COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

DIVISION OF PUBLIC UTILITY REGULATION

STAFF REPORT OF DIVISION OF PUBLIC UTILITY REGULATION

CASE NO. PUR-2022-00073

EX PARTE: IN THE MATTER CONSIDERING UTILITY DISTRIBUTED ENERGY RESOURCE INTERCONNECTION-RELATED ISSUES AND QUESTIONS

SEPTEMBER 19, 2022

SUMMARY

On May 24, 2022, the Commission issued an Order for Comment ("Order") providing interested parties an opportunity to comment on utility DER interconnection issues. The Order also directed the Staff of the Commission ("Staff") to file a report ("Staff Report") on the comments submitted to the Commission.

Written comments were received from the following entities: Sun Tribe Solar, LLC and Sun Tribe Development LLC; Secure Futures, LLC; Virginia, Maryland & Delaware Association of Electric Cooperatives; Appalachian Power Company; Virginia Electric and Power Company d/b/a Dominion Energy Virginia; Kentucky Utilities Company d/b/a Old Dominion Power Company; Chesapeake Solar & Storage Association and The Coalition for Community Solar Access; and Appalachian Voices.

Additionally, public written comments were received from the following persons: Matthew Meares, on behalf of Sunworks NC, LLC; Harrison T. Godfrey and Michael Weiss, on behalf of Virginia Advanced Energy Economy; Chris Gordon, on behalf of EDF Renewables; Hillel Halberstam, on behalf of SynerGen Solar, LLC; Harry Warren, on behalf of Center for Renewables Integration, Inc.; William Giese and Jeremiah Miller, on behalf of Solar Energy Industries Association; and Laura Gonzalez, on behalf of Clean Virginia.

A summary of Staff's conclusions and recommendations is as follows:

1. Given the large number of issues raised by the parties, Staff is unsure that all issues can be addressed simultaneously within the same docket. However, Staff believes there are multiple avenues for addressing the various issues. These pathways include (i) making reforms to the existing Regulations ("Regulations Reform"); (ii) establishing working groups; (iii) implementing pilot studies; (iv) establishing separate proceedings outside the scope of the Regulations Reform; and (v) using utility administration and application processes.
2. Due to the variance in the complexity and investigation that is required, Staff believes one option for the Commission's consideration is for the Regulations Reform to be a multi-step process. In other words, in Staff's opinion, a targeted approach could be used that opens up only selected portions of the Regulations for reform at a time; that may be the most effective way to address the variety of issues described above. If so directed by the Commission, Staff is willing to work with the parties to determine which topics could be addressed more immediately, and then develop an outline for any upcoming rulemaking proceeding on the Regulations Reform.

Table of Contents

DIVISION OF PUBLIC UTILITY REGULATION

Commonwealth of Virginia, *ex rel.* State Corporation Commission
***Ex Parte:* In the matter considering utility distributed energy resource interconnection-related issues and questions**

CASE NO. PUR-2022-00073

INTRODUCTION

As part of its Final Order in Case No. PUR-2021-00127, the State Corporation Commission ("Commission") found that it would, by separate order, open a docket to explore interconnection issues related to utility distributed energy resources ("DER") in a comprehensive manner. On May 24, 2022, the Commission issued an Order for Comment ("Order") providing interested parties an opportunity to comment on utility DER interconnection issues. The Order also directed the Staff of the Commission ("Staff") to file a report ("Staff Report") on the comments submitted to the Commission.

Written comments were received from the following entities: Sun Tribe Solar, LLC and Sun Tribe Development LLC (collectively, "Sun Tribe"); Secure Futures, LLC ("Secure Futures"); Virginia, Maryland & Delaware Association of Electric Cooperatives ("VMDAEC"); Appalachian Power Company ("APCo"); Virginia Electric and Power Company d/b/a Dominion Energy Virginia ("Dominion"); Kentucky Utilities Company d/b/a Old Dominion Power Company ("KU-ODP"); Chesapeake Solar & Storage Association ("CHESSA") and The Coalition for Community Solar Access ("CCSA") (collectively, "CHESSA/CCSA"); and Appalachian Voices.

Additionally, public written comments were received from the following persons: Matthew Meares, on behalf of Sunworks NC, LLC ("Sunworks"); Harrison T. Godfrey and Michael Weiss, on behalf of Virginia Advanced Energy Economy ("VAEE"); Chris Gordon, on behalf of EDF Renewables ("EDF"); Hillel Halberstam, on behalf of SynerGen Solar, LLC ("SynerGen Solar"); Harry Warren, on behalf of Center for Renewables Integration, Inc. ("CRI"); William Giese and Jeremiah Miller, on behalf of Solar Energy Industries Association ("SEIA"); and Laura Gonzalez, on behalf of Clean Virginia ("Clean Virginia").

The Commission noted that parties may wish to address eight questions provided in its Order as part of their comments. Significantly, some, but not all parties, addressed all eight questions in the Order. After reviewing the comments, Staff identified common topics discussed by multiple parties. Accordingly, this Staff Report will summarize these common topics instead of using a question-by-question format. First, the Staff Report will discuss the topics identified by the non-utility parties.[1] If a utility also discussed a topic identified by the non-utility parties, its comments will be included in the non-utility response section. After the issues raised by the non-utility parties have been summarized, the Staff Report will summarize topics discussed by the utilities. The Staff Report will also discuss the reform that is currently taking place for the Federal Energy Regulatory

[1] Non-utility parties include Sun Tribe, Secure Futures, CHESSA/CCSA, Appalachian Voices, Sunworks, VAEE, EDF, SynerGen Solar, CRI, SEIA, and Clean Virginia. Many of the non-utility comments are specifically directed at Dominion's interconnection process.

Commission's ("FERC") interconnection procedures. The Staff's conclusions and recommendations on the various topics will be provided at the end of the Staff Report.

TOPICS IDENTIFIED BY THE NON-UTILITY PARTIES

The common topics identified by the non-utility parties included, among other things, long study timelines, direct transfer trip ("DTT"), the Institute of Electrical and Electronics Engineers' ("IEEE") Standard 1547, and cost allocation. Each common topic is discussed in detail below.

Application Process

According to VAEE, the interconnection application process must be made streamlined and uniform to the greatest extent possible.[2] VAEE stated that each utility's interconnection application process should be online and contain all the application and supporting materials.[3] These websites should include, but not be limited to, online forms, application checklists, parameter manuals (unit-cost guides), tracking for submitted applications, easy-to-find contact information, resources to answer common questions, and easy-to-find contact information for a timely dispute resolution process.[4] VAEE asserted that online applications improve speed and workflow and reduce costs.[5] According to

---

[2] VAEE at 3 and 8.
[3] *Id.* at 8.
[4] *Id.*
[5] *Id.* at 9.

Appalachian Voices, Hawaii has an online DER application process and tracking functions.[6]

Dominion commented that it is currently pursuing a process through which interconnection requests and associated fees can be submitted online.[7] APCo also commented that it launched an automation and management software tool for processing and tracking DER interconnection applications in 2020 and that the software tool allows developers to submit a pre-application request and an application online.[8] KU-ODP also commented that it is developing an online DER interconnection portal for customers.[9] Finally, VMDAEC commented that Shenandoah Valley Electric Cooperative has created a Distributed Resource Integration Requirements document to facilitate early communications about the process requirements, procedures, and expected timelines.[10]

Long Study Timelines

Sunworks, EDF, CHESSA/CCSA, and SEIA expressed concerns about excessive study timelines. These parties stated that utilities in Virginia are not meeting the deadlines set forth in the Regulations Governing Interconnection of Small Generators, 20 VAC 5-314-10 *et seq.* ("Regulations").[11] According to CHESSA/CCSA, while Dominion currently estimates a 12-month study timeline for ICs who are in "position A," the study

[6] Appalachian Voices at 27.
[7] Dominion at 5.
[8] APCo at 2-3.
[9] KU-ODP at 3.
[10] VMDAEC at 7-8.
[11] Sunworks at 1; EDF at 1; CHESSA/CCSA at 5; SEIA at 6.

process can take more than 16 months to complete for a single project.[12] CHESSA/CCSA further stated that study delays are exacerbated because projects are studied sequentially.[13] As such, projects behind project A can take multiple years to complete.

