2025 CHARGED CONVENING REPORT

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charged

Charting a path for Greater Electrification on the Distribution system

This document was prepared by the CHARGED Steering Committee and Support Team, which consists of representatives from Advanced Energy United, GridLab and RMI, and a number of consulting organizations who are participating in CHARGED as subject matter experts.

We thank Participants for their collaborative engagement and technical input throughout discussions at the 2025 CHARGED Convening.

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*DISCLAIMER

The views contained in this report do not represent the views of any of the Participant's organizations and cannot be attributed to any single Participant. The Convening discussions presented in the group chapters reflect a synthesis of Participant views. Participants did not engage in group discussions outside of their specifically assigned group. The Convening discussions do not represent a consensus view of the individual Participant or the Participant's organizations.

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INTRODUCTION

OVERVIEW OF THE CHARGED INITIATIVE

The CHARGED initiative supports states as they electrify their transportation and building sectors, ensuring that the electricity distribution system is ready for this new era, while strengthening affordability and reliability for customers. CHARGED engages multiple stakeholders to develop technical solutions that support utility planning and operations for electrification. While CHARGED does not aim to identify a single "standard", it aims to help the industry move beyond the current state-by-state piecemeal approach to utility planning and operations for electrification. The underlying principle is that processes that bring utilities, technology providers, and public interest groups together in collaborative ways can generate creative and effective solutions that will help utilities and states across the country to learn from each other and accelerate the adoption of effective practices.

CHARGED was launched by GridLab, RMI and Advanced Energy United with a convening in 2024 ("Inaugural Convening") that brought 60 representatives from a diverse set of organizations together to develop solutions using collaborative problem solving across several technical and regulatory themes. Since the Inaugural Convening, CHARGED has initiated three broad sets of workstreams that traverse solution development to implementation—"ideation", "implementation", and "education":

- Ideation engages multiple stakeholders across the industry through a collaborative approach to develop innovative solutions with broad applicability;
- Implementation works with specific organizations at the state level such as utilities to deploy solutions through pro-bono subject matter expertise and facilitation support;
- Education builds on ideation and implementation to socialize learnings across a wider set of actors, including regulators.

Under the Ideation workstream, in early 2025, CHARGED initiated three virtual working groups that directly followed from recommendations developed in the Inaugural Convening—proactive investment framework, flexible grid connection, and GIS best practices. Through the Implementation workstream, CHARGED has been collaborating with three utilities on flexible grid connection and program harmonization.

The 2025 CHARGED Convening was held August 12-14 in Chicago as an opportunity for in-person exchanges and ideation. The thematic organization of the 2025 Convening was inspired by previous CHARGED efforts. This report contains preread materials shared with 2025 Convening participants and summary results of the Convening discussions. The report is intended to serve as a reference for those that attended the 2025 Convening and to provide visibility to those that did not participate.

2025 CONVENING OBJECTIVES AND WORKING GROUPS

The objectives of the 2025 Convening were threefold—connect, leverage and innovate.

Connect: Interact and build relationships with different organizations and experts across the industry that are instrumental to achieving the vision of CHARGED. This includes bringing new partner organizations into the CHARGED initiative.

Leverage: Build on previous CHARGED efforts and solutions identified in the Inaugural Convening and being further developed in the ongoing Ideation and Implementation activities.

Innovate: Collaboratively develop solutions that can advance CHARGED objectives and that can be implemented across a diversity of states and utilities. In contrast to the Inaugural Convening, which was structured around more traditional utility disciplines and functions, at the 2025 Convening we aimed to facilitate more cross-disciplinary interaction, which is often needed to implement electrification solutions.

Participants at the convening were divided into the following six working groups:

- Locational DSM
- Data platform and data access
- Medium and heavy duty fleet electrification
- Holistic approaches to grid asset utilization
- Program harmonization and streamlining
- Risk management tools for proactive investment

Although these working groups have overlapping themes, each working group's objective, scope and structure were designed to minimize duplication and ensure that each working group could achieve tangible outputs. The objectives and agendas for each working group were informed by interviews with working group participants prior to the Convening.

ORGANIZATION OF REPORT

This report summarizes the work associated with the 2025 CHARGED Convening held August 12-14 in Chicago. Following this Introduction, the report presents a summary of the 2025 Convening. Subsequently, each of the six working groups from the 2025 Convening have their own sections. Each working group section contains two chapters—a chapter that includes the preread, or "Briefing Document" material provided to participants prior to the convening—and a chapter that summarizes the discussions of that working group at the Convening or "Convening Discussions". The intention of the Briefing Document was to give convening discussions a "running start" and to provide a common set of assumptions and information for all participants, recognizing the complex nature of the topics.

KEY TERMS

For the purposes of this document, here are some key terms. This is not an exhaustive list. Additional terms that are specific to a particular working group are defined in their respective chapters.

Demand side management (DSM) programs	Refers to efforts to reduce the overall consumption of energy (energy efficiency) or the shape of energy consumption (such as load shifting, shed-based demand response) of a customer; it can reflect more traditional program designs or innovative and different future program designs.
Least-regrets solutions	This term was introduced in the Inaugural Convening. These are intended to be practices that most or all jurisdictions can implement in the near term (e.g., within the next three years) with minimal downside, regardless of policy focus, resources, demand characteristics, or regulatory structure. Solutions can be any format, including technical, analytical and process oriented. A focus of the Inaugural Convening was to prioritize a subset of least-regrets solutions for implementation.
Longer-term solutions	This term was introduced in the Inaugural Convening. These are solutions that we expect will require significant exploration and discussion beyond the inaugural convening—possibly through a combination of analysis, ideation, or demonstration.

In some cases, chapters may reference least-regrets and longer-term solutions that were identified at the Inaugural Convening.

SUMMARY OF CONVENING FINDINGS

The sections below provide highlights from each working group in terms of their objectives, activities, key insights and potential solutions and opportunities. Details are found in the chapters dedicated to each working group.

LOCATIONAL DSM WORKING GROUP

Objectives: Align on what successful locational demand-side management (LDSM) looks like; establish requirements for making LDSM effective and scalable; and identify next steps for implementing LDSM at scale.

Working group activities:

- Outlined a strategic goal based on what successful LDSM looks like
- Identified challenges across program deployment phases
- Aligned on opportunities for overcoming these challenges across relevant stakeholders
- Developed potential solutions for advancing opportunities in the near- and long-term.

Key insights:

- Ideally, LDSM can be deployed when and where it is needed, can provide reliable services, and has a viable business model that is attractive to customers, aggregators, and utilities.
- Challenges with deploying LDSM successfully fall across four key themes: integrating LDSM early in the utility planning process; accurately quantifying value and incentive levels for LDSM resources; fragmentation and lack of interoperability across utility, aggregator, vendor and customer technologies; and challenges with data sharing and transparency between utilities on grid needs and values and LDSM aggregators on LDSM performance and capabilities.
- Aggregators, customers, regulators, and utilities all have an important role to play in advancing LDSM solutions, but significant progress in the near-term is dependent on utility action regarding planning and valuation.

Potential solutions and opportunities:

- For planning purposes, utilities can make significant progress in the near-term through:
  - Demonstrations to validate reliable performance in ways that can be incorporated to realize cost savings in distribution planning and operations;
  - Extending their planning horizon to enable LDSM to be implemented and proven in advance of the need or allow backup utility investment if needed LDSM is not realized;
  - Conducting scenario planning to identify least regrets solutions for LDSM and utility upgrades;
  - Defining LDSM requirements in advance of the need coupled with derating and over-procurement to build confidence from a reliability perspective; and
  - Streamlining grid connection processes.

- For valuation purposes, utilities can make significant progress in the near-term through:
  - Defining procurement needs with sufficient specificity and consistency to enable aggregators to efficiently bid LDSM solutions as NWA to utility upgrades;
  - Developing a model cost-benefit evaluation framework for when to incorporate LDSM; and
  - Accounting for additional LDSM potential at the start of forecast and planning processes to robustly quantify potential for avoided utility investment.

DATA ACCESS AND DATA PLATFORM WORKING GROUP

Objectives: To develop a framework to advance the practical development of data platforms with a focus on utility data sharing with external organizations; leverage and align on the ComEd workshop data categories[1] for sharing on a data platform; develop principles for minimum common data platform requirements; establish those minimum common platform requirements (or guidelines for minimum common platform requirements); and begin a conversation on how utilities and utility vendors could technically adopt and adhere to minimum common platform requirements.

Working group activities:

- Defined collective strategic goals for the working group
- Conducted a SWOT (Strengths, Weaknesses, Opportunities and Threats) analysis of current data platform practices
- Agreed on data types and categories and developed technical design principles
- Identified key technical elements necessary for a data platform as well thematic challenges for each element
- Aligned on minimum common platform requirements for each key technical element

Key insights:

- Data access platforms can be a means of providing accurate, reliable, and usable data through a robust, secure, and easy-to-use interface for a standardized and broad set of use cases.
- Challenges with improving data access and designing common platforms fall across seven technical themes: onboarding; authentication and authorization; security and privacy; data scope, availability, and definition; data quality; non-standard implementation; and metrics to measure platform usage and success.
- Principles for successful data platform design include, among other things, making sure the platform is reliable, operational, modular, adaptable, user-centric, and secure.

Potential solutions and opportunities:

- To address the identified platform challenges and meet the design principles, the working group developed a series of technical requirements.
- The working group further outlined two potential near-term projects to advance these principles and requirements:

1 ComEd, ICC Data Access Working Group: Overview of ComEd and JNGO Memorandum of Understanding, 2024, https://www.icc.illinois.gov/docket/P2022-0486/documents/359481/files/629728.pdf

1. Develop a set of national data platform technical standards and best practices with a 'coalition of leaders' (utilities, states, third parties, and utility vendors); and
2. Build a data platform implementation playbook for use by regulators, utilities, and other stakeholders to demonstrate the value of data platforms and to outline a process to scope and implement a platform for a specific state and/or utility.

MEDIUM AND HEAVY DUTY VEHICLE FLEET ELECTRIFICATION WORKING GROUP

Objective: To reduce barriers to medium- and heavy-duty vehicle (MHDV) electrification, the working group will develop a proactive and pragmatic implementation framework for fleet operators and charging providers to collaboratively pursue electrification at their location, covering data requirements, power needs assessments, and bridging solutions. The framework will outline strategies that consider perspectives and solutions across utility planning, grid connection, and program design.

Working group activities:

- Clarified barriers to fleet electrification and define successful fleet electrification at scale
- Identified needs for utilities, fleet operators, and charging providers to enable faster energization
- Aligned on best practices for cost and risk sharing between utilities, fleet operators, and charging providers
- Developed two potential solutions for CHARGED to implement

Key insights:

- Lack of open communication between fleet operators and utilities leads to a lack of electrification of depots. Large fleet operators with multiple locations could prioritize easy-to-electrify depot locations first, but require information from the utility on existing grid infrastructure to aid with that effort.
- Fleet operators face fragmented and delayed incentives and funding mechanisms as well as unclear regulatory requirements, as well as varied regulatory landscapes across states.
- Utilities face pressure to predict and plan for future demand that has higher uncertainty than in the past, while dealing with grid congestion, internal processes not set up to deal with some of the specific needs of fleets, and lack of clear mandates from regulators or funding to engage with fleet operators, energy service providers, or original equipment manufacturers (OEMs).
- Charging providers deal with unpredictability in financing, permitting, regulations, and grid connection processes.

Potential solutions and opportunities:

- Support grid connection and permitting reforms by mapping best practices, including developing a flowchart or guide for utilities to improve their grid connection process for fleet customers
- Enable access to high-quality capacity maps for fleet operators with multiple depots to allow them to prioritize easy-to-upgrade locations first

HOLISTIC APPROACHES TO GRID ASSET UTILIZATION WORKING GROUP

Objective: Develop implementation guidance and best practices to maximize value from operational assets (e.g., distribution system monitoring and controls technologies, utility software platforms, network models, etc.) to extract maximum value from grid assets (e.g., transformers, wires, loads, distributed energy resources, etc.), so as to enable more cost-effective electrification while maintaining reliability.

Working group activities:

- Aligned on definitions for grid assets and operational assets
- Identified key technical, regulatory, and management challenges to improving asset utilization
- Explored success definitions for maximizing asset utilization
- Classified operational assets into necessity tiers, from foundational to tertiary tiers
- Explored "budget" and "deluxe" versions of asset deployment for two use cases: (1) Dynamic flexible interconnection for distributed energy resources to manage grid constraints and (2) locational demand flexibility to shape peak demand for overloaded circuits
- Debated and challenged beliefs around DERMS as a critical asset to increasing grid utilization
- Identified potential steps for improving industry understanding on operational asset utilization and measuring grid asset utilization

Key insights:

- Utilities and regulators are lacking a vision for maximizing utilization of operational assets
- There is a spectrum of approaches to asset deployment—from low-cost, lower capability approaches to high-cost, higher capability approaches. Utilities should examine where budget approaches can be used today to address grid constraints.
- Defining metrics and measuring utilization is complex but essential for improving asset utilization

Potential solutions and opportunities:

- Developing quantitative metrics for benchmarking and reviewing utility performance on grid utilization
- Designing a framework to evaluate operational asset investments and defining success measures for operational asset utilization
- Devising and conducting a tabletop simulation of Dynamic Operating Envelopes (DOEs) with a host utility to alleviate constrained feeders/substations

PROGRAM HARMONIZATION AND STREAMLINING WORKING GROUP

Objective: Develop principles and strategies to help utilities harmonize and streamline multiple customer programs—aligning their design and operations to meet diverse distribution system needs across the service territory, while also accounting for bulk system requirements and supporting beneficial electrification.

Working group activities:

- Aligned on a definition of program harmonization
- Identified circumstances where harmonization may be useful
- Prioritized the design elements around which to harmonize
- Conducted a harmonization activity for a hypothetical utility's program portfolio
  - In the harmonization activity, each group was presented with a utility portfolio containing three distinct demand response programs
  - The group explored how these programs could be harmonized, with a focus on consolidation, based on the program characteristics
- Identified potential steps for implementation of program harmonization

Key insights:

- For the purpose of this working group, program harmonization was defined as an alignment, consolidation, and/or optimization of a given utility's portfolio of load flexibility programs across various dimensions (noting that program harmonization is more than consolidation).
- Program harmonization can have benefits to utilities, aggregators, and customers.
- To ground program harmonization, program dimensions may be useful to consider first when exploring opportunities to harmonize, such as the grid services being provided, or compensation structures.
- Program harmonization may not be appropriate at all times, for example, when program enrollment is saturated or there is no unrealized value.

