The Transition to a High-DER Electricity System

CREATING A NATIONAL INITIATIVE ON DER INTEGRATION FOR THE UNITED STATES

A Report of the
Energy Systems Integration Group's
Distributed Energy Resources Task Force

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ESIG
ENERGY SYSTEMS INTEGRATION GROUP

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The Transition to a High-DER Electricity System: Creating a National Initiative on DER Integration for the United States

A Report of the Energy Systems Integration Group's Distributed Energy Resources Task Force

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Contents

List of Abbreviations

DER	Distributed energy resource
DSO	Distribution system operator
FERC	Federal Energy Regulatory Commission
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent system operator
LSE	Load-serving entity
NARUC	National Association of Regulatory Utility Commissioners
NASEO	National Association of State Energy Officials
PV	Photovoltaics
RTO	Regional transmission organization
T-D	Transmission-distribution
TSO	Transmission system operator

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Executive Summary

Distributed energy resources (DERs)—generation, storage, electric vehicles, and responsive load connected to the distribution system—have the potential to bring a range of benefits to the U.S. electricity system and the customers it serves: demand flexibility, lower greenhouse gas and criteria pollutant emissions, customer choice, competition, rapid innovation, cybersecurity, and enhanced reliability and resilience.[1] Enabling DERs to provide these benefits will require ongoing and significant changes in multiple areas—DER interconnection, distribution and transmission planning, data access and communication, distribution system operations, utility regulation, tariffs, electricity markets—that better integrate DERs into electricity systems (referred to as "DER integration").

Several initiatives, from the Federal Energy Regulatory Commission's (FERC) Order 2222 (FR, 2020) to California's Rulemaking on a High Distributed Energy Resources Future (CPUC, 2021), are underway to address DER integration issues. However, these initiatives are limited in jurisdictional and geographical scope and have different areas of focus. They reflect a provincial and piecemeal approach to addressing DER integration issues that will lead to limited national progress toward realizing the benefits that DERs can provide. FERC Order 2222, for example, provides limited guidance on how distribution operators should carry out non-discriminatory overrides of market dispatch instructions; state regulators and utilities will need to develop solutions.

Currently, individual states, such as California and New York, are developing their own distribution-level solutions to DER integration. While these efforts are reflective of the actions of individual, forward-looking states, this approach is inefficient, as each state has to essentially reinvent the wheel. This situation will lead to a proliferation of disparate standards, terminology, and approaches around DER integration across the United States, which in turn will generate confusion and increase costs among manufacturers, developers, and other DER service providers. It will ultimately result in less access to distribution systems for DER providers, higher DER costs, and lower DER benefits to customers.

Need for a National Initiative on DER Integration

A U.S. national initiative around DER integration issues could help to accelerate national progress on

1 The term "DERs" is used here to refer broadly to generation, storage, electric vehicles, and responsive load connected to the distribution system, including resources located on a customer's premises and connected behind the distribution utility's revenue meter (behind-the-meter DERs) and resources connected directly to a utility's distribution system (front-of-the-meter DERs).

DER integration. This initiative could address three fundamental gaps around DER integration in the United States:

- The lack of a **common vocabulary, framework, and vision** for thinking about DER integration across different jurisdictions
- The lack of a **common understanding around shorter-term, least-regrets strategies** for DER integration that are consistent across distribution utilities, including strategies for enhancing distribution and transmission planning, data sharing and communication, distribution operations, and DER interconnection and aggregation review
- The lack of a **structured dialogue on solutions to longer-term issues** around DER integration, such as the design of distribution system operator (DSO) operations, markets, and regulation; federal-state jurisdictional overlap; independent system operator (ISO) market design; and incentive frameworks for regulated utilities[2]

A national initiative around DER integration could build on recent, related cross-state initiatives in the United States, such as the National Association of Regulatory Utility Commissioners (NARUC) and National Association of State Energy Officials (NASEO) Task Force on Comprehensive Electricity Planning,[3] and could draw from the recent experiences of Australia's OpEN Energy Networks Project and the United Kingdom's Open Networks Project. A U.S. national initiative could also build on related Order 2222 efforts, including the Energy Systems Integration Group's (ESIG's) report *DER Integration into Wholesale Markets and Operations* (ESIG, 2022a) (hereafter referred to as the ESIG DER integration report), and related efforts by the Electric Power Research Institute (EPRI, 2022), and Advanced Energy Economy and GridLab (AEE and GridLab, 2022). These efforts describe key challenges that must be solved to facilitate FERC Order 2222 in the short term and expand opportunities for integrating DERs into power systems over the longer term. All highlight the need for, and call for, broader venues that facilitate cross-state knowledge sharing.

Design of a National Initiative

This report proposes a national initiative to develop greater consistency and consensus around DER integration in the United States. The report outlines a possible design, process, and governance for a structured work effort that would address the three gaps described above. The report is intended to be useful for multiple audiences, including national-level organizations that may wish to integrate these elements into their ongoing efforts and stakeholders who may be participants in the national initiative.

This report proposes a national initiative to develop greater consistency and consensus around DER integration in the United States. It is intended to be useful for multiple audiences, including national-level organizations that may wish to integrate these elements into their ongoing efforts and stakeholders who may be participants in the national initiative.

The proposed design of this national initiative, in terms of objectives, scope, and execution, draws on the insights from the ESIG DER integration report and the second report in the ESIG series, *Lessons Learned for the U.S. Context: An Assessment of UK and Australian Open Networks Initiatives* (ESIG, 2022a; 2022b). The initiative would also build on existing efforts, such as the NARUC-NASEO Task Force and work by the Electric Power Research Institute on coordination between transmission system operators and distribution system operators. While many of these efforts are focused on specific topics, the national initiative described here is intended to be more comprehensive and provide common reference points that enable broader consensus among stakeholders. The initiative would be broadly inclusive, enabling participation by different kinds of utilities (investor-owned, municipal, cooperative) and their

2 The term "ISO" is used generically in this report to refer to both state-specific ISO and regional transmission organization (RTO) markets. Where necessary, we distinguish between ISOs and RTOs.

3 See the Task Force on Comprehensive Electricity Planning's Resources for Action at https://www.naruc.org/taskforce/resources-for-action.

associations (the American Public Power Association, Edison Electric Institute, and National Rural Electric Cooperative Association), regulators, NARUC, and NASEO, as well as participation by jurisdictions that are within and outside of RTOs and ISOs.

We envision a staged approach to a national initiative, with an initial focus on technical foundations and developing a common vocabulary, framework, and vision (Track 1), a subsequent focus on least-regrets strategies (Track 2), and a final focus on initiating structured dialogue to address issues that will require more time to resolve (Track 3). The first two tracks map to five workstreams, each addressing a different category of DER integration issues (see Table ES-1). Some of these workstreams, or elements thereof, may be part of ongoing efforts, and as such would not need to be duplicated in this initiative.[4]

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Creating Common Concepts and Vocabulary, Potential Solutions That Can Be Tailored, and More Alignment Across the Industry

The most important value of a U.S. national initiative around DER integration, relative to each jurisdiction developing solutions independently, is the potential to create common concepts and vocabulary, more standardized solutions to nearer-term DER integration challenges, and more alignment across the industry on how to resolve longer-term challenges. Greater national consensus around DER integration would help to provide distribution utilities and their regulators with

TABLE ES-1

Tracks, Workstreams, and Challenges Addressed in a Proposed National Initiative Around DER Integration

Track	Workstream	Challenges
Track 1: Technical foundations	**Workstream A:** Common vocabulary, framework, and vision	Regulators, utilities, and other stakeholders lack a common foundation for thinking about the potential models and functions for future distribution system operations.
Track 2: Least-regrets strategies	**Workstream B:** Coordinated planning	Distribution and transmission planning are often not well coordinated, in terms of inputs (e.g., load and DER forecasts), engineering studies, and investments; distribution planning is often not well integrated across different utility departments; infrastructure planning (e.g., electric vehicle charging networks) is often not coordinated with utility planning.
	Workstream C: Data access and communication	The electricity industry lacks more standardized rules and procedures for sharing and communicating distribution-level data, for instance, on distribution interconnection queues, planning assumptions, and distribution operations.
	Workstream D: Distribution operations	Distribution utilities will need to upgrade their operations to enable new functionality in the nearer term, including non-discriminatory overrides to ISO dispatch of DER aggregations under Order 2222 and dynamic export limits for interconnecting DERs.
	Workstream E: Interconnection and aggregation review	Distribution utilities will need to develop and enhance DER interconnection and aggregation review processes, including technical standards (IEEE 1547-2018 adoption), and transparent procedures for reviewing DER aggregations under Order 2222.
Track 3: Dialogue on longer-term issues		The industry lacks a structured dialogue on DER integration issues that will require several years to address, such as DSO functions and regulation, clarifying federal-state jurisdiction, ISO market design, and utility regulation.

4 This could include follow-on efforts emanating from the NARUC-NASEO Task Force on Comprehensive Electricity Planning.

more visibility on possible paths forward for DER integration, grid technology manufacturers with more clarity on where to focus innovation, DER developers with more consistency in rules across states, and ISOs with a more discrete set of models for nearer-term and future distribution system planning and operations that they would need to accommodate.

This national initiative would not seek to produce one-size-fits-all solutions to DER integration issues across the United States. The U.S. electricity sector is too diverse and complex, in terms of both industry structure and its federalist regulatory system, for blanket solutions to be effective. Instead, the national initiative would seek to develop a limited number of potential solutions that different jurisdictions and utilities can choose from and tailor to their own conditions. For instance, in some jurisdictions, distribution system operations might be more passive, with the distribution utility having a minimal role in DER operations, whereas in other jurisdictions the distribution system operator may actively dispatch, control, and run markets for DERs. The concepts and strategies developed in a national initiative would need to be broad enough to accommodate different approaches, while at the same time recognizing that different approaches share a common technical foundation in physics, engineering, and economics.

Stakeholder engagement will be a critical and challenging component of a U.S. national initiative around DER integration. The Australian and United Kingdom open networks projects illustrated the importance of stakeholder buy-in for generating meaningful results. The U.S. electricity system is much larger, and its stakeholders are more numerous and diverse. Obtaining stakeholder buy-in will require transparency, broad representation, and opportunities for meaningful input. At the same time, however, the organizers of a national DER integration initiative will need to ensure that it is focused enough to produce actionable results. This report proposes a potential governance structure and stakeholder engagement model that would balance these two imperatives.

A national dialogue could create common technical foundations on nearer-term strategies, a longer-term vision, and transition strategies, thus accelerating progress toward finding solutions to DER integration challenges and ultimately toward realizing the benefits of DERs.

The Time Is Right

Designing and implementing an impactful national initiative around DER integration will be challenging. It will require careful attention to both design and process as well as skilled organizers that can effectively balance trade-offs and bridge gaps among stakeholders. To be successful, the initiative would need to provide regulators, utilities, and other stakeholders with common concepts, frameworks, and strategies they can use, while still providing flexibility to tailor them to local needs. Despite the challenges of developing consensus and standardization across such a complex and diverse industry, the potential benefits are significant.