According to Sunworks, many smaller projects (less than 5 megawatts ("MW") in size) have entered the queue intending to either be included in the community solar program or to sell the power to Dominion under the small generator portion of the Virginia Clean Energy Plan.[14] For example, Sunworks stated that since December 2019, 18 projects, ranging between 2 MW to 5 MW, have filed to interconnect at the South Hill substation.[15] Sunworks believes this increase in interconnection requests has inundated Dominion's capability to conduct the study process in a timely manner.[16]

Similarly, Dominion commented that its volume of interconnection requests has increased significantly.[17] Furthermore, Dominion stated that more than half of all projects studied as part of its interconnection queue ultimately do not move forward past the study phase, resulting in substantial efforts expended on speculative projects that do not come to fruition.[18]

[12] CHESSA/CCSA at 5. "Position A" means any interconnection request that is not interdependent with another interconnection request.
[13] *Id.* at 5 and 7.
[14] Sunworks at 1.
[15] *Id.*
[16] *Id.*
[17] Dominion at 3.
[18] *Id.*

According to CHESSA/CCSA, Dominion has attempted to address the bottleneck around feasibility study timelines by increasing its in-house staff and outside consultants; however, these changes only address the first study phase,[19] and potentially push the bottleneck to subsequent study processes.[20] Some key solutions suggested by the parties to help reduce interconnection study delays are discussed below.

Cluster/Serial/Pseudo-Parallel Study

Sunworks, Appalachian Voices, and SEIA discussed utilizing a cluster study approach for interconnection studies, instead of the serial queue approach (which is the current approach found in the Commission's Interconnection Regulations).[21] In a cluster study, a utility can group a number of interconnection requests and study all of them jointly. As part of its comments, Dominion stated that it is currently evaluating whether cluster studies could improve the current interconnection process and is considering a pilot for a targeted cluster study approach.[22] According to Dominion, it is exploring facilitating targeted cluster studies for smaller solar generating facilities (1-3 MW range).[23]

Sunworks and SEIA commented that there are problems with using cluster studies. Sunworks stated that under the cluster study approach if one project within a cluster removes itself from the queue, all other projects in the cluster are affected.[24] This can lead

[19] The interconnection study process typically consists of (i) the Feasibility Study; (ii) the System Impact Study; and (iii) the Facilities Study.
[20] CHESSA/CCSA at 8.
[21] Sunworks at 2-5; Appalachian Voices at 38; SEIA at 4.
[22] Dominion at 5.
[23] *Id.* at 6.
[24] Sunworks at 5.

to multiple rounds of studies which may defeat the benefits of a cluster study.[25] SEIA further stated that there could be non-cooperation issues when a developer pulls out of the cluster late in the study process.[26] For the reasons stated above, Sunworks recommended that the queue process remain serial, but implement higher barriers for entry.[27] These barriers for entry will be discussed further below.

CHESSA/CCSA have suggested an in-between option between the serial approach and cluster approach, which they call the "pseudo-parallel" study method.[28] Under the pseudo-parallel method, later queued studies would be able to start the study process as soon as the earlier queued project's system impact study report (or combined study, as applicable) is complete.[29]

Increased Study Fees/Financial Commitments

Sunworks, CHESSA/CCSA, and SEIA commented on application or study fees and other financial commitments. In order to reduce the number of speculative projects in the queue, Sunworks stated that higher barriers of entry should be implemented.[30] In the current fee and deposit structure, there is a nonrefundable processing fee of $1,000 to enter the queue for Level 2 and Level 3 interconnection requests. From there, Level 3 interconnection projects must submit a study deposit of $10,000 plus $1.00 per kilowatt (alternating

[25] *Id.*
[26] SEIA at 4.
[27] Sunworks at 5.
[28] CHESSA/CCSA at 21
[29] *Id.*
[30] Sunworks at 5.

current) ("kW_{AC}") upon being designated as a Project A or electing to proceed with the studies as a Project B. Sunworks recommended that the study deposit fee be charged to all Level 2 and 3 projects upon entering the queue.[31] CHESSA/CSSA also suggested increasing study fees to support staffing at the utilities, to ensure that studies are conducted within the time frame outlined in the Regulations.[32]

Sunworks also proposed a new requirement of a security deposit equal to 10 times the study deposit.[33] In addition to the increased study and security deposits, Sunworks suggested a withdrawal penalty for projects leaving the queue after they have applied.[34] Specifically, Sunworks proposed that the penalty amount should be nine times the study deposit, which the increased security deposit would already cover.[35] SEIA also suggested increased project maturity requirements for projects to enter the interconnection queues, as a way to limit the number of speculative projects.[36]

Condensing the Study Process

CHESSA/CCSA recommended condensing and optimizing the study process to reduce study timelines.[37] According to CHESSA/CCSA, the optimized process could be modeled after the New York and Massachusetts interconnection processes, which allows

[31] *Id.* at 6.
[32] CHESSA/CCSA at 20.
[33] Sunworks at 6.
[34] *Id.* at 11.
[35] *Id.*
[36] SEIA at 16.
[37] CHESSA/CCSA at 21.

for a formalized and initial preliminary analysis that replaces the scoping meeting.[38] This would be followed by the formal study process, beginning with the system impact study.[39] CHESSA/CCSA stated that the optimized study process would require less administrative processing time between study steps and better determine whether a project is financeable earlier in the process.[40]

Performance Based Framework (Penalties and Incentives for Utilities)

VAEE, SEIA, and Clean Virginia suggested a more performance-based framework for utilities to adhere to in order to achieve improved interconnection timelines.[41] Under this framework, utilities would be subject to penalties if interconnection timelines were not met. Conversely, adequate incentives would be created for utilities to achieve outstanding performance in reducing interconnection times beyond a reasonable threshold. According to VAEE and Clean Virginia, the Hawaii Public Service Commission established penalties and rewards for utilities that exceeded or decreased interconnection timelines compared to an established benchmark.[42] Additionally, Appalachian Voices, CHESSA/CCSA, and Clean Virginia recommended that utilities file a report on their performance relative to meeting study timelines, as a way to hold utilities more accountable and to provide greater transparency.[43]

---

[38] *Id.* at 21-22.
[39] *Id.* at 22.
[40] *Id.*
[41] VAEE at 6; SEIA at 2; Clean Virginia at 1.
[42] VAEE at 6; Clean Virginia at 9.
[43] Appalachian Voices at 38; CHESSA/CCSA at 20-21; Clean Virginia at 9-10.

As part of its comments, Dominion stated that it would be publishing a Queue Performance Report to provide insight on the processing of interconnection requests from the application stage through the completion of the interconnection process.[44]

Long Construction Timelines

EDF stated that Dominion's construction timelines have been extended up to one year from the execution of a Small Generator Interconnection Agreement ("SGIA").[45] Dominion also commented that it has observed delays during construction, including additional costs to mobilize and demobilize contractors due to changing milestone dates.[46] Additionally, VMDAEC stated that supply chain issues for equipment have already become a concern for DER interconnections.[47]

Lack of Information

CHESSA/CCSA and SEIA commented on the lack of information in the interconnection study reports. According to CHESSA/CCSA, the level of detail in Dominion's study reports is insufficient to provide developers insight into the reviews performed by the utility and the types of grid constraints and issues under investigation in the study process.[48] SEIA stated the interconnection process exists largely in a so-called "black box" where it can be difficult or sometimes impossible to determine the costs or

[44] Dominion at 5.
[45] EDF at 1.
[46] Dominion at 4.
[47] VDMAEC at 6-7.
[48] CHESSA/CCSA at 9.

timelines associated with interconnecting a project.[49] Sunworks commented that greater cost information should be provided to developers.[50] Furthermore, CHESSA/CCSA claimed that Dominion does not provide a comprehensive statement of upgrade costs until the final stage of the interconnection study process.[51] SEIA stated that this lack of information until the final study creates a significant risk to the developer in terms of providing and planning for accurate development timelines and cost estimates.[52] According to CHESSA/CCSA, Massachusetts' utility study reports include detailed information regarding study methodology and costs.[53] Accordingly, CHESSA/CCSA recommended that Dominion provide greater clarity regarding its interconnection upgrade process by providing a more detailed breakdown of the scope, methodology, and interconnection upgrade costs in the studies.[54] The parties made other recommendations for ways to improve the means of obtaining more information, which are discussed below.