Potential solutions and opportunities:

- The working group recognized that program harmonization is a topic that requires concrete discussions with a specific utility's program portfolio in mind, rather than more theoretical exploration.
- When exploring program harmonization at a specific utility, the following steps may be taken:
  1. Build internal utility alignment and structure to address portfolio-wide load flexibility goals
  2. Inventory the portfolio of programs along multiple dimensions to identify opportunities for harmonization
  3. Create an action plan for harmonization that takes into account multiple stakeholder types and their perspectives

RISK MANAGEMENT TOOLS FOR PROACTIVE INVESTMENT WORKING GROUP

Objective: Define implementation strategies for risk management of proactive investment, such as performance incentive mechanisms, addressing both the technical dimensions (e.g., a utilization metric) and the regulatory dimensions.

Working group activities:

- Defined proactive investment, including the objectives of these investments, and how it is different from traditional utility investment

- Outlined risks of action or inaction from making proactive investments
- Defined, categorized, and analyzed technical measures of success, complementary measures of success to reflect impacts to customers, and regulatory mechanisms that could be leveraged to reduce risk of proactive investments.

Key insights:

- Proactive investment may be developed to reach objectives such as increased and more timely energization of new loads, reliability, cost/rate savings, and policy goals. The objectives can inform which metrics should be used to assess the rationale and appropriateness for the investment.
- Load factor and utilization factor can be helpful metrics for determining if a proactive investment has achieved its objectives.
- It is essential to implement a package of metrics to look at both technical measures of success, but also complementary measures (i.e., reliability, costs/sales, resilience, operational flexibility) to have a well-rounded perspective for more accurate planning.
- Establishing clear prerequisites for utility planning practices—such as best-in-class load forecasting—could enable more transparent and confident dialogue around proactive investments.

Potential solutions and opportunities:

- Developing a toolkit of proactive investment metrics to standardize the evaluation of proactive investments would enable a better understanding of rationale for the investments, and allow for better monitoring of their success over time.
- A framework or guide for distribution system planning best practices could be a tool for utilities and stakeholders to advance proactive investments and reduce risk.

LOCATIONAL DSM
BRIEFING DOCUMENT

OVERVIEW

Objective: Define requirements for locational DSM that improves the effectiveness of locational DSM measures; and establishes a pathway for these measurements to be integrated into utility planning. Different approaches to implementing DSM measures will be discussed for group alignment, including both customer programs and third-party/aggregator acquisition, and how these implementation approaches factor into the overall effectiveness and integration into planning.

Relevance to CHARGED: Locational DSM was a core focus of the 2024 Convening, including the main topic of a specific workstream (the targeted and integrated deployment workstream). While various least-regrets and longer-term solutions were identified, challenges remain to implement locational DSM in ways that can maximize grid capacity, such as limited representation in planning. A goal of this year's discussions on locational DSM is to leverage and encourage cross-disciplinary conversations, especially between planning and program perspectives.

Locational DSM Definition: Locational targeting of both traditionally passive (e.g., energy efficiency) and active (e.g., dispatchable storage) demand side management (DSM) that provide load reductions to defer specified distribution system investments (as opposed to generalized, unspecified distribution system marginal costs).

This chapter is organized into four sections:

1. ***Connections to Previous CHARGED Efforts***, which describes how the group topic relates to previous and ongoing CHARGED activities, including from the 2024 Inaugural Convening.
2. ***Challenges and Emerging Practices***, which discusses current challenges, emerging practices to deal with these challenges, and provides examples of emerging practices.
3. ***Potential Solutions for discussion at the workshop***, which includes a recap of core challenges, and solutions that span near-term and longer-term components, along with open questions that would benefit from discussion during the Convening.
4. ***Reading List***, which includes suggested preworkshop reading and additional references for those that are interested.

For context, the development of this chapter, and all materials in the briefing document, were based on several perspectives within the internal CHARGED team.

CONNECTIONS TO PREVIOUS CHARGED EFFORTS

The 2024 Convening included workstreams on distribution system planning, and targeted and integrated deployment (which by definition encompassed locational DSM). Both of these workstreams discussed and ranked a number of least-regrets solutions and longer-term solutions that are relevant to this working group including the following.

- Solutions originating from the planning workstream (and all ranked as high priority solutions by 2024 convening attendees) included the following.
  - Considering managed charging, demand response (DR), and other DSM programs in investment planning,
  - Using AMI data, where available, in load forecasting and planning, and
  - Planning for operational flexibility.
- Solutions in the targeted and integrated deployment workstream included the following.
  - Improving coordination among programs, planning, and rates (e.g., processes, data management and sharing, cross-training of staff)—this solution was ranked as the most important among the proposed least-regrets solutions by 2024 convening attendees.
  - Using planning data, program evaluations, and data analytics to better target and design DSM programs where there are expected distribution capacity needs.
  - Partnering with aggregators or allowing them to bid into residential and commercial programs (e.g., interruptible tariffs), since they have visibility into deployed measures that are controllable.
- Longer-term solutions included data sharing platforms that support advanced program design by leveraging existing program data, and support customer targeting to address grid conditions

Currently, solutions are being developed in three ongoing CHARGED virtual-format "ideation" working groups, which will conclude in Q4 of 2025, including a proactive investment framework.

CHALLENGES, EMERGING THEMES AND PRACTICES

Building Trust in Locational DSM Resources

- A central challenge with DSM relates to trust concerns among utility planners and operators, spanning concerns about performance, cost, customer uncertainty, and value, including:
  - Resource performance is not sufficiently predictable (particularly at the aggregate).[2]
  - Less reliable and predictable dispatch and response relative to utility owned resources. Not all resources can be dispatched remotely and customers will not respond reliably.
  - T&D operators may not trust DR for responding to system contingency events.
  - Customer adoption may be slow, expensive, insufficient in volume for response confidence, and not sustainably cost-effective over time.
  - Needs ongoing customer maintenance and participation (e.g., site disabled by blown fuse)
  - Customer internet problems may impede remote dispatch.
  - Cost-effectiveness of DSM annual payments versus a one time grid investment, especially if the DSM measure is multi-year and the planned upgrade is deferred.
  - Short-term 5-year forecasts premised on distrust of DER reliability in construction timelines effectively blocks consideration of DSM for distribution purposes.

2 This perception is a problem for solar, even, which is relatively predictable. Distribution utility planners fully subtract any PV contributions and plan for loss of PV at peak as a "normal" condition.

- **Information needs** to address the trust factor
  - System operators tend to have limited awareness of flexible load and DR measures. It is difficult to build comfort with operators in a field setting because DR and DSM programs are subject to existing pilot and tariff rules, and it can be difficult to modify those to answer new dispatch-related questions. Partnerships with national labs that have building and controls testing labs can help build trust with operators.[3]
  - There is a need to provide information on the uncertainty of the load impact from DSM measures (which are typically provided as point estimates)—and to provide this information for different levels of aggregation. The uncertainty of performance may increase at the distribution level as compared to the bulk power system.

Integrating locational DSM into distribution planning broadly

- **Limiting factors in integrating DSM into distribution system planning**
  - Distribution system planning processes are still inconsistent across the US. Without this forcing function, utilities may not invest in the tools, data collection, or modeling upgrades that may better characterize locational DSM.
  - States and utilities are still learning how to develop and define requirements for utility distribution plans that provide results useful for regulators and stakeholder review. It is difficult for stakeholders to meaningfully interrogate utility plans as to whether DSM opportunities are being fully leveraged.
  - There are few incentives to incorporate locational DSM into the development of least-cost / least-risk distribution grid expansion.
- **Key challenges for distribution system planners with regards to DSM**
  - **Program visibility:** Awareness that DSM programs/capabilities exist, which capabilities are being deployed where, and how they may impact peak loads or load profiles.
  - **Operational visibility:** Resources (ex: demand response) should be incorporated into historical load data and reflected in future forecasts.
  - **Operational alignment / control:** For resources that are dispatchable, they are most often used for bulk system services, which may not fully align with local distribution peak capacity needs, but can count as a distribution resource
  - **Planning / forecasting tools:** Incorporating DSM programs requires tools/processes capable of using input data at scale. Advanced tools, such as LoadSEER, are capable of integrating data and differentiating it within historical and forecast data.
  - **Accurate and granular load profiles:** These profiles are needed with sufficient geographic and temporal characteristics (including seasonal peaks).
  - **Distribution system topology information:** Lack of visibility behind distribution/low voltage transformers affects planners' ability to see the spatial distribution of program impacts. Typically, DER forecasts are aggregated at the feeder level, without customer-level topology mapping.
  - **Accounting for energy efficiency (EE):** Deducing the amount of EE baked into the baseline of load forecast, and how to adjust forward projections.

3 These platforms exist at a number of labs including NREL, PNNL, and SLAC.

Load forecasting considerations

- EE is relatively well understood and often baked into utility planning historical data, though it is generally not always considered as part of future-looking forecasts. Similar to DR, where DR event calls can occur without planner awareness, the effect becomes embedded within historical data. System-wide programs tend not to get enough participation on a feeder level to warrant the level of effort to explicitly consider DSM measures.
- Flexible load is challenging, in part, due to its broad definition and dependence on incentive structures, such as EV charging TOU rates or EV managed charging programs. Similar to EE, it is implicit in historical data; information on past behavior can be used to inform forecasting such as the timing/magnitude of charging. However, if customers have flexibility but don't have an avenue to benefit from engaging it, it may not be appropriate to include flexibility in planning.
- Forecasting challenges have changed with the emergence of power-injecting DERs and electrification. This has shifted the core challenge to predicting the adoption trajectory of such DERs, and predicting customer behavior for these new systems. In both cases, distribution planners tend to be extra conservative.
- Utility load forecasting methods may not be well aligned with common EE industry practices for estimating potential EE savings, leading to a disconnect in expected load forecasts. For example, potential DSM savings are calculated assuming a 'baseline' level of efficiency, which may not be representative for regions with older building stock.

Limitations on implementing locational DSM

- **Lack of methodology consensus:** There is no unifying example, especially on how to determine the magnitude of incentives or structure and administer a successful program. Examples exist, such as in New York, but feel difficult to adapt effectively to other jurisdictions.
- **Utility operational systems:** The ability of distribution utilities to dispatch DSM technologies is still underdeveloped, due in part to a lack of integration between DR platforms and operation systems (such as ADMS) that have visibility of grid conditions and can trigger a dispatch. Even with the integration, operations systems may struggle to track and execute dispatches given the locational and structural system characteristics (e.g., an unmanageable number of substations).
- **Communications and control infrastructure:** Communications from utility systems to DSM technologies face challenges. Cost is prohibitive, especially if installing a physical communication device at the customer site and/or using a cell modem. Internet-based approaches are available either through aggregators/manufacturers, but these may come with trust or cost barriers; IEEE 2030.5 compliant communications platforms are still rare and require compliant DSM technologies such as inverters that leverage 2030.5.
- **Visibility and reliability concerns:** DSM impacts are often not clearly visible, predictable, or reliable from a utility planner and operator perspective. Limited experience and mistrust regarding customer adoption and the reliability of customer responses can cause utility planners to discount potential contributions of DSM in resource planning.
- **Scalability of non-wires alternatives (NWA) and local value programs:** Pilot programs focused on NWA and local value of DSM (or DER) have struggled to scale effectively. Fewer than half of NWA pilots result in successful project awards, limiting broader adoption and effectiveness.

- **High soft costs and interoperability barriers:** Permitting, interconnection, and customer acquisition costs remain significant barriers. Additionally, achieving interoperable communications protocols that enable efficient, technology- and vendor-agnostic aggregation has proven challenging.
- **Fragmented aggregation market:** The market for aggregating DERs is highly fragmented, with original equipment manufacturers (OEMs), energy service providers (ESPs), and aggregators competing to control the customer relationship and utility interactions. Diverse platforms with limited overlap hinders broader integration.

Information needs across key actors

- Information for **program designers and managers** include grid needs (such as overload, voltage support, frequency response) characterized by time (event timing and duration) and location.
- **Aggregators** require the same information to comply with the request and recruit customers. In addition, they require information on DSM measure locations, asset details, and incentives.
- **Distribution system operators** need visibility into DSM asset characteristics, including location, capacity size, hours of operation, constraints, confirmation of dispatch received, historical performance data, and expected performance to project DER behavior. Clear and aligned information between feeder/substation peaks and system peak events is needed for operators who lack control over calling events. Without it, specific locational benefits may be reduced, require more participants, and lack usefulness (depending on the local peak time).
- **Customers** require clarity on incentives, when their resources will be dispatched, and who is controlling their devices.

Examples of DSM integration efforts

- New York has several geotargeted DSM approaches used as planning tools and solutions. Con Edison and Central Hudson both have utilized such programs successfully. (Con Edison deferred an investment upgrade for 10 years via locational NWA. For APS, locational DSM was not planned but a sufficient number of participants were present to alleviate a locational constraint.)
- California has a Distribution Investment Deferral Framework directive (Kevala 2022, PGE 2021).
- Portland General Electric has a DSP exercise that forecasts DSM measures on an agent-based model and aggregates load at the feeder level. IRP modeling must include EE and DR.

Lessons Learned

- Allowing enough time to get a critical mass of DSM adoption is critical to success and requires a longer forecast.
- Incentives for new connectors, changing operating behavior, or existing connectors are necessary for procurement.
- Dispatchability for distribution purposes is a key element of building trust in the performance and ability to provide capacity and/or energy.

- Locational DSM can be pathway agnostic (e.g., programs, procurement via NWA solicitation). For NWA programs, understanding approach, planning, decision making steps, marketing strategies can help guide the process. While still valuable in certain locations, NWA solicitations are not widely scalable as they are a large effort of both utilities and bidders for limited success. Thus all approaches for Locational DSM should be considered in tandem with one another.
- Timelines, regulatory approval, and procurement mechanisms need streamlining. Utility DSPs and grid investments are currently identified off-cycle, usually in response to customer growth. Waiting to identify a large project for initiating the planning process, waiting for regulatory approval, and long-lead time implementation cycles are inefficient. Mechanics of identifying locational value should be agreed upon and standardized, and co-deployment that includes targeted DSM with flexible load and possibly solar and storage should be part of the toolkit to improve efficiency.

POTENTIAL SOLUTIONS FOR DISCUSSION AT THE WORKSHOP

Recap of core challenges

The core challenges for Locational DSM include:

- Utility distribution system planners need to have enough confidence in predictable customer adoption and reliable response from DSM resources to be willing to incorporate them into the long-term planning.
- Load forecasts require accuracy on the quantity, location, and reliability of DSM resources.
- Control and operationalization of DSM assets is an ongoing challenge.

