Virginia Distributed Energy Resource (DER) Interconnection Working Groups

Final Report for the Virginia State Corporation Commission's DER Interconnection Working Group Process

VOLUME 1

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The working group process described in this report was convened by the Virginia State Corporation Commission and was facilitated by the Great Plains Institute. The Great Plains Institute prepared this report in consultation with Virginia State Corporation Commission Staff.

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Contents, Volume 1

This document is **Volume 1** of the Final Report for the Virginia DER Interconnection Working Group Process. A compiled PDF of all presentations made throughout the working group process is found in **Volume 2**.

Acronyms and Abbreviations

APCo/AEP	Appalachian Power Company/American Electric Power
ASO	Affected System Operator
Commission	Virginia State Corporation Commission
Co-op	Electric cooperative, cooperative association
DER	Distributed Energy Resource
DTT	Direct Transfer Trip
FERC	Federal Energy Regulatory Commission
GTSA	Grid Transformation and Security Act (2018)
IC	Interconnecting Customer
IOU	Investor-Owned Utility
IR*	Interconnection Request or Application
IREC	Interstate Renewable Energy Council
KU	Kentucky Utilities
kV	Kilovolt
kW	Kilowatt
ms	Millisecond
MW	Megawatt
NY CESIR	New York Coordinated Electric System Interconnection Review
PNNL	Pacific Northwest National Laboratory
RTO	Regional Transmission Operator
SCC	Virginia State Corporation Commission
SGIA*	Small Generator Interconnection Agreement
VA-DSA	Virginia Distributed Solar Alliance
VCEA	Virginia Clean Economy Act (2020)
VMDAEC	Virginia, Maryland, and Delaware Association of Electric Cooperatives

Acronyms marked with an asterisk (*) reflect the terminology used in Chapter 314 of the Virginia Administrative Code, Regulations Governing Interconnection of Small Electrical Generators and Storage.

Executive Summary

A. Background

Regulatory Background

In May 2022, the Virginia State Corporation Commission (SCC or Commission) opened Case No. PUR-2022-00073, *In the matter considering utility distributed energy resource interconnection-related issues and questions*, to explore issues related to distributed energy resource (DER) interconnection in Virginia.[1] Parties were invited to provide comments and filings in the case to develop a record on such issues.

On September 9, 2022, SCC Staff filed a report informed by these comments.[2] In their report, Staff identified a range of DER interconnection issues to be explored and noted that certain issues would likely be best explored and addressed through specific mechanisms or venues. On March 3, 2023, the Commission issued an Order in Case No. PUR-2022-00073 establishing the mechanisms (working groups, a Staff-administered survey, or a rulemaking) through which the issues identified in the Staff Report should be addressed.[3]

In the March 3, 2023 Order, the Commission directed Staff to convene two working groups to address six identified issues. Per the Order, the two working groups were directed to focus on the following topics:

- ***Working Group 1:*** *Study timelines, construction timelines, and cost allocation*
- ***Working Group 2:*** *Interconnection costs, cost transparency, and dark fiber/direct transfer trip ("DTT")*

SCC Staff selected the Great Plains Institute (GPI) to facilitate both working groups and to prepare this final report, which should identify points of consensus where found. This report documents the process for these two working groups, points of working group discussion, and DER interconnection issues raised by participants. It also lists the solutions that working group participants developed to address identified issues.

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[1] Virginia State Corporation Commission, Division of Public Utilities Regulation, *Order for Comment* (May 24, 2022), Case No. PUR-2022-00073, *In the matter considering utility distributed energy resource interconnection-related issues and questions*. Available at: https://www.scc.virginia.gov/docketsearch/DOCS/777501!.PDF

[2] Virginia State Corporation Commission, Division of Public Utilities Regulation, *Staff Report* ex parte: *In the matter considering utility distributed energy resource interconnection-related issues and questions* (September 19, 2022), Case No. PUR-2022-00073. Available at: https://www.scc.virginia.gov/docketsearch/DOCS/7nqp01!.PDF

[3] Virginia State Corporation Commission, Division of Public Utilities Regulation, *Order* (March 3, 2023), Case No. PUR-2022-00073, *In the matter considering utility distributed energy resource interconnection-related issues and questions*. Available at: https://www.scc.virginia.gov/docketsearch/DOCS/7q_301!.PDF

Working Group Process

The SCC's DER Interconnection Working Groups ("working groups") met for the first time at a combined meeting in July 2023. Following this initial meeting, Working Group 1 met two times to discuss issues specific to study timelines, construction timelines, and cost allocation and to identify potential solutions that may address those issues. Working Group 2 met three times to discuss interconnection costs, cost transparency, and dark fiber/DTT, and to identify potential solutions that may address those issues. In December 2023, both working groups met for a final combined session in which participants discussed and refined the potential solutions developed throughout the working group process. Process participants included investor-owned utilities, electric cooperatives, renewable energy developers, consumer and environmental advocacy organizations, state agency representatives, and others.

The solutions included in this report were developed by working group participants themselves through multiple discussions. Participants were initially asked to develop potential solutions for consideration, then to refine those solutions, and finally to assess whether they could support each solution as refined (and as included in this report). In the final meeting, participants reached consensus on 13 solutions and did not reach consensus on two solutions. **Importantly, consensus means that all parties who were present in the final meeting said that they at least did not oppose the solution.** In some circumstances, individual parties reached consensus on moving a solution forward even if that party did not support all sub-components of that solution. Participant feedback on each solution included in this report (including participant feedback regarding specific solution sub-components) is provided in **Appendix D, *Summary of Participant Feedback on Solutions***.

B. Proposed Solutions

Table ES-1 on the following page contains a list of the 13 consensus and two non-consensus solutions developed and refined throughout the working group process. The table contains only the solution title and a brief summary of the rationale. The solutions in Table ES-1 and throughout this report are not listed in any order of prioritization or ranking and are enumerated for organizational purposes only. **For full solution language and additional details on the rationale for the solution and implementation considerations if that solution is pursued, please refer to Section V, *Solutions*.** For a summary of participant feedback received on each solution, please refer to **Appendix D, *Summary of Participant Feedback on Solutions***.

Solutions should be interpreted as written. For example, if the solution states that the Commission should explore a specific topic, it should be interpreted as solely the specified exploration (consistent with the parameters as written in the solution). Though findings from that exploration may have the potential to trigger subsequent actions or next steps, **no findings, actions, or next steps should be inferred from the solution text itself unless explicitly specified.**

While preparing this Final Report, parties expressed interest in further conversation regarding how these solutions could be implemented to help address DER interconnection issues in Virginia.

Table ES-1: List of Solutions

Solution Title	Summary of Rationale
Consensus Solutions	
1. Meet and evaluate exceeding current study timeline requirements	Implementing strategies that would help utilities meet existing Chapter 314 study timeline requirements is a reasonable near-term goal. In the long term, however, Virginia should evaluate meeting the more aggressive study timelines that other jurisdictions have demonstrated to be feasible. Strategies that could help utilities meet both near- and long-term timeline goals may involve actions by several involved parties.
2. Secure site access early for the utility	Delays in site access for the utility can lead to delays in the construction of necessary interconnection facilities. These delays could occur due to site ownership issues, permitting issues, inadequate site plans, etc.
3. Improve communications between ICs and utilities	Improved communication between ICs and utilities may offer mutual benefits. ICs would better know what information is necessary to expeditiously proceed through the interconnection request (IR) process and would better understand their project status; utilities would be able to more easily notify ICs of materials that may be missing or that may require revision.
4. Improve access to and quality of actionable information that ICs need to make informed project decisions	With access to more data (and more granular information, including geospatial data) early in the development process, developers would be able to make more informed decisions regarding project location, project feasibility, etc.
5. Regularly review and update interconnection guidance materials and ensure that such materials are easily accessible	Some utilities publish interconnection guidance materials, including information related to cost estimates for certain necessary equipment and upgrades, but those materials have limited use to developers if they are outdated, difficult to access, or unreliable. By regularly updating and improving access to these materials, developers can make more informed project decisions.
6. Monitor changes in cost estimates throughout the study process	Developers noted that the cost estimates they receive from utilities can vary substantially throughout the study process, making it difficult to gauge a project's actual financial viability. Some changes in cost estimates may be unavoidable, but tracking those changes could help utilities identify trends over time and, accordingly, develop more reliable cost estimate ranges.

Solution Title	Summary of Rationale
7. Investigate establishing a DER rate class	Currently, the individual project that triggers the need for an upgrade is entirely responsible for the costs associated with that upgrade, even if earlier projects contributed to that need or later projects may benefit from the associated upgrades. Allocating the cost to interconnect DERs via a dedicated DER tariff is one possible way to more fairly distribute upgrade costs. Under this model, all or part of incurred DER interconnection costs would be spread across a dedicated DER customer class, with a specialized DER tariff.
8. Explore and, if appropriate, implement a proactive cost allocation strategy	As with Solution 7, a proactive cost allocation strategy is another possible approach that does not require an individual project to be responsible for all upgrade costs. Under this model, the utility would identify the cost of all system upgrades that would be necessary to support interconnection and would allocate them across individual projects based on each project's size/share of the necessary upgrades.
9. Ask utilities proposing to require direct transfer trip (DTT) to file information rationalizing this requirement with the Commission demonstrating that it is the least-cost solution to meet safety and reliability requirements in accordance with "Good Utility Practice" as defined in 20VAC5-314-20.	Not all of Virginia's utilities regularly use or require DTT, but each of Virginia's utilities have unique systems with unique needs. This solution would require utilities to provide clarity on their system, the circumstances in which DTT is/is not required on their system, and what other technologies may fill a similar role. This would help developers and the Commission better understand what is driving some utilities to require widespread use of DTT while other utilities have not implemented such requirements.
10. Conduct an analysis identifying ways to interconnect DERs at the rate necessary to meet State policy (as expressed in the Grid Transformation and Security Act) while ensuring the safety, reliably, and operability of the electric power system in accordance with "Good Utility Practice" as defined in 20VAC5-314-20.	Several parties noted that at Virginia's current rate of DER deployment, the state is unlikely to reach its clean energy goals and requirements. The Commission must identify a feasible pathway towards meeting state policy while also allowing utilities to continue to meet their own statutory requirements throughout and following that transition.

Solution Title	Summary of Rationale
11. Initiate a process to review and revise technical standards for inverter-based DERs.	One of Dominion's primary reasons for requiring the use of DTT (and specifically the use of dedicated fiber to accomplish DTT) is that it is the only technology they have found that meets their 160 millisecond (ms) threshold for DERs shut-off in response to fault conditions. However, other parties noted that the 160 ms standard is the most conservative threshold that can be applied under IEEE 1547-2018 and is unnecessarily conservative in many cases, especially in instances in which an inverter-based resource's unique capabilities could still meet IEEE standards. This solution would allow for an analysis that takes all of these considerations into account when evaluating and potentially implementing revised technical standards.
12. Hold an evidentiary process evaluating the need for DTT, as opposed to other technologies	Parties expressed an interest in a Commission-led evidentiary proceeding in which they could submit evidence to the record about the merits of using DTT for DER interconnection vs. other technologies in identified circumstances, whether DTT has a role to play in Virginia's energy transition (and if so, defining that role), and what lessons learned from other jurisdictions' experiences with DTT could be applied to the Virginia context.
13. Consider regulatory changes that would incentivize DER interconnection	Several alternative regulatory schemes exist that could incentivize DER interconnection in Virginia, including various performance-based mechanisms. The Commission has opened a performance-based regulation proceeding, Case No. PUR-2023-00210, which will be an opportunity to explore some of these approaches. The Grid Transformation and Security Act could enable these performance-based mechanisms, as well as other potential regulatory mechanisms.
Non-Consensus Solutions	
14. Comprehensive impact studies considering the abilities of inverter-based resources	This solution would offer a means by which utilities could move from the current "screening-based" approach for evaluating system safety and reliability (which Dominion uses to determine whether a project requires DTT) to a study-based approach, which may enable deployment of additional technology options.
15. Explore and, if appropriate, implement a holistic approach to cost allocation that accounts for broad-scale societal benefits of DERs	As DERs are being increasingly deployed across Virginia, there is a need for extensive system upgrades. However, these upgrades could be done on a wider scale than on a project-by-project basis, and the upgrades themselves may result in broad societal benefits. This approach would require high-level holistic system planning and accurate identification and quantification of the costs and benefits of DERs on the system.

C. Report Overview

Volume 1 of this report includes five sections, an executive summary, and four appendices, as summarized in Table ES-2. Volume 2 of this report, included as a separate document, contains all presentation materials from the working group process; this includes filings made by working group participants and groups that are not parties to this process (GPI, SCC Staff, and guest speakers).

Table ES-2: Overview of Report Sections, Volume 1

Section Title	*Section Overview (if applicable)*
Executive Summary	N/A
Section I: Introduction	N/A
Section II: Background	Contextual overview of the factors that led to the establishment of the DER interconnection working groups in Virginia, including technical need, regulatory directives, and key legislative developments.
Section III: Process	Overview of the DER interconnection working group process, including: • A list of participating organizations; • The ground rules that guided each working group meeting; • The participant-identified desired outcomes for each working group and the working group process overall; • A summary of all seven working group meetings; and • A table outlining participants' opportunities to provide feedback outside of the working group meetings.
Section IV: Issues to be Addressed	Issues that participants identified throughout the working group process, categorized by the working group topic with which they best align. These are the issues that the solutions summarized in Table ES-1 and listed in greater detail in Section V seek to address.
Section V: Solutions	Comprehensive list of solutions that are summarized in Table ES-1, including the following for each solution. • Identification as either a consensus or non-consensus solution • Solution number and short title • Solution text • Identification of the working group topics to which the solution aligns • Participants' rationale and implementation considerations for that solution
Section VI: Conclusion	N/A
Appendix A: Working Group Participating Parties	List of all individuals that participated in at least one working group meeting
Appendix B: Dominion's Responses to Homework 1	Dominion's responses to Working Group 2, Meeting 2 participants' clarifying questions regarding the Company's use of DTT, included in this report for informational purposes

Section Title	*Section Overview (if applicable)*
Appendix C: Matrix of Identified Issues and Solutions	Matrix that maps the participant-identified issues (listed in Section IV) to the participant-developed solutions (listed in Section V) and identifies the working group topics to which each issue and solution pertains.
Appendix D: Summary of Participant Feedback on Solutions	Narrative summary of participant feedback received on all 15 solutions included in this report

I. Introduction

Across the United States, electric utilities, regulatory commissions, renewable energy developers, consumer and environmental advocates, and other parties are confronting the need to deploy renewable energy resources at the pace necessary to meet clean energy goals while maintaining grid safety, reliability, and affordability. These renewable energy resources must be connected to either the electric distribution or transmission system through a process called *interconnection*.

To achieve clean energy goals, utilities typically need access to a diverse portfolio of renewable resources. This includes distributed energy resources (DERs)—such as community solar systems—that interconnect to the distribution grid. However, as more DERs connect to the distribution grid, the grid becomes increasingly "congested" and interconnection of additional DERs becomes difficult. In a congested system, utility facilities and equipment are near capacity and upgrades are necessary to maintain system safety and reliability.

For this reason, many jurisdictions have established processes through which proposed DER projects can be studied so that each project's distribution grid impacts can be assessed and mitigated through grid upgrade investments. However, in some jurisdictions, these processes and the ways in which they have been implemented are now insufficient to meet the market demand and policy need for rapid DER deployment. At the same time, grid upgrades have become cost prohibitive for many DER developers. In response, many jurisdictions are needing to review their interconnection processes and guidelines to determine the following:

- How—and how quickly—the positive and negative impacts of DERs are studied before resources are allowed to interconnect;
- How those studies are used to determine whether grid upgrades may be needed to accommodate new resources;
- How necessary grid upgrades are funded; and
- How to enable information transparency throughout the interconnection process to allow utilities, developers, and regulators to fulfill their respective roles in the renewable energy deployment process.

This report details the progress and recommendations of two complementary working groups that were established by the Virginia State Corporation Commission to address some of the issues described above.

II. Regulatory Background

Virginia is one of the jurisdictions in which interconnection processes may now be insufficient to meet the market demand and policy need for rapid DER deployment. In Virginia, the policy need for DER deployment is supported in part by the 2020 Virginia Clean Economy Act (VCEA), which established that specified electric utilities must meet the Commonwealth's 100% renewable portfolio standard by either 2045 or 2050, depending on the utility.[4]

Interconnection rules for DERs in Virginia are established in Chapter 314 of the Virginia Administrative Code, *Regulations Governing Interconnection of Small Electrical Generators and Storage*.[5] Net metered DER interconnection rules are established separately in Chapter 315, *Regulations Governing Net Energy Metering*.[6]

The interconnection rules in Chapter 314 were originally adopted in 2009 and were last updated in October 2020. Since that update, discussion of the Virginia DER interconnection procedures has taken place primarily through two dockets at the Virginia State Corporate Commission (SCC):

- Case No. PUR-2021-00127 was opened to consider approval of Phase II of Virginia Electric and Power Company d/b/a Dominion Energy Virginia's (Dominion's) ten-year plan to transform its electric grid. In its final order in that docket on January 7, 2022, the SCC stipulated that it would "open a separate docket to explore utility DER interconnection issues in a comprehensive manner."[7]
- Case No. PUR-2022-00073, *In the matter considering utility distributed energy resource interconnection-related issues and questions,* was opened in May 2022 as that separate docket. In the opening order, the SCC issued the following direction:
    - Interested parties may provide comments on utility DER interconnection issues including (but not limited to) obstacles to DER interconnection and potential solutions to those issues, best practices from other jurisdictions, and potential Commission-level actions that would facilitate DER interconnection.
    - SCC Staff may prepare a report documenting findings from these comments.

On September 19, 2022, SCC Staff filed their report summarizing the findings from the initial comment period in Case No. PUR-2022-00073. Staff found that interested parties identified

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[4] The full text of the VCEA (as signed into law by Governor Northam on April 11, 2020) is available here: https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+CHAP1193+pdf

[5] Virginia Administrative Code, Chapter 314: Regulations Governing Interconnection of Small Electrical Generators and Storage (20VAC5-314 *et seq.*) (as revised on October 15, 2020). Available at: https://law.lis.virginia.gov/admincode/title20/agency5/chapter314/

[6] Virginia Administrative Code, Chapter 315: Regulations Governing Net Energy Metering (20VAC5-315 *et seq.*) (as revised on March 1, 2020). Available at: https://law.lis.virginia.gov/admincode/title20/agency5/chapter315/

[7] Virginia State Corporation Commission, Division of Public Utilities Regulation, *Final Order* (January 7, 2022), Case No. PUR-2021-00127, *Petition of Virginia Electric and Power Company for approval of a plan for electric distribution grid transformation projects pursuant to § 56-585.1 A 6 of the Code of Virginia*. Available at: https://scc.virginia.gov/docketsearch/DOCS/6byy01!.PDF

many issues, not all of which could be reasonably addressed via the same mechanism. Staff therefore recommended that DER interconnection issues identified by parties be addressed by one or more specified mechanisms.

Informed by the Staff Report, on March 3, 2023, the SCC issued another Order in Case No. PUR-2022-00073. This Order established that DER interconnection issues identified in the Staff Report should be addressed by one or more of the following three mechanisms:

1. Working groups
2. A Staff-administered survey
3. A rulemaking proceeding

Accordingly, the Order directed Staff to convene two DER interconnection working groups, each focusing on three topics identified in the Staff Report as being well-suited to the working group mechanism. The two working groups as directed under the SCC Order are as follows.

- One working group focusing on issues pertaining to DER interconnection study timelines, construction timelines, and cost allocation; and
- A second working group focusing on DER interconnection costs, cost transparency, and dark fiber/direct transfer trip ("DTT").

Other issues identified in the Staff Report were directed to be addressed via a Staff-administered survey or a rulemaking proceeding (Case No. PUR-2023-00069).[8]

Following the March 3, 2023 Order, the SCC issued a Request for Proposals to select a consultant to convene the two DER interconnection working groups. The Great Plains Institute (GPI) was selected to provide facilitation services for both working groups and to prepare this final report documenting the two working groups' findings and identifying points of consensus. GPI, in collaboration with SCC Staff, held an initial combined meeting for both working groups on July 26, 2023. The final working group meeting was held on December 8, 2023.

[8] The rulemaking proceeding occurring under Case No. PUR-2023-00069 aims to identify whether the Chapter 314 regulations should be revised. In this Case, SCC Staff have been directed to explore and consider six topics: (i) language concerning material modifications; (ii) language concerning dispute resolutions; (iii) insurance requirements for Level 1 Interconnections; (iv) cybersecurity; (v) the definition of DER; and (vi) DER performance standards. In a Ruling issued in this Case on November 6, 2023, parties were directed to, "address and establish study and engineering requirements necessary to safely and reliably interconnect Net Metering DERs." The Ruling also granted Dominion Energy interim authority to continue its use of DTT technology only in specific circumstances, and established the right for ICs to appeal Dominion Energy's requirement for DTT for the project, if the Company uses its interim authority to require it. The rulemaking proceeding docket and associated documents are available here: https://www.scc.virginia.gov/docketsearch#caseDocs/144084.

Virginia State Corporation Commission, Division of Public Utilities Regulation, *Hearing Examiner's Ruling* (November 6, 2023), Case No. PUR-2023-00069, *In the matter of revising the Commission's regulations governing interconnection of Small Electrical Generators and Storage*. Available at: https://www.scc.virginia.gov/docketsearch/DOCS/7vkz01!.PDF

III. Process

A. Participating Parties

The two working groups included parties who had been involved in Case Nos. PUR-2022-00073 and PUR-2021-00127 and were also open to other interested parties. The organizations listed in Table 1 participated in at least one meeting of one or both of the working groups. This list does not include SCC Staff or GPI facilitators. A full list of all individuals that participated in this working group process is included in **Appendix A, *List of Participating Parties***.

