion. Within ten (10) Business Days of the Utility's determination, the Utility shall offer to convene a customer options meeting to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Generating Facility to be connected safely and reliably. At the time of notification of the Utility's determination, or at the customer options meeting, the Utility shall:

3.3.1 Offer to perform facility modifications or minor modifications to the Utility's System (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Utility's System. The Interconnection Customer shall have ten (10) Business Days to agree to pay for the modifications to the Utility’s electric system or the Interconnection Request shall be deemed to be withdrawn. If the Interconnection Customer agrees to pay for the modifications to the Utility’s electric system, the Utility will provide the Interconnection Customer with an executable Interconnection Agreement within ten (10) Business Days of the Interconnections Customer’s agreement to pay; or

3.3.2 Offer to perform a supplemental review under Section 3.4 if the Utility concludes that the supplemental review might determine that the Generating Facility could continue to qualify for interconnection pursuant to the Fast Track Process, and provide a non-binding good faith estimate of the costs of such review. The Interconnection Customer shall have ten (10) Business Days to accept in writing the Utility’s offer to perform a Supplemental Review and post any deposit requirement for the Supplemental Review, or the Interconnection Request shall be deemed to be withdrawn; or

3.3.3 Offer to continue evaluating the Interconnection Request under the Section 4 Study Process. The Interconnection Customer shall have ten (10) Business Days to agree in writing to its Interconnection Request continuing to be evaluated under the Section 4 Study Process, and post any deposit requirement for the Study Process, or the Interconnection Request shall be deemed to be withdrawn.

3.4 Supplemental Review

If the Interconnection Customer agrees to a supplemental review, the Interconnection Customer shall agree in writing within ~~fifteen~~ ten (10) Business Days of the offer, and submit a deposit for the estimated costs or the request shall be deemed to be withdrawn. The Interconnection Customer shall be responsible for the Utility's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Utility will return such excess within 20 Business Days of the invoice without interest.

3.4.1 Within ten (10) Business Days following receipt of the deposit for a supplemental review, the Utility will determine if the Generating Facility can be interconnected safely and reliably.

3.4.1.1 If so, the Utility shall forward an executable Interconnection Agreement to the Interconnection Customer within ten (10) Business Days.

3.4.1.2 If so, and Interconnection Customer facility modifications are required to allow the Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Utility shall ask if the customer agrees to make the necessary modifications. The customer will be given 10 Business Days to agree, in writing, to the required modifications. The Utility will forward an executable Interconnection Agreement to the Interconnection Customer within 15 Business Days after confirmation that the Interconnection Customer has agreed to make the necessary modifications at the Interconnection Customer's cost.

3.4.1.3 If so, and minor modifications to the Utility's System are required to allow the Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Utility shall forward an executable Interconnection Agreement to the Interconnection Customer within ten (10) Business Days that requires the Interconnection Customer to pay the costs of such System modifications prior to interconnection.

If so, but the costs of interconnection including System Upgrades and Interconnection Facilities cannot be determined without further study or review, the Utility will notify the Interconnection Customer that the Utility will need to complete a Facilities Study under Section 4.4 to determine the necessary costs of interconnection.

If not, the Interconnection Request will continue to be evaluated under the Section 4 Study Process, provided the Interconnection Customer indicates it wants to proceed and submits the required deposit within 15 Business Days.

Section 4. Study Process

4.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Generating Facility with the Utility's System if the Generating Facility exceeds the size limits for the Section 3 Fast Track Process, is not certified, or is certified but did not pass the Fast Track Process or the 20 kW Inverter Process. The Interconnection Customer may be required to submit additional information or documentation, as may be requested by the Utility in writing, during the Study Process.

4.2 Scoping Meeting

4.2.1 A scoping meeting will be held within ten (10) Business Days after the Interconnection Request is deemed complete, unless the Interconnection Customer is preliminarily designated as interdependent with more than one (1) Interconnection Requests pursuant to Section 1.8.3.1, or as otherwise mutually agreed to by the Parties. The Utility and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting. The scoping meeting may be omitted by mutual agreement in writing.

4.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the Utility should perform a System Impact Study, a Facilities Study, or proceed directly to an Interconnection Agreement.

4.2.3 If the Utility, after consultation with the Interconnection Customer, determines the project should proceed to a System Impact Study or Facilities Study, the Utility shall provide the Interconnection Customer, no later than ten (10) Business Days after the scoping meeting, either a System Impact Study Agreement (Attachment 7) or a Facilities Study Agreement (Attachment 8), as appropriate, including an outline of the scope of the study or studies and a nonbinding good faith estimate of the cost to perform the study or studies, which cost shall be subtracted from the deposit outlined in Section 1.4.1.2..

4.2.4 If the Parties agree not to perform a System Impact Study or Facilities Study, but to proceed directly to an Interconnection Agreement, the Parties shall proceed to the Construction Planning Meeting as called for in Section 5.

4.3 System Impact Study

4.3.1 In order to retain its Queue Position the Interconnection Customer must return a System Impact Study Agreement signed by the Interconnection Customer within 15 Business Days of receiving an executable System Impact Study Agreement as provided for in Section 4.2.3.

4.3.2 The scope of and cost responsibilities for a System Impact Study are described in the System Impact Study Agreement. The time allotted for completion of the System Impact Study shall be as set forth in the System Impact Study Agreement.

4.3.3 The System Impact Study shall identify and detail the electric system impacts that would result if the proposed Generating Facility were interconnected without project modifications or electric system modifications, or to study potential impacts, including, but not limited to, those identified in the scoping meeting. The System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the electric system, including the distribution and transmission systems, if required.

4.3.4 At the Utility's option, and solely for purposes of administering a Commission-approved Competitive Resource Solicitation, a Utility may designate a Queue Number and act as authorized representative for Interconnection Customer(s) proposing a Generating Facility requesting to interconnect to the Utility's System for evaluation through the Solicitation. The Utility shall evaluate combinations of such Interconnection Requests for purposes of conducting the System Impact Grouping Study(ies) of combinations of Generating Facilities within the Queue Number in order to achieve the resource need identified in the Competitive Resource Solicitation. Such studies in connection with a Competitive Resource Solicitation shall be implemented based upon the Queue Number relative to the Queue Position of all other Interconnection Requests. The Utility may also study an Interconnection Request separately to the extent provided for under the terms of the Competitive Resource Solicitation or if otherwise warranted by Good Utility Practice such as to evaluate the locational remoteness of a proposed Generating Facility.

Through completing the System Impact Grouping Study(ies) of the requested combinations of Interconnection Requests, the Utility must select one of the studied combinations that achieves the capacity solicited through the Competitive Resource Solicitation Process prior to the start of any Interconnection Facilities Study. While conducting the Interconnection Facilities Study(ies) for the selected combination of resources, the Utility may suspend further study of the Interconnection Customers that have opted in to the System Impact Grouping Study that are not included in the selected combination and such customers may elect during this period to return to their original Queue Position, subject to 1.7.3, or participate in a new Competitive Resource Solicitation, if available.

4.3.5 The System Impact Study report will provide the Preliminary Estimated Upgrade Charge, which is a preliminary indication of the cost and length of time that would be necessary to correct any System problems identified in those analyses and implement the interconnection.

4.3.6~~5~~ The System Impact Study report will provide the Preliminary Estimated Interconnection Facilities Charge, which is a preliminary non-binding indication of the cost and length of time that would be necessary to provide the Interconnection Facilities.

4.3.7~~6~~ If the Utility has determined that an Interdependency exists and the Project is designated as a Project B, the Project B Interconnection Request shall receive a System Impact Study report, addressing a scenario assuming Project A is constructed and a second scenario assuming Project A is not constructed.

4.3.8~~7~~ After receipt of the System Impact Study report(s), the Interconnection Customer shall inform the Utility in writing ~~h~~ if it wishes to withdraw the Interconnection Request and to request an accounting of any remaining deposit amount pursuant to Section 6.3.

~~4.3.8If requested by the Interconnection Customer following delivery of the System Impact Study report, the Utility shall provide the Interconnection Customer an executable Interim Interconnection Agreement within ten (10) Business Days. The Interim Interconnection Agreement shall be identical in form and content to the Final Interconnection Agreement, but will not include Detailed Estimated Upgrade Charges, Detailed Estimated Interconnection Facility Charge, Appendix 4 (Construction Milestone schedule listing tasks, dates and the party responsible for completing each task), and other information that otherwise would be determined in Section 5.~~

4.3.9 At the time the System Impact Study Report is provided to the Interconnection Customer, the Utility shall also deliver an executable Facilities Study Agreement to the Interconnection Customer. After receipt of the System Impact Study Report and Facilities Study Agreement, when the Interconnection Customer is ready to proceed with the design and construction of the Upgrades and Interconnection Facilities, the Interconnection Customer shall return the signed Facilities Study Agreement to the Utility in accordance with Section 4.4 and shall also submit payment or Financial Security reasonably acceptable to the Utility equal to the cost of any Network Upgrades identified in the Preliminary Estimated Upgrade Charge, as set forth in the System Impact Study Report, that would be borne by the Interconnection Customer under a future Interconnection Agreement. This payment or Financial Security shall be held by the Utility as a non-refundable prepayment for the estimated cost of Network Upgrades to be designed by the Utility in the Section 4.4 Facilities Study. The preliminary Network Upgrade prepayment amount shall be trued up by the Utility in the Detailed Estimated Upgrade Charges included in a future Interconnection Agreement or shall be forfeited to the Utility to construct the Network Upgrades if the Interconnection Request is subsequently withdrawn by the Interconnection Customer. For Interconnection Customers that have already received their system impact studies, and have proceeded to the facilities study phase, the non-refundable pre-payment for network upgrades shall be due within 30 business days of this requirement being adopted by the Commission. Failure to timely make such pre-payments will result in the Utility removing the Interconnection Request from the queue.

4.4 Facilities Study

4.4.1 A solar Interconnection Customer must request a Facilities Study by returning the signed Facilities Study Agreement within 60 Calendar Days of the date the Facilities Study Agreement was provided. Any other Interconnection Customer must request a Facility Study by returning the signed Facilities Study Agreement within 180 Calendar Days of the date the Facilities Study Agreement was provided. Failure to return the signed Facilities Study Agreement within the foregoing applicable time period will result in the Interconnection Request being deemed withdrawn.

4.4.2 When an Interdependent Project A exists, a Project B Interconnection Request will not be required to comply with Section 4.4.1 until Project A has signed the ~~Final~~ Interconnection Agreement, and made payments and provided Financial Security as specified in Section 5.2 or withdrawn. If Project B has not provided written notice of its intent to proceed to a Facilities Study under Section 1.8.2.2, upon the Project A fulfilling the requirements in Section 5.2 or withdrawing the Interconnection Request, the Utility shall notify the Project B Interconnection Customer that it has the time specified in Section 4.4.1 to return the signed Facilities Study Agreement or the Interconnection Request shall be deemed withdrawn.

4.4.3 The scope of and cost responsibilities for the Facilities Study are described in the Facilities Study Agreement. The time allotted for completion of the Facilities Study is described in the Facilities Study Agreement.

4.4.4 The Facilities Study report shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the System Impact Studies and to allow the Generating Facility to be interconnected and operated safely and reliably.

4.4.5 The Utility shall design any required Interconnection Facilities and/or Upgrades under the Facilities Study Agreement. The Utility may contract with consultants to perform activities required under the Facilities Study Agreement. The Interconnection Customer and the Utility may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the Utility, under the provisions of the Facilities Study Agreement. If the Parties agree to separately arrange for design and construction, and provided that critical infrastructure security and confidentiality requirements can be met, the Utility shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

Section 5. Interconnection Agreement and Scheduling

5.1. Construction Planning Meeting

5.1.1. Within ten (10) Business Days of receipt of the Facility Study report, the Interconnection Customer shall request a Construction Planning Meeting, where failure to comply shall result in the Interconnection Request being deemed withdrawn. The Construction Planning Meeting request shall be in writing and shall include the Interconnection Customer's reasonably requested date for completion of the construction of the Upgrades and Interconnection Facilities.

5.1.2. The Construction Planning Meeting shall be scheduled within ten (10) Business Days of the Section 5.1.1 request from the Interconnection Customer, or as otherwise mutually agreed to in writing by the parties.

5.1.3. The purpose of the Construction Planning Meeting is to identify the tasks for each party and discuss and determine the milestones for the construction of the Upgrades and Interconnection Facilities. Agreed upon milestones shall be specific as to scope of action, responsible party, and date of deliverable and shall be recorded in the ~~Final~~ Interconnection Agreement (see Appendix 4 to Attachment 9) to be provided to Interconnection Customer pursuant to Section 5.2.1 below.

5.1.4. If the Utility cannot complete the installation of the required Upgrades and Interconnection Facilities within two (2) months of the Interconnection Customer's reasonably requested In-Service Date, the Interconnection Customer shall have the option of payment for work outside of normal business hours or hiring a Utility-approved subcontractor to perform the distribution Upgrades. Any Utility-approved subcontractor performance remains subject to Utility oversight during construction. The Utility shall make a list of Utility-approved subcontractors available to the Interconnection Customer promptly upon request.

5.2. ~~Final Interconnection Agreement~~Interconnection Agreement

5.2.1. Within fifteen (15) Business Days of the Construction Planning Meeting, the Utility shall provide an executable ~~Final~~ Interconnection Agreement containing the Detailed Estimated Upgrade Charges, Detailed Estimated Interconnection Facility Charge, Appendix 4 (Construction Milestone and payment schedule listing tasks, dates and the party responsible for completing each task), and other appropriate information, requirements, and charges. ~~The Final Interconnection Agreement will replace any Interim Interconnection Agreement, which shall terminate upon execution of the Final Interconnection Agreement by the Interconnection Customer and the Utility.~~

5.2.2. Within ten (10) Business Days of receiving the ~~Final~~ Interconnection Agreement, the Interconnection Customer must execute and return the ~~Final~~ Interconnection Agreement, where failure to comply results in the Interconnection Request being deemed withdrawn.

5.2.3. After the Parties execute the ~~Final~~ Interconnection Agreement, the Utility shall return a copy of the ~~Final~~ Interconnection Agreement to the Interconnection Customer and interconnection of the Generating Facility shall proceed under the provisions of the ~~Final~~ Interconnection Agreement.

5.2.4. The ~~Final~~ Interconnection Agreement shall specify milestones for payment for Upgrades and Interconnection facilities and/or, provision of Financial Security for Interconnection facilities, if acceptable to the Utility, that are required prior to the start of design and construction of Upgrades and Interconnection Facilities. Payment and Financial Security must be received by close of business forty-five~~sixty~~ (~~60~~45) Business ~~Calendar~~ Days after the date the Interconnection Agreement is delivered to the Interconnection Customer for signature, where failure to comply results in the Interconnection Request being deemed withdrawn.

5.3 Interconnection Construction

Construction of the Upgrades and Interconnection Facilities will proceed as called for in the ~~Final~~ Interconnection Agreement and Appendices.

Section 6. Provisions that Apply to All Interconnection Requests

6.1 Reasonable Efforts

The Utility shall make reasonable efforts to meet all time frames provided in these procedures unless the Utility and the Interconnection Customer agree to a different schedule. If the Utility cannot meet a deadline provided herein, it shall at its earliest opportunity notify the Interconnection Customer, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

6.2 Disputes

6.2.1 The Parties shall~~agree to~~ attempt to resolve all disputes arising out of the interconnection process according to the provisions of this S~~s~~ection 6.2. ~~Where an Interconnection Customer seeks to resolve a dispute involving its Queue Number according to the provisions of this section, any disputed loss of Queue Number shall not be final until Interconnection Customer abandons the process set out in this section or a final Commission order is entered.~~

6.2.2 In the event of a dispute, ~~either~~ the initiating Party (“Initiating Party”) shall provide the other Party (“Responding Party”) with a written n~~N~~otice of d~~D~~ispute ("Notice of Dispute"). Such Notice of Dispute shall describe in detail the nature of the dispute.

6.2.3 The Responding Party shall provide a written response to the Initiating Party ~~If the dispute has not been resolved~~ within ten (10) Business Days after receipt of the Notice of Dispute.~~, either Party may contact the Public Staff for assistance in informally resolving the dispute. If the Parties are unable to informally resolve the dispute, either Party may then file a formal complaint with the Commission.~~

6.2.4 If the Parties are unable to informally resolve the dispute, then within ten (10) Business Days of the date on which the Initiating Party receives the response of the Responding Party, the Initiating Party may either (1) ~~either Party may~~ contact the Public Staff for assistance in informally resolving the dispute, (2) file a formal complaint with the Commission, or (3) provide written notice to the Responding Party that it is abandoning the dispute process. If the Initiating Party fails to take one of the actions specified in this Section 6.2.4 within the specified time period, the Interconnection Request shall be deemed withdrawn.

6.2.5 If either Party requests the assistance of Public Staff in informally resolving the dispute pursuant to Section 6.2.4, the Parties shall exert reasonable efforts to establish a meeting date with Public Staff ("Public Staff Meeting") that is within twenty (20) Business Days of the date on which the applicable Party requested the assistance of Public Staff. If the Parties are unable to informally resolve the dispute with the assistance of Public Staff, then within twenty (20) Business Days of the Public Staff Meeting, the Initiating Party shall either (1) file a formal complaint with the Commission or (2) provide written notice to the Responding Party that it is abandoning the dispute process. If the Initiating Party fails to take one of the actions specified in this Section 6.2.5 within the specified time period, the Interconnection Request shall be deemed withdrawn.

6.2.6 Each Party agrees to conduct all negotiations in good faith.

6.3 Withdrawal of An Interconnection Request

6.3.1 An Interconnection Customer may withdraw an Interconnection Request at any time prior to executing a ~~Final~~ Interconnection Agreement by providing the Utility with a written request for withdrawal.

6.3.2 An Interconnection Request shall be deemed withdrawn if the Interconnection Customer fails to meet its obligations specified in the Interconnection Procedures, System Impact Study Agreement or Facility Study Agreement or to take advantage of any express opportunity to cure.

6.3.3 Within ~~90~~ 60 ~~Calendar~~ Business Days of any voluntary or deemed withdrawal of the Interconnection Request, the Utility will provide the Interconnection Customer with a final accounting report of any difference between (1) the

Interconnection Customer's cost responsibility for the actual cost of such work performed, and (2) the Interconnection Customer's previous aggregate Interconnection Facility Request Deposit payments to the Utility for such work. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Utility shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Utility within 30 Calendar Days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Utility shall refund to the Interconnection Customer an amount equal to the difference within 30 Calendar Days of the final accounting report.