Potential solutions

Addressing planners' needs

- Concrete data on which customers are participating and where (for example, account numbers tied to specific feeders) and the degree to which load profiles are impacted.
- More compelling case studies showing locational DSM.
- Understanding the cost of DSM programs versus the alternatives, including customer acquisition, program, communications and IT, billing and settlement and EM&V costs..
- The load forecast of the availability of more DSM resources in the future matters to determine the longevity of the deferral. The utility needs appropriate methods to measure and verify load reduction or shifts.
- Distribution plans are effective for communicating utility practices to public stakeholders, but not strictly necessary for integrating DSM into distribution planning. For states and utilities not yet required to file plans, avoiding tying DSM to distribution plans may help speed DSM incorporation because of the length and degree of effort required.

Building trust

- Improving visibility and dispatch capabilities; DERMS may be helpful in this regard.
- "Test runs" for DR can help demonstrate the impact and increase preparedness. In an emergency, PGE called DSM resources 30 minutes before being disconnected from the transmission line and were fortunately able to ride through the event without outages.
- Tracking how customer adoption trends and load impacts are progressing compared to

prior forecasts (back-casting) will be important to gain trust in the forecast approaches.

- Aggregators can also take more of the responsibility of performance, reducing the risk for the utility. They can provide historical data and statistical analysis to back up claims.
- Relatedly, non-program (RFP) approaches may help build trust as it shifts the risk of customer engagement away from the utility.
- Geotargeting of programs to specific areas could make it much easier to incorporate them as forecast resources by having sufficient quantity to move the needle.

Analytical considerations

- **Local cost-benefit analysis** based on the rated capacity, proposed upgrade, load growth and deferral potential. Targeting to high value, high probability locations is important given the level of effort involved by all stakeholders.
- **Feasibility analysis of DSM-based capacity deferral** that includes the types of technologies, performance windows, and level of participation needed.
- **Multi-objective modeling and constrained optimization** to better align locational DSM measures into a lower cost overall grid plan.
- **Distribution Locational Marginal Prices (dLMPs)** can, in theory, improve process efficiency via a standardized way to create locational prices that reflect congestion needs of the distribution system. This is a subject of analytical research; however, there are practical implementation considerations of implementing dLMPs.
- Rigorous **Non-Wires Solutions (NWS) screening** for large investments. Smaller opportunities (e.g., deferring a reconductor) may not need extensive community-wide deployment.

Pricing and compensation

- There are a few viable approaches to calculating compensation amounts—value of deferring utility investments, reducing utility O&M costs, option value and risk reduction.
- **Time value of money calculations** determine the value of deferral of investments over a period of time associated with a specific amount of DSM measures. This has been the most common method in valuation studies[4] and is reasonable but relies heavily on the accuracy of forecasts. Shifting an investment timeline can significantly change the overall value. A key consideration is that it relies on deferred project costs increasing more slowly than the utility cost of capital. Given changes in transformer availability and uncertainty from tariffs, the "value of deferral" may be negative, as projects effectively get more expensive in present-year dollars over time, rendering this method unusable for DSM value calculation.
- **Risk management approach,** which is similar to insurance. Large investments over long timelines are associated with forecast uncertainty. Procuring DSM-based capacity in smaller increments can derisk this investment by 'buying' additional time, ensuring load growth is within planned estimates, and creating value via avoided risk. This approach may minimize risk, also, in the context of proactive investments.
- **Compensation mechanisms:** Up-front rebates for new installations are strongly preferred by consumers since future payments may be uncertain and difficult to account for. This rebate could have a "paid over time" structure and/or monitoring/control to ensure

4 Such as in Illinois Illinois Commerce Commission, Investigation into the value of, and compensation for, distributed energy resource, value of DER, final report 2025 www.icc.illinois.gov/programs/climate-and-equitable-jobs-act-implementation-investigation

performance over the expected time period. Once enough resources are deployed, either enrolling in a specific performance period or paying year-over-year for distribution services to existing resources can support extended performance. A market-based approach may incentivize timely use, rather than the current Value of DER approaches which drives adoption but with lessened benefits.

Open questions

- How should we define "predictability", "reliability", and "visibility". What are the acceptable ranges for these terms and how should they be quantified (time or percentage)?
- What does the utility vs. aggregator vs. customer need for successful implementation?
- Are there unique considerations for DSM resources that are passive (e.g., lighting, insulation, HVAC upgrades) versus DSM measures that are controllable?
- What kinds of data need to be shared and how do we compensate for delivering on that value?
- What models for locational DSM exist? What are their benefits and challenges?
- How can locational incentives be calculated? What are the corresponding inputs/outputs?
- How should non-performance be addressed?
- What is needed on the operations side to leverage locational DSM for distribution needs?
- What are the barriers for implementing locational DSM in utilities—is a particular group (i.e., procurement or finance) opposed to locational DSM?
- Are there technological or interoperability limitations with DERMS or integration with utility systems that are a limiting factor for locational DSM?
- Is your DSM budget tied to IRP Planning? DSP?
- Have you deployed an NWA or have you studied them in the past? What are the main barriers?
- Do you have an internal utility mechanism to coordinate across T&D planning and programs?
- Do you have or plan to develop a locational value methodology reflected in tariffs or programs?

READING LIST

Preworkshop suggested reading

- CHARGED Inaugural Convening Report (Distribution planning, and Targeted and integrated deployment chapters), 2024 chargedinitiative.org/wp-content/uploads/2025/12/CHARGED-Inaugural-Convening-Report-2024-2.pdf
- Lawrence Berkeley Laboratory, Locational value of distributed energy resources, 2021
- eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf
- Energy Systems Integration Group, Integrated Planning Report, 2025
- www.esig.energy/integrated-planning/

- Lawrence Berkeley Laboratory, Denver Training for states on integrated distribution system planning: Planning for load growth and local resources, 2025 emp.lbl.gov/publications/denver-training-states-integrated
- Brattle, New York's grid flexibility potential, 2025 www.brattle.com/insights-events/publications/brattle-experts-conduct-a-study-to-determine-new-yorks-grid-flexibility-potential-in-2030-and-2040/

Additional references

- Illinois Commerce Commission, Investigation into the value of, and compensation for, distributed energy resource, value of DER, final report 2025 www.icc.illinois.gov/programs/climate-and-equitable-jobs-act-implementation-investigation
- Miguel Heleno et al., Applied Energy, Optimizing equity in energy policy interventions: A quantitative decision-support framework for energy justice, 2022 www.sciencedirect.com/science/article/pii/S0306261922010510
- Kevala, Distribution investment deferral framework: evaluation and recommendations, 2022 verdantassoc.com/wp-content/uploads/DIDF-Evaluation-and-Recommendations-11-14-22-FINAL.pdf
- Pacific Gas and Electric 2023 Distribution deferral opportunity report, 2023. https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/DDOR.pdf

LOCATIONAL DSM
CONVENING DISCUSSION

WORKING GROUP OBJECTIVES

Original objectives from the Briefing Document

To define requirements for locational demand-side management (LDSM) that improves the effectiveness of LDSM measures; and establishes a pathway for these measurements to be integrated into utility planning. Different approaches to implementing DSM measures will be discussed for group alignment, including both customer programs and third-party/aggregator acquisition, and how these implementation approaches factor into the overall effectiveness and integration into planning.

Working group alignment on objectives

Building upon the above, the working group aligned on the following top-level objectives for the Convening and final report out herein:

- Align on what successful LDSM looks like;
- Establish requirements for making LDSM effective and scalable; and
- Identify next steps for implementing LDSM at scale.

LOCATIONAL DSM DEFINITION AND STRATEGIC GOAL

Definition

For the purposes of this working group, LDSM is defined as locational targeting of both traditionally passive (e.g., energy efficiency) and active (e.g., dispatchable storage) demand side management that provide load reductions to defer specified distribution system investments (as opposed to generalized, unspecified distribution system marginal costs).

Strategic goal

Working group participants engaged in an exercise where they were asked to identify what LDSM needs to be able to do in an ideal state (i.e., under perfect or near-perfect conditions). Through this exercise, participants aligned on three themes, outlined below:

1. It can be **deployed where and when it is needed**. This means:
    a. It can be deployed quickly;
    b. It is flexible and able to respond to changing grid needs; and
    c. It likely comes from multiple aggregators who enroll multiple technologies and customer types to enable needed speed and flexibility.
2. It is a **trusted** resource. This means:
    a. It is reliable, predictable, and dependable;

   b. It is transparent so utilities and aggregators all understand the planning, implementation, and delivery strategies; and
   c. There are clear connections at all operational levels.
3. It is a **viable business model**. This means it is attractive to
   a. Customers with clear benefits to encourage enrollment;
   b. Aggregators to do LDSM in addition to other programs;
   c. Utilities so it is equally considered alongside poles and wires solutions; and
   d. Regulators with equitable net benefits for all ratepayers.

CHALLENGES FOR SUCCESSFULLY DEPLOYING LOCATIONAL DSM

Outline of challenges

Working group participants were asked to brainstorm and identify the barriers to LDSM that emerge in each of the four utility program deployment phases: 1) planning; 2) procurement and program design; 3) implementation; and 4) evaluation. Following this brainstorming, the working group collectively identified themes that consistently emerged, regardless of the deployment phase:

Resource integration into planning

- The planning process has not yet evolved to account for behind-the-meter (BTM) as reliable peak load reducing resources at the distribution level.
- Utilities and regulators are not well educated about resource technological capabilities.
- Reliable performance is sometimes not demonstrated to full satisfaction of distribution planners
- There is a lack of forecasting accuracy and capability at specific locations (e.g., for BTM resources & load).
- It can be difficult to account for its uncertainty in the planning process.

Valuation

- It is difficult to accurately value LDSM resources.
- Current models do not easily value bulk and distribution value together to determine combined net benefits of solutions.
- There is a gap in mapping resources to value depending on network and circuit attributes.
- The uncertainty of timing with new loads can make it challenging to value avoiding investment.

Customer and technology fragmentation

- There is a fragmented landscape of technology, customers, and aggregator players, as well as variation in customer segment participation rates.
- The diversity of locational needs can make standard program design challenging.
- It can be difficult to enroll a high number of customers or kWs locationally

Transparency & Data Sharing

- It is difficult to make distribution planning transparent to regulators and stakeholders.
- There is not enough visibility into data that would support customer targeting, account verification, and technology assessment.

APPROACHES FOR LOCATIONAL DSM DEPLOYMENT

Stakeholder roles and needs in addressing challenges

To address the first three challenges, participants were asked to identify what different stakeholders (aggregators, utilities, customers, and regulators) can offer and what they need from others.

To better account for **resource integration into planning**:

1. **Aggregators** can provide clear resource potential and capabilities. At the same time, they need clear price and location signals from the utility and the ability to re-up costs of the portfolio over time.
2. **Utilities** can provide load disaggregation (how much flexibility, how many EVs on a circuit, etc.); flexibility in the planning process to move faster; and more accurate/precise information on system needs and timing. On the other hand, they need to know what resources can be provided with some degree of certainty; the adoption propensity for marketing levers and monetary values; and the regulatory construct to support longer budget time horizons, flexibility, and sandboxes to innovate.
3. **Customers** can provide commitments to show up and invest in resources. What they need to do this is a clear value proposition for participation and education of the capabilities and benefits of LDSM.
4. **Regulators** can create a new definition for cost-effectiveness and provide clear directives on expectations and incentives for utility action. To support this, they need education on the capabilities and constraints of LDSM resources, including a fuller understanding of the limits of what LDSM can solve.

To improve the accuracy of LDSM resource **valuation**:

1. **Aggregators** can provide historical performance data for utilities to incorporate into stochastic planning; set resource priorities by location, attributes, limits; provide an assessment of potential for adoption of new resources at a given incentive level; provide realistic timelines and cost; and deliver upon commitments. At the same time, they need to know the avoidable locational marginal costs of service and the avoided costs in agreed units; and a determination of what percentage of the avoided costs are provided to the aggregator, participating customer, or other ratepayers .
2. **Utilities** can consider energy management systems in lieu of panel-upgrade driven transformer replacements; use longer-term 10-plus year planning with probabilistic and scenario-based models; explore blended technology portfolios to improve performance and cost-effectiveness; streamline internal processes such as interconnection queues; and identify ‘low-hanging’ fruit by way of ideal locations and requirements. To support this, they need protection from penalties for using LDSM to avoid investment in utility assets and understanding of resource availability.

3. **Regulators** can provide a framework for how to perform cost-effectiveness analysis and allocate avoided costs (i.e., what is shared and how among ratepayers, utilities, and aggregators—balancing incentivizing utilities with cost-effectiveness); as well as an outline of the avoidable, locational marginal cost of service with avoided costs in agreed units.

To address the challenge of **customer and technology fragmentation**:

1. **Aggregators** need transparent and predictable payments, impact measurements, penalties, event parameters, and locational needs; information that supports their ability to target customer acquisition and enrollment based on locational needs; and a performance measurement plan.
2. **Utilities** can build pilot programs to foster the development of new technologies; provide program alternatives (price/kW/location) to aggregators; pursue program-level marketing, including directing customers to lists of aggregators; design flexible programs that can dispatch for multiple locations, needs, hours, and frequency; and provide for the ability of aggregators to communicate with and enroll multiple technologies. At the same time, they need the staff, tools, and resources to manage LDSM programs; a framework for group dispatch and locational requirements; and a performance measurement plan that is clear and ensures the aggregators receive the data they require.
3. **Customers** need value propositions and incentives for enrolling different technologies and participating with multiple BTM devices.
4. **Regulators** can approve a technology-agnostic budget instead of one that is portfolio-based and encourage or require interoperability and open communication standards.

Actionable solutions in the near- and long-term

Next, participants engaged in an exercise to identify where significant progress could be made. This exercise further narrowed in on the top two challenges—resource integration into planning and valuation—and identified solutions in the near- (1 year) and long-term (5 years). Over the **next year**, participants identified six solutions where significant progress could be made, shown in the table below.