The timing is right for a national initiative. Many jurisdictions are currently struggling with FERC Order 2222 implementation and are beginning to consider how the distribution system should evolve with higher levels of DERs—and they are doing so without the benefit of common technical foundations on nearer-term strategies, a longer-term vision, and transition strategies. A national dialogue could create these common reference points, accelerating progress toward finding solutions to DER integration challenges, and ultimately toward realizing the benefits of DERs.

Introduction

DERs have the potential to provide significant benefits to the U.S. electricity system and its customers, including demand flexibility, lower emissions of greenhouse gases and criteria pollutants, consumer choice, competition, rapid innovation, cybersecurity, and enhanced reliability and resilience. Realizing these benefits, however, will require addressing regulatory and technical challenges to the integration of DERs into a range of electricity system planning, access, market, and regulatory processes (referred to in this report as "DER integration"). Although state and federal initiatives are beginning to tackle these challenges, they are doing so in a piecemeal fashion—for example, through individual states and individual regional transmission organizations and independent system operators (RTOs/ISOs) rather than through a coordinated effort—that will lead to slow and scattered progress.

DERs have the potential to provide significant benefits to the U.S. electricity system and its customers, including demand flexibility, lower emissions of greenhouse gases and criteria pollutants, consumer choice, competition, rapid innovation, cybersecurity, and enhanced reliability and resilience.

The United States has an exceptionally diverse electricity sector. Its federalist regulatory structure divides regulatory decisionmaking among states, local governments, and the federal government, with significant differences in policy objectives among them. For historical reasons, municipal utilities and rural cooperatives account for roughly one-quarter of U.S. electricity sales. Some states chose to allow retail competition, whereas in others vertically integrated utilities continue to have a monopoly on retail services. Utilities and other load-serving entities (LSEs) in some states participate in RTOs or state-specific ISO markets, whereas in other states LSEs participate in energy imbalance markets, take balancing services from generation and transmission providers, or operate as individual utilities.

This diversity is, in many ways, a strength of the U.S. electricity industry. It facilitates experimentation and local solutions to local problems. However, it also means that solutions to emerging problems are often fragmented and incremental. If each jurisdiction takes a different approach to DER integration, the result will be a proliferation of terminology, concepts, and approaches that will ultimately increase DERs' costs and reduce their benefits. The current trend is toward this more fragmented approach, as evidenced by California and New York, which are developing their own distribution-level solutions to DER integration.

One solution to address fragmentation has historically been national initiatives, often led by industry associations like the National Association of Regulatory Utility Commissioners (NARUC). For DER integration, a U.S. national initiative could address three principal challenges:

- The lack of a **common vocabulary, framework, and vision** for thinking about DER integration across different jurisdictions
- The lack of a **common understanding around shorter-term, least-regrets strategies** for DER integration that are consistent across distribution utilities
- The lack of a **structured dialogue on solutions to longer-term issues** around DER integration

This report develops a work plan and process for a potential national DER integration initiative that would address these three challenges. This initiative would build on similar cross-state efforts in the United States, such as the recent NARUC and National Association of State Energy Officials (NASEO) Task Force on Comprehensive Electricity Planning. It could draw from the experience of Australia's OpEN Energy Networks Project and the United Kingdom's Open Networks Project.

If each jurisdiction takes a different approach to DER integration, the result will be a proliferation of terminology, concepts, and approaches that will ultimately increase DERs' costs and reduce their benefits.

This report is organized into three main sections: a high-level overview of the proposed initiative; a description of the technical components of a proposed workplan, organized around three tracks; and a description of key process elements. A final section offers concluding thoughts.

Overview of a National Initiative

This section outlines the central elements of a national initiative: its goals and expected benefits, structure and design, and governance and engagement.

Goals and Expected Benefits

A national initiative on DER integration should have clear objectives and expected benefits. A U.S. national initiative's goals could include:

- **Consistency in terminology, concepts, and vision.** Greater consistency and coherence across the United States with regard to terminology, concepts, and future vision for different elements of DER integration: distribution planning, DER interconnection, data access and communication, distribution system operations, utility regulation and tariffs, and markets.
- **Nearer-term, least-regrets strategies.** More visibility and consensus on nearer-term, least-regrets strategies for expanding functionality and operational capabilities on the distribution system, both to support the Federal Energy Regulatory Commission (FERC) Order 2222 implementation and, more broadly, to cost-effectively support DER deployment.
- **Dialogue on longer-term issues.** Advancing structured dialogue on priority longer-term issues around DER integration, such as distribution system operator (DSO) functions and regulation, overlapping federal-state jurisdiction, ISO market design, and

utility regulation, which would enable alignment across the industry on key issues and potential solutions.

Achieving these goals would produce a range of benefits for different actors, as well as broader societal benefits. Electricity consumers would have more choice. Distribution utilities and state and federal regulators would have greater visibility on potential paths forward for DER integration. Grid technology manufacturers would have a clearer sense of where to focus innovation and commercialization of new technologies. DER developers would have access to more standard rules for DERs across states and utilities. RTOs would be able to work with a more discrete set of approaches to distribution planning and operations across states, helping them to ensure that different approaches are interoperable. Broader societal benefits might include lower emissions and increased resilience of the power system.

Achieving these goals would produce a range of benefits for different actors—electricity consumers, distribution utilities, state and federal regulators, grid technology manufacturers, DER developers, RTOs—as well as broader societal benefits.

Overall Structure and Design

The proposed structure and design for a national DER integration initiative offered here builds on several lessons from the Australian and United Kingdom open networks projects:

- The scope of a U.S. initiative should be manageable and deliverable in well-defined phases.
- Each phase should build on other, ongoing efforts outside of the initiative and on work completed in previous phases of the initiative.
- The work plan should be relevant and deliver near-term results, while at the same time maintaining a focus on the future.
- Stakeholder engagement is essential for creating the broader buy-in needed for consensus and actionable results.

With these lessons in mind, the proposed design of a U.S. initiative is divided into three tracks.

Track 1: Technical Foundations

Track 1 will identify a set of general models for distribution system operation and markets that can be applied across jurisdictions, with a focus on defining grid functions and mapping functions to different actors in each model. These models will provide a reference point for the other two tracks to help ground discussions.

Track 2: Least-Regrets Strategies

Track 2 will identify near-term, least-regrets strategies for improving distribution system operations that are common across jurisdictions, or, at the very least, common for a specific type of jurisdiction. These strategies will include, but not be limited to, implementation issues of FERC Order 2222. Track 2 would be subdivided into four discrete workstreams focused on separate topics.

Track 3: Longer-Term Issues

Track 3 will begin a structured dialogue around DER integration issues that will take more time to resolve, such as non-discriminatory access to the distribution system, overlapping federal-state jurisdiction over distribution markets, and changes in utility regulation needed to provide a better incentive framework to support cost-effective and fair adoption and use of DERs. The structured dialogue would draw on the models developed in Track 1 and the near-term strategies developed in Track 2.

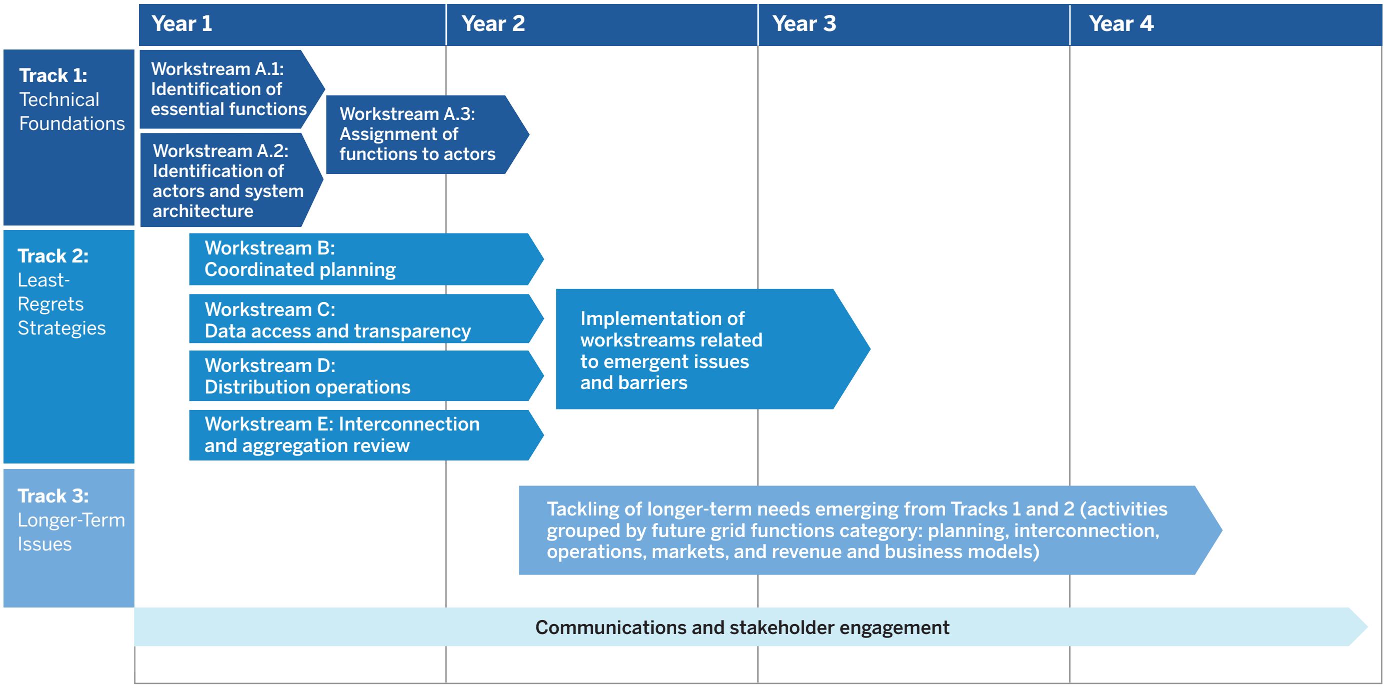
These three tracks would be completed using a phased approach over three to four years, with each phase building on the previous ones. See Figure 1.

Governance and Engagement

A U.S. national initiative should be designed to be relevant to all states regardless of industry structure, market design, or state policy goals. Given the U.S. electricity sector's diversity, ensuring broad relevance

FIGURE 1

Illustrative Timeline for Implementing the Three Tracks



Source: Energy Systems Integration Group.

while producing meaningful results will be a challenge. Overcoming this challenge will require careful design of the initiative's governance structure and its engagement with stakeholders. The approach proposed here attempts to balance broad representation and participation with a centralized process and a core team that includes a steering committee and implementation team. This approach emphasizes transparency, early inclusion, proactive engagement, and multiple structured avenues for stakeholder participation. The initiative will need to include a variety of stakeholder types to be effective—regulators and other public interest groups, distribution utilities, state and local planning agencies, RTOs/ISOs, DER developers and aggregators, researchers and experts, and other relevant parties. Each of the initiative's tracks would include participation by the most suitable representatives from each of these organization types.

Technical Components and Overview of the Tracks

Technical Foundations: Models of Distribution System and Market Operations (Track 1)

Objective

Track 1 will develop a framework and terminology that provide the technical foundations for the least-regrets strategies in Track 2 and the structured dialogue in Track 3. This framework will provide a common reference point for possible nearer- and longer-term approaches to DER integration in terms of the roles and responsibilities of customers, DER aggregators, LSEs, distribution utilities, and ISOs. At the core of the framework are distribution system operations and coordination between operations and markets on the distribution and transmission systems. As an output, Track 1 will develop a few potential models of a DSO that will enable integration of high levels of DERs into the power system. Track 1 is envisioned to have a single workstream, Workstream A.

