BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 157

In the Matter of:	)	
In the Matter of 2018 Biennial Integrated	)	**NCSEA'S INITIAL**
Resource Plans and Related 2018 REPS	)	**COMMENTS**
Compliance Plans	)	

NCSEA'S INITIAL COMMENTS

The North Carolina Sustainable Energy Association ("NCSEA"), an intervenor in the above-captioned proceeding, submits these comments on the smart grid technology plans ("SGTPs") filed by Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC, ("DEP") (DEC and DEP, collectively, "Duke"), and Virginia Electric and Power Company, d/b/a Dominion North Carolina Power ("DNCP" or "Dominion") in accordance with the *Order Granting Second Extension of Time and Closing Discovery Period* issued by the North Carolina Utility Commission ("Commission") in this docket on December 17, 2018.

I. DATA ACCESS IN THE 2018 SMART GRID TECHNOLOGY PLANS

Commission Rule R8-60.1(c)(3) sets forth the contents that are required to be included in SGTPs. The Rule specifically states that:

> (3) For all smart grid technologies currently being deployed or scheduled for implementation within the next five years:
> . . .
> (iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.
> (v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

NCSEA applauds Duke's recognition that customer access to energy usage data is an important part of the future of energy efficiency in North Carolina. However, Duke's proposals fall short of describing and implementing a progressive and modern program which will allow customers to fully utilize the potential power access to their energy usage data.

In the *Duke Energy Carolinas 2018 Smart Grid Technology Plan* ("DEC SGTP") and the *Duke Energy Carolinas 2018 Smart Grid Technology Plan* ("DEP SGTP") (DEC SGTP and DEP SGTP, collectively, "Duke SGTP"), Duke seemingly outlines an understanding of the importance of customer access to energy usage data: "[c]ustomers today want a new experience – a better experience - built upon information about how they personally use energy and tools to harness that energy and power their lives."[1] Despite this acknowledgement, though, Duke does not show that they will implement the most up-to-date data access protocol for their recently installed customer smart meters within Rule R8-60.1's 5-year planning horizon.

While NCSEA acknowledges that Duke "facilitated several meetings with NCSEA, Public Staff and other interested parties to discuss guidelines regarding third-party access to customer usage data[,]"[2] NCSEA believes that Duke's summary does not adequately describe the nuance of those meetings. Namely, NCSEA (and other stakeholders) advocated for the Green Button Connect data access protocol ("GBC"), which is the current industry standard data access protocol:

> Green Button refers to an industry-led standard, ratified by the [American National Standards Institute]-accredited [North American Energy Standards Board], for downloading and sharing customer usage and cost data. The standard was developed by the National Institute of Standards and

[1] DEC SGTP, p. 1; DEP SGTP, p. 1.
[2] DEC SGTP, p. 6; DEP SGTP, p. 5.

Technology ("NIST") and the Smart Grid Interoperability Panel. Green Button has its roots in the American Recovery and Reinvestment Act of 2009 ("ARRA"), which directed the Federal Communications Commission to develop a national broadband plan to include digital strategies for "energy independence and efficiency." Goal #6 of the National Broadband Plan states, "To ensure that America leads in the clean energy economy, every American should be able to use broadband to track and manage their real-time energy consumption."

Federal support for the deployment of advanced meters in America stemming from ARRA included the development of interoperability standards for grid investments, such as customer energy usage data. NIST, as well as the Smart Grid Interoperability Panel, coordinated the standard's development over many years with input from many stakeholders, including utilities. Green Button uses common Internet web services methods and modern IT standards such as XML. More than 50 utilities nationwide have implemented Green Button "Download My Data," a subset of the standard that is limited to the particular file containing energy usage data. The complete version of the Green Button standard, GBC, has been deployed by investor-owned utilities across the states of California and Illinois, and in Washington, D.C. In New York, the Commission has required its regulated utilities pursuing advanced metering to implement GBC, with the first implementation expected by Consolidated Edison in 2018. In Colorado, Xcel Energy will provide GBC to all customers in 2020 as part 1 of its AMI deployment. Of the 70 million advanced meters in the U.S., over 25 million currently have, or will soon have, access to data via the GBC standard.[3]

In the most recent DEC and DEP rate cases (Docket Nos. E-2, Sub 1142 and E-7, Sub 1146[4]), NCSEA witness Michael Murray provided analysis as to why the GBC standard is the current prevailing standard for smart meter data access technology being adopted by investor-owned utilities and is superior to its predecessor offering, the Green Button Download My Data ("DMD") standard.

