August 1, 2022

Clerk of the Commission
c/o Document Control Center
State Corporation Commission
1300 E. Main St.
Richmond, VA 23219

Re: SEIA's Initial Comments Regarding Utility DER Interconnection Issues – PUR-2022-0073

State Corporation Commission,

I am writing this letter on behalf of the Solar Energy Industries Association ("SEIA") in response to the May 24th, 2022 Order for Comment ("Order") issued in Docket Number PUR-2022-00073 ("Docket") regarding interconnection issues related to utility distributed energy resources ("DER"). With more than 1,000 member companies nationwide, SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 20% of U.S. electricity generation by 2030. SEIA works with its member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power.

SEIA membership is extensive in Virginia, with millions of dollars in projects invested and installed under the PBR process. Over 179 solar companies operate in Virginia, and to date over 3.7 gigawatts of solar have been installed across the state, enough to power over 427,000 homes and representing 4.31% of the state's total electricity generation.[1] Broadly, SEIA supports an iterative, engineering-based approach to interconnection that provides stability and resilience to the broader energy grid, lowers the cost to interconnection grid-beneficial DERs, and eliminates barriers to interconnection by leveraging smart demand response ("DR") and DER technology. As we will demonstrate in the following comments, Virginia has an opportunity to lead the nation in adopting transformative interconnection policies that will foster a more resilient, cost-effective, and efficient electric grid by taking both short- and long-term steps that incentivize, rather than discourage, the development of these resources. Thank you for providing us the opportunity to submit these comments.

[1] *See https://www.seia.org/sites/default/files/2021-03/Virginia.pdf*

Summary and Organization of Comments

SEIA's comments seeks to address the eight questions posed in the Commission's May Order while proving national and international context, case studies, and succinct policy recommendations. SEIA's comments below build off of our June 2022 whitepaper, *Lessons from the Frontline: Principles and Recommendations for Large-Scale and Distributed Energy Interconnection Reform,* attached to these comments as *Attachment A.* The general principles for interconnection reform are:

1. **Transparent process and outcomes** that are detailed and have clear rules with supported timelines for key activities.
2. **Performance-based metrics and goals with rigorously enforced rules** for improved customer service, including penalties when not meeting enhanced benchmarks.
3. **Reasonable, allocable, and allowable costs** that are durable during the estimation phase and directly relate to the connecting project. Cost reflective charges for monopoly services are essential such that they reflect incremental costs and benefits of how consumers and other parties use the system. This includes minimizing harmful distortions arising from the recovery of fixed charges for using energy networks.
4. **Aligned incentives** so that monopoly operators act in the interests of all consumers. Special attention should focus on mitigation and where possible removing data and customer relationship monopolies in order to seed pre-competition activities and harnessing markets and competition where it can bring benefits to consumers.
5. **A level playing field** so that all technologies and business models can compete equally, without barriers to entry to the market.
6. **Efficient allocation of risk** so that those best placed to manage the uncertainty inherent in a rapidly changing system shoulder the risks involved.
7. **Support for vulnerable communities** to address energy bill burdens and build resiliency.

Given the general lack of inherent innovation seeking norms within the monopoly utility business model, it is critical to categorize interconnection reforms along a spectrum, from incremental to transformational. Incremental reforms tweak existing processes for better or faster transactional improvements that address lots of "when, what and how" reform questions. Faster improvements include using digital signatures and auto checking submission information and other low hanging fruit. Better enhancements include utilizing online portals built using common information model interoperability standards, or other means. Transformation reforms start to answer "why" questions and their answers open the conversation to smarter, innovative approaches.

For example, and especially for residential and small business customers, does the connection process discriminate against customers seeking to change how they use the grid for generation and storage compared to controllable loads? These questions are important due to how generation, storage *and load* connection innovations cannot be separated from system-wide innovations for integrated resource planning and how utilization costs are recovered. These questions are necessary due to how many proposed smarter interconnection reforms today have limited utilization due to needing wider structural regulatory reforms to address monopoly conflicts of interest and a business model dominated by capital rate recovery. When connecting new generation, storage *and load*, there is a highly asymmetrical burden of interconnection requirements and relationship for generation and storage. When we extend that analysis by noting the largely passive utility approaches for managing highly controllable loads like electric vehicle charging, these stunted relationships exemplify today's misaligned utility business model that assumes customers cannot bring flexibility to the market and exposes the utility bias to overbuild networks.

While performance-based regulatory reform will take significant time to implement, interconnection innovations are available today. At a minimum, interconnection innovation begins with giving generation and storage customers choices that reflect market-based options for grid integration. Customers always need grid access rights that define firm versus flexible interconnection options, as detailed further below. This choice structures market participants to better define and efficiently allocate marginal grid integration costs. It also changes customer relationships, making them participatory instead of the "fit & forget" relationships that dominate today's interconnection processes.

A longer-term vision will help orientate stakeholders for how today's reforms align to longer term grid modernization needs. For example, for front of the meter resources participating in wholesale markets, they should largely move to a "connect & manage" relationship where unbiased network operators use bi-directional firm-to-flexible access charges to balance capital reinforcements with full stack flexibility procurement, including flexible interconnection. For behind the meter generation and storage directly connected to customer load, participants should move to a "connect & notify" interconnection relationship whereby their bounded access rights are coupled with behavioral tariffs to balance generation and storage flexibility (supply contributions) with uncontrolled and controllable load (demand).

Addressing Commission Questions

1. *What are the primary obstacles (e.g., sources of delay or cost) to the interconnection of DER on the distribution system?*

While Virginia continues to be one of the top adopters of renewable energy capacity across the southern United States, the primary obstacles to DER interconnection are not unique when compared to other states in the region, or even broadly across the country. In general, they are:

Cost: The cost of interconnecting a DER is an obstacle in two ways; soft costs and hard costs. Soft costs are incurred on behalf of the developer and incorporated into the end-use prices of a development as a result of both general operating procedures (such as interconnection application preparation, review, and submittal) as well as unexpected costs due to lack of information or transparency on the part of the utility regarding things like infrastructure upgrades needed to facilitate the interconnection of a project, interconnection studies, extended development timelines, and interconnection application resubmittals. In some cases, a developer might have no way of knowing in advance that 1) a particular infrastructure upgrade was needed and/or 2) was not given an accurate estimate of the cost of that upgrade. Depending on the answers to these two questions, these costs may result in a project being cancelled or delayed which just means that project is overhead customer acquisition cost on any subsequent project.

Based on the general principles above, reasonable, allocable, and allowable costs are defined by balancing cost reflectivity, stability, and predictability. Reflective costs represent the degree of averaging versus granularity. If costs cannot be predicted well, then cost signals must be useful for market analysis of risk and have stability in their application to varied use cases. With the addition of transparency and performance-based principles for interconnection reform, current and most incremental interconnection improvements aspire to meet these principles, but other market failures prevent wider innovation.

Market failures: Another aspect of cost within the realm of interconnection is the "first mover problem". From *Lessons From the Frontline*:[2]

> "Under the first mover problem, one project developer makes an initial investment in interconnection network upgrades that ultimately results in benefits to several, subsequent interconnection customers. For example, developer A pays $1 million for an infrastructure upgrade to connect their project, which results in additional capacity for connection on the distribution grid. Then developer B connects their project to the same location, without incurring these costs, instead benefiting from the upfront investment made by developer A."

As this example shows, free rider market failure unfortunately dominates utility approaches to cost allocation for interconnection. It is helpful to note that this is not just a generation and storage issue, but also a *load free rider* issue when first mover schemes are coupled with "causer pay" upgrades that likely also provide reliability benefits to load customers.

A variety of alternative market organization schemes are possible for allocating interconnecting customer access to constrained networks, from simplistic proportioning to capping cost increases at a nominal percentage more than the estimate, or even auctions. Cluster studies are often suggested to group interconnection applicants, yet all these schemes suffer from prototypical non-cooperative game theory challenges. Cluster studies often suffer from non-cooperation issues when a developer pulls out of the scheme late in the interconnection process. Non-cooperative schemes deteriorate if developers cannot form alliances or if all agreements need to be self-enforcing.

Flexible interconnection, available today by the utility merely ensuring developers always have the choice between firm versus flexible interconnection options, have been shown to

[2] *Id.* at 13-14.

FLEX INTERCONNECTION IN NEW YORK

Despite New York state's ambitious goal to reach 70% renewable energy by 2030, an analysis by Rochester Gas and Electric ("RG&E") in the mid-2010s constrained the ability of solar developers to build generating capacity due to traditional one-way power flow analysis. Under R&E, an AVANGRID subsidiary, worked with Smarter Grid Solutions, a software company that provides and develops distributed energy resource management systems ("DERMS") to utilize flexible interconnection concepts to increase the allowable amount of renewable generating capacity from 2.6MW to 15MW. Instead of paying the cost prohibitive reinforcements for a firm interconnection agreement, the solar developer accepted a flexible interconnection that is more cost effective to be curtailed for the 10s – 100s of hours in the year when the grid constraints need to be managed in real-time.

This pilot project showcases the ability of DERs to dynamically respond to real time grid conditions while deferring or eliminating the costs of expensive traditional grid infrastructure updates. RG&E expects to expand and standardize DERs connected under flexible interconnection agreements beginning in 2022.

You can read more about this pilot project here: https://www.tdworld.com/distributed-energy-resources/article/21163388/reactive-power-dispatch-adds-flexibility-to-grid

provide cooperative schemes for both allocating marginal grid integration costs as well as structuring market participants for better cost allocation collaboration for firm interconnection access rights.

Flexible interconnection first allocates marginal grid integration costs by typically providing cheaper and faster interconnection when cost prohibitive reinforcements limit firm interconnection. Last-in-first-off (LIFO), pro-rata or shared access rights (e.g. curtailment risk contracts) are the most common of many possible principles of access regimes for flexible interconnection agreements. As more subsequent developers seek access to this congested grid, both firm interconnection reinforcements (through "causer pay") as well as flexible interconnection (through uneconomic curtailment risk – especially LIFO) provide a market signal for then clustering participants. The existing flexible interconnection participants, plus these new developers still seeking interconnection, now form a structured alliance for cooperation in clustering for firm interconnection rights. It moreover structures participants for bi-lateral trades of access rights (e.g. buying and selling one's position in LIFO curtailment order), continuing to bring market-based innovation to interconnection.

Flexible interconnection therefore considers the commercial framework on an equal level with the technical interconnection requirements. It has been shown to better address the first mover, free rider, and non-cooperative participant issues that hinder current as well as incremental interconnection reform. If left unaddressed, these issues remain a major deterrent to renewable development in the state.

The underlying principle that flexible interconnection brings to cost allocation is an enhanced structuring of market participants for cooperative grid modernization for efficient allocation of risk. Resource owners that accept flexible interconnection are for instance best placed to manage their curtailment risk tolerance.

Direct Transfer Trip Requirements

Direct transfer trip, or "DTT", is another impediment to the effective implementation of DERs utilizing flexible interconnection. DTT is a requirement in Virginia and does not take into account how coincident solar controllability is with the grid operation issues it causes. Flexible interconnection through the use of real-time control automation was originally implemented[3] due to how the DTT approach does not scale beyond a few resources. DTT is a protection-based scheme that fails to use PCS response, much of which is now a required AIF capability and industry has already created[4] a performance certification program. As a protection scheme, DTT systems do not scale for coordinating control responses given the complexity of overlapping protection zones that can lead to sympathetic tripping. Accounting for the DTT requirement often results in significant costs levied on the developer for smaller DG projects that is not warranted given advanced inverter controls and PCS certification have shown to be effective at real-time constraint management.

Uncertainty/Lack of Transparency

In Virginia, as in other states, the interconnection process exists largely in a so-called "black box" where it can be difficult or sometimes impossible to determine what costs or timelines are associated with interconnecting a project. This represents a significant risk to the developer in the form of providing and planning for accurate development timelines and cost estimates. For a customer, this lack of transparency is a market inefficiency. This can create confusion, unexpected costs, project delays, and can even result in the cancellation of a project. If a developer wants to develop a project on a particular circuit, or in a particular area, the level playing field principle applies and they and their competitors should have extensive foreknowledge on how long it will take to interconnect that project, what steps or studies need to be conducted and their timelines, and what upgrades may be needed and their associated cost (or at the very least a range of potential costs).

Timing

As discussed at length throughout the 2021 Grid Transformation planning docket (PUR-2021-00127), interconnection timelines are and continue to be a major issue for developers in VA. At present according to the most recent Dominion Virginia Interconnection Queue report, there are 636 active projects currently in the queue ranging from less than 1MW to over 30MW with time-in-queue ranging from 89 days on the low end to over 1,700 days at the most, with an average time-in-queue of 526 days and a median time-in-queue of 542 days. These timelines could be drastically improved, and shortening them should be a primary goal of interconnection

[3] SSE, 2013. Active Network Management (Orkney) https://www.ofgem.gov.uk/sites/default/files/docs/2013/06/dg_learning.pdf.
[4] EPRI, 2019. Power Control Systems, Overview of the new UL1741 CRD. https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/def2bf0a236b946f85257f71006ac98e/$FILE/29535296.pdf/EPRI_Power%20Control%20Systems%20-%20UL%201741%20CRD_ITWG%20Aug%202019.pdf

Advanced Inverter Functions: A Primer

Advanced inverter functions, or "AIFs", are a slate of inverter settings, programs, operating parameters, and other technological capabilities that provide complex monitoring, communication, command and control, and demand responsive abilities to commercially available inverters installed in the field. These functions are designed to assist in building grid stability through a variety of autonomous and semi-autonomous decisions made by the inverter or a grid operator in response to certain grid conditions. Most inverters installed today are capable of activating AIFs through minor programming or software updates.

reform. "Connect and manage" and "connect and notify" methods both address timelines by setting reasonable time periods to achieve certain milestones, whether that be interconnection application review and approval, studies, or removing certain interconnection screens entirely and relying instead on the activation of grid-beneficial AIFs and energy storage.

Insurance Requirements for Level 1 Interconnection

Finally, Virginia is unique among most states in that IOUs impose additional, arbitrary insurance requirements on Level 1 and net energy metering ("NEM") developments in the state. To SEIA's knowledge, Virginia is the only state that requires this additional insurance amount and according to rooftop solar developer in SEIA's membership, this requirement is cost-prohibitive and possibly a deterrent to adopting rooftop solar.

2. What solutions have utilities implemented to facilitate the efficient interconnection of DER to the distribution ? Have they been effective? How can they be improved?

Providing Accurate Interconnection Timelines and Upgrade Costs

Compared to international peers, US utilities have substantial improvement opportunities. Providing solar developers the choice between firm or flexible interconnection has for example become business as usual for the utilities in the U.K., and developers can access more system information up-font, including headroom estimates and estimated costs.

Describing the study process and other assumptions, for the now mature U.K. flexible connection market, joint utility resources and a best practice guide date back to 2015.[5] There are many Active Network Management[6] resources available,[7] including an updated best practice guide[8] and performance-

[5] ENA, 2015. Active Network Management Good Practice Guide. https://www.energynetworks.org/assets/images/Resource%20library/ANM%20Good%20Practice%20Guide%202015.pdf

[6] Active Network Management is the U.K. industry term for DERMS products as well as the overarching techno-economic framework for flexible connections.

[7] ENA, Accessed July 2022. Open Networks Programme, specifically "WS1A: Flexibility Service". https://www.energynetworks.org/creating-tomorrows-networks/open-networks/flexibility-services

[8] ENA, 2018. Open Networks Project, Curtailment Process and ANM Reliability Good Practice Guide. https://www.energynetworks.org/assets/images/Resource%20library/ON18-WS1-P7%20Good%20Practice%20Guide%20v1.1%20(REPUBLISHED).pdf

based customer service that usually means connection studies are completed in no more than three months.[9]

Activating Advanced Inverter Functions

While some utilities in Virginia, such as Dominion, have explored incremental interconnection reform concepts as they apply to DERs generally, there remains gaps in potential policy solutions being explored that negatively impact the ability of renewable developers to interconnect resources overtime, and likely create bottlenecks in future development unless action is taken today by those utilities to incorporate new and innovative interconnection concepts. Lacking developer choice and the range of flexible interconnection options, the reality is that most DERs being installed in Virginia today have the ability to utilize advanced inverter functions ("AIFs") that help defer the cost of infrastructure upgrades, expedite interconnection, and create a more reliable and resilient electric grid but they are not being fully leveraged, or in some cases even activated, by utilities secondary to their approval for interconnection. Whereas states with high DER penetration, such as Hawaii and California, are readily activating these functions to harden their grid, create *more* hosting capacity, and in some cases even eliminate the interconnection process entirely, Virginia has not. This represents a massive and growing missed opportunity to address a myriad of short- and long-term interconnection issues by simply creating processes and profiles to allow these grid-beneficial functions to activate.