6.4 Interconnection Metering

Any metering necessitated by the use of the Generating Facility shall be installed at the Interconnection Customer's expense in accordance with all applicable regulatory requirements or the Utility's specifications.

6.5 Commissioning and Post-Commissioning Inspections

6.5.1 Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. If the Interconnection Customer is not proceeding under Section 2.3.2, the Utility must be given at least ten (10) Business Days ~~written notice~~, or as otherwise mutually agreed to in writing by the Parties, of the tests and may be present to witness the commissioning tests.

6.5.2 In the case of any Generating Facility that was not inspected prior to commencing parallel operation, the Utility shall be authorized to conduct an inspection of the medium voltage AC side of each Generating Facility (including assessing that the anti-islanding process is operational). The Interconnection Customer shall pay the actual cost of such inspection within 30 Business Days after the Utility provides a written invoice for such costs.

6.5.3 The Utility shall also be entitled, on a periodic basis, to inspect the medium voltage AC side of each Interconnected Generating Facility on a reasonable schedule determined by the Utility in accordance with the inspection cycles applicable to its own distribution system. The Interconnection Customer shall pay the actual cost of such inspection within 30 Business Days after the Utility provides a written invoice for such costs.

6.5.4 The Utility shall also be entitled to inspect the medium voltage AC side of an Interconnected Generating Facility in the event that the Utility identifies or becomes aware of any condition that (1) has the potential to either cause disruption or deterioration of service to other customers served from the same electric system or cause damage to the Utility's System or Affected Systems, or (2) is imminently likely to endanger life or property or cause a material adverse effect on the security of, or damage to the Utility's System, the Utility's Interconnection Facilities or the systems of others to which the Utility's

System is directly connected. The Interconnection Customer shall pay the actual cost of such inspection within 30 Business Days after the Utility provides a written invoice for such costs.

6.6 Confidentiality

6.6.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

6.6.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements.

6.6.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

6.6.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

6.6.3 If information is requested by the Commission from one of the Parties that is otherwise required to be maintained in confidence pursuant to these procedures, the Party shall provide the requested information to the Commission within the time provided for in the request for information. In providing the information to the Commission, the Party may request that the information be treated as confidential and non-public in accordance with North Carolina law and that the information be withheld from public disclosure.

6.6.4 All information pertaining to a project will be provided to the new owner in the case of a change of control of the existing legal entity or a change of ownership to a new legal entity.

6.7 Comparability

The Utility shall receive, process, and analyze all Interconnection Requests received under these procedures in a timely manner, as set forth in these procedures. The Utility shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facility is owned or operated by the Utility, its subsidiaries or affiliates, or others.

6.8 Record Retention

The Utility shall maintain for three (3) years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

6.9 Coordination with Affected Systems

The Utility shall develop Affected System communication protocol with potential Affected Systems, upon request by the Affected System, such that reciprocal notification of Interconnection Requests, as applicable per the specified communication protocol, between the Utility and the Affected System can be addressed and implemented.

The Utility shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable studies within the time frame specified in these procedures. The Utility will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. The Interconnection Customer will cooperate with the Utility in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Utility which may be an Affected System shall cooperate with the Utility with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

6.10 Capacity of the Generating Facility

6.10.1 If the Interconnection Request is for a Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices, unless otherwise agreed to by the Utility and the Interconnection Customer.

6.10.2 For the purposes of this Standard, the capacity of the Generating Facility shall be considered the maximum rated capacity of the Generating Facility, except where the gross generating capacity of the Generating Facility is limited (e.g., through the use of a control system, power relay(s), or other similar device settings or adjustments as mutually agreed upon by the Utility and Interconnection customer). The Generating Facility's capacity shall be considered the Maximum Generating Capacity specified by the Interconnection Customer in the Interconnection Request. The Maximum Generating Capacity approved in the study process will subsequently be included as a limitation in the Interconnection Agreement. ~~The Interconnection Request shall be evaluated using the maximum rated capacity of the Generating Facility, unless otherwise agreed to by the Utility and the Interconnection Customer.~~

6.11 Sale of a Generation Facility

6.11.1 The Interconnection Customer shall notify the Utility of the pending sale of a proposed Generation Facility in writing. The Interconnection Customer shall provide the Utility with information regarding whether the sale is a change of ownership of the Generation Facility to a new legal entity, or a change of control of the existing legal entity.

The Interconnection Customer shall promptly notify the Utility of the final date of sale and transfer date of ownership in writing. The purchaser of the Generation Facility shall confirm to the Utility the final date of sale and transfer date of ownership in writing, and submit an Interconnection Request requesting transfer control or change of ownership together with the change of ownership fee listed in Attachment 2.

6.11.2 Existing Interconnection Agreements are non-transferable. If the Generation Facility is sold to a new legal entity, a new Interconnection Agreement must be executed by the new legal entity prior to the interconnection or for the continued interconnection of the Generating Facility to the Utility's system. The Utility shall not withhold or delay the execution of an Interconnection Agreement with the new owner provided the Generation facility or proposed Generation facility complies with requirements of 6.11.

6.11.3 The technical requirements in the Interconnection Agreement shall be grandfathered for subsequent owners as long as (1) the Generating Facility's maximum rated capacity has not been changed; (2) the Generating Facility has not been modified so as to change its electrical characteristics; and (3) the interconnection system has not been modified.

6.12 Isolating or Disconnecting the Generating Facility

6.12.1 The Utility may isolate the Interconnection Customer's premises and/or Generating Facility from the Utility's System when necessary in order to construct, install, repair, replace, remove, investigate or inspect any of the Utility's System, or if the Utility determines that isolation of the Interconnection Customer's premises and/or Generating Facility form the Utility's System is necessary because of emergencies, forced outages, force majeure or compliance with prudent electrical practices.

6.12.2 Whenever feasible, the Utility shall give the Interconnection Customer reasonable notice of the isolation of the Interconnection Customer's premises and/or Generating Facility form the Utility's System.

6.12.3 Notwithstanding any other provision of this Standard, if at any time the Utility determines that the continued operation of the Generating Facility may endanger either (1) the Utility's personnel or other persons or property or (2) the integrity or safety of the Utility's System, or otherwise cause unacceptable power quality problems for other electric consumers, the Utility shall have the right to isolate the Interconnection Customer's premises and/or Generating Facility from the Utility's System

6.12.4 The Utility may disconnect from the Utility's System any Generating Facility determined to be malfunctioning, or not in compliance with this Standard. The Interconnection Customer must provide proof of compliance with this Standard before the Generating Facility will be reconnected

6.13 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission hereunder, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, incidental, consequential, or punitive damages of any kind.

6.14 Indemnification

The Parties shall at all times indemnify, defend and save the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney's fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inaction of its obligations hereunder on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

6.15 Insurance

The Interconnection Customer shall obtain and retain, for as long as the Generating Facility is interconnected with the Utility's System, liability insurance which protects the Interconnection Customer from claims for bodily injury and/or property damage. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. This insurance shall be primary for all purposes. The Interconnection Customer shall provide certificates evidencing this coverage as required by the Utility. Such insurance shall be obtained from an insurance provider authorized to do business in North Carolina. The Utility reserves the right to refuse to establish or continue the interconnection of the Generating Facility with the Utility's System, if such insurance is not in effect.

6.15.1 For an Interconnection Customer that is a residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be a standard homeowner's insurance policy with liability coverage in the amount of at least $100,000 per occurrence.

6.15.2 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $300,000 per occurrence.

6.15.3 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility greater than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $1,000,000 per occurrence.

6.15.4 An Interconnection Customer of sufficient credit-worthiness may propose to provide this insurance via a self-insurance program if it has a self- insurance program established in accordance with commercially acceptable risk management practices, and such a proposal shall not be unreasonably rejected.

6.16 Disconnect Switch

The Utility may require the ~~i~~Interconnection Customer to install a manual load-break disconnect switch or safety switch as a clear visible indication of switch position between the Utility System and the ~~i~~Interconnection Customer. The switch must have padlock provisions for locking in the open position. The switch must be visible to, and accessible to Utility personnel. The switch must be in close proximity to, and on the Interconnection Customer's side of the point of electrical interconnection with the Utility's system. The switch must be labeled "Generator Disconnect Switch." The switch may isolate the Interconnection Customer and its associated load from the Utility's System or disconnect only the Generator from the Utility's System and shall be accessible to the Utility at all times. The Utility, in its sole discretion, determines if the switch is suitable and necessary. When the installation of the switch is not otherwise required (e.g. National Electric Code, state or local building code) and is deemed necessary by the Utility for certified, inverter-based generators no larger than 10 kW, the Utility shall reimburse the Interconnection Customer for the reasonable cost of installing a switch that meets the Utility's specifications.

6.17 Certification Codes and Standards

Attachment 4 specifies codes and standards the Generating Facility must comply with.

6.18 Certification of Generator Equipment Packages

Attachment 5 specifies the certification requirements for the Generating Facility.

ATTACHMENT 1

Glossary of Terms

20 kW Inverter Process - The procedure for evaluating an Interconnection Request for a certified inverter-based Generating Facility no larger than 20 kW that uses the Section 3 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request Application Form, simplified procedures, and a brief set of Terms and Conditions. (See Attachment 6.)

Affected System – A Utility~~n electric system~~ other than the interconnecting Utility's System that may be affected by the proposed interconnection. The owner of an Affected System might be a Party to the Interconnection Agreement or other study agreements needed to interconnect the Generating Facility.

Applicable Laws and Regulations - All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Auxiliary Load - The term "Auxiliary Load" shall mean power used to operate auxiliary equipment in the facility necessary for power generation (such as pumps, blowers, fuel preparation machinery, exciters, etc.)

Business Day - Monday through Friday, excluding State Holidays. **Calendar Days** – Sunday through Saturday, including all holidays. **Commission** - The North Carolina Utilities Commission.

Competitive Resource Solicitation - A competitive generation procurement process through which a Utility solicits, or Utilities jointly solicit, new Generating Facilities offering to deliver energy to the Utility for purpose of meeting the requirements of applicable laws or regulations, including but not limited to G.S. § 62-110.8.

Default - The failure of a breaching Party to cure its breach under the Interconnection Agreement.

Detailed Estimated Interconnection Facilities Charge - The estimated charge for Interconnection Facilities that is based on field visits and/or detailed engineering cost calculations and is presented in the Facility Study report and ~~Final~~ Interconnection Agreement. This charge is not final.

Detailed Estimated Upgrade Charge - The estimated charge for Upgrades that is based on field visits and/or detailed engineering cost calculations and is presented in the Facility Study report and ~~Final~~ Interconnection Agreement.

Distribution System - The Utility's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades - The additions, modifications, and upgrades to the Utility's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the service necessary to allow the Generating Facility to operate in parallel with the Utility and to inject electricity onto the Utility's System. Distribution Upgrades do not include Interconnection Facilities.

Electric Generator Lessor - The owner of solar energy facility that leases the facility to a customer generator lessee, including any agents who act on behalf of the electric generator lessor.

Fast Track Process - The procedure for evaluating an Interconnection Request for a certified Generating Facility no larger than 2 MW that meets the eligibility requirements of Section 3.1, customer options meeting, and optional supplemental review.

~~**Final Interconnection Agreement** – The Interconnection Agreement that specifies the Detailed Estimated Upgrade Charge, Detailed Interconnection Facility Charge, mutually agreed upon Milestones, etc. and terminates and replaces the Interim Interconnection Agreement.~~

Financial Security – A letter of credit or other financial arrangement that is reasonably acceptable to the Utility and is consistent with the Uniform Commercial Code of North Carolina that is sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Utility’s Interconnection Facilities. Where appropriate, the Utility may deem Financial Security to exist where its credit policies show that the financial risks involved are de minimus, or where the Utility’s policies allow the acceptance of an alternative showing of credit-worthiness from the Interconnection Customer.

Generating Facility - The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Good Utility Practice - Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority - Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, the Utility, or any affiliate thereof.

In-Service Date – The date upon which the construction of the Utility's facilities is completed and the facilities are capable of being placed into service.

Interconnection Agreement – The Interconnection Agreement that specifies the Detailed Estimated Upgrade Charge, Detailed Interconnection Facility Charge, mutually agreed upon Milestones, etc.

Interconnection Customer - Any valid legal entity, including the Utility, that proposes to interconnect its Generating Facility with the Utility's System.

Interconnection Facilities – Collectively, the Utility's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Utility's System. Interconnection Facilities are sole use facilities and shall not include Upgrades.

Interconnection Facilities Delivery Date – The Interconnection Facilities Delivery Date shall be the date upon which the Utility's Interconnection Facilities are first made operational for the purposes of receiving power from the Interconnection Customer.

Interconnection Request - The Interconnection Customer's written request, in accordance with these procedures, to interconnect a new Generating Facility, or make changes to a prior Interconnection Request (such as items including but not limited to changes in capacity, equipment substitution requests, etc.), or ~~to change the capacity of, or make an equipment substation request Material Modification~~ to~~,~~ make changes to an existing Generating Facility that is interconnected with the Utility's System.

Interdependent Customer (or Interdependent Project) means an Interconnection Customer~~-~~ (or~~-~~ Project) whose Upgrade or Interconnection Facilities requirements are impacted by another Generating Facility, as determined by the Utility.

Material Modification means a modification to machine data or equipment configuration or to the interconnection site of the Generating Facility that has a material impact on the cost, timing or design of any Interconnection Facilities or Upgrades or that may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers~~, which includes any required study revisions resulting from the modification.~~. Material Modifications include certain project revisions as defined in Section 1.5.1.~~"**Material Modification**" means a modification to machine data or equipment configuration or to the interconnection site of the Generating Facility that has a material impact on the cost, timing or design of any Interconnection Facilities or Upgrades. Material Modifications include project revisions proposed at any time after receiving notification by the Utility of a complete Interconnection Request pursuant to Section 1.4.3 that 1) alters the size or~~

~~output characteristics of the Generating Facility from its Utility-approved Interconnection Request submission; or 2) may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers.~~

~~Indicia of a Material Modification, include, but are not limited to:~~

- ~~A change in Point of Interconnection (POI) to a new location, unless the change in a POI is on the same circuit less than two (2) poles away from the original location, and the new POI is within the same protection zone as the original location;~~
- ~~A change or replacement of generating equipment such as generator(s), inverter(s), transformers, relaying, controls, etc. that is not a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;~~
- ~~A change from certified to non-certified devices ("certified" means certified by an OSHA recognized Nationally Recognized Test Laboratory (NRTL), to relevant UL and IEEE standards, authorized to perform tests to such standards);~~
- ~~A change of transformer connection(s) or grounding from that originally proposed;~~
- ~~A change to certified inverters with different specifications or different inverter control specifications or set-up than originally proposed;~~
- ~~An increase of the AC output of a Generating Facility; or~~
- ~~A change reducing the AC output of the generating facility by more than 10%.~~

~~The following are not indicia of a Material Modification:~~

- ~~A change in ownership of a Generating Facility; the new owner, however, will be required to execute a new Interconnection Agreement and Study agreement(s) for any Study which has not been completed and the Report issued by the Utility.~~
- ~~A change or replacement of generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. that is a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;~~

- ~~An increase in the DC/AC ratio that does not increase the maximum AC output capability of the generating facility;~~
- ~~A decrease in the DC/AC ratio that does not reduce the AC output capability of the generating facility by more than 10%.~~

Maximum Generating Capacity - The term shall mean the maximum continuous electrical output of the Generating Facility at any time as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period. Requested Maximum Generating Capacity will be specified by the Interconnection Customer in the Interconnection Request and an approved Maximum Generating capacity will subsequently be included as a limitation in the Interconnection Agreement.~~**Maximum Physical Export Capability Requested** - The term shall mean the maximum continuous electrical output of the Generating Facility at any time at a power factor of approximately unity as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period.~~

~~**Interim Interconnection Agreement** – The Interconnection Agreement that specifies the Preliminary Estimated Interconnection Facilities Charge, Preliminary Estimated Upgrade Charge, excludes Milestones, and must be cancelled and replaced with a Final Interconnection Agreement.~~

~~"**Material Modification**" means a modification to machine data or equipment configuration or to the interconnection site of the Generating Facility that has a material impact on the cost, timing or design of any Interconnection Facilities or Upgrades. Material Modifications include project revisions proposed at any time after receiving notification by the Utility of a complete Interconnection Request pursuant to Section 1.4.3 that 1) alters the size or output characteristics of the Generating Facility from its Utility-approved Interconnection Request submission; or 2) may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers.~~

~~Indicia of a Material Modification, include, but are not limited to:~~

- ~~A change in Point of Interconnection (POI) to a new location, unless the change in a POI is on the same circuit less than two (2) poles away from the original location, and the new POI is within the same protection zone as the original location;~~

~~A change or replacement of generating equipment such as generator(s), inverter(s), transformers, relaying, controls, etc. that is not a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;~~

~~A change from certified to non-certified devices ("certified" means certified by an OSHA recognized Nationally Recognized Test Laboratory (NRTL), to relevant UL and IEEE standards, authorized to perform tests to such standards);~~

~~A change of transformer connection(s) or grounding from that originally proposed;~~

~~A change to certified inverters with different specifications or different inverter control specifications or set-up than originally proposed;~~

~~An increase of the AC output of a Generating Facility; or~~

~~A change reducing the AC output of the generating facility by more than 10%.~~

~~The following are not indicia of a Material Modification:~~

~~A change in ownership of a Generating Facility; the new owner, however, will be required to execute a new Interconnection Agreement and Study agreement(s) for any Study which has not been completed and the Report issued by the Utility.~~

~~A change or replacement of generating equipment such as generator(s), inverter(s), solar panel(s), transformers, relaying, controls, etc. that is a like-kind substitution in size, ratings, impedances, efficiencies or capabilities of the equipment specified in the original or preceding Interconnection Request;~~

~~An increase in the DC/AC ratio that does not increase the maximum AC output capability of the generating facility;~~

~~A decrease in the DC/AC ratio that does not reduce the AC output capability of the generating facility by more than 10%.~~

~~**Maximum Physical Export Capability Requested** - The term shall mean the maximum continuous electrical output of the Generating Facility at any time at a power factor of approximately unity as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period.~~

Month – The term "Month" means the period intervening between readings for the purpose of routine billing, such readings usually being taken once per month.