[3] *Direct Testimony of Michael E. Murray on Behalf of North Carolina Sustainable Energy Association*, pp. 16-18, Docket No. E-7, Sub 1146 (January 23, 2018).

[4] In each of the recent Duke rate cases, Duke sought to strike NCSEA Witness Murray's testimony on the basis of lack of relevance and being beyond the scope of the underlying rate case. Duke's Motion to Strike was granted, in part, in Docket E-2, Sub 1142, but denied in E-7, Sub 1146. Regardless of those two outcomes, NCSEA Witness Murray's testimony is relevant to Duke's planned data access plans in the Duke SGTPs.

As Witness Murray describes in his testimony, DMD's usefulness is severely limited:

> Green Button Download My Data ("DMD") allows customers to manually download their electricity usage information in a standardized, machine-readable file format known as XML. This file can be uploaded by a consumer to third party software applications. DMD is useful, but it requires customers to manually log into their utility's website, download the Green Button XML file, and manually import it to another software tool each time they want to access or use their data. DMD is helpful for one-time uses, such as sending the file to a solar installer to get a price quote. But DMD is too burdensome for ongoing data collection to be useful. Most applications for energy efficiency require ongoing access; therefore, DMD is considered very limited in terms of overall usefulness.[5]

In the Duke SGTPs, Duke does not make explicitly clear whether their data access system upgrade will follow the GBC or the more-limited DMD standard. However, Duke acknowledges in discovery responses that Duke has recently begun the process to "develop and implement" DMD and is only now studying the effects of GBC:

> In October 2018, Duke Energy initiated an effort to develop and implement functionality similar to the Green Button Download My Data functionality within the authenticated area of the Duke Energy website for DEC and DEP. This functionality would give customers the ability to download usage data in a standard format consistent with those defined by the Green Button alliance. If implemented, this new data access capability could be available to customers by late 2019. Furthermore, as part of its developing Grid Improvement Plan, Duke Energy is currently investigating and analyzing functionality consistent with the Green Button Connect My Data protocol.[6]

Duke does not state with certainty that *either* program will be implemented, but acknowledges that DMD, if implemented, will not be rolled out until "late 2019" and indicates that GBC is still in an investigation and analysis phase.

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[5] *Direct Testimony of Michael E. Murray on Behalf of North Carolina Sustainable Energy Association*, p. 18, Docket No. E-7, Sub 1146 (January 23, 2018).

[6] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to North Carolina Public Staff Data Request No. 1-7, attached hereto and incorporated herein as *Exhibit 1*.

As set forth in the Duke SGTPs, Duke is only planning on utilizing a data access protocol with "functionality *similar to* the Green Button Download My Data" and that has "functionality *consistent with*" GBC. These vague statements indicate that Duke does not intend to utilize DMD or GBC, but rather Duke's "version" of one of those two programs. However, DMD and GBC were the programs discussed during the stakeholder meetings and also in previous filings to the Commission (including NCSEA Witness Murray). While NCSEA would not categorically object to a program rolled out by Duke, particularly one that is practically identical to the GBC standard, NCSEA does believe that the stakeholders and Commission should know (1) what, if any, differences there are between Duke's programs and the DMD/GBC standards and, (2) if there are no differences, then why did Duke utilize its own program(s) rather than DMD/GBC?