Near-term solutions where significant progress can be made in the next year

CHALLENGE	SOLUTION: WHAT CAN THE STAKEHOLDER DO?	HOW?
Planning	**Utilities and aggregators** can make significant progress on demo pilots to show capabilities and performance.	1. Gather comprehensive existing data and identify gaps 2. Define pilots to fill the gap. 3. Build pilot budget and find funding. 4. Confirm pilot details via MxU. 5. Enroll customers and deploy resources.
	Utilities can make significant progress on extending their planning horizon and incorporating scenarios to identify best locations.	1. Seek approval and funding for longer-term forecasts to enable LDSM to be implemented and proven in advance of need, or allow backup utility investment if needed LDSM is not realized. 2. Conduct scenario planning to identify least regrets solutions for LDSM and utility, including by: a. Defining parameters for "overload". b. Developing a time series forecast of load on each asset. c. Defining characteristics of a good candidate asset for LDSM (vs load transfers, etc.)
	Utilities can make significant progress on streamlining their grid connection processes.	1. Use standard communications protocols. 2. "Certify" trusted developers for streamlined review. 3. Add resources and tools to speed the process.
Valuation	**Utilities** can make significant progress defining procurement needs.	Develop a framework for about six utility locational use cases and standards for "signaling" need to aggregators in the planning process with a time horizon. Locational needs and standards could include: • Area (e.g. substation for broad area/feeder level constraint in rural area) • Reliability – load transfer on DA schemes • Electrification hotspots • Microgrids • Natural disaster response & mitigation
	Utilities can make significant progress developing a model framework to evaluate when to incorporate LDSM	Define requirements for "how" to operationalize in planning and operations with specific utility and state parameters that could apply more broadly.
	Utilities can make significant progress on accounting for additional LDSM potential at the start of forecast and planning processes.	Utility incorporates locational DSM in advance of need and with derating/over-procurement to build confidence in reliability. Define and refine performance metrics and expectations.

Over the **next five years**, participants identified five solutions where significant progress can be made on planning and valuation by regulators, aggregators, and utilities, shown in the table below.

Long-term solutions where significant progress can be made in the next five years

CHALLENGE	SOLUTION: WHAT CAN THE STAKEHOLDER DO?	WHAT NEEDS TO HAPPEN FIRST?
Planning	**Regulators** can make significant progress on approving spend for longer term upgrade avoidance.	To approve a filing, the following needs to be included: • Pilot results • Load forecasting • Cost-effectiveness score • Budget • Stakeholder support • Comparison to alternatives • Examples from other jurisdictions
	Aggregators can make significant progress on robust potential studies (likely performed by third parties).	Studies need to be pursued with closer collaboration between developers and consultants. Procurement processes for price discovery and potential assessment need to be conducted.
	Regulators can make significant progress on allocating the value among stakeholders.	The size of the value "pie" needs to be determined with high accuracy. "Pie" shares need to be allocated among: • Utility/shareholder incentives • Customer incentives • Aggregator earnings • Ratepayer savings • OEM payments
Valuation	**Regulators** can make significant progress on supporting the deployment of scalable multi-vendor, multi-technology, and multi-use case pilots.	Stakeholders need to identify the opportunities and needs of such an investment to support effective programs.
	Utilities can make significant progress on data-sharing related to anticipated location-specific grid needs.	Stakeholders need to work with utilities on ICA/HCA maps to identify anticipated grid needs and signal needs for resources. This work must also address: • Security and confidentiality • Internal sharing & coordination

Next steps: potential projects

When discussing the opportunities to advance these near- and long-term solutions and to achieve the strategic goal, the working group identified three potential projects to pursue:

1. **Conduct a study that captures the challenges, gaps, and needs from utilities and aggregators.** The goal of this project would be to provide a useful set of guidelines that generate buy-in from stakeholders. Methods would include interviewing utilities involved in non-wires solutions (NWS) as well as aggregators to identify challenges.
2. **LDSM planning and risk management framework.** This project would establish a framework for identifying the use cases for NWS in the utility planning and procurement process. It would provide a flexible sandbox approach to holistically look at locational needs against different resource options.
3. **Create a framework for designing & implementing standardized RFPs for LDSM.** This project could help a specific utility design their RFP process or build a more generalized framework with utility input to improve information access, data sharing, and process transparency and ultimately, increase the likelihood of procurement success.

DATA ACCESS AND DATA PLATFORMS

BRIEFING DOCUMENT

OVERVIEW

Objective: To develop a framework to advance the practical development of data platforms with a focus on utility data sharing with external organizations; leverage and align on the ComEd workshop data categories for sharing on a data platform; develop principles for minimum common data platform requirements; establish those minimum common platform requirements (or guidelines for minimum common platform requirements); and begin a conversation on how utilities and utility vendors could technically adopt and adhere to minimum common platform requirements.

Relevance to CHARGED: Utilities are some of the most data rich entities, managing system, asset, program and customer data pipelines on the day to day. Today, this data is not being adequately processed for learning and sharing both within utility departments and externally with customers and stakeholders. Effective data sharing can be an enabler for electrification and can support transparent and collaborative planning, interconnection, program design and participation (facilitating market access, innovative tariff designs, and customer opportunities), and operations (monitoring and dispatch signals). Utilities and regulators need minimum common platform requirements or guidelines for defining minimum common platform requirements for each building block of a data platform, in order to effectively scale utility data platforms.

This chapter is organized into six sections:

1. ***Connections to Previous CHARGED Efforts***, which describes how the group topic relates to previous and ongoing CHARGED activities, including from the 2024 Inaugural Convening.
2. ***Scope and definitions***, which clarifies what will be discussed in the working group.
3. ***Challenges and Emerging Practices***, which discusses current challenges, emerging practices to deal with these challenges, and provides examples of emerging practices.
4. ***Potential Solutions*** for discussion at the workshop, which includes a recap of core challenges, potential solutions, and open questions for discussion during the Convening.
5. ***Broader Considerations for Data Platform Development*** (Beyond the Workshop), which includes potential solutions outside of the scope for the Convening but worth keeping in mind.
6. ***Reading List***, which includes suggested pre-workshop reading and additional references for those that are interested.

For context, the development of this chapter, and all materials in the briefing document, were based on several perspectives within the internal CHARGED team.

CONNECTIONS TO PREVIOUS CHARGED EFFORTS

Improving data sharing across operations, departments, and actors (intra-utility, utility to external actor, and external actor to utility) was treated as a cross-cutting issue across workstreams at the 2025 Inaugural convening with a major focus on intra-utility data sharing. Potential solutions were primarily highlighted in the Targeted and Integrated Deployment group (although data sharing was a theme that resonated across all workstreams) which emphasized data sharing among utility departments, as well as data platforms that enable utilities to improve program design by learning from and leveraging existing program data.

SCOPE AND DEFINITIONS

The information in this chapter provides a broad background and context for the working group. Not all information will be used in the working group, based on the scope below.

In scope: Technical platform design and technical elements for implementing minimum common platform requirements.

Out of scope: Regulatory policy, including regulatory or utility motivation for data platforms, security and liability related to platform investment risks, and a policy roadmap for implementation of data platforms.

Table of Definitions

TERM	DEFINITION	EXAMPLE	ANALOGY
Data Platform	Overall means to share utility data to the public	NY IEDR	Pizza
Design principles	Guidance for the development of requirements	"This is scalable, secure and efficient"	Pizzas must be tasty
Minimum common platform requirements	The details, descriptions and characteristics of what the utility data platform should do	Use 128 bit encryption and 2-factor authentication	Use organic, wholemeal and U.S. sourced flour

CHALLENGES, EMERGING THEMES AND PRACTICES

Commonalities and differences in data platform elements

- Generally, a data platform consists of two key layers (often with several sub-layers and middleware depending on the platform design):
  - **Frontend layer:** This represents the external layer which stakeholders would interact with to securely access data
  - **Backend layer:** This represents the collection of internal systems that would provide access to data from internal utility systems
- Other common data platform elements that are needed across states and utilities include:
  - Use cases and associated data categories, types and requirements
  - Data formats
  - Data access methods (API, downloadable xml etc.)

- Data quality assurance and cleansing protocols
- Customer authentication & authorization methods
- Critical Energy Infrastructure (CEI) data risk assessments.

- Unique data platform elements by state/utility include:
  - Customer requirements which may be subject to local ISO settlement requirements.
  - Program and policy tracking data would need to address state/utility specific elements.
  - Vertically-integrated utilities vs restructured states may affect sharing across institutions/ market orgs
  - Different methods and protocols for collecting and storing data across utilities (different softwares, units, and data categories).
  - Different data availability and quality.
  - Different designs of the backend of the platform would need to account for the unique characteristics of each utility's existing data sources and systems.

Data categories, needs, and use cases

- As part of an effort with Commonwealth Edison Company (ComEd) on data platform development, a visualization effort generated 5 data categories with 17 types. The five categories are customer, system, rate & tariff, program, and policy goals & metrics.
  - A challenge in developing and implementing a data platform roadmap is determining which to prioritize and whether all categories should be made available. One position is that data types across the customer, system and tariff/rate information categories should be made available regardless of individual utility/state characteristics. Each data type within each category is more valuable as part of a broader set of data types. Third parties generally use these data types together.
  - There may also be categories not yet captured, such as DER data/DER registry. This will be crucial for DER participation in distribution and bulk power markets and the inevitable coordination between both.
  - There may also be additional information required to use the data commercially and questions regarding liability risks.
- Identifying priority data category needs for each stakeholder defines who requires access to what data, and can help ensure the platform design meets users' needs. These needs vary and alignment can be challenging.
  - For **market participants (solar/EV developers, aggregators etc.)** customer, system and rates/tariff data may be most useful creating customer propositions, though the specific requirements for customer data types may vary depending on the jurisdiction.
  - For **regulators and SEOs,** rates, programs, and metrics data may be most useful for the purpose of oversight and meeting policy goals.
  - For the **clean energy industry,** system data may be most useful for increasing renewables penetration.
  - For **market providers**, system, customer, and program information may be most useful to help them make more accurate proactive investments, understand the effectiveness/ shortcomings of existing programs, and plan for future load.
- **Platform users and customers** have their own unique set of challenges and questions that should be considered for data sharing and platform access, including the following.

- Does there need to be a registration for accessing data? If so, what is the process?
- Regarding consent and authorization, what sensitivities exist? Can it be streamlined? E.g., using two-factor authentication to verify identity.
- Is an NDA necessary for a member of the public to access some or all utility data?
- Is it possible to access a live feed to the utility data?
- What technical support can be provided for users accessing the platform? Is there clear and up to date guidance on the platform, and issues, and upcoming features?

Considerations for data platform design and development

- Questions to consider in platform development and design may include the following.
  - What are the different platform design principles, options, and related pros and cons?
  - How is data handled, cleaned, and prepared for access on the platform?
  - What are the pros and cons of incorporating a data lake/single source of truth into platform design with automated data updates to ensure data is up-to-date for users?
  - What processes are there for accreditation/trusted access?
  - Will a data platform have associated governance? By whom?
  - Will the platform hit into a wider data ecosystem, allowing scaling using the same protocols for 3rd party to utility, and 3rd party to 3rd party?
  - How can out of the box, software as a service (SaaS) solutions impact platform design?
  - How is the platform design accounting for customer consent, confidentiality, and grid security frameworks?
- On the latter question, frameworks for accessing data have implications for customer and system data (privacy and Critical Energy/Electric Infrastructure Information (CEII) impacts), both between the customer and the utility and also between the utility and a third-party. Consider:
  - **Customer Consent & Authorization (Individual Customer Data):** Developing a framework for a simple yet secure and transparent way for customers to authorize third parties to access their data.
  - **Grid Security (System Data):** Developing a framework for how tiers of system data can be made available such as 1) publicly available, 2) available to specific users provided security assurances (e.g., NDA, trust frameworks etc.) and 3) not made available at all. This process should methodologically go through each system data type, determine whether there is a true security threat to making it available and then should be assigned a value of importance to stakeholders based on specific use cases.

Platform development investment

- Developing data platforms may pose investment challenges across the two core layers:
  - **Frontend layer:** For most utilities, the frontend will always require new investment given the assumption that the status quo does not sufficiently provide access to the data needed (e.g., legacy customer data platforms) or provided needed data at all. Moreover, most existing utility solutions provide a somewhat fragmented data offering (different types of data across different platforms such as customer portals, hosting capacity maps, interconnection portals, regulatory reports etc.). Providing a centralized data platform necessitates a new front end instead of retrofitting legacy structures. The latter may entail bespoke solutions plagued by legacy platform designs and less sophisticated ways

to access data (i.e., downloading spreadsheets vs. access via an API).

- **Backend layer:** The backend of a platform may need significant new investments depending on the existing utility data infrastructure and whether the utility seeks to enhance or design an entirely new system. For example, if a utility has a complete system model they can share that information immediately. They could also have a partial system model which could be shared immediately while enhancements are made to the model over time to improve visibility into the system. However, if they have a very limited system model then investments may be needed to create a modern system model which could then be shared with stakeholders.

Other general challenges

- Developing and/or improving data platforms are significant, resource-intensive efforts.
- There may be significant stakeholder fatigue as many have gone through exhaustive processes in multiple states and are still waiting to see things implemented in an easy and scalable way.
- Some utilities will have better data quality than others, affecting a common approach.
- To make the platform valuable, it has to be designed to scale from the start. This means designing it to accommodate many users, datasets, and refreshes.
- Governance of the platform is complex —that is, how the platform will be managed through implementation, how decisions will be made on future iterations of the platform and who will be at the table to make these decisions.
- There may be varying technological capabilities across utilities, including inconsistent, incomplete data models; legacy customer consent and authentication processes; and a lack of modern access methods such as APIs.
- There are also security and liability discussions to be had for the implementation phase of a platform design, including who bears the risks for different investments.

Notable examples of platform design processes and discussions

- An ambitious “data sharing infrastructure” is being developed in Great Britain, owned by the National Electricity System Operator, under regulatory oversight. The design builds off the “digital spine” concept and completed feasibility study, similar to Google X’s Tapestry project.
- New York’s Integrated Energy Data Resource (IEDR) shows that states have some say in the conversation around data sharing security concerns. This might mean it’s easier for states to regulate data sharing than it is for utilities to standardize independently.
- A group of New England utilities has submitted a Grid Readiness and Integration Proposal focused on customer and DER data, demonstrating utility interest in DER data/registry as part of a platform (Ropeik 2024).
- As shared previously, the ComEd process for data platform development is worth reviewing and reflecting on, particularly as it was the first utility to voluntarily commit to a platform and self-run a process. Three key elements have made the process and workshops successful: 1) having a clear objective for the end outcome; 2) running a software development requirements gathering process; and 3) having several distinct ways to engage with stakeholders that built off each other and aligned with a software development requirements gathering process. It should be noted that the ComEd effort has focused on platform design and not buildout as of yet.