Nameplate Capacity – The term "Nameplate Capacity" shall mean the manufacturer's nameplate rated output capability of the generator. For multi-unit generator facilities, the "Nameplate Capacity" of the facility shall be the sum of the individual manufacturer's nameplate rated output capabilities of the generators.

Net Capacity – The term "Net Capacity" shall mean the Nameplate Capacity of the Customer's generating facilities, less the portion of that capacity needed to serve the Generating Facility's Auxiliary Load.

Net Power - The term "Net Power" shall mean the total amount of electric power produced by the Customer's Generating Facility less the portion of that power used to supply the Generating Facility's Auxiliary Load.

Network Upgrades - Additions, modifications, and upgrades to the Utility's Transmission System required to accommodate the interconnection of the Generating Facility to the Utility's System. Network Upgrades do not include Distribution Upgrades.

North Carolina Interconnection Procedures – The term "North Carolina Interconnection Procedures" shall refer to the most recent North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generator Interconnections as approved by the North Carolina Utilities Commission.

Operating Requirements - Any operating and technical requirements that may be applicable due to Regional Reliability Organization, Independent System Operator, control area, or the Utility's requirements, including those set forth in the Interconnection Agreement.

Party or Parties - The Utility, Interconnection Customer, and possibly the owner of an Affected System, or any combination of the above.

Point of Interconnection - The point where the Interconnection Facilities connect with the Utility's System.

Preliminary Estimated Interconnection Facilities Charge - The estimated charge for Interconnection Facilities that is developed using high level estimates~~unit cost~~, including overheads~~s~~ and is presented in the System Impact Study report ~~and Interim Interconnection Agreement~~. This charge is not based on field visits and/or detailed engineering cost calculations.

Preliminary Estimated Upgrade Charge - The estimated charge for Upgrades that is developed using high level estimates including ~~unit costs and~~ overheads ~~estimates, if applicable,~~ and is presented in the System Impact Study report~~ and Interim Interconnection Agreement~~. This charge is not based on field visits and/or detailed engineering cost calculations.

Project A - An Interconnection Customer that has a lower Queue Number than Interdependent Project B.

Project B - An Interconnection Customer that has a higher Queue Number than Interdependent Project A.

Project C – An Interconnection Customer that has a higher Queue Number than Interdependent Project B.

Public Staff - The Public Staff of the North Carolina Utilities Commission.

Queue Number - The number assigned by the Utility that establishes a Customer's Interconnection Request's position in the study queue relative to all other valid Interconnection Requests. A lower Queue Number will be studied prior to a higher Queue Number, except in the case of Interdependent Projects and Interconnection Requests participating in a Competitive Resource Solicitation. The Queue Number of each Interconnection Request shall be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection.

Queue Position - The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, based on Queue Number.

Reasonable Efforts - With respect to an action required to be attempted or taken by a Party under the Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Animal Waste to Energy Facility – An electric generating facility 2 MW or less in capacity that uses swine or poultry waste as its energy source, and is eligible for an expedited ~~review~~study process pursuant to G.S. 62-133.8(i)(4).

Standard - The interconnection procedures, forms and agreements approved by the Commission for interconnection of Generating Facilities to Utility Systems in North Carolina.

Standby Generation Facility -An electric generating facility primarily designed for standby or backup power in the event of a loss of power supply from the Utility. Such facilities may operate in parallel with the Utility for a brief period of time when transferring load back to the Utility after an outage, or when testing the operation of the Facility and transferring load from and back to the Utility.

Study Process - The procedure for evaluating an Interconnection Request that includes the Section 4 scoping meeting, System Impact Study, including optional system Impact Grouping Study(ies), and Facilities Study.

System - The facilities owned, controlled or operated by the Utility that are used to provide electric service in North Carolina.

Utility - The entity that owns, controls, or operates facilities used for providing electric service in North Carolina.

Transmission System - The facilities owned, controlled or operated by the Utility that are used to transmit electricity in North Carolina.

Upgrades - The required additions and modifications to the Utility's System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

ATTACHMENT 2

NORTH CAROLINA
INTERCONNECTION REQUEST APPLICATION FORM

Utility: ____

Designated Utility Contact: ____

E-Mail Address: ____

Mailing Address: ____

City: ________________________ State: ____________ Zip: ______

Telephone Number: ____

Fax: ____________________________

An Interconnection Request Application Form is considered complete when it provides all applicable and correct information required below.

Preamble and Instructions

An Interconnection Customer who requests a North Carolina Utilities Commission jurisdictional interconnection must submit this Interconnection Request Application Form by hand delivery, mail, e-mail, or fax to the Utility.

Request for: Fast Track Process ____ Supplemental Review______
Study Process ____ Standby Generator / Closed Transition______
~~—~~(Refer to Section 3 of the Interconnection Standards for guidance in selecting Fast Track Review options. All Generating Facilities larger than 2 MW must use the Section 4 Study Process.)

Processing Fee or Deposit

Fast Track Process – Non-Refundable Processing Fees

- ~~If the Generating Facility is 20 kW or smaller, the fee is $100~~.
- If the Generating Facility is larger than 20 kW but not larger than 100 kW, the fee is $750~~$250~~.
- If the Generating Facility is larger than 100 kW but not larger than 2 MW, the fee is $1,000~~$500~~.

Supplemental~~t~~ Review - Deposit

- If the Generating Facility is larger than 20 kW but not larger than 100 kW, the deposit is $750.
- If the Generating Facility is larger than 100 kW but not larger than 2 MW, the deposit is $1,000.

Study Process – Deposit

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the Utility an Interconnection Facilities Deposit Charge of $20,000 plus $1.00 per kW_{AC}.

Standby Generator / Closed Transition - Deposit

- If the Facility is less than 1 MW, deposit is $2,500.
- If the Facility is equal to or greater than 1 MW the deposit is $5,000.

Change in Ownership – Non-Refundable Processing Fee

- If the Interconnection Request is submitted solely due to a transfer of ownership or change of control of the Generating Facility, the fee is ~~$50.~~ $500.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: ______________________________

Primary Contact Name: ______________________________

Title: ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: ______________ Zip: ______________

County: ______________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Secondary Contact Name: ______________________________

Title: ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: ______________ Zip: ______________

County: ______________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Facility Location (if different from above):

Project Name: ______________________________

Address: ______________________________

City: ______________ State: ______________ Zip: ______________

County: ______________

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: ______________________________

Title: ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ________________________ State: ______________ Zip: _______________

Telephone (Day) __________________ (Evening) __________________

Fax: ___________________________

Application is for: ______ New Generating Facility

______ Capacity Change to a Proposed or Existing Generating Facility

______ Change of Ownership of a Proposed or Existing Generating Facility to a new legal entity

______ Change of Control of a Proposed or Existing Generating Facility of the existing legal entity.

________ Equipment Substitution

_______ Other

P~~If capacity addition change to existing Generating Facility, p~~lease provide additional information regarding the proposed change(s)~~describe~~:

____

____

____

Will the Generating Facility be used for any of the following?

Net Metering? Yes _____ No _____

To Supply Power to the Interconnection Customer? Yes _____ No _____

To Supply Power to the Utility? Yes _____ No _____

To Supply Power to Others? Yes _____ No _____
(If yes, discuss with the Utility whether the interconnection is covered by the NC Interconnection Standard.)

Is the Generating Facility owned by the Interconnection Customer or Leased from an Electric Generator Lessor in NC?

Owned__________

Leased__________Docket No. ____________

Requested Point of Interconnection: ____

Requested In-Service Date: ____

For installations at locations with existing electric service to which the proposed Generating Facility will interconnect, provide:

Local Electric Service Provider*: ____________________________________

Existing Account Number: ____

To be provided by the Interconnection Customer if the local electric service provider is different from the Utility

Contact Name: ____

Title: ____

E-Mail Address: ____

Mailing Address: ____

City: ______________________________ State: ______________ Zip: _______________

Telephone (Day): ___________________ (Evening): _________________________________

Fax: _______________________________

~~**Generating Facility Information**~~

~~Data applies only to the Generating Facility, not the Interconnection Facilities.~~

~~Prime Mover: Photovoltaic (PV) ____ Fuel Cell ___ Reciprocating Engine ___~~

~~Gas Turbine ___ Steam Turbine ___ Micro-turbine ___~~

~~Other~~

~~Energy Source:~~

~~Renewable~~

- ❑ ~~Solar – Photovoltaic~~
- ❑ ~~Solar – thermal~~
- ❑ ~~Biomass – landfill gas~~
- ❑ ~~Biomass – manure digester gas~~
- ❑ ~~Biomass – directed biogas~~
- ❑ ~~Biomass – solid waste~~
- ❑ ~~Biomass – sewage digester gas~~
- ❑ ~~Biomass – wood~~
- ❑ ~~Biomass – other (specify below)~~
- ❑ ~~Hydro power – run of river~~
- ❑ ~~Hydro power - storage~~
- ❑ ~~Hydro power – tidal~~
- ❑ ~~Hydro power – wave~~
- ❑ ~~Wind~~
- ❑ ~~Geothermal~~
- ❑ ~~Other (specify below)~~

~~Non-Renewable~~

- ❑ ~~Fossil Fuel - Diesel~~
- ❑ ~~Fossil Fuel - Natural Gas (not waste)~~
- ❑ ~~Fossil Fuel - Oil~~
- ❑ ~~Fossil Fuel – Coal~~
- ❑ ~~Fossil Fuel – Other (specify below)~~
- ❑ ~~Other (specify below)~~

Generating Facility Information

Data applies only to the Generating Facility, not the Interconnection Facilities.

Prime Mover Information (Refer to U.S. EIA Form 860 Instructions, Table 2 Prime Mover Codes and Descriptions at https://www.eia.gov/survey/form/eia_860/instructions.pdf)

Prime Mover Code ________

Prime Mover Description ____

Energy Source Information (Refer to U.S. EIA Form 860 Instructions, Table 28 Energy Source Codes and Heat Content at https://www.eia.gov/survey/form/eia_860/instructions.pdf)

Fuel Type	Energy Source Code	Energy Source Description

Type of Generator: Synchronous ____ Induction ____ Inverter ____

~~Total Generator Nameplate Rating: __________ kW$_{AC}$ (Typical) __________ kVAR~~ Total Generator/Storage Nameplate Capacity: __________ kW$_{AC}$ (Typical) __________ kVAR

Storage Nameplate Energy: ____________ kWh

Interconnection Customer or Customer-Site Load:____________ kW$_{AC}$ (if none, so state)

Interconnection Customer Generator Auxiliary Load: ____________ kW$_{AC}$

Typical Reactive Load (if known): ____________ kVAR

Maximum Generating Capacity requested~~Maximum Physical Export Capability Requested:~~ ____________ kW$_{AC}$

(The maximum continuous electrical output of the Generating Facility at any time at a power factor of approximately unity~~-~~ as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period)

~~h~~Production profile: provide below the maximum import and export levels (as a percentage of the Maximum Physical Export Capability Requested) for each hour of the day, as measured at the Point Of Interconnection. Power flow in excess of these levels during the corresponding hour shall be considered an Adverse Operating Effect per section 3.4.4. of the Interconnection Agreement.

Maximum import and export, hour ending:

0100 imp: exp: %	0200 imp: exp: %	0300 imp: exp: %
0400 imp: exp: %	0500 imp: exp: %	0600 imp: exp: %
0700 imp: exp: %	0800 imp: exp: %	0900 imp: exp: %
1000 imp: exp: %	1100 imp: exp: %	1200 imp: exp: %
1300 imp: exp: %	1400 imp: exp: %	1500 imp: exp: %

1600 imp: exp: %	1700 imp: exp: %	1800 imp: exp: %
1900 imp: exp: %	2000 imp: exp: %	2100 imp: exp: %
2200 imp: exp: %	2300 imp: exp: %	2400 imp: exp: %

Please provide any additional pertinent information regarding the daily operating characteristics of the facility here or attached as noted. Also note information about intended reactive flows:

____

____

____

____

List components of the Generating Facility equipment package that are currently certified:

Number	Equipment Type	Certifying Entity
1. ________	________________	________________
2. ________	________________	________________
3. ________	________________	________________
4. ________	________________	________________
5. ________	________________	________________

Generator (or solar panel information)

Manufacturer, Model & Quantity:

____

____

Nameplate Output Power Rating in kW_{AC}: Summer __________ Winter ______________

Nameplate Output Power Rating in kVA: Summer __________ Winter ______________

Individual Generator Rated Power Factor: ________ Leading ________ Lagging

Total Number of Generators in wind farm to be interconnected pursuant to this Interconnection Request (if applicable): __________ Elevation: ________

Inverter Manufacturer, Model & Quantity: ____________________________________

~~For solar projects provide the following information:~~

Latitude: _______ Degrees (decimal format, to at least 4 places)~~________ Minutes North~~

Longitude: _______ Degrees (decimal format, to at least 4 places)~~________ Minutes West~~

For solar projects provide the following information:

Orientation: _______ Degrees (Due South=180°)

❑ Fixed Tilt Array ❑ Single Axis Tracking Array ❑ Double Axis Tracking Array

Fixed Tilt Angle: ________ Degrees

Impedance Diagram - If interconnecting to the Utility System at a voltage of 44-kV or greater, provide an Impedance Diagram. An Impedance Diagram may be required by the Utility for proposed interconnections at lower interconnection voltages. The Impedance Diagram shall provide, or be accompanied by a list that shall provide, the collector system impedance of the generation plant. The collector system impedance data shall include equivalent impedances for all components, starting with the inverter transformer(s) up to the utility level Generator Step-Up transformer.

Load Flow Data Sheet - If interconnecting to the Utility System at a voltage of 44-kV or greater, provide a completed Power Systems Load Flow data sheet. A Load Flow data sheet may be required by the Utility for proposed interconnections at lower interconnection voltages.

Excitation and Governor System Data for Synchronous Generators - If interconnecting to the Utility System at a voltage of 44-kV or greater, provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be required at lower interconnection voltages. A copy of the manufacturer's block diagram may not be substituted.

Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: __________ Instantaneous ______ or RMS ________

Harmonics Characteristics: ____

Start-up requirements: ____

Inverter Short-Circuit Model Data

Model and parameter data required for short-circuit analysis is specific to each PV inverter make and model. All data to be provided in per-unit ohms, on the equivalent inverter MVA base.

Inverter Equivalent MVA Base: ___________ MVA

Values below are valid for initial 2 to 6 cycles:

Short-Circuit Equivalent Pos. Seq. Resistance (R1): _____________ p.u.

Short-Circuit Equivalent Pos. Seq. Reactance (XL1): _____________ p.u.

Short-Circuit Equivalent Neg. Seq. Resistance (R2): _____________ p.u.

Short-Circuit Equivalent Neg. Seq. Reactance (XL2): _____________ p.u.

Short-Circuit Equivalent Zero Seq. Resistance (R0): _____________ p.u.

Short-Circuit Equivalent Zero Seq. Reactance (XL0): _____________ p.u.

Special notes regarding short-circuit modeling assumptions:

____

____

Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____________

(*) Neutral Grounding Resistor (if applicable): ____________

Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: ______________ P.U.

Direct Axis Transient Reactance, X'_d: _________________ P.U.

Direct Axis Subtransient Reactance, X''_d: ______________ P.U.

Negative Sequence Reactance, X_2: __________________ P.U.

Zero Sequence Reactance, X_0: _____________________ P.U.

KVA Base: ________________

Field Volts: ________________________________

Field Amperes: ____________

Induction Generators:

Motoring Power (kW): ____________________________

I_2^2t or K (Heating Time Constant): ____________________

Rotor Resistance, Rr: ____________________________

Stator Resistance, Rs: ___________________________

Stator Reactance, Xs: ____________________________

Rotor Reactance, Xr: _____________________________

Magnetizing Reactance, Xm: ______________________

Short Circuit Reactance, Xd'': ______________________

Exciting Current: ________________________________

Temperature Rise: _______________________________

Frame Size: ____________________________________

Design Letter: __________________________________

Reactive Power Required In Vars (No Load): ___________

Reactive Power Required In Vars (Full Load): ___________

Total Rotating Inertia, H: __________ Per Unit on kVA Base

Note: Please contact the Utility prior to submitting the Interconnection Request to determine if the specified information above is required.

Interconnection Facilities Information

Will more than one transformer be used between the generator and the point of common coupling?

Yes ____ No ____ (If yes, copy this section and provide the information for each transformer used. This information must match the single-line drawing and transformer specification sheets.)

Will the transformer be provided by the Interconnection Customer? Yes ____ No _____

Transformer Data (if applicable, for Interconnection Customer-owned transformer):

Is the transformer: Single phase ___ Three phase ___ Size: _________ kVA

Transformer Impedance: _________ % on __________ kVA Base

If Three Phase:

Transformer Primary Winding ________________________________ Volts,

❑ Delta ❑ WYE, grounded neutral ❑ WYE, ungrounded neutral

Primary Wiring Connection
❑ 3-wire ❑ 4-wire, grounded neutral

Transformer Secondary Winding ________________________ Volts,

❑ Delta ❑ WYE, grounded neutral ❑ WYE, ungrounded neutral

Secondary Wiring Connection
❑ 3-wire ❑ 4-wire, grounded neutral

Transformer Tertiary Winding ________________________ Volts,
❑ Delta ❑ WYE, grounded neutral ❑ WYE, ungrounded neutral

Transformer Fuse Data (if applicable, for Interconnection Customer-owned fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: _________________ Type: ___________ Size: _____ Speed: _______

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ______________________________ Type: _______________________

Load Rating (Amps): ____ Interrupting Rating (Amps): ___________

Trip Speed (Cycles): ________

Interconnection Protective Relays (if applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.	______	______	______
2.	______	______	______
3.	______	______	______
4.	______	______	______
5.	______	______	______
6.	______	______	______

If Discrete Components:
(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer	Type:	Style/Catalog No.	Proposed Setting
______	______	______	______
______	______	______	______
______	______	______	______
______	______	______	______
______	______	______	______

Current Transformer Data (if applicable):
(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ______ Type: ______

Accuracy Class: ______ Proposed Ratio Connection: ______

Manufacturer: ______ Type: ______

Accuracy Class: ______ Proposed Ratio Connection: ______

Potential Transformer Data (if applicable):

Manufacturer: ______ Type: ______

Accuracy Class: ______ Proposed Ratio Connection: ______

Manufacturer: ______ Type: ______

Accuracy Class: ______ Proposed Ratio Connection: ______

General Information

1. One-line diagram
   Enclose site electrical one-line diagram showing the configuration of all Generating Facility equipment, current and potential circuits, and protection and control schemes.
   - The one-line diagram should include the project owner's name, project name, project address, model numbers and nameplate sizes of equipment, including number and nameplate electrical size information for solar panels, inverters, wind turbines, disconnect switches, latitude and longitude of the project location, and tilt angle and orientation of the photovoltaic array for solar projects.
   - The diagram should also depict the metering arrangement required whether installed on the customer side of an existing meter ("net metering/billing") or directly connected to the grid through a new or separate delivery point requiring a separate meter.
   - List of adjustable set points for the protective equipment or software should be included on the electrical one-line drawing.
   - This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Generating Facility is larger than 50 kW.
   - Is One-Line Diagram Enclosed? Yes ___ No ___
2. Site Plan
   - Enclose copy of any site documentation that indicates the precise physical location of the proposed Generating Facility (Latitude & Longitude Coordinates and USGS topographic map, or other diagram) and the proposed Point of Interconnection.
   - Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address) _________________
   ____
   - Is Site Plan Enclosed? Yes ___ No ___
3. Is Site Control Verification Form Enclosed? Yes ___ No ___
4. Equipment Specifications
   Include equipment specification information (product literature) for the solar panels and inverter(s) that provides technical information and certification information for the equipment to be installed with the application.
   - Are Equipment Specifications Enclosed? Yes ___ No ___
5. Protection and Control Schemes
   - Enclose copy of any site documentation that describes and details the operation of the protection and control schemes.
   - Is Available Documentation Enclosed? Yes ___ No ___
   - Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).
   - Are Schematic Drawings Enclosed? Yes ___ No ___
6. Register with North Carolina Secretary of State (if not an individual)

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request Application Form is true and correct.