This framework will provide a common reference point for possible nearer- and longer-term approaches to DER integration in terms of the roles and responsibilities of customers, DER aggregators, LSEs, distribution utilities, and ISOs.

Applicability to ISO and Non-ISO Regions

While the ESIG DER integration report was focused on DER integration into ISO-operated markets (ESIG, 2022a), this national initiative is envisioned to be applicable broadly across the United States to both ISO and non-ISO regions. Many of the fundamentals are the same in both of these contexts. All have an interconnected transmission (bulk power) system, an electricity distribution system, and various users of the combined system (i.e., loads and resources) connected to it. While the geographical context for this report is the United States, this basic structure is consistent globally. In this context, a transmission system operator (TSO) or balancing area authority is responsible for maintaining real-time supply-demand balance and supporting system frequency. Wherever there is a bulk system, it is partitioned into one or more TSOs or balancing area authorities. A distribution utility or DSO is responsible for maintaining reliable, safe operation of the distribution system, including the connections to customers and the interface with the bulk power system.

The ISO is a particular application of a balancing area authority that is subject to FERC jurisdiction and meets the criteria established in FERC Orders 888 and 2000.[5] While some of the discussion in this section is specific to ISOs in order to include a level of specificity in describing the kinds of discussions that Track 1 will involve, the framework developed in Track 1 would also be broadly relevant to non-ISO regions. In ISO-operated markets, including energy imbalance markets, the ISO operates real-time markets that coordinate and

5 Federal Energy Regulatory Commission, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* (Order 888), 1996, https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform/order-no-888; Federal Energy Regulatory Commission, Regional Transmission Organizations (Order 2000), 1999, https://www.ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf.

optimize the dispatch of generation and storage across a large geographical area, providing price signals to LSEs that help to optimize LSE programs, tariffs, and ISO market participation. In regions where transmission providers do not participate in ISO-operated markets, coordination typically occurs on hour-ahead or longer time scales; LSEs rely on measures of avoided costs (bilateral trading prices, shadow prices) rather than market prices to help optimize programs, tariffs, and DER operation.

Although DER integration in and outside of organized markets will have different characteristics, the two contexts share the same fundamentals in terms of interconnection considerations and requirements, distribution engineering and operations, and basic economic and regulatory principles. Thus, in a national initiative it would still be possible to cast a wide enough net to make the Track 1 framework development relevant to both ISO and non-ISO regions. While the discussion below assumes that an ISO or RTO operates bulk power systems and markets, with relatively small changes this discussion can be adapted to a generation and transmission provider or an individual utility.

This section proposes terms for how to conceptualize different approaches for DER integration, and presents examples of grid functions served by specific actors and potential models for distribution system operations and markets. The discussion here is meant to be illustrative and provide fodder for discussion. We anticipate that a national initiative would develop an agreed-upon set of terms, identify and map grid functions, and develop potential DSO models.

Framing the Discussion on DSOs Models

For purposes of this report, the DSO is the entity responsible for some essential functions (to be determined) regarding the operation of the distribution system and its interfaces with the bulk system (transmission-distribution (T-D) interfaces), planning and investment in the distribution system, and interconnection of new resources and loads. The specific functions that a given DSO is responsible for depend on the DSO model adopted. Track 1 aims to develop a framework and terminology that can help navigate what future DSO models may look like.

Figure 2 illustrates the two end-point models for distribution system and market operations. At one extreme ("Total DSO" in the figure), the DSO is responsible for all distribution system and market operations. The DSO must manage its local distribution area (a single T-D interface) to ensure reliable real-time operation in coordination with the ISO or TSO. It is responsible for customer/DER interconnections and for planning distribution network infrastructure. In many ways the Total DSO is like an adjacent balancing area authority from the perspective of the TSO, except that the Total DSO is embedded within the TSO's system.[6]

At another extreme ("Total TSO" in Figure 2), the TSO extends its network model and operational capabilities into distribution systems and is responsible for all distribution system and market operations. The TSO models and has visibility over the entire transmission and distribution system and is responsible for real-time reliable operation of the transmission-distribution system, interconnection and planning for transmission-distribution system infrastructure, and dispatch and settlement of DERs.[7]

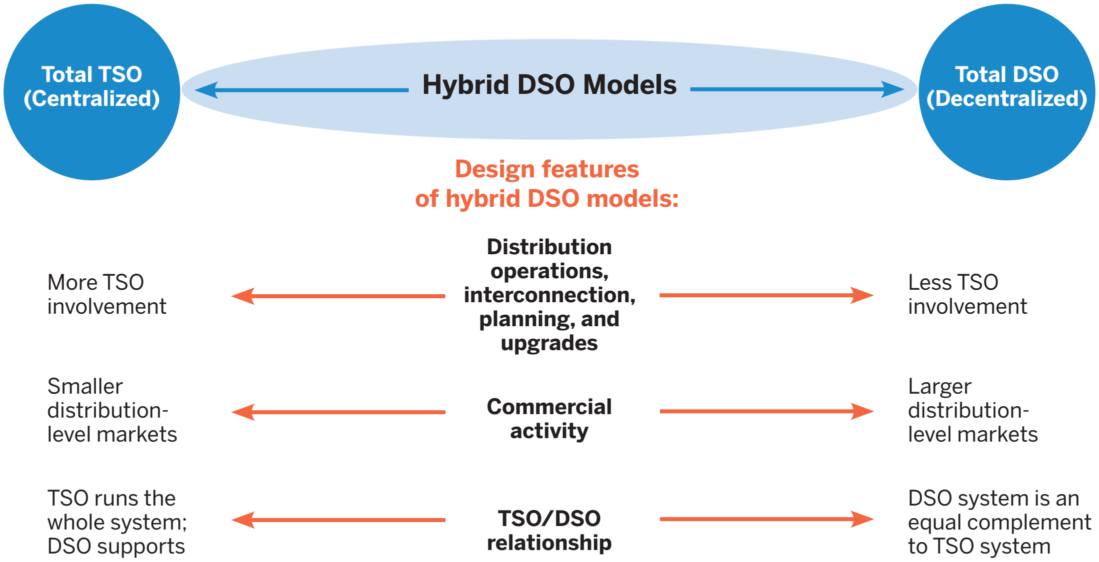
A key difference between the Total DSO and Total TSO models is the number of distinct entities with which the TSO interacts. In the more decentralized Total DSO model, the TSO only interacts with the Total DSO and not with individual DERs or aggregators. In the more centralized Total TSO model, the TSO interacts with all network users that participate in the system, whether they participate directly with the Total TSO or through a DER aggregator. In the Total TSO model, the DSO has minimal responsibilities.

6 For example, the Total DSO is essentially the Metered Sub-System model currently being used by municipal utilities embedded within the California Independent System Operator system.

7 If the Total TSO is an ISO/RTO, it also runs the bulk system markets in which DERs may participate, directly or through a third-party aggregator (not through the DSO).

FIGURE 2

Spectrum of Models for Distribution System Operations and Distribution Market Operations



Source: Energy Systems Integration Group.

Between the extremes of the Total DSO and Total TSO models there are many hybrid permutations that vary according to system and market operator functions. There are a number of factors that might influence where on this spectrum the hybrid DSO model may reside, such as expected DER growth, ownership and operation of DERs, and the current level of sophistication in distribution interconnection, planning, and operations.[8]

A number of design parameters may help navigate through the hybrid space, such as whether an ISO exists, whether there is retail competition, who owns distribution system assets, and the nature of the services provided by DERs. In Track 1, the type of questions shown in Table 1 can be used to frame the development of a few different DSO models that will have applicability to a wide set of jurisdictions in the United States.

8 A distribution system with high expected DER growth, non-utility ownership and operation of DERs, and existing sophistication in distribution interconnection, planning, and operations might be more inclined toward the Total DSO end of the spectrum.

TABLE 1

Framing Questions to Influence the Design of a Hybrid DSO Model

Contextual Questions
Is the TSO an ISO/RTO? I.e., is there a wholesale market for potential participation by network users?
Is there retail competition (that is, a competitive LSE function)? If so, does the DSO offer "bundled" network and LSE services, or is the DSO "wires only" (as in Texas, United Kingdom, Australia)?
Design Questions for Both ISO and Non-ISO TSOs
How many entities does the TSO want to interact with at each T-D interface? Which entities will interact with the TSO directly, for what purpose, how?
Can network users provide distribution grid services? Which services, and how can they be procured, dispatched, measured, and settled—by the TSO or DSO?
Can customers/DERs provide bulk system services? Which services? What TSO-DSO coordination is required?
Can network users transact with each other? How does that work? Does DSO or TSO run a transactive market?
Who is responsible for interconnection to the distribution system? Is flexible interconnection an option?
Is the DSO also the actor who owns, maintains, and operates the physical distribution network assets?
Which actor is responsible for planning distribution network infrastructure investment?
What are the roles of third-party aggregators of customers/DERs?
Design Questions for ISOs
Can network customers participate in the TSO markets? Which market services and products are enabled? What TSO-DSO coordination is required?
What are the roles of third-party aggregators of customers/DERs, and what is their relationship to the ISO and the DSO?

Note: DER = distributed energy resource; DSO = distribution system operator; ISO = independent system operator; LSE = load-serving entity; RTO = regional transmission organization; T-D = transmission-distribution; TSO = transmission system operator.

Source: Energy Systems Integration Group.

Relationship to Structural Participation Models

The ESIG DER integration report described three structural participation models to reflect the different ways that DERs can participate in ISO markets based on which entity is bidding the DER into the ISO market and being settled by the ISO (ESIG, 2022a). These structural participation models are the:

- **DER aggregator model**, in which a DER aggregator submits supply offers in ISO markets and follows dispatch and control instructions from the ISO
- **LSE model,** in which DERs participate either directly or indirectly in ISO markets through LSE demand bids and metered demand
- **Total DSO model**, in which a DSO combines DER supply offers and demand bids into a net demand curve at the transmission-distribution interface, ensuring that any DER quantities that clear ISO markets will not violate distribution-level constraints

These structural participation models are related to, but are distinct from, different approaches to distribution system and market operations. Whereas structural participation models focus on which entity is participating in ISO markets, approaches to distribution system and market operations address the questions of which entity or entities are responsible for ensuring reliability on the distribution system (the DSO) and which entity clears distribution-level markets for local and wholesale services (distribution market operator). What constitutes a "distribution market" is not yet well defined, and providing a working definition of this term would be an important area of focus for a national initiative.