Table 1: Participating Organizations

Advanced Energy United	Novel Energy Solutions
Appalachian Power Company/American Electric Power (APCo/AEP)	Old Dominion Electric Cooperative (ODEC)
Arlington County Government	Pacific Northwest National Laboratory
BlueWave Solar	Pivot Energy
Burns & McDonnell	Quanta Technology
Clean Virginia	RLC Engineering
Coalition for Community Solar Access (CCSA)	RWE
Comcast	Secure Solar Futures
Chesapeake Solar & Storage Association (CHESSA)	Solar Energy Industries Association
CleanGrid Advisors	Solar Landscape
Cypress Creek Renewables	Solar United Neighbors of Virginia
Dominion Energy (Dominion)	Southern Environmental Law Center (SELC)
DSD Renewables	Strang, Inc.
East Point Energy	Summit Ridge Energy
Gentry Locke	Sun Tribe
GreeneHurlocker	Sunvest
GridEdge Networks	Thompson McMullan, P.C.
Hexagon Energy	Tiger Solar
Holocene Energy	Total Energies
Interstate Renewable Energy Council	United States Department of Energy
Kentucky Utilities (KU)	University of Virginia
McGuire Woods	Virginia Department of Energy
New Energy Equity	Virginia Distributed Solar Alliance (VA-DSA)
New Leaf Energy	Virginia House of Delegates (Norfolk)

Nexamp, Inc.	Virginia, Maryland & Delaware Association of Electric Cooperatives
North Ridge Resources	Virginia Solar, LLC
Northern Virginia Electric Cooperative (NOVEC)	VSF Solar I, LLC

B. Ground Rules and Desired Outcomes

Commission Staff directed that this working group process result in a final report (combined for both working groups) that summarizes all identified issues and potential solutions to those issues, and that identifies consensus where it was found. This report serves to fulfill that request.

During Meeting 1—which was combined for both working groups—participants identified their desired outcomes for the DER interconnection working group process and for the two working groups individually. These outcomes served to help direct working group progress to the extent feasible based on their alignment with the working group requirements established under the Commission's March 3, 2023 Order.

Desired Outcomes for the Overall Working Group Process

- Build a shared understanding of the problem(s) so the groups can work towards a solution
- Consider utility customers' voices (including low-income customers) and the perspectives of non-IOU customers (e.g., co-op members), including cost impacts to those parties
- Improve communication from and between all parties
- Identify problems through a discovery process informed by prior work in Virginia and successes in other states
- Identify what channels exist that would address those problems and determine appropriate action-oriented next steps accordingly
- Identify solutions that are aligned with utilities' obligation to provide electric services and maintain a safe, reliable, operable, and affordable grid for all customers
- Align interconnection processes with broader state policy goals

Desired Outcomes for Working Group 1

Working Group 1 topics: Study timelines, construction timelines, and cost allocation

- Fair, non-discriminatory approaches and fees for DER use of the distribution grid
- Consideration for important differences, including differences in technologies, generator (e.g., utility vs. shared/community solar), behind-/front-of-meter projects
- Fair cost allocation methodologies, informed by a shared understanding of all the parties that benefit from system upgrades
- Reasonable study timelines and faster interconnection process
- Learning by building upon efforts already conducted by other groups, existing resources, and exploring pilot opportunities

- Enforcement mechanisms for existing rules

Desired Outcomes for Working Group 2

Working Group 2 topics: Interconnection costs, cost transparency, and dark fiber/DTT

- Faster, earlier, more granular, and more predictable interconnection cost estimates
- Improved understanding of the rationale for DTT over alternative technologies, and identification of potential alternative technologies that could meet system needs, if such screens or thresholds exist
- Consideration for how DTT costs impact behind-the-meter projects
- Identification of how utilities' safety, security, and reliability obligations do/do not intersect with anti-islanding and/or power system protection needs
- Adoption of system standards and identification of the types of projects to which those standards should apply

Meeting Ground Rules

All working group meetings began with an overview of the ground rules, which are intended to keep conversations as valuable and solutions-oriented as possible. The ground rules remained the same throughout the working group process and are listed below.

1. ***Respect each other.*** *Help us to collectively uphold respect for each other's experiences and opinions, even in difficult conversations.*
2. ***Respect the time.*** *Our time together is limited and valuable, so please be mindful of the time and of others' opportunity to participate.*
3. ***Share your perspective and help others share theirs.*** *We need everyone's wisdom to achieve better understanding and develop robust solutions.*
4. ***Enable honesty through non-attribution.*** *Outside of this group, you may share what was said, who was present, and perspectives shared at an organizational level, but please refrain from attributing perspectives to individual participants without first obtaining that individual's permission. All meeting notes and materials will also adhere to this.*

C. Meetings

GPI convened and facilitated the following seven meetings for the DER interconnection working groups.

- One initial kickoff meeting, combined for both working groups;
- Two dedicated meetings for Working Group 1 (directed per the SCC's March 3, 2023 Order to focus on issues related to the study process, construction timelines, and cost allocation);

- Three dedicated meetings for Working Group 2 (directed per the SCC's March 3, 2023 Order to focus on issues related to interconnection costs, information transparency,[9] and dark fiber/DTT); and
- One final meeting that was combined for both working groups.

A high-level summary of the key points of discussion for each working group meeting is provided below (note: this final report serves as the post-meeting summary and Commission Update Report for the final combined working group meeting). Brief post meeting summaries and detailed Commission update reports for each meeting are available in the docket for Case No. PUR-2022-00073.[10]

Combined Initial Meeting for Both Working Groups

Wednesday, July 26, 2023

The initial meeting was combined for both working groups and served as a kick-off meeting for the DER interconnection working group process. The meeting began with an overview of the Commission's March 3, 2023 Order directing that the working groups be established and provided an overview of the topics to be explored via the working group process. Next, SCC Staff provided a level-setting presentation on Virginia's current DER interconnection rules and answered questions from participants about those rules. All presentation materials for both working groups are included in **Volume 2** of this report.[11]

The remainder of the initial meeting was broken into two parts. The first part served as a topic-specific kickoff meeting for Working Group 1 (study timelines, construction timelines, and cost allocation), and the second part served as a topic-specific kickoff meeting for Working Group 2 (interconnection costs, cost/information transparency, and dark fiber/DTT). For each session, participants were asked to identify outcomes that they would like to see resulting from the working group process. These participant-developed outcomes are listed above in Section III.B, *Ground Rules and Desired Outcomes*.

Participants were also asked to identify the questions they would most like to explore through the working group process. Following the meeting, parties had the opportunity to identify their top-priority questions from the list of questions generated during the meeting, further refine or add context to any of these questions, and suggest additional questions to explore.

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[9] In this report, the "information transparency" topic area is sometimes referred to as "cost/information transparency" to account for the fact that many of the information transparency issues identified throughout this process pertained to the availability of cost-related information, which aligned more closely with the "information transparency" topic than the "interconnection costs" topic.

[10] Please see the docket for Case No. PUR-2022-00073 for working group meeting summaries and Commission update reports: https://www.scc.virginia.gov/docketsearch#caseDocs/143131. This report serves as both the post-meeting summary and commission update report for the combined final meeting for both working groups.

[11] **Volume 2** of this report compiles all presentations made throughout the working group process. This includes presentation materials from working group participants as well as SCC and GPI.

Working Group 1 Meetings

Working Group 1, Meeting 2: Study Process and Timelines

Wednesday, September 27, 2023

Working Group 1, Meeting 2 began with a presentation from SCC Staff on Virginia's current sequential study process and study timelines for Level 3 interconnections, as outlined in Chapter 314 (20 VAC 5-314.10 *et seq.*). Next, Dominion, APCo/AEP, and KU shared what their internal processes and interconnection queues look like, and other participating parties were asked to share what challenges they have encountered related to the utilities' queues.

The working group then identified and discussed strategies that could potentially improve the efficiency of Virginia's *current* sequential study process. This included discussion of strategies that could address information access issues and improve information transparency. Participants also discussed the potential pros and cons of implementing certain financial mechanisms, such as increased study deposits and the establishment of monetary penalties, as a means to address these issues.

The working group then identified and discussed potential *alternatives* to Virginia's current study process, including both sequential and non-sequential alternative methodologies. This included discussion of methodologies including a "pseudo-parallel" study process; various approaches to cluster/group studies; and a combined sequential study process, such as New York's Coordinated Electric System Interconnection Review (NY CESIR) methodology.

Working Group 1, Meeting 3: Construction Timelines and Cost Allocation

Wednesday, October 25, 2023

Working Group 1, Meeting 3 began with a discussion dedicated to construction timelines. During this portion of the meeting, participants identified some of the key issues associated with construction timelines and discussed potential solutions to those issues. Participants identified several potential construction timeline issues that could be pursued through solutions developed via this process (e.g., site access issues, equipment setting confirmation, timely completion of necessary documents, etc.).

The remainder of Working Group 1, Meeting 3 focused on issues and potential solutions related to cost allocation. Prior to the meeting, participants were informed that they would have an opportunity to share their preferred cost allocation strategies at the meeting. One participant representing an environmental advocacy organization presented a cost allocation methodology involving a dedicated DER interconnection tariff. Another participant (a developer) presented on the following different cost allocation strategies considered or pursued in other jurisdictions:

- Retroactive cost sharing ("Cost Sharing 1.0")—New York
- Proactive cost sharing ("Cost Sharing 2.0")—New York
- Multi-beneficiary cost sharing—Massachusetts
- Rate-basing costs to the point of common coupling—California, Germany
- Proactive system planning/upgrades—New York, Massachusetts, New Jersey

During the remainder of the meeting, participants identified other strategies that could address aspects of cost allocation issues. Participant-suggested strategies included targeted cluster studies and cost allocation for small projects; improving efficiency (including administrative efficiency) throughout the interconnection process, such that fewer costs need to be allocated; and a system-wide holistic approach much like the proactive system planning/upgrades explored in New York, Massachusetts, and New Jersey.

With the remainder of the meeting time, parties brought up additional points that should be considered when identifying strategies to address cost allocation issues. These considerations include, but are not necessarily limited to, cost allocation methods for non-IOU electricity providers (e.g., co-ops, municipal utilities) and whether the 2018 Grid Transformation and Security Act (GTSA) might enable the exploration and adoption of creative cost allocation approaches.

Working Group 2 Meetings

Working Group 2, Meeting 2: Dark Fiber/DTT, Part 1—Issue identification, preliminary identification of potential solutions

Tuesday, September 19, 2023

Working Group 2, Meeting 2 began with several level-setting presentations on the use of DTT and dedicated fiber to accomplish DTT. First, Dominion provided an overview of their use of DTT and dedicated fiber. In their presentation, Dominion emphasized that DTT provides both anti-islanding and fault protection benefits; specifically, the use of dedicated fiber to accomplish DTT enables rapid communication in the event of an arc flash hazard. Next, Pacific Northwest National Laboratory (PNNL) and the Interstate Renewable Energy Council (IREC) presented on grid engineering practices and standard protection under high DER-adoption scenarios and on DER islanding risks and mitigation measures that address those risks, respectively. All presentations are available in Volume 2 of this report.

Following these presentations, the working group discussed DTT and its alternative technologies in greater detail. This portion of the meeting sought participant feedback on what DTT and its alternative technologies offer as means to meet reliability standards, and included a discussion on the advantages and disadvantages of each technology. Participants then identified the core issues they are experiencing related to the use of DTT, and were asked to share what solutions or recommendations they think should be considered that might address those issues. Participants were also asked to identify whether any specific approaches should *not* be considered to address these issues.

The topics discussed during Working Group 2, Meeting 2 were highly complex and warranted further discussion. Accordingly, potential solutions related to dark fiber/DTT were further refined in Working Group 2, Meeting 4 (summarized below). In preparation of the continued discussion, participants had two "homework" assignments to complete following Working Group 2, Meeting 2 and in advance of Working Group 2, Meeting 4. These assignments included an opportunity to ask Dominion clarifying questions about the Company's use of DTT ("Homework 1") and an opportunity to rank and further refine the potential solutions identified during Working Group 2, Meeting 2 (“Homework 2”). For informational purposes, Dominion’s responses to Homework 1 are attached to this report as **Appendix B, *Dominion’s Responses to Homework 1***.

Working Group 2, Meeting 3: Interconnection Costs and Information Transparency

Tuesday, October 10, 2023

Working Group 2, Meeting 3 began with presentations from investor-owned utilities (IOUs) and Virginia, Maryland, and Delaware Association of Electric Cooperatives (VMDAEC) about the cost information that they currently have available, the ways that parties can access that information and/or ask questions about the application process, and other relevant topics related to cost and information availability. VMDAEC’s presentation also included an overview of some of the key differences between co-ops and IOUs pertaining to both interconnection and utility business practices.

Next, GPI facilitated a discussion on interconnection cost challenges and their implications. This included identification of the different challenges that parties have experienced related to interconnection costs and cost transparency and conversations intended to help parties better understand the implications of those challenges.

Following the identification of these challenges, participants discussed potential strategies that might address these issues. This included discussions of how issues related to interconnection cost transparency, granularity, and accuracy could be addressed, as well as conversations regarding how those solutions could be implemented. This also involved identification of potential solutions that could make key information available at an earlier point in the interconnection process, and a discussion about what (if any) enforcement mechanisms are needed to encourage parties to provide more accurate information in a more timely manner.

Working Group 2, Meeting 4: Dark Fiber/DTT, Part 2—Further discussion and refinement of potential solutions identified in Working Group 2, Meeting 2

Monday, October 30, 2023

During Working Group 2, Meeting 4, parties continued discussing the potential solutions to dark fiber/DTT-related issues that participants identified during Working Group 2, Meeting 2. In Working Group 2, Meeting 4, parties first discussed the four potential solutions developed in Working Group 2, Meeting 2 that would be primarily Commission-directed and Commission-led. This included an overview of Dominion’s past and current pilots related to potential alternatives to dark fiber and/or DTT, which related closely to one of the participant-recommended potential solutions from Working Group 2, Meeting 2.[12] Next, participants discussed the three potential solutions developed during Working Group 2, Meeting 2 that would have been utility-led (but Commission directed).

For seven potential solutions related to dark fiber/DTT, participants discussed whether all or portions of that potential solution were already being addressed, whether that potential solution

[12] Dominion provided a summary of their past and ongoing pilots in their response to Homework 1, Question 5. Dominion’s responses to Homework 1 are included as **Appendix B** to this document for informational purposes.

should be pursued, and considerations related to how the potential solution should be implemented, if at all.

Throughout this meeting, the potential solutions related to dark fiber/DTT that were developed during Working Group 2, Meeting 2 were modified and refined.

Combined Final Meeting for Both Working Groups

Monday, December 4, 2023

In advance of the combined final meeting for both working groups, GPI sent participants a draft version of a list of 23 potential solutions (included in the "November 13th draft potential solutions document," which is described in greater detail in Section III.D, *Opportunities for Participant Feedback*). All 23 potential solutions provided to participants in advance of the combined final meeting were developed throughout the working group process. Participants had an opportunity to submit written feedback and suggestions related to these potential solutions. GPI incorporated this feedback to the extent reasonable and appropriate.

Based on participant feedback, GPI was able to propose a package of 16 potential solutions for discussion at the final combined meeting. This package took into consideration participant feedback, including suggestions related to places of overlap between certain potential solutions and opportunities for consolidation.

During the final combined meeting, participants provided additional feedback and further modified the revised package of potential solutions, refined the package down to 15 solutions, and identified where consensus did or did not exist among these solutions. At this final combined meeting, participants were able to reach consensus on 13 solutions and did not reach consensus on two solutions. Importantly, consensus means that no party was opposed to including the solution as written in this report for consideration, though parties may not have reached full agreement regarding whether specific aspects of each individual solution should or should not be pursued.

The solutions as written in Section V of this document reflect the language developed in collaboration with the working groups during the final combined meeting.

D. Opportunities for Participant Feedback

Throughout the working group process, participants had extensive opportunities to provide feedback on the material discussed and the potential solutions under development. All seven working group meetings described above in Section III.C, *Meetings* served as opportunities for participants to provide verbal feedback, as did the written feedback opportunities summarized below in Table 2. Written and verbal feedback received throughout the working group process helped inform the solutions included in this document for consideration.

Table 2: Opportunities for Written Feedback

Opportunity	Summary	Date
Participant identification of key questions following Meeting 1	Participants had the opportunity to identify their five top-priority questions (out of the questions that parties brought up during the first combined meeting), provide additional context on those questions, and/or recommend additional questions that they felt should also be considered.	August 9, 2023
Homework 1 for Working Group 2, Meeting 2: Clarifying Questions on DTT/Dark Fiber for Dominion Energy[13]	Opportunity for participants to submit clarifying questions to Dominion regarding the Company's use of DTT/dark fiber to help further the group's shared knowledge in this area in advance of future meetings.	October 6, 2023
Homework 2 for Working Group 2, Meeting 2: Potential Solutions to Challenges Associated with DTT/Dark Fiber	Opportunity for participants to revise or clarify the potential solutions related to DTT/dark fiber that were developed during Working Group 2, Meeting 2 and to identify what they considered to be their top three potential solutions related to DTT/dark fiber, for further discussion.	October 13, 2023
Feedback on November 13th DRAFT potential solutions document ("November 13th draft potential solutions document")	Opportunity for participants to comment/provide feedback on the DRAFT potential solutions document provided to all working group members on November 13th (referred to throughout this report as the "November 13th draft potential solutions document"). That document contained the draft potential solutions as developed throughout the working group process, including written feedback and meetings held up until that point in time.	November 27, 2023

In addition to these opportunities for participants to provide written feedback, Working Group 1 participants had an opportunity to present on their preferred cost allocation strategies during Working Group 1, Meeting 3. Several participants chose to prepare brief presentations on this topic; cost allocation topics covered in participants' presentations are listed in Section III.C, *Meetings*, of this report. More detailed summaries of participants' presentations are available for review in the Working Group 1, Meeting 3 Commission Update Report in the docket for Case No. PUR-2022-00073.

[13] Dominion provided responses to participants' questions on October 25, 2023. Dominion has requested that its responses to Homework 1 be included as an attachment to this report for informational purposes, and those are available in **Appendix B, *Dominion's Responses to Homework 1***.

IV. Issues to be Addressed

Throughout the working group process, participants identified issues related to the six working group topics (*study timelines, construction timelines, cost allocation, interconnection costs, cost/information transparency, and dark fiber/DTT*) that should be addressed. Participant-identified issues are listed in this section in accordance with the working group topic to which they are best aligned, though several issues relate to multiple topics. There is also an "Other High-Level Issues" category that lists issues identified through this process, but that pertain holistically to interconnection issues in Virginia.

Note that identification of an issue does not necessarily mean that all involved parties experienced that issue or felt that it needed to be addressed. This section simply lists all issues raised throughout the process as a record of the discussions, regardless of the degree to which the working group emphasized the issue or the working group's magnitude of concern about the issue. For additional context regarding participant-identified issues and the discussions regarding those issues during working group meetings, please refer to the Commission Update Reports for each meeting, available in the docket for Case No. PUR-2022-00073.[14]

Each identified issue—as well as all topics to which that issue pertains and the solutions that, if pursued, could address all or part of that issue—are mapped out in **Appendix C, *Matrix of Identified Issues and Solutions***.

A. Identified Issues Related to Study Timelines

- Some utilities have failed to meet the study timelines required under Chapter 314.
- Study timeline information is not granular enough to enable parties to identify the specific steps/sub-steps in which delays are occurring.
- Study fees do not fully cover the cost to utilities to conduct the studies.
- Long study timelines encourage speculative projects; markets and prices can change, and issues can arise and/or be resolved by the time a project is finally through the study process.
- There is a wide range of equipment with different specifications/capabilities; this equipment is currently studied on a case-by-case basis.
- There are no penalties for ICs or utilities failing to meet established timelines throughout the process.
- The study process can take so long that projects in the queue can miss out on potential incentive opportunities.
- Parties lack insight into what approaches utilities are taking in other jurisdictions to address grid safety, reliability, and operability concerns in their own study processes.

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[14] Please see the docket for Case No. PUR-2022-00073 for working group meeting summaries and Commission update reports: https://www.scc.virginia.gov/docketsearch#caseDocs/143131. This report serves as both the post-meeting summary and commission update report for the combined final meeting for both working groups.

- Some utilities may lack the necessary resources (internal or external capacity, financial means, etc.) to implement strategies that would help them meet or eventually exceed current study timelines.[15]
- ICs no longer planning to pursue interconnection do not always notify the utility of their withdrawal in a timely manner, so those projects continue to be unnecessarily studied.

Several solutions listed below in Table 3 and described in greater detail in Section V could address all or part of these identified issues.

Table 3: Solutions that May Address Study Timeline Issues

Solution (# and short title)	Category
1. Meet and evaluate exceeding current study timeline requirements	Study and Construction Timelines
3. Improve communications between ICs and utilities	Interconnection Costs and Information Transparency
4. Improve access to and quality of actionable information that ICs need to make informed project decisions	Interconnection Costs and Information Transparency
5. Regularly review and update interconnection guidance materials and ensure that such materials are easily accessible	Interconnection Costs and Information Transparency
6. Monitor changes in cost estimates throughout the study process	Interconnection Costs and Information Transparency
11. Initiate a process to review and revise technical standards for inverter-based DERs	Approaches to Meeting Safety and Reliability Requirements
12. Hold an evidentiary process evaluating the need for DTT, as opposed to other technologies	Approaches to Meeting Safety and Reliability Requirements
15. Explore and, if appropriate, implement a holistic approach to cost allocation that accounts for broad-scale societal benefits of DERs	High-Level Regulatory Changes

B. Identified Issues Related to Construction Timelines

- Right-of-way, site control, and permitting issues can prevent the utility responsible for constructing interconnection facilities from accessing the site.
- ICs sometimes need to request changes to the construction schedule, but it can be difficult for utilities to be in a state of “perpetual readiness” to adjust to these changes and/or incorporate the revised construction timeline into the utility’s broader schedule.
- ICs can be delayed in completing and submitting their Application for Service to the utility once their SGIA is executed.

[15] In the context of this identified issue and this report, “exceeding” current study timelines refers to whether the study process can be completed in less time than is currently stipulated under the Chapter 314 regulations.

- Incomplete or insufficiently detailed site plans can delay the utility's engineering analysis.
- End-of-year interconnection targets (i.e., after December 15th) can be difficult for utilities to meet due to staffing limitations.
- Changes to inverter settings (from the settings that were checked and confirmed by the utility earlier in the process) are sometimes identified during the facility commissioning phase.
- Developers are not always mobilized or ready for the utility's construction components to begin, even when the utility is ready.
- Site-specific issues (e.g., environmental issues) associated with the interconnection location may arise, and these issues typically are not identified at an earlier point in the interconnection process.