For example, Dominions *2021 Grid Transformation Plan* acknowledges that they have "seen growth in DERs and expects that growth to continue exponentially in the coming years" and that the "rise of DERs requires a fundamental change to the electric grid."[10] And yet throughout the entire report, advanced inverter functions (or as Dominion refers to them "smart inverters") are mentioned only once, in the glossary of the report.

ADVANCED INVERTER FUNCTIONS (AIFS) VERSUS FLEXIBLE INTERCONNECTION

AIFs, and especially through limited or no-export interconnection agreements are a subset of flexible interconnection agreements. Based on AIF capabilities, limited or no-export schemes were developed in Hawaii as mediated solutions to non-cooperative utility and solar developer disagreements on how best to manage grid constraints. With AIFs enabled, participants were able to still interconnect through a "connect & notify" relationship.

What they lack, and the wider flexible interconnection scheme includes, is (1) developers always having firm versus flexible choice, and (2) a utility provided curtailment risk assessment that includes DER developer data rights to independently verify the curtailment assessment risk.

Mature interconnection schemes are extending these frameworks, for example implementing "connect & notify" smart export relationships as the default for residential scale customers, and a "connect & manage" relationship for front-of-the-meter customers.

[9] NGESO, Accessed July 2022. https://www.nationalgrideso.com/industry-information/connections/your-connections-journey
[10] *See* Dominon's Grid Transformation Plan Phase II,

Supporting Flexible Interconnection for more Holistic Interconnection Innovation

In terms of the overall approach, flexible interconnection incorporates real-time control to managed grid access during grid constraints, typically acceptable with 95-99% grid access. The utility will need to provide a curtailment assessment, essentially an annual power flow analysis that sums the constraint periods. Given feeders are largely designed for peak demand and based on how conservative design are for this and other the snapshot, worst case conditions, stakeholders have also shown that curtailment assessments can generally be sufficiently accurate even when substations do not today have SCADA data and/or AMI data is lacking. Given the financial risk of curtailment tolerance is an economic decision by the solar developer & owner, flexible interconnection is only a viable option when developers have the right to request the grid data and the models used to analyze curtailment risk. Third party solar financers for instance typically require due diligence studies by an independent entity.

Under a long-term flexible interconnection scenario, advanced metering infrastructure ("AMI"), DERMS, and other types of technology will allow utilities to thoroughly utilize many of the functionality in DERs in holistic and dynamic ways but waiting for these types of capital-intensive and time consuming buildouts is unnecessary until triggered via locational and specific market-based needs. Some states, like California, Hawaii, and Illinois, already leverage AIFs without large amounts of AMI or a DERMS because AIFs are largely autonomous and reactive to dynamic grid conditions across a variety of electric grids. This is due to how AIFs support moving from static hosting capacity to an uncoordinated, dynamic hosting capacity.

Substation and even central controller DERMS can enhance this further by enabling coordinated, dynamic hosting capacity. For instance, utilization of DER within volt-var optimization (VVO) distribution control to further optimize feeder voltage to increase hosting capacity, or in situations where multiple flexible interconnection customers need to be managed in real-time with multiple and overlapping grid constraints due to radial loop or mesh grid conditions. Initially, and especially at the residential solar scale, AIFs are often the most appropriate and cost-effective way to largely resolve grid constraints due to how moving to a "connect & notify" relationship better aligns to streamlined interconnection for residential customers. From the general principles, residential and small business customers generally lack the knowledge to analyze their curtailment risk and their marginal export is better managed in a non-discriminatory way through access rights that include generation, storage and load and management via behavior schemes like time-of-use rates.

Leveraging Energy Storage

As one of the lowest cost new generation resources, new solar energy can be cheaper than the operating cost of existing fossil and nuclear plants. When combined with storage, variable solar energy then becomes a reliable, dispatchable resource that provides energy and ancillary services. They also provide network services for deferring or mitigating large, expensive transmission or distribution reinforcements. This is especially true for peaking plants, where combined solar and storage have been shown to achieve a 99% capacity value. A study by the three California investor-owned utilities found solar and storage have a capacity value of 99.8%, achieving a theoretical "perfect generator" in CAISO's grid.[11] Today CAISO touts the benefit of battery storage moving from concept to reality.[12]

With the 50% cost reduction in energy storage in the last decade, customers are increasing pairing solar with energy storage to provide resiliency and enhanced grid services like time-varying import and export. Even at moderate adoption, energy storage can shift a controllable resource like solar-only AIF capabilities to a dispatchable solar+storage resource.

Yet storage is by definition one of the most flexible resources for today's modern grid. Interconnection reform must therefore holistically provide firm versus flexible interconnection choices to developers, and must harmonize connection relationships for generation, storage *and load*.

To streamline storage adoption challenges today, IREC's recently released Building a Technically Reliable Interconnection Evolution for Storage (BATRIES) toolkit[13] includes many low-hanging fruit and best practices, including "model language that utility regulators can use to update state interconnection rules to reduce the costs and time to safely interconnect energy storage and solar-plus-storage systems. The solutions are nationally applicable and can be applied in diverse states and markets across the U.S."

3. *What additional solutions do utilities plan to implement, or are considering for implementation, to facilitate the interconnection of DER on the distribution system?*

As already noted above, we are providing an innovation framework for utilities to work collaboratively with their customers to find the most affordable marginal grid modernization investments and provide market-based solutions that lower barriers to entry and ensure a level playing field for interconnection. We recognize that these cooperative relationships will provide opportunities for additional innovation and collaboration in the future, from better aligning business practices for expanding customer energy efficiency to non-wires alternatives and other full stack flexibility services. We welcome the opportunity to discuss how these approaches support system-wide innovation and more affordable integrated resource planning.

4. *Are there "best practices" in place in other jurisdictions that the Commission should consider?*

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[11] Joint IOU utilities of CA, 2020. Contextualized here: https://www.pv-magazine.com/2020/07/20/solar-plus-storage-has-a-99-8-capacity-value-in-california/

[12] CAISO, From Idea to Reality - Battery Storage Comes of Age on the California Grid, March 2, 2022. http://www.caiso.com/about/Pages/Blog/Posts/New-video-on-historic-growth-of-battery-storage-released.aspx

[13] IREC, Accessed July 2022. https://energystorageinterconnection.org/

Best practices as noted by industry leaders or researchers:

EPRI has a series of public reports[14,15,16] that describe flexible interconnection, noting that flexible interconnection "is a term that is likely to rapidly become familiar within the distributed energy resource (DER) integration community…. it refers to the number of options that are available for DER interconnection, and in particular to options that involve real-power control. These modes of control are increasingly available in DER but are not typically used." EPRI also has a private report[17] noting demonstration projects in the U.K., France, the U.S. and Canada.

NREL has been studying flexible interconnection since 2015,[18] describing it as the "ability of a developer to avoid upgrades by accepting that its system may have real power curtailed as necessary to avoid system violations."[19] NREL has furthermore correlated how flexible interconnection enables advanced hosting capacity, having developed summaries for utilities, policymakers, and solar developers.[20]

Smarter Grid Solutions, a company that first implemented[21] flexible interconnection in the U.K. in the late 2000's has a white paper[22] describing flexible interconnection as "arrangements with customers that allow dynamic curtailment to be used to manage specific technical and operational constraints that would otherwise have required grid reinforcement. Curtailment, in the form of reducing or preventing power export from generators at certain times when the grid is under stress, has become an important tool to manage these technical issues. Therefore curtailment is a grid management tool to allow DER technologies to efficiently share network hosting capacity."

The technology for flexible interconnection relies on real-time control technology that can be one or both of: (1) autonomous distributed energy resource (DER) controls located at the solar/DER resource to assist in managing its power flow to be within grid limits, and (2) sometimes coordinate DER control with utility distribution equipment via a DERMS. Autonomous DER

[14] EPRI, 2018. Understanding Flexible Interconnection. https://www.epri.com/research/products/000000003002014475
[15] EPRI, 2020. Principles of Access for Flexible Interconnection: Cost Allocation Mechanisms and Financial Risk Management. https://www.epri.com/research/products/000000003002019635
[16] EPRI, 2020. Principles of Access for Flexible Interconnection Solutions: Rules of Curtailment. https://www.epri.com/research/products/000000003002018506
[17] EPRI, 2018. Flexible Interconnection for Distributed Energy Resources: Emerging Practices at Early-Adopter Utilities. https://www.epri.com/research/products/000000003002012964
[18] NREL, 2019. Active Management Integration. https://www.nrel.gov/docs/fy19osti/70278.pdf
[19] NREL, 2019. An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions. https://www.nrel.gov/docs/fy19osti/72102.pdf
[20] NREL, access July 2022. https://www.nrel.gov/solar/market-research-analysis/advanced-hosting-capacity-analysis.html
[21] SSE, 2013. Active Network Management (Orkney) https://www.ofgem.gov.uk/sites/default/files/docs/2013/06/dg_learning.pdf
[22] Smarter Grid Solutions, 2022. Clearing queues, reducing costs and speeding up grid connections whitepaper. https://info.smartergridsolutions.com/flexible-interconnections-2022

controls, for instance the capabilities required to meet IEEE 1547-2018, have been shown to meet limited or no-export real-time control needs and industry has developed a UL 1471 Power Control Systems (PCS)[23] performance certification. Hawaii's Quick Connect Pre-Approval Program,[24] that allows solar PV interconnection without full prior utility approval, use PCS certification to ensure solar connected to constrained feeder operates within grid limits. The Quick Connect program is an example of a "connect and notify" interconnection process for small DERs.

Autonomous DER control is essential, especially for contingency operations when for example a loss of communications with utility supervision occurs. While not always necessary, higher-level DERMS control can unlock additional hosting capacity, for instance in optimizing DER voltage control dispatch with the utility's voltage regulation equipment.

California Rule 21

In preparation for high deployment of DER and addressing both system-wide innovation needs and interconnection reform,[25] California continues to work towards Smart Inverter Operationalization and Grid Modernization Planning (Track 3), leveraging their ongoing Rule 21 effort that dates back to 1982.[26] Stakeholders continue to pilot adopting AIFs and likewise DERMS for managing grid constraints with smart DER controls, as noted in their on-going Smart Inverter Working Group (SIWG).[27]

SIWG Phase 3 functionality includes AIF capabilities for limited/no-export, noting the Active Power Mode specification "provides a mechanism through which the maximum active power of one DER system or an aggregation of DER systems and load within a facility can be limited at a Referenced Point."[28] Stakeholder anticipate that as these rules are finalized in the coming year, California's solar+storage market will continue explosive growth.

New York

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[23] EPRI, 2019. Power Control Systems, Overview of the new UL1741 CRD. https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/def2bf0a236b946f85257f71006ac98e/$FILE/29535296.pdf/EPRI_Power%20Control%20Systems%20-%20UL%201741%20CRD_ITWG%20Aug%202019.pdf

[24] HECO, accessed July 2022. https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/rooftop-solar/quick-connect

[25] CPUC, 2021. Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M422/K949/422949772.PDF

[26] CPUC, Accessed July 2022. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/rule-21-interconnection

[27] CPUC, Accessed July 2022. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/rule-21-interconnection/smart-inverter-working-group

[28] CPUC, 2017, pg 23. SIWG Phase 3 DER Functions: Recommendations to the CPUC for Rule 21, Phase 3 Function Key Requirements, and Additional Discussion Issues. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/rule21/smart-inverter-working-group/siwg_phase_3.pdf

Compared to European stakeholders (see below), U.S. stakeholders are only very recently starting to deploy flexible interconnection solutions. New York State's Interconnection Technical Work Group is working to develop a roadmap and implementation for each utility,[29] leveraging successful findings from Avangrid's Flexible Interconnection Capacity Solution project.[30] Recently, EPRI provided a detailed techno-economic analysis of flexible interconnection for New York State.[31]

Hawaii

Hawai'i has one of the most developed rooftop PV markets in the United States. To date, there is over 850MW of distributed generation installed across several different open and closed distributed energy generation ("DER") programs.[32] In Oahu, the amount of systems installed across the island amount to one in three single-family residences having a rooftop PV system.

As a result of this explosive growth across the state in the last decade, Hawai'i's regulators, utility companies, and various energy and environmental stakeholders have engaged in extensive technical discussions regarding the implementation and activation of these resources across Hawai'i's six major electrical grids (Oahu, Hawaii, Maui, Kauai, Molokai, and Lanai). Hawaii's Rule 14H, which governs the interconnection of DER systems across Hawaiian Electric's various island grids, has been updated and amended across several different regulatory proceedings to accommodate rapid changes in both inverter and energy storage technology, as well as rapid adoption of these resources across the state. As a result of this, Hawaii's Rule 14H is often cited as one of the most advanced interconnection frameworks utilizing advanced inverter functionality currently adopted in the United States, despite Hawaii's relatively small market size. Additionally, the high amount of energy storage products paired with residential PV installations[33] make it a case study on the impacts of distribution level storage adoption impacts in high rooftop PV penetration states.

While interconnection standards are commonly discussed in broader DER policy proceedings, the adoption of current and future AIFs in Hawaii began earnestly within the context of the Reliability Standards Working Group (Docket No. 2011-0206) when it became evident that rooftop solar adoption in Hawaii would only continue to increase and that the existing interconnection framework was insufficient to either allow rapid adoption of DERs or to fully utilize the functionality of the resources operating on the grid. This proceeding evolved to

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[29] NY DPS ITWG, Accessed July 2022. https://www3.dps.ny.gov/W/PSCWeb.nsf/All/DEF2BF0A236B946F85257F71006AC98E

[30] Avangrid, 2022. Flexible Interconnection: REV Demo Lessons Learned and Scalability Roadmap. https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/def2bf0a236b946f85257f71006ac98e/$FILE/33858072.pdf/Flexible%20Interconnection%20Scalability_V3%20-%20ITWG%20-%20Final.pdf

[31] EPRI, 2021. The Value of Flexible Interconnection for Solar Photovoltaics Enabled by DERMS: Detailed Techno-Economic Analysis in New York State. https://www.epri.com/research/programs/067418/results/3002018505

[32] https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A22E02B12024D02562

[33] Over 90% of rooftop PV systems installed in Oahu in 2020 was paired with a storage system.

be incorporated into the 2014 DER docket (Docket No. 2014-0192), the 2019 consolidated DR/DER Docket (2019-0323) and the Hawaiian Electric Companies' 2017 Grid Modernization Plan. Thousands of hours of work across a variety of industry stakeholders, including representatives of the utility, the PUC, the energy and environmental industry in Hawaii, major inverter manufacturers, engineers, and technical experts, have resulted in a number of nationally utilized standards, primarily the UL 1741 Supplement A inverter testing standard and the IEEE 1547-2018 interconnection and interoperability standards.

The primary objective of these policy discussions was, and continues to be, developing methodologies, screens, testing standards, and policies to integrate DERs on "high penetration" circuits, which for Hawaii is typically measured at 250% of gross daily minimum load ("GDML") and reflected in Hawaiian Electric's Hosting Capacity maps and analysis. The AIFs developed through these discussions concomitantly informed other related policy discussions, such as the development of advanced DER program design, chiefly the customer self-supply and the smart export tariffs in 2017, and the NEM+ and Battery Bonus smart dispatch program ("SDP") in 2021. Almost all of the programs created after the end of the net metering program in 2015 were designed to utilize various AIFs to increase grid reliability while simultaneously allowing for the incorporation of greater amounts of DER onto the grid, in an expedited and efficient manner.

As a result of the automatic (ex. SDP or CSS programs) or opt-in (ex. NEM+ program) activation of certain AIFs, such as volt-watt, a typical DER system in Hawaii is allowed to either skip certain interconnection screens, or in the case of Oahu's Quick Connect pilot program, skip the interconnection process entirely under certain conditions.[34] Because the Hawaiian Electric Companies, the PUC, and energy stakeholders have more or less concluded that activating and at times compensating customers in exchange for the activation of these programs represents a net benefit to the functionality and reliability of the overall electric system in Hawaii, discussions about hosting capacity, daily minimum load, and "the right amount of rooftop solar" penetration on secondary circuits are largely irrelevant. Instead, the Hawaiian interconnection model is one that is increasingly moving towards expediting interconnection on high penetration circuits by leveraging AIFs and energy storage technology, or, in some cases, completely eliminating the interconnection process entirely and moving towards a notification process rather than interconnection applications, reviews, screens, and studies.