Hosting Capacity Map

In January 2021, Dominion released a hosting capacity tool on its website.[55] This tool uses computer simulations to determine how much generation can be placed at a given point on the distribution grid without causing voltage or thermal issues.[56] According to Appalachian Voices, hosting capacity maps reduce the number of applications by helping

[49] SEIA at 6.
[50] Sunworks at 7.
[51] A more detailed discussion on costs is provided later in the Report.
[52] SEIA at 6.
[53] CHESSA/CCSA at 9-10.
[54] *Id.* at 25.
[55] Dominion at 4.
[56] *Id.*

DER developers avoid submitting applications that are likely to fail.[57] Sun Tribe and CHESSA/CCSA support the advancements made by Dominion on its hosting capacity maps.[58] Sun Tribe recommended expanding this tool to rural areas and requiring a similar tool be developed by APCo.[59] VAEE recommended hosting capacity analyses as a requirement for all utilities in Virginia.[60] In addition to current hosting capacity maps, Appalachian Voices recommended deployment of an additional variation called "locational value maps."[61] According to Appalachian Voices, a locational value map would help developers identify locations where a DER might be able to defer or avoid a distribution grid capacity investment that would otherwise be necessary due to growing loads.[62]

Interconnection Queue Report

Recently, Dominion and APCo began publishing their small generator interconnection queue on their website.[63] This queue provides a snapshot of the status of interconnection requests within each utility's queue, and includes information such as substation name, substation transformer, circuit, and queue position. This information provides greater transparency into the interconnection queue, allowing developers to make more informed decisions. Dominion and APCo both update this information quarterly.[64]

---

[57] Appalachian Voices at 13.
[58] Sun Tribe at 3; CHESSA/CCSA at 6 and 19.
[59] Sun Tribe at 3.
[60] VAEE at 14.
[61] Appalachian Voices at 13.
[62] *Id.*
[63] Dominion at 4. APCo's Virginia Interconnection Queue can be found at https://www.appalachianpower.com/business/builders/generating-equipment.
[64] *Id.*

Sun Tribe, VAEE, and CHESSA/CCSA acknowledged the publication of this queue report, and VAEE recommended a similar queue report be published by all utilities within Virginia.[65] Additionally, all three parties recommended that the information be updated monthly as opposed to quarterly.[66]

Posting Study Reports Online

Sunworks recommended that all interconnection reports created since 2015 be made publicly available online in a way that can be sorted by substation, transformer, and circuit.[67] Sunworks stated that this process would be similar to that of PJM Interconnection L.L.C. ("PJM"), which makes all studies in its queue publicly available on its website.[68] Sunworks selected 2015 as the earliest date for these reports, because in its view, reports earlier than 2015 would contain outdated cost information.[69] Sunworks also provided variations to its recommendation, which include: (i) only providing reports for canceled projects; (ii) only providing the most recent report for a given circuit; and (iii) eliminating any reports older than five years.[70]

Excessive Cost of Interconnection

Several parties commented on the excessive or increased cost of interconnection. Parties provided various reasons for this issue. Sunworks pointed specifically to increased

[65] Sun Tribe at 4; VAEE at 23; CHESSA/CCSA at 6 and 19.
[66] Sun Tribe at 4; VAEE at 23; CHESSA/CCSA at 19.
[67] Sunworks at 9.
[68] *Id.* at 8-9.
[69] *Id.* at 9.
[70] *Id.* at 9-10.

costs for the requisite materials, and inflation.[71] Appalachian Voices stated that utility-recommended equipment upgrades and installations might not be justified.[72] These upgrades include, among other things, protection equipment, voltage regulators, capacitor banks, grid ties, switches, and software.[73] Secure Futures stated that costs imposed on ICs should not include costs related to the distribution system as a whole.[74] In addition to the upgrades identified above, several parties stated that the cost of requiring fiber-optic cables for DTT implementation is unnecessary due to available, less expensive alternatives. A more detailed discussion of DTT is provided below.

Dark Fiber/DTT

The requirement for usage of dark fiber-optic cable for DTT implementation was one of the most pressing issues commented on by the parties. According to CHESSA/CCSA and Secure Futures, Dominion's requirement to install DTT equipment is the most significant cost driver for projects seeking to interconnect to its distribution system.[75] Depending on whether the existing distribution structures can directly support fiber or require upgrades, dark fiber deployment costs vary significantly. Sun Tribe, Sunworks, and VAEE commented that the costs for installing fiber-optic cables can be over $250,000 per mile.[76] CHESSA/CCSA stated that the expense associated with DTT deployment is not limited to just the cost of the receiver equipment and fiber needed

---

[71] *Id.* at 1-2.
[72] Appalachian Voices at 16.
[73] *Id.* at 16-24.
[74] Secure Futures at 4.
[75] CHESSA/CCSA at 14; Secure Futures at 2.
[76] Sun Tribe at 1; Sunworks at 15; VAEE at 7.

between the small generating facility and the substation, but can also include substation equipment needed to house the DTT receiver, such as a new or additional control house.[77] CHESSA/CCSA further stated that costs for everything associated with the DTT equipment have been reported to be between $2-$3 million on average and as high as $7 million.[78] Furthermore, Sun Tribe expressed concern that the cost estimates for dark fiber are not provided by utilities until the facilities study phase, which is the last study phase of the process.[79] Secure Futures and EDF stated that expenses related to dark fiber are cost prohibitive for small-scale projects.[80] Furthermore, Sunworks asserted that Dominion has done an inferior job of justifying why the transfer trip must use fiber optics.[81] Several parties have included various alternatives to Dominion's current DTT requirements, and these options are discussed below.

IEEE 1547-2018 and Compliant Inverters

CHESSA/CCSA stated that instead of DTT, utilities should be obligated to study and utilize the functionality of certified inverters to detect "islanding."[82] CRI commented that IEEE has published its testing protocol (IEEE 1547.1-2020), UL has published its testing procedure (UL 1741 3rd edition including Supplement SB), and accordingly such

[77] CHESSA/CCSA at 14.
[78] *Id.*
[79] Sun Tribe at 1. A more detailed discussion on costs being provided earlier in the study process is provided later in this Report.
[80] Secure Futures at 3; EDF at 1.
[81] Sunworks at 14.
[82] CHESSA/CCSA at 14. "Islanding" is the condition in which a DER continues to supply power to the grid while the power supplied by electric utility is disrupted.

certified equipment is beginning to reach the market.[83] Furthermore, CRI stated that PJM has put forward the "PJM Guideline for Ride Through Performance of Distribution-Connected Generators," which consists of recommendations for ride-through capabilities and trip settings under the new IEEE standards.[84] According to the CRI, Maryland has initiated three rulemakings to update and improve Maryland's Small Generator Interconnection Regulations resulting from the Maryland Interconnection Process workgroup.[85] Maryland's RM 68 included a definition for "smart inverter" as any inverter hardware system certified to be compliant with IEEE 1547-2018, or subsequent revisions to these standards.[86] In RM 77, which is currently going through the rulemaking process, language has been proposed that states, "After April 1, 2023, any small generator facility requiring an inverter that submits an interconnection request shall use a smart inverter with either a default or a site-specific utility required inverter settings profile, as determined by a utility."[87] In addition to Maryland, CHESSA/CCSA commented that National Grid determined that most inverters that are UL 1741 certified do not require DTT and, instead, can use reclose blocking.[88] CHESSA/CCSA also commented that several states, including Maryland, New York, and Pennsylvania, are now incorporating these requirements into interconnection rules, requiring utilization of these standards between January and April of 2023, depending on the jurisdiction.[89]

[83] CRI at 3.
[84] *Id.*
[85] *Id.*
[86] *Id.* at 8.
[87] *Id.* at 9.
[88] CHESSA/CCSA at 24.
[89] *Id.* at 27-28.