Furthermore, assuming the programs identified are adequately identical to GBC/DMD, Duke's stated plan for data access is still too uncertain, too slow, and several steps behind the current iteration of best practices in data access. GBC is the standard for good utility practice across the country, and DMD lags. With GBC, "developers of energy management software can, with customer authorization, automatically and securely retrieve meter data in their software."[7] Meanwhile, DMD requires customers to repeatedly log in, download files, and provide them to developers of energy management software. As Witness Murray noted in his testimony, the superiority of GBC over DMD was noted as far back as *2012* by the Edison Foundation:

> Green Button [DMD] requires customers to download their energy usage data to a computer and then manually upload it to a third party application. The downloading process is a barrier. As the Green Button movement

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[7] *Direct Testimony of Michael E. Murray on Behalf of North Carolina Sustainable Energy Association*, p. 18, Docket No. E-7, Sub 1146 (January 23, 2018).

> matures, an automation process, known as "Green Button Connect My Data," where the customer clicks a button to push the data to a third-party, will become the norm.[8]

Seven years later, and Duke Energy is just now in final consideration over whether to implement DMD, an outdated and somewhat cumbersome protocol that does not provide the same level of opportunity to expand energy efficiency as GBC. GBC has been the recommended evolution of data access for years, yet Duke is, at best, seeking to implement an outdated protocol instead of the current standard. Moreover, GBC is a protocol that will be viable for the foreseeable future. GBC allows customers to authorize third party software or application developers to have real-time access to their energy usage data, and those third-party companies can provide energy management analysis which will help Duke's customers. DMD requires customers to repeatedly download data in an onerous and lengthy process which does not utilize the customers' time nor their investment in an energy management company.

Finally, Duke offers no rationale for considering DMD rather than GBC. In the stakeholder meetings, Duke was understandably concerned about the security of customer data, but in practice, DMD is no different than GBC in this regard. DMD and GBC offer the same data, but DMD is a more onerous process for the customer and third-party to review and analyze. GBC simplifies the transfer of data, but the data is protected all the same. The next potential question is price, but Witness Murray showed in his testimony that GBC has a "very modest" price and, for instance, in Xcel Energy's territory in Colorado the implementation of GBC only cost customers a one-time cost of "$1.00 to

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[8] *Id*. at 19, *quoting Green Button: One Year Later*, Edison Foundation IEE Issue Brief, p. 7 (September, 2012), available at http://www.edisonfoundation.net/iee/Documents/IEE_Green%20Button%20Report_Final.pdf.

$1.30 per meter[.]"[9] On that note, it's evident given the much more user friendly interaction of GBC, the probability of the program paying for itself via user savings is much higher with GBC than DMD. Further, Duke has failed to provide evidence of any price disparity. Given the same level of security issues that must be addressed and lack of evidence regarding price for implementation, there appears to be no rationale for implementing DMD instead of GBC. NCSEA encourages the Commission to direct Duke to implement the GBC protocol for its data access program.

II. GRID MODERNIZATION

Over the past year, the idea of what it means to update and modify the grid has been oft-debated in front of the Commission. Duke introduced the "Power/Forward" proposal in the DEP rate case (Docket No. E-2, Sub 1142) as an approximately $13 billion plan split between the two Duke territories in North Carolina. Then, in the DEC rate case (Docket No. E-7, Sub 1146), DEC sought a rider to pay for its Power/Forward Proposal in the DEC territory with the understanding that the same method would then be introduced in DEP to recover the costs for the grid modification proposal.

The Commission directed Duke convene a stakeholder meeting (per a stipulation agreed to between the Public Staff and DEP) on the Power/Forward Proposal in its final order in Docket No. E-2, Sub 1142,[10] and, at those meetings, described a comprehensive proposal for Duke's planned "upgrades" to the grid. As evidenced in the stipulation agreed to by NCSEA in Docket No. E-7, Sub 1146,[11] NCSEA was not and is not fundamentally

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[9] *Id*. at 26.
[10] *Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase*, p. 15, Docket No. E-2, Sub 1142 (February 23, 2018).
[11] See *Pilot Grid Rider Agreement and Stipulation Among Certain Parties*, Docket No. E-7, Sub 1146 (May 31, 2018).

opposed to some of the proposed modernization proposals for grid in North Carolina. Namely, NCSEA supports advancements in voltage control, hosting capacity analysis and stakeholder input related thereto, electric vehicle investment and infrastructure, and energy storage. In fact, NCSEA would posit that each of these investments are currently prudent.