Table 4: Solutions that May Address Construction Timeline Issues

Solution (# and short title)	Category
2. Secure site access early for the utility	Study and Construction Timelines
3. Improve communications between ICs and utilities	Study and Construction Timelines
13. Consider regulatory changes that would incentivize DER interconnection	High-level Regulatory Changes

C. Identified Issues Related to Cost Allocation

- The "100% cost causation" model (under which the project that triggers the need for system upgrades is responsible for all upgrade costs, even though other prior projects may have contributed to that need) is cost-prohibitive for many projects and interferes with DER deployment due to the high financial burden it places on developers. This is especially problematic when DTT is required, as it is a very costly technology.
- Cost allocation methodologies for co-ops must align with the not-for-profit, member-ownership model and must account for the fact that many co-ops are distribution-only utilities.
- Smaller utilities serving rural regions tend to have a lower-income customer or member-owner base. This population may be more sensitive to increased rates, which could result from certain alternatives to Virginia's current approach to cost allocation.
- Utilities have administrative costs (IT, interconnection process management, communications, etc.), and increased administrative costs associated with those departments—even if those costs are intended to facilitate DER interconnection—which need to be recovered somehow.
- It is unclear what should happen in circumstances in which project viability is adversely impacted post-SGIA (e.g., if a project in the queue depends on certain upgrades, those upgrade costs are not necessarily refundable).
- If costs are socialized more broadly and a DER project defaults, the host utility could be at risk of bearing cost recovery responsibility.

Table 5: Solutions that May Address Cost Allocation Issues

Solution (# and short title)	Category
1. Meet and evaluate exceeding current study timeline requirements	Study and Construction Timelines
5. Regularly review and update interconnection guidance materials and ensure that such materials are easily accessible	Interconnection Costs and Information Transparency
7. Investigate establishing a DER rate class	Cost Allocation
8. Explore and, if appropriate, implement a proactive cost allocation strategy	Cost Allocation
9. Ask utilities proposing to require DTT to file information rationalizing this requirement with the Commission demonstrating that it is the least-cost solution to meet safety and reliability requirements in accordance with "Good Utility Practice" as defined in 20VAC5-314-20	Approaches to Meeting Safety and Reliability Requirements
10. Conduct an analysis identifying ways to interconnect DERs at the rate necessary to meet State policy (as expressed in the Grid Transformation and Security Act) while ensuring the safety, reliably, and operability of the electric power system in accordance with "Good Utility Practice" as defined in 20VAC5-314-20	Approaches to Meeting Safety and Reliability Requirements
11. Initiate a process to review and revise technical standards for inverter-based DERs	Approaches to Meeting Safety and Reliability Requirements
12. Hold an evidentiary process evaluating the need for DTT, as opposed to other technologies	Approaches to Meeting Safety and Reliability Requirements
13. Consider regulatory changes that would incentivize DER interconnection	High-level Regulatory Changes
14. Comprehensive impact studies considering the abilities of inverter-based resources	Approaches to Meeting Safety and Reliability Requirements
15. Explore and, if appropriate, implement a holistic approach to cost allocation that accounts for broad-scale societal benefits of DERs	High-level Regulatory Changes

D. Identified Issues Related to Interconnection Costs

Note: The issues listed in this section include those that relate specifically to the actual cost of interconnection and its associated implications. Issues related to interconnection cost information are identified in Section IV.E, *Identified Issues Related to Cost/Information Transparency,* and issues related specifically to costs associated with the use of dark fiber/DTT are identified in Section IV.F, *Issues Related to Dark Fiber/DTT*.

- Study fees do not fully cover the cost to utilities to conduct the studies.

- Current study deposit fees are too low; this leads to an influx of speculative and otherwise potentially unviable projects in the queue.
- In lower-income regions, increased interconnection costs are leading to more projects being proposed and pursued by large development firms and fewer being proposed by local entities/landowners.
- Interconnection costs can fluctuate significantly among Virginia's utilities, even among similar types of upgrades.

Table 6: Solutions that May Address Interconnection Cost Issues

Solution (# and short title)	Category
1. Meet and evaluate exceeding current study timeline requirements	Study and Construction Timelines
4. Improve access to and quality of actionable information that ICs need to make informed project decisions	Interconnection Costs and Information Transparency
5. Regularly review and update interconnection guidance materials and ensure that such materials are easily accessible	Interconnection Costs and Information Transparency
6. Monitor changes in cost estimates throughout the study process	Interconnection Costs and Information Transparency
7. Investigate establishing a DER rate class	Cost Allocation
8. Explore and, if appropriate, implement a proactive cost allocation strategy	Cost Allocation
13. Consider regulatory changes that would incentivize DER interconnection	High-level Regulatory Changes
15. Explore and, if appropriate, implement a holistic approach to cost allocation that accounts for broad-scale societal benefits of DERs	High-level Regulatory Changes

E. Identified Issues Related to Cost/Information Transparency

- Developers often lack the necessary information (cost, circuit, facilities, geospatial, past findings from past studies, etc.) to make informed business decisions about project feasibility before commencing the interconnection process.
- When information gaps are present, addressing those gaps requires additional back/forth communication, which increases timelines.
- Smaller utilities are typically more resource-constrained than large utilities and may not have the personnel or financial capacity to conduct studies in-house, develop dedicated DER interconnection teams, develop/provide/maintain certain resources (geospatial resources, regularly updated manuals, etc.).
- DERs that would potentially impact third party-owned transmission facilities in distribution-only utility service territories require an affected system operator (ASO) study. ASO studies can be time-intensive and can have their own unforeseen costs/delays, but fall outside of the distribution-only utility's control/authority.

- Not all developers/ICs are familiar with or aware of the interconnection guidance materials that some utilities have available.
- Cost information in utility-provided materials can be inconsistent with the cost estimates provided to ICs through the study process.
- Project and upgrade costs sometimes change throughout the study process.
- Information quality (from utilities to ICs and from ICs to utilities) is not always sufficient to allow ICs to make informed business decisions and to allow utilities to provide comprehensive feedback or timely estimates.
- Even within an individual utility, information quality and level-of-detail can vary depending on the utility staff/team assigned to the project; utilities lack a standardized way of providing/delivering the type of information required at the level of detail that would be most helpful to developers.
- Developers/ICs lack technical system-specific information that could help them determine whether a project is feasible earlier in the process (e.g., whether a substation is on the verge of requiring cost-prohibitive transmission-level impacts).

Table 7: Solutions that May Address Cost/Information Transparency Issues

Solution (# and short title)	Category
1. Meet and evaluate exceeding current study timeline requirements	Study and Construction Timelines
3. Improve communications between ICs and utilities	Study and Construction Timelines
4. Improve access to and quality of actionable information that ICs need to make informed project decisions	Interconnection Costs and Information Transparency
5. Regularly review and update interconnection guidance materials and ensure that such materials are easily accessible	Interconnection Costs and Information Transparency
6. Monitor changes in cost estimates throughout the study process	Interconnection Costs and Information Transparency
9. Ask utilities proposing to require DTT to file information rationalizing this requirement with the Commission demonstrating that it is the least-cost solution to meet safety and reliability requirements in accordance with "Good Utility Practice" as defined in 20VAC5-314-20	Approaches to Meeting Safety and Reliability Requirements

F. Identified Issues Related to Dark Fiber/DTT

The issues listed in this section generally refer to Dominion, as Dominion is the utility that currently requires the use of DTT (and uses dedicated fiber to accomplish DTT). However, the solutions associated with these identified issues would apply to any utility requiring the use of DTT.

- Dominion has not found an alternative to DTT that can meet the Company's obligation to deliver safe and reliable power (e.g., through fault clearing and other required means) to customers equally well and within the appropriate technical standards.

- Dominion's 34.5 kilovolt (kV) system (higher voltage than many other utilities) allows for increased DER interconnection overall (when compared to lower-voltage systems). However, in Dominion's view, this higher system voltage also tends to decrease the ability for an inverter-based resource to locally sense fault conditions and appropriately trip offline within the established time threshold (for Dominion, this standard is 160 ms).
- Though Dominion recognizes and acknowledges the anti-islanding capabilities of inverter-based resources, the Company has not found that such resources can clear faults within 160 ms in all scenarios analyzed in the screening process.
- Dominion's 160 ms fault protection requirement is the most conservative (i.e., "lower bound") threshold allowed under IEEE 1547-2018 standards; a less conservative threshold could still meet the IEEE technical requirements.
- Utilities must ensure that their system is safe for the public, system equipment, and lineworkers, who may unknowingly be exposed to energized lines. DTT has reliably served this communication purpose.
- DTT (including the use of dedicated fiber as the communication medium to accomplish DTT) is very expensive. Under Virginia's current approach to cost allocation, the requirement that DTT be installed to enable DER interconnection is cost-prohibitive for ICs, which is interfering with DER deployment.
- There is not a well-established risk threshold at which the DER deployment benefits of DTT outweigh its costs.
- There is a lack of understanding and transparency as to what alternatives to DTT Dominion has explored, what were the findings of those alternatives analyses, and why those findings lead to the conclusion that DTT is still required.[16]

Table 8: Solutions that May Address Dark Fiber/DTT Issues

Solution (# and short title)	Category
7. Investigate establishing a DER rate class	Cost Allocation
8. Explore and, if appropriate, implement a proactive cost allocation strategy	Cost Allocation
9. Ask utilities proposing to require DTT to file information rationalizing this requirement with the Commission demonstrating that it is the least-cost solution to meet safety and reliability requirements in accordance with "Good Utility Practice" as defined in 20VAC5-314-20	Approaches to Meeting Safety and Reliability Requirements
10. Conduct an analysis identifying ways to interconnect DERs at the rate necessary to meet State policy (as expressed in the Grid Transformation and Security Act) while ensuring the safety,	Approaches to Meeting Safety and Reliability Requirements

[16] Throughout the working group process, Dominion has provided valuable information explaining the rationale for their use of DTT (and dedicated fiber to accomplish DTT) over other technologies. This included several presentations, all of which are available in Volume 2 of this report. Dominion also responded to a series of technical questions from participants regarding the Company's use of DTT. Dominion's responses to these questions are included in **Appendix B, *Dominion's Responses to Homework 1***.

reliably, and operability of the electric power system in accordance with "Good Utility Practice" as defined in 20VAC5-314-20	
11. Initiate a process to review and revise technical standards for inverter-based DERs	Approaches to Meeting Safety and Reliability Requirements
12. Hold an evidentiary process evaluating the need for DTT, as opposed to other technologies	Approaches to Meeting Safety and Reliability Requirements
13. Consider regulatory changes that would incentivize DER interconnection	High-Level Regulatory Changes
14. Comprehensive impact studies considering the abilities of inverter-based resources	Approaches to Meeting Safety and Reliability Requirements (*non-consensus*)
15. Explore and, if appropriate, implement a holistic approach to cost allocation that accounts for broad-scale societal benefits of DERs	High-Level Regulatory Changes (*non-consensus*)

G. Other High-Level Issues

- The current rate of DER deployment in Virginia is insufficient to meet the clean energy goals required under VCEA, which applies to specified utilities' whole electric systems (distribution, transmission, and generation).
- Utilities are seeing a drastic increase in DER interconnection applications and may lack the resources and/or procedures necessary to keep up with those applications.

Solutions that could address high-level issues are not documented in a table because nearly any solution could address large aspects of identified issues. For example, all solutions listed in this report have the potential to address the fact that Virginia's current rate of DER interconnection is insufficient to meet the clean energy goals required under VCEA, as all 15 solutions have the potential to address Virginia's DER interconnection issues in some capacity.

V. Solutions

This section contains the consensus and non-consensus solutions that participants developed throughout the working group process. Participants were initially asked to propose potential solutions for consideration, then to refine those solutions, and finally to assess whether they could support each solution as refined (and as included in this report).

In the final meeting, participants reached consensus on 13 solutions and did not reach consensus on two solutions. ***Importantly, consensus means that all parties who were present in the final meeting said that they at least did not oppose including the solution in this report for consideration.*** Some consensus solutions include sub-components on which the working group did not reach full agreement (i.e., not all participants reached agreement regarding which sub-components within that solution should/should not be pursued); this is noted where applicable.

These solutions reflect feedback received from participants on the November 13th draft potential solutions document, as well as participant feedback received during the final combined meeting. All solutions were suggested and refined by working group participants.

This section is broken into three parts (A–C), as follows.

- ***Part A:*** **Overarching considerations**
  - High-level considerations related either to the working group process or that should be considered broadly within several or all solutions.
  - Considerations to keep in mind when evaluating and considering solution implementation.
- ***Part B:*** **Consensus solutions**
  - Solutions 1–13, which working group participants agreed to include in this report during the final combined meeting.
  - Participants agreed that as written, these solutions could address identified issues and reached consensus (i.e., did not oppose) moving them forward for further consideration. However, not all participants were in full agreement regarding whether individual sub-components within specific solutions should be pursued.
  - Solutions should be interpreted as written. For example, if the working group reached consensus that the Commission should explore a specific topic, the consensus solution should be interpreted as solely that exploration. Next steps that may follow a solution (if that solution is implemented) should not be inferred from the solution text itself unless explicitly specified.
  - Includes solutions related to all topic areas.
- ***Part C:*** **Non-consensus solutions**
  - Solutions 14 and 15.
  - Participants did not reach consensus that these solutions could address identified issues or should be included in this report; some participants supported inclusion, while others opposed.
  - Includes solutions related to approaches to meeting safety and reliability requirements and high-level regulatory changes.

Each solution in this section is structured with the following components.

[Solution #]: Solution short title

Solution #X: Solution text, with language as refined during the final combined working group meeting

Associated Topic(s), Solution #X: List of all working group topics (*study timelines, construction timelines, cost allocation, interconnection costs, cost/information transparency, and/or dark fiber/DTT*) that pertain to this solution, based on the Working Group topics outlined in the Commission's March 3, 2023 Order

Rationale and Implementation, Solution #X: Rationale for why participants suggested this as a solution and a description of the aspects of the solution that participants considered to be important for implementation, as informed by working group participants throughout this process.

Solutions are not listed in order of priority. The enumeration and ordering used throughout this section exists for organizational purposes only. Additionally, individual solutions may or may not be mutually exclusive and should be considered as a suite of options that could be pursued in combination with or separately from other solutions.

A matrix that matches solutions to the six working group topics and to the issues identified throughout the working group process is included in **Appendix C, *Matrix of Identified Issues and Solutions***. A summary of written and verbal participant feedback received on each solution, including feedback received during the final combined meeting for both working groups, is provided in **Appendix D, *Summary of Participant Feedback on Solutions*.**

A. Overarching Considerations

During Meeting 1, which was combined for both working groups, parties suggested some items that are not necessarily solutions, but that should be considered throughout the working group process or during solution evaluation and/or implementation. These overarching considerations are provided below in Table 9 and are enumerated for organizational purposes only (i.e., the overarching considerations are not listed in order of priority).

During the final combined meeting on December 4, 2023, participants expressed consensus for Overarching Considerations A.1–A.7, as documented in Table 9. Because participants expressed consensus on adding language pertaining to good utility practices to several solutions during the December 4, 2023 meeting, Overarching Consideration A.8 was added following that meeting, as it could pertain to many solutions.

Table 9: Overarching considerations related to the working group process and/or solution implementation

Consideration	Meeting Suggested
A.1: Post informational materials related to the process on a publicly available webpage in advance of the meeting. *Note: GPI compiled a resource library for the working groups in alignment with this suggested consideration.*	Combined Meeting 1
A.2: Consider pursuing outcomes that would enhance the Virginia Department of Energy's application to the Solar for All competition under the United States Environmental Protection Agency's Greenhouse Gas Reduction Fund. Specifically, the program seeks approaches that would address cost barriers for low-income households and communities.	Combined Meeting 1
A.3: Consider the value of in-person meetings moving forward.	Combined Meeting 1

Consideration	Meeting Suggested
Note: The working group meetings remained remote and were conducted in a virtual format throughout the process.	
A.4: Consider and provide clarity on how the conversations and outcomes from these working groups (which relate to Chapter 314) may affect facilities subject to Chapter 315, including the applicability of these interconnection rules to other projects, such as behind-the-meter projects and projects seeking to export to the wholesale power market.	Combined Meeting 1
A.5: Develop an approach that allows for sharing of technical resources throughout the interconnection process to allow additional parties to develop model scenarios for cost analysis.	Combined Meeting 1
A.6: Pursued solutions should enable compliance with Virginia's energy policy goals and legislative requirements, such as those established under the VCEA.	• Combined Meeting 1 • Working Group 1, Meetings 2 and 3 • Working Group 2, Meetings 3 and 4
A.7: Recommendations, solutions, and procedures under consideration should consider the similarities, differences, and variable needs/requirements of all utilities, cooperatives, etc. under SCC jurisdiction. Any solution being pursued should be developed with these factors in mind and should consider how interconnection processes and needs differ among utilities in terms of service territory and business model.[17]	Working Group 1, Meeting 2
A.8: Utility actions and requirements established under solutions should be conducted in alignment with "Good Utility Practice" as defined in 20VAC5-314-20.[18]	Final Combined Meeting

[17] In their written feedback in response to the November 13th draft potential solutions document, Virginia, Maryland, and Delaware Association of Electric Cooperatives (VMDAEC) emphasized the importance of taking utility size, practice, business model, resources, and service territory into consideration when developing and evaluating potential solutions.

[18] In accordance with Chapter 314, *Regulations Governing Interconnection of Small Electrical Generators and Storage* of the Virginia Administrative Code, "Good Utility Practice" is defined 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 that, 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 include practices, methods, or acts generally accepted in the region." (20VAC5-314-20, *Definitions* https://law.lis.virginia.gov/admincode/title20/agency5/chapter314/section20/)

B. Consensus Solutions

During the final combined meeting, participants reached consensus on including the following solutions in this report, as written. **As previously stated, consensus means that parties present in the final meeting did not oppose the solution**. Parties agreed that these solutions, if implemented, could address identified DER interconnection issues in Virginia. **In some circumstances, certain parties were able to accept moving a solution forward as a consensus solution even though they did not support all sub-components of that solution;** this and other participant feedback received in writing and during the final combined meeting is included in **Appendix D, *Summary of Participant Feedback on Solutions***.

Study and Construction Timelines

1. Meet and evaluate exceeding current study timeline requirements

Solution 1: The Commission should take action to ensure that utilities are meeting the study timeline requirements that are currently outlined in Chapter 314 of the Virginia Administrative Code, *Regulations Governing Interconnection of Small Electrical Generators and Storage*. The Commission should also evaluate ways to shorten current study timeline requirements such that Virginia's study timelines are aligned with best practices in other states. The group discussed the following approaches as potential ways to meet and evaluate exceeding[19] current study timeline requirements but did not reach consensus on any of them. Aspects of these approaches may pertain to utilities, ICs, or regulators.

i. Consider alternatives to the current study process (such as a combined study approach, a "pseudo-parallel" approach, or a targeted group/cluster study approach).
ii. Improve data access and quality as suggested in Solution 4.
iii. Improve study timeline granularity.
iv. Audit utility resources.
v. Increase the study deposit fee.
vi. Adopt manufacturer specifications and/or preferred manufacturer or equipment lists
vii. Establish monetary penalties for causing delays, applied to whichever party (utility or IC) is causing the delay.

Associated Topic(s), Solution 1: Study timelines, cost allocation, interconnection costs, cost/information transparency

Rationale and Implementation, Solution 1: Several parties felt that, at a minimum and as a "near-term" goal, utilities should meet the study timeline requirements outlined in Chapter 314. However, these parties felt that simply meeting the Chapter 314 timeline requirements is not an appropriate end-goal for this process and that ultimately, study timelines should be further reduced to the point at which they are consistent with practices in other jurisdictions.

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[19] In the context of this identified issue and this report, "exceeding" current study timelines refers to whether the study process can be completed in less time than is currently stipulated under the Chapter 314 regulations.

Approaches i–vii, described in greater detail below, reflect participant-recommended strategies that could reduce study timelines. The group did not reach consensus on which (if any) of these approaches should be pursued but acknowledged that these were all potential pathways that could help utilities meet and eventually exceed the current study timeline.

Approach i: Consider alternatives to the current study process (such as a combined study approach, "pseudo-parallel" approach, or a targeted group/cluster study approach)

Parties identified several potential alternative study methodologies (including sequential and non-sequential strategies) that Virginia could explore, including methodologies that have been implemented in other jurisdictions. Suggested methodologies are summarized below.

- A *combined study process*, in which projects that pass an initial screening (15 business day process) can proceed directly to the SGIA phase. If a project fails the initial screening, it undergoes a 60 business day study process that contains the same three major study components that are required in Virginia (feasibility study, system impact study, and facilities study). Only projects with applications that have been deemed complete are eligible to be combined with other such projects, and projects must meet certain conditions to be eligible for a combined study. This approach could also mitigate some cost allocation issues by expediting the overall study timeframe, thus reducing administrative costs. New York's Coordinated Electric System Interconnection Review (NY CESIR) approach follows this methodology and offers a model upon which Virginia could develop a combined study process.
- A *"pseudo-parallel" study process* in which later-queued projects can start the interconnection process as soon as an earlier project's study has been completed. This introduces a brief period of overlap in which several projects are working through different stages of the interconnection process simultaneously.
- *Targeted group/cluster studies* for distributed generators might address some issues with the current sequential study process while avoiding some of the pitfalls encountered in other jurisdictions that employ group processes. Under this approach, clusters of projects that are collectively under a certain established size threshold (e.g., collectively under a specified size in megawatt (MW) or collectively under the hosting capacity of the substation transformer) could be studied more quickly, and interconnection costs could be allocated across that cluster to avoid having all incurred costs falling on what otherwise would have been one singular project.

Approach ii: Improve data access and quality as suggested in Solution 4

Improving access to and quality of information provided by ICs and utilities alike has the potential to address several study inefficiencies. Data that parties identified as potentially beneficial includes (but may not be limited to) the following.