For Interconnection Customer:

Signature ______________________________________Date:________________
(Authorized Agent of the Legal Entity)

Print Full Name _____________________________________

Company Name ____

Title With Company ____

E-Mail Address ____

Mailing Address: ____

City: _________________________ State: _____________ Zip: _______________

County: ______________________________

Telephone (Day): _________________ (Evening): ____________________________

Fax: ______________________

In the Matter of the Application of	**)**	
[Developer Name] for an	**)**	**SITE CONTROL VERIFICATION**
Interconnection Agreement	**)**	
with [Utility Name]	**)**	

I, [Authorized Signatory Name], [Title] of [Developer Name], under penalty of perjury, hereby certify that, [Developer Name] or its affiliate has executed a written contract with the landowner(s) noted below, concerning the property described below. I further certify that our written contract with the landowner(s) specifies the agreed rental rate or purchase price for the property, as applicable, and allows [Developer Name] or its affiliates to construct and operate a renewable energy power generation facility on the property described below.

This verification is provided to [Utility Name] in support of our application for an Interconnection Agreement.

Landowner Name(s): ____

Land Owner Contact information (Phone or e-mail): ___________________________________

Parcel or PIN Number: _____________________________

County: ______________________

Site Address:____

Number of Acres under Contract (state range, if applicable): ______________________

Date Contract was executed _______________________________

Term of Contract ____________________________

______[signature]_______________

[Authorized Signatory Name]

[Authorized Signatory Name], being first duly sworn, says that [he/she] has read the foregoing verification, and knows the contents thereof to be true to [his/her] actual knowledge.

Sworn and subscribed to before me this ________ day of __________________, 201____.

_________[signature]____________
[Authorized Signatory Name]

[Title], [Developer Name]

___________[Signature of Notary Public]________
Notary Public

____
Name of Notary Public [typewritten or printed]

My Commission expires__________

ATTACHMENT 3

Generating Facility Pre-Application Report Form

Preamble and Instructions

An Interconnection Customer who requests a Pre-Application Report must submit this Pre-Application Report Request by hand delivery, mail, e-mail, or fax to the Utility along with the non-refundable fee of $500 ~~$300~~.

DISCLAIMER: Be aware that this Pre-Application Report is simply a snapshot in time and is non- binding. System conditions can and do change frequently.

❑ Check here if payment is enclosed. Fee is required for application to be considered complete.

Date:

____

Interconnecting Customer Name (print): ____________________________________

Contact Person: ____

Mailing Address: ____

City: ____________________________ State: ____________ Zip Code: _________

Telephone (Daytime): __________________

E-Mail Address: ____

Alternative Contact Information (e.g., system installation contractor or coordinating company) Name (print): _

____

____

Role: _

____

____

Contact Person: _

____

____

Mailing Address: _

____

____

City: ______________________________ State: _____________ Zip Code: _________

Telephone (Daytime): _______________________________

E-Mail Address: ____

Facility Information:

1) Proposed Facility Location

Address (or cross-roads): _

____

____

City: ______________________________ State: _______ Zip Code: _________

❑ Site Map provided (Google, MapQuest, etc.)

❑ Grid Coordinates (decimal) - Latitude: _____________ Longitude: _____________

❑ Pole or Tower number if available: _______________________

2) Primary Energy Source

~~Choose one:~~

~~Renewable~~	~~Non-Renewable~~
☐ ~~1. Solar – Photovoltaic~~	☐ ~~17. Fossil Fuel - Diesel~~
☐ ~~2. Solar – thermal~~	☐ ~~18. Fossil Fuel - Natural Gas (not waste)~~
☐ ~~3. Biomass – landfill gas~~	☐ ~~19. Fossil Fuel - Oil~~
☐ ~~4. Biomass – manure digester gas~~	☐ ~~20. Fossil Fuel – Coal~~
☐ ~~5. Biomass – directed biogas~~	☐ ~~21. Fossil Fuel – Other (specify below)~~
☐ ~~6. Biomass – solid waste~~	☐ ~~22. Other (specify below)~~
☐ ~~7. Biomass – sewage digester gas~~	
☐ ~~8. Biomass – wood~~	
☐ ~~9. Biomass – other (specify below)~~	
☐ ~~10. Hydro power – run of river~~	
☐ ~~11. Hydro power - storage~~	
☐ ~~12. Hydro power – tidal~~	
☐ ~~13. Hydro power – wave~~	
☐ ~~14. Wind~~	
☐ ~~15. Geothermal~~	
☐ ~~16. Other (specify below)~~	

~~3) Prime Mover~~

~~Choose one:~~

~~1. ☐ Photovoltaic (PV)~~	~~5. ☐ Steam Turbine~~
~~2. ☐ Fuel Cell~~	~~6. ☐ Micro-turbine~~
~~3. ☐ Reciprocating Engine~~	~~7. ☐ Other, including Combined Heat and Power (specify below)~~
~~4. ☐ Gas Turbine~~	

(Refer to U.S. EIA Form 860 Instructions, Table 28 Energy Source Codes and Heat Content at https://www.eia.gov/survey/form/eia_860/instructions.pdf)

Fuel Type	Energy Source Code	Energy Source Description

3) Prime Mover (Refer to U.S. EIA Form 860 Instructions, Table 2 Prime Mover Codes and Descriptions at https://www.eia.gov/survey/form/eia_860/instructions.pdf)

Prime Mover Code ________

Prime Mover Description ____

4) Type of Generator

Choose one:

1. ☐ Inverter-based Machine 2. ☐ Rotating Machine 3. ☐ Rotating Machine with Inverters	

~~5) Size: _____________ kWAC~~

5) Generator/Storage Nameplate Capacity: kW

Maximum Generating Capacity requested: _____________ kWAC

Storage Nameplate Energy: _____________ kWh

6) Generator Configuration:

❑ Single-phase ❑ Three Phase

7) Interconnection Configuration

❑ New Generation

❑ Stand-alone

❑ Addition to existing commercial or industrial customer's delivery

Customer's Electric Utility account number: ____________________

Customer's Electric meter number: __________________________

Is Customer's kW load going to increase or decrease?

❑ No

❑ Yes, Details ____________________________________

Proposed Point of Interconnection on Customer-side of Utility meter

____

OR

❑ Addition to existing generation

❑ Stand-alone

❑ Addition to existing commercial or industrial customer's delivery

Customer's Electric Utility account number: ____________________

Customer's Electric meter number: __________________________

Is Customer's kW load going to increase or decrease?

❑ No

❑ Yes, Details ____________________________________

Type of Existing Generation: ________________________________

Size of Existing Generation: _____________ kW_{AC}

Proposed Point of Interconnection on Customer-side of Utility meter

____

Additional Comments

____

____

____

____

Attachment 4

Certification Codes and Standards

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

NEMA MG 1-1998, Motors and Small Resources, Revision 3

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

NFPA 70 (2002), National Electrical Code

UL1741, Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources

Attachment 5

Certification of Generator Equipment Packages

1.0 Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in Attachment 4 of the North Carolina Interconnection Procedures, (2) it has been labeled and is publicly listed by such NRTL at the time of the Interconnection Request, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the Parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the Interconnection Customer's side of the point of common coupling shall be required to meet the requirements of the North Carolina Interconnection Procedures.

6.0 An equipment package does not include equipment provided by the Utility.

Attachment 6

Interconnection Request Application Form for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW

This Interconnection Request Application Form is considered complete when it provides all applicable and correct information required below. Additional information to evaluate the Interconnection Request may be required.

Processing Fee

A non-refundable processing fee of $200 ~~$100~~ must accompany this Interconnection
Request Application Form.

If the Interconnection Request is submitted solely due to a transfer of ownership of the Generating Facility, the non-refundable fee is $50.

Interconnection Customer

Name: ______________________________

Primary Contact Person: ______________________________

Title ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: ________ Zip: __________

County: ______________________________

Telephone (Day): ______________ (Evening): ______________

Fax: ______________

Secondary Contact Name: ______________________________

Title: ______________________________

E-Mail Address: ______________________________

Mailing Address: ______________________________

City: ______________ State: ______________ Zip: ______________

County: ______________

Telephone (Day): ____________________ (Evening): ______________________________

Fax: ____________________________

Contact (if different than Interconnection Customer)

Name: ____

E-Mail Address: ____

Address: ____

City: ___________________________ State: ________ Zip: ____________

County: ____

Telephone (Day): ________________ (Evening): ______________________

Fax: ___________________________

Owner(s) of the Generating Facility: ______________________________

Generating Facility Information

Facility Location (if different from above):

Address: ______________________________

City: ______________ State: ________ Zip: ____________

County: ______________________________

Utility: ______________________________

Account Number: ______________________________

Is the Generating Facility owned by the Interconnection Customer or Leased from an Electric Generator Lessor in NC?

Owned__________

Leased__________Docket No. ____________

Inverter Manufacturer: ________________ Model: ________________

Nameplate Rating (each inverter): ______________ kW (AC) (each inverter)

______________ kVA (AC) (each inverter)

______________ Volts (AC) (each inverter)

Single Phase: ________ Three Phase: ________

System Design Capacity[1]: ______________ kW (AC) (system total)

______________ kVA (AC) (system total)

For photovoltaic sources only:

Total panel capacity: ______________ kW (DC) (system total)

Maximum Generating Capacity requested~~Maximum Physical Export Capability Requested~~:[2] _*(calculated)*[3]_ kW (AC)

[1] Total inverter capacity.

[2] At the Point of Interconnection, this is the maximum possible export power that could flow back to the utility. Unless special circumstances apply, load should not be subtracted from the System Design Capacity.

[3] For a photovoltaic installation, the utility will calculate this value as the lesser of (1) the total kW inverter capacity and (2) the total kW panel capacity (no DC to AC losses included, for simplicity).

For other sources:

~~Maximum Physical Export Capability Requested~~Maximum Generating Capacity requested:[2] ____________ kW (AC)

~~Prime Mover: Photovoltaic ☐ Reciprocating Engine ☐~~

~~Fuel Cell ☐ Turbine ☐ Other ☐~~

~~ENERGY SOURCE TABLE~~

~~Renewable~~	~~Non-Renewable~~
~~H-1. Solar – Photovoltaic~~ ~~H-2. Solar – thermal~~ ~~H-3. Biomass – landfill gas~~ ~~H-4. Biomass – manure digester gas~~ ~~H-5. Biomass – directed biogas~~ ~~H-6. Biomass – solid waste~~ ~~H-7. Biomass – sewage digester gas~~ ~~H-8. Biomass – wood~~ ~~H-9. Biomass – other (specify below)~~ ~~H-10. Hydro power – run of river~~ ~~H-11. Hydro power - storage~~ ~~H-12. Hydro power – tidal~~ ~~H-13. Hydro power – wave~~ ~~H-14. Wind~~ ~~H-15. Geothermal~~ ~~H-16. Other (specify below)~~	~~H-17. Fossil Fuel - Diesel~~ ~~H-18. Fossil Fuel - Natural Gas (not waste)~~ ~~H-19. Fossil Fuel - Oil~~ ~~H-20. Fossil Fuel – Coal~~ ~~H-21. Fossil Fuel – Other (specify below)~~ ~~H-22. Other (specify below)~~

~~Energy Source: ________________ (choose from list above)~~

Prime Mover Information (Refer to U.S. EIA Form 860 Instructions, Table 2 Prime Mover Codes and Descriptions at https://www.eia.gov/survey/form/eia_860/instructions.pdf)

Prime Mover Code _________

Prime Mover Description ____

Energy Source Information (Refer to U.S. EIA Form 860 Instructions, Table 28 Energy Source Codes and Heat Content at https://www.eia.gov/survey/form/eia_860/instructions.pdf)

Fuel Type	Energy Source Code	Energy Source Description

Is the equipment UL 1741 Listed? Yes ____ No ____

If Yes, attach manufacturer's cut-sheet showing UL 1741 listing

Estimated Installation Date: ________ Estimated In-Service Date: ________

The 20 kW Inverter Process is available only for inverter-based Generating Facilities no larger than 20 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the North Carolina Interconnection Procedures, or the Utility has reviewed the design or tested the proposed Generating Facility and is satisfied that it is safe to operate.

List components of the Generating Facility equipment package that are currently certified:

Number	Equipment Type	Certifying Entity
1. ________	________________________	____________________
2. ________	________________________	____________________
3. ________	________________________	____________________
4. ________	________________________	____________________
5. ________	________________________	____________________

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Interconnection Request Application Form is true. I agree to abide by the Terms and Conditions for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW and return the Certificate of Completion when the Generating Facility has been installed.

Signed~~:~~ ____~~:~~

Full Name ______________________________

Company Name ______________________________

Title With Company ______________________________

E-Mail Address ______________________________

Mailing Address: ______________________________

City: ____________________ State: ______________ Zip: ______________

County: ____________________

Telephone (Day): ______________ (Evening): ____________________

Fax: ______________

~~Title:~~ ______________________________ ~~Date:~~ ______________

Contingent Approval to Interconnect the Generating Facility (For Utility use only)

Interconnection of the Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW and return of the Certificate of Completion.

Utility Signature: ____

Title: __________________________________ Date: ____________

Interconnection Request ID number: _______________________________

Utility waives inspection/witness test? Yes ____No _____

- -

Certificate of Completion
for Interconnecting a Certified Inverter-Based
Generating Facility No Larger than 20 **kW**

Is the Generating Facility owner-installed? Yes _____No _____

Interconnection Customer

Name: ____

Contact Person: ______________________________________

E-Mail Address: ______________________________________

Address: ____

City: __________________________ State: _______ Zip: ___________

County: ____

Telephone (Day): ________________ (Evening): _____________________

Fax: __________________________

Location of the Generating Facility (if different from above)

Address: ____

City: __________________________ State: _______ Zip: ___________

Electrician

Name: ____

Company: ____

E-Mail Address: ______________________________________

Address: ____

City: __________________________ State: _______ Zip: ___________

County: ____

Telephone (Day): ________________ (Evening): _____________________

Fax: __________________________

License Number: __________________________

Date Approval to Install Generating Facility granted by the Utility: ___________

Interconnection Request ID Number: ______________________________

Inspection:

The Generating Facility has been installed and inspected in compliance with the local building/electrical code of ______________________________

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

Signature: ______________________________

Print Name: ______________________ Date: ______________

As a condition of interconnection, you are required to send/ email/ fax a copy of this form along with a copy of the signed electrical permit to (insert Utility information below):

Utility Name: ______________________________

Attention: ______________________________

E-Mail Address: ______________________________

Address: ______________________________

City: ______________________ State: _______ Zip: __________

Fax: ______________________

Approval to Energize the Generating Facility (For Utility use only)

Energizing the Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW.

Utility Signature: ______________________________

Title: ______________________ Date: ______________

Terms and Conditions for Interconnecting a Certified Inverter-Based Generating Facility No Larger than 20 kW

1.0 Construction of the Facility

The Interconnection Customer (Customer) may proceed to construct (including operational testing not to exceed two hours) the Generating Facility when the Utility approves the Interconnection Request and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may interconnect the Generating Facility with the Utility's System and operate in parallel with the Utility's System once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Utility, and

2.3 The Utility has either:

2.3.1 Completed its inspection of the Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Utility, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Utility shall provide a written statement that the Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Utility does not schedule an inspection of the Generating Facility within ten Business Days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Utility waives the right to inspect the Generating Facility.

2.4 The Utility has the right to disconnect the Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable American National Standards Institute (ANSI) standards and all applicable regulatory requirements.

3.0 Safe Operations and Maintenance

The Customer shall be fully responsible to operate, maintain, and repair the Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

The Customer shall not operate the Generating Facility in such a way that the Generating Facility would exceed the Maximum Generating Capacity.

4.0 Access

The Utility shall have access to the disconnect switch (if a disconnect switch is required) and metering equipment of the Generating Facility at all times. The Utility shall provide reasonable notice to the Customer, when possible, prior to using its right of access.

5.0 Disconnection

The Utility may temporarily disconnect the Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Generating Facility does not operate in a manner consistent with these Terms and Conditions.

5.4 The Utility shall inform the Customer in advance of any scheduled disconnection, or as soon as is reasonable after an unscheduled disconnection.

6.0 Indemnification

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations hereunder on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7. 0 Insurance

All insurance policies must be maintained with insurers authorized to do business in North Carolina. The Parties agree to the following insurance requirements:

7.1 If the Customer is a residential customer of the Utility, the required coverage shall be a standard homeowner's insurance policy with liability coverage in the amount of at least $100,000 per occurrence.

7.2 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $300,000 per occurrence.

7.3 The Customer may provide this insurance via a self-insurance program if it has a self-insurance program established in accordance with commercially acceptable risk management practices.