CHESSA/CCSA recommended that, at a minimum, the utilities must enable opportunities for interconnection customers ("ICs") to pay for dynamic studies to evaluate inverter capability.[90] If the dynamic study shows that DTT is not required, the utilities should be required to consider and implement other alternatives, such as inverter-based solutions.[91] Sun Tribe also stated that the Commission should evaluate the review metrics used to determine the need for DTT.[92]

CHESSA/CCSA and Secure Futures commented that consideration should also be given to project size and interconnection level when considering the use of inverters. For example, CHESSA/CCSA recommended that all Level 2 interconnections and Level 3 interconnections under 5 MW use inverters as opposed to DTT.[93] Similarly, Secure Futures stated that requiring dark fiber is not permissible in the Regulations for Level 2 interconnections of 2 MW or less, which require that the interconnection exceed the 2018 IEEE 1547 Standard only when new IEEE standards conflict with the 2018 IEEE 1547 Standard.[94] Secure Futures further stated that it had installed a recloser for a 1 MW system in the service territory of APCo in 2017 under an approved Level 2 Interconnection.[95] According to Secure Futures, APCo required a recloser to be installed but did not require

[90] *Id.* at 24.
[91] *Id.*
[92] Sun Tribe at 6.
[93] CHESSA/CCSA at 14-15.
[94] Secure Futures at 2. *See* section 20VAC5-314- 60 D.7. of the Regulations.
[95] *Id.* at 3.

dark fiber or cellular DTT, nor did it require any substation or other distribution system upgrades.[96]

According to Appalachian Voices, a capability that IEEE-1547-2018-compliant inverters offer that other inverters do not is the ability for a utility to modify inverter settings remotely and dynamically.[97] Appalachian Voices points out that a utility with remote control of an inverter could implement all sorts of inverter setting changes that might operate beyond a DER owner's awareness, which could impact the revenue and profitability of a DER.[98]

Dominion stated that IEEE-1547-2018 is the product of various stakeholders' efforts, including several members of Dominion's engineering team.[99] Dominion further noted that the objective of the standard is to establish minimum DER performance requirements to which certified inverter-based DERs must adhere to in order to ensure DERs do not negatively affect the electric power system.[100] While Dominion supports IEEE-1547-2018 and its ride-through and grid support capability requirements for DER, it still believes that any utilization of DER ride-through or voltage regulation functionalities should be at Dominion's discretion and should be evaluated based on system needs on a case-by-case basis.[101] Dominion asserted that its current system protection standards do not support the anti-islanding capabilities of DER inverter-based resources as an alternative

[96] *Id.*
[97] Appalachian Voices at 21 and 35.
[98] *Id.* at 36.
[99] Dominion at 10.
[100] *Id.*
[101] *Id.*

to Dominion-owned and maintained system protection schemes for DTT.[102] Specifically, Dominion commented that anti-islanding functions of DER inverter-based resources alone do not replace the multiple functions and layered protection that DTT provides to the electric power system beyond anti-islanding.[103] Dominion further commented that it does not believe that any revisions to the Regulations are currently necessary with regards to IEEE 1547-2018, because existing rules and procedures requiring that Level 1 and Level 2 interconnections meet the IEEE 1547 requirements sufficiently address this issue.[104]

APCo stated that it had no preference regarding IEEE 1547 but noted that the adoption of the IEEE 1547-2018 standard addresses both intentional and unintentional islanding of DERs and standardizes the technical requirements for DERs connected to any distribution utility.[105] KU-ODP suggested that any revisions to the Regulations include updated references to applicable safety requirements and industry standards.[106] This includes updates related to IEEE 1547.[107]

CHESSA/CCSA, Appalachian Voices, SEIA, and Sun Tribe stated that given the highly technical nature of IEEE 1547, they recommend that the Commission separately convene technical experts to discuss the various implementation challenges.[108] Similarly,

[102] *Id.* at 11.
[103] *Id.*
[104] *Id.* A description of Level 1 interconnections can be found in section 20VAC5-314-40 of the Regulations.
[105] APCo at 6
[106] KU-ODP at 5.
[107] *Id.*
[108] CHESSA/CCSA at 28; Appalachian Voices at 37; SEIA at 17; Sun Tribe at 6.

VMDAEC also stated that proposed changes or actions related to IEEE 1547 should be explored in a separate proceeding.[109]

Cellular Communications Alternative

Several parties suggested using cellular communications as an alternative to dark fiber. VAEE urged the Commission to consider and enable the use of whatever communications options can meet the project's needs, allowing for the most cost-effective and reliable option to be used in all cases.[110] This includes the use of cellular communication.[111] VAEE, Sunworks, and Secure Futures highlighted a case study that involved Dominion and Central Virginia Electric Cooperative in which cellular communication was used as opposed to dark fiber.[112] According to the parties, this case study was outlined in the paper "New Intelligent Direct Transfer Trip Over Cellular Communication," published in 2019 at the 72nd Conference for Protective Relay Engineers. Secure Futures stated that, in this case study, Siemens engineers concluded that DTT cellular communications provided an efficient and cost-effective approach for utility communications with distributed generation systems.[113]

Additionally, Sun Tribe stated that it is aware that Dominion is currently piloting a backup relay for its transfer trip communications.[114] According to Sun Tribe, a backup

[109] VMDAEC at 16.
[110] VAEE at 15.
[111] *Id.*
[112] VAEE at 16; Sunworks at 15; Secure Futures at 7.
[113] Secure Futures at 7.
[114] Sun Tribe at 5

relay would allow DERs to meet safety requirements without dark fiber by utilizing more cost-effective communication mediums such as cellular modems.[115]

Finally, EDF commented that Eversource successfully used cellular communications for DTT on their system.[116] Sun Tribe commented that Duke Energy allows the use of alternate communications means other than dark fiber for transfer trip and relay protection on transmission interconnected generation projects.[117]

Number of Fiber Strands

Sun Tribe stated that a dark fiber line for Dominion is typically comprised of 72 strands of optical glass.[118] If dark fiber is necessary for a DER project, VAEE recommended that the Commission allow projects only to use the 24 dark fiber strands needed to communicate between the substation and the project for system protection.[119] This would enable up to two more DER projects to share the remaining strands without running a new line for each project, thus decreasing costs.[120] Sun Tribe also stated that a solar project may only require two strands to communicate between the substation and the project for system protection.[121] Therefore, allowing the other DER projects to use the remaining strands in an existing fiber-optic cable instead of having to install a new

---

[115] *Id.*
[116] EDF at 1.
[117] Sun Tribe at 5.
[118] *Id.* at 1.
[119] VAEE at 16.
[120] *Id.*
[121] Sun Tribe at 1.

dedicated fiber-optic cable would significantly reduce costs.[122] Sun Tribe and VAEE stated that Dominion is piloting this approach on at least one project.[123]

Cost Transparency

A number of parties commented that they would like more cost information to be provided in the study reports and cost estimates provided earlier in the study process. Specifically, CHESSA/CSSA and SEIA stated that more information regarding upgrades and their associated costs should be included in the study reports.[124] Additionally, CHESSA/CSSA, Sun Tribe, VAEE, and Appalachian Voices requested that a comprehensive statement of upgrade costs be provided earlier in the study process so that developers can make informed decisions earlier in the study process.[125] Under the current system, comprehensive cost estimates, which include the cost estimate for dark fiber and substation upgrades, are provided at the end of the study process (in the Facilities Study Report). CHESSA/CSSA stated that developers have experienced project cost estimates for interconnection upgrades surging by over $2 million between the system impact study and the facilities study.[126] According to VAEE, this has created unnecessary risk for developers and impacted the viability of projects after substantial time and money had been

[122] *Id.*
[123] Sun Tribe at 1; VAEE at 16.
[124] CHESSA/CCSA at 10,12, and 25; SEIA at 3
[125] CHESSA/CCSA at 10; Sun Tribe at 1-2; VAEE at 16; Appalachian Voices at 11 and 14.
[126] CHESSA/CCSA at 10-11.

invested in the projects.[127] A few recommendations were provided by some parties to help improve cost transparency, and control excessive costs in general.

Unit Cost Guide

Dominion has recently published a Guide for Interconnection Parameters for DER.[128] Dominion stated that this Guide for Interconnection Parameters contains a unit-cost guide to provide estimated distribution and substation facilitates costs for typical DER upgrades.[129] Several parties recognized this Guide as an important resource for estimating costs. Sun Tribe recommended that APCo publish a similar guide.[130]

Earlier Substation/Dark Fiber Cost Estimates

Sun Tribe and VAEE recommended that a utility substation engineer participate in the initial scoping meeting to provide early insight and visibility into approximate substation upgrade costs.[131] Additionally, Sun Tribe suggested that utilities be required to provide fiber costs as part of the earlier occurring Feasibility Study as opposed to the Facilities Study.[132]

[127] VAEE at 7.
[128] Dominion at 5.
[129] *Id.*
[130] Sun Tribe at 4.
[131] Sun Tribe at 2; VAEE at 23.
[132] Sun Tribe at 2.