Europe

[34] https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/rooftop-solar/quick-connect

Given that flexible interconnection has become a standard offering[35,36,37,38] in many European countries, it is helpful to note studying flexible interconnection is not per se more complex but does require the utility to analyze more than the static, snapshot worst case conditions on the feeder. In both cases, the utility applies a power flow study to evaluate DER operation relative to grid operation limits like voltage rise or thermal limits on equipment. So instead of doing a power flow study for a few 10s or 100s of snapshot hours in the year, flexible interconnection curtailment studies the operational limits for at least an entire year of data. The input datasets for flexible interconnection are therefore the complete set of aggregated load and generation instead of only a snapshot for traditional studies.

It is helpful to keep in mind that these studies are today already highly automated and, compared to several years ago, an annual power flow analysis at 1-second resolution data can be completed in minutes.[39]

Describing the study process and other assumptions, for the now mature U.K. flexible connection market, joint utility resources and a best practice guide for standardized flexible interconnection date back to 2015.[40] There are many Active Network Management[41] resources available,[42] including an updated best practice guide[43], an explainer and FAQ,[44] and performance-based customer service that usually means connection studies are completed in no more than three months.[45]

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35 Bletterie, et al., 2016. Increased hosting capacity by means of active power curtailment. https://ieeexplore.ieee.org/document/7861396

36 Kolstad, et al., 2017. Case Study on the Socio-Economic Benefit of Allowing Active Power Curtailment to Postpone Grid Upgrades. https://www.mdpi.com/1996-1073/10/5/632/pdf

37 Furusawa, et al., 2019. Constrained connection for distributed generation by DSOs in European countries. https://www.econstor.eu/bitstream/10419/194181/1/104820815X.pdf

38 Brandstätt, et al., 2020. Rethinking the Network Access Regime: The Case for Differentiated and Tradeable Access Rights. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/09/OEF124.pdf

39 Sandia, 2021. Rapid QSTS Simulations for High Resolution Comprehensive Assessment of Distributed PV. https://www.osti.gov/servlets/purl/1644448

40 ENA, 2015. Active Network Management Good Practice Guide. https://www.energynetworks.org/assets/images/Resource%20library/ANM%20Good%20Practice%20Guide%202015.pdf

41 Active Network Management is the U.K. industry term for DERMS products as well as the overarching techno-economic framework for flexible connections.

42 ENA, Accessed July 2022. Open Networks Programme, specifically "WS1A: Flexibility Service". https://www.energynetworks.org/creating-tomorrows-networks/open-networks/flexibility-services

43 ENA, 2018. Open Networks Project, Curtailment Process and ANM Reliability Good Practice Guide. https://www.energynetworks.org/assets/images/Resource%20library/ON18-WS1-P7%20Good%20Practice%20Guide%20v1.1%20(REPUBLISHED).pdf

44 ENA, 2021. Flexibility Connections: Explainer and Q&A https://www.energynetworks.org/industry-hub/resource-library/on21-prj-open-networks-flexibility-connections-explainer-and-q-and-a-(19-aug-2021).pdf

45 NGESO, Accessed July 2022. https://www.nationalgrideso.com/industry-information/connections/your-connections-journey

5. *What additional actions could the Commission take to help facilitate the interconnection of DER on the distribution system?*

As noted in SEIA's whitepaper, there are a variety of faster and better short-term interconnection reforms. With respect to general reforms that impact large-scale and distributed projects SEIA recommends that utilities and RTOs:

- Ensure customer service metrics are met: Add staff, adhere to interconnection timelines and be subject to penalties if unmet, and advance needed policies related to planning, forecasting, and standards to ensure progress is made toward state and national clean energy goals;
- Automate and standardize processes where appropriate; and
- Collect more information about infrastructure upgrade costs for all types of projects and make them transparent and accessible to developers.

With respect to interconnection reforms for distribution level projects, SEIA recommends that state regulators require each distribution utility to:

- Improve and open the black box of distribution system planning and perform proactive forecasting and scenario development to meet state clean energy goals; and
- Provide greater transparency and accuracy of interconnection estimates of infrastructure upgrade costs using hosting capacity maps, through the study process, or through preapplication processes.

Regulators should also:

- Reform cost sharing for infrastructure upgrades and split costs between interconnection customers and other system beneficiaries; and
- Increase project maturity requirements for projects to enter the interconnection queues.
- Utilities should stop solving for grid constraints assuming all customers want firm access, especially when the constraints represent rare or limited conditions. Utilities should instead start providing more flexible interconnection solutions to create customers choice in the most affordable grid modernization pathways.

Specifically, recommendations in the short-term include:

- Convene a stakeholder technical working group prior to the end of 2022 or within 6 months to explore short- and long-term interconnection reform goals, and allow for an iterative, evidence-based approach to refining and improving the interconnection process. Stakeholders should include staff from the major IOUs, the SCC, industry including developers *and* inverter manufacturers, national labs, community stakeholders, and other relevant parties that the Commission deem appropriate.
- Create a roadmap to institute short- and long-term interconnection reform goals, such as the adoption of IEEE 1547-2018, activation of certain AIFs and/or a workplan to address

legacy inverter updates, roadmaps to implement "connect and manage" (for FTM resources) and "connect and notify" (for BTM resources) practices as standard.
- Remove arbitrary interconnection insurance requirements for level 1 and NEM interconnection applications.

6. *What steps should the Commission take with regard to aggregation of interconnected DERs for possible participation by such aggregations in the PJM wholesale market, per FERC Order 2222? Are any such steps best addressed in this docket or in a separate proceeding?*

SEIA believes DER should have the right to participate in wholesale markets as per FERC Order 2222 but that interconnection reform should not wait for 2222 implementation. The implied controls automation for flexible interconnection and AIF export will provide DER controls automation sufficient for Order 2222 dispatch needs.

7. *Are there any changes to the Regulations Governing Interconnection of Small Electrical Generators and Storage (20VAC5-314) or other Commission actions that could enable the usage of IEEE-1547-2018 compliant inverters to facilitate the integration of DER on the distribution system? Are any such changes or actions best addressed in this docket or in a separate proceeding?*

For brevity, we have not detailed proposed revisions to 20VAC5-314 in order for the commission and utilities to response to the above comments and clarify how they are incorporating flexible interconnection and AIF for transformational customer service reforms to align with customer access needs today and for the next decade.

SEIA agrees that implementing IEEE 1547-2018 in alignment with the active National Electrical code version in effect in the state (for which we also highly recommend use of the latest published version), and ensure stakeholders keep up to date relative to new and emerging technologies via creating a interconnection innovations workgroup. Several other jurisdictions have formed similar working groups to address ongoing interconnection issues as they emerge. Replicating this best practice will enable Virginia to realize the maximum benefits possible from the use of customer flexibility and advanced inverter controls.

SEIA recommends that this technical working group will be convened within the next six months or sooner and promptly begin the work of 1) assessing how other states are adopting the current IEEE 1547 and the current testing protocols, including PCS performance by harmonizing with the soon to be published UL 1741 CRD, 2) establishing with industry, accredited testing laboratories, and certification entities a practical certification timeline, and 3) recommending technical revisions to 20VAC5-314 that provide customers the full range of firm versus flexible interconnection options.

8. *Are there additional changes that could be made to the Regulations Governing Interconnection of Small Electrical Generators and Storage (20VAC5-314) that could facilitate the integration of DER on the distribution system? If so, please describe such proposed changes.*

The FERC SGIP contains little discussion or acknowledgement of non- or limited-export enabled control through flexible interconnection or AIF. A number of states that have followed the FERC SGIP model, and several other states do not have any process associated with reviewing flexible interconnection or AIF projects. At a minimum, 20VAC5-314 should be revised to include flexible interconnection and smart export through AIF capability that is certified via PCS performance as currently being developed via UL 1741 CRD. Specific model language and harmonization needs are noted in IREC's recent BATRIES[46] report.

Conclusion

We again thank the Commission for allowing us to comment on this critically important policy matter. Interconnection is the base upon which all innovative energy policy is built, and allows for the use of a variety of behind and in-front of the meter resource to function symbiotically with one another and the broader electric grid to build resiliency and stability, while helping to reduce the cost to the consumer and foster the development of more clean energy. This docket and any additional dockets or work products are an opportunity for Virginia to be a leader in innovative, cost-effective, and evidence-based interconnection reform in the South and across the United States.

Sincerely,

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The Solar Energy Industries Association (SEIA) is the national trade association for the United States solar industry. With more than 1,000 member companies nationwide, SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 20% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other

[46] IREC, Accessed July 2022. The Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage, the "BATRIES Toolkit". https://energystorageinterconnection.org/

strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power.

NOTES:

- Attachment A: SEIA Interconnection Whitepaper (June 2022)
- Attachment B: SEIA Presentation of Flex interconnection Concepts (March 2022)

Lessons from the Front Line:

Principles and Recommendations for Large-scale and Distributed Energy Interconnection Reform

Dave Gahl, Melissa Alfano, and Jeremiah Miller

June 14, 2022

Acknowledgments: Thank you to the Coalition for Community Solar Access and the Interstate Renewable Energy Council and many SEIA member companies for their input and review of this whitepaper.

SEIA Solar Energy Industries Association®

I. Executive Summary

The United States solar industry continues to rapidly expand, but outdated interconnection policies pose a major threat to solar and storage deployment across the nation. Because solar power is one of the lowest-cost resources for electricity and because solar paired with storage is also a way for customers to supply their own clean power and save money when compared with distribution utility costs, applications to interconnect solar and energy storage projects have skyrocketed.

Interconnection policies in regional transmission organizations ("RTOs"), vertically integrated utilities, and distributed utilities have not kept pace with the demands of this new energy marketplace. Interconnection procedures designed for the by-gone thermal generation era are not aligned with today's advanced technologies, and interconnection delays now constitute a major threat toward meeting state and national clean energy goals.

This paper advances a series of reform principles, as well as near-term and longer-term interconnection reform recommendations. With respect to general reforms that impact large-scale and distributed projects SEIA recommends that utilities and RTOs:

- Add staff, adhere to interconnection timelines, and advance needed policies related to planning, forecasting, and standards to ensure progress is made toward state and national clean energy goals;
- Automate and standardize processes where appropriate; and
- Collect more information about infrastructure upgrade costs for all types of projects and make them accessible to developers.

With respect to interconnection reform for large-scale projects, SEIA recommends that the Federal Energy Regulatory Commission ("FERC") standardize queue management requirements across RTOs and require each RTO to:

- Make better transmission system operating information more accessible to interconnection customers; and
- Explore alternate models for paying for network upgrade costs.

With respect to interconnection reforms for distribution level projects, SEIA recommends that state regulators require each distribution utility to:

- Improve and open the black box of distribution system planning and perform proactive forecasting and scenario development to meet state clean energy goals; and
- Provide greater transparency and accuracy of interconnection estimates of infrastructure upgrade costs using hosting capacity maps, through the study process, or through preapplication processes.

State regulators should also:

- Reform cost sharing for infrastructure upgrades and split costs between interconnection customers and other system beneficiaries; and
- Increase project maturity requirements for projects to enter the interconnection queues.

Finally, as smart grid technologies continue to be deployed, RTOs, vertically integrated utilities, and distribution utilities should stop solving for grid constraints that only exist in the system under limited conditions and start providing more flexible interconnection solutions that take the use of these technologies into account.

II. INADEQUATE INTERCONNECTION POLICIES POSE A MAJOR THREAT TO STATE AND FEDERAL DECARBONIZATION GOALS

Encouraged by state and federal policies, solar markets across the nation have seen tremendous growth. The solar industry installed more than 20 gigawatts ("GW") of capacity in 2021, with utility scale projects accounting for 17 GW.[1] Distribution level projects have also been growing steadily as well, and now nearly 5 percent of viable homes for solar have residential solar systems.[2] Even with expected headwinds for many clean energy projects around the country with an average annual growth rate of 33 percent over the past several years, analysts still forecast increasing solar deployments, and solar paired with energy storage resources, for some time to come.[3] Because solar is now one of the lowest cost sources of electricity, and because customers can supply their own power with on-site solar resources, applications to interconnect large-scale and small-scale solar projects have skyrocketed.

In the PJM Interconnection L.L.C. ("PJM") alone, a large-scale power market that includes 13 states and the District of Columbia, approximately 153 GW worth of energy projects are waiting for interconnection agreements.[4] Based on the backlog, PJM has stopped accepting new interconnection applications for a year to focus on processing existing requests.

At the distribution utility level, companies building rooftop solar for customers and on-site projects for commercial customers have also increasingly seen interconnection delays. And the attractive sites capable of interconnecting larger distributed projects, such as community solar projects, without the need for major technology upgrades have dwindled. For example, despite an ambitious solar incentive program and aggressive

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[1] *See* U.S. Solar Market Insight Report, 2021 Year in Review. Wood Mackenzie, SEIA. March 2022. p 5.
[2] Ibid.
[3] Ibid. These headwinds also include a very damaging trade petition at the U.S. Department of Commerce that would impose punitive solar import tariff and has temporarily frozen the solar market.
[4] *See* https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

clean energy goals, initially 900 megawatts ("MW") worth of Massachusetts solar projects were delayed in 2020 due to various interconnection study processes by the distribution utilities as well as the RTO. For some of these projects, there is no clear timeline for resolution.[5] Similar issues have emerged in Maine. Together, more than 1,300 MW worth of distributed solar projects remain stymied by interconnection bottlenecks in Massachusetts and Maine.[6]

Furthermore, large-scale solar projects are interconnecting to an aging transmission system built for fossil fuel-fired, central station power plants. Clean energy projects are coming online to replace these fossil fuel plants, but the retirement of a single centralized coal plant typically results in multiple solar projects, in different areas, coming on-line to meet system needs. And as a result, new transmission facilities are needed to allow those new projects to interconnect to the grid. This, and the fact that the transmission system is aging and requires the replacement of many transmission assets, has resulted in prohibitively high infrastructure upgrade costs. In other words, increasingly expensive improvements to the grid are needed to connect projects.

High upgrade costs are also now emerging on the distribution system as the number of less constrained interconnection points are dwindling in key states and bi-directional power flows are becoming the norm. These smaller-scale projects must also rely on an older, less functional grid, that was only designed only to transmit power from generators to end users, and not from multiple customer generators across the system.

If distribution utilities, vertically integrated utilities, and RTOs are going to reach state and national clean energy and greenhouse gas ("GHG") reduction goals, such as SEIA's goal to supply 30 percent of the nation's electric power by the year 2030, or the Biden Administration's goal to reduce economy-wide GHG levels approximately 50 percent by 2030, then legislators, regulators, and utility operators must adopt key interconnection reforms as soon as possible.

This paper explains principles that should guide reform, proposes near-term reforms to encourage the faster connection of distributed and large-scale projects, and lays the foundation for longer-term interconnection changes.

Failing to adopt meaningful interconnection reforms will slow progress toward efforts such as transitioning to electric vehicle fleets, switching to electric heating sources for buildings, and cleaning up the national electric generation fleet. Without more carbon-free sources of energy such as solar and storage to power these cars, buildings and homes, decision-makers will see many of their decarbonization goals go unrealized.

[5] There are also examples of approved distribution utility projects that have been subject to further study by the RTO leaving some projects in permanent limbo and without any clear timeframe for resolution.
[6] *See* U.S. Solar Market Insight Report, 2021 Year in Review. Wood Mackenzie, SEIA. March 2022. p 31.

III. THREE INTERCONNECTION REFORM PRINCIPLES

Based on extensive discussion with leading SEIA member companies, outside interconnection experts, and SEIA's on-the-ground experience, the following three principles should guide all interconnection reform discussions at both the RTO and utility level.

a. Interconnection Processes Must be Detailed, Transparent, and Clear

Any entity that oversees the interconnection of solar and storage projects must establish rules with clear, enforceable timelines for key activities. Regulators must establish detailed timeframes for the utilities or RTOs to process applications, complete project impact analyses, ensure the timely construction of interconnection infrastructure and conduct final inspections before energizing the project. Further, utilities and RTOs should provide infrastructure upgrade cost estimates that are as accurate as possible and estimates for infrastructure upgrades needed before interconnection, as soon as practicable in the interconnection process.