Despite this, NCSEA was disappointed to see the lack of such programs and advancements being included in the Duke SGTPs. Duke, to its credit, does incorporate bits and pieces of programs that are related to these underlying topics, but falls short of presenting a planning horizon fit for its status as a progressive renewable state. Furthermore, to the extent that Duke is still advancing the Power/Forward proposal (in whatever iteration it currently holds), any such advancement should clearly be included and discussed in Duke's SGTPs under Rule 8-60.1. However, Duke has failed to do so. Accordingly, NCSEA requests the Commission require Duke to clarify how the status of its Power/Forward proposal and how it plans to tie such a plan to its SGTPs.

A. <u>INTEGRATED SYSTEMS OPERATION PLANNING</u>

Furthermore, and more specifically, Duke and Dominion's SGTPs fail to provide a sustainable and well-thought out plan for integrating renewable energy resources across the grid and also to incorporate new technologies which will allow for a reliable, resilient, and clean energy grid. Duke, to its credit, has provided an analysis of its new Self-Optimizing Grid ("SOG") Program, which it says will "enable the system to reduce outage duration from fault events" and "will allow for multiple circuit rerouting options to re-energize segments and minimize customer outage events."[12] NCSEA applauds the effort of any utility to utilize new technology for a forward-thinking two-way grid that enables

[12] DEC SGTP, p. 10; DEP SGTP, p. 10.

distributed generation and storage to provide generation, resilience, and reliability. To that end, NCSEA further applauds the implementation of microgrids, solar PV, and battery storage which can help to alleviate issues for all customers.

Duke also states that it "recognizes the need to have an agile and adaptive grid with the ability to be able integrate growing amounts of DER (Distributed Energy Resources), storage, promoting enhanced segmentation, two-way power flows, voltage support, and other capability enhancements over time."[13] Thereafter, Duke lays out its plan to perform test cases and do capability planning for further DER integration:

> The initial focus is on capability planning, to be followed during the 2019-2021 timeframe with an initial proof of concept on voltage support capabilities related to storage and DER integration on the distribution system. Following a successful completion of a proof of concept in 2021, a pre-scale with a focus on enabling additional use case capabilities that allow for edge and low latency decision making to occur will be pursued from 2021 through 2022 to further evaluate capabilities.[14]

While NCSEA applauds any effort to integrate DER into the aging grid to improve reliability and resiliency while utilizing clean energy sources, this effort falls short and does not offer any concrete details with hard deadlines. Furthermore, it excludes stakeholder input which is paramount to a smart grid planning process. Dr. Caroline Golin provided testimony in the DEC's most recent rate case that concluded, in part, as follows:

> I recommend that the Commission order the Company to open a stand-alone docket in order to thoroughly and thoughtful define and plan for a modernized grid. The stand-alone docket should be predicated on clear grid investment goals and 1 metrics. Duke should be required to conduct robust distribution resource planning that take a holistic view of the grid and the technologies that are capable of meeting grid needs. This includes the proper forecasting and evaluation of the role of DERs, the inclusion of third parties, and transparency in the analysis process. Distribution resource

[13] DEC SGTP, p. 47; DEP SGTP, p. 53.
[14] DEC SGTP, p. 48; The DEP SGTP includes a less specific time frame for a similar rollout within its Medium & Low Voltage Enhanced Volt/Var Capability Prescale section on p. 53.

> planning should be accompanied by thorough cost/benefit analyses that compare several investment pathways to meeting grid investment goals. Finally, Duke should be required to give greater deference to the role of DERs as potential investments for improved reliability.[15]

Dr. Golin further recommended the Commission open a docket or stakeholder working group in tandem with the then-proposed Power/Forward Grid Modernization Proposal, to "assess the impacts of shifts in [Duke's] investment strategy with current mechanisms for cost recovery and implications for rate design."[16] While these requests range beyond the scope of the instant docket, NCSEA would restate and reemphasize the necessity of collaboration with stakeholders as Duke moves forward with the assessment of the grid and is DER planning. The horizon planning for a such an important shift to distributing generation across the grid in an informed and efficient way will require the feedback from interested and educated parties who have an interest.