- *Information that would be provided by utilities to ICs:*
    - Generic costing information for potentially needed upgrades.
    - Previous queue study results, which could help inform ICs whether a site is located within a region that is favorable for pursuing interconnection (PJM makes

previous transmission study results available). Confidentiality issues regarding prior studies would need to be resolved for these studies to be made available.
    - Regularly updated hosting capacity maps or distribution asset maps (used by National Grid), with information on absolute capacity at substations, feeders, etc. (see Solution 4 for further details)
    - Weekly queue updates.
- *Information that would be provided by ICs to utilities:*
    - Finalized project designs, provided before submitting the IR (to the extent feasible) to reduce the potential for design changes to occur after the study phase has commenced. Project design information that participants felt would be helpful includes, but may not be limited to, the following:
        - Accurate one-line diagram
        - Transformer configurations
        - Proof of site control
        - Site layout
        - Equipment data sheets
    - Timely responses to utility data inquiries.

Utility-specific characteristics such as utility size and the demand for interconnection in the utility's service territory should be considered before requiring that all utilities provide the information listed in Approach ii, as such information may not be substantially beneficial to ICs seeking to interconnect in service territories with little demand for DER interconnection. Additionally, the administrative and financial resources required to develop and provide such information could be burdensome for smaller utilities. For this reason, the appropriateness of providing the following data should be considered on a utility-by-utility basis.

Utilities also expressed some concerns about information safety and security and asked that these factors be considered when identifying what information could or should be shared and/or distributed, and also when implementing this approach, if it is considered.

Approach iii: Improve study timeline granularity

The current study process can take up to 16 months, and the study timeline requirements outlined in Chapter 314 are not granular enough for parties to identify the specific steps and/or sub-steps during which slowdowns occur. Delays in these sub-steps contribute to both study timeline days and overall process delays.

More granular timeline information within study processes (to the sub-step level of detail) could help parties identify where relative delays are occurring within individual study steps, which may include more easily addressable administrative delays (e.g., delays that may be occurring because parties are waiting on information from other entities). However, this approach should only apply to study components that the utility processing the IR has control over. For example, utilities do not always have control over transmission impact studies (e.g., transmission service requests and ASO studies), which could be required. Distribution-only utilities including co-ops have limited control over third-party ASO studies, which could be required if an interconnection might impact third party-owned transmission facilities.

Virginia could look into approaches similar to those employed in other states to identify potential implementation strategies. For example, in Maine and Massachusetts, utilities must file quarterly updates with the Commission regarding where they are in the study process/along timelines. Any pursued approaches should consider instances in which a specific step in the study process may fall outside of a utility's control (e.g., an ASO study that may be required for certain interconnection requests in a distribution-only utility's service territory, in which case the utility's ability to provide granular information about such a study may be limited).

Approach iv: Audit utility resources

The points in the process in which timeline delays occur (if at all) varies by utility. To address delays that may be occurring due to utilities' internal and external capacity constraints, the Commission could direct utilities to identify both if and where they need additional resources (e.g., internal staff, external consultants, or other resources) to meet timeline requirements. Based on an individual utility's identification of needed resources, there may be opportunities in which ICs could provide utilities with some of this support or with information that may reduce the utility's workload.

Utilities specifically noted that it can be difficult to meet end-of-year (i.e., after December 15^{th}) timelines due to limited resources and staff capacity at that time. An internal resource audit could help utilities identify how to distribute tasks for internal staff and/or external consultant resources such that DER interconnection workloads are better balanced during that or other times of year.

Approach v: Increase the study deposit fee

The current study deposit fee for Level 3 interconnection requests is $10,000 + $1/kW. Increasing the study deposit fee has caused projects to withdraw in the past and doing so again could help discourage speculative interconnection requests that are holding up queue positions. Increased study fees would also help account for the increased study costs that several utilities have experienced and would help support utilities' increased resource needs, allowing them to more efficiently handle and process additional applications. However, efforts to increase study deposit fees should consider ways to do so that will not financially deter local applicants or other applicants that may be more price sensitive.

Approach vi: Adopt manufacturer specifications and/or preferred manufacturer or equipment lists

Common manufacturer specifications and/or preferred manufacturer or equipment lists would limit the different specifications that would need to be studied for each project. This would simplify equipment-related portions of the analysis, potentially reducing timelines for that portion of the study process, and could be especially useful for key equipment such as inverters. This approach could also include a means by which developers can nominate additional vendors to the preferred manufacturer or equipment lists in the interconnection request form to account for technological advances over time, as well as an ever-changing landscape of vendors.

Preferred equipment lists should note conditions that may cause delays, but that fall outside of utility control (e.g., supply chain issues). Some jurisdictions (e.g., Massachusetts) have state-level equipment settings for qualifying generators and some RTOs maintain preferred manufacturer lists. Virginia could refer to preferred specifications from these other jurisdictions as an example of how this solution might be implemented, which could occur at the State-level or utility-level.

Approach vii: Establish monetary penalties for causing delays, applied to whichever party (utility or IC) is causing the delay

Monetary penalties could be applied to whichever party (utility or IC) is causing timeline delays. One participant suggested that Virginia review the penalty models used for DER interconnection delays in Duke Energy Progress and Santee Cooper service territories, which are more strict than the penalties described in FERC Order No. 2023, but which improved queue manageability.

Additionally, monetary-based enforcement mechanisms pertaining to information quality, such as making it more costly for parties to submit inaccurate or incomplete information throughout the SGIA process, may improve information quality, potentially reducing delays associated with poor information.

2. Secure site access early for the utility

Solution 2: Incent ICs to secure early site access for the utility and provide the utility with high-quality site plans as early as possible.

Associated Topic(s), Solution 2: Construction timelines

Rationale and Implementation, Solution 2: Utilities require site access and permits to begin building the attachment facilities that, through the study process, are found to be necessary for interconnection. However, utilities can only do this if they are authorized to access the site, all necessary permits are obtained, and they have high-quality site plans that enable facility engineering and design. Earlier site access for utilities increases the likelihood that utilities can start interconnection facility construction without delays. A strategy that would incentivize ICs to secure site access early in the process and ensure that provided site plans are sufficient to enable utility-side engineering and design, would help reduce the potential for site-related construction timeline delays.

Interconnection Costs and Information Transparency

3. Improve communications between ICs and utilities

Solution 3: Utilities should work with ICs to identify potential opportunities to improve communications throughout the interconnection process. Improvements should work to ensure that all parties have the most up-to-date information regarding the application process, the study process, the construction phase, and necessary payments. Communications aspects requiring improvement may vary by utility, and potential improvement strategies may vary accordingly (e.g., a dedicated interconnection ombudsperson at large utilities or at the Commission; a petition process through which ICs can receive Commission support if a utility falls behind, etc.).

Associated Topic(s), Solution 3: Interconnection costs, cost/information transparency, study timelines, construction timelines

Rationale and Implementation, Solution 3: Both utilities and developers identified value in improving communications throughout the application process. Parties noted that communications improvements would likely improve parties' understanding of their responsibilities associated with ongoing responsibilities and next steps, resulting in process-wide efficiencies. Communications improvements should enable parties to more easily obtain critical information at the necessary level of granularity, allowing projects to move through the SGIA process more smoothly while minimizing information-related delays.

Utilities had different suggestions for what approaches may work best for ICs in their respective service territories, since utilities' communications strategies vary. ICs provided feedback related to their experiences communicating with utilities throughout the interconnection process.

- VMDAEC prefers that ICs reach out directly to the distribution co-op serving the region in which they seek to interconnect. Individual co-ops may have different preferred communications processes and are generally small enough for direct outreach to be an appropriate initial strategy. Developers did not identify issues with or suggest changes to VMDAEC's communications processes.
- Dominion has different teams and different points of contact for different phases in the interconnection process. During the pre-application phase, ICs can reach out to their contract administrator for high-level information. Subsequently, ICs can contact engineering teams within Dominion's Protection Department or Substation Department during the study phase.
  - ICs expressed concerns that information quality can vary throughout Dominion's interconnection process depending on the utility staff involved in a certain step.
  - Dominion stated that if ICs are having issues with information quality throughout the process, they should reach out to Dominion and can schedule a separate dedicated check-in call to provide clarity.
  - ICs suggested that providing information through a more standardized process (e.g., through a brief standardized preliminary study report as done in Massachusetts and New York) might address this.
- KU prefers that parties first seek interconnection information on their website and reach out if they still have questions. KU stated that this is an effective communications

strategy because the utility receives very few interconnection requests in its Virginia service territory. ICs did not identify issues with or suggest changes to KU's communications processes.

- APCo/AEP has a dedicated software tool (PowerClerk) that applicants use to submit information and proceed through the interconnection process. This tool enables the DER interconnection service agreement process and, if applicable, the SGIA process to occur in a centralized "place," (rather than over email), resulting in communications efficiencies. APCo/AEP encourages ICs to use this tool to its full advantage. ICs did not share issues with or suggest changes to APCo/AEP's communications processes.

Improved communications between utilities and ICs could be mutually beneficial to both parties. It would help ICs understand whether they need to submit additional materials or information to utilities while working through the interconnection process, and would prevent delays on the utility side by making it more clear to ICs that the application and other supporting materials they submit are complete.

4. Improve access to and quality of actionable information that ICs need to make informed project decisions

Solution 4: Utilities that meet appropriate and reasonable pre-determined thresholds[20] should ensure that parties have access to actionable information to fulfill their responsibilities throughout the interconnection process in a timely manner while maintaining consideration for data sensitivity and confidentiality concerns. Certain data may require specific protection strategies (e.g., aggregation, secure hosting, etc.) for safety and privacy purposes. The group discussed the following approaches as potential ways to achieve this, but did not reach consensus on all of them:

i. Completed interconnection studies for past DER projects (with sensitive information redacted) and the interconnection status of those projects.
ii. Regularly updated maps with interconnected and queued projects and remaining projects if possible.
iii. Distribution assets list or map (e.g., total capacity for DER of transformers and feeders at substations, substations with DER already installed, circuits with fiber already installed).
iv. Other geospatial resources identified in the August 1, 2023 *Staff Distributed Energy Resources ("DER") Survey* in Case No. PUR-2022-00073.

Access to the above informational resources would allow ICs to develop more informed project proposals and submit more comprehensive interconnection applications, thus reducing utility and IC administrative inefficiencies.

Associated Topic(s), Solution 4: Cost/information transparency, study timelines, construction timelines

[20] Some developers suggested that the DER deployment need associated with different utility sizes (as outlined in the VCEA) could be considered for use as the "thresholds" for Solution 4.

Rationale and Implementation, Solution 4: Developers expressed that access to this information would help them make more informed business decisions about where a project may or may not be feasible and whether it should be pursued. Helping developers make more informed business decisions would likely reduce the amount of non-viable projects in the queue and overall would result in downstream study process efficiencies. Participants outlined four potential approaches (approaches i–iv) that could help developers make more informed decisions but did not reach consensus that all approaches should be pursued.

Approach i: Completed interconnection studies for past DER projects, with sensitive information redacted, and IC status of those projects

If a proposed DER project has substantial similarities to a nearby DER project that was already studied, access to the completed studies for the previous DER project could help developers more accurately estimate potential costs and challenges that may occur with their own project. Access to this information may allow developers to make more informed decisions about cost and site feasibility for certain projects during the application phase, thus reducing the potential that a proposed project would be financially or geographically infeasible. Specifically, developers expressed an interest receiving access to the two most recent studies completed on a given circuit so long as that study is no more than five years old.

Approach ii: Regularly updated maps with interconnected and queued projects and remaining projects if possible)

Approach iii: Distribution assets list or map (e.g., total capacity for DER of transformers and feeders at substations, substations with DER already installed, circuits with fiber already installed)

Approach iv: Other geospatial resources identified in the August 1, 2023 Staff Distributed Energy Resources ("DER") Survey in Case No. PUR-2022-00073.

Approaches ii, iii, and iv all pertain to spatial information (maps or lists) that developers felt would help them make more informed business decisions. Developers use geospatial resources including hosting capacity maps to identify sites that may be suitable for DER deployment. If utilities were to make existing geospatial resources more granular and make additional resources available, developers could make more informed decisions before submitting their IR and, if applicable, proceeding through the SGIA process. Some utilities already make hosting capacity information publicly available on their websites, but additional information could be included, either publicly on their websites or privately as part of the study process. Additionally, for utilities that already publish this information, it could be updated more frequently.

Developers also noted that having access to information including feeder load profiles (which would inform energy storage profiles), whether a circuit already has fiber installed, and whether a substation already has a DER panel would be especially useful in advance of the facilities study. Knowing, for example, that the substation to which a proposed DER would interconnect already has a DER panel installed may make that project more financially viable, as the IC would not need to pay for this upgrade.

5. Regularly review and update interconnection guidance materials and ensure that such materials are easily accessible

Solution 5: Some utilities produce informational interconnection materials that are intended to help developers make informed decisions about DER project feasibility. Utilities that publish interconnection guidance materials should regularly review and update these materials as appropriate to ensure that they accurately reflect current conditions and remain as useful as possible to developers.

Associated Topic(s), Solution 5: Interconnection costs, study timelines, construction timelines

Rationale and Implementation, Solution 5: Some utilities develop and publish materials that are intended to help developers make more informed project design decisions and make more accurate upgrade costs estimates. However, these materials become less useful if they become outdated, as they may no longer reflect current market conditions. Available materials vary by utility, and developers had varied awareness of these resources

- Appendix D to Dominion's *Interconnection Parameters for Distributed Energy Resources* manual provides estimated cost ranges for equipment commonly needed to support upgrades, but not all participants were aware of this resource. Additionally, some developers noted that the costs in the manual do not reflect recent equipment cost changes, such as those resulting from inflation, and that the cost categories in the manual are not reflective of how costs are estimated in Dominion's study process. This makes it difficult for developers to compare cost estimates between the values included in the manual and those provided throughout the study process.
- APCo/AEP is in the process of revising its distribution interconnection manual, *DER Technical Interconnection and interoperability Requirements (TIIR) for the AEP Distribution System*, which will reflect APCo/AEP's goal of having a universal interconnection process across the many jurisdictions in which it conducts business. Like Dominion's manual, this resource provides cost estimates for common necessary upgrades, but those cost estimates may not reflect rapidly changing costs.

More accurate and reliable equipment and upgrade cost information could help developers better estimate their anticipated interconnection costs before submitting an IR. Regularly updating this information to more accurately reflect actual market conditions would improve information reliability, though cost data presented in these materials should clearly state that any described costs remain estimates. One participant suggested that an annual review and update would be appropriate, but this might vary by utility and by the specific content included in the utility's guidance materials. Additionally, because developers had varied awareness and knowledge of these resources, utilities that provide such materials should consider ways to improve knowledge of these resources and where they can be found.

6. Monitor changes in cost estimates throughout the study process

Solution 6: Develop a way to identify, monitor, and track which cost estimates are most subject to change throughout the study process. This could help utilities better understand and refine cost estimate ranges for particular types of upgrades.

Note: Solution 6 should only be applied if a combined study approach is not adopted.

Associated Topic(s), Solution 6: Interconnection costs, cost/information transparency

Rationale and Implementation, Solution 6: Developers noted that cost estimates for necessary upgrades can fluctuate throughout the study process. Some utilities already provide cost estimate "ranges" for certain common equipment and upgrade needs in the interconnection guidance materials described in Solution 5. However, identifying which cost estimates are most prone to changing could help utilities establish more precise cost estimate ranges that are informed by observed cost fluctuations.

Cost Allocation

The following solutions to cost allocation issues are general in nature and could apply to any/all costs related to DER interconnection. Solutions that would address cost allocation through broad regulatory changes are described under *High-Level Regulatory Changes*.

7. Investigate establishing a DER rate class

Solution 7: The Commission should initiate a process to investigate the option of establishing a dedicated DER rate class across which interconnection costs would be spread or allocated via a specific tariff. The investigation should take into consideration utility type, size, and the scale of DER interconnection within the utility's service territory when considering whether this may be appropriate for any utility.

Associated Topic(s), Solution 7: Cost allocation, interconnection costs

Rationale and Implementation, Solution 7: Interconnection costs could be allocated through a dedicated DER tariff. The tariff could be developed with several different rate structures based on the capacity that an individual customer subject to this DER tariff would need on the system, and charges could be tailored to individual projects.

Because interconnection upgrade costs would be spread across a dedicated customer class, this approach offers an alternative to the current "100% cost causation" model in which the project triggering the need for an upgrade bears the financial responsibility for that upgrade. If pursued, this solution would allow ICs to share the cost of interconnection with other DER providers, similar to the way that load customers share infrastructure costs with other load customers. The Commission could explore ways that this solution could be implemented in the context of the GTSA, which enables creative approaches to grid modernization. In Washington D.C., Pepco recently filed a similar tariff for specific net energy metering projects (currently under Public Service Commission consideration) which could serve as an example if this solution is pursued.[21]

8. Explore and, if appropriate, implement a proactive cost allocation strategy

[21] Potomac Electric Power Company (Pepco), Petition of Potomac Electric Power Company to approve a tariff Change for 20 kW and below residential NEM solar interconnections (April 4, 2023), Docket Nos. ET2023-01 and RM40-2023. Available at: https://edocket.dcpsc.org/apis/api/Filing/download?attachId=188440&guidFileName=e0463f9b-08ee-4268-b7b5-8b3d6faec1ee.pdf

Solution 8: The SCC should explore and, if appropriate, implement an alternative cost sharing/cost allocation strategy through which projects make proactive payments to prevent any one project from bearing full upgrade cost responsibilities. The utility would identify the cost of all system upgrades that would be necessary to support interconnection and would then establish how much each project must pay based on their size/share of the needed upgrades on a per-kW basis. This strategy has been found to be effective except in situations in which there is a need for transmission-level upgrades, which can be too costly even with this sharing approach.

Utilities should proactively use the GTSA to upgrade the grid in preparation for DER in the case where upgrades are uniform for any DER class or size, subject to Commission approval. This exploration should take into consideration utility type, size, and scale of DER interconnection when considering whether this may be appropriate for any utility.

Lessons learned from New York's approach to proactive cost sharing should help the SCC understand the potential implications of enacting this model in Virginia. If this approach to cost sharing is found likely to result in positive outcomes, the SCC should investigate how such an approach could be implemented.

Associated Topic(s), Solution 8: Cost allocation, interconnection costs

Rationale and Implementation, Solution 8: Many participants expressed interest in moving away from Virginia's current 100% cost causation model in which costs are distributed across the interconnecting DER projects that trigger a need for upgrades. New York's *proactive cost sharing* approach ("Cost Sharing 2.0") offers a potential alternative to Virginia's current approach. Under this approach, the utility identifies the cost of all system upgrades that would be necessary to support interconnection, then establishes how much each project must pay based on their size/share of the needed upgrades on a per-kW basis. This strategy has been found to be effective except in situations in which there is a need for transmission-level upgrades, which can remain too costly for some DER projects even with this sharing approach.

With Commission approval, the GTSA could be used as a mechanism to enable proactive cost sharing allocate costs more effectively while modernizing utilities' distribution grids.

Approaches to Meeting Safety and Reliability Requirements

This section includes solutions that relate to utilities' obligation to maintain a safe, reliable, operable, and affordable grid for all customers, and the role that DERs play in maintaining such a system as Virginia aims to meet statewide clean energy policy goals and statutory requirements. Criteria and requirements for maintaining system safety and reliability with DER interconnection are set forth in the standards contained in IEEE 1547-2018. Parties disagreed on Dominion's application of those standards for DERs and sought clarification on Dominion's rationale for applying these technical standards to DERs.

Dominion uses dedicated fiber as a communications medium to accomplish DTT; throughout the working group process, Dominion emphasized that DTT enables them to maintain a safe, reliable, operable, and affordable grid for all customers. Developers and advocacy organizations, however, noted that a safe, reliable, operable, and affordable grid for all customers could be achieved through either alternative means of accomplishing DTT (e.g., technologies that do not require dedicated fiber) or deployment of non-DTT technologies. Developers and advocates have argued that the high costs associated with DTT (including but not necessarily limited to the use of dedicated fiber to accomplish DTT) are interfering with Virginia's ability to meet its clean energy goals and have questioned whether DTT is necessary for Dominion's system.

The solutions in this section seek to address this disagreement, with consideration for the following:

- When DTT may or may not be an appropriate technology for utilities to use to meet their obligation to maintain a safe, reliable, operable, and affordable grid for all customers;
- Whether the technical standards driving utilities' use of DTT are necessary and appropriate; and
- Whether alternative lower-cost technologies exist that could accomplish what Dominion seeks to accomplish through its use of dark fiber/DTT.

9. Ask utilities proposing to require DTT to file information rationalizing this requirement with the Commission demonstrating that it is the least-cost solution to meet safety and reliability requirements in accordance with "Good Utility Practice" as defined in 20VAC5-314-20.

Solution 9: Direct utilities requiring that DTT be installed as part of the DER interconnection process to file information rationalizing this requirement with the Commission. The information should be filed at a cadence determined to be appropriate by the Commission (e.g., annually). Filed materials should include, but may not be limited to:

i. System-specific information
ii. The contexts in which the utility requires DTT
iii. Which safety and reliability requirement(s) the utility is seeking to meet
iv. The tests the utility conducted to determine the need for DTT (as opposed to other technologies including inverter-based solutions)
v. What other technologies the utility has pursued or evaluated to address the issues being solved by DTT and why those alternative technologies were found to be inadequate. This should include a discussion of how the utility will meet safety and reliability requirements, including but not limited to the risk and probability of islanding and fault occurrence (and, accordingly, the need for fault protection).

This information should be available in a standardized format (report and/or table) to facilitate comparison between utilities using DTT vs. alternative technologies (e.g., inverter-based solutions) and should be shared with the Commission.

Associated Topic(s), Solution 9: Dark Fiber/DTT, cost/information transparency

Rationale and Implementation, Solution 9: Developers requested greater clarity on how Virginia's utilities have used fiber or alternative technologies to enable DTT across their unique systems, as well as contextual system-specific information to provide clarity on the differences between utility systems. Developers felt this would improve their understanding of which anti-islanding and system protection technologies each utility has tried, and how those technologies have or have not worked for the utility's system.