Cost Cap

Under the current structure, after an SGIA is signed and executed by the developer, they are told that the final bill will be issued at the end of the construction process to reflect the actual cost of the upgrades. CHESSA/CCSA stated that the absence of an upward bound on cost overruns for construction serves as a roadblock to financing for projects.[133] CHESSA/CCSA recommended implementation of a cost envelope and cap on estimates to provide reasonable certainty regarding interconnection costs.[134] According to CHESSA/CCSA, other states have implemented a cost cap for interconnection costs.[135] For example, CHESSA/CCSA stated that Massachusetts and California cost estimate overruns are capped at 25% of the total project cost. In Massachusetts and California, utility shareholders are responsible for additional costs beyond the cap.[136] CHESSA/CCSA asserted that other cost envelope models have assessed cost overruns to the utility rate base.[137] Furthermore, CHESSA/CCSA recommended that the utilities should be required to provide regular reports to the project owner as expenses accrue to ensure that the project owner is aware of the expenses as they occur.[138]

[133] CHESSA/CCSA at 11.
[134] *Id.* at 12.
[135] *Id.* at 11.
[136] *Id.*
[137] *Id.*
[138] *Id.* at 12.

SGIA Refundability

CHESSA/CCSA stated that under the current Regulations a developer must submit a letter of credit or surety bond for the entire amount of the interconnection upgrade within 30 days of receiving the SGIA.[139] Additionally, after the execution of the SGIA, the upgrades (non-project specific expenses) are considered nonrefundable if there are any interdependent projects in the queue behind the developer's project.[140] According to CHESSA/CCSA, the requirement of security instruments to immediately cover 100% of the expense of the interconnection (including the nonrefundable portion) creates an undue financial burden on the developer.[141] Adding to the challenge, CHESSA/CCSA stated that the Dominion Distributed Solar request for proposal process is not a first-come, first-served program.[142] Therefore, a project needs to provide a potentially significant nonrefundable deposit for interconnection without knowing if they have a buyer for their project or power produced.[143] Accordingly, CHESSA/CCSA recommended the implementation of interconnection deposit refundability policies.[144] CHESSA/CCSA stated that in New York, a developer must initially pay 25% of the upgrade cost with the remaining 75% due after certain milestones are achieved.[145] If the developer terminates the interconnection

[139] *Id.* at 15-16.
[140] *Id.* at 16.
[141] *Id.*
[142] *Id.*
[143] *Id.*
[144] *Id.* at 24.
[145] *Id.*

agreement before the final milestone, they would not be required to pay the additional 75%, and their deposit would be returned minus any expenses incurred.[146]

Cost Allocation

Under the current Regulations, the first project in the queue that causes the need for an upgrade pays 100% of the cost for the upgrade. This is generally considered the cost causation principle. Sunworks stated that the types of upgrades now being required are much more expensive, and no single project can support or bear these costs.[147] Accordingly, several parties have suggested various models for cost sharing options to reform the "cost-causer" model. These options are discussed below.

Cost Sharing between Developers

As part of the cluster study pilot proposed by Dominion, interconnection costs would be allocated among multiple projects, thereby reducing the cost paid by each interconnection customer ("IC") on a per-project basis.[148] Sunworks also proposed cost sharing between ICs; however, that cost sharing would be limited in scope.[149] Under Sunworks' proposal, cost sharing would only apply to situations where distribution or substation upgrades exceed $1 million of actual costs incurred for a period of five years from the date that equipment is placed in service.[150] A secondary project which uses these

[146] *Id.*
[147] Sunworks at 14.
[148] Dominion at 5-6.
[149] Sunworks at 14.
[150] *Id.*

resources would be required to pay their pro rata share of these upgrades to the prior project, based on the number of MW requested to interconnect.[151]

Cost Sharing between Various Beneficiaries

Several parties stated that costs should be shared across a range of beneficiaries, recognizing that bulk power system upgrades and the associated benefits may flow to customers other than to the DERs seeking to interconnect. CHESSA/CCSA recommended that the Commission consider implementing cost sharing mechanisms that have been implemented in other states such as Massachusetts, New York, and Maine.[152] CHESSA/CCSA used New York as an example. In New York, this cost sharing mechanism is called "Pro rata cost sharing," whereby a developer pays its share of the system upgrades.[153] The subsequent projects that seek to interconnect to the upgraded substation would pay their portion of the upgrade cost until the entire capacity is used up and the upgrade costs are fully paid.[154] In the situation where not enough projects interconnect to support the total cost of the upgrade, the utility can include the remaining costs of the upgrade in rate base five years after the upgrade was triggered.[155] Clean Virginia also identified and described five cost sharing models considered by Maryland.[156] According to Clean Virginia, the Maryland Interconnection Working Group developed a cost-sharing proposal in which utilities provide the upfront costs of upgrades, and DER

[151] *Id.*
[152] CHESSA/CCSA at 23.
[153] *Id.*
[154] *Id.*
[155] *Id.*
[156] Clean Virginia at 3-4.

project developers refund the utility.[157] As described by Clean Virginia, this proposal also included some ratepayer protection provisions.[158] Sun Tribe and VAEE stated that Tennessee Valley Authority ("TVA") considers network upgrades such as transfer trip communications (dark fiber) to benefit the entire system, not just the individual DER.[159] Therefore, these costs are ultimately borne by TVA, not the project developer.[160] According to CHESSA/CCSA, ideally, cost sharing models should be implemented in conjunction with reforms to distribution system planning procedures and the implementation of grid modernization measures.[161]

Conversely, APCo and VMDAEC commented that costs should be allocated to those who install and operate the DERs, and not to customers who do not benefit from the DERs.

Material Modification

Sun Tribe, VAEE, SynerGen Solar, and CHESSA/CCSA commented on the material modification section of the Regulations. Specifically, Sun Tribe and VAEE stated that there appears to be some confusion between developers and utilities regarding the interpretation of the existing language related to the ability to downsize a project before and after the Feasibility Study.[162] According to Sun Tribe and VAEE, developers believe

---

[157] *Id.* at 6.
[158] *Id.* at 6-7.
[159] Sun Tribe at 5; VAEE at 17.
[160] Sun Tribe at 5.
[161] CHESSA/CCSA at 23.
[162] Sun Tribe at 2-3; VAEE at 7.

an IC is permitted to downsize its project by up to 25% prior to execution of the Feasibility Study Agreement and up to 10% after the Feasibility Study Agreement, without such downsizes being considered a material modification.[163] However, the current utility interpretation of this provision is that the IC can only choose one of the two.[164] According to VAEE, the current PJM proposal allows for two downsizes throughout the study process.[165] Sun Tribe and VAEE also stated that Southern Company allows for a 60% project downsize prior to phase 2 of the study process and 15% before phase 3.[166] As such, Sun Tribe and VAEE would like some clarity on the reading of the provision.[167]

SynerGen Solar proposed a revision to the material modification section related to changing the point of interconnection ("POI") to a new location.[168] Specifically, SynerGen Solar would like to add language that would allow a change in the POI on the same property to not trigger a material modification.[169]

CHESSA/CCSA commented that the current material modification section restricts the ability to incorporate energy storage into an existing interconnection application without triggering a material modification.[170] They stated that the current Regulations do

---

[163] Sun Tribe at 2; VAEE at 7.
[164] Sun Tribe at 2-3; VAEE at 7-8.
[165] VAEE at 17
[166] Sun Tribe at 5; VAEE at 17-18.
[167] Sun Tribe at 3; VAEE at 8.
[168] SynerGen Solar at 3.
[169] *Id.*
[170] CHESSA/CCSA at 17.

not allow for changes to the daily production profile, which essentially precludes the addition of energy storage without triggering a material modification request.[171]

Dispute Resolution

Secure Futures, VAEE, and CHESSA/CCSA commented on dispute resolution aspects of the interconnection study process. Specifically, Secure Futures recommended implementation of an expedited dispute resolution process for Level 2 interconnection concerns.[172] VAEE suggested that parties be required to provide easy-to-find contact information for a timely dispute resolution process.[173] CHESSA/CCSA requested that the current dispute resolution procedures be enhanced. First, CHESSA/CCSA recommended a mechanism to discuss study results and cost estimates before a construction call is scheduled.[174] Currently, the construction call is the first opportunity the IC has to discuss the study results with the utility and any associated disputes. Second, CHESSA/CSSA recommended a tolling of time and milestones when a dispute has been initiated.[175] This would include tolling the 30-business day timeline required for signing the SGIA and fulfilling the payment/financial security requirements of the SGIA, until the dispute is resolved.[176] Finally, CHESSA/CCSA suggested using an ombudsperson to help facilitate certain escalated disputes and avoid further regulatory action.[177] According to VAEE, New

---

[171] *Id.*
[172] Secure Futures at 5.
[173] VAEE at 8.
[174] CHESSA/CCSA at 25. According to section 20VAC5-314-70 F.1. of the Regulations, a construction call is scheduled within 15 business days of the report for the final study.
[175] *Id.* at 26.
[176] *Id.*
[177] *Id.* at 13.