NCSEA has previously recommended that the utilities implement integrated distribution planning. To its credit, Duke has proposed to implement Integrated System Operations Planning ("ISOP"). However, details are lacking, and the stakeholder feedback is absent. NCSEA requests the Commission to direct Duke to hold stakeholder meetings on a quarterly basis about ISOP or any iteration of integrated distribution planning. To that end, NCSEA requests the Commission require Duke file updates on the status of ISOP implementation, including summaries of stakeholder meetings, on an annual basis, with an opportunity for parties to comment on related matters as the Commission sees fit.

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[15] See *Direct Testimony of Caroline Golin on Behalf of NCSEA*, pp. 57-58, Docket No. E-7, Sub 1146 (January 23, 2018).
[16] *Id.*

III. Demand Side Demand Response – Conservation Voltage Reduction

In its SGTP, DEP proposes to conduct a cost/benefit analysis for converting DEP's Demand Side Demand Response ("DSDR") program from the current peak shaving operational strategy to a Conservation Voltage Reduction ("CVR") operational strategy. CVR would target an estimated 2% voltage reduction for the majority of the hours of the year to reduce load by approximately 1.4% for enabled circuits, compared to the current 3.6% and emergency 5% voltage reduction capabilities. NCSEA supports a DSDR/CVR evaluation as described in the SGTP and urges DEP to complete that evaluation as soon as possible so DEP and its stakeholders can determine whether the overall load reduction benefits from a CVR operational mode outweigh any reduction to the DSDR program's maximum peak shaving capabilities.

However, NCSEA is concerned about how Duke has used DSDR as a reason for the glacial pace of its interconnection queue. Specifically, Duke has claimed that the DSDR's voltage regulators ("LVR") limit the amount of solar that can be interconnected into the grid, and has implemented a policy prohibiting the interconnection of distributed energy resources projects beyond a line voltage regulator, effectively limiting where solar photovoltaic ("PV") projects can be interconnected to the grid.[17] NCSEA disagrees with this and believes that solar generation can be interconnected without negative

[17] "The primary justification for Duke's adoption of the [LVR Policy limiting QF interconnection] was that interconnection of solar generators beyond voltage regulators would incrementally reduce the effectiveness of the Distribution System Demand Reduction (DSDR) operated by DEP. However, company representatives acknowledged that Duke never attempted to quantify this impact. Duke has never provided NCSEA with any engineering study or other quantitative analysis in support of the LVR Policy." See *NCSEA's Initial Comments*, p. 35, Docket No. E-100, Sub 101 (January 29, 2018).

consequences.[18] NCSEA has previously stated that Duke's LVR screen is unreasonable and restates that position here. Furthermore, while NCSEA supports CVR as a demand-side management ("DSM") measure, NCSEA remains concerned about the impact on DER, especially given that Duke was unwilling to provide its expected impact on DER in its data request responses.

In response to data requests on this issue, Duke did not specifically state how Duke's plan to utilize CVR in its DSDR program will impact new PV projects seeking to interconnect to the grid.[19] However, NCSEA objects to any program which Duke will attempt to implement which will limit renewable generation, be adverse to the goals of House Bill 589 and N.C. Gen. Stat. 62-2(a)(10),[20] or otherwise slow the interconnection queue. NCSEA supports this program, but not if it adversely impacts renewable generation being interconnected to the grid.

IV. INTERCONNECTION

The interconnection of non-utility generation is a connective tissue impacting many energy issues in North Carolina. As noted by Chairman Finley, the interconnection "docket is interrelated to other dockets like the implementation of House Bill 589, and avoided cost, and IRP, and all of that stuff, so it's sort of a stumbling block we've got to address."[21] As

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[18] See *Direct Testimony of Paul Brucke, P.E. on Behalf of NCSEA*, pp. 7-11, Docket No. E-100, Sub 101 (November 19, 2018).