8.0 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, or expense, including reasonable attorney's fees, relating to or arising from any act or omission hereunder, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, incidental, consequential, or punitive damages of any kind.

9.0 Termination

The agreement to interconnect and operate in parallel may be terminated under the following conditions:

9.1 By the Customer

By providing written notice to the Utility and physically and permanently disconnecting the Generating Facility.

9.2 By the Utility

If the Generating Facility fails to operate for any consecutive 12-month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 Permanent Disconnection

In the event this Agreement is terminated, the Utility shall have the right to disconnect its facilities or direct the Customer to disconnect its Generating Facility.

9.4 Survival Rights

This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 Assignment/Transfer of Ownership of the Facility

10.1 This Agreement shall not survive the transfer of ownership of the Generating Facility to a new owner.

10.2 The new owner must complete and submit a new Interconnection Request agreeing to abide by these Terms and Conditions for interconnection and parallel operations within 20 Business Days of the transfer of ownership. The Utility shall acknowledge receipt and return a signed copy of the Interconnection Request Application Form within ten Business Days.

10.3 The Utility shall not study or inspect the Generating Facility unless the new owner's Interconnection Request Application Form indicates that a Material Modification has occurred or is proposed.

ATTACHMENT 7

System Impact Study Agreement

THIS AGREEMENT ("Agreement") is made and entered into this ____ day of 20___by___ and between____, a______________________________ organized and existing under the laws of the State of ____, ("Interconnection Customer,") and ____, a________________ existing under the laws of the State of__________________________, ("Utility"). The Interconnection Customer and the Utility each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer, Dated ________________and received by the Utility on ___________________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Generating Facility with the Utility's System; and

WHEREAS, the Interconnection Customer has requested the Utility to perform a system impact study to assess the impact of interconnecting the Generating Facility with the Utility's System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the North Carolina Interconnection Procedures.

2. The Interconnection Customer elects and the Utility shall cause to be performed a system impact study consistent with the North Carolina Interconnection Procedures.

3. The scope of the system impact study shall be subject to the assumptions set forth in Appendix A to this Agreement.

4. A system impact study will be based upon the technical information provided by Interconnection Customer in the Interconnection Request. The Utility reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the information requested by the Utility is not provided by the Interconnection Customer within a reasonable timeframe to be identified by the Utility in writing, the Utility shall provide the Interconnection Customer written notice providing an opportunity to cure such failure by the close of business on the tenth (10th) Business Day following the posted date of such notice, where failure to provide the information requested within this period shall result in the study being terminated and the Interconnection Request being deemed withdrawn. ~~If the Interconnection Customer modifies its Interconnection Request or the technical information provided therein is modified, the time to complete the system impact study may be extended.~~ The period of time for the Utility to complete the ~~S~~system ~~I~~impact ~~S~~study shall be tolled during any period that the Utility has requested information in writing from the Interconnection Customer necessary to complete the ~~S~~study and such request is outstanding.

5. In performing the study, the Utility shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the S~~s~~ystem I~~i~~mpact ~~feasibility~~ S~~s~~tudy.

6. The System Impact Study Report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Generating Facility as proposed:

6.1. Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection, considering the Nameplate Capacity of the Generating Facility;

6.2. Initial identification of any thermal overload or voltage limit violations resulting from the interconnection, considering the Maximum Generating Capacity of the Generating Facility;

6.3. Initial review of grounding requirements and electric system protection

7. The System Impact Study shall model the impact of the Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Generating Facility is being installed.

8. The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of

Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9. A System Impact Study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary.

10. The System Impact Study will also include an analysis of distribution and transmission impacts as may be necessary to understand the impact of the proposed Generation Facility ~~–~~on electric system operation.

11. A System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service.

12. The System Impact Study will provide the Preliminary Estimated Upgrade Charge, which is a preliminary indication of the cost and length of time that would be necessary to correct any System problems identified in those analyses and implement the interconnection

13. The System Impact Study will provide the Preliminary Estimated Interconnection Facilities Charge, which is a preliminary indication of the cost and length of time that would be necessary to provide the Interconnection Facilities.

~~**14.** A system impact study shall provide the information outlined in Section 1.3.2 of the Interconnection Procedures.~~

14~~5~~. A distribution ~~System~~ system ~~Impact~~ impact ~~S~~study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

15~~6~~. Affected Systems may participate in the preparation of a System Impact Study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a System Impact Study that covers potential adverse system impacts on their electric systems, and the Utility has 20 additional ~~—~~Business Days to complete a system impact study requiring review by Affected Systems.

16~~7~~. The Utility shall have an additional 15 Business Days from the time set forth in Section 19.0 the System Impact Study Agreement to complete the dual scenario System Impact Study reports for a Project B.

17~~8~~. If the Utility uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the System Impact Study shall consider all generating facilities (and with respect to paragraph 18.3 below, any identified Upgrades associated with such interconnection with a lower Queue Number) that, on the date the system impact study is commenced –

17~~8~~.1. Are directly interconnected with the Utility's electric system; or

17~~8~~.2. Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

17~~8~~.3. Have a pending Interconnection Request to interconnect with the Utility's electric system with a lower Queue Number.

18. The System Impact Study shall be completed within a total of 65 Business Days if transmission system impacts are studied, and 50 Business Days if distribution system impacts are studied, but in any case, shall not take longer than a total of 65 Business Days unless the study involves Affected Systems per Section 16.0 or the studied Interconnection Request is a Project B per Section 17.0 or the System Impact Study is a Grouping Study implemented pursuant to Section 4.3.4 of the Interconnection Procedures, which shall be completed during the timeframe of the Competitive Resource Solicitation. The period of time for the Utility to complete the System Impact Study shall be tolled during any period that the Utility has requested information in writing from the Interconnection Customer necessary to complete the Study and such request is outstanding.

19~~20~~. Any study fees shall be based on the Utility's actual costs and will be deducted from the Interconnection Facilities deposit made by the Interconnection Customer at the time of the Interconnection Request. After the study is completed, the Utility shall deliver a summary of costs incurred.~~professional time.~~

2~~1~~0. The Interconnection Customer must pay any study costs that exceed the Interconnection Request Deposit without interest within 20 Business Days of receipt of the invoice. If the deposit exceeds the invoiced fees or the Interconnection Customer's costs exceed the aggregate deposits received and the Interconnection Customer withdraws the Interconnection Request, the amount of funds equal to the difference will be settled in accordance with Section 6.3 of the NC Interconnection ~~interconnection~~ Standard.

21~~2~~. Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of North

Carolina, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

22~~3~~. Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

23~~4~~. No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

24~~5~~. Waiver

24~~5~~.1. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

24~~5~~.2. Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

25~~6~~. Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

26~~7~~. No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

2~~8~~7. Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

28~~9~~. Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

2~~9~~8.1. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

2~~9~~8.2. The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

29~~30~~. Reservation of Rights

The Utility shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, or classifications of service, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Utility]	**[Insert name of Interconnection Customer]**
______________________________	______________________________
Signed ______________________	Signed ______________________
Name (Printed):	Name (Printed):
______________________________	______________________________
Title ______________________	

System Impact Study Agreement
Appendix A

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the Interconnection Request subject to any modifications in accordance with the Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied (to be completed by the Interconnection Customer and the Utility).

~~2) Designation of alternative Points of Interconnection and configuration.~~

~~1) and 2) are to be completed by the Interconnection Customer.~~ Other assumptions (listed below) are to be provided by the Interconnection Customer and the Utility.

ATTACHMENT 8

Facilities Study Agreement

THIS AGREEMENT ("Agreement") is made and entered into this _________ day of ________________ 20____ by and between _______________________________, a ______________________________ organized and existing under the laws of the State of _____________________________, ("Interconnection Customer,") and, ____, a ________________ existing under the laws of the State of __________, ("Utility"). The Interconnection Customer and the Utility each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Generating Facility or generating capacity in addition to an existing Generating Facility consistent with the Interconnection Request Application Form completed by the Interconnection Customer, dated ____________________ and received by the Utility on ___________________; and the single-line drawing provided by the Interconnection Customer, dated ___________________ and received by the Utility on ___________________ and

WHEREAS, the Interconnection Customer desires to interconnect the Generating Facility with the Utility's System; and

WHEREAS, the Utility has completed a System Impact Study and provided the results of said study to the Interconnection Customer (this recital to be omitted if the Parties have agreed to forego the system impact study); and

WHEREAS, the Interconnection Customer has requested the Utility to perform a Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the system impact study and/or any other relevant studies in accordance with Good Utility Practice to physically and electrically connect the Generating Facility with the Utility's System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the North Carolina Interconnection Procedures.

2. The Interconnection Customer elects and the Utility shall cause to be performed a facilities study consistent with the North Carolina Interconnection Procedures.

3. The scope of the facilities study shall be subject to data provided in Appendix A to this Agreement.

4. The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact studies. The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Utility's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the construction time required to complete the installation of such facilities.

   If the study is for a Project B, the study shall assume the interdependent Project A is interconnected.

5. The Utility may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Generating Facility if it is willing to pay the costs of those facilities

6. A deposit of the good faith estimated facilities study cost is required from the Interconnection Customer. If the unexpended portion of the Interconnection Request deposit made for the Interconnection Request exceeds the estimated cost of the facilities study, no payment will be required of the Interconnection Customer.

7. In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the Utility's receipt of this Agreement, or completion of the Facilities Study for an Interdependent Project A whichever is later. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days. The Utility reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the facilities study. If the information requested by the Utility is not provided by the Interconnection Customer within a reasonable timeframe to be identified by the Utility in writing, the Utility shall provide the Interconnection Customer written notice providing an opportunity to cure such failure by the close of business on the tenth (10th) Business Day following the posted date of such notice, where failure to provide the information requested within this period shall result in the study being terminated and the Interconnection Request being deemed withdrawn. ~~-~~The period of time for the Utility to complete the Facilities Study shall be tolled during any period that the Utility has requested information in writing from the Interconnection Customer necessary to complete the Study and such request is outstanding.

8. Once the facilities study is completed, a facilities study report shall be prepared and transmitted to the Interconnection Customer.

9. Any study fees shall be based on the Utility's actual costs and will be deducted from the Interconnection Request deposit made by the Interconnection

Customer at the time of the Interconnection Request. After the study is completed the Utility shall deliver a summary of costs incurred.~~professional time.~~

10. The Interconnection Customer must pay any study costs that exceed the Interconnection Request deposit without interest within 20 Business Days of receipt of the invoice. If the unexpended portion of the Interconnection Request deposit exceeds the invoiced fees and the Interconnection Customer withdraws the Interconnection Request, the Utility shall make refund to the Customer pursuant to Section 6.3 of the North Carolina Interconnection Procedures.

~~10.~~11. If the Interconnection Customer submitted prepayment or Financial Security reasonably acceptable to the Utility for Network Upgrades under Section 4.3.9 of the North Carolina Interconnection Procedures, the Parties agree that this prepayment or Financial Security shall be held by the Utility as a non-refundable prepayment for the estimated cost of Network Upgrades and Interconnection Customer expressly agrees this prepayment amount shall be forfeited to the Utility to construct the Network Upgrades if the Interconnection Request is subsequently withdrawn. The Network Upgrades prepayment amount shall be trued up by the Utility in the Detailed Estimated Upgrade Charges amount calculated during Facilities Study and identified in a Facilities Study report to be included in a future Interconnection Agreement.

~~11.~~12. Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of North Carolina, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

~~12.~~13. Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

~~13.~~14. No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

~~14.~~15. Waiver

The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

~~15.~~16. Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

~~16.~~17. No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

~~17.~~18. Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

~~18.~~19. Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Utility be liable for the actions or inactions of the

Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

~~19.~~20. Reservation of Rights

The Utility shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, or classifications of service, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

For the Utility

Name: ______________________________

Print Name: ______________________________

Title: ______________________________

Date ______________________________

For the Interconnection Customer

Name: ______________________________

Print Name: ______________________________

Title: ______________________________

Date ______________________________

Facilities Study Agreement
Appendix A

Data to Be Provided by the Interconnection Customer with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, circuits, etc.

On the one-line diagram, indicate the Maximum Generating Capacity ~~generation capacity~~ attached at each metering location. (Maximum load on CT/PT)

On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of metering is required for each generation connection to the new ring bus or existing Utility station. Number of generation connections: ___________________

____

Will an alternate source of auxiliary power be available during CT/PT maintenance?

Yes ___________ No ___________

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes ___________ No ___________

(Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Generating Facility?

____

____

What protocol does the control system or PLC use?

____

____

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, distribution line, and property lines.

Physical dimensions of the proposed interconnection station:

____

Bus length from generation to interconnection station:

____

Line length from interconnection station to Utility's System.

____

Tower number observed in the field (Painted on tower leg)*:

____

Number of third party easements required for lines*:

____

* To be completed in coordination with Utility.

Is the Generating Facility located in Utility's service area?

Yes __________ No __________ If No, please provide name of local provider:

____

Please provide the following proposed schedule dates:

Begin Construction	Date: ____________________
Generator step-up transformers receive back feed power	Date: ____________________
Generation Testing	Date: ____________________
Commercial Operation	Date: ____________________

ATTACHMENT~~Attachment~~ 9

NORTH CAROLINA

INTERCONNECTION AGREEMENT

For State-Jurisdictional Generator Interconnections

Effective XX/XX/XXXX ~~May 15, 2015~~

Docket No. E-100, Sub 101

Between

Utility Name

And

Customer Name

“Project Name”

TABLE OF CONTENTS

Page No.

Article 1. Scope and Limitations of Agreement 1
1.1 Applicability 1
1.2 Purpose 2
1.3 No Agreement to Purchase or Deliver Power or RECs 2
1.4 Limitations 2
1.5 Responsibilities of the Parties 2
1.6 Parallel Operation Obligations 3
1.7 Metering 3
1.8 Reactive Power 4
1.9 Capitalized Terms 4
Article 2. Inspection, Testing, Authorization, and Right of Access 4
2.1 Equipment Testing and Inspection 4
2.2 Authorization Required Prior to Parallel Operation 5
2.3 Right of Access 5
Article 3. Effective Date, Term, Termination, and Disconnection 6
3.1 Effective Date 6
3.2 Term of Agreement 6
3.3 Termination 6
3.4 Temporary Disconnection 7
Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades 9
4.1 Interconnection Facilities 9
4.2 Distribution Upgrades 9
Article 5. Cost Responsibility for Network Upgrades 9
5.1 Applicability 9
5.2 Network Upgrades 9
Article 6. Billing, Payment, Milestones, and Financial Security 10
6.1 Billing and Payment Procedures and Final Accounting 10
6.2 Milestones 10
6.3 Financial Security Arrangements 11
Article 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default 11
7.1 Assignment 11
7.2 Limitation of Liability 12
7.3 Indemnity 13
7.4 Consequential Damages 13
7.5 Force Majeure 14
7.6 Default 14
Article 8. Insurance 15
Article 9. Confidentiality 16
Article 10. Disputes 17
Article 11. Taxes 17
Article 12. Miscellaneous 17
12.1 Governing Law, Regulatory Authority, and Rules 17
12.2 Amendment 17

Page No.

12.3 No Third-Party Beneficiaries 18
12.4 Waiver 18
12.5 Entire Agreement 18
12.6 Multiple Counterparts 18
12.7 No Partnership 18
12.8 Severability 19
12.9 Security Arrangements 19
12.10 Environmental Releases 19
12.11 Subcontractors 19
12.12 Reservation of Rights 20
Article 13. Notices 21
13.1 General 21
13.2 Billing and Payment 22
13.3 Alternative Forms of Notice 23
13.4 Designated Operating Representative 24
13.5 Changes to the Notice Information 25

Appendix 1 – Glossary of Terms

Appendix 2 – Description and Costs of the Generating Facility, Interconnection Facilities, and Metering Equipment

Appendix 3 – One-line Diagram Depicting the Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades

Appendix 4 – Milestones

Appendix 5 – Additional Operating Requirements for the Utility's System and Affected Systems Needed to Support the Interconnection Customer's Needs

Appendix 6 – Utility's Description of its Upgrades and Best Estimate of Upgrade Costs

This Interconnection Agreement ("Agreement") is made and entered into this ____ day of __________, 20__, by ____ ("Utility"), and ____ ("Interconnection Customer") each hereinafter sometimes referred to individually as "Party" or both referred to collectively as the "Parties."

Utility Information

Utility: ____

Attention: ____

Address: ____

City: _________________________ State: _______ Zip: ______

Phone: _________________ Fax: ____________________________

Interconnection Customer Information

Name: ____

Project Name: ____ _

Attention: ____

E911 Address: ____

City: _________________________ State: _______ Zip: ______

Phone: _________________ Fax: ____________________________

County: ____________________________

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 Applicability

This Agreement shall be used for all Interconnection Requests submitted under the North Carolina Interconnection Procedures except for those submitted under the 20 kW Inverter Process in Section 2 of the Interconnection Procedures.

1.2 Purpose

~~If an Interim Interconnection Agreement, t~~This ~~Agreement documents the Utility's ability to interconnect the Generating Facility and provides the Preliminary Estimated Interconnection Facilities Charge and the Preliminary Estimated System Upgrade Charge that was developed in the System Impact Study. Milestones have not been established and the Utility offers no estimate on when the required facilities might be installed.~~

~~If a Final Interconnection Agreement~~Interconnection Agreement, ~~t~~This Agreement governs the terms and conditions under which the Interconnection Customer's Generating Facility will interconnect with, and operate in parallel with, the Utility's System.

1.3 No Agreement to Purchase or Deliver Power or RECs

This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power or Renewable Energy Certificates (RECs). The purchase or delivery of power, RECs that might result from the operation of the Generating Facility, and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity with the applicable Utility.

1.4 Limitations

Nothing in this Agreement is intended to affect any other agreement between the Utility and the Interconnection Customer.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Utility shall construct, operate, and maintain its System and Interconnection Facilities in accordance with this Agreement, and with Good Utility Practice.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriters' Laboratories, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the System or equipment of the Utility and any Affected Systems.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Appendices to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Utility and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the Utility's System, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Appendices to this Agreement.

1.5.6 The Utility shall coordinate with all Affected Systems to support the interconnection.

1.5.7 The Customer shall not operate the Generating Facility in such a way that the Generating Facility would exceed the Maximum Generating Capacity.