POTENTIAL SOLUTIONS FOR DISCUSSION AT THE WORKSHOP

Recap of core challenges

- Data platforms can vary substantially by design, technical capabilities, protocols, customer requirements, and user needs.
- There's emerging alignment around data categories and types, though clarity is needed on which are applicable across states/utilities and which are priority needs by stakeholder type.
- Data platform design/development triggers critical questions on approach, access, outcomes, data validation, governance, users, confidentiality, customer consent, and grid security.
- Enhancing existing or developing entirely new frontend and backend layers of data platforms can be significantly resource- and cost-intensive.
- The increasing number of platform development efforts may create stakeholder fatigue, duplicative efforts, and fragmented designs.

Potential solutions for discussion

- **Framework for backend layer development:**
  - Designing a long-term, durable platform means ensuring the backend is designed to support such an objective. A utility could use existing systems, enhance those systems, or build new systems. Any of these options should ensure the following.
    - Each set of data within each data category is appropriately linked, cleaned and validated for dissemination.
    - There are appropriate links across data categories where appropriate (e.g., customer mapped to their feeder).
    - Significant rework of the platform is not needed if legacy systems are replaced.
  - When designing the backend for a data platform, utilities typically move to build out a data lake which would be designed based on a uniform data model. A data lake ensures the foundational infrastructure is in place to consolidate, link clean and validate the data. This ensures that even if legacy systems that provide some or all of this data are replaced (e.g., meter data management system), the data platform is not directly connected to specific data sources but a modern data lake that is independent of any specific data source.
- **Key elements to standardize**:
  - **Linking data categories and types in a unified data model:** Standardization of these components will be foundational. The unified data model is critical to ensure utilities follow the same structures and formats. This allows the market to build standardized solutions and gives clarity and replicability to market participants.
  - **Data requirements:** This may include specifics on granularity of data, update frequency, amount of historical data etc. These may be harder to standardize given the different capabilities across utilities and specific ISO metering requirements. However, guidance could be provided on ideal requirements so platforms can evolve over time.
  - **Customer Consent & Authentication Processes:** This process can be one of the biggest roadblocks to data access due to archaic utility processes. Standardization is needed.

- **Grid Security Framework:** Different utilities have different opinions on what system data should be public vs provided via NDA vs. not public at all. However, standardization would strongly benefit the industry and electrification processes.
- **Methods of access:** Providing access to data via APIs is the standard and modern way for securely sharing data. This is a strong candidate for standardization.
- **Performance metrics/Uptime:** Data platforms should be treated as critical infrastructure and maintained as such, with uniform guidelines to ensure consistent functioning.

- **Standardization implementation mechanisms:**

  Methods of standardization, with different levels of maturity, include the following:

  - **Documentation:** This entails standardizing data access by establishing guidelines via technical documentation that are updated over time as standards evolve.
  - **Digital tools/platform:** Digital tools and/or a platform would build on technical documentation to provide more sophisticated and potentially more streamlined ways to adopt data standards. This would require building digital tools that reflect the documentation (and is updated as standards are updated) to make standardization easier to adopt by states and utilities. Two examples could be 1) providing open sourced code to support platform development and 2) building a unified data model and frontend of the platform which could then be licensed by utilities and states with access to updates as they are made.
    - **Pro:** This would streamline adoption across utilities and states, drive efficiencies, and improve scalability as the platform is built once for nationwide deployment.
    - **Con:** This may require significant resources to build digital tools.

- **Gathering software development requirements:** Any process to determine the requirements of a platform should be grounded in software development principles, starting with understanding third parties objectives to determining detailed software platform requirements to meet those objectives. Determine the data requirements for each data category and type to enable each use case, which include the following elements:

  - **Data dimensions:** The specific data points that are of most value to third parties within the broader data category and type (e.g., billing quality interval data versus raw meter data).
  - **Update frequency:** The frequency with which the data must be refreshed to ensure it remains valuable and able to support the identified use cases.
  - **Data granularity:** The level of detail or precision needed for a type of data.
  - **Historical data:** The amount of historical data that should remain accessible to authorized third parties to ensure the data is useful.
  - **Access method:** The different mechanisms through which authorized third parties would request, receive, and access a particular type of data.
  - **Standards:** Established industry guidelines or protocols to help enable interoperability between systems accessing the data by authorized third parties.

Open questions

- What does data access standardization mean to the group?
- What standardization is necessary to improve data sharing?
- What makes sense to standardize vs what to leave to the discretion of utilities and states?

- What outputs should we focus on to support the objective? What can't the convening produce, but could set in motion?
- What is already done and does not warrant duplication?
- What are the building blocks of a utility data platform?
- Can uniform processes be established for customer consent and grid security frameworks?
- Are all 17 data types/5 categories applicable across states and jurisdictions? Are there data types that all data platforms should contain (e.g., customer, system and tariff/rate data categories)?

BROADER CONSIDERATIONS BEYOND THE CONVENING SCOPE

- **Steps for data platform development** (inspired by the ComEd and NARUC frameworks):
  - **Collaboratively develop a design approach and a roadmap:**
    - Define a platform vision in collaboration with stakeholders. (This may include developing requirements, a process to develop a customer consent framework, and a process to develop system data grid security framework.)
    - Define which stakeholders need access to data and would be platform users.
    - Define the objectives of stakeholders and the corresponding use cases in which they would use data.
    - Determine the data categories and types required for each use case.
    - Ensure stakeholders can partake in iterative engagement.
    - Identify whether common infrastructure questions are considered and designed for, and relatedly, whether governance structures have been established.
  - **Further stakeholder engagement process considerations:** Engagement with stakeholders should begin early, be iterative, and include diverse stakeholder types. Other considerations for effective and robust engagement include the following.
    - **Set an upfront understanding that there is only so much data:** While use cases may be diverse across stakeholders, there is only so much data within the utility and there are generally a common set of data categories and types needed across stakeholders.
    - **Conduct dedicated interviews by stakeholder type:** Given the broad set of stakeholders needing data, dedicated interviews should be conducted for each individual stakeholder group (utilities, consumer advocates, customers, service providers, etc). This creates focused venues where the needs of each specific stakeholders group could be focused on.
    - **Synthesize the objectives and data need:** Following the visioning, data collection, and interviews input, synthesize the results into an outline of key use cases, data categories, data types and data requirements.
    - **Follow-up iteratively with stakeholders:** Solicit follow-up reviews and engagement with stakeholders to ensure the results reflect their needs and to provide insights on the array of needs that require alignment.
  - **Implementation options:**
    - Implementation could begin with building a utility data centric alpha (with limited portals, datasets, refreshes) and a strategic plan for how this platform could scale to a digital ecosystem or data sharing infrastructure.

  - A modular approach could be considered, where aspects of existing standards or data sharing protocols such as Green Button and UK data standardization processes, could be leveraged in the interim.
  - A very basic version could create bespoke data copies for download stored specifically for this, but this is not scalable. Data should be accessed at source, creating live links, rather than data for periodic download. This type of integrated approach is far more complex but far more scalable.

- **Roles in national-level standardization**
  - In order to deploy a national-level standardization effort, a critical mass of buy-in from organizations and jurisdictions is needed, such as these types of organizations.
    - 2-3 utilities representing entire regions
    - 2-3 states and/or regions
    - Major third party/industry orgs representing platform users
    - Organizations with expertise developing data standards
    - Utility trade associations/thought leaders
    - Potentially, agencies dealing with CEII/NERC for the system data component
  - A utility-led approach alone is likely unsuitable and may not reflect the necessary change in design and approach. Instead, there needs to be a cross-section of stakeholders and organizations, including utilities, regulators, and data users that are intentionally engaged in collaborating and executing change.
  - There may be roles for NARUC (regulatory coordination) and national standards bodies.
  - Commissions can play several different roles depending on the willingness of utilities to move forward on data platforms.
    - Facilitate regulatory processes to define platform requirements and processes/Issue orders memorializing requirements/processes.
    - Establish governance structure of platform.
    - Conduct consistent oversight of the platform and course correct in the event development deviates from the plan.
  - State agencies can also play several roles, including platform owner. This can carry risk especially when it comes to utilities being willing to share customer and system data both of which is considered sensitive. State commissions/agencies can also engage with other states to work towards a standard and/or adopt new standards to avoid running duplicative regulatory processes.

READING LIST

Preworkshop suggested reading

- ComEd, ICC Data access working group: progress update, 2025 www.icc.illinois.gov/downloads/public/DAWG/ComEd%20-%20JNGO%20MOU%20-%20Data%20Sharing%20Platform%20-%20DAWG%20Session%20(May%2015).pdf

- CHARGED, Inaugural Convening Report (Data access and sharing chapter), 2024 chargedinitiative.org/wp-content/uploads/2025/12/CHARGED-Inaugural-Convening-Report-2024-2.pdf
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- NARUC Grid Data Sharing Summary of State Practices, 2022
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- Ofgem, Decision on updates to Data Best Practice Guidance and Digitalisation Strategy and Action Plan Guidance | Ofgem, 2023 www.ofgem.gov.uk/decision/decision-updates-data-best-practice-guidance-and-digitalisation-strategy-and-action-plan-guidance

DATA ACCESS AND DATA PLATFORMS

CONVENING DISCUSSION

WORKING GROUP OBJECTIVES

Original objectives from the Briefing Document

To develop a framework to advance the practical development of data platforms with a focus on utility data sharing with external organizations; leverage and align on the ComEd workshop data categories for sharing on a data platform; develop principles for minimum common data platform requirements; establish those minimum common platform requirements (or guidelines for minimum common platform requirements); and begin a conversation on how utilities and utility vendors could technically adopt and adhere to minimum common platform requirements.

Working group alignment on objectives for report-out

The working group aligned on the following three objectives for the convening report-out:

1. Share the working group's aligned-on strategic goal, draft design principles, and requirements with utilities, regulators, and other stakeholders (including utility vendors and data users), in order for others to apply these in their work.
2. Share proposed steps for how the common data platform requirements could be taken forward.
3. Cultivate wide stakeholder buy-in to develop and implement design requirements by demonstrating internal utility value and progress.

DATA ACCESS DEFINITIONS, SCOPE, AND STRATEGIC GOAL

For the purposes of this working group and this chapter, the table below defines the terms utility, utility vendors, customers, data platform users/third parties, and stakeholders.

Defining interested parties

TERM	DEFINITION
Utility	The Investor Owned Utility business
(Utility) vendors	Technology firms working for the utility to provide data platforms and/or source systems for data
Customers	The utility customer (may be residential, industrial, commercial)
Data platform users/third parties	Broad term for anyone accessing a utility data platform (may include customers, DER developers, aggregators, academics etc.)
Stakeholders	Broad term for all interested parties in utility data platforms (may not necessarily use the platform).

Scope

In order to focus the discussion and deliver actionable solutions, the working group took the initial briefing document scope and further refined it, emphasizing a focus on technical requirements of platform design rather than policy and security discussions. This delineation is captured in the table below.

Data access and sharing working group scope parameters

IN SCOPE	OUT OF SCOPE
Designing the programmatic interface to share data with external partners, which includes: • Technical platform design; • Cyber security; and • Technical elements for implementing minimum common data platform requirements.	• Regulatory policy, including regulatory or utility motivation for data platforms; • Liability related to platform investment risks; and • Policy roadmap for implementation.

Strategic goal

Participants were presented with a draft strategic goal for the working group over the course of the Convening, identifying the "who", "why", "what", and "how" for successful data platform deployment. The working group collaboratively discussed the draft, made amendments, and aligned on the following strategic goal:

> For authorized external and internal users that need to efficiently exchange utility customer, system, rates, program, and metrics information, the data access platform is a solution that provides accurate, reliable, and usable data through a robust, secure, and easy-to-use interface for a set of standardized use cases.

MOTIVATIONS AND CHALLENGES FOR IMPROVING DATA ACCESS

Working group motivations

When asked what motivates them to improve data access work towards the aligned upon objectives, participants shared the following:

- Data is **foundational to all other topics** and is critical for **scaling clean energy**.

  - This is true both for advanced energy companies and utilities so they can all do their jobs better and so the investments being made in DERs and the grid can be maximized.
- **Improving customer programs** requires enhanced data access and sharing.
  - There is a lot of data being generated (e.g., from AMI), but not accessed or used to its fullest potential by customers or the market.
  - A common platform can drive beneficial data use for all types of utilities (e.g., water).
- Improving access necessitates **streamlining customer, third-party, and utility data use**.
  - Improving the availability of customer-specific data is especially necessary given more complex rates, market integration, and the greater reliance on third parties outside of the utility (e.g., aggregators and developers).
- Removing silos limiting inter- and intra-organization data exchange allows for **getting the most out of data.**
  - There is a need to move beyond bespoke solutions for customer programs and towards a platform that enables a broad suite of tools, programs, and planning.

Outline of challenges

Following the discussion of what motivates participants to advance this topic, the working group discussed the initial list of challenges facing data platform development captured in the briefing document. They further generated seven thematic pain points as described below.

Onboarding

- Challenging onboarding processes hinder third-party and account holder participation.
- Restrictive terms, fragile processes, inconsistent and at times limited utility support, and a lack of automated or self-service tools prevent efficient integration and can deter potential users.

Authentication and Authorization

- Cumbersome authorization and consent processes, manual registration, bespoke (not Green Button Certified) authentication, and antiquated technical requirements tied to previous implementations create delays and can discourage new data platform users and utility vendors.
- These characteristics make it challenging for third-parties to register to use platforms and for customers to easily and securely authorize third parties to access their data in a streamlined manner.
- Customers often have to create and use utility online accounts that vary in quality and accessibility. Customers then frequently need to initiate data sharing, which is a significant barrier to engagement.

Security and Privacy

- There is a cost to maintaining privacy and critical infrastructure security processes against current security standards and best practices.
- Security challenges may also emerge with regard to monitoring and revoking access, when necessary.

Data Scope, Availability, and Definition

- There is a disconnect between the data shared and the data needed for essential business and regulatory functions (e.g., program enrollment, bill consolidation, aggregation), making it difficult for data platform users to perform meaningful analysis and meet customer requirements.
- Accessing necessary data remains challenging due to complex formats, models, and billing structures, which limits the ability to fully utilize available options and solutions.

Data Quality

- There are no clearly defined service level agreements on data custodians covering data quality and availability. As a result, there may be services that are inaccurate or unreliable.

Non-Standard Implementations

- Highly customized, non-standard implementations across individual utilities create siloed experiences and limited interoperability between utility and non-utility solutions.
- Bespoke customization often adds value only to a single utility, rather than addressing broader industry needs or standards.