Relatedly, distribution utilities, vertically integrated utilities, and RTOs should publish more information about areas on the bulk power grid, and on the distribution utility grids, where power projects of all sizes could help meet system needs. This information should be available upon request to any interested stakeholder, as well as updated regularly. Not only is this information useful to energy project developers, but it would also help regulators, customers, and businesses seeking clean electricity.

b. Interconnection Rules Must Be Rigorously Enforced

The rules regarding tasks, timelines, and responsibilities should be rigorously enforced by oversight entities. Policies to improve performance, including penalties, should be used to ensure utilities are meeting and conducting timely studies and interconnecting large and small generators. To avoid penalties, based on our interviews and experience, too often distribution utilities will unilaterally "stop the clock," for a variety of reasons, resetting interconnection timelines with little explanation of delays or transparency regarding new targeted dates. At the large-scale level, long delays in RTOs processing requests based on lack of staff create a vicious cycle when large numbers of projects unable to stay in the queue for three to four years, withdraw from the queue, creating cascading restudies from those withdrawals, and further delay the processing of interconnection requests. Tariffs set timelines for processing interconnection applications, but then only hold utilities and RTOs to the "reasonable efforts" standard, a standard that FERC has never found to be violated.[7] Distribution utilities often rely on the outdated practice of conducting studies sequentially without following industry best practices to manage multiple applications at once in a timely and efficient manner. As a

[7] *See Tenaska Clear Creek Wind, LLC v. Southwest Power Pool, Inc.*, 177 FERC ¶ 61,200 (2021) (Clements Dissent at p 1).

result, an interconnection application can remain on hold for a long time before a study is commenced.

Utilities should not be able to simply reset interconnection timelines based on updating analysis that is only indirectly relevant to the project, or simply because they have too many applications to consider. Regulators must hold utilities and RTOs to a higher standard for processing interconnection applications, and provide the adequate incentives, or disincentives, for utilities and RTOs to process interconnection requests in a transparent and timely manner.

c. Infrastructure Upgrade Cost Estimates Must Be Reasonable, Directly Related to the Connecting Project, and Durable

When an infrastructure upgrade is needed to connect a project, either on the distribution system or the transmission system, the cost estimate that is provided to the interconnecting customer must be reasonable, transparent, and reflect the costs needed to connect safely to the grid. Such upgrade costs must also be commensurate with the project in terms of size and geography.

For example, for a distributed project grid upgrade costs should not be based on assumptions that the project and the accompanying upgrade would result in complete protection against total transformer and system failure. This kind of over-protection and system gold plating only drives up cost and kills projects.

Furthermore, for large-scale projects, analyses related to system impacts of connecting a project should be limited to areas on the transmission system that are most likely to be affected by the new resource, not distant RTO zones or utilities that would only be affected during a widespread system failure.

Lastly, for both large-scale and distributed projects, in cases where preliminary assessments of costs are provided, the final costs must be "durable," or in other words, within a reasonable range of the initial estimate. Too often, developers run into issues where an infrastructure upgrade cost is identified, but final cost estimates or actual installation costs balloon to several times the initial estimate with little oversight; significantly impacting the economics of the project and in many cases causing the project to drop out of the queue.

IV. General Recommendations for Interconnection Reform

The following reforms are applicable to both transmission and distribution interconnections.

a. Encourage RTOs and Utilities to Recruit and Maintain Staff

The RTOs and utilities need to add staff to process applications, work through issues, conduct studies, and move projects through the queue faster than ever before.[8] RTOs and utilities need to forecast resourcing needs proactively in response to climate goals and regulatory programs and hire adequate interconnection support and engineering staff, redeploy existing staff, and generally prioritize this work. RTOs and utilities need to ensure there is adequate capability to deal with increased interconnection requests to the distribution and transmission system, in addition to evolving transmission and distribution planning needs that may require additional or shared functional staff to support the climate goals of the state and/or region.

b. Require Adoption of State-of-the-Art Study Processing Methods

Utilities and RTOs should create automated, web-based portals for submitting interconnection requests and for rapid information exchange. These web portals should include centralized, searchable databases for commonly asked questions, lessons learned, and standardized data collection and entry. To the extent possible, utilities and RTOs should develop automated processes for application intake, studies, and project modification submissions, to reduce delays associated with lags in information exchange and review between interconnection process stakeholders.

Relatedly, the RTOs and distribution utilities should move toward publishing interconnection queues that provide *real-time* updated information on the queue itself, so the market has insight into project status as well as metrics that show how quickly or slowly projects are moving through the interconnection process. This real-time information would help developers and customers and allow stakeholders to more accurately forecast construction timelines for new resources on the system. Regulators should require utilities and RTOs to report these data to track and monitor their progress and for use in measuring performance and for enforcement.[9]

c. Collect Infrastructure Upgrade Cost Data

Although a number of states collect information on interconnection upgrade costs for completed projects, to our knowledge no state or RTO is systematically collecting information on interconnection project estimates for *all* complete project applications or the corresponding *estimated* costs to interconnect those projects.

High interconnection costs can be the difference between a project moving forward or being withdrawn. Furthermore, monopolistic utilities have historically no incentive to provide accurate or transparent costs to better inform customers throughout the interconnection process. Based on our members' experience, utility cost estimates do not often correspond to market prices for materials or labor and therefore transparency into additional utility "adders" or "overheads" would provide needed insight into how

[8] State regulatory agencies should also dedicate more staff to providing oversight of utility interconnection work.

[9] *See Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (2018), *errata notice*, 167 FERC ¶ 61,123, *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137, *errata notice*, 167 FERC ¶ 61,124, *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019).

utilities arrive at their cost estimates. More comprehensive data should be collected and reported that shows interconnection infrastructure upgrade costs assigned to pending, active or withdrawn projects in the queue, including:

- The estimated cost of interconnection facilities and/or network upgrades associated with the project;
- The actual cost of interconnection facilities and/or network upgrades associated with the project; and
- A breakdown of the interconnection delays by transmission zone, or feeder line, to determine whether there is a particular transmission owner or utility associated with the interconnection delays.

These data points would be tremendously useful to interconnection customers and would help educate the market about system needs, as well as provide more useful information to regulators about the state of the grid itself.

d. Consider Interconnection Reforms Alongside Updated Clean Energy Policies

Based on our direct experience in key states, policymakers and regulators should ensure that interconnection policies evolve and keep pace with changing clean energy goals. For instance, when a state enacts policies to: create a community solar program, adopt incentives to encourage distributed solar, increase renewable energy procurements, or increase its renewable or clean energy portfolio standard obligations, decision-makers should also be thinking about the needed changes to interconnection to make achieving the goal possible.

Too often states have passed ambitious laws and watched their implementation timelines slip and programs run into trouble because policymakers failed to consider outdated interconnection rules. These delays have serious consequences, including freezing development capital, increasing project transaction and financing costs, and slowing the deployment of clean energy. At the very least, policymakers should always direct regulators to review interconnection rules when they are making any major changes to clean energy policy, if not outright direct specific additional reforms with hard timelines for implementation.

V. Near-Term Large-Scale Interconnection Reforms

For large-scale solar and storage projects, the following recommendations apply to needed interconnection changes in RTO and vertically integrated transmission utilities.[10]

a. Provide System Operating Data and Study Assumptions to Project Developers

More transparent and more granular transmission system information is an important element to improving the large-scale interconnection processes. The transmission planning process should provide more information to generation developers on points of interconnection with the lowest likely interconnection costs. Generation developers suffer from information asymmetry with respect to project siting. Project developers do not know how costly network upgrades will be until they are far along in the interconnection process—so to obtain this information, projects need to enter the interconnection queue. This is inefficient for project developers and for transmission providers.

Instead, transmission providers should make available, on a secured website, the following:

- Study models and assumptions that will be used for each cluster of projects to be studied;
- A list of the transmission lines that are currently capacity-constrained and a list of lines expected to be constrained once certain projects in the queue come online;
- Information on transfer capability and points of interconnection of planned transmission; and
- A database of FERC jurisdictional distribution and sub-transmission lines to clarify the interconnection rules to which the interconnection customer would need to follow.

This information, coupled with the requirement to provide interconnection customers with the option of using third-party consultants to produce required studies, would help unclog interconnection queues by encouraging better project planning by developers and eliminating the need for these "exploratory" requests. [11]

b. Standardize Queue Management Requirements

The slow pace of completing interconnection studies is increasingly becoming a major roadblock to bringing large-scale resources online. Study timelines vary by RTO, but

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[10] Reforms related to large-scale interconnection reforms were first proposed by SEIA, along with American Clean Power and Advanced Energy Economy in comments submitted to FERC on February 14, 2022. *See* Comments of the Clean Energy Coalition, FERC Docket No. RM21-17 (Feb. 14, 2022). This whitepaper elaborates on several proposals in the February FERC comments.

[11] *See* section V.c. infra. p 10.

large-scale projects are often forced to spend significant upfront capital and then wait sometimes up to five years, in the case of PJM, for studies to be completed.

While FERC Order No. 2003 and Order No. 845 show that there is a need for independent entity variations in certain instances, there are certain queue management practices that are unrelated to geographical and market differences that could be standardized across the regions. These include:

- Standardizing interconnection milestone requirements for receiving applications, maintaining progress through the application process, or suspending queue positions.
- Establishing a "first-ready, first-served" process, and requiring projects to demonstrate project readiness earlier in the process. These demonstrations would include:
    - site control;
    - a demonstration of permitting progress, either filed applications or received permits;
    - an executed power purchase agreement or other significant financial agreement to show project viability; and
    - the payment of "gated" deposits that increase as the project moves through the review period.
- Standardizing interconnection study deposits from developers, as well as procedures and penalties for project withdrawal.
- Requiring that utilities use the same assumptions for interconnection studies that they use in their transmission planning studies.

c. Explore New Models for Paying for Network Upgrade Costs

There are several proposals before FERC today involving revisiting the question of who pays for the required network upgrades to interconnect large-scale projects. Under most tariffs, the interconnection customer pays 100 percent, or nearly 100 percent, of these costs. So called "participant funding" was intended to address certain concerns, including the efficient siting of resources.[12] Consumer advocates often view participant funding as a way to protect retail ratepayers from the cost of network upgrades.

However, with the change in resource mix, and the lack of significant upgrades to the transmission system, those concerns are not as prevalent as they once were. The efficient siting of renewable resources not only includes access to transmission, but also siting in areas that would provide optimal access to solar and wind injections.

[12] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, P 695 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

Going forward, FERC should do away with the participant funding and crediting mechanism entirely, instead requiring transmission providers to establish a fee, separate from any interconnection deposit, based on project size, to be charged for submitting an interconnection request.[13] For projects that require network upgrades, the fee would be applied towards the cost of the network upgrades. The remaining cost of the network upgrade would be allocated to the load zone served by the project.[14]

d. Reform the Transmission Planning Process

While reforming the interconnection process is necessary, the queue backlogs generators currently face are just symptoms of a flawed transmission planning process. On April 21, 2022, FERC issued a Notice of Proposed Rulemaking that would require RTOs and transmission utilities in non-RTO regions to engage in long-term, forward-looking planning that incorporates factors, such as federal, state, and local laws and regulations that affect the future resource mix and demand; trends in technology and fuel costs; resource retirements; generator interconnection requests and withdrawals; and extreme weather events.[15] The demand for clean energy will continue to grow. States will continue to set clean energy goals. Large, sophisticated customers will continue to demand clean energy.[16] Better transmission planning that encourages new transmission to serve growing demand from a diverse set of resources will help address many of issues causing the interconnection queue delays.

e. RTO/Utilities Can Head Off Affected Systems Problems

Furthermore, the RTOs and utilities should proactively engage affected parties to find proactive solutions when affected system issues arise. Project developers occasionally run into roadblocks when, upon analysis, their project is projected to have an impact on a neighboring transmission system. RTOs/utilities, however, can come up with solutions to these kinds of problems without waiting for FERC or another utility to act. When RTOs/utilities work together to plan for seams issues triggered by a large-scale project ultimately more clean energy projects can be interconnected to the grid based upon joint

[13] *See* Comments of the Solar Energy Industries Association, Docket No. RM21-17 (Oct. 12, 2021).

[14] Should a fee structure not be implemented, FERC should adopt a methodology that encourages developer certainty for any cost allocation of upgrade costs, such as cost cap.

[15] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 179 FERC ¶ 61,028 (2022).

[16] *See* Amazon, Renewable Energy, https://sustainability.aboutamazon.com/ (establishing a goal of 100% renewable energy by 2025); Walmart, Setting Records, Walmart Continues Moving Toward Becoming a Totally Renewable Business, https://corporate.walmart.com/ (establishing a goal of 100% renewable energy by 2035); Apple, Apple powers ahead in new renewable energy solutions with over 110 suppliers, https://www.apple.com/newsroom/2021/03/apple-powers-ahead-in-new-renewable-energy-solutions-with-over-110-suppliers/ (establishing a goal of a carbon neutral supply chain by 2030); *see also* Rich Glick, Matthew Christiansen, FERC and Climate Change, 40 Energy L.J. 1, 8 (2019).

transmission projects.[17] By working collaboratively with developers, grid managers can unlock tremendous value for customers.

VI. Near-Term Distributed Utility Reforms

a. Improve Distribution System Planning and Prioritize Climate Goals

Any discussion of interconnection reform by distribution utilities must begin with the need for better, more transparent, distribution system planning. Even leading states that have put effort into improving the distribution planning process, such as New York, have a long way to go toward making the distribution planning process more in-line with the needs of a modern utility system.

Planners must look at the exercise through the lens of envisioning a decarbonized grid, maintaining reliability and promoting grid resilience. Transparent and proactive distribution system planning would provide project developers insight into utility operations, steer projects to locations on the grid that would help improve resiliency, support future electrification, or defer massive infrastructure upgrades. Thoughtful planning can ensure that infrastructure is built to serve the needs of the state instead of becoming a bottleneck on the pathway to decarbonization.

Ideally, through the distribution planning process the utility would forecast distributed energy resource ("DER") growth, identify saturation points on their systems, and then plan a combination of cost-effective solutions to improve reliability and increase hosting capacity. Solutions such as installing more DER and energy storage to offset or delay grid infrastructure and improve ratepayer benefits should also be considered.

Too often the distribution planning process is a "black box" which provide market participants very little input or insight.[18] Regulators should require utilities to open this box and include the industry and other distribution-system users in early discussions regarding forecasts, scenarios, market trends, and technology and technical assumptions. Too often utilities simply retreat behind closed doors, produce their plans, and drop them on the stakeholder community, as well as regulators with very little explanation or opportunity to meaningfully engage. Although better system planning will not solve every interconnection problem, better planning will help improve the accuracy of estimating interconnection upgrade costs and would be helpful when considering changes to cost sharing.

[17] Michael Goggin, Rob Gramlich, Michael Skelly, Transmission Projects Ready to Go: Plugging in to America's Untapped Renewable Resources, at 4 (April 2021), https://cleanenergygrid.org/wp-content/uploads/2019/04/Transmission-Projects-Ready-to-Go-Final.pdf

[18] *See* https://www.seia.org/sites/default/files/resources/SEIA-GridMod-Series-2_2017-July-FINAL_0.pdf

b. Provide Accurate Estimates of Infrastructure Upgrade Costs Up Front Or Use a Preapplication Report

Ideally, enough system information and accurate hosting capacity maps would be available to allow developers to make informed decisions about whether to pay the required interconnection upgrade costs. If a developer knows upgrade costs will run from $500,000 - $1,500,000 they may choose to avoid a full application process, saving the need for more exhaustive studies and analysis.

However, where that information is not yet available distribution utilities should establish a low-cost, pre-application process for DER project developers that may be used as a screen to understand potential interconnection upgrade costs. Project developers should be able to submit a pre-application proposal to the utility that scopes out the project location, size, configuration, and interconnection point. The proposal should yield a durable estimate of the interconnection upgrade cost needed at that site to safely connect the project. This is a no-regrets approach, employed by at least 12 states, that could save project developers and utilities considerable time and effort later in the interconnection process.[19]

These initial estimates, while they can be transmitted in ranges of likely costs, should also be reasonable. The final costs should not be significantly higher than the initial estimate. Too often, projects receive the final cost estimate near the end of the development process that is orders of magnitude greater than the initial estimate, resulting in the developer withdrawing the project from the queue. Establishing a pre-screening process can prevent the inefficiencies resulting from late-stage withdrawals.

c. Reform Cost Sharing for Infrastructure Upgrades

A major issue in distribution utility upgrades involves the problem of sharing costs among multiple DERs that benefit from an infrastructure upgrade. Under the current practice, the project developer, not the utility, pays for any upgrade needed to connect their project. This practice sometimes results in benefits not just to the interconnection project owner, but also to the customers of the utility. But these benefits also accrue to subsequent interconnection customers as well, often creating a free-ridership issue that is becoming a critical barrier to renewable energy deployment. There are several issues with this model that need to be revisited.