1.6 Parallel Operation Obligations

Once the Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Generating Facility in the applicable control area, including, but not limited to: 1) any rules and procedures concerning the operation of generation set forth in Commission-approved tariffs or by the applicable system operator(s) for the Utility's System and; 2) the Operating Requirements set forth in Appendix 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the Utility's reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Appendices 2 and 3 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power

1.8.1 The Interconnection Customer shall design its Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Utility has established different requirements that apply to all similarly situated generators in the control area on a comparable basis. The requirements of this paragraph shall not apply to wind generators.

1.8.2 The Utility is required to pay the Interconnection Customer for reactive power that the Interconnection Customer provides or absorbs from the Generating Facility when the Utility requests the Interconnection Customer to operate its Generating Facility outside the range specified in Article 1.8.1 or outside the range established by the Utility that applies to all similarly situated generators in the control area. In addition, if the Utility pays its own or affiliated generators for reactive power service within the specified range, it must also pay the Interconnection Customer.

1.8.3 Payments shall be in accordance with the Utility's applicable rate schedule then in effect unless the provision of such service(s) is subject to a regional transmission organization or independent system operator FERC-approved rate schedule. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb reactive power under this Agreement, the Parties agree to expeditiously file such rate schedule and agree to support any request for waiver of any prior notice requirement in order to compensate the Interconnection Customer from the time service commenced.

1.9 Capitalized Terms

Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 of the North Carolina Interconnection Procedures or the body of this Agreement.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

2.1.1 The Interconnection Customer shall test and inspect its Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the Utility of such activities no fewer than ten (10) Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day, unless otherwise agreed to by the Parties. The Utility may, at its own expense, send qualified personnel to the Generating Facility site to inspect the interconnection and observe the testing. The Interconnection Customer shall provide the Utility a written test report when such testing and inspection is completed.

2.1.2 The Utility shall provide the Interconnection Customer written acknowledgment that it has received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Utility of the safety, durability, suitability, or reliability of the Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Generating Facility.

2.1.3 In addition to the Utility's observation of the Interconnection Customer's testing and inspection of its Generating Facility and Interconnection Facilities pursuant to this Section, the Utility may also require inspection and testing of Interconnection Facilities which can impact the integrity or safety of the Utility's System or otherwise cause adverse operating effects, as described in Section 3.4.4. Such inspection and testing activities will be performed by the Utility or a third-party independent contractor approved by the Utility and at a time mutually agreed to with the Interconnection Customer and will be performed at the Interconnection Customer's expense. The scope of required inspection and testing will be consistent across similar types of generating facilities.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Utility shall use Reasonable Efforts to list applicable parallel operation requirements in Appendix 5 of this Agreement. Additionally, the Utility shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Utility shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Generating Facility in parallel with the Utility's System without prior written authorization of the Utility. The Utility will provide such authorization once the Utility receives notification that the Interconnection Customer has complied with all applicable parallel operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access

~~2.3.1~~ ~~Upon reasonable notice, the Utility may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Generating Facility first produces energy to inspect the interconnection, and observe the commissioning of the Generating Facility (including any required testing), startup, and operation for a period of up to three (3) Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Utility at least five (5) Business Days prior to conducting any on-site verification testing of the Generating Facility.~~Upon reasonable notice, the Utility may send a qualified person to the premises of the Interconnection Customer at or before the time the Generating Facility first produces energy to inspect the interconnection and those Interconnection Customer facilities which can impact the integrity or safety of the Utility's System or otherwise cause adverse operating effects, as described in Section 3.4.4, and observe the commissioning of the Generating Facility (including any required testing), startup, and operation for a period of up to three (3) Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Utility at least five (5) Business Days prior to conducting any on-site verification testing of the Generating Facility.

2.3.1~~2~~ Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Utility shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

2.3.2~~3~~ Each Party shall be responsible for its own costs associated with following this Article, with the exception of Utility-required inspection and testing described in Section 2.1.3, the costs for which shall be the responsibility of the Interconnection Customer.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as the Interconnection Customer may request and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with Article 3.3 of this Agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Utility 20 Business Days written notice and physically and permanently disconnecting the Generating Facility from the Utility's System.

3.3.2 The Utility may terminate this agreement ~~for~~ upon the Interconnection Customer's failure to timely make the payment(s) required by Article 6.1.1 pursuant to the milestones specified in Appendix 4, or to comply with the requirements of Article 7.1.2 or Article 7.1.3.

3.3.3 Either Party may terminate this Agreement after Default pursuant to Article 7.6.

3.3.4 Upon termination of this Agreement, the Generating Facility will be disconnected from the Utility's System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this Agreement or such non-terminating Party otherwise is responsible for these costs under this Agreement.

3.3.5 The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination, including any remaining term requirements for payment of Charges that are billed under a monthly payment option as prescribed in Article 6.

3.3.6 The provisions of this article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 Emergency Conditions

"Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the Utility, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Utility's System, the Utility's Interconnection Facilities or the systems of others to which the Utility's System is directly connected; or (3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or the Interconnection Customer's Interconnection Facilities.

Under Emergency Conditions, the Utility may immediately suspend interconnection service and temporarily disconnect the Generating Facility. The Utility shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Generating Facility. The Interconnection Customer shall notify the Utility promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Utility's System or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

The Utility may interrupt interconnection service or curtail the output of the Generating Facility and temporarily disconnect the Generating Facility from the Utility's System when necessary for routine maintenance, construction, and repairs on the Utility's System. The Utility shall provide the Interconnection Customer with two~~five~~ (2~~5~~) Business Day notice prior to such interruption. The Utility shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages

During any forced outage, the Utility may suspend interconnection service to effect immediate repairs on the Utility's System. The Utility shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Utility shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects

The Utility shall notify the Interconnection Customer as soon as practicable if, based on Good Utility Practice, operation of the Generating Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Generating Facility could cause damage to the Utility's System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Utility may disconnect the Generating Facility. The Utility shall provide the Interconnection Customer with five (5) Business Day notice of such disconnection, unless the provisions of Article 3.4.1 apply.

3.4.5 Modification of the Generating Facility

The Interconnection Customer must receive written authorization from the Utility before making a Material Modification or any other change to the Generating Facility that may have a material impact on the safety or reliability of the Utility's System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the Utility's prior written authorization, the latter shall have the right to temporarily disconnect the Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Generating Facility, Interconnection Facilities, and the Utility's System to their normal operating state as soon as reasonably practicable following a temporary or emergency disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Appendix 2 of this Agreement. The Utility shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, and the Utility.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Utility's Interconnection Facilities.

4.2 Distribution Upgrades

The Utility shall design, procure, construct, install, and own the Distribution Upgrades described in Appendix 6 of this Agreement. If the Utility and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, on-going operations, maintenance, repair, and replacement, shall be directly assigned to the Interconnection Customer.

Article 5. Cost Responsibility for Network Upgrades

5.1 Applicability

No portion of this Article 5 shall apply unless the interconnection of the Generating Facility requires Network Upgrades.

5.2 Network Upgrades

The Utility shall design, procure, construct, install, and own the Network Upgrades described in Appendix 6 of this Agreement. If the Utility and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Utility elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, on-going operations, maintenance, repair, and replacement shall be borne by the Interconnection Customer.

Article 6. Billing, Payment, Milestones, and Financial Security

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Interconnection Customer shall pay 100% of required Interconnection Facilities and any other charges as required in Appendix 2 pursuant to the milestones specified in Appendix 4.

The Interconnection Customer shall pay 100% of required Upgrades and any other charges as required in Appendix 6 pursuant to the milestones specified in Appendix 4.

Upon receipt of 100% of the foregoing pre-payment charges for Upgrades, the payment is not refundable due to cancellation of the Interconnection Request for any reason.

6.1.2 If implemented by the Utility or requested by the Interconnection Customer in writing within 15 Business Days of the Interconnection Facilities Delivery Date, the Utility shall provide the Interconnection Customer a final accounting report within 120 Business Days addressing any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Utility for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Utility shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Utility within 20 Business Days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Utility shall refund to the Interconnection Customer an amount equal to the difference within 20 Business Days of the final accounting report. If necessary and appropriate as a result of the final accounting, the Utility may also adjust the monthly charges set forth in Appendix 2 of the Interconnection Agreement.

6.1.3 The Utility shall also bill the Interconnection Customer for the costs associated with operating, maintaining, repairing and replacing the Utility's System Upgrades, as set forth in Appendix 6 of this Agreement. The Utility shall bill the Interconnection Customer for the costs of providing the Utility's Interconnection Facilities including the costs for on-going operations, maintenance, repair and replacement of the Utility's Interconnection Facilities under a Utility rate schedule, tariff, rider or service regulation providing for extra facilities or additional facilities charges, as set forth in Appendix 2 of this Agreement, such monthly charges to continue throughout the entire life of the interconnection.

6.2 Milestones

The Parties shall agree on milestones for which each Party is responsible and list them in Appendix 4 of this Agreement. A Party's obligations under this provision may be extended by agreement, except for timing for Payment or Financial Security-related requirements set forth in the milestones, which shall adhere to Section 5.2.4 of the Standards. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, it shall immediately notify the other Party of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) request appropriate amendments to Appendix 4. The Party affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless (1) it will suffer significant uncompensated economic or operational harm from the delay, (2) the delay will materially affect the schedule of another Interconnection Customer with subordinate Queue Position, (3) attainment of the same milestone has previously been delayed, or (4) it has reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements

Pursuant to the Interconnection Agreement Milestones Appendix 4, the Interconnection Customer shall provide the Utility a letter of credit or other financial security arrangement that is reasonably acceptable to the Utility and is consistent with the Uniform Commercial Code of North Carolina. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Utility's Interconnection Facilities and shall be reduced on a dollar-for-dollar basis for payments made to the Utility under this Agreement during its term. In addition:

6.3.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Utility, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

6.3.2 The letter of credit must be issued by a financial institution or insurer reasonably acceptable to the Utility and must specify a reasonable expiration date.

6.3.3 The Utility may waive the security requirements if its credit policies show that the financial risks involved are de minimus, or if the Utility's policies allow the acceptance of an alternative showing of credit-worthiness from the Interconnection Customer.

Article 7. Assignment,Liability, Indemnity, Force Majeure, Consequential Damages, and Default

7.1 Assignment

7.1.1 The Interconnection Customer shall notify the Utility of the pending sale of an existing Generation Facility in writing. The Interconnection

Customer shall provide the Utility with information regarding whether the sale is a change of ownership of the Generation Facility to a new legal entity, or a change of control of the existing legal entity.

7.1.2 The Interconnection Customer shall promptly notify the Utility of the final date of sale and transfer date of ownership in writing. The purchaser of the Generation Facility shall confirm to the Utility the final date of sale and transfer date of ownership in writing

7.1.3 This Agreement shall not survive the transfer of ownership of the Generating Facility to a new legal entity owner. The new owner must complete a new Interconnection Request and submit it to the Utility within 20 Business Days of the transfer of ownership or the Utility's Interconnection Facilities shall be removed or disabled and the Generating Facility disconnected from the Utility's System. The Utility shall not study or inspect the Generating Facility unless the new owner's Interconnection Request indicates that a Material Modification has occurred or is proposed.

7.1.4 This Agreement shall survive a change of control of the Generating Facility' legal entity owner, where only the contact information in the Interconnection Agreement must be modified. The new owner must complete a new Interconnection Request and submit it to the Utility within 20 Business Days of the change of control and provide the new contact information. The Utility shall not study or inspect the Generating Facility unless the new owner's Interconnection Request indicates that a Material Modification has occurred or is proposed.

7.1.5 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Utility, for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will promptly notify the Utility of any such assignment. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof.

7.1.6 Any attempted assignment that violates this article is void and ineffective.

7.2 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, incidental, consequential, or punitive damages of any kind, except as authorized by this Agreement.

7.3 Indemnity

7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 7.2.

7.3.2 The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inaction of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.3.3 If an indemnified Party is entitled to indemnification under this Article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such claim, such indemnified Party may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

7.3.4 If an indemnifying Party is obligated to indemnify and hold any indemnified Party harmless under this Article, the amount owing to the indemnified Party shall be the amount of such indemnified Party's actual loss, net of any insurance or other recovery.

7.3.5 Promptly after receipt by an indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified Party shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

7.4 <u>Consequential Damages</u>

Other than as expressly provided for in this Agreement, neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

7.5 <u>Force Majeure</u>

7.5.1 As used in this article, a Force Majeure Event shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Default

7.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money or provision of Financial Security) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of the other Party. Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in Article 7.6.2, the defaulting Party shall have five (5) Business Days from receipt of the Default notice within which to cure such Default.

7.6.2 If a Default is not cured as provided in this Article, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Agreement.

Article 8. Insurance

8.1 The Interconnection Customer shall obtain and retain, for as long as the Generating Facility is interconnected with the Utility's System, liability insurance which protects the Interconnection Customer from claims for bodily injury and/or property damage. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. This insurance shall be primary for all purposes. The Interconnection Customer shall provide certificates evidencing this coverage as required by the Utility. Such insurance shall be obtained from an insurance provider authorized to do business in North Carolina. The Utility reserves the right to refuse to establish or continue the interconnection of the Generating Facility with the Utility's System, if such insurance is not in effect.

8.1.1 For an Interconnection Customer that is a residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be a standard homeowner's insurance policy with liability coverage in the amount of at least $100,000 per occurrence.

8.1.2 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility no larger than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $300,000 per occurrence.

8.1.3 For an Interconnection Customer that is a non-residential customer of the Utility proposing to interconnect a Generating Facility greater than 250 kW, the required coverage shall be comprehensive general liability insurance with coverage in the amount of at least $1,000,000 per occurrence.

8.1.4 An Interconnection Customer of sufficient credit-worthiness may propose to provide this insurance via a self-insurance program if it has a self-insurance program established in accordance with commercially acceptable risk management practices, and such a proposal shall not be unreasonably rejected.

8.2 The Utility agrees to maintain general liability insurance or self-insurance consistent with the Utility's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Utility's liabilities undertaken pursuant to this Agreement.

8.3 The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

Article 9. Confidentiality

9.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

9.2.3 All information pertaining to a project will be provided to the new owner in the case of a change of control of the existing legal entity or a change of ownership to a new legal entity.

9.3 If information is requested by the Commission from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to the Commission within the time provided for in the request for information. In providing the information to the Commission, the Party may request that the information be treated as confidential and non-public in accordance with North Carolina law and that the information be withheld from public disclosure.

Article 10. Disputes

10.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this Article.

10.2 In the event of a dispute, either Party shall provide the other Party with a written notice of dispute. Such notice shall describe in detail the nature of the dispute.

10.3 If the dispute has not been resolved within 20 Business Days after receipt of the notice, either Party may contact the Public Staff for assistance in informally resolving the dispute. If the Parties are unable to informally resolve the dispute, either Party may then file a formal complaint with the Commission.

10.4 Each Party agrees to conduct all negotiations in good faith.

Article 11. Taxes

11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with North Carolina and federal policy and revenue requirements.

11.2 Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this Agreement is intended to adversely affect the Utility's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

Article 12. Miscellaneous

12.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of North Carolina, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.2 Amendment
The Parties may amend this Agreement by a written instrument duly executed by both Parties, or under Article 12.12 of this Agreement.

12.3 No Third-Party Beneficiaries
This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

12.4 Waiver

12.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

12.4.2.1 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

12.5 Entire Agreement

This Agreement, including all Appendices, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

12.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

12.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. All Utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

Each Party shall notify the other Party, first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

12.11.2 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.3 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

12.12 Reservation of Rights

The Utility shall have the right to make a unilateral filing with the Commission to modify this Agreement with respect to any rates, terms and conditions, charges, or classifications of service, and the Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this Agreement; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before the Commission in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties except to the extent that the Parties otherwise agree as provided herein.

Article 13. Notices

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement (Notice) shall be deemed properly given if delivered in person, delivered by recognized national courier service, sent by first class mail, postage prepaid, or sent electronically to the person specified below:

If to the Interconnection Customer:

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________________ State: ________ Zip: ______

E-Mail Address: ______________________________

Phone: ______________________ Fax: ______________________

If to the Utility:

Utility: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________________ State: ________ Zip: ______

E-Mail Address: ______________________________

Phone: ______________________ Fax: ______________________

13.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below: If to the Interconnection Customer:

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________________ State: ________ Zip: ______

E-Mail Address: ______________________________

If to the Utility:

Utility: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________________ State: ________ Zip: ______

E-Mail Address: ______________________________

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by either Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________ State: ________ Zip: ______

Phone: ______________ Fax: ______________

E-Mail Address: ______________________________

If to the Utility:

Utility: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________ State: ________ Zip: ______

Phone: ______________ Fax: ______________

E-Mail Address: ______________________________

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

Interconnection Customer: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________________ State: ________ Zip: ______

Phone: ______________________ Fax: ______________________

E-Mail Address: ______________________________

Utility's Operating Representative:

Utility: ______________________________

Attention: ______________________________

Address: ______________________________

City: ______________________ State: ________ Zip: ______

Phone: ______________________ Fax: ______________________

E-Mail Address: ______________________________

13.5 Changes to the Notice Information

Either Party may change this information by giving five Business Days written notice prior to the effective date of the change.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Utility

Name:____

Print Name: ____________________________________

Title: ____

Date: __________________

For the Interconnection Customer

Name:____

Print Name: ____________________________________

Title: ____

Date: __________________

Glossary of Terms

See Glossary of Terms, Attachment 1 to the North Carolina Interconnection Procedures.

Interconnection Agreement
Appendix 2

Description and Costs of the Generating Facility, Interconnection Facilities, and Metering Equipment

Equipment, including the Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer, or the Utility. The Utility will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

One-line Diagram Depicting the Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades

This agreement will incorporate by reference the one-line diagram submitted by the Customer on __________________________ , dated ____________________, with file name "___________________________" as part of the Interconnection Request, or as subsequently updated and provided to the Company.

Milestones

Requested Upgrade In-Service Date: ____________

Requested Interconnection Facilities In-Service Date __________

~~For an Interim Interconnection Agreement, this Appendix 4 is null and void.~~

Critical milestones and responsibility as agreed to by the Parties:

The build-out schedule does not include contingencies for deployment of Utility personnel to assist in outage restoration efforts on the Utility's system or the systems of other utilities with whom the Utility has a mutual assistance agreement. Consequently, the Requested In-service date may be delayed to the extent outage restoration work interrupts the design, procurement and construction of the requested facilities.