York and Massachusetts employ ombudspersons within the Commission to help troubleshoot disputes, and Minnesota enlists outside engineers to help mediate issues.[178]

Insurance Requirements

CHESSA/CCSA and SEIA recommended eliminating the proof of liability insurance requirement for Level 1 interconnections and all net energy metering ("NEM") customers.[179] According to CHESSA/CCSA, a proof of insurance requirement unnecessarily slows the process of interconnection. CHESSA/CCSA stated that these insurance requirements are outdated since the utility industry has grown experienced in inverter-based technologies.[180] CHESSA/CCSA further stated that more states have eliminated the proof of insurance requirement for small, inverter-based generators.[181] As part of their comments, CHESSA/CCSA provided a table showing the liability insurance requirements in state interconnection procedures for various states.[182]

Flexible Interconnection

SEIA stated that flexible interconnection incorporates real-time control to manage grid access during grid constraints.[183] VAEE commented that a flexible interconnection could be used to lessen the effects of DERs on the grid by reducing the need for upgrades

---

[178] VAEE at 22.
[179] CHESSA/CCSA at 19; SEIA at 17.
[180] CHESSA/CCSA at 19.
[181] *Id.* at 18.
[182] *Id.*
[183] SEIA at 9.

to the grid.[184] Specifically, this can be accomplished by limiting the amount of output that can be produced and transferred onto the grid from DERs and, therefore, reducing the need for upgrades or new infrastructure.[185] Appalachian Voices stated that a distributed energy resource management system ("DERMS") does offer the capability to remotely control inverter settings dynamically, which could become useful when IEEE-1547-2018-compliant inverters become abundant in the market.[186]

KU-ODP stated that it is deploying a modern advanced distribution management system ("ADMS") as part of its centralized grid operations strategy.[187] KU-ODP is also considering DERMS to be integrated with the ADMS platform.[188] APCo commented that it is also considering the implementation of ADMS and DERMS to manage higher penetrations of DERs.[189]

Nevertheless, Appalachian Voices stated that DERMS are typically needed only at the highest levels of DER capacity.[190] Appalachian Voices also commented that no ADMS is working as advertised.[191] Similarly, SEIA stated that California, Hawaii, and Illinois utilize advanced inverter functions ("AIFs") without needing DERMS because AIFs are largely autonomous and reactive to dynamic grid conditions.[192]

---

[184] VAEE at 20.
[185] *Id.*
[186] Appalachian Voices at 25.
[187] KU-ODP at 2-3.
[188] *Id.* at 3.
[189] APCo at 4.
[190] Appalachian Voices at 24.
[191] *Id.* at 25.
[192] SEIA at 9.

Cybersecurity

APCo, Dominion, and VAEE commented on the need for cybersecurity measures for DERs. These three parties identified the increasing need for a minimum standard for cybersecurity and more robust security protocols for all DERs.[193] VAEE further stated that adopting appropriate, risked-based levels of cybersecurity and data management protocols can ensure the grid remains secure while not creating overly burdensome requirements for DER developers.[194]

Ongoing Workgroups

Several parties have suggested workgroups for IEEE-1547 and other issues. Parties have also recommended ongoing workgroups to develop interconnection policies and technical requirements. According to VAEE, New York has established two working groups, the Interconnection Technical Working Group and the Interconnection Policy Working Group, which meet regularly to continue improving the interconnection process in that state.[195] VAEE stated that the New York Public Service Commission maintains a dedicated webpage to distributed generation information where information on these working groups and other related information is found.[196] Clean Virginia also stated that Maryland has an Interconnection Working Group.[197]

---

[193] APCo at 4; Dominion at 7; VAEE at 6.
[194] VAEE at 6.
[195] *Id.* at 11.
[196] *Id.*
[197] Clean Virginia at 3.

FERC Order 2222

FERC Order 2222 is a rule requiring independent system operators ("ISOs") and regional transmission organizations ("RTOs") in the U.S. to develop plans that give DERs access to wholesale energy markets. FERC Order 2222 would allow for DER aggregation and participation in wholesale markets. Several parties commented on the potential impacts of DER aggregation pursuant to FERC Order 2222. VAEE stated that the Commission should set up systems that "establish[es] an objectively quantifiable basis for measuring, quantifying, and allocating relevant identified benefits and costs," which also means that the Commission should work to avoid duplication of DER benefits in its benefit-cost analysis.[198]

EDF stated that the PJM Non-Retail Behind the Meter cap for DERs is not easily accessible information.[199] Certain cooperatives cannot exceed that cap, but developers don't know how much room there is left under the cap.[200]

CHESSA/CCSA stated that the implementation of FERC Order 2222 will require the deployment of new hardware and software infrastructure that allows distribution companies to have greater visibility and control over the real-time operations of aggregated DERs on their distribution system.[201]

---

[198] VAEE at 24.
[199] EDF at 1.
[200] *Id.*
[201] CHESSA/CCSA at 28.

Appalachian Voices stated that FERC Order 2222 will prompt more prospective DER owners to add energy storage (batteries) to their project designs in order to export power to the grid when economic conditions are favorable.[202] Appalachian Voices also stated that FERC Order 2222 will exacerbate all the current issues.[203]

SEIA believes that DER should have the right to participate in wholesale markets as per FERC Order 2222 but that interconnection reform should not wait for FERC Order 2222 implementation.[204]

APCo commented that FERC Order 2222 could potentially change the use of an existing connected DER from a load program managed under state retail tariffs to one that can inject reliable real-time energy into the RTO markets.[205] APCo also stated that the Commission will have a central and key role in coordinating the participation of aggregated DERs in PJM's market, including setting retail rates at the distribution level; supervising utility review of DER participation in aggregations; evaluating DER interconnection; and overseeing issues regarding distribution system operation and reliability.[206]

VMDAEC stated that participating in the implementation of DER projects should be the individual choice of each Cooperative and that FERC Order 2222 threatens this autonomy.[207] According to VMDAEC, the opt-in/opt-out language from FERC Order

[202] Appalachian Voices at 35.
[203] *Id.* at 34.
[204] SEIA at 17.
[205] APCo at 3.
[206] *Id.* at 6.
[207] VMDAEC at 3.

2222 establishes a mandatory opt-in for utilities that serve 4,000 gigawatt-hours ("GWh") or more of load in a given year.[208] VMDAEC urged the Commission to allow Cooperatives that meet or surpass the 4,000 GWh threshold to opt out of the requirements of PJM pursuant to FERC Order 2222.[209] VMDAEC states that Cooperatives should be able to opt out due to the following concerns:[210]

1. A distribution Cooperative interconnecting DER will incur significant costs to install required software, hardware, metering, sub-metering, protection and isolation equipment, and other related devices, as well as additional personnel to oversee the impact and operations of DER participants in both day-ahead and real-time markets and other PJM products selected by DER participants.

2. Current retail tariffs were not designed to allow a member-consumer end-user to participate as both a retail load and simultaneously as a wholesale provider or market seller in the PJM markets. There will likely be needed tariff changes which the Commission should oversee.

3. Challenges with which Cooperatives are struggling today regarding DER integration under the SGI Rules (and sometimes challenges with NEM under the NEM Rules) will only be exacerbated.

If the Cooperatives cannot opt out, VMDAEC has several questions or concerns related to the implementation of the requirements of PJM pursuant to FERC Order 2222, including:[211]

1. When should distribution utilities be required to begin allowing retail members to participate as wholesale providers?

2. Will the Commission permit a retail member to be registered as both a retail member-consumer and a wholesale provider simultaneously?

---

[208] *Id.*
[209] *Id.* at 10.
[210] *Id.* at 2 and 4.
[211] *Id.* at 11-13.

3. What will be the cost recovery mechanism for the equipment, hardware, and software that would be needed to effectively oversee and implement the requirements of allowing retail members to participate as wholesale providers?

4. In regard to NEM projects, does the Commission intend to allow all equipment installed behind the retail meters that have the capacity to inject energy into the distribution grid to inject electric power into that distribution grid?