Participants requested that utilities provide a report containing the following information and expressed a preference that to the extent practical, this information be displayed in a tabular format to make it easier to compare practices across utilities.

- System-specific information, including the most prevalent voltage across the utility's system, the AC system sizes being proposed within the utility's service territory, and other attributes.
- The extent to which the utility is already conducting the comprehensive impact studies described in Solution 14.
- The specific technical drivers under existing policy that contribute to the utility's DTT requirement, alternative strategies the utility has explored or considered to meet these technical drivers, and an explanation as to why those alternative strategies were rejected.
- Which tests (including technical screens) have failed that are causing the utility to require the use of DTT.
- What is driving the need to deploy DTT, based on completed studies. These may include the comprehensive studies described in Solution 14, as well as other relevant completed studies.
- How many strands of unused dark fiber are being deployed to accomplish DTT, how many strands are required to enable that functionality, and whether any unused fibers could be used or shared for other resources.

Because some utilities may not be experiencing issues related to the use of DTT, this exercise could help identify which solutions (if implemented) might apply to which utilities. For this reason, the requested information should be presented in a standardized format so that responses can be compared across utilities if, when, and where possible. The Commission should develop a template through which utilities can provide their responses, including a table for information that can reasonably be shared in that format.

Note: that Solution 9 may not be required if Solutions 11 and 12 are implemented, depending on the results of those Solutions if they are pursued.

10. Conduct an analysis identifying ways to interconnect DERs at the rate necessary to meet State policy (as expressed in the Grid Transformation and Security Act) while ensuring the safety, reliably, and operability of the electric power system in accordance with "Good Utility Practice" as defined in 20VAC5-314-20.

Solution 10: Ask the Commission to conduct an analysis to determine how to interconnect DERs safely and reliably at a pace, scale, cost, and level of risk aligned with state policy mandates. This analysis should include consideration for the following.

- The safety and reliability issues that are (or are not) addressed via DTT, as compared to other potential technologies (including but not necessarily limited to inverter-based resources) that meet the appropriate standards,
- The cost effectiveness of using DTT (as opposed to the costs of conducting site-specific studies and/or pursuing other technologies that meet the appropriate standards) for this purpose, and
- An assessment of and guidance on the validity and efficacy of various anti-islanding and grid protection solutions, including inverter-based resources and other technologies that have been or are currently being explored via pilots.

Associated Topic(s), Solution 10: Dark Fiber/DTT, interconnection costs, cost allocation

Rationale and Implementation, Solution 10: Dominion emphasized that by using DTT, the Company is able to meet their obligation to maintain a safe and reliable grid. However, developers noted that the high cost of this technology (in particular when accomplished via the use of dedicated dark fiber) can be cost prohibitive to many DER projects, especially under the current 100% cost causation model is financially responsible for the upgrade. If the use of DTT (and dedicated fiber) is interfering with Virginia's ability to deploy DERs and alternative lower-cost technologies that still meet safety and reliability needs are not identified, Virginia may not be able to meet its clean energy goals and obligations. Developers also noted that utilities in other markets have successfully implemented project-specific studies (in contrast to Dominion's light load screening approach) and inverter-based protection standards that have reduced or eliminated the need for DTT.

Because of the need to ensure grid safety and reliability in the public interest while also complying with clean energy laws such as the VCEA, the Commission should conduct an analysis to identify feasible and commercially reasonable paths forward that are sensitive to system safety, reliability and cost considerations while addressing energy resource needs, and that would not depend on subsidy by individual ICs. This would require the Commission to determine what constitutes reasonable achievement of these metrics (some of which may be established under statute).

The Commission's analysis should be based on the latest IEEE standards and should consider the fact that DTT provides fault prevention benefits and contributes to grid safety and reliability under increased DER penetration, though other technologies exist that provide grid safety and reliability benefits. The analysis should provide context and information that will allow any utility proposing to require DTT to embark on a revision of technical standards for inverter based DERs to take advantage of all inverter capabilities as described in greater detail under Solution 11.

This analysis would also provide the Commission with the ability to assess the validity of and risk/likelihood of potential grid safety and reliability scenarios, understand how these issues have been solved in other markets, and understand how to apply these findings in a way that serves the public interest in Virginia. Specifically, this analysis should enable the Commission to make an assessment or provide guidance as to the validity of various anti-islanding and fault prevention strategies by considering the following:

- Anti-islanding and grid protection needs, both separately and together
- What level of risk is "acceptable" and the financial mechanisms through which risks that may occur could be covered
- Infrequent events that have large, widespread system impacts, and the probability/likelihood of such events occurring

This analysis should be completed by or in collaboration with a nationally recognized independent engineering association or laboratory as well as representatives from utilities that have successfully implemented interconnection standards that can reduce or remove the requirement for DTT.

Findings from this analysis should help inform Solution 11 (revision of technical standards) and Solution 14 (comprehensive studies for projects in which fiber is being proposed), but this analysis does not need to be completed before those steps can commence. Ultimately, this analysis should identify whether Virginia can realistically meet its clean energy requirements under continued use of this technology.

Note: Solution 10 does not need to be completed before Solution 11 can commence, if both solutions are pursued.

11. Initiate a process to review and revise technical standards for inverter-based DERs.

Solution 11: The Commission should initiate a process (e.g., a working group) through which the utilities review and revise technical standards for inverter-based DERs to take advantage of all inverter capabilities. This review and revision should be conducted in consultation with a qualified and impartial third party, such as a nationally recognized independent engineering association or laboratory and should take into consideration the technical standard needs for different-sized DERs. The review should also take into account utility response time requirements (e.g., Dominion's 160 ms response time).

As a result of the process, the Commission should direct the utilities to review and revise technical standards for inverter based DERs to take advantage of all inverter capabilities, and to propose those revised standards to the Commission. This should not necessarily be applied to all utilities equally. The Commission should take into consideration utility type, size, and scale of DER interconnection when determining which utilities would be required to do this.

This review should take stakeholder input into consideration, including but not limited to utilities, developers, PJM, consumer advocates, and any relevant state agencies. It should also consider information from other regulatory or industry forums that are working on this issue.

Associated Topic(s), Solution 11: Dark Fiber/DTT, cost/information transparency

Rationale and Implementation, Solution 11: Participants expressed support for a process that would help determine whether or not DTT is required to ensure system safety and reliability when DERs of different sizes (e.g., <1MW, 1–5MW, 5–20MW, and >20MW) interconnect to the grid, or whether alternative technologies (e.g., inverter-based resources) could also serve this role. Similarly, participants questioned whether the technical standards that are driving the use of DTT—including Dominion's 160 ms standard—are necessary for maintaining system safety and reliability.

Under Solution 11, affected utilities would propose revised standards to the Commission for consideration. The proposals should consider alternatives to DTT including inverter based DERs. This will allow affected utilities to further explore alternative technologies, identify how technical standards could and should be revised to allow for those alternatives to be used while maintaining system safety and reliability, and present these updated standards to the Commission for review and consideration.

Through this approach, the Commission can first determine if the existing technical standards are necessary for utilities to meet their grid safety, reliability, and operability requirements, informed by both utility feedback and feedback from other parties. If the current standards are found to be unnecessarily conservative, the Commission can work with utilities to identify what technical standard(s) would be appropriate. Informed by these findings, the Commission can then determine if DTT (accomplished via the use of dedicated fiber or any other approach) is necessary to meet the updated technical standard(s) while enabling utilities to fulfill their obligations to maintain a safe, reliable, operable, and affordable grid for all customers, or if alternative technologies could be utilized.

As revised, the technical standards should include a way to study project-specific islanding and protection needs such that DTT is only used as a "last resort." This could involve proceeding through an analysis of criteria, evaluated in this order:

- Basic screening based on project size and equipment
- Site-specific studies to determine the risk of islanding/fault contribution
- Implementation of inverter-based protection and local protection
- Consideration for the DTT if the project would fail to meet the three previous criteria (basic screening, site-specific studies, and inverter-based protection)

Under this scenario, DTT would only be implemented if all other technical solutions to meeting risk thresholds are exhausted; this is in contrast to current standards that require DTT for all projects that fail Dominion's 3:1 screening.

If implemented, Solution 11 should be completed quickly so that subsequent studies, reports, and evaluations (such as those that would be completed under Solution 14, if pursued) can commence under these new technical standards. Solution 11 could be included as an attachment to the filing described under Solution 9 (if pursued).

Note: The information gathered through Solution 9 (if pursued) can and should inform the technical standard revision process outlined under this solution, but Solution 9 does not need to be completed before the technical standard revision process can commence.

12. Hold an evidentiary process evaluating the need for DTT, as opposed to other technologies

Solution 12: Ask the Commission to open an evidentiary process through which they will explore the need for DTT to support DER interconnection in Virginia, as opposed to other technologies (including inverter-based resources). The process should explore what standards (if any) DTT meets that other technologies cannot meet, the reasons for these differences, and other key factors related to the use of DTT in Virginia for this purpose, as well as in other jurisdictions in which DTT has been used in the past (e.g., PHI's Delaware service territory, which has eliminated blanket DTT requirements while continuing to meet safety and reliability standards). This should include testimony under oath.

Associated Topic(s), Solution 12: Dark Fiber/DTT, cost/information transparency

Rationale and Implementation, Solution 12: A formal evidentiary Commission proceeding would allow parties to establish a robust Commission record on DTT. Through this record, the Commission could analyze whether or not DTT has a role to play in DER interconnection in Virginia, and, if it does, what the bounds of that role might be. Such a process also provides an opportunity to explore lessons learned from other jurisdictions that could help inform utility and regulatory decisions in Virginia.

High-level Regulatory Changes

13. Consider regulatory changes that would incentivize DER interconnection

Solution 13: Ask the Commission to consider implementing regulatory changes (e.g., performance-based regulation or changes or adoption of the latest IEEE standards) that would incentivize utilities to support interconnecting more DERs.

Associated Topic(s), Solution 13: All

Rationale and Implementation, Solution 13: Formal adoption of relevant technical standards and/or adoption of alternative regulatory schemes such as performance-based regulation could encourage DER interconnection by establishing mechanisms that would actively incent utilities to support DER proliferation and interconnection in their service territories. The GTSA may offer a legal basis for this, as it establishes that electric distribution grid transformation projects are in the public interest. In accordance with SB 1265 and HB 1770, the Commission opened a proceeding of this nature in December 2023, in Case No. PUR-2023-00210.[22] This proceeding may offer a viable opportunity through which alternative regulatory strategies and mechanisms that would incentivize DER interconnection could be explored and could significantly affect all working group topics.

C. Non-Consensus Solutions

During the final combined working group meeting, parties were unable to reach consensus on whether the solutions listed in this section (Solutions 14 and 15) should be included in this report for consideration. These two solutions are described below as non-consensus solutions because some parties felt strongly about their inclusion for consideration, and other parties remained strongly opposed to their inclusion for consideration. This differs from the consensus

[22] Please refer to the docket for Case No. PUR-2023-00210, *In the matter concerning implementing performance-based adjustments to combined rates of return under §§ 56-585.1 A 2 c and 56-585.8 E of the Code of Virginia* for the most up-to-date information on this proceeding: https://scc.virginia.gov/DocketSearch#caseDocs/144672

solutions listed above in Section B (Solutions 1–13), which parties did not oppose, even though they may not have reached agreement regarding whether individual solution sub-components should be pursued.

Approaches to Meeting Safety and Reliability Requirements

14. Comprehensive impact studies considering the abilities of inverter-based resources

Solution 14: Require utilities proposing to require DTT to conduct comprehensive impact studies on the issues that they seek to address, with consideration for the abilities of inverter-based resources. The studies should identify the risk and reliability concerns that they seek to avoid by requiring DTT (including the probability of any risk or reliability concerns being realized) and should analyze whether inverter-based resources could address those concerns while meeting the technical standards as revised under Solution 11. A third party (contracted by the Commission) should help determine which studies are needed, and those studies should take into consideration the abilities of certified inverter-based resources.

Associated Topic(s), Solution 14: Dark Fiber/DTT, cost/information transparency

Rationale and Implementation, Solution 14: Through the analysis described in Solution 10 (if pursued), the Commission may identify alternative ways to safely and reliably interconnect DERs. Additionally, if Solution 11 is pursued and utilities revise their technical standards as described in that solution, the abilities of and use opportunities for inverter-based resources that would meet those standards must be studied.

To ensure that utilities are able to comprehensively evaluate and understand system risks and opportunities associated with inverter-based resources, the comprehensive studies should at a minimum explore the following.

- Risks associated with islanding, miscommunication, and failure to clear a fault within the timeframe necessary to ensure safety and meet established standards (IEEE 1547-2018, Sections 8.1.1 and 8.2.3)
- Solutions for ground fault overvoltage (IEEE 1547-2018, Section 7.4)
- Effective grounding/solutions for transient overvoltage (IEEE 1547-2018, Section 7.4)
- Arc flash incident energy calculations
- Recloser coordination (or protection system coordination through alternative means included fuses, circuit reconfigurations, etc.)
- Protection system desensitization
- Potential to relax utility requirements to trip at the inverter rather than the recloser

Note: Findings from this analysis should be informed by Solution 10 (if pursued), but Solution 10 does not need to be completed before these comprehensive studies can commence. However, Solution 11 (if pursued) should be completed before utilities begin these comprehensive studies.

High-level Regulatory Changes

15. Explore and, if appropriate, implement a holistic approach to cost allocation that accounts for broad-scale societal benefits of DERs

Solution 15: Through an evidentiary process, the SCC should explore alternative cost sharing/cost allocation strategies enacted in other jurisdictions that better distribute costs across all beneficiaries of DER projects, including but not limited to the those included in the Grid Transformation and Security Act.

The SCC should use lessons learned from other jurisdictions to understand the potential implications of enacting this type of model in Virginia. If this approach to cost sharing is found likely to result in positive outcomes, the SCC should investigate how such an approach could be implemented in the Commonwealth.

Associated Topic(s), Solution 15: Cost allocation, interconnection costs

Rationale and Implementation, Solution 15: Many participants identified Virginia's current 100% cost causation model as a core issue and expressed interest in exploring alternative cost allocation strategies used in other jurisdictions and, ultimately, adopting an alternative approach that may have positive outcomes in Virginia.

According to some participants, because DER deployment can have broader benefits beyond the scope of the individual project or group of projects that trigger a need for upgrades, the costs to interconnect those projects should also be broadly allocated. Specifically, DER interconnection and associated upgrades have the potential to be broadly beneficial to a utility's electric system, the environment, and society. However, not all participants agreed that DERs were inherently beneficial or that those benefits and their associated costs could be reasonably identified and appropriately identified, which would be required for cost allocation. For example, accurately capturing DER benefits would depend on several additional complex factors, such as operating assumptions for energy storage projects that would contribute to such benefits.

Still, this more "holistic" approach to cost allocation for DERs and associated grid upgrades has been explored or practiced in several other jurisdictions.

- *Multi-beneficiary cost sharing (DPU Docket No. 20-75, Massachusetts):* Costs associated with upgrades that would benefit not just the interconnecting project(s) but also the system more broadly are eligible to be recovered through the utility's rates. For this approach, it is important to understand which upgrades contribute to what benefits (including broader societal benefits) and the extent of those benefits.
- *Rate-base costs to the point of common coupling (California's Rule 21, Germany):* This approach is similar to the cost allocation approach used for the bulk electricity system and is based on the rationale that DER interconnection has broader societal benefits, so costs should be allocated similar to how they are allocated for broadly beneficial bulk electric system upgrades. This approach is used as a way to encourage grid advancements in support of greenhouse gas emissions reduction goals and requirements. Note that this practice does not apply to all DER facilities interconnecting in California.

- *Integrated proactive system planning (Coordinated System Planning in New York, Electric Sector Modernization Plan in Massachusetts, and Proactive System Upgrade Planning in New Jersey):* Utilities submit proposals identifying where upgrades may be necessary to support DER deployment and identify what sorts of benefits those upgrades would generate. Based on that proposal and following regulatory review/evaluation and approval, utilities make the necessary capital investments. The costs for those investments are recovered through load customers, DER customers, etc., and do not necessarily need to be allocated evenly across a utility's entire rate base. Instead, costs could be allocated based on where identified benefits may occur. Participants suggested that in Virginia's case, evaluative criteria should be based on state-level policy goals and the VCEA.

The approaches listed above range from authorizing that portions of interconnection costs can be allocated across a utility's rate base (e.g., multi-beneficiary cost sharing in Massachusetts) or a geographic region (e.g., California's Rule 21) to having utilities conduct holistic distribution system planning and develop capital investment plans that include upgrades that would benefit society by allowing more DERs to interconnect, which—according to these approaches—are inherently beneficial.

These more holistic cost allocation strategies consider broader system and/or societal benefits and would allocate costs accordingly. However, this model assumes that those benefits would occur and would be measurable and/or quantifiable. Any of these approaches would likely require a comprehensive shift in the way that the utilities conduct business related to planning and DERs and the way that the SCC oversees such processes.

VI. Conclusion

This report summarizes the State Corporation Commission's (SCC, or Commission) DER interconnection working group process that the Great Plains Institute (GPI) convened and facilitated over the course of seven meetings held between July and December 2023. Per the Commission's March 3, 2023 Order in Case No. PUR-2022-00073, the process involved exploring issues and identifying potential solutions related to six key topics, discussed across two different working groups: Working Group 1 focused on study timelines, construction timelines, and cost allocation, and Working Group 2 focused on interconnection costs, cost transparency, and the use of dark fiber/DTT.

The 13 consensus solutions and two non-consensus solutions listed in this document reflect participants' suggestions throughout the collaborative working group process; the solutions were developed, refined, and finalized not by SCC Staff or GPI facilitators, but by working group participants themselves.

The solutions have a variety of potential implementation pathways and methodologies; some individual solutions may be best implemented in conjunction with other solutions, and others may stand alone. Individual solutions may require further analysis, refinement, or specification to determine whether that solution should be implemented and—if so—what would constitute the most appropriate and/or effective pathway to implementation. While preparing this Final

Report, parties expressed interest in further conversation regarding how these solutions could be implemented to help address DER interconnection issues in Virginia.

GPI appreciates the time, effort, and involvement of all parties, without whom this comprehensive list of solutions would not have been possible.

Appendix A: Working Group Participating Parties

Excluding SCC Staff and GPI facilitators, more than 120 unique individuals attended at least one of the working group meetings. The following list reflects all individual participants. Participants who joined only by phone are not included on this list, as Zoom is unable to capture these individuals' names.

GPI and SCC staff

Trevor Drake	GPI	Fred Ochsenhirt	SCC	Pam Genung	SCC
Alissa Bemis	GPI	Jason Brannick	SCC	Schuyler Ingram	SCC
Aileen Cole	GPI	Mike Cizenski	SCC	Yousuf Malik	SCC
Amy Ward	GPI	Neil Joshipura	SCC	Carlos Gil	SCC
Val Stori	GPI	Jeff Dodson	SCC	Armando deLeon	SCC
Jay-Ar Llamido	SCC	David Essah	SCC	Beth Clowers	SCC

DER Interconnection Working Group Process Participants

Name	Organization
Aaron Berryhill	Virginia Department of Energy
Aaron Sutch	Solar United Neighbors of Virginia
Abigail Thompson	Gentry Locke
Alden Cleanthes	VA-DSA & Secure Solar Futures
Alex Fox	Total Energies
Amin Zamani	Quanta Technology
Ammar Qusaibaty	US DOE
Andrew Durham	RWE
Annie Lopez	East Point Energy
Arnold Singleton	Northern Virginia Electric Cooperative (NOVEC)
Ben Hoyne	Solar United Neighbors
Ben Messer	Hexagon Energy
Ben Shute	McGuire Woods
Benjamin Piiru	Nexamp
Bill Pezalla	Old Dominion Electric Cooperative (ODEC)
Brian Alexander	CleanGrid Advisors
Brian Conroy	RLC Engineering
Brian Obermeier	Burns & McDonnell
Brian Starling	Dominion
Bryson Rupnik	Sun Tribe

Name	Organization
Caitlin Vincent	Solar Energy Industries Association
Carl Wilkins	Quanta Technology
Carlos Casablanca	APCo/AEP
Carrie Hearne	Virginia Department of Energy
Charles Schliep	Solar Landscape
Charlie Coggeshall	CCSA
Cliona Robb	Thompson McMullan, P.C.
Connie Schroeder	Dominion Energy
Dan Coleman	Dominion Energy
Danielle Richardson	Novel Energy Solutions
Dennis Stephens	Unknown
Don Hall	AEP
Drew Swick	AEP
Dylan McAuliffe	Solar Landscape
Ed Brolin	RWE
Eric Wallace	GreeneHurlocker
Erin Curran	Sunvest
Eva Kaso-Collette	BlueWave Solar
Gil Jaramillo	Northern VA Electric Cooperative (NOVEC)
Harry Warren	CleanGrid Advisors
Heather Anderson	Northern VA Electric Cooperative (NOVEC)
Howard Spinner	Northern VA Electric Cooperative (NOVEC)
Ian Santos-Meeker	New Energy Equity
Del. Jackie Glass	Virginia House of Delegates (Norfolk)
Jacob Crocker	APCo/AEP
Jacob Midkiff	Dominion Energy
Jacob Newton	VMDAEC
Jagdeep Singh	Burns & McDonnell
Jake Springer	Nexamp
James Wolf	APCo/AEP
Jason Martin	Holocene Energy
Jeff Tarr	New Energy Equity
Jerry Warchol	Dominion Energy
JJ Petti	Sun Tribe
Joe Leisner	Strang, Inc.