Measuring Platform Usage and Success

- There is difficulty demonstrating platform value due to limited insight into platform performance and what use cases are enabled for third-party platform users.
- There is a need for a shared definition of “customer benefits” and “cost-effectiveness” that go beyond the benefits incurred to data platform users, and includes system benefits through use of common standards.
- There is a need for metrics to track the usage of the platform to demonstrate its benefits.

APPROACHES FOR DATA PLATFORM DEVELOPMENT

Data platform design principles

Working group participants conducted an exercise to determine the key design principles necessary for effective platform development. Participants were asked to complete the sentence, "A utility data platform should be…so that it…". Through this exercise, nine principles were identified, with the objective for each captured in the table below.

Data platform design principles, as identified and described by the working group

A DATA PLATFORM SHOULD BE…	SO THAT IT…
Reliable, dependable, and trusted	Can support core business/regulated processes, market development, and deployment.
Operational	Can support ongoing processes, is available when called upon, and can support business processes such as market settlement.
Self-describing and extensible	Can evolve and grow as the context changes and adapt to the unique needs of certain contexts.
Low-level and cross-cutting	Addresses common needs across many stakeholders without getting too narrow in the use cases of certain users.
Modular	Is more resilient to changes and flexible to accommodate new capabilities without compromising the structure (e.g., future user segments, use cases, and value propositions).
Designed for change management	Is extensible and can change without breaking integrations and is future-proofed.
User-centric	Meets the needs of the diverse set of users (not just utilities or customers but also third parties; easy to use/provides necessary information when needed without unnecessary barriers/burdens to use.
Useful to customers	Is capable of creating value and is a net benefit to all ratepayers by helping bring downward pressure to rates.
Secure and privacy protected	Protects customer privacy and critical infrastructure and complies with relevant laws.

Data platform requirements

Based on the identified challenges and design principles, participants collaboratively identified a broad set of technical standards requirements by answering the question: "A data platform must have…which means that the platform can…". These are laid out in the table below.

Data platform requirements and purposes, as identified and described by the working group

CHALLENGE	REQUIREMENT (A DATA PLATFORM MUST HAVE…)	PURPOSE (WHICH MEANS IT CAN…)
Onboarding	Self-service onboarding with a publicly available sandbox and best practices for legal documents (e.g., terms & conditions).	Accept users at scale across jurisdictions and enable users to test technical requirements in advance of fuller roll-out.
	Multiple pathways and right-sized onboarding based on user type, needs, and data risk.	Accommodate the type of onboarding that makes sense for the user; avoids overly onerous onboarding for low-risk users, use cases and data types.
Authentication and Authorization	Ability to serve account holders with and without digital presence (through something akin to "open ID connect").	Enable users to connect with the platform with minimal friction.
Security*	Identity and access management control functionality by user type, data type and other elements where appropriate.	Allows for appropriate access into varying levels of detailed information.
	An access control framework to configure identity and access management control functionality.	Provide fine-grained appropriate access.
Privacy	The ability for the account holder to provide, revoke, and monitor who has access.	Support transparency, customer control, and auditing while providing the customer with control over access to usage information.
Data Model	A robust data model that outlines minimum data dimensions and relations for foundational data elements.	Fulfill common use cases; have a publicly available data dictionary; support access to a standardized data set; and provide clarity on how data points relate to each other
	A robust data model built on utility and industry developed standards.	Provide data in a way that is understandable across states and entities.
Data Scope, Availability, and Definition	A discovery service and publicly accessible API "inpoint".	Be found and made available to stakeholders.
Data Quality	The ability to communicate the type of data quality.	Designate and communicate whether data is billing quality and revenue grade.
	The ability to communicate system health with users.	Understand whether some or all of the platform is currently available for use and, if not, what the technical blockers are.
Non-Standard Implementation	Technical standards across requirements where appropriate (e.g., an open standard with clear API specification).	Provide data access based on standards developed by a broad set of stakeholders.
	Best practices across technical platform requirements where appropriate (i.e., where technical standards are not appropriate).	Provide access to data based on practices developed across a broad set of stakeholders.
	Certification and conformance processes to ensure standardized implementation and rectification for production deployments.	Be independently verified as likely to deliver data access benefits and developed more modularly.
Measuring Usage and Success	Platform metrics and reporting.	Transparently provide information on its performance and usage, which is necessary evidence by which its value can be assessed.

** Comply with North American Electric Reliability Corporation (NERC), Critical Infrastructure Protection (CIP), and other cyber and privacy requirements where relevant*

Next steps: potential projects

When discussing the near-term opportunities to advance these principles and requirements and to achieve the strategic goal, the working group identified two potential projects to pursue:

1. **Developing a set of national data platform technical standards and best practices with a 'coalition of leaders'.** This project would develop national data platform technical standards and best practices with utilities, states, third parties and utility vendors. The standards would be rolled out iteratively to be incorporated into ongoing data platform implementations, providing proofs of concept for replication and wider adoption.
2. **Building a data platform implementation playbook.** This playbook would be for use by regulators, utilities, and other stakeholders to propose, review, approve and implement data platforms. The playbook would systematically address why a data platform is a critical step toward grid modernization and lay out key steps for a process to scope and implement a platform for a specific state and/or utility.

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MEDIUM AND HEAVY DUTY FLEET ELECTRIFICATION

BRIEFING DOCUMENT

OVERVIEW

Objective: Develop strategies to reduce barriers to MHDV electrification that consider perspectives and solutions across utility planning, grid connection, and program design. This working group will develop an implementation framework for fleets and charging providers to pursue electrification at their location, covering data requirements, power needs assessments, and bridging solutions. We will focus on "return to base," or"behind-the-fence", MHD vehicles which are electrifying the fastest (e-delivery vans, return-to-base class 8, and e-school buses) given their charging location, schedule, and load are those charging providers are most pressed to support; and that they offer opportunities for flexible interconnection and bidirectional charging.

Relevance to CHARGED: Barriers such as delayed timelines, infrastructure costs, and rate increases threaten electric fleet cost competitiveness and electrification goals more broadly. MHDV fleets can have particularly large power requirements relative to other distribution-connected loads, as well as different load shapes, which raises unique challenges. Ensuring that utilities and fleet owners/operators are equipped to pursue the most cost effective path for an electrified future is critical to reducing overall utility and customer risks.

This chapter is organized into four sections:

1. ***Connections to Previous CHARGED Efforts***, which describes how the group topic relates to previous and ongoing CHARGED activities, including from the 2024 Inaugural Convening.
2. ***Challenges and Emerging Practices***, which discusses current challenges, emerging practices to deal with these challenges, and provides examples of emerging practices.
3. ***Potential Solutions for discussion at the workshop***, which includes a recap of core challenges, and solutions that span near-term and longer-term components.
4. ***Reading List***, which includes suggested preworkshop reading and additional references for those that are interested.

For context, the development of this chapter, and all materials in the briefing document, were based on several perspectives within the internal CHARGED team.

CONNECTIONS TO PREVIOUS CHARGED EFFORTS

The CHARGED initiative was created to enable electrification across transportation and buildings, with electrification of medium and heavy-duty fleets as a significant use case. The Inaugural Convening identified least-regrets solutions and longer-term solutions that can support fleet electrification. Given the cross-cutting nature of fleets, solutions were identified across the different workstreams—planning, grid connection, operations, deployment, rates and incentives. Some examples are included.

- Distribution planning: improved load forecasting, such as better understanding load growth for large customers, especially fleets
- Rates and Incentives: Offering some form of opt-out TOU rates for all customers, with customer education/opt-in rates for commercial fleets
- Targeted and integrated deployment: Establishing partnerships with industry organizations such as local and regional fleet associations
- Grid connection: Static flexible interconnection, which uses load management strategies and technologies to reduce the overall impact of the resources on the system, reducing system upgrade costs and shortening connection times
- Distribution operations: Prioritize foundational investments beneficial today but for future electrification growth

Currently, solutions are being developed in three ongoing CHARGED working groups, which will conclude in Q4 of 2025, and can help address barriers to MHDV electrification. These include topics of flexible grid connection, proactive investment frameworks and GIS best practices.

CHALLENGES, EMERGING THEMES AND PRACTICES

Challenges *fleets* face electrifying specific vehicle classes

Those the working group will focus on:

- **Class 2 and 3 pick-ups and utility vans:** Many of the use cases for this vehicle class are well suited for electrification. They drive comparatively short distances and return to base overnight, making charging straightforward. Electric options are relatively available and cost competitive but only for specific use cases (e.g., a small van like the Ford eTransit or a delivery van like the Rivian). Some class 2-3 use cases do not have good EV options, like minibuses. There is a gap between the ROI that truckmakers and researchers claim, and that fleet owners calculate.
- **Class 8 city and regional return to base trucks:** Vehicles are available, although in small quantities, several mega-fleets are adopting them, and the performance of the leading options (e.g., Tesla and Windrose) is sufficient in distance and capacity for them and many fleets. However, options are very expensive compared with ICE alternatives, the multi-megawatt charging loads take a very long time for utilities to serve, and the charging stations are expensive to build. Although analysis suggests this is avoidable, many fleets are impacted negatively by demand charges. High electricity costs have a chilling effect on adoption since fuel savings are needed to offset the high upfront cost.
- **Class 8 school and municipal buses:** Adoption has surged (nearly 5,000 e-school buses in operation across 49 states) largely due the EPA's Clean School Bus Program. These funds have meant some rural areas are adopting even before places with ebus commitments. California, New York, Illinois, and Pennsylvania lead on state backed ebus spending. Municipal transit agencies now own 7,000 full-size battery and fuel-cell electric buses with 10-15,000 expected by 2030 (lower end is without any federal incentives).

Those the working group will NOT focus on and why:

- **Class 4 and 5 box trucks:** Limited product availability and high costs for the vehicles that are available.
- **Class 6 and 7 refuse and tractor trucks:** Very limited/no product availability.

- **Class 8 long haul trucks:** Neither public charging nor vehicle performance is ready for this use case yet. This use case requires charging to be available across a broader set of geographies and requires high power chargers in places where the grid may not be able to support it.

Challenges *utilities* face serving fleet electrification

- There is a mismatch between the speed at which some fleets want to electrify versus the speed at which utilities can bring power to the site—grid connection approvals often face 1-3 year delays or longer.
- In most cases, the utility service request process is not well designed for fleets.
- It is challenging to make distribution investments given the uncertainty of when, where, and what kind of load will come from fleet electrification because there are significant cost implications for building the capacity to serve those loads, upgrade the transformers, substations, and new feeders, and plan for peak demand spikes, either too soon or not soon enough.

Cross-cutting challenges

- Outside of the large, well-resourced fleets (e.g., Amazon, FedEx, Penske) internal resources and experts are rare to address the challenges of transitioning one's fleet from ICE to EV. Lack of knowledge and government mandates are big impediments for small- and medium-sized fleets.
- There is a lack of understanding on the part of both utilities and fleet owner/operators regarding the load expectation (timing, quantity, profile) and the certainty of it, which presents a barrier to making timely, appropriate investments. This relates to challenges with forecasting, predictive modeling, and the effective sharing of data.
- Uncertainty has increased around the future policy environment for MHDV electrification.

Planning challenges of serving fleets vs. traditional customers

- **Less "predictably" flexible:** Fleets are unique in their load generally goes from zero to high demand[5].
  - For example, a fleet of Amazon delivery vehicles generally has a day-time delivery duty-cycle, meaning their vehicles would be charging all at once overnight. If all the vehicles charge together, even at a lower power draw, the cumulative demand impact can still be high, constraining the grid. But depending on fleet and depot size and set up, overnight charging means the total energy needed to recharge can be spread over many hours, reducing the power demand from each vehicle.
  - A "charging as a service" provider like Mobility House or a publicly accessible charging depot may have little to no advanced notice when or how many vehicles will be charging at one time, which can create spikes in power demand on the grid at any time of day. This scenario is very difficult for utilities to plan for and a challenge for operators to address in real time, which incentivizes utilities to build to total nameplate demand of a site, even if the business-as-usual operations would be 20% of that total demand.

5 This means that while fleets may be flexible, the nature of that flexibility is not as predictable in advance, which has implications for how much utility planners and operators can rely on their flexibility.

- Unlike fleets, other large customers have more predictable and manageable energy demand patterns making it easier for them to reach reasonable terms of agreements with utilities and work within demand management programs to help reduce local and system peaks.

- **Difficult to forecast utility load:** It's not clear what the right "risk-mitigating" approach is that balances the consequences of under investment with over investment.
  - Given that models and forecasts will be wrong, utilities need to understand the implications of both over and under forecasting. In addition, the time dimension is critical; it is a very different circumstance if a load arrives 1-2 years later than expected versus not arriving at all.
- **New relationships/change management:** Sharing lead times and data with charging providers is a new process for fleets.
  - Although fleets often don't know when they'll replace a vehicle (i.e., it dies), Fleets usually plan to replace a vehicle 3-7 years ahead. If they've made electrification commitments, that is information that could be shared early with utilities. However, this depends on the size and sophistication of the fleet, as well as lease vs. buy. Smaller fleets might drive a vehicle until it dies and then immediately replace it.
  - Medium-duty (Class 3–6) EVs can charge more easily at Level 2 or moderate DC fast charging at depots so their load impact is more incremental and distributed, and as such, easier to forecast at the distribution level with 1-3 years' notice. Heavy-duty (Class 7–8) EVs may need megawatt-scale charging and where demand is already high, like at industrial hubs and ports, may require transmission upgrades and coordinated interconnection planning might need 4-7 years lead time.
  - Companies with large fleets that have a centralized plan across operating geographies can likely share 10 year plans with utilities (based on assumed EV battery and charger technology advancements). Other companies may be more decentralized in their operations (fleet and facilities staff are not always closely coordinated). Logistics-only providers are not accustomed to expanding their grid needs and actively coordinating with their utilities, so they do not always know the value of their long-term internal planning for utilities. Beyond the larger fleets, the 40% share of "mom-and-pop" fleet owners will be last to consider electrification and will be the least technically advanced when it comes to electrification.
- **Examples of planning processes the working group will discuss:**
  - Traditional ratemaking processes: PG&E's EV Fleet Program (California) and Con Edison's PowerReady Program (New York)
  - Proactive planning processes:
    - Xcel Energy (Colorado) offers Fleet EV Solutions with pre-approved funding and planning guidance separate from traditional rate cases. They coordinate investments against fleet's vehicle procurement timelines.
    - San Diego Gas & Electric (SDG&E)'s Power Your Drive for Fleets program employed proactive stakeholder engagement and streamlined regulatory processes to align fleet and utility timelines.
    - New York has initiated a proactive planning proceeding

- Tools: EPRI EV2Scale[6] and RMI GridUp[7] publicly available tools which estimate load from real and modeled vehicle operations and electrification plans/adoption; ElectroTempo is a higher-tier modeling product with a license fee

Consequences of utilities failing to address the special characteristics of fleets

- **Utilities will miss out on a new market segment and revenue stream** for new infrastructure and electricity sales. Utilities are also at risk of missing out on the load flexibility opportunities fleets have to offer, especially at scale, if they do not strategically engage with stakeholders and proactive plan grid infrastructure. Without coordination, utilities miss opportunities to design smart charging programs or vehicle-to-grid (V2G) strategies that could provide demand response, peak shaving, or ancillary services.
- **Fleet owner/operators will miss out on fleet operation up time and either incur substantial costs** from long delays or decide to not pursue electrification, missing out on the efficiency gains electrification has to offer.
- **Utility customers may be impacted with higher rates** if utilities inefficiently plan for electrification and only build infrastructure on a project-by-project basis, resulting in a costly piece-meal approach to building infrastructure for electrification.