	Milestone	Completion Date	Responsible Party
1)			
2)			
3)			
4)			
5)			
6)			
7)			
8)			
9)			
10)	Expand as needed		

Signatures on next page

Interconnection Agreement
Appendix 4

Agreed to for the Utility

Name: ____

Print Name: ______________________________________

Date: ______________________

Agreed to for the Interconnection Customer

Name: ______________________________________

Print Name: ______________________________________

Date: ______________________

Interconnection Agreement
Appendix 5

Additional Operating Requirements for the Utility's System and Affected Systems Needed to Support the Interconnection Customer's Needs

The Utility shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the Utility's System.

Interconnection Agreement
Appendix 6

Utility's Description of its Upgrades and Best Estimate of Upgrade Costs

The Utility shall describe Upgrades and provide an itemized best estimate of the cost, including overheads, of the Upgrades and annual operation and maintenance expenses associated with such Upgrades. The Utility shall functionalize Upgrade costs and annual expenses as either transmission or distribution related.

Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC
Rebuttal Testimony of John W. Gajda

Rebuttal Exhibit JWG-2

Duke Energy Distributed Energy Resource Method of Service Guidelines

Contents

1 DEC and DEP obligations 3
2 Interconnection to the transmission system or distribution system 4
2.1 Interconnection method as dictated by DER capacity 4
2.1.1 Consideration of individual DER capacity 4
2.1.2 Consideration of aggregate utility-scale DER capacity (per distribution circuit and per retail substation) 6
2.2 Interconnection to a general distribution circuit: method “D” 7
2.2.1 Considerations & alternatives 7
2.2.1.1 System upgrades: distribution and retail substation 7
2.2.1.2 Alternatives when facilities cannot be further upgraded 7
2.3 Interconnection: direct connection to a retail substation: method “S” 8
2.3.1 Limiting impacts to the transmission system 8
2.3.2 Considerations & alternatives 8
2.3.3 Special notes 9
2.4 Interconnection to the transmission system: method “T” 10
3 Other interconnection project study and design guidelines 11
3.1 Applicability of double circuits for DER 11
3.2 Interconnection locations beyond line voltage regulators (LVRs) 12
3.2.1 DEC and DEP: “Planned” LVR locations previously identified 12
3.2.2 DEP only: continuous system maintenance of DSDR circuit voltage criteria 13
3.2.3 Smart Inverter functionality 13
3.2.4 Clarifications on “partial double circuits” 13
3.2.5 Certain DERs exempt 14
3.3 Line extensions on new ROW 15
3.3.1 Distribution line construction and ownership by private entities 15
3.4 Circuit Stiffness Review (CSR) screen & evaluation 16
3.4.1 Exempted projects 17
3.4.2 Evaluation criteria & methodology 17
3.4.2.1 POI stiffness evaluation 17
3.4.2.2 Substation bus stiffness evaluation 18

4 Glossary of terms 19

5 Revision history 20

1 DEC and DEP obligations

DEC and DEP (Companies) comply with their interconnection obligations under PURPA[1] and applicable state laws by adhering to the North Carolina Interconnection Procedures approved by the North Carolina Utilities Commission (effective May 15, 2015, Docket No. E-100, Sub 101, the "NCIP")) and the South Carolina Generator Interconnection Procedures approved by the South Carolina Public Service Commission (effective April 24, 2016, Case No. 2015-362-E, the "SCGIP")). Consistent with those standards and procedures, the Companies determine and apply technical interconnection guidelines through the administration of Good Utility Practice.[2]

DEC and DEP consider all necessary system upgrades to the general electrical system that are required in order to provide distributed energy resources (DER) reasonable and non-discriminatory access to the DEC and DEP distribution systems, the primary purpose of which is to serve existing and future retail customers. As firm retail electric providers, DEC and DEP seek to interconnect DER in a manner that allows each resource to operate within its contractual parameters without negatively impacting existing utility customers' quality of service or cost of service. DEC and DEP are not, however, obligated under the NCIP or SCGIP to make modifications that are, or reasonably could be determined to be, detrimental to the operation of its system or detrimental to DEC's and DEP's public service obligations as regulated public utilities or retail electric service providers.

[1] Public Utility Regulatory Policy Act of 1978.
[2] Good Utility Practice is defined in the NCIP and SCGIP as any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

2 Interconnection to the transmission system or distribution system

2.1 Interconnection method as dictated by DER capacity

2.1.1 Consideration of individual DER capacity

In most cases, the electrical size (in MW) of a generator interconnection is the primary consideration, all factors considered, as to whether it makes sense to interconnect to the distribution system or to the transmission system. This section's guidelines are intended to more quickly guide interconnection projects to the proper method of interconnection and system at which to interconnect, based on a consideration of the factors involved: (1) impacts to transmission & distribution system reliability/power quality, (2) operational ease and flexibility for the utility, and (3) overall cost (in general, project developers bear all or most up-front costs). Exceptions can be made, but only when a specific project's characteristics and impacts do not fit well into these guidelines, and the optimal balance of factors are the primary consideration.

Table 1 provides general guidance as to the proper method of interconnection.

TABLE 1: Interconnection method based on size of facility

Interconnection method	Interconnection facility (MW) (lower limit)	Interconnection facility (MW) (higher limit)	Guideline for system/ interconnection point
T[3]	> 20 MW	--	transmission system
S	> 10 MW (25 kV or 35 kV class) > 6 MW (15 kV class) > 3 MW (where local retail distribution substation is served from 44 kV sub-transmission)	≤ 20 MW	direct connection to a retail substation[4]
D	--	≤ 10 MW (25 kV or 35 kV class) ≤ 6 MW (15 kV class) ≤ 3 MW (where local retail distribution substation is served from 44 kV sub-transmission) ≤ 2 MW (5 kV class)[5]	general distribution circuit

[3] Method "T" interconnections are specifically guided by DEC's or DEP's appropriate FCR (Facility Connection Requirements) documents, which are accessible at DEC's and DEP's OASIS sites (oasis.oati.com/duk/ and oasis.oati.com/cpl/).
[4] In general, due to the existence of legacy terminology across operating areas, a "retail substation" is the term used within DEC to describe a substation which serves general retail distribution loads from circuits connected to the substation's distribution bus. In this document, the term "retail substation" will be used to describe this type of substation, which in DEP is often called a "T/D" or "T to D" substation.
[5] Interconnections at 5 kV, above 2 MW, are not permitted. Such facilities must interconnect at a higher voltage class.

2.1.2 Consideration of aggregate utility-scale DER capacity (per distribution circuit and per retail substation)

Aggregate capacity of distribution-connected utility-scale projects[6], per distribution circuit, shall not exceed the planning capacity of that circuit. Aggregate capacity of distribution-connected utility-scale projects, per retail substation, shall not exceed the capacity of that substation, as defined by the (1) nameplate capacity[7] of the substation transformer bank or (2) the capacity of other substation components, whichever is less.

Calculation of aggregate capacity of DER on a substation or a circuit shall not include the types of facilities shown in Table 2, nor shall interconnection of the following facilities be subject to aggregate capacity limitations on the circuit or substation.

This requirements may change in the future as DER planning guidelines further mature.

TABLE 2: DERs exempt from aggregate capacity limitations on the circuit or substation

<table>
<tr><th></th><th>Tariff</th><th>Individual DER capacity[8]</th><th>Aggregate DER capacity per circuit, segment or regulated zone</th></tr>
<tr><td>Exemption #1</td><td>Net Metered</td><td>Up to 1 MW</td><td rowspan="4">The aggregate DER capacity for the first regulated zone of the circuit (substation bus regulation or circuit exit regulation) is limited to the circuit planning capacity or other lesser value as determined in the Supplemental Review or System Impact Study.

The aggregate DER capacity for further regulated zones (beyond any LVRs) is limited to that which does not cause backfeed of the line voltage regulator. [9] [10] [11]</td></tr>
<tr><td>Exemption #2</td><td>Sell Excess</td><td>Up to 1 MW</td></tr>
<tr><td>Exemption #3</td><td>PPA with co-located load on secondary of transformer</td><td>Up to 1 MW</td></tr>
<tr><td>Exemption #4</td><td>PPA, stand-alone</td><td>Up to 250 kW[12] [13]</td></tr>
</table>

[6] For the purposes of these requirements, utility-scale projects are defined as utility-scale/sell-all DER which do not meet the “exempt” definitions in Table 2.

[7] For the purposes of this document, “nameplate capacity” refers to the “OA” or “ONAN” rating, typically the MVA rating upon which the transformer percent impedance is based.

[8] If a single-phase DER facility > 20 kW causes unacceptable imbalance on any portion of the distribution circuit, the interconnection may be deemed infeasible for a single-phase interconnection and may be required to alter its design to three phase.

[9] Note that for South Carolina, there are reserved circuit capacities for individual DER ≤ 20 kW, detailed in section 2.1 of the South Carolina Interconnection Standards (effective 4/26/2016). Such DER will be also deemed exempt from all considerations, including backfeed of an existing LVR, and the cost of any associated studies or upgrades for DER included as part of these reserved circuit capacities are the responsibility of DEC and DEP.

[10] DEC and DEP will employ reasonable methods, as determined by internal engineering resources responsible for performing interconnection studies, and subject to change, to identify the high-level potential for backfeed at the time of the interconnection request under review. When such a potential is suspected, a Supplemental Review or System Impact Study shall be performed in order to determine if backfeed may occur under any circuit loading conditions.

[11] When backfeed is identified in the Supplemental Review or System Impact Study, for exempt sites as identified in this table, DEC/DEP Distribution management and DET (Distributed Energy Technologies) management shall be made aware and shall confer and decide as to the proper disposition of the project(s) in question.

[12] “PPA” facilities ≥ 250 kW are considered the low end of “utility-scale” facilities, and, for purposes of these guidelines, present the potential for significant impact on a distribution circuit.

[13] IEEE 1547-2003, section 4.1.6, requires DER ≥ 250 kVA at a single PCC (Point of Common Coupling) to have monitoring provisions for its status, real and reactive power flow and voltage. Duke Energy requires such

2.2 Interconnection to a general distribution circuit: method "D"

This size of interconnection as indicated in Table 1 should generally be accommodated onto the general distribution system, at the most logical interconnection point consistent with optimizing the factors of reliability, operational ease and flexibility for the utility, and overall cost, and subject to other considerations in this document related to distribution interconnections.

2.2.1 Considerations & alternatives

2.2.1.1 System upgrades: Distribution and retail substation

The System Impact Study (SIS) shall identify and detail the electric system impacts that would result if the proposed generating facility were interconnected without project modifications or electric system modifications. The SIS shall evaluate the impact of the proposed interconnection on the reliability of the electric system, including the distribution and transmission systems, if required. The SIS shall include identification of system upgrades required to correct any system problems identified.

When performing a SIS for a method "D" interconnection, DEC or DEP, as applicable, will consider (among other mitigation options) necessary upgrades to existing retail substation facilities, upgraded to their maximum standard design criteria.

For method "D" interconnections, any extension of distribution facilities to connect DER facilities cannot be "dedicated" by their nature and must be constructed consistent with the DEC or DEP Line Extension Plan and with other practices consistent with DEC or DEP standard distribution system design. The interconnection recloser and meter must both be located at the POI (at the point of change in ownership of facilities).

Interconnection Customers can consider constructing their own lines; such lines would be completely owned, operated and maintained by the Interconnection Customer. The POI would remain at the point of change in ownership of facilities.

2.2.1.2 Alternatives when facilities cannot be further upgraded

If local distribution facilities and/or retail substation facilities cannot be sufficiently further upgraded in order to accommodate the proposed generating facility, then the remaining alternative for the Interconnection Customer is:

1. New retail substation (along with necessary transmission facilities to serve the substation) and general distribution facilities, constructed by Duke Energy, to serve the requested point of interconnection. This can only be considered if this would be consistent with area planning needs and any other specific constraints associated with local transmission and distribution infrastructure (which cannot be pre-determined). Distribution lines can also be designed and constructed by the Interconnection Customer, at their option.

monitoring per this capacity criteria, as this size of DER facility is consistent with more noticeable impacts to distribution planning and operations in both DEC and DEP.

2.3 Interconnection: direct connection to a retail substation: method “S”

2.3.1 Limiting impacts to the transmission system

It should be noted that DEC/DEP maintains the right to limit the total number of taps on a transmission line when DEC/DEP has determined they may grow to be too great in number for that transmission line. In such a case, DEC/DEP may propose alterations to the local area transmission infrastructure in order to get back to a higher reliability arrangement, whatever that may be. The options available for facilities within this size range will be highly impacted by the specific transmission & distribution facilities in the area.

These considerations are guidelines; DEC and DEP maintain full discretion as to the ultimate method of interconnection.

2.3.2 Considerations & alternatives

There are three primary methods for interconnections within this category: (1) connection to an existing nearby retail substation, (2) connection to an existing nearby retail substation along with an additional transformer installation, or (3) construction of a new general retail substation:

(1) Connection to an unregulated bus at an existing nearby retail substation, utilizing a DER-dedicated distribution circuit and associated dedicated circuit breaker. This would involve substation modifications, and may not always be available if (a) there are no available breaker positions, (b) if some breaker positions are in place for area load growth, or (c) where substation rebuild options do not include the establishment of an accessible unregulated bus. The assessment of the feasibility of this overall method and its options are at the discretion of transmission planning, substation engineering, and/or distribution planning. If this method is not deemed feasible, then the remaining two options below can be considered.

(2) Connection to a new unregulated bus established with an additional substation transformer at an existing substation, utilizing a DER-dedicated distribution circuit and associated dedicated circuit breaker. (Note: such an expansion shall be built to normal general retail substation standards, only where a second transformer and distribution voltage shall match that of the local operating voltage of the surrounding circuits so that the substation transformer could remain possibly available for general distribution load currently or in the future if the DER facility were to shut down. Essentially this should be treated like a normal substation expansion with an additional transformer, assuming such expansion can be feasibly done.)

(3) Connection to a new unregulated bus established at a new retail substation, utilizing a DER-dedicated distribution circuit and associated dedicated circuit breaker. (Note: such a substation shall be built to normal general retail substation standards, and distribution voltage shall match that of the local operating voltage of the surrounding circuits so that the substation transformer could remain possibly available for general distribution load currently or in the future if the DER facility were to shut down.) In such a situation, note that transmission system reliability considerations may require alterations or reconfigurations to the local transmission system infrastructure, at the generator’s cost, in order to maintain overall system reliability.

2.3.3 Special notes

(1) For method "S" interconnections, extension of distribution voltage class lines from the POI back to substation facilities shall be dedicated by nature, meaning that they are only in place to serve one or more DER interconnections. While Duke Energy can offer to construct such dedicated lines, the Interconnection Customer can also elect to construct a portion or all of the line required.

(2) Note that any DER-dedicated Duke-owned distribution circuit would be likely limited in capacity to no more than 600 amps, and possibly less, due to prevailing available construction methods on general distribution. This could limit 15 kV class interconnection capacity to ~13 MW or less, and could present unique challenges in connecting facilities in the approximate range of 13 MW to 20 MW when substation designs must utilize 15 kV class due to the prevailing distribution voltages in the area.

(3) DER-dedicated circuits constructed and owned by Duke Energy and installed for generation may be built to slightly different standards than conventional "greenfield new general distribution circuits," if their design allows more capacity by slight changes such as increased pole height (with associated increased phase to neutral spacing) and/or reduced span lengths. In no case should the circuit design parameters exceed the ability for Duke Energy distribution field crews to maintain the line. This means that pole height, conductor size, etc., must be maintained within expected usual maximums for distribution field crews to be able to provide effective maintenance services.

(4) At the discretion of transmission and/or distribution planning, an interconnection directly to an unregulated bus can be required to be set at (a) fixed power factor, at unity or off of unity, or (b) active voltage regulation.

2.4 Interconnection to the transmission system: method "T"

Note: method "T" interconnections are specifically guided by DEC's or DEP's appropriate FCR (Facility Connection Requirements) documents, which are accessible at DEC's and DEP's OASIS sites (oasis.oati.com/duk/ and oasis.oati.com/cpl/).

3 Other interconnection project study and design guidelines

3.1 Applicability of double circuits for DER

In general, construction of full or partial "double circuits" (multiple three-phase circuits on one set of poles in a single right of way (ROW)) for line extension to a DER site is not considered Good Utility Practice, whether the consideration is the location of line voltage regulators (LVRs) or some other factor. The inherent ROW present for a second circuit in an existing single-circuit line is a key part of DEC's and DEP's area planning approach for the transmission & distribution system, as part of the Companies' continuous obligation to serve current and future retail customers. Any double-circuiting of an existing single-circuit line must be installed only as part of a comprehensive long-term plan to serve area load. Such double-circuiting cannot be installed solely as a DER interconnection solution, as doing so would impair DEC's and DEP's area planning obligations.

3.2 Interconnection locations beyond line voltage regulators (LVRs)

DEC and DEP have identified that interconnection of uncontrolled[14] utility-scale[15] generation resources with no dependable capacity,[16] at locations beyond LVRs and in high quantities across an entire system, is not consistent with Good Utility Practice. At high quantities across an entire system, facilities with the aforementioned attributes are more naturally adapted to the first zone of regulation outside the substation. Interconnection of such facilities beyond LVRs will likely require non-standard LVR settings, which can (1) limit the switching flexibility of the distribution system, (2) inhibit the effective management of circuits in certain operating areas if regulator control technologies for backfeed are not yet an accepted and tested practice, and/or (3) negatively impact the measured effectiveness of some volt/var control systems such as DEP's DSDR[17] system. Alternatively, interconnection of such facilities beyond LVRs will likely require operation of generating facilities in a reactive power absorption mode, which is not compatible with some volt/var optimization systems and would require further consideration for the impacts to the transmission system if done at wide scale. Therefore, DEC and DEP have established technical guidelines that restrict location of uncontrolled utility-scale generation with no dependable capacity, as referenced and defined above, to the first regulated zone of distribution circuits (substation bus regulation or circuit exit regulation).

3.2.1 DEC and DEP: "Planned" LVR locations previously identified

In some cases, a DEC or DEP Distribution Capacity Planning five-year load-growth study may have already been performed and completed (without having yet been field implemented) prior to the date the Interconnection Customer executes the SIS Agreement to initiate the SIS. In such cases, if such Capacity Planning study had identified changes in LVR placement on the circuit, the planned LVR placement(s) for the circuit (rather than what is currently installed) will be included as part of the SIS. Interconnection locations beyond such planned LVRs will be considered equivalent to interconnection locations beyond existing LVRs. Upon request, DEC or DEP will provide a load-growth study summary with the recommended planned LVR location to the DER interconnection customer.