[19] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to NCSEA Data Request No. 2-11, attached hereto and incorporated herein as *Exhibit 2*.

[20] "Upon investigation, it has been determined that the rates, services and operations of public utilities as defined herein, are affected with the public interest and that the availability of an adequate and reliable supply of electric power and natural gas to the people, economy and government of North Carolina is a matter of public policy. It is hereby declared to be the policy of the State of North Carolina: […] To promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS) that will do all of the following:
a. Diversify the resources used to reliably meet the energy needs of consumers in the State.
. . .
c. Encourage private investment in renewable energy and energy efficiency." N.C. Gen. Stat. § 62-2(a).

[21] *Staff Conference Transcript for September 18, 2017*, p. 11, Docket No. M-1, Sub 7 (October 5, 2017).

set forth above, NCSEA is opposed to any policy or program that either Dominion or Duke intend to implement that will cause the interconnection of non-utility generation to slow further. As NCSEA stated more broadly in its Initial Comments filed in the interconnection docket on January 29, 2018, both Duke and Dominion's interconnection rate has grinded to a halt over the past few years and, while Duke and Dominion have complained and alleged that recent changes to North Carolina energy policy instituted with the enactment of S.L. 2017-192 (commonly referred to as "House Bill 589" or "H.B. 589") have caused issues with the interconnection of solar facilities, NCSEA and other intervenors have proposed numerous suggestions to improve the rate of interconnection.[22] Despite this wide-ranging and ongoing problem, neither Duke nor Dominion have proposed solutions in their SGTPs that would improve interconnection rates.

V. GRID LOCATIONAL GUIDANCE

R8-60(i)(10)(ii)c defines smart grid technologies to include technologies "that improve the operational integration of distributed and/or intermittent generation sources, energy storage, demand response, demand-side resources and energy efficiency[.]" NCSEA believes that this description includes the necessity for operational planning and grid locational guidance for new generation sources, energy storage, demand response, demand-side resources and energy efficiency, and, as such, believes that Duke should be compelled to work with stakeholders on creating an information exchange regarding grid capacity.

In Reply Comments filed in the Interconnection and Competitive Procurement of Renewable Energy ("CPRE") dockets, Duke alleged that interconnection queue issues are

[22] *NCSEA's Initial Comments*, Docket No. E-100, Sub 101 (January 29, 2018).

caused by solar developers: "CPRE Non-Participants are *singularly responsible* for their interconnection costs, including any grid upgrades, and also are more likely to be speculative (i.e., not have negotiated a PPA or other offtake commitment to support financing and construction of their facility)."[23] NCSEA categorically disputes this position and believes that with adequate stakeholder interplay, Duke could greatly improve the interconnection queue rate and also incorporate solar generation (and other clean energy technologies) to improve the grid.

As NCSEA Witness Dr. Caroline Golin stated in her testimony in the DEC rate case, Duke could alleviate these interconnection issues and also will improve grid resiliency and reliability by performing hosting capacity analyses.

> Understanding the distribution systems' capacity to accommodate DER can help customers and DER developers identify preferred locations for interconnection. Additionally, if the hosting capacity results are applied to streamline the Company's interconnection process, customers will benefit from fewer delays and reduced uncertainty.[24]

Dr. Golin goes on to recommend that the Commission implement a new proceeding and stakeholder process to examine grid modernization and allow the "participants should determine the most appropriate methodology and timeline to begin calculating and publishing circuit hosting capacity."[25] NCSEA has taken this position numerous times before the Commission including the Interconnection docket where NCSEA supported Interstate Renewable Energy Council, Inc.'s ("IREC") proposal that the utilities provide hosting capacity maps, as are provided in other states by utilities.[26] Hosting capacity

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[23] *Reply Comments of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, p. 12, Docket Nos. E-100, Sub 101, E-2, Sub 1159, and E-7, Sub 1156 (September 19, 2018)
[24] *Direct Testimony of Caroline Golin on Behalf of NCSEA*, p. 31, Docket No. E-7, Sub 1146 (January 23, 2018).
[25] *Id*.
[26] *NCSEA's Initial Comments*, p. 25, Docket No. E-100, Sub 101 (January 29, 2018).

analyses and other grid locational guidance are a cornerstone to improving the connection of new generation to the grid.