Name	Organization
John Kotula	New Leaf Energy
John Rainey	Northern VA Electric Cooperative (NOVEC)
John Stevens	APCo/AEP
Jontille Ray	McGuireWoods
Josephus Allmond	Southern Environmental Law Center
Juergen Holbach	Quanta Technology
Julia English	McGuireWoods
Julio Romero Agüero	Quanta Technology
Karyn Boenker	Pacific Northwest National Laboratory
Kate Tohme	New Leaf Energy
Katie Taylor	Dominion Energy
Kavita Ravi	BlueWave Solar
Ken Niemann	Comcast
Kevin Whyte	Northern VA Electric Cooperative (NOVEC)
Larry Harris	Unknown
Laura Gonzalez	Clean Virginia
Lauren Wood Biskie	Dominion Energy
Leslie Elder	Summit Ridge Energy
Liz Veazey	Solar United Neighbors
Maggie Howe	East Point Energy
MaryDoris Casey	DSD Renewables
Matthew Katz	CCSA/CHESSA
Matthew Meares	Virginia Solar, LLC
Michael Hornung	Kentucky Utilities/Old Dominion Power Co.
Michael McCormick	Unknown
Michael Weiss	Advanced Energy United
Michele Bair	APCo/AEP
Mike Nester	Dominion Energy
Mike Skiffington	Virginia Department of Energy
Monica Gorena	NOVEC
Mrinmayee Kale	New Leaf Energy
Nachum Sadan	GridEdge Networks
Nick Blanton	Secure Futures, LLC
Nick D’Antonio	McGuireWoods
Nick Ford	Hexagon Energy, LLC

Name	Organization
Nitzan Goldberger	CCSA/CHESSA
Palmer Moore	Nexamp Inc.
Patrick Harper	Cypress Creek Renewables
Rich Allevi	Sun Tribe
Richard LaVigne	Dominion Energy
Rick Lovekamp	Kentucky Utilities
Ron Figg	North Ridge Resources
Russ Edwards	Tiger Solar
Sam Brumberg	VMDAEC
Samantha Weaver	CCSA/CHESSA
Santosh Bhattarai	Dominion Energy
Sarah Cosby	Dominion Energy
Sathish Anabathula	University of Virginia
Sean Stevens	Dominion Energy
Shauna Thompson	BlueWave Solar
Shay Banton	Interstate Renewable Energy Council
Sophia Hill	Pivot Energy
Srinidhi Narayanan	Quanta Technology
Stephanie Kane	Old Dominion Electric Cooperative (ODEC)
Stephen Steffel	Quanta Technology
Steve Burr	Arlington County Government
Todd Wall	Pacific Northwest National Laboratory
Tom DeAngelis	East Point Energy
Tony Smith	Secure Solar Futures
Trevor Francis	Sun Tribe
Tyler Schwartz	Appalachian Power Company
Tyler Smith	Nexamp
Walter McLeod	VSF Solar I, LLC
Will Castle	APCo/AEP

Appendix B: Dominion’s Responses to Homework 1

Dominion’s responses to Homework 1 begin on the following page.

Virginia SCC Interconnection Working Group #2

Participant Responses to Homework 1: Clarifying Questions on DTT/Dark Fiber for Dominion Energy

During Working Group 2, Meeting 2 (9/19), participants expressed interest in submitting clarifying questions to Dominion Energy regarding the Company's use of DTT/dark fiber. Participants felt this would be a good way to increase transparency around Dominion Energy's requirements and rationale for using dark fiber and address potential knowledge gaps in advance of future meetings given the highly technical nature of the topic. Participants were asked to submit their questions in order of priority.

Dominion Energy agreed to respond to the working group's top 10 questions and may choose to respond to additional questions outside of that top 10 as time allows. The list of questions below was developed through reviewing, and as needed, consolidating similar questions received by different parties in their responses to Homework 1. For this reason, the language in the questions listed below may not exactly match the language that participants submitted, but no substantive changes to question content were made. Overall, participants' top questions fit into the following two topic categories:

- Questions pertaining to DTT evaluation and alternatives screening criteria, and
- Questions pertaining to Dominion Energy's system characteristics, and the role that DTT plays in the Company's system.

Please note that we received several questions pertaining to specific cost allocation strategies. These questions are not included in this list because they are outside of the scope of informational and clarifying questions on DTT/dark fiber; but can be discussed in detail during the upcoming 10/25 meeting that will cover cost allocation issues (Working Group 1, Meeting 3).

Participants' Questions for Dominion Energy on DTT/Dark Fiber

Evaluation and Alternatives Screening Criteria

1. What is the exact protection issue that DTT addresses?

   Safety is Dominion Energy's number one priority. The most hazardous conditions that a distributed energy resource ("DER") can pose to the public and Dominion Energy's staff include but are not limited to:

   • A generator or DER that continues to supply current to a fault on the utility distribution system after the utility source separates the system from the faulted sections.

   It is critical that fault conditions are detected and isolated quickly in order to maintain safe operations. Accordingly, Dominion Energy, in compliance with IEEE 1547-2018 (sections 4.7, 6.2 and 6.4) requires that third party generators isolate within 160 milliseconds after the loss of a utility source for a fault.
   Dominion Energy uses primarily overcurrent-based methods to detect faults on its distribution system. Inverter-based generators primarily use voltage-based and frequency-based methods to detect faults. The Company's 34.5 kV distribution system, which comprises approximately 80 percent of its service territory, is electrically stronger than most other utility systems. Impedance-based fault conditions on the 34.5 kV feeders tend to result in less significant voltage changes at the respective inverter terminals, which ultimately makes it harder for inverters to sense the fault and come offline. Moreover, when inverters coexist with traditional generators, synchronous machines, and additional dissimilar inverters, the inverter's ability to detect and isolate a fault condition can take longer than the two-second anti-islanding requirement identified by the Institute of Electrical and Electronics Engineers Standards. Thus, when detailed engineering studies identify that these risks are present based on the location, size, and other unique project characteristics, Dominion Energy uses DTT to ensure safe grid operation.

   During fault events, fast clearing time is important and every second counts. Any delay in isolating an energy source will increase arc flash energy, the risk of fire or other electrical hazards, personal safety risks for the general public, and the risk for equipment damage.

2. What specific objective metrics are Dominion using to evaluate protection schemes with respect to distributed generation (i.e., maximum islanded time, current, voltage)?

   Dominion Energy uses the following criteria to evaluate protection schemes with respect to distributed generation:

   1. **The proposed protection scheme must be able to isolate a fault within 160 milliseconds. This requirement permits Dominion Energy to fulfill its obligation to safely and reliably trip and isolate all sources (its own and all third-party sources) directly or indirectly for faults occurring on the utility distribution system. The protection scheme must also isolate any faulted customer generators or DERs from the Electric Power System ("EPS").**

   2. **Assuming there are no faults in the islanded zone, the proposed protection scheme must prevent any DER from maintaining energization of any portion of the utility circuit within two seconds, in the absence of a utility source to decrease exposure to the public.**

   3. **The proposed protection scheme must not cause any operating conditions that would result in a reduction in the "quality of service" to other utility customers. Reduction in quality includes any presence of abnormal voltages (including Flicker problems), abnormal frequency, or abnormal harmonic levels.**

   4. **The proposed protection scheme should be able to prevent the DER from tripping when sensing faults outside its protective zone, or not trip for events that are not faults. Fault selectivity/sensitivity is critical and this requirement ensures a reliable interconnection to the EPS.**

3. How was the 3:1 ratio determined to be a core screening metric for DTT implementation (Dominion noted that this was previously 5:1)? As referenced in Dominion's recent filing in PUR-2023-0069, most other utilities studied use a different light load-to-generation requirement. What ratio were the other utilities using, and how/why were those ratios found to be unacceptable?

   Inverters determine the presence of an island and/or faulted condition based on voltage and/or frequency changes. More dramatic changes in voltage and frequency occur as the load to generation imbalance increases. The higher the load compared to aggregate generation, the more drastic the voltage/frequency changes are when the utility upline source is disconnected from the faulted line section. With high load to generation proportions, inverters are able to detect voltage/frequency changes and promptly disconnect. Under the 3:1 ratio,

Dominion Energy is assured inverters will respond within the 160-millisecond requirement noted in response to Question 2.

The 5:1 requirement used in the past was a perpetuation of the ratio required for synchronous generators to avoid DTT. In 2013, Dominion Energy's System Protection Group determined that a 3:1 ratio contained the appropriate margin to ensure that inverter-based resources ("IBRs") will self-isolate in the event of a system disturbance.

Dominion Energy does not base its 3:1 ratio requirement on other utilities; rather Dominion Energy has determined that a 3:1 load ratio represented the tipping point under which a DER will trip in the appropriate 160 milliseconds time. This requirement provides Dominion with the appropriate margin to account for any changes in load type or circuit topology. Each utility has different safety standards and operational practices and ultimately, it is up to each utility to determine the acceptable thresholds based on its knowledge of and experience with its own unique system. It is important to note that Dominion Energy is not an outlier in this requirement. According to EPRI survey #3002016638 that was completed in 2019, which surveyed 35 U.S. based utilities, 14 of the 35 utilities use a threshold of 1 MVA or less as a starting point to determine the need for DTT. Seventeen (17) of the 35 utilities utilize a light load to cumulative generation requirement and 5 of 35 use the same 3:1 light load to generation ratio requirement as the Company. Furthermore, all 35 utilities identified the use of DTT to isolate faults from the public. Reference question 14 for additional information.

4. How is Dominion considering cost when evaluating protection schemes?

   As previously mentioned, Dominion Energy's highest priority is to maintain a safe and reliable grid. All protection schemes the utility employs are first vetted, designed, and measured against this principle. That said, cost is considered if safety and reliability are not compromised. The Company will continue to seek the most cost-effective engineering safeguards for interconnection and will apply new solutions after they are thoroughly assessed and deemed appropriate for the Company's system.

5. If Dominion has considered alternatives to DTT/dark fiber through pilots or dedicated studies, could Dominion provide a list of such pilots and/or studies and share the results?

   It is important to emphasize that the vast majority of the costs associated with DTT are associated with the communication medium for the protection scheme. To ensure the Company continually evaluates the most reliable and least cost

options for the DTT protection scheme, the Company has thoroughly vetted several alternative communication mediums. Summaries of these efforts are outlined below.

In April 2016, Dominion Energy conducted a pilot project using a Power Line Carrier ("PLC") system, which consisted of a high frequency signal injected onto the power line. The concept is similar to PLC frequently used on Transmission systems. On the distribution system, the numerous underground and single phase taps were noted to attenuate the high frequency signal, which required the installation of signal regenerators to maintain signal strength. These signal regenerators were found to delay the response time of the protective scheme. Ultimately, the PLC system did not operate fast enough to meet the 160 millisecond timing requirement identified in the response to Question 2.

In 2019, Dominion Energy conducted a pilot project where the Company installed a parallel cellular DTT path with an existing telephone line to help improve the reliability of the existing telephone line. Telephone lines are being phased out by the telecom companies and are known to have maintenance issues. As a result, many existing telephone lines are experiencing significant reliability issues. The identified project installed a parallel cellular path to the telephone line with the hopes of improving the overall communication signal reliability. The project concluded that the cellular signal ended up dropping out more than the telephone lines.

In 2021-2022, Dominion Energy ran a yearlong pilot project using Ethernet based communication systems, as an alternative to dark fiber, provided by two regional telecommunication providers for several of the Company's transfer trip schemes. As part of the project, four distribution circuits across our territory were selected. This pilot project identified that all four circuits experienced significant signal dropout rates. Furthermore, the project found that the worst circuit outage time caused by communication dropouts was 219 hours over the course of the year. Causes of the circuit dropouts were identified to result from network switching and maintenance activities on the third-party communication system. The noted circuit dropouts ultimately led to multiple forced outages for the generators due to loss of communication.

Current pilot projects in progress are as follows:

Dual Cellular Communication: This project was kicked off in 2022. The project involves the testing of dual cellular DTT signals for use as an alternative to Dark Fiber. The system consists of two cellular signals, with each signal being

provided by a separate cellular carrier. The goal is to identify that having redundant cellular communication paths will improve the overall signal reliability.

Ground Switch: This project was kicked off in 2023. The concept uses a ground switch on a recloser to deliberately introduce a system ground after the recloser has tripped for a sensed fault condition. Application of the system grounds would pull the voltage down on the circuit and ideally force all DER within the faulted zone to trip offline.

Minimum Import Requirement for net metering sites: This project was kicked off in 2023. With the minimum import requirement for net metering sites, the Company would utilize high speed reverse power relaying at the point of interconnection for net metering sites. This particular technology would prevent a net metering site from injecting power back onto the system and would require the inverter to throttle power produced by the DER site to meet a minimum import threshold. When this threshold is not met, the site would accordingly be tripped by utility owned, maintained, and operated protective relaying. The Company is currently benchmarking other utilities that have implemented this technology to understand the equipment requirements and potential interconnection policy changes.

6. What makes DTT required for distributed generation projects (as opposed to other technologies, e.g., cellular, string inverters, new smart meters)? Is the requirement based solely on resource size, risk level, load on the feeder transformer, and/or other technical considerations?

DTT becomes a requirement to isolate the generation source from a faulted area after an engineering study reveals that there is a risk for a DER to feed a fault within the utility-owned Distribution system in the absence of the utility source. The DTT requirement is based on the aggregate generating facilities with respect to the local load in that zone. A light load to generation ratio ("LTGR") study is performed at each upline reclosing device on the utility feeder. DTT is required at any device where the LTGR is less than 3:1 in its zone. For more information regarding the reasoning behind choosing the LTGR threshold of 3:1 please refer to the response to question #3.

A communications-based protection scheme such as DTT is preferred over local protection such as the customer's inverter protection settings for the following reasons:

- **Fault selectivity. The customer's inverter protection settings typically respond to voltage and frequency abnormalities, which could be caused by disturbances elsewhere on the system. Communication between the POI**

and upline devices ensures that the DER is only removed for a fault in its zone.

- **Local protection based on frequency and voltage may not identify and isolate for a faulted condition fast enough to meet Dominion Energy's system protection standards of tripping within 160 milliseconds.**

- **Complete reliance on customer-owned equipment exposes Dominion Energy personnel and customers to the Company's third-party equipment reliability and maintenance practices. Dominion does not have the resources to verify that all developers are properly servicing and maintaining their equipment. Furthermore, Dominion has discovered many situations where the settings Dominion has instructed developers to apply to their inverters were not applied properly to the inverter(s), or in some cases, not applied at all.**

- **Dominion Energy has no observability of inverter settings and has no ability to detect that inverter settings have changed. This is an industry-wide problem that utilities are standing up Distributed Energy Management Systems ("DERMS") to manage.**

Fiber-based DTT is the required method for communications-based protection because it is proven to be fast, reliable, and secure. In the past, Dominion has deployed other communication-based protection schemes, such as telecommunications and ethernet based schemes, only to experience that such schemes fall significantly short of the Company's performance requirements. One of the most common issues the Company experienced with mediums other than fiber was inadvertent signal drops that caused frequent, unnecessary "nuisance" outages to the generation site. Additionally, with the communication mediums being owned by third party vendors, delays in coordinating repairs between all parties frequently elongated outages.

7. Would Dominion support having cellular communications be an alternative option for any interconnection customers instead of using fiber optic communications for DTT, based on Dominion's request to be allowed to do so for certain mid-sized (>250 kW and ≤1 MW) NEM projects as described in their 9/15/2923 Motion in Case No. PUR-2023-00069?

The Company will be using dual channel 4G cellular for mid-sized NEM projects, when selected by applicants as an alternative communication medium to fiber. As

long as dual channel 4G cellular meets the speed and reliability requirements outlined above, the Company will support having this as an alternative to fiber optic communications for mid-sized NEM projects. Dominion Energy's past experience with single channel cellular DTT is that it does not meet the Company's reliability requirements. By solely using single channel cellular DTT, sites would likely trip offline multiple times per day for loss of communication. Any offering made for dual cellular DTT for midsized net metering sites should come with the understanding that although the Company has had favorable results in its application, this alternative to fiber is not yet proven and the interconnected DER could be subject to nuisance trips. For DER sites greater than 1 MW, cellular DTT will not be an option until this technology's reliability record is proven through field testing. Premature adoption of this technology could result in larger quantities of lost generation which could create system operating challenges.

System Characteristics

8. What is different about Dominion's system that prevents it from adopting protection schemes that are not dependent on DTT? We have heard to date that the 34.5kV system is unique, but our understanding is that there are other utilities with 34.5kV systems that do not default to DTT based on a 3:1 screening.

   The majority of distribution circuits across the US are 15 kV class. Dominion Energy's system, however, is approximately 80% 34.5 kV distribution. The 34.5 kV distribution voltage has increased capacity to both carry load and host DER, which means that there can be more DER on a 34.5 kV circuit than on a 15 kV class feeder. These feeders are also generally "stiffer", meaning that they have higher fault current levels than 15 kV class feeders. Ultimately voltage tends to fluctuate less for disturbances or changes in load on 34.5 kV distribution feeders. The physical characteristics of this system create challenges for primary detection methods based on voltage and frequency that are commonly used in inverter-based resources. Higher fault current levels that 34.5 kV distribution systems contribute create hazardous conditions that need to be mitigated quickly. Arc flash energy is a function of current magnitude and time, which emphasizes the need to trip sources of fault current as soon as possible. Additionally, as DER adoption grows, fault current levels are also expected to rise, which makes fast tripping an increasingly important need for distribution grids. The arcing distance of 34.5 kV systems is greater than that of 15 kV class systems. This means that vegetation, animals, or foreign object contact can cause faults in 34.5 kV systems at farther distances from energized lines than in 15 kV class systems and further emphasizes the need to utilize a high speed, dependable protection system on 34.5 kV distribution systems.

9. Do dark fiber and its associated DTT have benefits for the grid beyond those that that benefit the generator that paid for the upgrades? For example, could the installed dark fiber and associated DTT potentially have broader system benefits?

   Potentially. DTT's ability to quickly isolate the generation from the faulted area provides increased protection for utility equipment, adjacent customer equipment, public/private property, and the public. At this time, dark fiber is primarily being used for direct transfer trip applications because of its reliability. However, there are broader system benefits that high speed communication could have in the future, especially in regards to communication assisted protection and DERMS integration.

10. Does Dominion include fiber on new or upgraded distribution lines regardless if work is related to DG?

    While the Company has installed fiber on distribution poles to support the Grid Transformation Plan and Rural Broadband initiatives approved by the VA SCC, Dominion does not currently include fiber on new or upgraded distribution lines.

    However, if the circuit rearrangement/upgrade will connect to an existing DER that has DTT, Dominion would be required to add fiber to the affected generation since Dominion is the initiator of the proposed work.

Additional Questions

Questions 11–15 were not found to be among participants' most widely requested questions. These questions may or may not pertain to the Screening Criteria or System Characteristics categories above. Dominion Energy may elect to respond to the following questions.

11. Utilities in other states conduct a Risk of Islanding (ROI) study to determine the need for DTT. Is Dominion conducting ROI studies for every distributed generation project? If so, what are the criteria for passing or failing an ROI screen?

    No, Dominion Energy does not perform ROI studies. Dominion currently uses the 3:1 evaluation to determine the risk of islanding. Every Generation Interconnection request of greater than 250kW undergoes this study.

    It is Dominion's policy to associate an islanding risk to any site that has a LTGR of less than 3:1 at any upline utility-owned reclosing device (*i.e.*, in-line reclosers, substation feeder breaker, substation transformer, transmission line). The Company is not an outlier within the industry in doing so. According to the 2019 EPRI Direct-Transfer-Trip Practices survey #3002016638 (screenshot below, Figure 7 from the survey), many of the utilities who participated in the survey have similar risk allocation criteria.

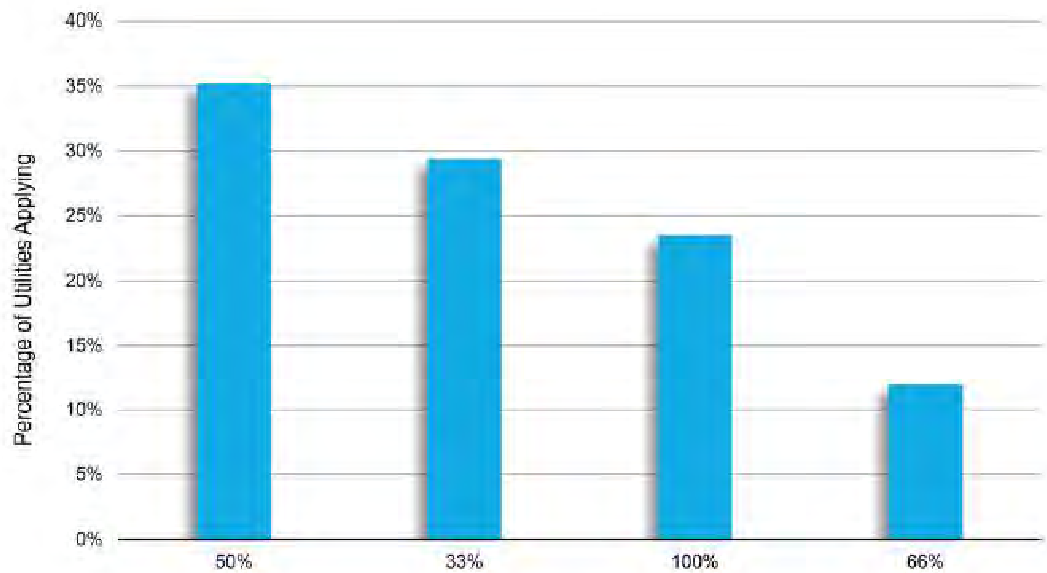

Figure 7 – Percentages of Minimum Load Used as DTT Requirement Threshold

12. Do all Dominion substations have fiber connectivity?

    No, not all of Dominion Energy's substations have fiber connectivity.

13. What is the proposed solution when there are multiple DTTs operating on the same feeder?

    There are currently numerous locations on the system that have multiple DER sites connected to the same in-line reclosers, feeder breaker, and transformer. The DG panel installed at the substation acts as the hub for all DTT signals that need to be processed for a given transformer. DER sites that connect to utility circuits that already have DTT in place can use existing infrastructure. These interconnecting DERs only purchase the additional equipment needed for their specific site. An example would be a DER site that requires DTT and is connecting to a circuit that has a DG panel inside the substation and fiber run to the nearest recloser upline of the DER site. In this case, the DER owner only purchases and installs additional fiber needed to connect their site to the existing upline fiber.

14. Is there a different threshold for Inverter based vs spinning generation for DTT requirements?

    For spinning generation, Dominion Energy uses a 5:1 light load to generation requirement. For inverter-based generation, Dominion Energy uses 3:1.

15. The IEEE 1547-2018 DER interconnection standard has a 2 second requirement for unintentional island protection. There are other protection elements in the PCC relay that detect faults and react to abnormal grid conditions. Various communication media can easily beat the 2 second limit. Since there is no need for fast tripping, what is the origin for the fiber DTT requirement?