1. First Mover Problem

Under the first mover problem, one project developer makes an initial investment in interconnection network upgrades that ultimately results in benefits to several, subsequent interconnection customers. For example, developer A pays $1 million for an infrastructure upgrade to connect their project, which results in additional capacity for connection on the distribution grid. Then developer B connects their project to the same

[19] *See* Zachary Peterson and Eric Lockhart, Evaluating the Role of Pre-Application Reports in Improving Distributed Generation Interconnection Processes, https://www.nrel.gov/docs/fy19osti/71765.pdf.

location, without incurring these costs, instead benefiting from the upfront investment made by developer A.

Unless a developer agrees to pay the infrastructure upgrade costs, much needed clean energy capacity is unlikely to be installed on the grid in the first place. With upgrade costs increasing on a year-to-year basis, significant amounts of DERs are not being developed because no developer is willing to pay interconnection upgrade costs that are higher than project returns. Given the magnitude of the challenge at hand, regulators need to come up with a better way to unlock areas on the grid that accommodate more distributed resources.[20]

To solve the first mover problem, first state regulators should consider revising who pays the costs for infrastructure upgrades. Additionally, regulators should establish a set amount of interconnection upgrade costs developers should pay and split remaining costs with the broader class of utility ratepayers who are also benefiting from the upgrade. Although establishing the developer contribution would require more technical analysis, this approach would help unlock much more clean energy potential on the grid and is under consideration in some jurisdictions. For example, Massachusetts is considering a model where developer contributions would be set on a $/kW basis that is known in advance of applying for interconnections, with a portion of potentially being socialized among utility ratepayers. This proposal has considerable promise and should be replicated in other states.

2. Unfair Cost Allocation Problem

The second issue involves fairness and we return to our example. Developer B benefits from the grid improvement paid for by developer A. Unless developer A paid in the first instance, any remaining projects wouldn't even be able to interconnect at all, let alone serve the need for their customers. Let's call this the "unfair allocation" problem. There are drawbacks to this approach. The first interconnection firm is still responsible for the entire cost of the upgrade, placing all the risk on the first developer. And some upgrade costs are so large that virtually no project by itself or jointly, can pay for the needed improvement.

To solve the "unfair allocation" problem, a few states have experimented with different approaches. Going back to our example, New York authorized developer A to collect a portion of the paid upgrade costs from developer B on a pro-rata basis. Connecting firms would be required to pay the firm making the initial upgrade, and any subsequently interconnecting firm would reimburse the first two firms. To date, however, this collection method was seldom used. As a result, in a second round of interconnection reforms, New York then authorized utilities to pay for the cost of upgrades in the first instance, and then collect from developers their pro rata share.

[20] Note that this problem will happening more frequently in utility territories as the low-hanging fruit of easy interconnection sites are taken.

Now Massachusetts is considering a similar approach. However, with the Massachusetts model, the utility pays the upgrade costs in the first instance and the utility charges firms on a pro-rata basis their share of the cost upgrade after interconnection, with ratepayers paying for the costs in the interim and being reimbursed as new projects pay their pro-rata fee.

d. Increase project maturity requirements for large DG

Finally, similar to our recommendation for transmission system projects, distribution utilities should establish a "first-ready, first-served" process, requiring projects to demonstrate project readiness earlier in the process. To enter the distribution utility queues after the preapplication stages, projects should be required to show a) site control, b) detailed design specifications, and c) the developing firm should be required to pay up front deposits.

These maturity requirements ensure that serious projects enter the queue and have a better chance toward reaching commercial operation, instead of more speculative projects that would waste the utility's time conducting studies when they have very little chance of reaching fruition.

VII. Long-Term Interconnection Reforms

The recommendations considered above should be considered near-term objectives for reform and will help RTOs and utilities improve their processes and make progress toward achieving state and federal policy goals. These are immediate steps that will help speed up the connection of clean energy resources.

But in the long run, even these common-sense improvements will be insufficient to drive the rapid interconnections that will be needed to completely decarbonize the electric system and meet the demands of growing electric load. After quickly executing on the near-term reforms, regulators should begin considering more systemic changes for both RTOs, vertically integrated utilities, and distribution utilities.

One concept that regulators should consider is providing "flexible" interconnection options to large-scale and small-scale clean energy resources. A flexible interconnection agreement connects the resource without major infrastructure upgrade cost but uses controls to monitor the state of the grid at any given time and adjust the project's output to respond to changing conditions.

While flexible interconnection has become standardized in some European countries, only a variety of small demonstrations have taken place in the US. New York stakeholders are potentially the furthest along, where Avangrid worked with Smarter Grid Solutions to connect large-scale solar to constrained distribution feeders. Their Spencerport solar projects were initially approved for only a combined 2.6 megawatts of firm connection. Using the flexible interconnection framework enabled 15 megawatts to connect.[21] As these projects demonstrate, providing flexible interconnection choices, coupled with smart grid technology investments, can provide interconnections solutions when typical approaches are cost prohibitive. New York stakeholders are now actively considering demonstration options from all the other utilities and are considering revisions to add flexible interconnection to their standardized interconnection requirements.

Today's interconnection procedures are organized around the concept that headroom or hosting capacity is limited based on static, snapshot of worst-case conditions. Regulators must keep in mind, however, that most parts of the grid have approximately 50% utilization annually. To a great degree, grid constraints are rare operating conditions compared to annual availability of most transmission or distribution lines. Instead, more aggressive deployment of smart grid technologies and grid management tools could avoid the need for many infrastructure upgrades.

In brief, in thinking through long-term interconnection reforms, regulators and utilities should be looking at the entire range of options to modernize that grid, not simply infrastructure upgrades, reconductoring lines, or building new substations, and come up with options for interconnecting projects that take customer flexibility and these newer technologies into account.

The same concept applies on the distribution grid. Market choice for firm versus flexible interconnection is equally applicable for in front of the meter large, distributed generation, and even for large behind the meter systems too. Small, distributed generation, less than 25 kilowatts, for residential and small business should aim to be further streamlined by moving to a "connect and notify" approach. This way controllable generation and storage are treated fairly with small customers connecting new controllable loads like electric vehicle charging or heat pumps.

With a more actively managed grid, RTOs and utilities would prioritize smart grid and customer flexibility solutions as the most affordable ways to modernize the electric system. Therefore, providing developers with the choice between firm versus flexible interconnection options on how to connect to "constrained" networks may lead to better outcomes, and potentially significant savings for ratepayers.

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[21] *See* Renewable energy generation boosted by more than 100% in US-first demonstration project (Dec. 8, 2021). https://www.powermag.com/press-releases/renewable-energy-generation-boosted-by-more-than-100-in-us-first-demonstration-project/

Dynamic Curtailment – Flexible Interconnection Technical Lessons Learned

Jeremiah Miller, PE

Dir. Storage
Markets & Policy

SEIA

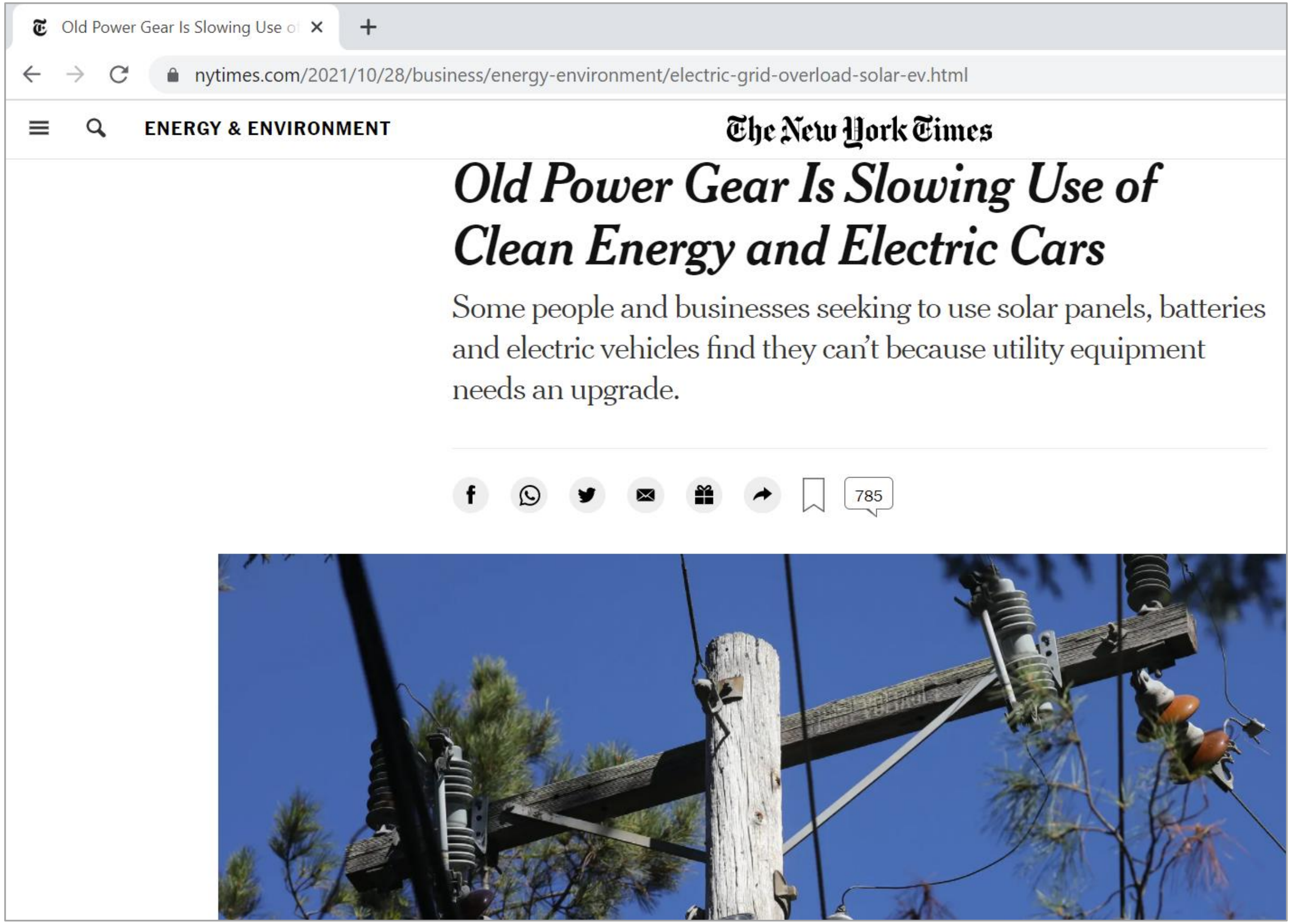
03/2022

SEIA Solar Energy Industries Association®

Powering the Solar+ Decade

When typical interconnection fails…

- **Cost prohibitive upgrades?** Have you experienced trying to interconnect a solar / wind / storage / fast EV charger and the costs are uneconomic and well beyond your prior experience?
- **Downsize?** Have you had to downsize that project to make the interconnection costs work?
- **Walk away from the project?** Cannot pencil out the costs? The utility says there just is not any headroom?
- **Closed feeder?** Utility says that feeder is closed to any more resources?



https://www.nytimes.com/2021/10/28/business/energy-environment/electric-grid-overload-solar-ev.html

What does interconnection innovation look like?

- Our industry rightly so focuses so much attention on how to streamline and improve solar and wind interconnection. Examples:
  - If only we would have online portals!
  - Embrace holistic process and planning solutions: e.g. no more physical signatures/payments!; systematically allow pre-applications!
- These are important. These are very important – essential. They represent lots of short-term solutions. Lots of “Faster and Better” transactional solutions
- But the solar industry needs utility approval to interconnect
- And examples of this process failing are increasing
- Are we missing something?

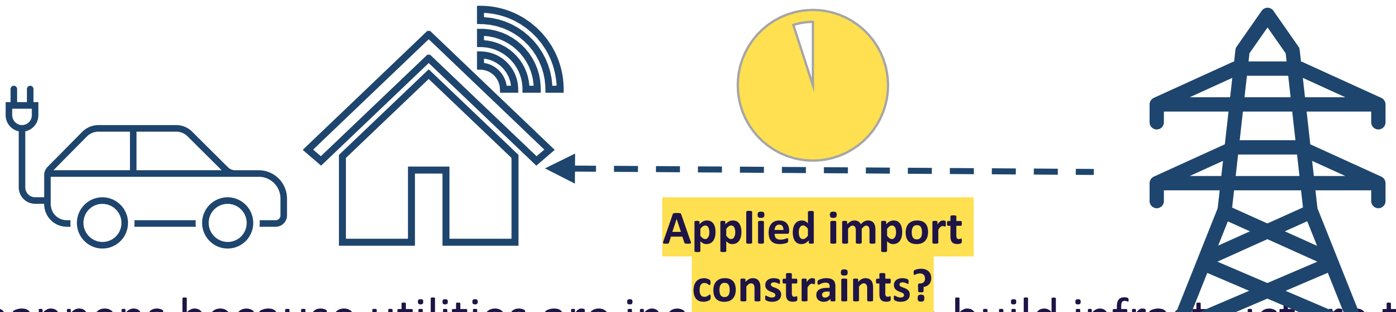
Thinking about interconnection innovation actually helps looking first at load!

- Many new loads today are smart – we can control them from our phones and computers.
- How are we using these smart loads to mitigate expensive grid upgrades?
- Are utilities best incentivized to help us control smart loads so that it saves us money and saves on grid costs?
- Do we need utility approval to connect new load to the grid? Why and why not?

- Turns out most load today is interconnected with a "connect and manage" relationship!
- Strict import constraints are exceptionally rare.

Innovative controllable load interconnection?

- We could have interconnection approval for new load.
- What would this look like?
- We try to incentivize this behavior, for instance through time-of-use (TOU) rates.
- But strict import constraints[1,2] are exceptionally rare.
- This is because import constraints are the equivalent of saying: “No utility, do not upgrade my neighborhood transformer – I will take on the risk of you not being able to serve my load.”



- This almost never happens because utilities are incentivized to build infrastructure to always reliably serve load. They get a guaranteed rate of return and socialize these electricity delivery costs on all customers.
- As noted, new load interconnects via a “connect & manage” relationship

1. https://www.nrel.gov/docs/fy19osti/70278.pdf
2. https://www.chargingfutures.com/media/1493/p1-access-options-at-transmission.pdf

Why is this so important to generation? Because Storage!

- We will need to look at import constraints for new load – new controllable charging from energy storage.
- And energy storage requires[1] interconnection, requires utility approval.
- A failure to think about interconnection for controllable load, yet requiring interconnection for generation and storage, is a failure to align incentives for consumers, generators, and utilities to find the most flexible schemes for addressing grid constraints.

- Finding innovative interconnection solutions for generation, storage, *and load* is at the center of the most affordable path to modernize our grid and decarbonize to meet our climate and social justice goals.

1. There are lots of storage loopholes. E.g. add wheels and call it a vehicle; building thermal storage & HVAC control; consumer electronics; etc. Industry needs to harmonize DER to include load.