NCSEA encourages the Commission to direct Duke to develop and distribute hosting capacity maps, or some other form of grid locational guidance. This would be consistent with R8-60.1 and R8-60(i)(10)(ii) and would address Duke's own concerns about speculative solar developers shown above. Moreover, this sort of analysis has been previously identified in Duke's own testimony. Duke Witness Jeffrey W. Riggins stated in the Interconnection docket that additional information regarding hosting capacity will reduce speculative, non-viable projects. Specifically, Mr. Riggins stated: "[a]dditional time is necessary for [Duke] to develop this additional information about the feasibility of Interconnection Customers' projects in preparation for the scoping meeting stage of the interconnection process. Ultimately, this additional information will 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."[27] The "additional information" Witness Riggins is discussing here would be the same type of information that would populate a hosting capacity map or other grid locational guidance. Essentially, Duke could greatly help to repair the interconnection queue by providing feedback to the stakeholders and greater solar community regarding hosting capacity.

[27] *Direct Testimony of Jeffrey W. Riggins on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*, p. 26, Docket No. E-100, Sub 101 (November 19, 2018).

IV. CONCLUSION

NCSEA requests that the Commission enter an Order consistent with the requests made herein and for such other and further relief as the Commission deems just and proper.

Respectfully submitted on this the 16th day of January, 2019.

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CERTIFICATE OF SERVICE

I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing document by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 16th day of January, 2019.

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Exhibit 1

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Please explain what, if anything, the Companies have done since the July 2018 Customer Usage Data Access Conference referenced in SGTP Exhibit 2 to investigate the "Green Button" customer data platform or other platforms that could offer customers with access to their customer usage data.

Response:

In October 2018, Duke Energy initiated an effort to develop and implement functionality similar to the Green Button Download My Data functionality within the authenticated area of the Duke Energy website for DEC and DEP. This functionality would give customers the ability to download usage data in a standard format consistent with those defined by the Green Button alliance. If implemented, this new data access capability could be available to customers by late 2019. Furthermore, as part of its developing Grid Improvement Plan, Duke Energy is currently investigating and analyzing functionality consistent with the Green Button Connect My Data protocol.

Provided by:
Evan W. Shearer, Principal Grid Smart Planning & Regulatory Support Specialist

Exhibit 2

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

Please describe the current impacts and additional requirements that the Distribution System Demand Response (DSDR) program imposes on distributed energy resources (DERs) that attempt to interconnect to the DEP system and compare this to any impacts to DERs that will be reduced or added by changing the DSDR program from a peak shaving operational strategy to a Conservation Voltage Reduction operational strategy.

Response:

Demand-Side Distribution Response (DSDR) impacts utility-scale distributed energy resources (DERs) today, such that larger, utility scale DERs are not allowed to be connected downstream of distribution line voltage regulators on the Duke Energy Progress (DEP) system.

The Company's Method of Service Guidelines outline these requirements in detail in section 3.2 and are provided with this response.

Conceptually, under a Conservation Voltage Reduction (CVR) operational strategy, the creation of more voltage headroom, through some downward changes to regulator band center settings, would create the potential for interconnection of more DER capacity, since some DER interconnection studies do reveal over-voltage during light load periods as a constraining factor for the requested capacity.

However, the Company is aware from extensive experience in interconnection studies, especially more recently as penetration is increasing, that there are multiple possible constraining factors to DER penetration other than just over-voltage. Therefore, the actual impacts of CVR to DER could only be determined through operational study and experience.

SGTP NCSEA 2-11 method-of-service-guidelines-20171013.pdf

SGTP NCSEA 2-11
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Contents

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.

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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.