Illustrative Examples for Workstream Deliverables

Within different models for distribution system and market operations, transmission and distribution system

TABLE 2
Illustrative Matrix of Actors and Functions in an ISO Context

	Actors					
Function	**Distribution System Operator (DSO)**	**Independent System Operator (ISO)**	**Distribution Utility**	**Load-Serving Entity (LSE)**	**DER Aggregator**	**Customer**
Distribution planning (including non-wires procurement)						
Registration of market participants						
Interconnection and DER aggregation review						
Resource verification, testing, and certification						
Determination of DERs' resource adequacy capacity						
Markets for resource adequacy capacity						
Outage reporting and management						
Submission of supply offers and demand bids						
Congestion management and security checks						
Day-ahead and real-time energy and ancillary service market clearing						
Security-constrained economic dispatch						
Frequency balancing through automatic generation control						
Energy and ancillary service market settlement (including performance penalties)						
Settlement of distribution and transmission charges						

Note: See the appendix of the ESIG DER integration report for a sample completed table for the DER aggregator model of FERC Order 2222 compliance (ESIG, 2022a).

Source: Energy Systems Integration Group.

operators perform different functions. Enumerating these functions can help to differentiate different DSO models, particularly for hybrid models. Thus, an important first step in Workstream A will be to catalogue actors and their functions, with the goal of mapping functions onto different actors (who does what?). Table 2 provides a simplified illustration of actors and functions. This mapping should be able to accommodate supply-side (DER aggregation) and demand-side (LSE) models of market participation. As noted above, while the example below pertains to a distribution area that is in an ISO, the concepts are broadly applicable.

This mapping of functions to actors in Workstream A would produce several potential models of distribution system and market operations, which would ideally be narrowed into a more limited, generalized set (e.g., four or five) of possible nearer-term and longer-term models.

This mapping of functions to actors in Workstream A would produce several potential models of distribution system and market operations, which would ideally be narrowed into a more limited, generalized set (e.g., four or five) of possible nearer-term and longer-term models. Although both the Australian and United Kingdom open networks projects sought to arrive at a single consensus model that would evolve over time (ESIG, 2022b), in a U.S. context it is unlikely that there will be a single model, even within the same multi-state RTO region, due to differences in regulatory frameworks and differences among utilities. However, reaching consensus on a small set of generalized models would allow stakeholders to ensure that the models can be interoperable for a single ISO/RTO.

In all likelihood, the small set of different models will be distinguished from one another by just a few functions. For instance, one key distinguishing feature will likely be their approaches to distribution planning and interconnection, and distribution-level congestion management. The set of models would form a continuum from the status quo and minimal responsibilities for distribution system operators, on one end, to a total DSO model, on the other. Table 3 illustrates one possible set and progression of models. This table is only meant to be illustrative and is not prescriptive.

In this progression, changes in distribution planning and interconnection that allow congestion on the distribution system drive the development of more sophisticated distribution system and market operations. A national initiative on DER integration would discuss how, and under what conditions, a jurisdiction might transition to different models. This discussion would allow regulators and utilities to locate themselves so that they better understand transition pathways.

Within a set of models for distribution system and market operations, different jurisdictions could choose a different model, and perhaps within each model somewhat different approaches. For instance, for some jurisdictions a model where the distribution utility performs minimal operational functions might be sufficient, whereas other jurisdictions may want more active distribution operations. This kind of framework would provide a common reference for different jurisdictions, enabling visibility on future end states and the transitions between different models.

Many of the functions in the functional mapping in Table 3 may be shared across multiple models. Where functions are shared across different models this can highlight least-regrets strategies at different points in the transition between different models. For instance, if real-time outage communication by distribution utilities is common across all models, this suggests that developing systems for outage planning, monitoring, and communication should be a near-term priority.

The set of models from Workstream A in Track 1 would provide a bottom-up technical foundation and common reference point for discussions on nearer-term priorities (Track 2), solutions to longer-term challenges (Track 3), and, importantly, a means to link nearer-term and longer-term actions. It would help ground discussions by providing specificity in terminology and concepts. It would also provide visibility on potential future states for distribution system and market operations, which would help to facilitate discussions around transition strategies between different models.

TABLE 3

Illustrative Models for Distribution System and Market Operations

Centralized (Toward Total TSO) ⮜⮜⮜			⮞⮞⮞ Decentralized (Toward Total DSO)	
	DSO Model 1	**DSO Model 2**	**DSO Model 3**	**DSO Model 4**
Distribution operations	DSO can override TSO dispatch of DERs for reliability but does not use DERs for distribution grid services	DSO dispatches DERs to provide non-wires services	DSO dispatches DERs to provide non-wires services and to enable dynamic import/export limits	DSO conducts security-constrained dispatch of DERs
Distribution interconnection	DSO is responsible for DER interconnection process with minimal TSO involvement	DER interconnection agreement provides for DSO curtailment of DERs for reliability	DSO allows DERs to interconnect with static and dynamic import/export limits	DSO allows DERs to interconnect with static and dynamic import/export limits and other potential options for flexible interconnection
Distribution planning and upgrades	DSO plans distribution capacity upgrades for load and DER growth but does not procure DERs for non-wires services	DSO plans distribution capacity upgrades for load and DER growth, and procures DERs as non-wires services in limited instances	DSO grid planning co-optimizes DER grid services and distribution capacity upgrades	DSO grid planning co-optimizes DER grid services and distribution capacity upgrades, with enhanced modeling of potential DER operating incentives
Commercial activity	DSO compensates DERs for grid services through programs and tariffs, but there are no compensated distribution services	DSO compensates DERs for grid services through programs, tariffs, limited payments for non-wires services, and any payments for curtailment	DSO compensates DERs for grid services through programs, tariffs, payments for non-wires services, and any payments for dynamic operating instructions	DSO operates competitive markets for energy and grid services
Relevant TSO features and TSO-DSO relationship	TSO models participating DERs at T-D interfaces; DSO supports DER participation in TSO	TSO and DSO coordinate to enable DERs to provide both transmission and distribution grid (non-wires) services	TSO and DSO coordinate to enable DERs to provide both transmission and distribution grid services (non-wires services, dynamic import/export limits)	DSO assumes a DER coordination role to reduce TSO need for real-time telemetry and control of DERs

Note: DER = distributed energy resource; DSO = distribution system operator; T-D = transmission-distribution; TSO = transmission system operator.

Source: Energy Systems Integration Group.

The set of models from Workstream A in Track 1 would provide a bottom-up technical foundation and common reference point for discussions on nearer-term priorities (Track 2), solutions to longer-term challenges (Track 3), and, importantly, a means to link nearer-term and longer-term actions.

To develop the models in Workstream A, the workstream organizers would convene industry experts and representatives, particularly from federal and state regulatory agencies, utilities, and ISOs.

Workstream Organization

The discussions in Track 1 / Workstream A will tackle foundational and challenging questions. It will be important to structure the effort productively to generate useful outcomes. One way of organizing this work would be through the following three steps.

Step 1 (Workstream A.1): Identification of essential functions. Identify the essential functions required for the high-DER electricity system, grouped into high-level categories such as transmission and distribution planning, resource adequacy, resource interconnection, transmission and distribution network services, and operations, markets, business, and revenue models.

Step 2 (Workstream A.2): Identification of actors and system architecture. Identify and define all the actors that comprise the operation of the whole system, and describe four or five alternative models of the system, defined in terms of different architectural relationships between transmission and distribution system operations and markets.

Step 3 (Workstream A.3): Assignment of functions to actors. Assign the functions identified in A.1 to the actors identified in A.2 in accordance with each of the structural models of A.2. In this way, Workstream A will produce four or five architectures that specify the functional roles and responsibilities of each of the actors under each of the models.

The outcomes of this workstream will be:

- Common terminology and concepts for a coherent U.S. national conversation on transitioning the electricity system to higher levels of diverse DERs.
- A range of alternative future models and transition paths that could be compatible with the diversity of U.S. utility regulatory frameworks.
- The identification of common features for which further development and standardization would benefit all architectural models and jurisdictions (e.g., interface definitions, data exchange content between actors).

Workstream A's main deliverable would be a report that describes different models for distribution system operation and markets, including the functions required in each model and the mapping of functions to actors.

Least-Regrets Strategies (Track 2)

The least-regrets track is designed with the intention of identifying technical and regulatory solutions that can be implemented in the near term to support the integration of DERs into a range of electricity system planning, access, market, and regulatory processes, regardless of long-term decisions on how to structure future DSOs or utility regulatory models. The work in this track is based on the notion that while regulatory models and market design are unique to specific geographies, the nature of DER technologies and the trends in DER adoption are consistent globally, as is the general power system architecture. While there are differences in distribution network design within the United States and between the United States and other countries, the foundation of distribution engineering and operations is common among them.

In the ESIG DER integration report, consistent with the similar effort by AEE and GridLab, we found that the changes needed in the near term are not about technological investments but about utility procedures and coordination (ESIG, 2022a; AEE and GridLab, 2022). Four main gap areas were identified. These gaps are specific to Order 2222, but some (such as interconnection and communication of distribution system conditions) are also relevant in the LSE structural participation model. The four gaps areas are:

- Distribution interconnection procedures for individual DERs
- Distribution utility review of proposed DER aggregations; Order 2222 allows utilities a maximum of 60 days for this review
- Communication of distribution system outages and abnormal configurations
- Distribution utility overrides of ISO dispatches

As discussed in the ESIG DER integration report, in general, distribution utility interconnection procedures and aggregation review processes need to evolve to support Order 2222 implementation; additional changes in distribution utility procedures for communicating distribution system conditions, and overriding ISO schedules and dispatches will be needed. State regulatory commissions will need to ensure that utilities develop procedures and processes that are efficient, fair, transparent, and non-discriminatory (ESIG, 2022a).

Building on these recommendations, the second track on least-regrets strategies aims to develop solutions to near-term challenges to DER integration. These topics, while relevant to the implementation of Order 2222, are helpful for other participation models (e.g., DER participation through an LSE). The four topics are:

- Coordinated planning (Workstream B)
- Data access and transparency (Workstream C)
- Distribution operations (Workstream D)
- Interconnection and aggregation review (Workstream E)

These topics overlap—for example, interconnection and operations are closely related, and data integration is an overarching theme across both planning and operations. However, each workstream is envisioned to be composed of a set of stakeholders and stakeholder types that will determine the depth, perspectives, and outcomes of that workstream. The initiative will have a "management"—level layer that works across these workstreams to ensure coordination at the interface points. The data workstream, for example, may consist of utility personnel adept in data operations and enterprise systems, while the coordinated planning workstream may include important contributions from utility personnel from planning departments.

Each workstream has within it a diverse set of topics that can be addressed. This report identifies topics that could be considered as high priority items, although the initiative itself will undertake a process of identifying the workstreams' priorities.

A common approach going from a broad focus to a specific technical deep dive can be applied within each workstream:

Each workstream is envisioned to be composed of a set of stakeholders and stakeholder types that will determine the depth, perspectives, and outcomes of that workstream.

1. Take stock of current practices
2. Do a needs and gaps assessment
3. Survey emerging methods and solutions
4. Prioritize topics for deep-dive discussions
5. Engage in deep-dive discussions resulting in recommendations

Coordinated Planning (Workstream B)

Emerging Issues

Historically, only limited coordination was needed either within distribution utilities for distribution planning or between distribution and transmission utilities (or departments) for distribution and transmission planning. Growth in DERs is, however, requiring more integrated distribution planning and closer coordination between distribution and transmission planning.

Although coordination within distribution utilities and between distribution and transmission systems are separate problems, they share common elements. The most important of these is coordination around load and DER forecasts, and DER operating assumptions.