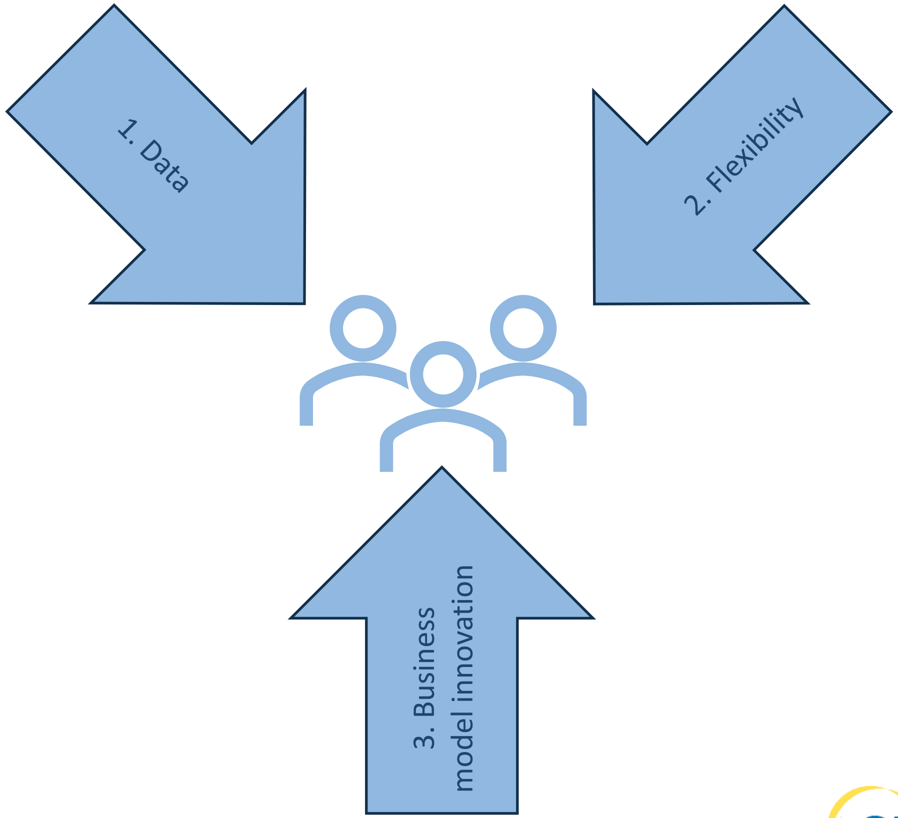
Grid modernization is both an edge and system wide-challenge

Innovations connecting generation, storage and load is inseparable with system-wide integrated resource planning.

- **Interconnection** ultimately is about *customer relationships*, yet… several concerns:
  - **Generation only?** Narrow interconnection thinking about customers seeking to change their grid use through the lens of generation.
  - **Proactive consideration of load?** Lack of consideration of changes in customer grid use for controllable load.
  - **Solutions scalable for storage?** More troubling, especially lack consideration of how energy storage is cost effective for many applications and also needs thoughtful interconnection innovations.

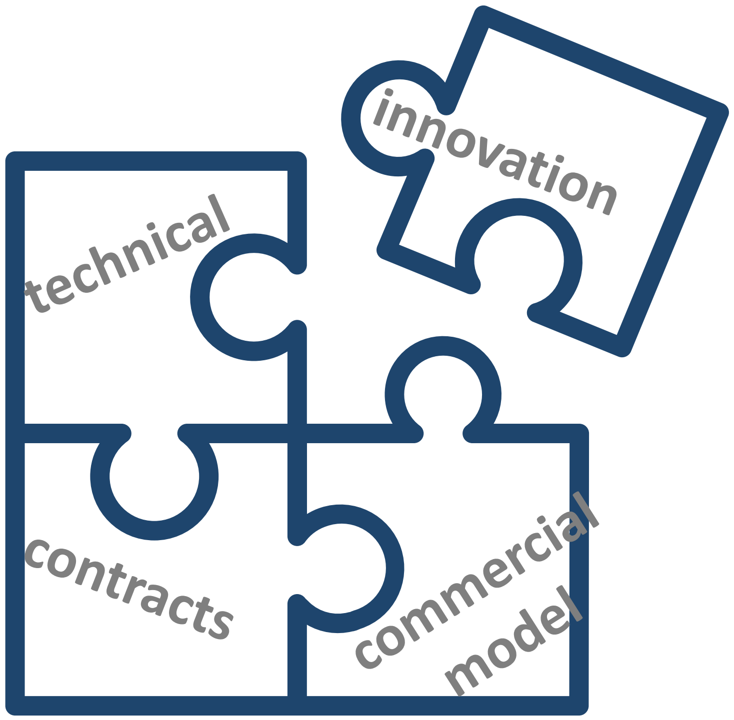
How can we connect better with customers who are seeking to change how they use the grid?

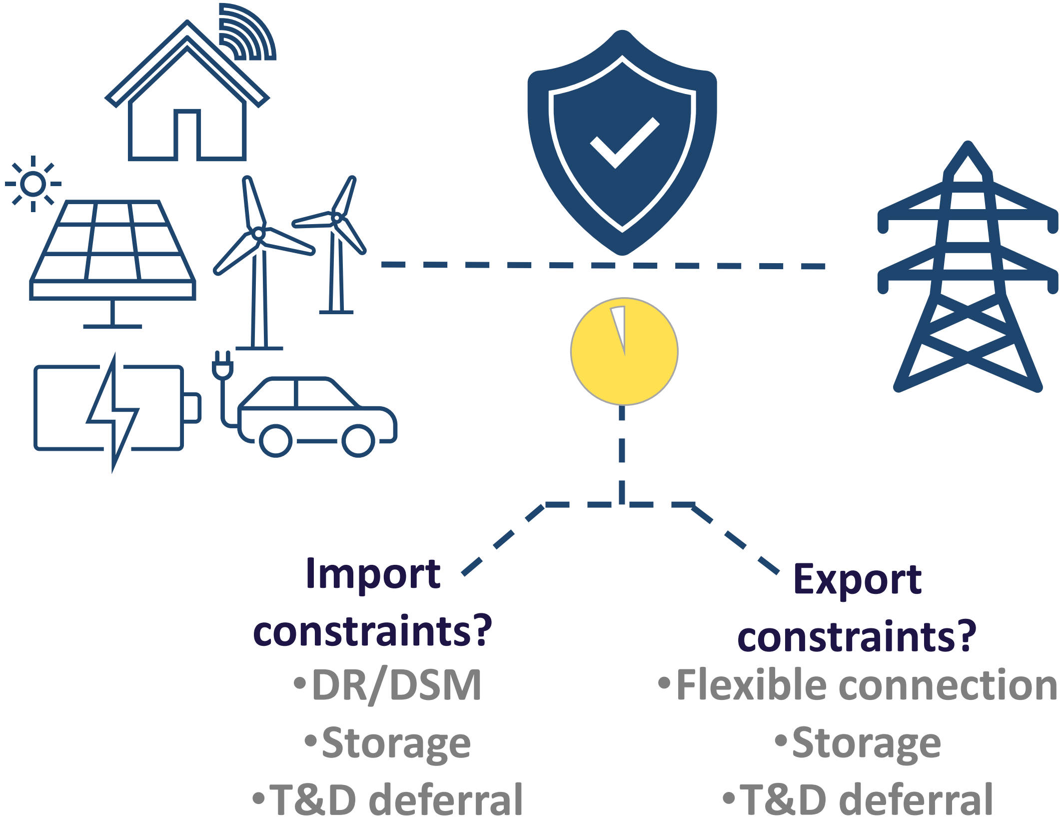
Customers should be at the heart of all grid modernization



The missing piece for holistic interconnection is intrinsic innovation in business models

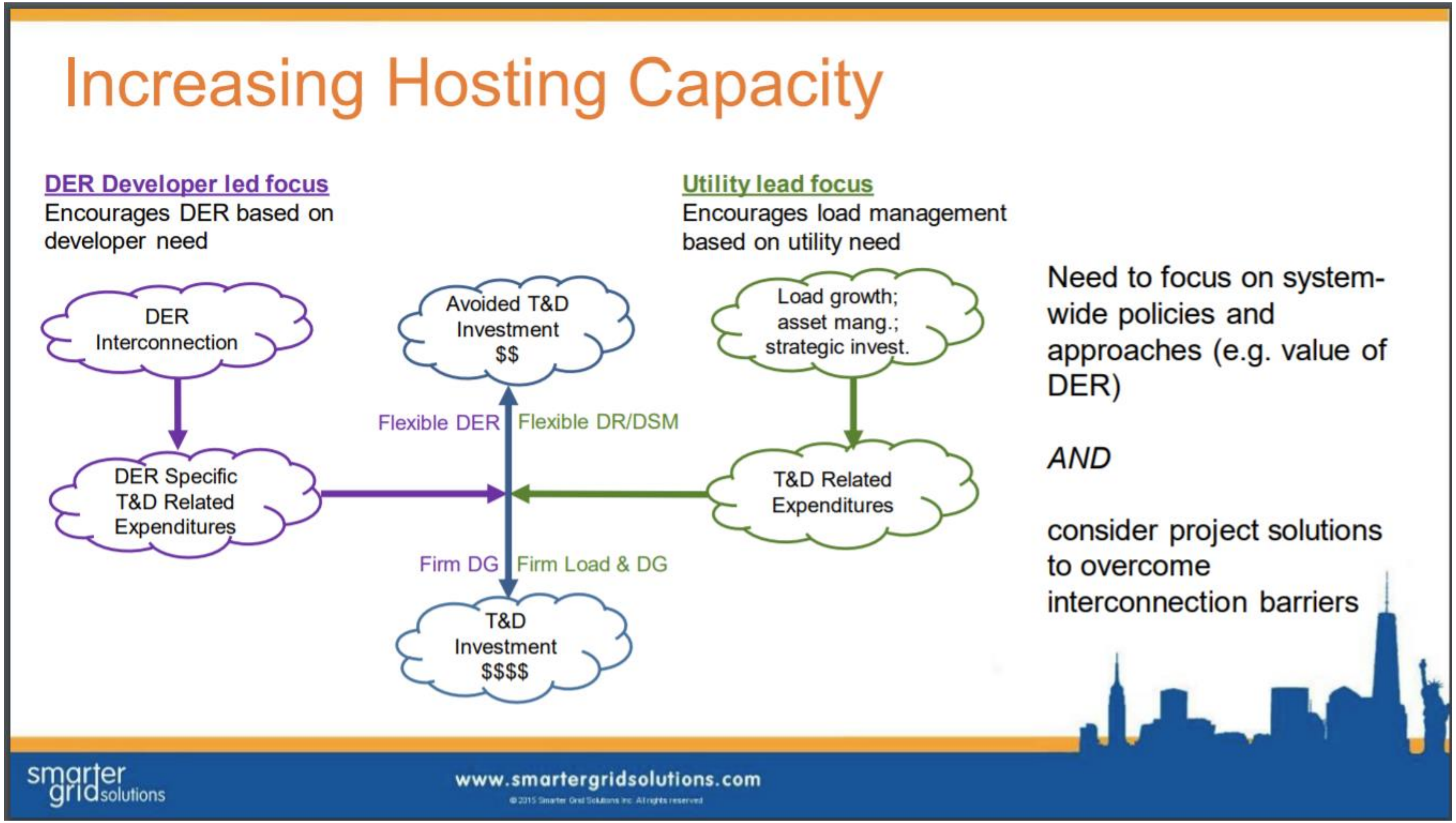
- Interconnection innovation is the missing piece to having much better customer-to-utility relationships





- Limited/No-export power control system standards address the grid edge technical requirements. Flexible interconnection adds the commercial and contractual pieces to support innovation

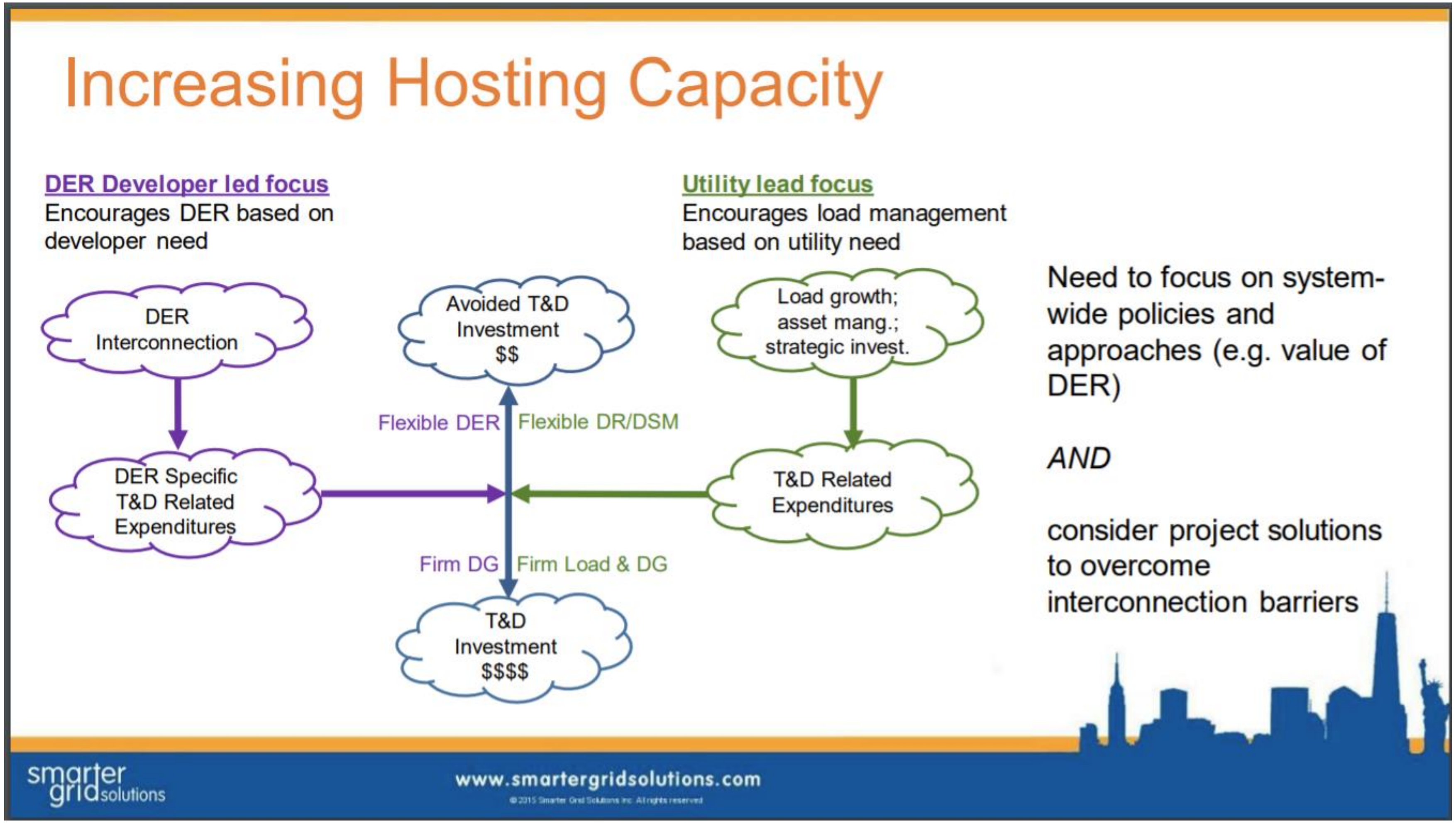
Need system wide services innovation



- **Need customer focused innovation** for new generation, storage, and load relationships but also for system wide services.
- **Grid modernization needed:** With our aging grid, but also with our electrification of heat and mobility to meet our decarbonization goals, we will need traditional reinforcements.
- **Prioritize full stack flexibility:** For system wide solutions, we need customer centered full stack flexibility services procurement to be at heart of finding the most affordable solutions.

https://jointutilitiesofny.org/sites/default/files/REV-EG-Hosting-Capacity-July-2016-FINAL.pdf

Need system wide services innovation *and* innovative interconnection relationships