Grid connection and flexibility of fleet loads

- Load flexibility has a high potential for lowering barriers to energization. The more a fleet can understand their own load constraints and find flexibility that is compatible with grid needs, the faster and cheaper energization can be. CHARGED has ongoing efforts exploring methods and deployment for flexible grid connections, with a goal to reduce barriers to electrification. However, customers are experts on their own load and knowing your fleet's operational and financial constraints will support electrification goals.
- Load Flexibility is highly fleet and use case dependent. It is also important to be clear on what we mean by flexibility. Fleets may not be able to change their patterns but if they charge at times that are good for the grid, flexibility does not necessarily matter. What is most important is the load shape relative to system peaks.
- Package delivery fleets tend to have an optimal driving pattern from a utility's view point, with relatively few miles in a day and a long overnight dwell time.
- Even regional-haul class 8 tractors will charge overnight, though they may need to charge at "full power" to be ready in the morning.
- Fleets can leverage DERs to shift or shave peaks and utilities should support those approaches through "flexible interconnection" programs (DERs can also help with managed charging or demand response more generally).
- At the end of the day, the use case dictates charging needs and some fleets will have flexibility and others will not. What is important is having the programs and processes in place that enable the utility to recognize and reward the value created when a fleet can provide flexibility.

6 msites.epri.com/evs2scale2030
7 gridup.rmi.org/

POTENTIAL SOLUTIONS FOR DISCUSSION AT THE WORKSHOP

Recap of core challenges

- Different fleet types face different challenges towards electrification, including economic and otherwise. MHDV solutions need to address a wide range of needs and market conditions.
- Planning for fleets is challenging from the utility perspective. These are large loads and there are gaps in information and methods that could contribute to robust load forecasts; risks are present to under and over forecasting. It's unclear what assurances utilities will need to confidentially move forward with planning for fleet electrification. It is unclear what the balance is to align on differences in planning horizons between fleets to ensure grid connection occurs in a timely and cost-effective manner.
- Flexible grid connection in a "static" (staggered/ramped) mode is more feasible than dynamic flexible grid connection, since fleets in general need to rely on consistent operations.
- Direct utility control is unlikely to be viable for most fleet types; in some cases, 3rd party control may be welcome.

Bridging solutions

- For purposes of this document, bridging solutions are defined as temporary solutions to alleviate grid constraints to facilitate fleet charging, such as a mobile charging station that leverages gas generators or solar and battery systems.
- The decision to utilize a bridging solution is really an economic one. If the cost of delayed or reduced operations is higher than the cost of deploying local resources to increase power supply, then a bridging solution makes sense. Further, it can be preferable to have these assets installed permanently, depending on the load grid constraints and associated costs.
- Depending on the situation, bridging solutions can include temporary gensets and mobile chargers, and managed charging. Most are temporary means to an end, while managed charging is often a long-term strategy.
  - If a utility has 1-3 years of upgrade delays, bridging solutions can include phased deployment of the vehicles and chargers, and the use of onsite battery storage.
  - Mobile chargers can be deployed to serve pilot/demo projects.
  - If the load is in a weak area of the grid or a rural area, batteries or hybrid solar-plus-storage systems can work.
  - Gas generators are increasingly deployed for bridging solutions, which is a concern for the durability of fleet electrification overall.
- Importance of bridging solutions
  - Battery backup or solar + storage onsite can be both a bridging solution and a long-term asset to a depot. These can also be more cost-effective depending on the location.
  - Temporary chargers, managed charging, and storage enable fleet operations to begin without waiting years for full infrastructure deployment. They help address the misalignment of fleet readiness with grid readiness.
  - They can enable procurement to proceed, which is important for building up the supply chain, coming down learning curves and gaining economies of scale.

- Small-scale pilots, phased rollouts, or temporary solutions provide hands-on experience to fleets.
- Bridging solutions also help phase investments so infrastructure spending is more in line with increased revenue from increased EV adoption and charging utilization.

- Limitations of bridging solutions
  - Bridging solutions can struggle to meet the power demands of large, fast-turnaround operations like ports or freight hubs.
  - Will likely require additional coordination among fleet operators, site hosts, and utility, plus equipment vendors, regulators, OEMs.

Solutions for program design

- **Better grid planning can alleviate the need for bridging solutions.** Characteristics of a well-designed utility program for fleets based on RMI's Electrification 101[8]
  - Relationship management: partnerships with fleet associations with dedicated fleet reps
  - Flexible and streamlined load connection
  - Rates/ tariffs offer TOU, demand-limiting, and cost modeling tools
  - Infrastructure support: offer make-ready incentives and turnkey options
  - Incentives: rebates, cost-sharing, load flexibility payments
  - Load flexibility: managed charging programs, DR/V2G pilots
  - Considerations for smaller, less advantaged fleets
  - Discoverable and transparent service request process
- Other best practices for consideration:
  - A utility program that proactively identifies load zones and reaches out to customers in those areas to get their electrification plans can support utility infrastructure planning and assure fleets of grid capacity in advance.
  - Incentive programs can be effective in guiding fleet behavior, especially as they struggle with cost competitiveness (which will be exacerbated with the loss of IRA incentives).
  - Lessons learned from LDV deployment, which is farther along.
  - "Future proof" grid investments (e.g., V2G readiness)

Open questions

- What kinds of advisory, financing, infrastructure design services should utilities provide to fleets electrifying?
- It's common advice to a fleet looking to electrify to talk to their utility early and often. But talk to them about what? What do utilities most need to know?
  - What kinds of data should utilities request from fleets to plan effectively?
  - How can utilities use vehicle telematics or depot operations data for planning?
  - What could streamline this process for a fleet served by multiple utilities?
- How should utilities balance cost recovery with speed and affordability for fleet operators? What strategies help make rates predictable for MHD fleets?

8 RMI, How Fleets and Utilities Can Work Together to Unlock Electrified Transportation, rmi.org/electrification-101-how-fleets-and-utilities-can-work-together-to-unlock-electrified-transportation

- How should utilities balance cost recovery with speed and affordability for fleet operators? What strategies can help mitigate demand charges for MHD fleets without shifting costs totally to the ratepayer?
- Should utilities focus more on MHD charging behind the fence depots or in public charging venues, and why?
- How can utilities better understand MHDV electrification as an opportunity for flexible interconnection? Utilities are often concerned about allowing, let alone incentivizing, bidirectional charging for MHDVs, but many fleets are saying this is how they get their TCO to pencil out? What do both sides need to ease that concern and understand V2G respectively?

READING LIST

Preworkshop suggested reading

- RMI, How to prepare the grid for electric medium- and heavy-duty trucks: Lessons from Los Angeles, 2025 www.missionpossiblepartnership.org/hubs/how-to-prepare-the-grid-for-electric-medium-and-heavy-duty-trucks-lessons-from-los-angeles/
- North American Council for Freight Efficiency, The messy middle: a time for action, 2023, nacfe.org/news/nacfe-releases-report-on-truckings-messy-middle/
- Electric Power Research Institute, EVs2Scale2030™ Grid Primer: An Initial Look at the Impacts of Electric Vehicle Deployment on the Nation's Grid, 2023 www.epri.com/research/products/000000003002028010

Additional references

- EPRI EV2Scale tool www.epri.com/evs2scale2030
- RMI GridUp tool gridup.rmi.org/

MEDIUM AND HEAVY DUTY FLEET ELECTRIFICATION

CONVENING DISCUSSION

WORKING GROUP OBJECTIVES

Original objectives from the Briefing Document

Develop strategies to reduce barriers to MHDV electrification that consider perspectives and solutions across utility planning, grid connection, and program design. This working group will develop an implementation framework for fleets and charging providers to pursue electrification at their location, covering data requirements, power needs assessments, and bridging solutions. We will focus on "return to base" fleets, also called "behind the fence," referring to vehicles that charge at the same location every night, such as delivery vans, return-to-base Class 8, and school buses. These MHD vehicles are electrifying the fastest, given their charging location, schedule, and load are those charging providers are most pressed to support, and offer opportunities for flexible interconnection and bidirectional charging.

Working group alignment on objectives for report-out

- Define a common understanding of what successful MHDV fleet electrification at scale looks like.
- Align best practices for cost and risk sharing between utilities, fleet operators, and third-party charging providers.
- Identify what utilities need from fleet operators and charging providers and vice versa to enable faster energization.

MHDV FLEET ELECTRIFICATION STRATEGIC VISION AND SCOPE

Strategic vision

To reduce barriers to medium- and heavy-duty vehicle (MHDV) electrification, the working group will develop a proactive and pragmatic implementation framework for fleet operators and charging providers to collaboratively pursue electrification at their location, covering data requirements, power needs assessments, and bridging solutions. The framework will outline strategies that consider perspectives and solutions across utility planning, grid connection, and program design.

The group developed this vision with inspiration from the briefing document and with the goal of producing a useful resource.

Scope

This working group focused on the types of MHDVs electrifying the fastest and most likely to charge "behind the fence". The group defined this scope to exclude Class 8 long haul trucks and Class 4-7 trucks with limited availability in order to address the specific challenges for return-to-base depots.

What? ***Electric vehicles, including:***

- Delivery vans
- Return-to-base Class 8 trucks
- School and passenger buses

Why? ***Because their charging location, schedule, and load present the greatest opportunities for:***

- Managed charging, if fleet operations can be optimized with charging schedules;
- Flexible interconnection, if fleet charging can better utilize existing grid infrastructure or new renewable sources and battery storage;
- Bidirectional charging, if the utility welcomes the added mobile energy storage assets and charging providers see the business case;
- Maximum public benefits, if designed to support the most polluting fleets to transition or the more publicly-visible fleets who could encourage the industry the shift;
- New revenue, if effectively designed so the utility recovers the upfront and operating costs, while sharing benefits across ratepayers.

Who? ***We are trying to engage and influence:***

- Utilities of all types and geographies, including:
  - Urban and rural;
  - Independent System Operators (ISOs), Investor-Owned Utilities (IOUs), and municipal utilities.
- Regulators
- Industry of all sizes and fleet portfolios, including:
  - Large-scale and national;
  - Small-scale, mom and pop fleets.

CHALLENGES FOR SUCCESSFULLY ENABLING MHDV FLEET ELECTRIFICATION

What's the most pressing barrier facing each stakeholder group to enabling successful MHDV fleet electrification at scale?

The working group split into small groups representing either fleet operators, utilities, or charging providers and brainstormed the current and most pressing challenges for their stakeholder, listed below.

Challenges for utilities:

- Lack of knowledge of customer base
- Pressure to predict and plan for demand that hasn't materialized yet
- Limited capacity—staff capacity, grid capacity
- Uneven policy/regulatory environment—lack of clarity around policy signals
- Cost containment—maintaining affordability but not shifting costs across classes, not just focusing on low hanging fruit of available capacity with large fleets and forcing small fleets to be last adopters and bear the higher costs
- Planning uncertainty (timeline, location, scale)
- Risk of grid congestion or delays

- Fragmented internal processes between customer teams, planning, operations, and regulatory affairs
- Misalignment between utility investment/planning cycles and fleet procurement cycles

Challenges for fleets:

- Difficulty with sites, including siting and permitting, space constraints, and charger placements
- Costs can be opaque for infrastructure upgrades or new equipment
- Lack of clarity from OEMs including prices, delivery timelines, standards, BABA compliance, supply chains, and interoperability
- Institutional inertia, as there is limited human capital in the transportation industry already qualified for electrification expertise
- Universal buy-in is required from a multi level perspective, from depot managers to drivers and maintenance
- Budgeting and financial burden of purchasing chargers and electric vehicles
- Right-sizing the tech for now and the future rather than waiting for improved future models
- Long interconnection timelines (1–5+ years) can delay electrification plans
- Distribution grid capacity is often insufficient to meet the high power demands of large-scale charging depots
- Incentives and funding mechanisms may be fragmented, competitive, or delayed and regulations can be opaque

Challenges for charging providers:

- Interconnection process vary widely across regions, utilities, and project sites as well as being slow, costly, cumbersome
- Permitting challenges - grid upgrades for utility and siting, utility is opaque about steps, difficulty securing appropriate sites with electrification potential
- Energization flowchart is unclear to charging providers (there are clearly lots of substeps not depicted to customer)
- Supply chain is impeded for grid components (transformers, etc.)
- Lack of clarity around profitability and difficulties financing and developing the sites
- Human resources constraints - small teams, backlogs for utilities due to low manpower
- Regulatory lag in developing performance standards, building codes, or market rules for MHDV charging

APPROACHES FOR MHDV FLEET ELECTRIFICATION

Next steps: potential projects

After the small groups were asked to identify the most pressing barriers to fleet electrification at scale for utilities, fleet operators, and charging providers, the next steps were to identify what actions could be taken by each group and to chart those actions by criticality and feasibility. From this list, the participants identified the most impactful and most feasible actions and what would need to be true in order to achieve them. By identifying the most impactful potential actions, the working group developed two potential solutions for CHARGED to consider implementing.

Support interconnection and permitting reforms

Mapping out interconnection/permitting reform best practices for MHDV fleet interconnection to advance the energization for MHDV fleet clients and depots nationally, supporting MHDV interconnection to advance the way distributed generation (DG) has in a few short years.

CHARGED develops a universal while adaptable flowchart-like guide for MHDV fleet interconnection. This guide would act as a resource for utilities to improve the interconnection process for fleet customers by standardizing the application and review, making both more predictable and efficient. Steps would include:

1. Conducting a literature review of permitting best practices;
2. Consolidating the existing research;
3. Developing form templates and samples;
4. Identifying and engaging potential problem locations for energization (for example due to geographic constraints, prevalence of data centers, road safety concerns, targeted air pollution and emission reduction zones, or especially high rates of MHDV electric adoption);
5. Defining the value proposition for adopting best practices for utilities; and
6. Socializing the findings with utilities.