Although coordination within distribution utilities and between distribution and transmission systems are separate problems, they share common elements. The most important of these is coordination around load and DER forecasts, and DER operating assumptions.

At the distribution level, the use of consistent inputs and assumptions across different functions (e.g., interconnection studies and distribution plans) will help to ensure that distribution investments are as right-sized as possible to trends in DER adoption and operations. For instance, utility assumptions about electric vehicle loads and solar photovoltaics (PV) + storage generation used in load forecasting for infrastructure planning should reflect trends in interconnection (e.g., inverter

Illustrative questions for coordinated planning:

- What gaps exist in T-D planning coordination? How should these be prioritized?
- How can T-D planning become more closely aligned to ensure consistency across different levels of granularity from the distribution circuit to the T-D interface level?
- What least-regrets steps can all utilities take to better integrate distribution planning?

loading ratios for distributed PV and export limits for PV + storage) and other utility planning and analysis (e.g., electric vehicle charging profiles and response to time-of-use tariffs).

At the transmission level, a lack of coordinated assumptions between ISOs and utilities may mean that ISOs invest in unnecessary transmission, or in the other direction, that distribution utilities' decisions may result in unexpected power flows at the transmission substation that could impact transmission reliability. The lack of coordinated scenario planning among ISOs, utilities, and state utility commissions and energy offices means that they do not have a common understanding of the implications, infrastructure needs, and operational risks of different scenarios of DER adoption. Collectively, these problems have the potential to unnecessarily drive up system costs and create reliability challenges.

With increased electrification, power system planning will need to engage non-traditional actors, such as municipal agencies, that will drive electric vehicle adoption and electrification of buildings. While such actors have been less involved in grid planning in the past, future planning activities will require closer engagement with these stakeholders.

Coordination challenges are exacerbated by the complex ecosystem of commercial utility planning tools that do not encourage an integrated planning mindset by, for example, enabling interoperability of planning tools, standardization of data formats, standardized data assumptions, and open source platforms.

State-level integrated distribution system planning proceedings have helped to increase literacy and transparency around how the distribution system operators can better integrate, plan, and operate distributed assets and loads. The recently completed NARUC-NASEO Task Force on Comprehensive Electricity Planning sought to tackle myriad challenges associated with the current state of utility planning; it generated a useful overlay to frame the integrated planning discussions by constructing a set of "cohorts" which reduce the various state and utility contexts to five paradigms. The task force identified coordination around DER forecasts and operating assumptions in distribution and distribution-transmission planning as a key gap.[9]

Approach and Potential Benefits

Workstream B will develop processes and methods for planning coordination within distribution utilities (integrated distribution planning) and between distribution and transmission planning (T-D planning coordination). It will build on two lines of work: (1) recent integrated planning efforts, such as the NARUC-NASEO Task Force on Comprehensive Electricity Planning; and (2) FERC Order 2222 planning issues, such as the Electric Power Research Institute's TSO-DSO coordination working group. Integrated distribution planning and T-D planning coordination would likely be separate sub-workstreams.

For integrated distribution planning, Workstream B could focus on the following:

- Jurisdictional review of emerging practices in integrated distribution planning, with a focus on methods for coordinated forecasting, integration of infrastructure planning (transportation, buildings, resilience) with electricity distribution system planning, the kinds of information sharing required across utility departments, process enhancements required to enable information sharing across departments, and changes in software and tools required for information sharing

9 See https://www.naruc.org/taskforce.

- Identification of key gaps in existing and emerging practices, and development of a template with options for resolving these gaps

For T-D planning coordination, Workstream B could focus on:

- Processes and methods for coordinated scenario planning among distribution utilities, state energy offices, commissions or other relevant agencies, and ISOs
- Processes and methods for sharing planning information between distribution utilities and ISOs, including how that information can be used by each actor
- Processes and methods for coordinating detailed engineering studies in distribution and transmission plans

Once areas of focus have been agreed upon, the general approach described earlier can be applied: (1) take stock of current approaches, (2) do a needs and gaps assessment, (3) survey emerging methods and solutions, (4) prioritize topics for deep-dive discussions, and (5) engage in deep-dive discussions resulting in solutions for specific challenges.

Potential benefits of the coordinated planning workstream:

- Lower transmission and distribution infrastructure costs and increased reliability as a result of coordinated planning
- Reduced administrative burden for regulators looking to apply coordinated planning practices
- Increased access to distribution systems, through more integrated distributed planning

Each step would be documented as a section in a report, and most importantly, the technical deep-dive discussions will generate a template document that provides a menu of options for utilities, ISOs, and regulators.

This workstream will engage a fairly broad set of stakeholders, including:

- Distribution utilities
- Transmission utilities
- NARUC-NASEO
- State regulators and energy offices
- ISOs/RTOs
- FERC
- DER providers/aggregators
- National labs and research organizations
- Corporate and municipal energy purchasers and other LSEs
- Municipal/county sustainability departments and other relevant departments
- Consumer and underserved community advocates

In contrast to typical power system planning conversations, Workstream B is intended to engage non-traditional actors such as corporate and municipal energy purchasers and infrastructure planners at the municipal and county levels.

Data Access and Transparency (Workstream C)

Emerging Issues

As distribution systems become increasingly accessible to non-utility parties, data sharing, privacy, and security will be critical for guiding efficient investments and facilitating reliable operations. By analogy, on the bulk system, ISOs provide extensive data on planning assumptions, interconnection, operations, and market

As distribution systems become increasingly accessible to non-utility parties, data sharing, privacy, and security will be critical for guiding efficient investments and facilitating reliable operations.

Illustrative questions for data access, transparency, and integration:

- What data and data-sharing gaps exist among utilities, aggregators, customers, and ISOs?
- What are data collection and sharing needs, in terms of granularity, accuracy, and frequency?
- How should these data be better integrated with operations and planning functions?

outcomes to market participants to help coordinate least-cost, reliable operations among many actors; market participants are required to share a significant amount of information with ISOs.

Limiting access to data promotes market power, inhibits innovation, drives up costs, and may impact reliability. Information sharing among utilities and DER developers/aggregators can facilitate more cost-effective integration of DERs. Data sharing among ISOs, distribution utilities, and DER aggregators and owners is important for facilitating reliable operation of the power system.

The types of data that could be discussed in Workstream C may include DER and load forecast assumptions, historical DER and load data, planned capacity expansions and network reconfiguring, hosting capacity, outage and congestion data, and distribution interconnection. Within each of these data categories, there are outstanding questions on what data are needed and the implications for planning and operations functions:

- **DER forecasting:** From the developer perspective, aggregated customer data such as panel ampacity and service levels for customer types at the node, circuit, or feeder level could facilitate efficiencies. Tighter coupling between DER forecasting and deployment can improve efficiencies.
- **Hosting capacity:** The sharing of hosting capacity data is relatively new to the industry, and there are outstanding issues on the development of hosting capacity data, and how to share hosting capacity data on a geographical and temporal basis that both meets developers' needs and is feasible from the utility perspective. The integration of hosting capacity information with interconnection agreements is a gap area and will be of increasing importance as flexible interconnection agreements are explored.
- **Historical DER and load data:** Data sharing from developers to utilities may be beneficial. Utility planning would benefit from greater granularity on DER technology types within aggregations, as well as knowledge about how individual DER types are operated. One pathway for this information could be from DER providers to utilities to the public.
- **Utility/ISO data sharing:** In the future, distribution utilities and DSOs may need more operational communications with ISOs, including scheduling and dispatch data for DER aggregations. Depending on the DSO's scope of responsibilities, ISOs may need information on distribution system conditions. It will be important to ensure that utilities and ISOs can make use of the information they receive. For instance, providing utilities with real-time dispatch information for DER aggregations is not meaningful if utilities are not yet optimizing resources on the distribution system.

Approach and Potential Benefits

Data access and transparency are enabling elements to facilitate DER planning, operations, and interconnection, making Workstream C a cross-cutting theme. Regular coordination checkpoints between this workstream and the others will be important. There is a functional dimension and a mechanical dimension to data:

1. The functional requirements of data address what kind of data are needed (and why) and the characteristics of these data in terms of granularity, frequency, and accuracy. The trade-offs among these three characteristics should be discussed for each class of data. (For planning purposes, advanced metering infrastructure (AMI) data are required at an hourly temporal granularity, can be received in batches on a monthly (or less) basis, and must be highly accurate.)
2. The mechanics of sharing data address how the data will be shared, such as data formats, communications protocols, and interoperability.

Data access and transparency are enabling elements to facilitate DER planning, operations, and interconnection, making Workstream C a cross-cutting theme.

Discussions about data are often dominated by the mechanics of sharing data. However, our recommendation is to prioritize the topic of functional requirements. As time permits, the mechanics of data, such as interoperability, communication protocols, and standardized data-sharing templates, can be developed. Development of the approaches on the mechanics of data sharing should be coordinated closely with technical institutions tackling these issues, such as the Electric Power Research Institute.

Benefits of the data workstream:

- Data are a foundational, enabling element to improved DER planning and operations functions. This means more efficient and cost-effective DER integration and more reliable operations.

This workstream could be structured around two classes of data categories: (1) utility and DER developer/aggregator data coordination, and (2) ISO-utility-aggregator data coordination.

The first would focus on DER planning and interconnection issues (hosting capacity data, DER forecasting, DER performance data), while the latter focuses on operations coordination (network and DER information that needs to be shared on day-ahead and real-time time frames).

The AEE-GridLab Order 2222 report described an illustrative framework for day-ahead and real-time coordination (AEE and GridLab, 2022) (Table 4, p. 23). The AEE-GridLab activity provided an illustrative example and was not intended to be prescriptive; further dialogue in the context of a national initiative could be helpful to build on this example. This type of framework or multiple frameworks, along with a comparison of each including the challenges, pros, and cons, could be one output of this workstream.

As noted above, for each data category, the following general approach can be used: (1) take stock of current approaches, (2) do a needs and gaps assessment, (3) survey emerging methods and solutions, (4) prioritize topics for deep-dive discussions, and (5) engage in deep-dive discussions resulting in solutions for specific challenges. These five steps that generate solutions applicable in the near term will be documented in a final report.

The following stakeholders will be engaged in this workstream:

- Distribution utilities
- NARUC and NASEO
- FERC
- DER providers/aggregators
- Grid modernization organizations
- National labs and research organizations

Distribution Operations (Workstream D)

Emerging Issues

Higher levels of DER participation in ISO markets, either directly through DER aggregation or indirectly through LSE demand bids or metered demand, require changes in distribution operations to ensure that DER schedules and dispatch in the ISO market are feasible (that they do not lead to reliability violations) at the distribution level.[10] In the nearer term, most distribution utilities will likely ensure feasibility by temporarily curtailing DER operations when needed. However, most utilities do not yet have standard processes—documented in an interconnection agreement—for curtailing DER operations or communicating with DER providers when curtailments are needed.

10 The problem of DERs participating directly in bulk power markets without management of physical flows at the distribution level is often referred to as "tier bypassing" in the language of grid architecture. Physical flows at the distribution system must be managed irrespective of whether a DER injection causes an actual flow of electricity across the transmission-distribution interface from distribution to transmission, or only reduces the net load at the interface.