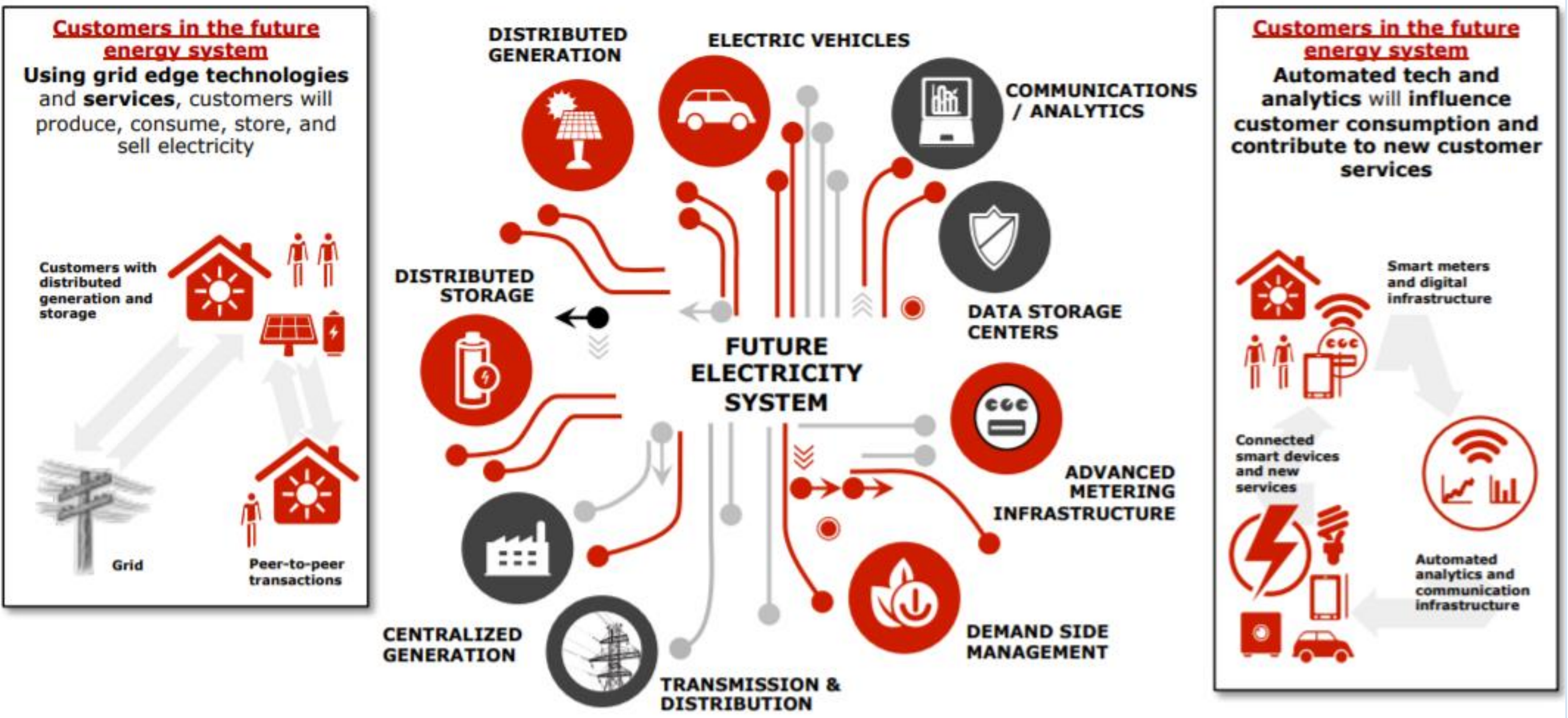
- **Options:** There are a range of flexible interconnection technologies: smart inverters; storage; power system control for limited/no-export; topology switching; DERMS; etc.
- **Relationships:** Yet flexible interconnection is more than a set of technical specifications.
- **Choice:** Flexible interconnection is a customer choice compared to firm interconnection (i.e. Restricted grid use vs 100% grid use)
- **Customer rights** for choosing flexible interconnection are critical, including data rights.

https://jointutilitiesofny.org/sites/default/files/REV-EG-Hosting-Capacity-July-2016-FINAL.pdf

Acting on Customer Centered Solutions

- **System-wide Solutions: Full Stack Flexibility Services – Procure as a First Priority!**
    - To mention a few, flexibility services include non-wires alternatives, smart wires and enhanced grid technologies, independent connection providers, energy efficiency and conservation, demand management, and so forth.
    - Only after finding these are insufficient should the most expensive grid upgrades be approved, and increasingly even these should be competitive. For example, community and campus microgrid solutions, offshore wind connections, new substation procurement, etc.
- **Customer Relationship Services – Prosumer Centered?**
    - Controllable load: how are you engaging customers to more provide load services to support grid modernization?
    - Generation: for connecting new generation, are you providing the full range of options to customers for the most affordable solutions grid edge investments?
    - Storage: are you considering how storage is both dispatchable generation and controllable load, and its further deployment will significantly alter how customers use the grid?
- **Protecting Vulnerable Populations to Energy Transformation Risks?**
    - Not all customers are able to fully participate in these new services, so how are you protecting vulnerable populations?
- **Analyzing competing system-wide and customer driven solutions requires DATA ACCESS!**
    - Customer rights to data during interconnection are critical to finding the most affordable grid edge solutions to modernize the grid

Data and Interconnection



World Economic Forum: https://www3.weforum.org/docs/WEF_Future_of_Electricity_2017.pdf

Flexible interconnection is the framework to enable dynamic hosting capacity, operationalizing dynamic curtailment

WEF 2017: "In terms of connections procedures, government-funded trials in the UK have demonstrated how to *reduce connection costs by up to 90% and connection time by about seven months*. This allows for faster and cheaper connections, supporting flexible management of energy flows and utilizing data such as real-time network hosting capacity. Success at this level requires a digitized grid with active network management."

(Emphasis added)

Better Flexible Interconnection Data Aligns to System-wide Digitalized Energy Systems

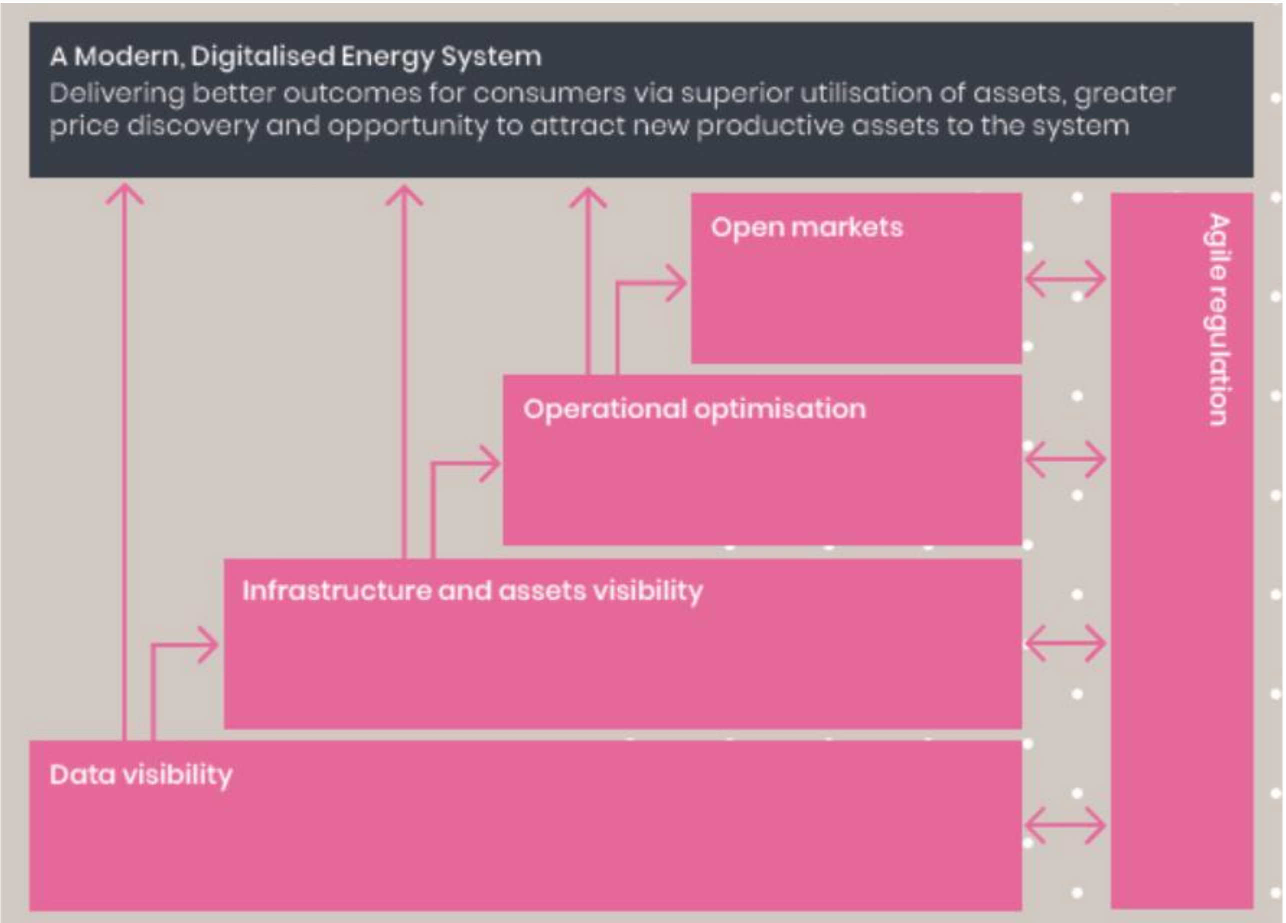
The most affordable and effective decarbonization investments need a combination of customer led and utility supported solutions.

Yet analysis is constrained by lack of data access.

And there is growing concern that digital monopolies and a range of solutions biases constrain finding the most affordable solutions.

Is industry able to analyze the most cost-effective grid modernization investments? Especially when customer solutions can defer or mitigate some?

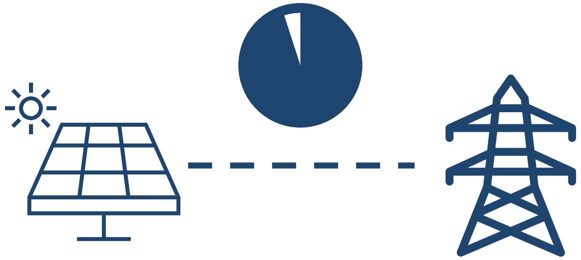
Are solar & DER customers able to analyze their most cost-effective interconnection options?



https://es.catapult.org.uk/report/energy-data-taskforce-report/

Flexible vs Firm Interconnection & Data Access

Flexible Interconnection

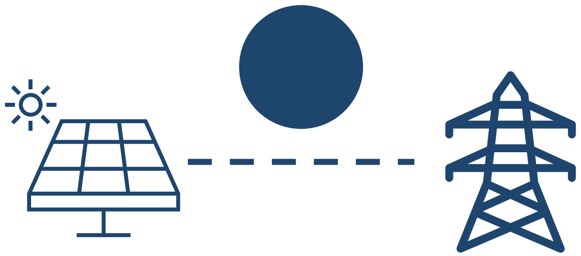


- Managed grid access during grid constraints, typically acceptable with 95-99% grid access
- Risk of curtailment provides market-based decision making for firm vs flexible interconnection; enables enhanced, dynamic hosting capacity assessments; choice is essential

DER developers & customers have the right to request grid data and the models used to analyze curtailment risks

- Can provide faster and cheaper interconnection; market-based customer relationship
- Practical pathway for future customers who may want to deploy storage

Firm Interconnection



- Firm or 100% access to the grid
- Always the best choice when grid utilization is low; lots of excess hosting capacity

Customer access to grid data necessary for long term planning horizons, like community solar or microgrid solutions

- Relies upon "static hosting capacity" that is based on snapshot, worst case conditions that are rare
- Fit and forget customer relationships

Define the Principles for Customer and System-Wide Innovations

The industry therefore needs to define the principles for acting on innovation, for grid edge interconnection of new generation, storage (and load!), *and* system-wide clean energy infrastructure investments. We therefore need:

- **Defined customer rights** that put customers at the center of grid modernization and that support their ability to make reliability and resiliency investments, leveraging their value for all customers.
- **Aligned incentives** so that monopoly operators act in the interests of all consumers. Special attention should focus on mitigation and where possible removing data and customer relationship monopolies.
- **Cost reflective** charges for monopoly services that reflect incremental costs and benefits of how consumers and other parties use the system. This includes minimizing harmful distortions arising from the recovery of fixed charges for using energy networks.
- **A level playing field** so that all technologies and business models can compete equally, without barriers to entry to the market.
- **Efficient allocation of risk** so that those best placed to manage the uncertainty inherent in a rapidly changing system shoulder the risks involved.
- **Harnessing markets and competition** where it can bring benefits to consumers.
- **Support for vulnerable communities** to address energy bill burdens and build resiliency.

Principles adapted from Ofgem, 2017

Data Access and Short-term Relationship Priorities

Customer Centered Interconnection = Customer centered grid modernization
- Proactively provide the full range of interconnection options for generation and storage (*and controllable load!*)
- **Digitize and shift to industry management of submitting and tracking interconnection applications**
- **Embrace holistic process and planning solutions: *e.g. no more physical signatures/payments!; systematically allow pre-applications!***
- **Ensure industry access to grid data for evaluating the most affordable grid modernization options**

Increase Level 1 to 15 or 20 kW - Expedite processing and reducing costs
- Pilot moving to a "connect and manage" relationship for generation, and "connect and value grid services" relationship for storage
- Move to "free the roof" relationships, allowing customers and DER developers to manage their investment risk for sizing generation and storage; support upsizing solar concurrent with EV and electrification of heat deployment incentives

Enforce Interconnection Timelines - Establish performance and service metrics, and guarantees
- Clear and explicit interconnection timelines for expeditiously processing the increasing volume of applicants

Interconnection and Grid Access Data
- **Establish grid data rights for industry due diligence studies of grid constrain management solutions for interconnecting to constrained grids; establish robust principles of access for customers to connect to constrained grids**

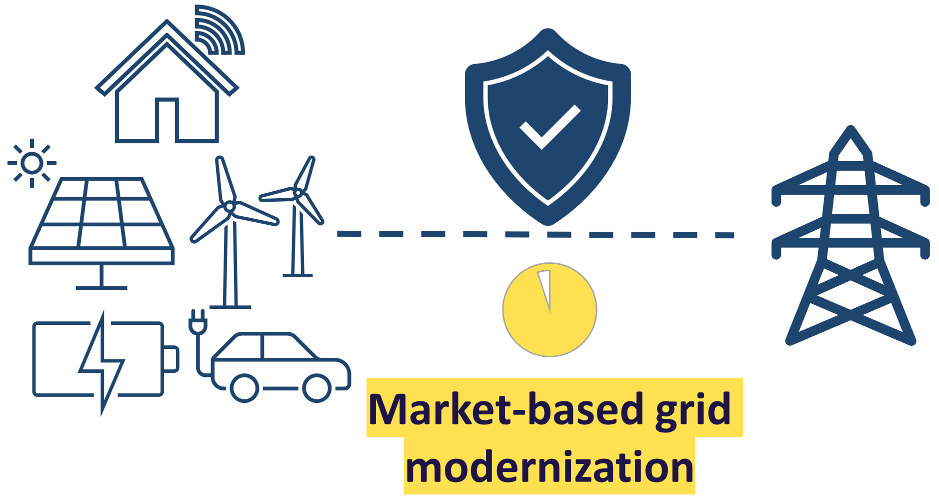
Interconnection Cost Certainty and Predictability
- Ensure actual system upgrade costs fall within a reasonable range (+ or - 25%) of the utilities' initial estimates
- **Provide firm vs flexible upgrade costs; ensure costumers always have both choices available and data rights to investigate**

Move Beyond the Cost-Causer Principle and Reform Cost-Allocation
- States across the country are exploring cost allocation models where utilities can recover upgraded hosting capacity costs through the ratemaking process or a regulatory asset and interconnection customers using the upgraded capacity pay a proportional share of the costs to reduce the amounts needed to be recovered. But is this process fully providing market signals?
- Move for instance to determining reinforcement costs based on a Common Connection Charging Methodology (CCCM) that holistically considers shallow versus deep recovery for new generation, storage, *and load*.

Move Beyond Confrontation to Genuine Mutual Collaboration
- Appoint a Customer Negotiation Commission for short-term conflict resolution and establish long-term collaborative processes like those recently noted in Hawaii (https://puc.hawaii.gov/energy/pbr/)

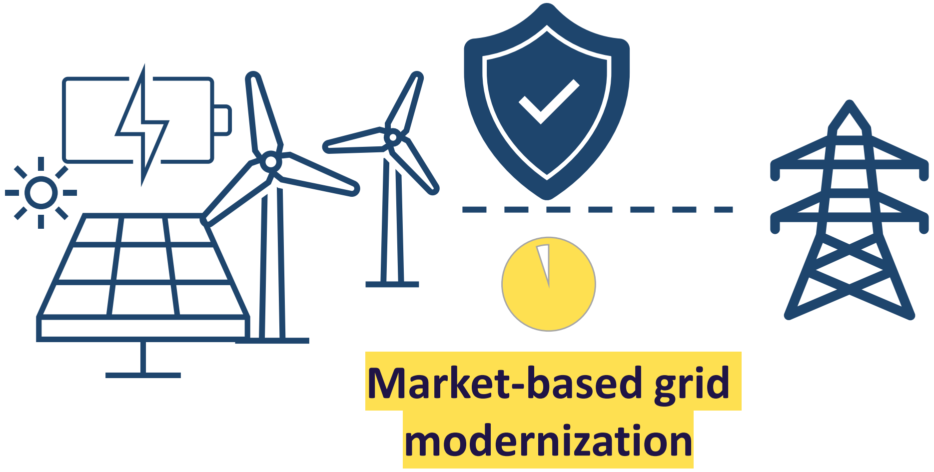
Moving to "Connect and Manage" relationship for generation, storage and load

- We already largely use a connect and manage relationship for load.
- We need to extend "connect & manage" to generation and storage.
- We will need similar, but different customer relationship end states for interconnecting to Transmission, Distribution utility scale, and small scale BTM
- Treating new load, generation and storage must be done fairly and consistently
- **Small DG & storage lessons learned:**
  - Most residential/small business customers lack sophisticated energy insight to analyze curtailment risk
  - Better to move to "connect and notify" relationship and use improved behavior techniques to manage real-time loading
  - Shared burden & risk: 3% curtailment rule?
  - Fair for EVs, heat pumps, solar and storage?