VMDAEC stated that all Cooperatives below the FERC Order 2222 requirement threshold would suffer irreparable harm if the Commission were to require them to opt into the requirements of FERC Order 2222.[212]

Dominion commented that FERC Order 2222 may significantly impact the resources available to it in administering the existing state interconnection queue, given the order's heavy reliance on electric utilities to review DER Aggregation ("DERA") requests.[213] Dominion believes that the following actions should be considered regarding DER aggregation pursuant to FERC Order 2222:[214]

1. Close coordination with PJM to ensure the development of consistent processes relating to the DERA interconnection process.

2. Establishment of a two-stage process for the approval of new DER aggregation resources, including a pre-registration process followed by a 60-day evaluation period, to ensure the DERA can safely operate as one collective resource on the distribution system when transacting in PJM markets, as proposed by PJM's compliance filing.

3. Update the Regulations to (a) require that all component DERs to be aggregated are subject to a previously signed interconnection agreement; (b) provide for an expanded study process, including expanded participation by affected systems; (c) limit the DERA's ability to change the participants in any particular aggregation grouping once the study process has begun; and (d) reaffirm the requirement that

[212] *Id.* at 15.
[213] Dominion at 7-8.
[214] *Id.* at 8.

interconnecting DERs be aggregated to the same electrical node or geographical location.

Dominion also stated that electric utilities will likely face a host of new regulatory challenges, policy, and technical issues associated with DER aggregations; these will require additional resources.[215]

KU-ODP had a similar comment to VAEE and VMDAEC regarding participation in the retail and wholesale markets, stating that compensation would be duplicated by dual participation in both markets.[216] Additionally, KU-ODP suggested that the Commission consider implementing appropriate technical reviews of DER installations that will be participating in wholesale aggregations.[217]

Due to the complexities related to FERC Order 2222, Sun Tribe, VAEE, CHESSA/CCSA, APCo, and Dominion believe that it would be appropriate to establish a separate proceeding for the planning and implementation of FERC Order 2222.[218]

TOPICS IDENTIFIED BY THE UTILITY PARTIES

The topics identified by the utilities which were not discussed above included, among other things, consumer education, NEM issues, DER performance standards, and staffing. Each topic is discussed in detail below.

[215] *Id.*
[216] KU-ODP at 4.
[217] *Id.*
[218] Sun Tribe at 6; VAEE at 25; CHESSA/CCSA at 28; APCo at 6; Dominion at 8.

Definition of "DER"

APCo stated that there is no clear definition of "DER" and the types of systems covered. DER can refer to a broad range of operational assets for electricity generation, energy storage, load management, and various control systems that connect physically to the electricity system at the distribution level.[219] According to APCo, a common definition of "DER" could provide a consistent framework for future discussions and policy advancements.[220] Furthermore, APCo commented that establishing interconnection requirements and rules for various types of DERs would, in turn, streamline the interconnection process for all types of covered DERs.[221]

Evaluation of Assortment of Equipment and Systems

APCo stated that increased DER interconnections will result in a greater need for new equipment, processes, software systems, and standards, including monitoring, metering, telemetry, bidirectional devices, reclosing/curtailment devices, and backend and headend systems.[222] APCo asserted that there is a need to evaluate the numerous varieties of equipment and systems being used by the developer.[223] As such, APCo recommended a state-approved list of customer DER equipment and technical attributes in order to

---

[219] APCo at 4.
[220] *Id.*
[221] *Id.* at 2.
[222] *Id.* at 1.
[223] *Id.*

accelerate the DER interconnection process.[224] According to APCo, California has implemented a list of customer DER equipment.[225]

Modeling

APCo stated that accurate modeling of DERs in transmission and distribution planning studies is needed to understand the potential opportunities and challenges related to bulk power system reliability.[226] In addition to the modeling, APCo commented that accurate, more granular historical and real-time data is needed to develop system models, validate results, and perform real-time and long-term analysis and planning.[227]

DER Performance Standards

Due to the increasing dependence on DER generation for a utility's reliability, APCo stated that performance standards are also needed for DERs to ensure that reliability is not degraded by DERs being interconnected without meeting reliability requirements.[228]

Consumer Education

KU-ODP commented that lack of customer education and compliance has caused issues with interconnections.[229] For example, a developer failing to provide adequate documentation or failing to build a project according to KU-ODP's standards has been

---

[224] *Id.*
[225] *Id.* at 4.
[226] *Id.* at 2 and 4.
[227] *Id.* at 3.
[228] *Id.* at 7.
[229] KU-ODP at 1.

known to lead to rework and delays.[230] Furthermore, KU-ODP stated that misleading information from installers, including those related to false rebates and claims, is negatively impacting the customer experience.[231]

Similarly, APCo recommended that consideration be given to advancing consumer education and protection measures to ensure that any customer opting to invest in DERs understands the potential benefits and costs of installing and operating such systems.[232]

NEM Issues

VMDAEC included a number of NEM issues in its comments. First, VMDAEC commented that the Commission should emphasize in its Regulations Governing NEM that the member requesting the interconnection is responsible for any network or distribution upgrades that might be required as a result of the interconnection.[233] Additionally, VMDAEC commented that Commission guidance is needed on when a utility is required to notify its members along a specific circuit once that circuit can no longer tolerate additional NEM penetration without significant and costly upgrades.[234] VMDAEC stated that Cooperatives are already beginning to see lightly-loaded circuits become "full" due to high NEM penetration.[235]

---

[230] *Id.* at 1-2.
[231] *Id.* at 2.
[232] APCo at 5.
[233] VMDAEC at 8.
[234] *Id.* at 9.
[235] *Id.*

In addition to VMDAEC, KU-ODP recommended a standardized application fee of $100 for net metering applications.[236] According to KU-ODP, this fee would help the Company respond timely to requests and prevent the inappropriate socialization of interconnection costs.[237]

Staffing

VMDAEC stated that the level of specialized staffing required to facilitate and manage DER projects continues to be an obstacle.[238] According to VMDAEC, less than one-quarter of a full-time employee ("FTE") is dedicated to small generator interconnection requests.[239] As DER penetration continues to increase, more dedicated and specialized FTEs will be needed.[240]

FERC NOPR – INTERCONNECTION REFORM

On June 16, 2022, FERC issued a Notice of Proposed Rulemaking ("NOPR") announcing proposed reforms to its standard generator interconnection procedures and agreements. The NOPR aims to address significant current backlogs in the interconnection queues by improving interconnection procedures. The NOPR includes several key areas of reform including, but are not limited to:

1. The transition from the current "first-come, first-served" approach to the first-ready, first-served cluster model;

[236] KU-ODP at 4. Currently, these is no application fee for prospective NEM customers.
[237] *Id.*
[238] VMDAEC at 5.
[239] *Id.*
[240] *Id.* at 6.

2. Impose firm deadlines and establish penalties if transmission providers fail to complete interconnection studies on time;

3. Require transmission providers to allow more than one resource to co-locate on a shared site behind a single point of interconnection and share a single interconnection request; and

4. Propose certain modeling and performance requirements for non-synchronous generating facilities to address the unique characteristics of the changing resource mix.

Staff notes that it utilized FERC's interconnection procedures and agreements as the basis for its most recent reforms to the Regulations in Case No. PUR-2018-00107. As such, Staff brings to the Commission's attention FERC's issuance of the NOPR, given the similarities in the issues being addressed in both proceedings.[241]

CONCLUSIONS AND RECOMMENDATIONS

After reviewing the comments, Staff acknowledges the concerns expressed by both the non-utility and utility parties regarding interconnection of DERs. Given the large number of issues raised by the parties, Staff is unsure that all issues can be addressed simultaneously within the same docket. However, Staff believes there are multiple avenues for addressing the various issues. These pathways include (i) making reforms to the existing Regulations ("Regulations Reform"); (ii) establishing working groups; (iii) implementing pilot studies; (iv) establishing separate proceedings outside the scope of the

[241] Additionally, Sunworks used the FERC NOPR as the basis of several of its comments.

Regulations Reform; and (v) using utility administration and application processes.[242] Staff's opinion on how to address the various topics is provided below.

Application Process

Staff agrees that moving the application process to an online portal would greatly benefit utilities and the developer community in terms of speed and workflow. Staff also concurs that the websites for interconnections should include other relevant information such as application checklists, contact information, etc. As such, utilities should continue working towards implementation of an online application process. Staff is open to discussions with the parties to determine what information can be placed online that would be helpful to the developer community, while not being overly burdensome to the utilities.