If no such planning study recommendation pre-dates the initiation of the SIS, and there are no LVR placement changes identified as part of DSDR continuous system maintenance (DEP only, see below), the SIS will only consider the location of any existing LVRs as part of the project study.

[14] "Uncontrolled" means that the facility output (MW) is not capable of being dispatched in a throttled manner by the grid operator.
[15] For the purposes of this document, "utility-scale" generally refers to stand-alone generation facilities (not directly co-located with load) 250 kW or larger.
[16] "No dependable capacity" means that the facility cannot be relied upon for production of a value of capacity (MW) for a specified period or when dispatched.
[17] Distribution System Demand Response.

3.2.2 DEP only: continuous system maintenance of DSDR circuit voltage criteria

The DSDR system in DEP requires adherence to specific circuit voltage criteria in order to maintain system performance. The condition of the circuit and its ability to meet the needed voltage criteria is reviewed as part of the Companies' distribution planning function, whether it is for a regular capacity planning study, for addition of a large "spot load" (commercial or industrial customer), or any other reason to study a circuit.

If during the SIS (the scope of which considers voltage levels on the entire circuit) there is a need identified for LVR placement changes in order to maintain DSDR system performance, the SIS shall include such LVR placement changes and associated cost responsibility in its scope. The cost of such LVR placement changes will only be cost assigned to the interconnection customer if the interconnection creates the need for the LVR placement changes.

Any LVR placement change(s) identified for the circuit (rather than what is currently installed) will be included as part of the assumed "current condition of the circuit" when the SIS if performed. Interconnection locations beyond the LVRs identified pursuant to this subsection will be considered equivalent to interconnection locations beyond existing LVRs, and the study will treat the identified LVR as an existing LVR under these guidelines. Upon request, DEP will provide a study summary with the required LVR placement changes to the DER interconnection customer.

3.2.3 Smart Inverter functionality

It is important to note that at this time DEC and DEP do not assume that generating facilities are capable of modification(s) to their operating characteristics (e.g., "smart inverter functions" such as volt-watt functions, voltage regulation functions, etc.). These modified operating characteristics are under consideration for future adoption by DEC and DEP, but are still considered technologies not yet fully embraced by industry standards and not yet as widely accepted Good Utility Practice. Moreover, use of these functions involves many other considerations, such as impacts to energy production (which in turn has contractual impacts), additional protection & control requirements, utility-to-customer control interface requirements, etc.

3.2.4 Clarifications on "partial double circuits"

When considering the restriction of connection of certain generating facilities below LVRs, it may appear that construction of a "partial double circuit" from the generation site back up to a location ahead of the LVR would facilitate the interconnection. However, as discussed above, the inherent ROW present for a second circuit in an existing single-circuit line is a key part of DEC's and DEP's area planning approach for their transmission & distribution systems, as part of the Companies' continuous obligation to serve current and future retail customers. Any double-circuiting of such a line can only occur as part of a comprehensive plan to serve area load, and cannot be installed solely an incremental consideration for an interconnection project.

3.2.5 Certain DERs exempt

It is important to note that certain DER sites are exempt from restriction to the first regulated zone of distribution circuits, and are therefore allowed to locate beyond LVRs:

TABLE 3 – DERs exempt from LVR guidelines

<table>
<tr><th></th><th>Tariff</th><th>Individual DER capacity[18]</th><th>Aggregate DER capacity per circuit, segment or regulated zone</th></tr>
<tr><td>Exemption #1</td><td>Net Metered</td><td>Up to 1 MW</td><td rowspan="4">The aggregate DER capacity for the first regulated zone of the circuit (substation bus regulation or circuit exit regulation) is limited to the circuit planning capacity or other lesser value as determined in the Supplemental Review or System Impact Study.

The aggregate DER capacity for further regulated zones (beyond any LVRs) is limited to that which does not cause backfeed of the line voltage regulator. [19] [20] [21]</td></tr>
<tr><td>Exemption #2</td><td>Sell Excess</td><td>Up to 1 MW</td></tr>
<tr><td>Exemption #3</td><td>PPA with co-located load on secondary of transformer</td><td>Up to 1 MW</td></tr>
<tr><td>Exemption #4</td><td>PPA, stand-alone</td><td>Up to 250 kW[22] [23]</td></tr>
</table>

[18] If a single-phase DER facility > 20 kW causes unacceptable imbalance on any portion of the distribution circuit, the interconnection may be deemed infeasible for a single-phase interconnection and may be required to alter its design to three phase.

[19] Note that for South Carolina, there are reserved circuit capacities for individual DER ≤ 20 kW, detailed in section 2.1 of the South Carolina Interconnection Standards (effective 4/26/2016). Such DER will be also deemed exempt from all considerations, including backfeed of an existing LVR, and the cost of any associated studies or upgrades for DER included as part of these reserved circuit capacities are the responsibility of DEC and DEP.

[20] DEC and DEP will employ reasonable methods, as determined by internal engineering resources responsible for performing interconnection studies, and subject to change, to identify the high-level potential for backfeed at the time of the interconnection request under review. When such a potential is suspected, a Supplemental Review or System Impact Study shall be performed in order to determine if backfeed may occur under any circuit loading conditions.

[21] When backfeed is identified in the Supplemental Review or System Impact Study, for exempt sites as identified in this table, DEC/DEP Distribution management and DET (Distributed Energy Technologies) management shall be made aware and shall confer and decide as to the proper disposition of the project(s) in question.

[22] "PPA" facilities ≥ 250 kW are considered the low end of "utility-scale" facilities, and, for purposes of these guidelines, present the potential for significant impact on a distribution circuit.

[23] IEEE 1547-2003, section 4.1.6, requires DER ≥ 250 kVA at a single PCC (Point of Common Coupling) to have monitoring provisions for its status, real and reactive power flow, and voltage. Duke Energy requires such monitoring per this capacity criteria, as this size of DER facility is consistent with more noticeable impacts to distribution planning and operations in both DEC and DEP.

3.3 Line extensions on new ROW

In situations where a line extension is necessary, such as when a DER is located beyond an existing LVR, or is simply located far from existing facilities, DEC or DEP will propose construction of a line extension to connect the site to the circuit at the most logical point on the circuit considering reliability, voltage, capacity, operational considerations, and cost, consistent with Good Utility Practice.[24] DEC or DEP will be responsible for design and construction of the non-dedicated (method "D") or DER-dedicated (method "S") line. The POI will be at the point of change in facilities ownership (at the generator site). DEC or DEP must initially attempt acquisition of ROW. In the event DEC or DEP are unable to acquire ROW during the Facilities Study design process, DEC or DEP will advise the DER owner to assume the obligation for ROW acquisition. Any such ROW shall comply with applicable DEC and DEP ROW specifications.

3.3.1 Distribution line construction and ownership by private entities

If the DER owner requests to build, own, and maintain the line from the circuit tap (as decided by DEC or DEP) to the DER, DEC or DEP will allow the DER owner to pursue this option. In such a situation, the POI will be at the point of change in facilities ownership, at the circuit tap. The DER owner is required to always build all medium voltage (MV) facilities (> 600 volts AC) with DEC/DEP construction and ROW specifications used as the minimum design standard, and all DER owner-constructed-and-owned MV facilities will be inspected by DEC/DEP or its authorized inspection contractor.

[24] If an LVR location is the consideration, the circuit "tap" will be ahead of the LVR location, along with all of the other considerations stated.

3.4 Circuit Stiffness Review (CSR) screen & evaluation

As part of the interconnection process, the SIS is designed to analyze the impact of interconnecting the proposed facility on electric system reliability and the potential for negative impacts to other customers on the system. Effective for all distribution system interconnection requests (except for those noted in the "exemptions" section), Duke Energy will identify (1) areas of high penetration/low grid stiffness[25] through a stiffness factor evaluation, in order to assure that the location of future interconnections do not detrimentally impact power quality and grid operations.

The stiffness factor takes into account the actual equivalent system impedance at the point of interconnection and the relative size of the generation source. It is intended to be an indicator of the potential impacts an individual project may have on the system voltage variability, harmonics impacts, and other related items at its point of interconnection in light of the strength or weakness of the system at that point. A small ratio indicates that the project individually represents a relatively large share of the total short circuit capability at the project site and, by inference, may have an outsized influence at that location across a number of factors. A low stiffness factor will also accentuate local impacts and can cause inverters to be sensitive to normal distribution system operations, such as capacitor bank operations.

The stiffness factor criterion also helps to evaluate the potential for unknowns that may occur in "high penetration" scenarios of utility-scale facilities on the localized distribution system. As of mid-2016, industry technical standards have not yet been developed for high penetration of large distributed generators and North Carolina is seemingly unique in the level of large utility-scale interconnections (especially at 5 MW) interconnecting to the rural distribution system. Such facilities are not necessarily designed for high penetration/low stiffness interconnections, especially when such facilities cannot yet be expected to operate in a voltage regulating mode.[26]

At this time, failure of the CSR evaluation screen is simply designed to trigger a slightly more rigorous study into two types of harmonics: steady-state harmonics and the transient impacts of transformer energization (when the DER facility connects back to the circuit after any time it has been disconnected). This is known informally as "Advanced Study" and is part of the overall SIS (System Impact Study) process.

[25] Stiffness factor, also known as "stiffness ratio," is defined in IEEE Std 1547.2™-2008, IEEE Application Guide for IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems: "The relative strength of the area EPS at the PCC compared with the DR, expressed in terms of the short-circuit kilovolt-amperes of the two systems. The general term "stiffness" refers to the ability of an area EPS to resist voltage deviations caused by DR or loading."

[26] Integrated volt/var control systems are not yet compatible with DER operation in a voltage regulating mode. Also, industry practices involving DER operation in a voltage regulating mode, on the distribution system, are clearly not mature at this time. The current IEEE 1547 standard generally prohibits such practice.

3.4.1 Exempted projects

In general, the following situations are to be exempted from the stiffness evaluation:

TABLE 4 – DERs exempt from CSR evaluation

	Tariff	Individual DER capacity
Exemption #1	Net Metered	Up to 1 MW
Exemption #2	Sell Excess	Up to 1 MW
Exemption #3	PPA with co-located load on secondary of transformer	Up to 1 MW
Exemption #4	PPA	Up to 1 MW[27]

3.4.2 Evaluation criteria & methodology

Proposed generator interconnection requests will be reviewed at the outset of the Section 4.3 SIS process to determine whether the project can (1) achieve a minimum POI "stiffness factor" of 25 (as further described below) and (2) achieve a minimum substation "stiffness factor" of 25 (as further described below), in order to pass this screen.

This stiffness evaluation will be performed at two locations – at the POI and at the substation.

3.4.2.1 POI Stiffness Evaluation

At the POI, this evaluation will be performed. A POI Stiffness Factor of exactly 25 or greater (no rounding) for the individual site will be considered as a "pass" for this screen.

$$\text{POI Stiffness Factor} = \frac{\text{Short circuit availability at POI (MVA) without any DER contribution}}{\text{specific DER facility maximum export (MW)}^{28}}$$

EXAMPLE: A 5 MW DER requests to interconnect on a 12.47 kV feeder.[29] The available fault current at the planned POI, at 12.47 kV, is 6,500 amps. The POI Stiffness Factor is:

$$SF_{POI} = \frac{\sqrt{3} \times 12.47 \times 6500 \div 1000}{5} = 28.08$$

28.08 > 25, so this would pass the "POI" portion of the CSR screen.

NOTE: POI Stiffness shall be calculated at the POI (high-voltage side of transformer) for utility-scale DER with a single transformer dedicated to the facility.

[27]The impacts of switching large blocks of transformer capacity onto the utility system are more of an issue when interconnection reclosers are present, which is generally for DERs ≥ 1 MW. Since this is the primary issue of concern studied when the CSR evaluation indicates lower stiffness, CSR does not have to be evaluated for DERs < 1 MW.
[28] The value of the DER capacity shall be the Requested Maximum Physical Export Capability at the POI.
[29] Note that the exact nominal distribution voltage should be used in the calculation of utility short-circuit MVA.

3.4.2.2 Substation bus Stiffness Evaluation

In addition, a separate evaluation will be performed at the substation bus with respect to all utility-scale DER connected to the substation, including the proposed DER. A substation bus stiffness factor of exactly 25 or greater (no rounding) will be considered as a "pass" for this screen.

$$\text{Substation Stiffness Factor} = \frac{\text{Short circuit availability at substation bus (MVA) without any DER contribution}}{\text{Total facility maximum export,connected beyond substation (MW)}^{30}}$$

EXAMPLE: A 5 MW DER wants to interconnect on a 12.47 kV feeder. There is already 2 MW of utility-scale DER off of this substation. The available fault current at the substation bus, at 12.47 kV and without contribution from DER, is 8,000 amps. The Substation Stiffness Factor is:

$$SF_{substation} = \frac{\sqrt{3} \times 12.47 \times 8000 \div 1000}{7} = 24.68$$

24.68 < 25, so this would not pass the "Substation" portion of the CSR screen.

[30] The value of the total DER capacity beyond the substation shall be the sum of the Requested Maximum Physical Export Capability for all non-exempt DER sites.

4 Glossary of terms

Non-dedicated distribution line or circuit: This is a distribution circuit which is designed to serve any common class of distribution customer: residential, commercial, industrial and DER. Such a circuit must be designed to +/- 5% voltage so as to assure that existing or future residential customers are assured of proper voltage levels.

DER-dedicated distribution line/circuit: In the context of this document, this refers to a distribution voltage class circuit that is built strictly for DER facilities; no other class of customer is to be located on this circuit. Such a circuit is allowed to be designed to +/- 10% voltage and can be used for DER interconnections only. Due to the unique nature of DER and the flows on this line, this line shall NOT be used for commercial or industrial customers (who normally might be tolerant of +/- 10% voltage).

5 Revision history

Revision	Date	Comments
1.0	9/11/2017	Initial release
1.1	9/20/2017	(a) Clarified that "S" interconnection is inclusive of 20 MW; "T" interconnection is for > 20 MW. (b) Changed Table 4 to indicate that sites are exempt from CSR evaluation below 1 MW. (c) Changed header title to read "DEC & DEP: Distributed Energy Resource (DER) Planning & Interconnection guidelines for DER no larger than 20 MW."
1.2	10/13/2017	Changed document title to "DEC & DEP: October 2017 Distributed Energy Resource (DER) Method Of Service guidelines for DER no larger than 20 MW." Also, "MVA" changed to "MW" in Table 1, as this is mostly a distribution system document, and this MW value is the value that corresponds to the Maximum Physical Export Capability Requested in the Interconnection Request.
1.21	11/01/2017	Clerical and grammatical errors addressed.

Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC
Rebuttal Testimony of John W. Gajda

Rebuttal Exhibit JWG-3

Duke Energy's "Carolinas TSRG Updates" Website

Carolinas TSRG Updates

Welcome to the central resource page for the Duke Energy Distributed Energy Resource (DER) Interconnection Technical Standards Review Group (TSRG). This TSRG was initiated by Duke Energy to bring together Duke Energy engineers with technical personnel of DER developers and installers actively involved in interconnection projects in Duke Energy Carolinas and Duke Energy Progress, in both North Carolina and South Carolina.

TSRG Documents

- Duke Energy Carolinas / Duke Energy Progress Interconnection TSRG – Structure and inaugural meeting agenda

Duke Energy Technical Standards

- Method of Service Guidelines
- Service Requirements Manual (sometimes called the "White Book"; contains Distribution System interconnection requirements)
- Transmission System, Generator Interconnection Requirements

Interconnection Commissioning Technical Training

- Training Presentation, 7-17-2018
- Distribution Standards Reference Guide, Version 4

End-of-Year Commissioning Guidelines, 2018

- Conditional Commissioning Process, Version 1
- Duke Energy PV Interconnection Commissioning, Version 5
- Commissioning Guidelines, Revision 1

Meetings

Meeting 3 (October 22, 2018)

Duke Energy Regional Headquarters Building, Raleigh, North Carolina

- Minutes and attendance
- Agenda
- Presentation – Limits to Voltage Disturbances Due to Inrush
- Presentation – Mitigation Options Overview
- Presentation – Determining Risk of Unintentional Islanding
- Reference – Volt/VAR Management and the Impact of DER

Meeting 2 (July 19, 2018)

Duke Energy Regional Headquarters Building, Raleigh, North Carolina

- Minutes and attendance
- Agenda
- Presentation – Salesforce/PowerClerk Update
- Presentation – Inverter-Based Resource Disturbance Analysis
- Presentation – Modeling Solar Generation in Transmission Studies

Meeting 1 (April 11, 2018)

Duke Energy Regional Headquarters Building, Raleigh, North Carolina

- Minutes and attendance
- Agenda
- Presentation – Transformer energization impact studies
- Presentation – DER interface device development
- Presentation – commissioning process
- Distribution-connected DER: clarifications on engineering standards and study criteria, DEC & DEP

Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC
Rebuttal Testimony of John W. Gajda

Rebuttal Exhibit JWG-4

NCSEA Response to DEC/DEP Data Request 2-18

Duke Energy
Docket No. E-100, Sub 101
NC Interconnection Standard
Duke Data Request No. 2
Item No. 2-18
Page 1 of 1

NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

Request:

Referring to your statement on Page 6, Lines 15-17, please identify any examples of which you are aware where DEC or DEP has relied upon the CSR system impact evaluation as "denying interconnection outright" without proposing any mitigation options to cure identified interconnection issues.

Response:

Objection. This request seeks confidential and proprietary business information which is irrelevant to the underlying proceeding. Further clarifying, this Request seeks information from "you" and "your" which Duke has defined as including both NCSEA and its witness, Paul Brucke. To the extent that NCSEA is answering with regard to Witness Brucke's testimony or background, the "you" or "your" referenced are specific to Witness Brucke.

Subject to said objections, and without waiving same, NCSEA and Witness Brucke state as follows:

Witness Brucke has not seen examples where Duke did not propose mitigation options but has seen many instances where the mitigation options are financially impractical. For example, if a project is not allowed to interconnect to a distribution feeder as requested, Duke may propose that a new substation be built, and the project connect to the transmission system, which generally would not be financially feasible for a typical 5 MW project. In these instances, Duke denies the requested interconnection and is proposing an interconnection that the interconnection customer did not request or consider as an option.