"Connect and Manage" needs more market-based processes and full stack flexibility solutions

- **Large DG and FTM lessons learned:**
  - Guaranteed "connect and manage" one-month interconnection approval
  - Always provided with firm and flexible interconnection options. Utility (or their service providers) perform curtailment assessment



  - Always ensure data rights access. 3rd party due-diligence requires curtailment risk reproducibility
  - Industry should have three months to accept the offer or reject and initiate material modifications and resubmit the application.

- **Utility Scale and transmission:**
  - Same firm vs flexible interconnection framework applies; move to guaranteed "connect and manage" three-month interconnection approval
  - Can leverage energy service vs network service framework

Curtailment: One Half of Bi-directionality Markets

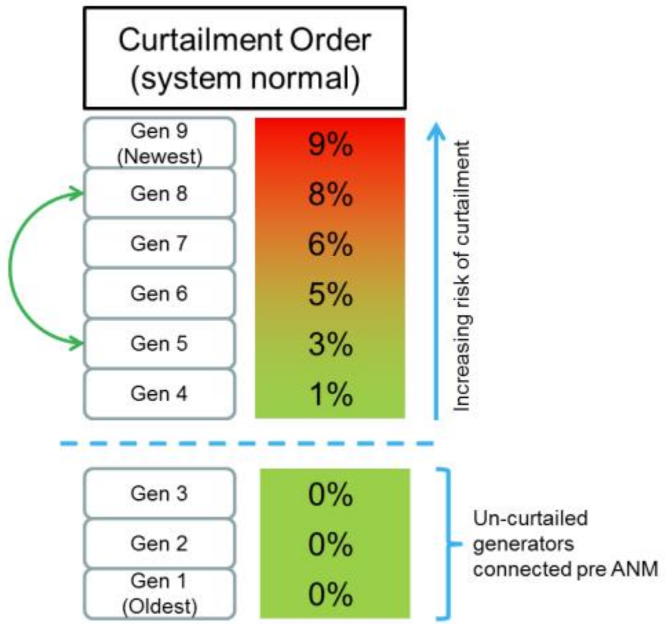


Figure 3: Trading between two generators that are at risk of being curtailed

- Curtailment doors should swing both ways – this is essential for affordable grid modernization
- The US needs a national standard for bi-directionality power control systems. Applicable at the key interfaces:
  - T-to-T interties (HVDC)
  - T-to-flexIPP
  - T-to-D
  - D-to-flexDG (FTM)
  - D-to-flexDER (BTM)
- And we need to look holistically at market processes
  - Tradable curtailment rights?
  - Increased curtailment risk triggering cluster upgrade and market-based cost allocation?

https://www.chargingfutures.com/media/1396/product-1-and-product-2-combined-report_version-10.pdf

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Gen & Storage Flexible Interconnection Policy Priorities

- **Small DG and Storage** – transition asap to connect and notify
- Intermediate policy solutions need to ensure storage, generation and load are treated fairly in interconnection management
- **Larger generation and storage priorities today?**
  - Interconnection is contractual, and contracts today already typically include system contingency curtailment risk
  - Tweak contracts to include flexible interconnection and curtailment risk; *no significant policy change needed*
  - Ensure developers always have firm vs flexible interconnection choice, and curtailment risk is provided
  - Ensure developers always have data access rights to self assess curtailment risk
  - Apply performance-based governance to interconnection studies and queues.
    - Carrots and sticks
    - Set a target date of 6 months to halve interconnection study and approval times
- Look holistically at data access opportunities for interconnection and system-wide optimization

Q&A Reference Material

Access rights are built upon several choices

Figure 1 – Access rights are a combination of different access choices

Firmness of rights This is the extent to which a user's access to the network can be restricted (physical firmness) and their eligibility for compensation (financial firmness) if it is restricted.

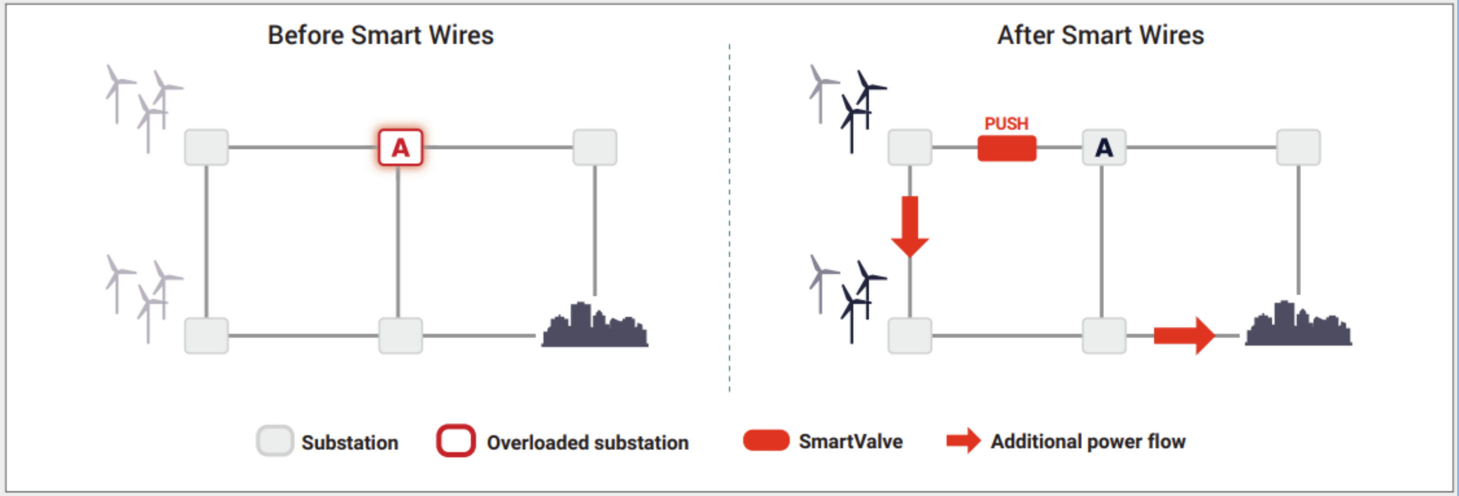
Time-profiled rights This would provide choices other than continuous, year-round access rights (eg 'peak' or 'off-peak' access).

Shared access rights Users across multiple sites in the same broad area obtain access to the whole network, up to a jointly agreed level.

Other arrangements we are considering (1) Short term rights - This would provide a choice for limited duration access (eg one year) where long term access is not immediately available or where the user does not want to make a long-term commitment. (2) New access conditions - This could involve introducing conditions on access, for example 'use-it-or-lose-it' or 'use-it-or-sell-it'.

https://www.ofgem.gov.uk/sites/default/files/docs/2019/09/summer_2019_-_working_paper_-_access_right_note_final_nd.pdf

Flexible Interconnection: Applicable to Transmission Too



CHALLENGE

- A utility seeks to connect 1 GW of wind generation.
- Substation A acts as a bottleneck, preventing this generation from accessing the market, and delaying the connection of numerous wind

SOLUTION

- Smart Wires technology can be installed in less than one year.
- SmartValves redirect power onto parallel lines and allow up to 50% of the wind generation to connect immediately.
- The utility can add more

IMPACT

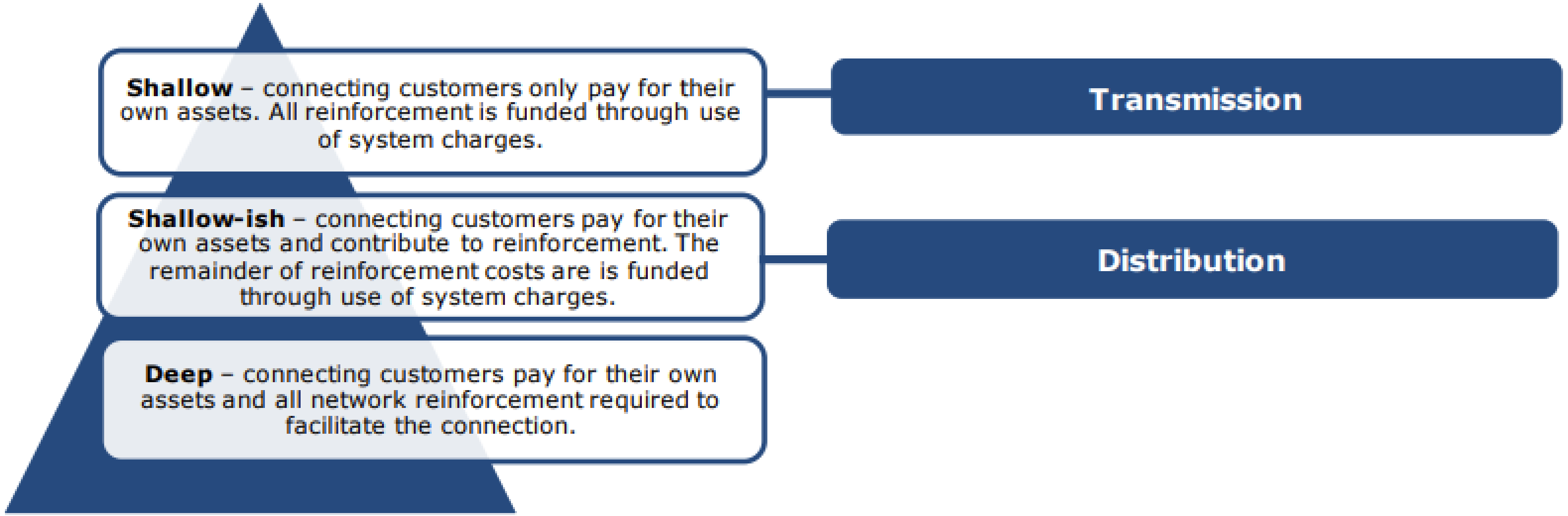
- The project enables the immediate, firm connection of 550 MW of new wind generation capacity.
- Renewable developers save tens of millions of dollars that they otherwise would have lost due to

https://www.smartwires.com/wp-content/uploads/dlm_uploads/2019/05/NewCaseStudy-Renewable.pdf

Look holistically at cost allocation

A customer's connection charge is determined by the connection charging boundary. The connection boundary is the extent to which customers pay for their connection, including their contribution to any reinforcement that is required to facilitate their connection. Customers connecting at distribution currently face a "shallow-ish" boundary.

We are assessing the case for making the boundary more shallow for demand and or generation (including whether it should be the same for both).



We previously highlighted the strong interactions between connection and DUoS charging. Given we are delaying our decisions on DUoS, we have tested the resilience of the different connection charging options against different possible outcomes on DUOS. We think that publishing an early minded-to position on connection charging on this basis has benefits (eg, in terms of planning ahead of RIIO-ED2), rather than waiting any longer.

https://www.chargingfutures.com/media/1512/access-scr-webinar-slides-26-march-2021.pdf

Static vs Dynamic Hosting Capacity

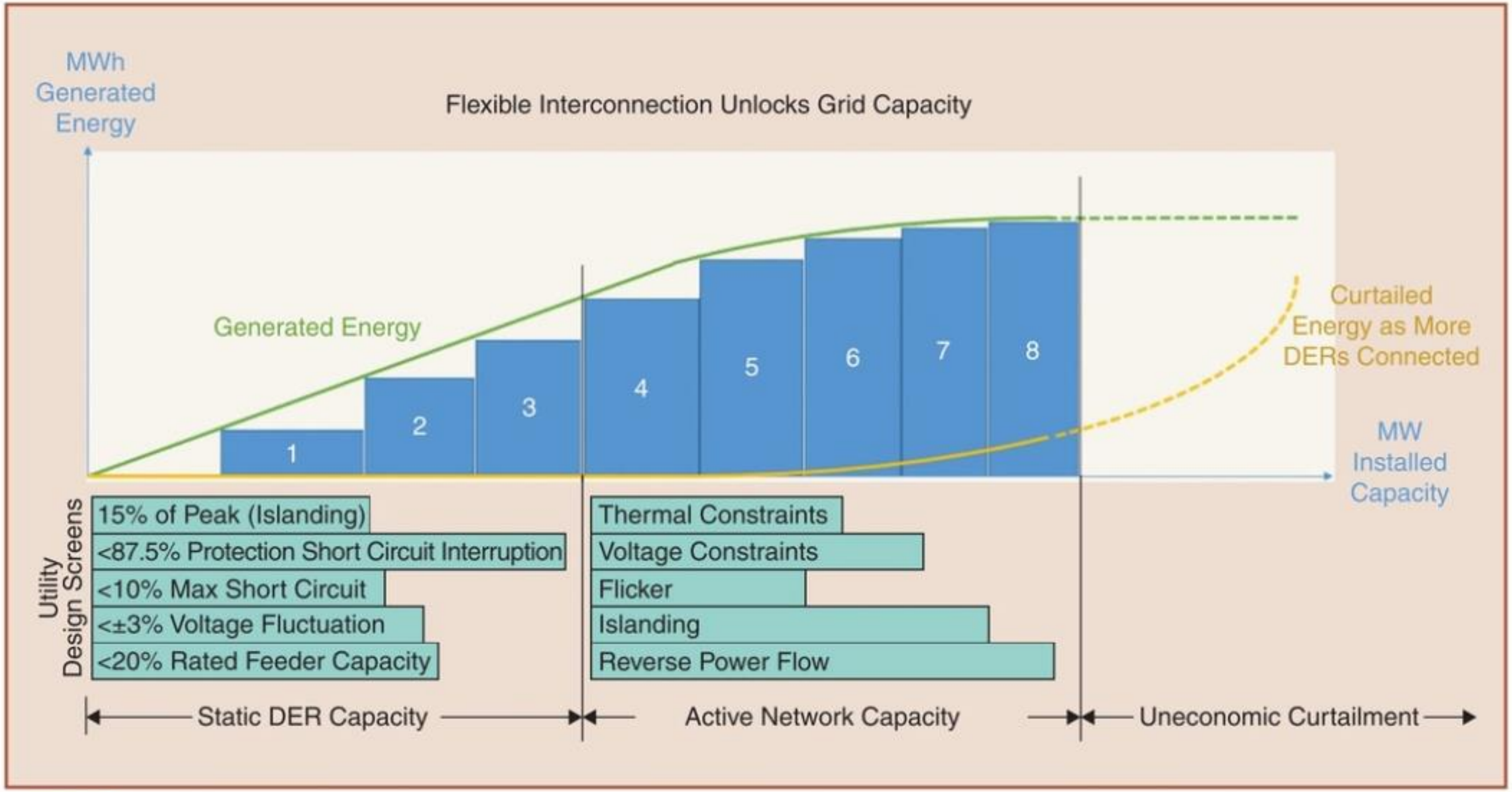


figure 1. Traditional static hosting capacity and increased dynamic hosting capacity delivered by ANM.

Curtailment: System-wide optimization

- Curtailment is very normal and typical in our industry
- Plant optimization
  - Solar is clipped as a normal part of plant design optimization. DC-AC ratio: 1.2+
- A small amount of curtailment on the grid is the same optimization, now for system-wide grid design

- Curtailment long shown to be effective in Europe:
- “Limited curtailment may be more cost effective than upgrading grid infrastructure. Curtailment of distributed generation (or “DG shedding”) has the potential to considerably increase the connection capacity and therefore accelerate the deployment of wind and solar power. **According to a study from the German distribution company, EWE Netz, the dynamic curtailment of 5% of the energy generated from solar PV increases the grid connection capacity by around 225%** without new grid investment (EWE Netz, 2015). While this might sound surprising for project developers, curtailment can lower the overall cost and accelerate the deployment of wind and solar PV.”

Source: IEA, 2016. Re-powering Markets: Market design and regulation during the transition to low-carbon power systems