Long Study Timelines

Staff believes this topic and associated solutions warrant further discussion beyond the instant proceeding and can be discussed as part of the Regulations Reform. Furthermore, Staff does not oppose the concept of piloting a targeted cluster study as proposed by Dominion, but further details and examination are needed to determine what such a pilot would look like and how it would be conducted in order to achieve the best results.

[242] Should the Commission make any specific findings and recommendations in this case, the Commission may wish to direct annual reporting requirements in this docket for utilities to report on the status of its efforts in complying with any Commission directives.

Long Construction Timelines

Staff believes to a limited extent this topic can be explored in the context of the Regulations Reform. Long construction timelines could be addressed in the context of reforms to the SGIA or construction meeting. Staff understands that utilities are facing supply chain issues that have real effects on the construction timelines but believes that the impact of supply chain issues are often situational and might be most appropriately addressed between the utilities and developers outside of the Regulations Reform or other Commission proceeding.

Lack of Information

Staff believes that this topic and associated solutions warrant further discussion beyond the instant proceeding. Staff also believes solutions can be implemented in the context of the Regulations Reform and utility administration and application. In Staff's opinion, hosting capacity maps are a valuable tool for the developer community. Staff recommends that all utilities consider developing a hosting capacity tool if it is not cost-prohibitive. Additionally, enhancements should continue to be made on existing hosting capacity tools. Hosting capacity map topics would fall outside the scope of the Regulations Reform, in Staff's view.

Staff also agrees that publishing an interconnection queue on a utility's website can be greatly beneficial to the developer community. Accordingly, Staff recommends that all utilities post on their websites an interconnection queue report similar to that currently provided by Dominion and APCo. Furthermore, Staff recommends the utilities update their interconnection queue reports monthly.

Staff believes that publicly posting completed interconnection study reports requires further discussion due to possible confidentiality concerns. That discussion could occur in the context of the Regulations Reform.

Excessive Cost of Interconnection

Excessive costs of interconnection, specifically related to dark fiber and DTT, appear to be a significant issue for the developer community. As such, Staff believes this topic warrants further discussion by means of a working group. Depending on the outcome of the working group, changes to the Regulations may then be warranted at a future time. The concept of a working group is discussed in more detail below.

Dark Fiber/DTT

Staff believes that this topic and associated alternatives warrant further discussion beyond the instant proceeding. Staff recognizes the possibility of using alternatives to fiber-optic cables for DTT. Staff also acknowledges that various other utilities, including APCo, may already utilize these alternatives for DTT. However, Staff agrees with CHESSA/CCSA, Appalachian Voices, SEIA, and Sun Tribe that a technical working group may be required to discuss potential alternatives to DTT, including cellular communications, the implementation of IEEE 1547 certified inverters, and other possible alternatives. Once the alternatives have been developed by the technical working group, related reforms can then be made to the Regulations. Staff also does not oppose pilot studies for: (i) the use of cellular communications as an alternative to fiber-optic cables; (ii) reduction in the number of strands of fiber installed; and (iii) shared usage of installed fiber-optic cables. The implementation of such pilot studies could be discussed as part of the working group.

Cost Transparency

The following cost transparency related topics can be discussed as part of the Regulations Reform: (i) provision of substation and dark fiber cost estimates earlier in the study process; (ii) cost caps; and (iii) cost refundability in the context of the SGIA. Similar to the hosting capacity maps, Staff believes that a unit cost guide is a valuable tool for the developer community, and Staff recommends that a similar guide be developed and published by all utilities.

Cost Allocation

Staff believes that cost allocation and associated alternatives warrant further discussion beyond the instant proceeding. Cost sharing can be discussed within the context of utilizing a cluster study approach or by itself. If considered appropriate by the Commission, a working group could be tasked with developing the appropriate cost sharing mechanisms. Once developed, cost sharing mechanisms could then be included as part of the Regulations Reform.

Material Modification

Staff believes that material modification warrants further discussion beyond the instant proceeding and can be discussed as part of the Regulations Reform.

Dispute Resolution

Staff believes that dispute resolution warrants further discussion beyond the instant proceeding and can be discussed as part of the Regulations Reform.

Insurance Requirements

Staff believes that this topic warrants further discussion beyond the instant proceeding. The portion related to Level 1 interconnections can be discussed as part of the Regulations Reform. The portion pertaining to NEM could be addressed as part of a proceeding to reform the NEM rules.

Flexible Interconnection

Staff believes that flexible interconnection, ADMS, and DERMS fall outside the scope of the Regulations and should be examined as part of a separate proceeding.

Cybersecurity

Staff agrees that cybersecurity measures are needed for DERs. Staff believes this topic warrants further discussion beyond the instant proceeding and can be discussed as part of the Regulations Reform.

Ongoing Workgroups

Staff does not oppose the concept of ongoing workgroups to continuously develop enhanced interconnection policies. However, further discussion on the formation of the workgroups will be required.

FERC Order 2222

On February 1, 2022, PJM submitted a compliance filing outlining how it will comply with FERC Order 2222. In this filing, PJM proposed revisions to the PJM Open Access Transmission Tariff ("OATT") in accordance with Order No. 2222 and associated orders. Specifically, PJM's proposed OATT revisions establish a market participation model for DER aggregations. On May 18, 2022, FERC requested additional information from PJM regarding its compliance filing. PJM provided the requested information on July 7, 2022. FERC has yet to issue an Order on PJM's compliance filing. PJM's compliance filing would allow DER aggregators to begin participating in the electric market in 2026.

Staff recognizes the complexities and challenges associated with the compliance requirements of FERC Order 2222 and DER aggregation as presented by the parties. Staff agrees with Sun Tribe, VAEE, CHESSA/CCSA, APCo, and Dominion that, given the complexities related to FERC Order 2222, a separate proceeding outside the scope of the Regulations Reform may be warranted for the planning and implementation of FERC Order 2222. However, since FERC has not issued an Order on PJM's compliance filing, Staff believes a separate proceeding may not be immediately required.

Definition of "DER"

Staff believes that this topic warrants further discussion beyond the instant proceeding and can be discussed as part of the Regulations Reform.

Evaluation of Assortment of Equipment and Systems

Staff believes this topic warrants further discussion beyond the instant proceeding and may fall outside the scope of the Regulations. This topic could be included as part of a working group discussion.

Modeling

Staff believes this topic falls outside the scope of the Regulations Reform. Modeling may need to be addressed with PJM or other entities. Modeling may also be discussed as part of a utility's integrated resource plan, especially since those are now required to include distribution system planning.

DER Performance Standards

Staff believes this topic warrants further discussion beyond the instant proceeding and can be discussed as part of the Regulations Reform.

Consumer Education

Staff believes this topic can be addressed, at least partially, in the near term by utilities providing additional information on their websites. This topic can also be further discussed as part of the Regulations Reform.

NEM Issues

Staff believes that NEM issues would fall outside the scope of the Regulations Reform and should be discussed as part of a proceeding to reform the NEM rules.

Staffing

Staff believes this topic falls outside the scope of the Regulations Reform. It is Staff's understanding that generally the Commission is not actively involved in determining utilities' staffing needs, although Staff does review payroll expenses during proceedings that review utilities' cost of service, such as triennial review proceedings.

In conclusion, as stated above, several of these topics can be addressed in the context of the Regulations Reform. However, due to the variance in the complexity and investigation that is required, Staff believes one option for the Commission's consideration is for the Regulations Reform to be a multi-step process. In other words, in Staff's opinion, a targeted approach could be used that opens up only selected portions of the Regulations for reform at a time; that may be the most effective way to address the variety of issues described above. For example, topics like dispute resolution may be ripe for immediate

Regulations Reform, while other issues, such as the implementation of IEEE 1547-2018 certified inverters, may better be addressed at a later time after a working group activity has been completed. If so directed by the Commission, Staff is willing to work with the parties to determine which topics could be addressed more immediately, and then develop an outline for any upcoming rulemaking proceeding on the Regulations Reform.

Additionally, Staff will continue to be attentive to the developments of the FERC NOPR and FERC Order 2222 proceedings. Staff will also explore and examine what other steps states have taken to improve their interconnection processes. This knowledge would ultimately help develop the most appropriate interconnection reforms for Virginia.