TABLE 4

AEE-GridLab Report's Illustrative Application of Coordination Principles

Illustrative Application of Coordination Principles for Behind-the-Meter Use Cases—Crawl Phase				
Pre-Day Ahead	**Day Ahead**	**Intraday**	**Real Time**	**Settlement**
• Aggregators likely to have data on location, technology, type, operating parameters, etc. from DER aggregation registration • Aggregators not likely to have information on distribution system data without requesting from electric distribution companies • Electric distribution company would have data on bid capacity from aggregation review • Maintenance of distribution planning assumptions that account for aggregations • Planned outages/reconfiguration communicated between electric distribution company and aggregator – Electric distribution company would notify ISO/RTO of planned and forced outages as needed – Aggregator notifies ISO/RTO of DER aggregation outages as needed	• Electric distribution company provides notification of any outages or expected distribution system constraints, and aggregator provides notification of DER outages to ISO-RTO that may impact delivery of DER aggregation's scheduled obligations • Formal procedures not yet defined for how electric distribution companies or ISOs will provide notice to aggregators of distribution constraints • Day-ahead schedules following market clearing for all ISO/RTO services that are provided by each DER aggregation shared with electric distribution company (by ISO/RTO) for reliability/safety review – Data provided by the ISO/RTO will be by service at the DER aggregation level only – Details of which resources may deliver the scheduled services may not be available, unless DER aggregation's full capability is bid in each hour	• Electric distribution company provides notification of distribution system constraints, and aggregator provides notification of DER outages to ISO-RTO that may impact delivery of DER aggregation's scheduled obligations • Aggregators are notified of restrictions impacting a DER aggregation's ability to meet the day-ahead schedule and update their schedules accordingly prior to real-time market closing – Restrictions will likely be communicated by electric distribution company to ISO/RTO and from ISO/RTO to aggregator • Aggregators will update day-ahead schedules with ISO/RTO if availability of DER aggregation planned to meet day-ahead schedule impacted	• Data on real-time performance (either through telemetry/SCADA or alternate means) provided by aggregator to ISO at granularity specified for products scheduled – Only break out of real-time values for load modifying resources vs. injecting resources within DER aggregation • If aggregator providing telemetry, data provided to ISO via Direct Inter-Control Center Communications protocol (ICCP) in most cases (some ISOs may allow alternative methods) • Electric distribution company overrides in real time, due to emerging issues creating reliability/safety risks of DER aggregations operating (likely only power-injecting)	• ISO supplies electric distribution company with settlement data from DER aggregation for dual participation issues • If aggregator is using third-party metering and data, settlement data may differ from utility meters (though difference should be small where there is an ISO requirement for revenue-grade metering) • Sub-metering behind-the-meter resources to participate separately may create additional steps necessary to reconstitute metered load to align with electric distribution company

Notes:

- Illustrative and not meant to be prescriptive for regulators
- DER = distributed energy resources; ISO = independent system operator; RTO = regional transmission organization; SCADA = Supervisory Control and Data Acquisition.
- The "crawl" phase as used in the AEE-GridLab report represents the early phases of Order 2222 implementation and is in contrast to the later "walk" and "run" phases of implementation.

Source: AEE and GridLab (2022).

Even if distribution utilities upgrade the distribution system to accommodate interconnecting customers under normal conditions, utilities may still need to curtail generation and load due to distribution equipment outages or situations when the distribution system is operating under conditions that were not studied during the interconnection process or aggregation review. Utilities may curtail DER operations by communicating an outage or other event to DER operators and requiring them to reduce generation, which the ESIG DER integration and AEE-GridLab reports referred to as "soft curtailment" (ESIG, 2022a; AEE and GridLab, 2022). Utilities may also curtail DER operations by directly reducing DER generation or isolating the DER (curtailing all exports to the grid), which these reports referred to as "hard curtailment."[11]

Illustrative questions for distribution operations:

- What is the menu of options for designing transparent, non-discriminatory overrides of DER schedules and dispatch?
- What monitoring, communications, and control technologies would be needed in the nearer and longer term to implement soft and hard overrides and eventually distribution-level dispatch of DERs?
- What rules, or changes in rules, are needed to facilitate multi-use applications of DERs?

In the near term, in the context of Order 2222 implementation, many utilities will need to develop transparent, non-discriminatory approaches to overrides of DER dispatch on different time scales (day ahead, intraday, real time). The ESIG DER integration report notes that for DER overrides to be non-discriminatory, utilities must fairly allocate limited distribution capacity among multiple DER aggregators that may use some of the same capacity (ESIG, 2022a). There are several possibilities for how utilities could do non-discriminatory curtailment, such as first-in last-out curtailment, pro rata (proportional) curtailment, tradable or non-tradable physical rights, or bid-based mechanisms.[12]

In the near term, in the context of Order 2222 implementation, many utilities will need to develop transparent, non-discriminatory approaches to overrides of DER dispatch on different time scales (day ahead, intraday, real time).

In addition to processes for non-discriminatory DER curtailment, another layer of complexity emerges from multi-use applications in which DERs provide services to both the ISO and distribution utilities, such as through non-wires services, which requires effective coordination approaches between distribution and transmission system operations. In most cases, these multi-use applications can be accommodated by adapting existing ISO market rules.[13] However, many distribution utilities do not yet have standardized rules for allowing DERs to provide both distribution-level and transmission-level services.

Approach and Potential Benefits

Workstream D will develop procedures, technical requirements, and regulatory frameworks for a menu of options for: (1) non-discriminatory utility overrides of ISO scheduling and dispatch, and (2) dual participation of DERs in distribution services and ISO markets.

11 With soft curtailment, DER aggregators receive override instructions and must comply or face financial and potentially other penalties. With hard curtailment, the utility directly controls DERs.

12 "First-in last-out" curtailment means that DERs that interconnect first are curtailed last.

13 Assuming that the ISO already has rules that enable DER aggregation under Order 2222. An important area for consideration is resource adequacy and must-offer requirements. If the DER is being used for distribution capacity services, it may not be able to be counted toward resource adequacy requirements on the bulk system.

Potential benefits of the distribution operations workstream:

- Greater certainty and higher value for DER owners and aggregators, through a shift toward transparent, rules-based distribution operations
- Greater certainty for the ISO about DER response to ISO dispatch instructions
- Safer and more reliable operation of the distribution system
- Reduced administrative burden for state regulators in enhancing distribution operations, including FERC Order 2222 implementation
- Greater certainty for state regulators on the kinds of grid technologies that utilities need in the nearer term for distribution operations

For these two areas, the workstream will develop a menu of options that covers a range of potential operational models. For instance, options for non-discriminatory utility overrides might include first-in last-out curtailment, pro rata curtailment, physical distribution rights, or bid-based mechanisms. Options for allowing multi-use applications might include front-of-the-meter resources that are contracted to the utility for use during distribution system peaks but are able to participate in ISO markets during distribution off-peak periods.

For each option, the workstream would lay out operating and market processes, technical requirements, and regulatory frameworks in a report or series of reports. Processes and technical requirements would cover utility monitoring, communication, and control needs. For different override options, for instance, what information about distribution system conditions would the utility need, and by when, to ensure that ISO market schedules and dispatch do not lead to distribution reliability violations? How would the utility communicate outages and events that require DER curtailment to DER operators, and on what time scales? To what extent would the utility need to control DERs to ensure compliance with override instructions?

The approach for each area in Workstream D would be similar to the general approach described earlier: (1) take stock of current approaches, (2) do a needs and gaps assessment, (3) survey emerging and potentially longer-term methods and solutions, and (4) develop a menu of detailed options, based on steps 1 to 3.

The following stakeholders will be engaged in Workstream D:

- Distribution utilities
- State regulators
- DER providers/aggregators
- Customers with on-site DER
- ISOs

Interconnection and Aggregation Review (Workstream E)

Emerging Issues

Distribution interconnection is a critical step for allowing DERs to access the distribution utility network and, as such, is the gateway to DER participation in both retail and wholesale markets. Enabling higher levels of DERs will require several enhancements to distribution interconnection processes: more rigorous technical standards, more streamlined and standardized processes, more sophisticated DER aggregation review processes, more sophisticated approaches to cost allocation for distribution upgrades, and rules for flexible interconnection.

Technical standards. The IEEE 1547-2018 standard requires advanced inverter functionality and enables autonomous voltage regulation (e.g., volt-VAR or volt-watt), which can address many voltage management

Distribution interconnection is a critical step for allowing DERs to access the distribution utility network and, as such, is the gateway to DER participation in both retail and wholesale markets.

issues related to DERs. However, despite endorsement from NARUC in 2020, only a limited number of states have adopted, or have open proceedings to discuss, this standard.

Streamlined and standardized process. Several states have made progress in streamlining distribution interconnection processes; increasing transparency over the interconnection process, its technical and regulatory requirements, and hosting capacity in different parts of the distribution system; reducing interconnection timelines; and creating clear expectations for the assignment of upgrade costs. However, improvements in distribution interconnection processes are uneven across states and have focused largely on solar PV. In addition, the lack of more standardized approaches to distribution interconnection across states creates unnecessary barriers for DER owners and operators.

Illustrative questions for interconnection and aggregation review:

- What are key issues and best practices with IEEE 1547-2018 implementation?
- What are emerging and possible future best practices around DER interconnection, in terms of timelines, technical and regulatory requirements, flexible interconnection, and upgrade cost allocation?
- What methods can be used to assess mixed aggregations in DER aggregation review?

DER aggregation review. Order 2222 requires distribution utilities to review DER aggregations within 60 days of registration. These aggregation reviews may need to cover different DER types, including mixed aggregations of generation, storage, and demand response. Many utilities have yet to develop methods and processes for DER aggregation review that tackle more challenging areas such as mixed aggregation review.

In some instances, it will be more cost-effective to curtail injections into the distribution system than to upgrade the distribution system to accommodate all injections at all times.

Cost allocation. Traditionally, distribution upgrade costs triggered by distributed generation in the interconnection process have often been paid by the project that triggers the upgrade.[14] This "first mover" approach to allocating upgrade costs can delay or halt what might otherwise be economical DER projects in congested areas of the distribution system, because new projects do not want to pay the full cost of the upgrade when subsequent interconnecting projects will benefit from but not pay for the upgrade. Additionally, there may be a rationale for utility ratepayers to pay a portion of upgrade costs if the upgrade will have broader system benefits or if DER projects will have net benefits to ratepayers.[15] Some jurisdictions are in the process of developing cost allocation mechanisms to address these issues.[16]

Flexible interconnection. In some instances, it will be more cost-effective to curtail injections into the distribution system than to upgrade the distribution system to accommodate all injections at all times. For instance, it may be cost-effective to curtail distributed PV generation for a few hundred hours per year rather than upgrade a substation to ensure that all of its output can be accommodated. More flexible approaches to interconnection and distribution system upgrades could thus reduce total distribution capital costs. An initial step in enabling more flexible approaches to interconnection will be to allow interconnecting customers to agree to limit injections during predefined periods of the year in

14 For loads, utility line extension policies have often allowed for cost sharing.

15 An example of broader system benefits could be a substation upgrade that also accommodates future load growth. "Net benefits" here refers to situations in which DERs provide net margin to utilities, meaning that the benefits to a utility exceed what the utility compensates the DERs through tariffs and other incentives.