    There is a requirement in IEEE 1547 for fast tripping during a fault event. Dominion's protection philosophy is consistent with this to clear faults as fast as possible. The 2 second requirement in IEEE 1547-2018 is for anti-islanding, not fault clearing. Dominion's concern is for fault conditions, not just anti-islanding. As previously noted, the threat of a DER site sourcing a fault in the absence of a utility connection is not negligible when there is sufficient generation to maintain an island. Fault clearing times being extended for any reason can lead to harmful conditions for both equipment and personnel (*i.e.*, Ground Fault Overvoltage, high Arc Flash energy, etc.). Fiber based DTT ensures a fast and reliable method for isolating DERs during fault conditions.

Appendix C: Matrix of Identified Issues and Solutions

Table C-1 maps each participant-identified issue (as listed in Section IV, *Issues to be Addressed*) to solutions (as described in Section V, *Solutions*) that could address all or part of that issue. The six working group topics to which an issue pertains are also identified to highlight where an issue might span several different topics. There is also a "high-level issue" topic category for issues broadly related to DER interconnection in Virginia.

Four of the identified issues are not directly addressed by any of the 15 solutions in this report. For all cases, this was either because 1) the issue fell outside of the scope of this working group process, or 2) the issue is not necessarily a problem that needs to be addressed, but rather is a factor that requires consideration if/when certain solutions are pursued for implementation. These four issues are identified in Table C-1.

Table C-1: Issues Identified Throughout the Working Group Process and their Associated Solutions

Issue	Topics Area(s) Associated With Issue							Relevant Solutions (Solution #)
	High-Level Issue	Working Group 1 Topics			Working Group 2 Topics			
		Study Timelines	Construction Timelines	Cost Allocation	Interconnection Costs	Cost/Info. Transparency	DTT/Dark Fiber	
Identified Issues: Study Timelines								
Some utilities have failed to meet the study timelines required under Chapter 314.		✓				✓		1, 3
Study timeline information is not granular enough to enable parties to identify the specific steps/sub-steps in which delays are occurring.		✓						1
Long study timelines encourage speculative projects—markets and prices can change and issues can arise and/or be resolved by the time a project is finally through the study process.		✓				✓		1, 3, 5, 6
There is a wide range of equipment with different specifications/capabilities that currently is studied on a case-by-case basis.		✓				✓		1

Issue	Topics Area(s) Associated With Issue							Relevant Solutions (Solution #)
	High-Level Issue	Working Group 1 Topics			Working Group 2 Topics			
		Study Timelines	Construction Timelines	Cost Allocation	Interconnection Costs	Cost/Info. Transparency	DTT/Dark Fiber	
There are no penalties for ICs or utilities failing to meet established timelines throughout the process.		✓						1
The study process can take so long that projects in the queue can miss out on potential incentive opportunities.		✓						1
Parties lack insight into what approaches utilities are taking in other jurisdictions to address grid safety, reliability, and operability concerns in their own study processes.		✓				✓	✓	1, 11, 12
Some utilities may lack the resources (internal or external capacity, financial means, etc.) necessary to implement strategies that would help them meet or eventually exceed current study timelines.		✓						1, 15
ICs no longer planning to pursue interconnection do not always notify the utility of their withdrawal in a timely manner, so those projects continue to be unnecessarily studied.		✓				✓		1, 3, 4
Identified Issues: Construction Timelines								
Right-of-way, site control, and permitting issues can prevent the utility responsible for constructing interconnection facilities from accessing the site.			✓					2

Issue	Topics Area(s) Associated With Issue							Relevant Solutions (Solution #)
		Working Group 1 Topics			Working Group 2 Topics			
	High-Level Issue	Study Timelines	Construction Timelines	Cost Allocation	Interconnection Costs	Cost/Info. Transparency	DTT/Dark Fiber	
ICs sometimes need to request changes to the construction schedule, but it can be difficult for utilities to be in a state of "perpetual readiness" to adjust to these changes and/or incorporate the revised construction timeline into the utility's broader schedule.			✓					3
ICs can be delayed in completing and submitting their Application for Service to the utility once their SGIA is executed.			✓					1, 3
Incomplete or insufficiently detailed site plans can delay the utility's engineering analysis.			✓					2
End-of-year interconnection targets (e.g., after December 15th) can be difficult for utilities to meet due to staffing limitations.			✓					1, 2, 3
Changes to inverter settings (from the settings that were checked and confirmed by the utility earlier in the process) are sometimes identified during the facility commissioning phase.			✓			✓		1, 3
Developers are not always mobilized or ready for the utility's construction components to begin, even when the utility is ready.			✓					1, 3

Issue	Topics Area(s) Associated With Issue							Relevant Solutions (Solution #)
		Working Group 1 Topics			Working Group 2 Topics			
	High-Level Issue	Study Timelines	Construction Timelines	Cost Allocation	Interconnection Costs	Cost/Info. Transparency	DTT/Dark Fiber	
Site-specific issues (e.g., environmental issues) associated with the interconnection location may arise, and these issues typically are not identified at an earlier point in the interconnection process.			✓					N/A—no solutions would eliminate the potential for site-specific issues to arise, but Solution 3 could ensure that parties are promptly notified of such issues.
Identified Issues: Cost Allocation								
The "100% cost causation" model—under which the project that triggers the need for system upgrades is responsible for all upgrade costs, even though other prior projects contributed to that need—is cost-prohibitive for many projects and interferes with developers' capacity to deploy DERs due to the high financial burden. This is especially problematic when DTT is required, as it is a very costly technology.	✓			✓			✓	5, 7, 8, 9, 10, 11, 12, 13, 14, 15

Issue	Topics Area(s) Associated With Issue							Relevant Solutions (Solution #)
	High-Level Issue	Working Group 1 Topics			Working Group 2 Topics			
		Study Timelines	Construction Timelines	Cost Allocation	Interconnection Costs	Cost/Info. Transparency	DTT/Dark Fiber	
Cost allocation methodologies for co-ops must align with the not-for-profit, member-ownership model and must account for the fact that many co-ops are distribution-only utilities.	✓			✓				N/A—No solutions directly address the differences between IOU and co-op business models, but Overarching Consideration A.8 ensures that this important difference is considered for each solution.
Smaller utilities serving rural regions tend to have a lower-income customer or member-owner base. This population may be more sensitive to increased rates, which could result from certain alternatives to Virginia's current "100% cost causation" model.	✓			✓				N/A—No solutions directly address differences in customer income between utility service territories, but several solutions take utility size or other relevant thresholds into consideration.

Issue	Topics Area(s) Associated With Issue							Relevant Solutions (Solution #)
	High-Level Issue	Working Group 1 Topics			Working Group 2 Topics			
		Study Timelines	Construction Timelines	Cost Allocation	Interconnection Costs	Cost/Info. Transparency	DTT/Dark Fiber	
Dominion's 34.5 kilovolt (kV) system (higher voltage than many other utilities) allows for increased DER interconnection overall (when compared to lower-voltage systems). However, in Dominion's view, this higher system voltage also tends to decrease the ability for an inverter-based resource to locally sense fault conditions and appropriately trip offline within the established time threshold (for Dominion, this standard is 160 ms).				✓				1, 7, 8, 13, 15
Unclear what should happen in circumstances in which project viability is adversely impacted post-SGIA (e.g., if a project in the queue depends on certain upgrades, those upgrades are not necessarily refundable).				✓				7, 8, 15
If costs are socialized more broadly and a DER project defaults, the host utility could be at risk of bearing cost recovery responsibility.				✓				7, 8,13, 15
Identified Issues: Interconnection Costs								
Study fees do not fully cover the cost to utilities to conduct the studies.				✓	✓			1
Current study deposit fees are too low; this leads to an influx of speculative projects and potentially unviable projects in the queue.					✓	✓		1, 4, 5

Issue	Topics Area(s) Associated With Issue							Relevant Solutions (Solution #)
	High-Level Issue	Working Group 1 Topics			Working Group 2 Topics			
		Study Timelines	Construction Timelines	Cost Allocation	Interconnection Costs	Cost/Info. Transparency	DTT/Dark Fiber	
In lower-income regions, increased interconnection costs are leading to more projects being proposed and pursued by large development firms and fewer being proposed by local entities/landowners.					✓			7, 8, 13, 15
Interconnection costs—even those associated with similar types of upgrades—can fluctuate significantly among Virginia's utilities, even with the same type of upgrades.					✓	✓		5, 6
Identified Issues: Cost/Information Transparency								
Developers often lack the necessary information (cost, circuit, facilities, geospatial, past findings from past studies, etc.) to make an informed business decision about project feasibility before commencing the interconnection process.		✓			✓	✓		1, 3, 4, 5, 6, 9
When information gaps are present, addressing those gaps requires additional back/forth communication, which increases timelines.		✓	✓			✓		1, 3, 5, 6, 9
Smaller utilities are typically more resource-constrained than large utilities and may not have the personnel or financial capacity to conduct studies in-house, develop dedicated DER interconnection teams, develop/host certain resources (geospatial resources, regularly updated manuals, etc.).		✓	✓		✓	✓		1

Issue	Topics Area(s) Associated With Issue							Relevant Solutions (Solution #)
	High-Level Issue	Working Group 1 Topics			Working Group 2 Topics			
		Study Timelines	Construction Timelines	Cost Allocation	Interconnection Costs	Cost/Info. Transparency	DTT/Dark Fiber	
DER interconnections that would potentially impact third party-owned transmission facilities in distribution-only utility service territories require an affected system operator (ASO) study, which can be time-intensive and can experience their own unforeseen costs/delays but fall outside of the distribution-only utility's control/authority.		✓						N/A—no solutions address the need for an ASO study, but several take ASO studies into account.
Not all developers/ICs are familiar with or aware of the interconnection guidance materials that some utilities have available.						✓		3, 4, 5
Cost information in utility-provided materials can be inconsistent with the cost estimates provided to ICs through the study process.		✓				✓		1, 5, 6
Project and upgrade costs sometimes change throughout the study process.		✓				✓		1, 5, 6
Information quality (from utilities to ICs and from ICs to utilities) is not always sufficient to allow ICs to make informed business decisions and to allow utilities to provide comprehensive feedback or timely estimates.		✓	✓			✓		1, 3, 4, 5, 6, 9
Even within an individual utility, information quality can vary depending on the utility staff/team assigned to the project; utilities lack a standardized way of providing/delivering the type of information required at the level of detail that would be most helpful to developers.		✓	✓			✓		1, 3, 4, 5, 9

Issue	Topics Area(s) Associated With Issue							Relevant Solutions (Solution #)
	High-Level Issue	Working Group 1 Topics			Working Group 2 Topics			
		Study Timelines	Construction Timelines	Cost Allocation	Interconnection Costs	Cost/Info. Transparency	DTT/Dark Fiber	
Developers/ICs lack technical system-specific information that could help them determine whether a project is feasible earlier in the process (e.g., whether a substation is on the verge of requiring cost-prohibitive transmission-level impacts).		✓			✓	✓		1, 3, 4, 5, 6, 9
Identified Issues: Dark Fiber/DTT								
Dominion has not found an alternative to DTT that can meet their obligation to deliver safe and reliable power to customers equally well, within appropriate technical standards.							✓	9, 10, 11, 12, 14
Dominion's 34.5 kilovolt (kV) system (higher voltage than many other utilities) allows for increased DER interconnection overall, but also has increased potential for system faults. When a fault occurs, there is no guarantee that a DER system will detect that fault and respond accordingly within the established time threshold (160 ms for Dominion).							✓	9, 10, 11, 12, 14
Inverter settings are sometimes changed after initially being checked and confirmed by the utility responsible for the DER's interconnection.			✓			✓	✓	4

Issue	Topics Area(s) Associated With Issue							Relevant Solutions (Solution #)
	High-Level Issue	Working Group 1 Topics			Working Group 2 Topics			
		Study Timelines	Construction Timelines	Cost Allocation	Interconnection Costs	Cost/Info. Transparency	DTT/Dark Fiber	
Though Dominion recognizes and acknowledges the anti-islanding capabilities of inverter-based resources, the Company has not found that such resources can clear faults within 160 ms in all scenarios analyzed in the screening process.		✓				✓	✓	9, 10, 11, 12, 14
Dominion's 160 ms (0.16 second) fault protection requirement is the most conservative (i.e., "lower bound") threshold allowed under IEEE 1547-2018 standards. A less conservative threshold would still meet the IEEE technical requirements.							✓	11, 13, 14
Utilities must ensure that their system is safe for the public, system equipment, and lineworkers, who may unknowingly be exposed to energized lines. DTT has reliably served this communication purpose.							✓	9, 10, 12, 14
DTT (including the use of dedicated fiber as the communication medium to accomplish DTT) is very expensive. Under Virginia's current approach to cost allocation, the requirement that DTT be installed to enable DER interconnection is cost-prohibitive for ICs and is interfering with DER deployment.				✓	✓		✓	7, 8, 10, 12, 15
There is not a well-established risk threshold at which the DER deployment benefits of DTT outweigh its costs.					✓	✓	✓	9, 10, 11, 14

Issue	Topics Area(s) Associated With Issue							Relevant Solutions (Solution #)
		Working Group 1 Topics			Working Group 2 Topics			
	High-Level Issue	Study Timelines	Construction Timelines	Cost Allocation	Interconnection Costs	Cost/Info. Transparency	DTT/Dark Fiber	
There is a lack of understanding and transparency as to what alternatives to DTT Dominion has explored, what were the findings of those alternatives analyses, and why those findings lead to the conclusion that DTT is still required.						✓	✓	9, 12, 14
Identified Issues: Other High-Level Issues								
The current rate of DER deployment in Virginia is insufficient to meet the clean energy goals required under VCEA, which applies to specified utilities' whole electric systems (distribution, transmission, and generation).	✓							All
Utilities are seeing a drastic increase in DER interconnection applications and may lack the resources and/or procedures to keep up with those applications.	✓	✓						1, 4, 5, 6

Appendix D: Summary of Participant Feedback on Solutions

D. Introduction

Appendix D provides a summary of participant feedback received on all 15 solutions included in this report. Summarized feedback includes written feedback received on the November 13th draft potential solutions document, as well as verbal feedback received during the final combined meeting for the working group process.

In this appendix, solutions and their respective feedback are structured similarly to how they are structed in Section V, *Solutions*, in the main body of this report. Both the solution short title and the full solution text are provided for clarity purposes.

[Solution #]: Solution short title

Solution #X: Solution text, with language as refined during the final combined working group meeting

Summary of Participant Feedback, Solution #X: Brief summary of written feedback received on this solution in response to the November 13th draft potential solutions document and verbal feedback received during the final combined meeting.

Summarized participant feedback is provided for both consensus and non-consensus solutions. As described throughout this report, **consensus means that all parties who were present in the final meeting said that they at least did not oppose the solution**. Some consensus solutions include sub-components on which the working group did not reach full agreement (not all participants reached agreement regarding which sub-components within that solution should/should not be pursued), but still did not oppose the solution as a whole; this is noted where applicable.

Solutions and the summary of participant feedback received on each solution begins on the following page.

F. Participant feedback on Consensus Solutions

Study and Construction Timelines

1. Meet and evaluate exceeding current study timeline requirements

Solution 1: The Commission should take action to ensure that utilities are meeting the study timeline requirements that are currently outlined in Chapter 314 of the Virginia Administrative Code, *Regulations Governing Interconnection of Small Electrical Generators and Storage*. The Commission should also evaluate ways to shorten current study timeline requirements such that Virginia's study timelines are aligned with best practices in other states. The group discussed the following approaches as potential ways to meet and evaluate exceeding[23] current study timeline requirements but did not reach consensus on any of them. Aspects of these approaches may pertain to utilities, ICs, or regulators.

i. Consider alternatives to the current study process (such as a combined study approach, a "pseudo-parallel" approach, or a targeted group/cluster study approach)
ii. Improve data access and quality as suggested in Solution 4
iii. Improve study timeline granularity
iv. Audit utility resourced
v. Increase the study deposit fee
vi. Adopt manufacturer specifications and/or preferred manufacturer or equipment lists
vii. Establish monetary penalties for causing delays, applied to whichever party (utility or IC) is causing the delay.

Summary of Participant Feedback, Solution 1: In the final combined meeting, participants expressed support for including Solution 1 for consideration but did not reach consensus on which (if any) of approaches i–vii should be pursued. Participant feedback on each approach is summarized below.

Participant feedback on Approach i: Consider alternatives to the current study process (such as a combined study approach, "pseudo-parallel" approach, or a targeted group/cluster study approach)

In their written feedback on the November 13th draft potential solutions document, participants did not reach agreement on which (if any) of the three potential alternative processes should be pursued.

Several participants expressed strong support for a combined study process modeled off of the NY CESIR approach. One such participant expressed that several states (including New York) pursued incremental study reforms before adopting the CESIR approach, but those incremental reforms did not address the state's study timeline issues. This participant suggested that NY's CESIR approach—especially when paired with broader distribution system planning reform—is

[23] In the context of this identified issue and this report, "exceeding" current study timelines refers to whether the study process can be completed in less time than is currently stipulated under the Chapter 314 regulations.

a viable model that Virginia can look to if pursuing a combined study approach. However, Dominion expressed opposition to this study approach.

Participants also expressed mixed support for the "pseudo-parallel" study process. Dominion opposed this approach, and KU noted that a parallel process could unfairly advantage or disadvantage certain projects that otherwise would not have required interconnection costs. However, another participant felt that minor revisions to Virginia's current study process that would allow some steps could be completed in a "pseudo-parallel" format offered flexibility and potential timeline benefits. For example, enabling this approach could allow "Project B" to begin its study process while "Project A" is still completing its studies, so long as "Project B" is being studied on an individual basis.

Some participants emphasized that if a targeted group/cluster study process approach is pursued, the "targeted" aspect is critical, as cluster studies have not been demonstrated to inherently improve study timelines in other jurisdictions. Targeted group studies in which projects that are "eligible" for clustering fall within clearly defined boundaries offer some potential improvement opportunities that cluster studies alone would not necessarily provide.

Of the three alternative methodologies considered under Approach i, Dominion expressed a preference for the targeted group/cluster study process but indicated an overall preference for retaining Virginia's current serial study process. Another participant expressed that group study approaches are best suited for transmission-side interconnection and should not be pursued as solutions to DER interconnection issues in Virginia.

Participant feedback on Approach ii: Improve data access and quality as suggested in Solution 4

Developers were widely supportive of Approach ii as a means to help them more easily access information that would help them to make more informed project decisions, but utilities provided mixed feedback. Specifically, the need to compile and provide this information in a standardized format could be expensive and administratively burdensome for small utilities (especially co-ops) while only minimally benefitting developers if there is little interconnection demand in the small utility's service territory. Parties (including developers) were largely in agreement that if pursued, this approach should take into consideration the utility's size, administrative capacity, and the overall value of providing such information, as it may be unnecessary in some service territories.

IOUs and co-ops both identified potential security risks and personal data privacy concerns associated with sharing some of the information listed in Approach ii. In particular, utilities expressed concern about providing prior study results, which may contain sensitive information including intellectual property, personally identifiable information, and information that—if shared inappropriately—could present physical security risks (e.g., facility locations, operating system behaviors, protection schematics, etc.). Utilities additionally noted that just because a potential project site may be located geographically close to a previously studied project does not necessarily mean that the two projects are "close" from a grid orientation perspective or that the prior project would necessarily offer valuable insights to developers. One developer agreed that multiple-year-old study results may not be deeply valuable in all circumstances.

Utilities also opposed providing weekly queue study results and co-ops opposed providing generic cost information, as this information could quickly become outdated and would no longer be reliable or valuable. Additionally, providing this information would be redundant for co-ops, which are required to adhere to federal Rural Utility Service equipment standards and contract requirements. One utility also noted that any generic costing information would need to be provided only at a high level, because more detailed estimates would require a time-intensive and costly engineering analysis. For larger sites requiring significant facility buildout, this sort of analysis would be highly involved.

Participant feedback on Approach iii: Improve study timeline granularity

Developers largely expressed support for Approach iii as a potential pathway to meet and potentially exceed current study timelines, while utilities generally expressed opposition. A primary point of opposition among distribution-only utilities (i.e., co-ops) was that because some study components fall outside of the distribution-only utility's control, such as ASO studies for projects that may have transmission system impacts; distribution-only utilities feel that they should not be obligated to provide granular timeline information study components over which they have limited or no control. With the addition of consideration for ASO studies, the co-ops were no longer opposed to this approach. Similar considerations may also be required for instances in which an interconnection would trigger the need for a transmission service request.

Participant feedback on Approach iv: Audit utility resources

Developers generally supported Approach iv, and Dominion expressed opposition. Parties did not provide extensive feedback on this approach but felt that it was a strategy that could be considered when seeking to meet and potentially exceed current study timelines.

Participant feedback on Approach v: Increase the study deposit fee

Developers were not in agreement as to whether increasing the study deposit fee was an appropriate strategy to pursue. Some were generally supportive of this approach, while others felt that increased study fees had the potential to discourage DER development. Additionally, though this approach is intended to discourage "speculative" projects from joining the queue by making it more costly to do so, one developer stated that under Virginia's current study process, development projects are inherently "speculative" because the process takes so long, and key inputs are not always readily available upfront. Another developer expressed that because other states (e.g., New York) have demonstrated that faster timelines can be met without very high deposit fees, this approach is not needed to meet or exceed Virginia's current study timelines.

Utilities expressed support for this approach. Specifically, the co-ops noted that the current study deposit fee does not fully cover the costs of the study process and argued that study deposit fees should at least be increased to cover average study costs for the utility with which an IC seeks to interconnect.

Participant feedback on Approach vi: Adopt manufacturer specifications and/or preferred manufacturer or equipment lists

In their written feedback on the November 13th draft potential solutions document, parties generally expressed either opposition or neutrality to this approach. Opposing parties felt that this could unintentionally disadvantage certain manufacturers and/or suppliers and could limit technology options and market innovation. Additionally, the co-op association noted that because co-ops already must adhere to Rural Utility Service specifications, this particular approach is unnecessary for them.