16 Examples include New York's Cost Sharing 2.0 mechanism, Massachusetts' proposed Capital Investment Project fee, and Maryland's Cost Allocation Mechanism.

exchange for lower or no assignment of upgrade costs. These static limits could ultimately be expanded into dynamic limits, which at some point would require DSO dispatch or direct control over DERs. Only a small number of jurisdictions have explored static or dynamic limits for DERs.

Approach and Potential Benefits

Workstream E would focus on developing three outputs: (1) guidelines for IEEE 1547-2018 adoption and implementation, (2) pro forma text for distribution interconnection rules, and (3) pro forma text for DER aggregation review rules.

The implementation guidelines for IEEE 1547-2018 adoption could build on the experience of the 16 states that had adopted or begun discussions on the standard as of early 2022,[17] as well as technical overviews by the Electric Power Research Institute and National Renewable Energy Laboratory.[18] The guidelines would highlight key decision points and trade-offs among different options for regulators and utilities.

Potential benefits of the interconnection and aggregation review workstream:

- Greater access to the distribution system for DER owners and operators, resulting in reduced costs and timelines for interconnection
- Safer and more reliable operation of the distribution system through enhanced standards and rules
- Reduced administrative burden for state regulators in improving interconnection rules and overseeing utilities' DER aggregation review
- More efficient and fairer approaches to cost allocation for distribution system upgrades
- More efficient use of the distribution system and lower distribution costs by enabling flexible approaches to interconnection

For DER aggregation review rules, the workstream could focus on methods and pro forma text for mixed aggregation review, or it could develop text for a pro forma DER aggregation review.

For interconnection rules, this workstream's work could take one of two approaches. The first approach would focus more narrowly on identifying gaps in existing interconnection rules and develop pro forma text for interconnection rules for these gap areas. The second approach would develop a complete set of pro forma interconnection rules. For DER aggregation review rules, the workstream could focus on methods and pro forma text for mixed aggregation review, or it could develop text for a pro forma DER aggregation review. Pro forma rules do not need to contain all of the detail that actual rules would have. They are intended to be a guide for utilities and regulators and do not need to be adopted verbatim. Whether or not utilities adopt pro forma rules verbatim, they can help to encourage greater standardization across jurisdictions. Both the interconnection and DER aggregation review work products would be captured in reports.

The following stakeholders would likely participate in the workstream:

- Distribution utilities
- State regulators
- NARUC
- Electric Power Research Institute
- DER aggregators
- DER developers

17 For a list of states that have open or completed inquiries or dockets on IEEE 1547-2018, see https://sagroups.ieee.org/scc21/standards/1547rev.

18 See https://pubs.naruc.org/pub/42B4D292-1866-DAAC-99FB-BF1866A134F4 and https://www.nrel.gov/grid/ieee-standard-1547.

Longer-Term Issues (Track 3)

Track 3 would address DER integration issues that will take more time to resolve, but where structured dialogue needs to begin soon. The ESIG DER integration report identified seven categories of these longer-term issues: distribution and transmission planning, distribution interconnection, data sharing and communications, distribution operations, market regulation, ISO market design, and utility regulation and business models (ESIG, 2022a).

TABLE 5

Longer-Term Challenges for DER Integration

Distribution and Transmission Planning
Utility planning-interconnection-operations integration: Closer alignment between the data and tools that distribution utilities use in planning, interconnection studies, and operations
Utility/ISO planning coordination: Coordination on DER forecasting and planned investments, to ensure that utilities and ISOs are using consistent assumptions in infrastructure planning
Distribution Interconnection
Interconnection standards: Adoption and implementation of industry-consistent interconnection standards and processes to accommodate new DER functionality and market participants
Flexible interconnection: Processes and rules for DERs to connect to the distribution system without upgrades, if DER owners agree to be curtailed (re-dispatched) when needed for reliability
Data-Sharing and Communications
DSO/ISO communication: Evolving protocols and processes through which DSOs and ISOs can communicate and share data in real-time operations
Utility/aggregator data-sharing: Rules on the kinds of distribution load and operational data, and its granularity and frequency, that utilities will share with DER developers and aggregators
Distribution Operations
Operational enhancements: Enhancements in utility monitoring, communications, and control capabilities
DSO functions: Operating needs, roles, and functional responsibilities for future DSOs, including monitoring, dispatch, and control needs and interactions among market participants, DSOs, and ISOs
Market Regulation
Non-discriminatory distribution operations: Regulatory changes, including functional independence of the system operator and open access distribution tariffs, to ensure non-discriminatory operation
State-federal jurisdiction: Approaches to managing areas of overlapping state-federal jurisdiction, such as interconnection, dual participation, distribution access tariffs, and distribution operations
ISO Market Design
Demand-side designs: Enhanced use of demand bids to play a more active role in wholesale markets and operations
Utility Regulation and Business Models
Incentives for maximizing DER value: Restructuring incentives for utilities so that they proactively seek to maximize the value of DERs on their distribution systems and in wholesale markets
DER compensation: New designs for tariffs and other approaches to compensation that better align DER operating incentives with wholesale market and distribution systems' needs

Notes: DER = distributed energy resource; DSO = distribution system operator; ISO = independent system operator.

Source: Energy Systems Integration Group (2022a).

In the longer term, and potentially in the nearer term in some jurisdictions, interconnection processes may need to accommodate customers (DERs and loads) that accept dynamic (time-varying) injection and withdrawal limits in exchange for lower distribution upgrade charges.

The issue areas in Table 5 overlap with the Track 2 (least-regrets strategies) workstream areas, as each area has both nearer-term and longer-term challenges. For instance, in the nearer term, utilities that participate in ISO markets will need to enhance their interconnection processes and create DER aggregation review processes to comply with FERC Order 2222. In many jurisdictions, utilities will likely also need to augment interconnection processes to allow DERs that accept static (time-invariant) export (injection) limits to avoid distribution upgrade charges. In the longer term, and potentially in the nearer term in some jurisdictions, interconnection processes may need to accommodate customers (DERs and loads) that accept dynamic (time-varying) injection and withdrawal limits in exchange for lower distribution upgrade charges. Nearer-term issues could be addressed in Track 2, while longer-term issues are addressed in Track 3.

The structured dialogue in Track 3 should also identify solutions to longer-term DER integration issues under the different models of distribution system and market operations identified in Track 1. For instance, ISO-DSO operational coordination needs will be very different under the more decentralized versus more centralized DSO models discussed above. Track 3 could also articulate, and validate with stakeholders, how solutions to these challenges could evolve over time as jurisdictions transition toward their preferred Track 1 model.

The actors-functions framework in Track 1 would help to provide a detailed roadmap of how functions change

TABLE 6

Illustration of a Roadmap for the Evolution of DSO Functions Over Time

DSO Function	Current Model	Intermediate Model	Target Model
Interconnection	Interconnecting customers pay for any upgrade charges identified through the interconnection process	Interconnecting customers can choose static injection limits, to avoid upgrade charges	Interconnecting customers can choose dynamic injection/withdrawal limits, to avoid upgrade charges
DER dispatch	DSO can only curtail or isolate DER for local reliability	DSO dispatches DER for distribution grid services, e.g., congestion management or non-wires alternatives	DSO conducts security-constrained economic dispatch of DER

Notes: DER = distributed energy resource; DSO = distribution system operator.

Source: Energy Systems Integration Group.

over time as models for distribution system and market operations evolve, capturing interrelationships among different functions. Table 6 illustrates both the evolution of functions and interrelationships between them, using an example of interconnection and dispatch at the distribution level. In this case, allowing resources to choose flexible (dynamic, non-firm) interconnection status is consistent with a more dynamic approach to DER management through dispatch.

While states' preferences for solutions might differ, national dialogue would provide state regulators with a framework for thinking about challenges, a clear sense of direction, and an understanding of the implications of different choices.

Some of the issue areas identified in Table 6, such as utility regulation or disputes around state-federal jurisdiction, may not have nearer-term least-regrets strategies. Nevertheless, it will be important to begin dialogue on these issues soon to enable their eventual resolution. For instance, dialogue on the future of utility regulation could help to address the question of whether utility regulation and cost recovery would need to fundamentally change, and if so, how, in order to incentivize utilities to maximize the value of DERs. Track 3 could play an important role in initiating longer-term dialogue by providing a consensus identification of challenges, enumeration of possible solutions, and some degree of alignment on priorities. While states' preferences for solutions might differ, national dialogue would provide state regulators with a framework for thinking about challenges, a clear sense of direction, and an understanding of the implications of different choices.

DER integration challenges will undoubtedly evolve over time. At the outset, organizers and participants would need to generate a list of potential topic areas for Track 3 and prioritize the topics that the initiative would take on. Ideally, federal and state regulators would play a leading role in setting Track 3 priorities.

This track would consist of a series of stakeholder workshops, with its main deliverable being a report, or potentially a series of reports, that documents discussions in the workshops and describes a longer-term vision, key challenges, potential solutions, and nearer-term priorities for each issue area. For each area, the discussions would close with a list of action items and some level of organizational accountability, to facilitate continued progress. These visions, and their supporting documents, would need to be periodically re-evaluated and updated, but absent this kind of strategic thinking, progress in addressing longer-term issues will likely be slow. Stakeholder engagement will be critical for the dialogue in Track 3 to produce broad buy-in and meaningful outcomes.

Implementation of the Initiative

This section describes potential approaches to the design of a national initiative on DER integration, including how to ensure that the design of an initiative matches its goals, organizational structures for an initiative, and strategies for stakeholder engagement.

Matching Initiative Goals to Design

The design of a U.S. national initiative around DER integration should grow directly out of the initiative's goals, which are to:

1. Develop a general framework and consistent terminology, concepts, and vision for considering distribution system operations, markets, and regulation with higher levels of DERs
2. Identify nearer-term least-regrets DER integration enhancements and solutions that are grounded in power system engineering and economics and could be applicable to diverse jurisdictions
3. Develop a portfolio of potential longer-term DSO models and TSO-DSO coordination arrangements that each jurisdiction could tailor to their individual needs, rather than develop a one-size-fits-all approach

The results of goals 1 and 2 will be broadly applicable to all U.S. jurisdictions, whereas the results of goal 3 will be a set of alternative DSO models that offer options for different jurisdictions to adapt and adopt to their own contexts. To be successful, the initiative's outputs need to be relevant across different jurisdictional contexts, implying a need for diverse stakeholder involvement. The initiative should seek to develop actionable solutions that are well grounded in engineering, economics, and policymaking.

To be successful, the initiative's outputs need to be relevant across different jurisdictional contexts, implying a need for diverse stakeholder involvement. The initiative should seek to develop action-able solutions that are well grounded in engineering, economics, and policymaking.