Additional feedback from parties included consideration for the administrative burden of updating a common list, a potential scenario in which developers could nominate additional vendors to be added to preferred manufacturer lists, and a suggestion to look to ISO NE's inverter setting requirements, which could be referred to if such a list is developed. One participant also noted that establishing manufacturer specifications is unlikely to result in significant study time efficiencies until utilities incorporate inverter-level controls into their study analyses.

During the final combined meeting, parties did not provide additional feedback on Approach iv, but did not oppose including it as a potential approach that could help Virginia's utilities meet and potentially exceed current study timelines.

Participant feedback on Approach vii: Establish monetary penalties for causing delays, applied to whichever party (utility or IC) is causing the delay

Feedback on whether Approach vii should be pursued was mixed and similar to the feedback received on Approach v (increase the study deposit fee). Several developers supported this approach, but some expressed opposition, as did utilities.

As noted in the participant feedback to Approach v, one party felt that this approach had the potential to discourage DER development in Virginia, and another participant felt that this was unnecessary, as it has not been required in other markets. One participant felt that this was a valuable consideration and noted that North and South Carolina could be examples of states that have improved queue management through the adoption of a more extensive penalty system, but an opposing party noted that the North and South Carolina markets are not a good analog for Virginia's market, and operate under processes more similar to the PJM market.

The co-ops felt that it was not appropriate to pass penalty costs on to member-owners—many of whom are low-income customers in rural communities—and expressed concern about the potential to be held financially responsible for ASO study delays, which fall outside of a distribution-only utility's control.

2. Secure site access early for the utility

Solution 2: Incent ICs to secure early site access for the utility and provide the utility with high-quality site plans as early as possible.

Summary of Participant Feedback, Solution 2: Participants did not express opposition to Solution 2 and overall felt that acknowledging the importance of site control and site access for utilities was key to addressing specific construction timeline delays. One participant noted that pursuing this solution would require evaluation of the ways that the terms "landowner" (or, alternatively, "option holder" and "IC") are currently legally defined.

Interconnection Costs and Information Transparency

3. Improve communications between ICs and utilities

Solution 3: Utilities should work with ICs to identify potential opportunities to improve communications throughout the interconnection process. Improvements should work to ensure that all parties have the most up-to-date information regarding the application process, the study process, the construction phase, and necessary payments. Communications aspects requiring improvement may vary by utility, and potential improvement strategies may vary accordingly (e.g., a dedicated interconnection ombudsperson at large utilities or at the Commission; a petition process through which ICs can receive Commission support if a utility falls behind, etc.)

Summary of Participant Feedback, Solution 3: Parties did not express opposition to this solution as written. APCo/AEP suggested that other utilities may want to consider an automated communications approach (such as the Powerclerk tool that APCo/AEP currently uses) if this solution is pursued.

4. Improve access to and quality of actionable information that ICs need to make informed project decisions

Solution 4: Utilities that meet appropriate and reasonable pre-determined thresholds[24] should ensure that parties have access to actionable information to fulfill their responsibilities throughout the interconnection process in a timely manner while maintaining consideration for data sensitivity and confidentiality concerns. Certain data may require specific protection strategies (e.g., aggregation, secure hosting, etc.) for safety and privacy purposes. The group discussed the following approaches as potential ways to achieve this, but did not reach consensus on all of them:

i. Completed interconnection studies for past DER projects (with sensitive information redacted) and the interconnection status of those projects
ii. Regularly updated maps with interconnected and queued projects and remaining projects if possible
iii. Distribution assets list or map (e.g., total capacity for DER of transformers and feeders at substations, substations with DER already installed, circuits with fiber already installed)
iv. Other geospatial resources identified in the August 1, 2023 *Staff Distributed Energy Resources ("DER") Survey* in Case No. PUR-2022-00073

Access to the above informational resources would allow ICs to develop more informed project proposals and submit more comprehensive interconnection applications, thus reducing utility and IC administrative inefficiencies.

Summary of Participant Feedback, Solution 4: In feedback received on the November 13th draft potential solutions document, parties expressed mixed perspectives on the approaches described that would accomplish Solution 4.

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[24] Some developers suggested that the DER deployment need associated with different utility sizes (as outlined in the VCEA) could be considered for use as the "thresholds" for Solution 4.

Participant views on Solution 4 generally aligned with those expressed in response to Solution 1, Approach ii (*Improve data access and quality as suggested in Solution 4)*. Developers were generally supportive of receiving access to the described information, but utilities generally expressed concerns about data privacy and security. One IOU suggested that confidentiality concerns could potentially be addressed by each utility having a standardized non-disclosure agreement that can be sent to ICs for data sharing, but also reiterated that any procedures established to facilitate sharing this information comes with additional costs to the utility.

Similarly, co-ops expressed concerns about the administrative and financial burden of providing such information, which may provide little benefit if they have few IRs in their service territory. However, like in Solution 1, participants agreed that if Solution 4 is pursued, it should be implemented on a per-utility basis, with utility obligations to provide certain materials in alignment with the utility sizes and DER deployment thresholds established under the VCEA.

5. Regularly review and update interconnection guidance materials and ensure that such materials are easily accessible

Solution 5: Some utilities produce informational interconnection materials that are intended to help developers make informed decisions about DER project feasibility. Utilities that publish interconnection guidance materials should regularly review and update these materials as appropriate to ensure that they accurately reflect current conditions and remain as useful as possible to developers.

Associated Topic(s), Solution 5: Interconnection costs, study timelines, construction timelines

Summary of Participant Feedback, Solution 5: Several developers expressed support for this solution and no parties expressed opposition.

6. Monitor changes in cost estimates throughout the study process

Solution 6: Develop a way to identify, monitor, and track which cost estimates are most subject to change throughout the study process. This could help utilities better understand and refine cost estimate ranges for particular types of upgrades.

NOTE: Solution 6 should only be applied if a combined study approach is not adopted.

Summary of Participant Feedback, Solution 6: In their written feedback on the November 13th draft potential solutions document, several developers expressed support for this solution, no parties expressed opposition, and some noted general neutrality towards this solution. During the final combined meeting, participants clarified that this would be a cost tracking exercise for utilities, not an extensive revision process. Developers agreed that this solution need only be applied if Virginia does *not* adopt a combined study approach. With these points of clarification, participants supported inclusion of this solution.

Cost Allocation

7. Investigate establishing a DER rate class

Solution 7: The Commission should initiate a process to investigate the option of establishing a dedicated DER rate class across which interconnection costs would be spread or allocated via a specific tariff. The investigation should take into consideration utility type, size, and the scale of DER interconnection within the utility's service territory when considering whether this may be appropriate for any utility.

Summary of Participant Feedback, Solution 7: Participants expressed mixed perspectives on Solution 7. All three IOUs expressed concern with this solution, noting that they generally are not regulated to create tariffs; rather, they develop tariffs to comply with regulations. One IOU was particularly opposed to this being pursued via a Commission-initiated process. However, the IOUs did not oppose including this as a consensus recommendation with the addition of the key terms "investigate" and "option," which allow for this solution to be evaluated in detail.

Several developers and one advocacy organization supported Solution 7. The advocacy organization considered the Commission-led investigation a key component of this solution, noting that it is unlikely that utilities will pursue this type of tariff without Commission direction. However, another advocacy organization noted that they would only support this solution if DTT is proven to be necessary.

8. Explore and, if appropriate, implement a proactive cost allocation strategy

Solution 8: The SCC should explore and, if appropriate, implement an alternative cost sharing/cost allocation strategy through which projects make proactive payments to prevent any one project from bearing full upgrade cost responsibilities. The utility would identify the cost of all system upgrades that would be necessary to support interconnection and would then establish how much each project must pay based on their size/share of the needed upgrades on a per-kW basis. This strategy has been found to be effective except in situations in which there is a need for transmission-level upgrades, which can be too costly even with this sharing approach.

Utilities should proactively use the GTSA to upgrade the grid in preparation for DER in the case where upgrades are uniform for any DER class or size, subject to Commission approval. This exploration should take into consideration utility type, size, and scale of DER interconnection when considering whether this may be appropriate for any utility.

Lessons learned from New York's approach to proactive cost sharing should help the SCC understand the potential implications of enacting this model in Virginia. If this approach to cost sharing is found likely to result in positive outcomes, the SCC should investigate how such an approach could be implemented.

Summary of Participant Feedback, Solution 8: Previously, this solution included consideration for both proactive and retroactive cost sharing mechanisms as potential alternative cost allocation strategies, informed by New York's experience with both. Participants discussed and provided feedback on both of these mechanisms throughout the working group process.

The proactive cost sharing approach ("Cost Sharing 2.0") described in this solution requires that projects proactively pay for the system upgrade costs necessary to support interconnection. Under this model, projects would proactively pay the utility based on their size/share of the needed upgrades. However, participants also considered a retroactive cost sharing approach ("Cost Allocation 1.0") in which the interconnecting project that triggers the need for upgrades pays for the necessary upgrades upfront, and subsequent projects reimburse that project based on their project-specific contributions to that need for upgrades.

In participants' written feedback in advance of the final combined meeting, no parties expressed support for this retroactive cost sharing model, but several parties expressed strong support for the proactive cost sharing model.

In the final combined meeting, parties generally expressed support for this solution once revised to consider only the proactive cost allocation strategy. Additionally, parties supported the inclusion of language identifying the GTSA as a potential mechanism through which this solution could be implemented, though Dominion noted that whether the GTSA could be applied in this circumstance likely depends on Commission approval, and future clarification is needed. Parties were also supportive of the addition of language indicating that utility size should be taken into consideration.

Approaches to Meeting Safety and Reliability Requirements

9. Ask utilities proposing to require DTT to file information rationalizing this requirement with the Commission demonstrating that it is the least-cost solution to meet safety and reliability requirements in accordance with "Good Utility Practice" as defined in 20VAC5-314-20.

Solution 9: Direct utilities requiring that DTT be installed as part of the DER interconnection process to file information rationalizing this requirement with the Commission. The information should be filed at a cadence determined to be appropriate by the Commission (e.g., annually). Filed materials should include, but may not be limited to:

i. System-specific information
ii. The contexts in which the utility requires DTT
iii. Which safety and reliability requirement(s) the utility is seeking to meet
iv. The tests the utility conducted to determine the need for DTT (as opposed to other technologies including inverter-based solutions)
v. What other technologies the utility has pursued or evaluated to address the issues being solved by DTT and why those alternative technologies were found to be inadequate. This should include a discussion of how the utility will meet safety and reliability requirements, including but not limited to the risk and probability of islanding and fault occurrence (and, accordingly, the need for fault protection)
vi. This information should be available in a standardized format (report and/or table) to facilitate comparison between utilities using DTT vs. alternative technologies (e.g., inverter-based solutions) and should be shared with the Commission

This information should be available in a standardized format (report and/or table) to facilitate comparison between utilities using DTT vs. alternative technologies (e.g., inverter-based solutions) and should be shared with the Commission.

Summary of Participant Feedback, Solution 9: In participant feedback received on the November 13th draft potential solutions document, developers and advocates were widely supportive of this solution, and only Dominion expressed opposition. During the final combined meeting, supportive parties argued that Solution 9 provided an opportunity for utilities requiring the use of DTT to both explain and demonstrate their rationale for this requirement. Specifically, developers and advocacy organizations view Solution 9 as a mechanism that would help identify whether DTT is required to meet safety and reliability requirements, or whether other approaches or technologies could sufficiently mitigate against the risks that drive Dominion's use of DTT.

Dominion emphasized that their DTT requirement is not in place to address islanding risks. Rather, DTT is the only technology Dominion has found that can meet the Company's fault isolation standard requiring that all power sources feeding a circuit trip offline in under 160 ms to ensure that the system is safe for the public and for lineworkers. Participants did not agree with Dominion's assertion that this standard is appropriate, as it is the most conservative threshold authorized under the IEEE 1547-2018 standard and may not be necessary in many cases (especially for DERs between 1–20 MW). Further discussion on participant feedback regarding the appropriateness of Dominion's 160 ms standard is included in Solution 11.

Ultimately, Dominion did not oppose this solution but clarified that their support for implementing it will depend on what the filing must include and the frequency at which this material will need to be filed, which are not formally established at this time. Additionally, Dominion was not supportive of requiring this filing for every IR in the queue. APCo/AEP suggested that this material be filed at some sort of regular interval, such as annually, plus on an as-needed basis if/when relevant industry-wide standards are updated. The working group did not establish a specific time interval for these filings, but parties including Dominion felt that an annual or similar basis as described was not unreasonable.

10. Conduct an analysis identifying ways to interconnect DERs at the rate necessary to meet State policy (as expressed in the Grid Transformation and Security Act) while ensuring the safety, reliably, and operability of the electric power system in accordance with "Good Utility Practice" as defined in 20VAC5-314-20.

Solution 10: Ask the Commission to conduct an analysis to determine how to interconnect DERs safely and reliably at a pace, scale, cost, and level of risk aligned with state policy mandates. This analysis should include consideration for the following.

- The safety and reliability issues that are (or are not) addressed via DTT, as compared to other potential technologies (including but not necessarily limited to inverter-based resources) that meet the appropriate standards,
- The cost effectiveness of using DTT (as opposed to the costs of conducting site-specific studies and/or pursuing other technologies that meet the appropriate standards) for this purpose, and
- An assessment of and guidance on the validity and efficacy of various anti-islanding and grid protection solutions, including inverter-based resources and other technologies that have been or are currently being explored via pilots.

Summary of Participant Feedback, Solution 10: In written feedback received on the November 13th draft potential solutions document, developers expressed broad support for

Solution 10 with the adoption of certain clarifying textual revisions, and only Dominion expressed opposition. Another utility expressed concern about whether the Commission or a hired third-party would have the knowledge and ability to assess the validity of and risk/likelihood of potential grid safety and reliability scenarios, which would require extensive knowledge of the utility's system. This participant expressed that this aspect of the analysis should remain the responsibility of each individual utility, as they better understand how their systems operate, where potential safety concerns exist, and how those potential safety risks could be eliminated.

During the final combined meeting, Dominion requested that the Company's statutory obligation to provide customers with a safe and reliable grid be further emphasized, and an advocacy group suggested that language related to acceptable risk levels be included in Solution 10. Both Dominion and the advocacy group felt that including reference to "good utility practice" addressed these concerns appropriately.

11. Initiate a process to review and revise technical standards for inverter-based DERs.

Solution 11: The Commission should initiate a process (e.g., a working group) through which the utilities review and revise technical standards for inverter-based DERs to take advantage of all inverter capabilities. This review and revision should be conducted in consultation with a qualified and impartial third party, such as a nationally recognized independent engineering association or laboratory and should take into consideration the technical standard needs for different-sized DERs. The review should also take into account utility response time requirements (e.g., Dominion's 160 ms response time).

As a result of the process, the Commission should direct the utilities to review and revise technical standards for inverter based DERs to take advantage of all inverter capabilities, and to propose those revised standards to the Commission. This should not necessarily be applied to all utilities equally. The Commission should take into consideration utility type, size, and scale of DER interconnection when determining which utilities would be required to do this.

This review should take stakeholder input into consideration, including but not limited to utilities, developers, PJM, consumer advocates, and any relevant state agencies. It should also consider information from other regulatory or industry forums that are working on this issue.

Summary of Participant Feedback, Solution 11: In their written feedback on the November 13th draft potential solutions document, developers, advocates, and an industry expert in attendance expressed strong support for this solution, emphasizing that Dominion's 160 ms requirement (which triggers the need for DTT) is of key importance. Dominion expressed opposition to this solution as provided for review at that time.

During the combined working group meeting, Dominion stated that this solution has substantial overlap with some of their ongoing or completed analyses, including their current dual cellular technology pilot. Dominion already shares these results with the Commission, but it is not done through a formal filing process.

Participants stated that they view this solution as a high-level look at the overall technical standard practices for utilities requiring DTT, which could occur via a Commission-led working group format in which parties (including, but not necessarily limited to PJM, developers, utilities, and relevant state agencies) could provide detailed feedback on and solutions to Dominion's 160 ms technical standard. One participant noted that in New York, an engineer participates in these sorts of conversations, and Massachusetts holds these discussions via a Technical Standards Working Group.

With these considerations, participants supported inclusion of Solution 11 in this report.

12. Hold an evidentiary process evaluating the need for DTT, as opposed to other technologies

Solution 12: Ask the Commission to open an evidentiary process through which they will explore the need for DTT to support DER interconnection in Virginia, as opposed to other technologies (including inverter-based resources). The process should explore what standards (if any) DTT meets that other technologies cannot meet, the reasons for these differences, and other key factors related to the use of DTT in Virginia for this purpose, as well as in other jurisdictions in which DTT has been used in the past (e.g., PHI's Delaware service territory, which has eliminated blanket DTT requirements while continuing to meet safety and reliability standards). This should include testimony under oath.

Summary of Participant Feedback, Solution 12: This solution was first presented to parties during the final combined meeting and was developed based on suggestions from several participants in response to the feedback received on the November 13th draft potential solutions document. For this reason, parties were not able to provide perspectives on this solution in advance of the final combined working group meeting. However, parties did not oppose including this solution for consideration.

High-level Regulatory Changes

13. Consider regulatory changes that would incentivize DER interconnection

Solution 13: Ask the Commission to consider implementing regulatory changes (e.g., performance-based regulation or changes or adoption of the latest IEEE standards) that would incentivize utilities to support interconnecting more DERs.

Summary of Participant Feedback, Solution 13: In their written feedback in advance of the final combined meeting, developers generally expressed support for this solution, and Dominion expressed opposition. During the final combined meeting, parties did not express opposition.

G. Participant Feedback: Non-Consensus Solutions

Approaches to Meeting Safety and Reliability Requirements

14. Comprehensive impact studies considering the abilities of inverter-based resources

Solution 14: Require utilities proposing to require DTT to conduct comprehensive impact studies on the issues that they seek to address, with consideration for the abilities of inverter-based resources. The studies should identify the risk and reliability concerns that they seek to avoid by requiring DTT (including the probability of any risk or reliability concerns being realized) and should analyze whether inverter-based resources could address those concerns while meeting the technical standards as revised under Solution 11. A third party (contracted by the Commission) should help determine which studies are needed, and those studies should take into consideration the abilities of certified inverter-based resources.

Summary of Participant Feedback, Solution 14: Developers expressed support for this solution in their written feedback November 13th draft potential solutions document, and only Dominion expressed opposition.

During the final combined meeting, participants were asked if they felt that this solution was duplicative of Solutions 9–11 as revised, but several developers felt that Solution 14 was distinct in that if implemented, it would offer a mechanism through which the DER interconnection process could shift from a screening-based approach to a study-based approach for identifying whether DTT is actually necessary. For this reason, developers felt that Solution 14 should be implemented on a per-project basis in conjunction with (and following completion of) Solution 11, if pursued.

Dominion maintained its opposition to this solution, stating that it indicates a general misunderstanding of the Company's 3:1 screening process.[25] Per Dominion, the "screen" in question is not a quick decision but is rather a highly involved engineering analysis. Dominion conducts this screen because the Company doubts about the accuracy of the transient-based studies used by others in the industry, including questions about the models informing those studies. However, a developer felt that there would be value in still pursuing this solution because they view Dominion's 3:1 screening process itself as too restrictive; if implemented, this solution would allow the 3:1 screening process to be evaluated by a neutral third party.

Still, Dominion noted that moving this component from a screening-based approach to a study-based approach would take more time, making it more difficult to meet and exceed the study timelines as desired under Solution 1.

If this solution is not pursued in the near-term, there may be potential for findings and results from Solutions 9–11 (if implemented) to inform future decisions related to Solution 14.

High-level Regulatory Changes

15. Explore and, if appropriate, implement a holistic approach to cost allocation that accounts for broad-scale societal benefits of DERs

Solution 15: Through an evidentiary process, the SCC should explore alternative cost sharing/cost allocation strategies enacted in other jurisdictions that better distribute costs across all beneficiaries of DER projects, including but not limited to the those included in the Grid Transformation and Security Act.

[25] Dominion's 3:1 screening process is described in their responses to Questions 3, 6, 11, and 14 in Homework 1. Dominion's responses to Homework 1 are available in **Appendix B** to this report.

The SCC should use lessons learned from other jurisdictions to understand the potential implications of enacting this type of model in Virginia. If this approach to cost sharing is found likely to result in positive outcomes, the SCC should investigate how such an approach could be implemented in the Commonwealth.

Summary of Participant Feedback, Solution 15: Participants expressed mixed views on this solution in their written feedback on the November 13th draft potential solutions document, ranging from strongly supportive as a high-priority item to strongly opposed. Parties were generally aligned in recognizing that it was necessarily to identify the costs and benefits associated with DERs in order to more holistically allocate associated costs but did not agree about whether such an analysis could be done comprehensively, what technologies and approaches could or should be considered "beneficial," or whether it was appropriate to allocate costs in this manner.

Notably, the co-ops expressed concerns about impacts this approach could have to their customers because not all customers would necessarily benefit from DERs and the associated upgrades on the system if those upgrades are only required due to the presence of a single DER project in a certain area, and many cooperative customers reside in low-income regions. However, developers generally expressed that this was a reasonable approach to cost allocation through which costs for necessary grid upgrades could be made in a comprehensive way that reduced the potential for patchwork-style system upgrades, which would likely be more costly over time.

During the final combined meeting, developers expressed that Solution 15 provided an opportunity for the Commission to explore a range of creative approaches to cost allocation, enabled by the GTSA. Some developers suggested that under a holistic model, utilities requiring investments in excess of technical standards could be financially responsible for this "additional" cost component. Other developers suggested models in which costs for investments "above and beyond" these requirements could be allocated across utility shareholders or ratepayers. The IOUs opposed a model in which these costs would be allocated to shareholders, but those in support of such a model argued that to the extent that an IOU is requiring upgrades that are determined to exceed good utility practice, the utility shareholders would be the beneficiaries of those investments and should therefore be required to pay those costs. The co-ops (which do not have shareholders) strongly opposed any cost allocation model that would involve the distribution of these or any additional costs across their member-owners.

If pursued, this non-consensus solution could result in an exploration of any number of cost allocation strategies for holistic, wide-scale grid investments. However, some parties remain strongly opposed to implementation of such an approach.