Together, these considerations point to a national initiative that:

- Focuses on generalized issues and solutions, requiring participants to see beyond their own contexts
- Engages a multi-disciplinary set of stakeholders that represent a spectrum of contexts and viewpoints and have the appropriate knowledge and expertise to contribute meaningfully to a topic area
- Balances generalized solutions and broad stakeholder engagement with the need to develop results specific enough to be actionable

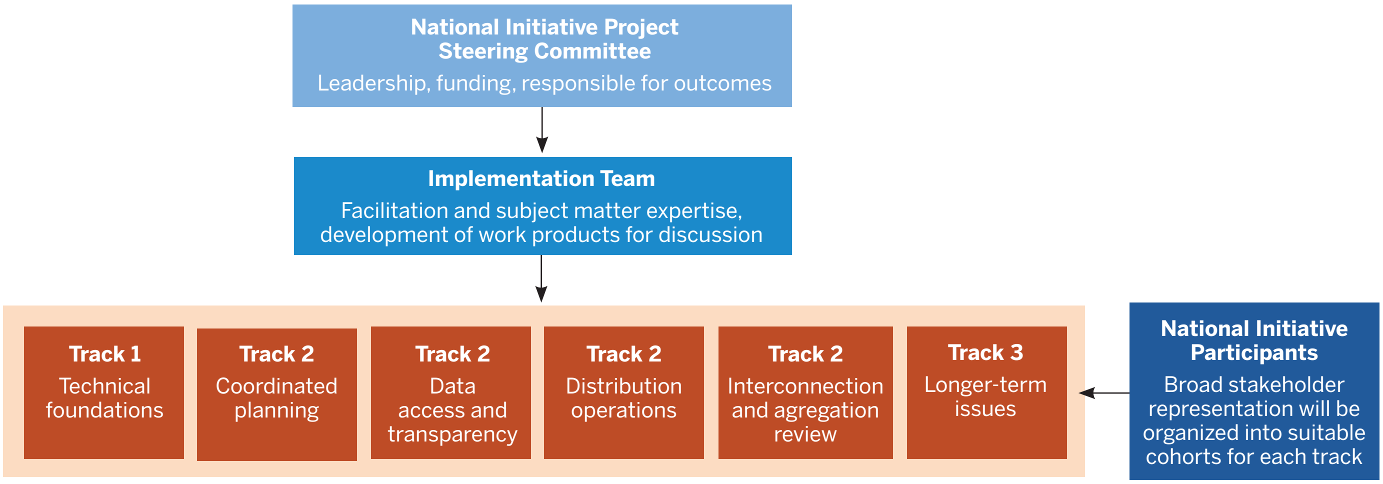
Initiative Design and Implementation

In order to successfully deliver the work set out in these tracks and workstreams, the initiative's design would need to:

- Provide the necessary decisionmaking structure to facilitate agreement and publish outputs and deliverables

FIGURE 3

Organizational Structure of the National Initiative



Source: Energy Systems Integration Group.

- Monitor progress and ensure that the work of each workstream stays on schedule
- Implement a structure for input and feedback from needed technical experts and other stakeholders
- Ensure coordination across workstreams to avoid gaps and overlaps and ensure whole-system consistency and efficient delivery

The complexity of this type of initiative requires diverse participation in terms of organization types and expertise, dedicated implementation staff who will prepare materials to maximize the opportunity for participant feedback, and leadership to steer the effort toward accomplishment of the goals. Figure 3 illustrates one potential approach for structuring this initiative.

The organizational structure illustrated in Figure 3 consists of three types of roles: a steering committee, an implementation team, and participants.

- **Steering committee:** Given the need for extensive coordination across the national initiative, a single committee, which may be a partnership among a few leading organizations, should be responsible for overseeing the initiative's design and implementation. The steering committee would need to have a clear charter from the funding organizations that stipulates responsibilities and terms of participation. The steering committee might include funders, the U.S. Department of Energy, NARUC, NASEO, the American Public Power Association, Edison Electric Institute, and the National Rural Electric Cooperative Association. The steering committee participants would not be compensated for their effort. This committee would ultimately determine the final products that would be published from the national initiative.
- **Implementation team:** The implementation team would be responsible for developing a clear work plan, in collaboration with the steering committee, and implementing the initiative's efforts. To manage a project of this complexity, the implementation team would need to have adequate funding to cover the initiative's administrative, staffing, and other costs and a clear mandate from funders. The implementation team should serve five core functions: recruiting appropriate participants for each track (and within Track 2, each workstream), developing work products for discussion in the workstream sessions, leading and facilitating discussions in the workstreams, revising work products to reflect participant input, and developing final work products for adoption by the steering committee as the initiative's deliverables.
- **Participants:** The participants should cover a broad set of perspectives and include a broad set of organization types. They would play different roles, from directly participating in tracks and workstream

discussions, to providing feedback on intermediate and final work products. Participants would not be funded for their participation.

Effectively Engaging Stakeholders

For the initiative to have industry-wide effect and usefulness it will require that participants who bring technical expertise, regulatory perspectives, and consumer advocacy interests are substantively engaged at all points of the process.

To that end, principles for participant engagement should include:

- **Transparency:** All deliverables and outcomes approved by the steering committee should be published unless there is a commercial, security, or privacy reason not to (sensitive material can be redacted from published papers).
- **Incorporation of multiple opportunities for substantive participant engagement:** Each of the workstreams should entail a series of activities for building and refining work products, as well as public consultations and webinars for "draft final" key deliverables in order to get the widest possible buy-in and encourage feedback from all parties.
- **A proactive approach and dedicated resources for participant engagement:** The implementation team will have among its core responsibilities to communicate effectively with workstream participants, to facilitate workstream working sessions, and to manage the more public consultations mentioned in the previous point.
- **Commitment by participants to participate throughout the process:** Having participants commit at the outset to participate through the full process will provide continuity in discussions and simplify administration.

Given the importance of broad and expert participation, the implementation team and steering committee should dedicate significant time and resources in the initiative's design to developing an effective, efficient, and fair approach to participation.

Participants with different backgrounds and representing different kinds of organizations can provide distinct perspectives and expertise to the initiative's tracks and workstreams. For instance, staff from regulatory commissions can provide insight on regulatory and incentive frameworks. Utility staff can provide grounding in distribution system operations. DER developers and aggregators can provide perspective on the challenges of distribution system access and DER operation. Ratepayer and consumer advocates can ensure that these parties' concerns are considered.

Within these and other kinds of organizations, it will be important to find staff that have the bandwidth and expertise to make meaningful, substantive contributions to the work. The implementation team, with guidance from the steering committee, will need to decide which kinds of participants are essential to include in each of the workstreams and which other kinds of stakeholders should be invited to public discussions and webinars for feedback on intermediate and final products.

Given the importance of broad and expert participation, the implementation team and steering committee should dedicate significant time and resources in the initiative's design to developing an effective, efficient, and fair approach to participation. This should be central to the design of the initiative from the outset and not an afterthought.

Conclusion

DERs have the potential to bring a range of benefits to the U.S. electricity system and the customers it serves: demand flexibility, lower greenhouse gas and criteria pollutant emissions, customer choice, competition, rapid innovation, cyber-security, enhanced reliability, and resilience. However, enabling DERs to provide these benefits will require ongoing and significant changes to better integrate DERs that span the topics of DER interconnection, distribution and transmission planning, data access and communication, distribution system operations, utility regulation, tariffs, and electricity markets.

This report proposes and outlines a comprehensive national initiative to accelerate progress on the integration of DERs across the United States. Although there are multiple efforts on DER integration currently underway, these are often led by individual states like California and New York. Cross-state initiatives are also ongoing, including the NARUC-NASEO Task Force on Comprehensive Electricity Planning and efforts led by the Electric Power Research Institute around DSO-TSO coordination, although these have a narrower focus. While these efforts are productive, overall the United States has a fragmented and piecemeal approach to DER integration. A more coordinated approach to DER integration will accelerate progress in realizing the many benefits of DERs in a future high-renewables electricity system.

Overall the United States has a fragmented and piecemeal approach to DER integration. A more coordinated approach to DER integration will accelerate progress in realizing the many benefits of DERs in a future high-renewables electricity system.

A national initiative would address three gaps around DER integration in the United States:

- The lack of a common vocabulary, framework, and vision for thinking about DER integration across different jurisdictions
- The lack of a common understanding around shorter-term, least-regrets strategies for DER integration that are consistent across distribution utilities
- The lack of a structured dialogue on solutions to longer-term issues for DER integration

Three Tracks to Address the Main Gaps

This report proposes a structure and work plan for a national DER integration initiative, organized around three tracks that would address these major gaps.

Track 1: Technical Foundations

Track 1 would develop a core set of models for distribution system and market operations, based on a detailed mapping of grid functions to different actors in these different models. Between the two "end point" models are several potential hybrid models in which DSOs take on more sophisticated functions related to distribution operations and markets. From these options, Track 1 would identify a core set (e.g., four to five) of feasible bookend and hybrid models.

Track 2: Least-Regrets Strategies

Track 2 would identify near-term, least-regrets strategies for enhancing distribution operations that are largely

common across jurisdictions. For instance, a near-term priority for most distribution utilities may be outage management and communication with DER service providers.

Track 3: Longer-Term Issues

Track 3 would create a structured dialogue around DER integration challenges that will require more time to resolve. The ESIG report *DER Integration into Wholesale Markets and Operations* identified seven categories of these longer-term issues: distribution and transmission planning, distribution interconnection, data sharing and communications, distribution operations, market regulation, ISO market design, and utility regulation and business models (ESIG, 2022a). Many of these categories would also have nearer-term, least-regrets strategies.

Careful Design and Implementation

The implementation of these three tracks is envisioned to be through a phased approach over multiple years, with each track building on the previous one(s). Track 1 would provide a common vocabulary, framework, and vision for Tracks 2 and 3. The least-regrets strategies in Track 2 would provide a foundation for dialogue in Track 3.

Given the U.S. electricity sector's diversity in industry structure, utility regulation, and wholesale markets, a national DER integration initiative would require careful design and implementation, particularly around governance and stakeholder engagement. The initiative would need to balance transparency, broad representation, and opportunities for meaningful input with the need to achieve actionable results. To be broadly inclusive, the initiative would need to enable participation by different kinds of utilities (investor-owned, municipal, cooperative) and their associations (the American Public Power Association, Edison Electric Institute, and National Rural Electric Cooperative Association), regulators, NARUC, and NASEO, as well as participation by jurisdictions that are within and outside of RTOs and ISOs.

Implementing a national DER initiative has the potential to bring a range of important benefits to consumers and the electric power system as a whole.

Broad Benefits

A successful initiative would have benefits for different stakeholder groups and for society more broadly. It would provide regulators, utilities, DER service providers, and ISOs with a common vocabulary, frameworks, and vision for distribution system and market operations, as well as greater consensus around nearer-term, least-regrets strategies and longer-term issues and potential solutions. By achieving more standardization in rules and regulations, it would provide more certainty and consistency for manufacturers, DER service providers, and customers. For RTOs, it would help to ensure interoperability of different models for distribution operations and markets across states. For consumers and society as a whole, addressing issues around DER integration would result in more choice, greater competition, lower electricity costs, lower emissions, more innovation, more secure electricity networks, and enhanced reliability and resilience. Implementing a national DER initiative may not be easy, but doing so has the potential to bring a range of important benefits to consumers and the electric power system as a whole, including the broad range of organizations that embody our power system, and provide critical support for the development of a reliable and affordable high-renewables grid.

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The Transition to a High-DER Electricity System: A National Initiative on DER Integration for the United States

A Report of the Energy Systems Integration Group's Distributed Energy Resources Task Force

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The report is available at https://www.esig.energy/der-integration-series-US-initiative.

To learn more about the recommendations in this report, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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