Enable access to highly-detailed capacity maps for fleets

Identifying the most opportune MHDV freight depots to electrify by illuminating for fleets and depot owners the fastest, easiest, cheapest depots for utilities to energize.

CHARGED would develop an approach to hosting capacity maps that meet the needs and capabilities of fleets while protecting sensitive utility information. This would focus on a user-centric design process to build utility resources around the needs and realities of fleets, in particular, fleets that don't have dedicated infrastructure experts. Charging providers would also support utilities to streamline or launch their processes to advance an ecosystem for fleet electrification. This would ease the fundamental communication gaps between utilities and fleets - from each's operations, how they track performance and other data to how their business decisions are made, which results in utility designed programs and tools poorly matched to the needs of fleet customers.

Additional voices

The group discussed that some critical voices were not represented in the room, and it will be important to engage with these groups in the future to carry conversations forward in order to address regional differences and any potential missed perspectives from the industry.

- Additional and more diverse utilities
- Manufacturers
- Regulators
- Fleet operators
- Charging providers

HOLISTIC APPROACHES TO GRID ASSET UTILIZATION

BRIEFING DOCUMENT

OVERVIEW

Objective: Develop implementation guidance and best practices on how to maximize utilization of operational grid assets. This working group will focus on extracting maximum value from distribution system monitoring and controls technologies, and identifying technology and process improvements that enable better grid asset utilization to achieve the objective of CHARGED, which is to enable reliable and affordable electrification.

Relevance to CHARGED: Asset utilization and grid modernization technology deployment has been discussed across regulatory proceedings in the context of dynamic flexible interconnection. Some places like the UK flexibility markets are using low-tech solutions for dispatch, such as text messaging, that do not require sophisticated tools or customer-level control. This working group will help identify appropriate uses of existing grid mod infrastructure and where new investments are needed—to facilitate key use cases—separating controls and monitoring functions from each other.

This chapter is organized into five sections:

1. ***Connections to Previous CHARGED Efforts***, which describes how the group topic relates to previous and ongoing CHARGED activities, including from the 2024 Inaugural Convening.
2. ***Definitions, Scope and Use Cases***, which describes how this group relates to other groups, key definitions, what topics are considered in and out of scope, and the specific use cases that this working group will be focused on.
3. ***Challenges and Emerging Practices***, which discusses current challenges, emerging practices to deal with these challenges, and provides examples of emerging practices.
4. ***Potential Solutions for discussion at the workshop***, which includes a recap of core challenges, and solutions that span near-term and longer-term components, along with open questions that would benefit from discussion during the Convening.
5. ***Reading List***, which includes suggested preworkshop reading and additional references for those that are interested.

For context, the development of this chapter, and all materials in the Inaugural Convening Briefing Document, were based on several perspectives within the internal CHARGED team.

CONNECTIONS TO PREVIOUS CHARGED EFFORTS

The CHARGED initiative was created to enable electrification across transportation and buildings in affordable and reliable ways. The Inaugural Convening was structured into different working groups—planning, grid connection, operations, deployment, rates and incentives and each of these identified least-regrets solutions and longer-term solutions. Many of these are relevant to this

working group's objective. In particular, the least-regrets solutions developed by the operations working group are worth noting, given their relevance to this current working group topic:

- **People:** Bring the operators into the conversation, not just about operations but also into conversations on planning, deployment, connection, rates.
- **Plan:** Develop an operations investment roadmap that identifies triggers for specific investments
- **Action:** Prioritize foundational investments beneficial today but for future electrification growth (e.g., GIS implementations).

These least-regrets solutions deviated significantly from those proposed in the Briefing document, which had focused significantly on DERMS, and had not included any mention of utility processes.

Currently, solutions are being developed in three ongoing CHARGED working groups, which will conclude in Q4 of 2025, and can help improve asset utilization. These include topics of flexible grid connection (which is focusing on both static and dynamic flexible grid connection, which were proposed as solutions in the Inaugural convening), proactive investment frameworks and GIS best practices.

DEFINITIONS AND SCOPE

Definitions

- **Assets and operational grid assets:** In the context of this working group objective, these terms are synonymous (that is the use of the term "assets" in the working group name and the term "operational grid assets" in the objective). They refer to **operational systems**. These can include systems like GIS, ADMS, DERMS. This is in direct contrast to the typical industry connotation that asset refers to wires and poles primarily.

  In order to have useful conversations about more than one specific type of operational asset, we have created categories of these investments to facilitate discussion. There may be different views on how individual assets have been categorized, but consider this to be an organizational tool rather than an assertion.
- **Foundational operational assets:** This includes core data and telemetry systems which provide basic situational awareness of the system and network models.
  - This tier provides visibility.
  - Examples include **GIS, OMS, SCADA, communication framework and data historians**.
  - These systems do not provide any advanced applications or solutions to grid issues but do form the foundation for other assets.
- **Primary operational assets:** This includes systems which support management and control of the grid by providing situational awareness, asset condition insights, and streamlined workforce management.
  - Examples include **AMI/MDMS**, **workflow management system (WMS), asset management systems** (which maintain records of physical asset location, condition etc.), **DER datahub or registry** (this can potentially be part of ADMS or a preliminary DERMs platform).
- **Secondary operational assets:** This tier provides more advanced control and/or monitoring than the previous categories. Includes **ADMS, preliminary customer program enablers, distribution automation, and FLISR**.

- **Tertiary operational assets:** This tier moves towards the grid edge and provides more advanced analytics. They are viewed as upcoming systems for most utilities. It includes **DERMS, digital twins, AI tools, market integration systems** (such as connecting with wholesale markets).

Scope

To ensure useful outcomes, the following topics are considered **out-of scope:**

- Cybersecurity
- Telecom
- IT infrastructure

CHALLENGES, EMERGING THEMES AND PRACTICES

Underutilization

- Underutilization of operational systems/assets could **manifest** in a variety of ways.
  - Deviations between the proposed capabilities and actual use by the utility.
  - Lack of integration into operations and planning processes
  - Tools are not fully leveraged and properly integrated with other operational assets and may have features disabled, for example,
    - A clean and accurate GIS model is necessary for accurate and optimal outputs from ADMS. Alabama Power had to retroactively correct its GIS/network model after implementing ADMS and FLISR.
    - The use of AMI solely for billing.
  - Long delays in the utility implementation of the proposed asset
  - Incomplete penetration of the proposed solutions across service territory
  - Poor cost-benefit analysis outcome
- There are various **causes** for underutilization including technical, regulatory and management factors.
  - **Regulatory:** Misaligned utility incentives; lack of a robust business case including well defined use cases and performance metrics that are tracked during implementation
  - **Management:** Insufficient direction from top-level management to staff (strong management will not allow major investments to languish), organizational misalignment and siloed utility operations; change management challenges—constraints due to legacy systems/practices, lack of training, ignoring user (or operator) perspectives, lack of institutional support
  - **Technical:** Lack of end-to-end integration and interoperability of operational assets including lack of IT/OT integration; lack of a data management strategy (e.g., using a common enterprise data bus); limitations caused by vendor interoperability, vendor product maturity, and how vendors license the products; data quality and model accuracy
  - Examples of how these factors map to the asset class are proposed.
    - **Foundational Assets:** poor IT/OT integration, data quality and model accuracy issues.
    - **Primary systems:** siloed utility operations, lack of trained workforce, and lack of integration.

    - **Secondary systems:** data/model quality issues, lack of integration, lack of defined use cases and lack of trained workforce.
  - It is worth noting that, historically, planners have built in sufficient margins that there has not been a large need for either planners or operators to leverage operational assets.
- It is not clear how to universally **characterize effective asset utilization**, but some general themes and indicators that may align with effective asset utilization are as follows.
  - **Fundamental:** Improvements in reliability indices, deferral of capital investments, and improvement in customer offerings or other customer benefits
  - **Metrics:** Improved load and utilization factors of distribution network components; favorable cost-benefit factors (ex-poste)
  - **People:** Operators are using the assets
  - **Technical:** Each asset or system is being used, at least, at a basic level (e.g., SCADA feeds to ADMS); for each successive operational investment, utility has extracted maximum value of preceding investments.
- The table below proposes options for assessing minimal, good and advanced dimensions by asset and asset class.

Illustrative example operational asset system utilization characteristics
(Not meant to be exhaustive)

	MINIMAL	GOOD	ADVANCED
Foundational			
GIS System **Functions include:** • *Asset Registry & Management* • *Network model Management & Visualization*	• Complete asset registry with accurate mapping and manual/infrequent updates	• Accurate mapping down to the meter and integration with 3rd party maps and services. • Supports operations, planning; Routinely updated; shared across departments.	• Seamless Integration with all other utility systems and remote sensing. • Custom GIS interfaces for different groups like planning and operations. • Digital Twin system development • Field crew real-time synchronization
Primary			
AMI/ MDMS **Functions include:** • *Meter data collection* • *Remote connect/ disconnect* • *Last Gasp for outages* • *Billing*	• Limited interval data collection (1-hour intervals or more) • Billing customers for usage	• High resolution measurements (e.g. 5-minute time interval) • Data integration with other operational assets like ADMS, OMS, etc. • On Demand meter pinging capabilities.	• Advanced Analytics (e.g. Load disaggregation for EV identification) • Advanced data analytics for planning studies (e.g. estimate transformer loading, 8760 analysis, load forecasting, etc.) • Developing customer engagement programs based on usage data
Secondary			
ADMS **Functions include:** • *State Estimation and Load Flow* • *Reliability Improvements (through FLISR)* • *Voltage Optimization*	• Used for real time visibility. • Manual control of field devices. • Islands of functionality with little to no integration.	• Advanced situational awareness through integration with field devices and AMI • Automated State Estimation and Power flow • Semi-automated FLISR or FLISR and VVO pilots on some feeders	• Seamless integration with other assets like AMI, GIS, OMS, etc. • System wide VVO and FLISR implementations
Tertiary			
DERMS[9] **Functions include:** • *DER Registry* • *DER Monitoring* • *DER Aggregation* • *DER Control*	• DER Asset Registry. • Monitoring limited to utility scale or C&I DERs.	• Monitoring of majority DERs irrespective of the size. • Integration with ADMS • DER Dispatch capability to aggregators or individual DERs for specific programs/use cases.	• System wide visibility of DERs • Forecasting based on integrated weather data • Service Stacking/Prioritization logic • Performs dispatch of DERs via direct or price-signal control considering distribution system conditions and forecasts.

9 For the purposes of this working group, DERMS are "the monitoring and control systems used to integrate distributed energy resources…with the grid." EPRI, Utility Strategies for Implementing Distributed Energy Resource Management Systems (DERMS), 2024, www.epri.com/research/products/000000003002031038

Drivers and users cases for operational asset investment

- Power injecting DERs, specifically distributed solar, have been significant drivers for DERMS.
- Loss of support for legacy software systems is a large driver for the foundational systems.
- Natural disaster concerns are the largest drivers for all classes of assets.
- Electrification is driving operational investments for assets other than DERMS
- Excluding natural disaster drivers, many use cases have been described in generic terms, such as "improved utilization/optimization of assets", "better situational awareness", or occasionally "non-wires alternatives".
- Typical use cases that are being discussed for specific asset classes include
  - DERMS: DER monitoring, peak shifting, VPP and DR programs, flexible grid connection, market integration, customer benefits
  - ADMS: Improved reliability, voltage optimization, DER monitoring, outage management, updating antiquated systems.
  - AMI: "Last gasp" outage detection, load disaggregation, advanced forecasting
- There are low-tech approaches for several use cases, for example,
  - Opting for static flexible grid connection over dynamic will not require DERMS
  - Demand response programs can be done through simple methods—for example, the Toronto Hydro Local Demand Response program using contractual DR with C&I customers (not DERMS) and has achieved 9 MW of summer reductions at a transformer; similarly, the UK flexible markets send dispatch signals via emails
  - Low tech approaches can be connected to high-tech customer systems—for example, sending a text message to a building EMCS instead of customer phones for DR
  - Low-tech approaches may not unlock as much grid capacity as a high-tech option (using DERMS, for example).
- In many cases, monitoring functions have been a core driver more than control functions. In many cases, control can be achieved via third parties or aggregators.

Staging operational assets

- Rather than a real technical driver, many grid modernization investments have been driven by policy goals and/or a desire to transition from manual and siloed operations to automated and integrated decision making.
- It is challenging to develop generalizable principles for *when* to move up the "ladder" of investment tiers, however, here are some more general determinants that additional systems are needed in place.
  - A system will stop "working" properly without an additional investment
  - Inability to keep up with scale of change with existing systems
- It is not clear what general principles exist for determining *how* to move up the "ladder" of investment tiers to improve utilization, however, modularity should be a cornerstone of proposing new investments. This modularity can be conceptualized by geography (e.g., targeting a certain area), or by staging capabilities of specific assets (beginning with basic capabilities and integrating more advanced ones later), or by staging systems integration steps.

  - One example of a modular approach has been PG&E's ADMS implementation which has been divided into three releases. Release 1 focused on replacing the legacy SCADA system with ADMS-based SCADA integrated with PG&E's network model, introducing rule-based FLISR and wildfire risk mitigation features. Release 2 expands ADMS to replace PG&E's existing outage management ecosystem. Release 3 focuses on enabling advanced ADMS functionalities such as Enhanced Powerline Safety Settings, Load Flow/State Estimation, Volt/VAR Optimization, and support for microgrid operation.
  - PG&E has adopted a modular approach to DERMS deployment beginning with a cloud-based DER telemetry platform integrated with its ADMS using IEEE 2030.5, targeting DERs larger than 1 MW. PG&E is piloting DERMS use cases such as day-ahead operational forecasting and flexible service connections for large EV charging stations facing grid constraints.
- Investments in specific operational asset types may depend on utility conditions, but these should be tied to the application use case, for example, Grid Edge DERMS may be most justifiable for managing voltage and power quality from large power-injecting DERs, such as community solar.

Case studies

- Australia dynamic operating envelopes implementation: this approach involves using CSIP-AUS, an Australian variant of iEEE2030.5/CSIP, to implement dynamic export limits at the connection point to manage network congestion in high-solar areas, initially using dedicated network models rather than full DERMS.
- UK flexibility markets: this approach includes a geographically modular implementation of DERMS, targeting 1-2 feeders that faced constraints. Broader distribution flexibility is achieved through a third party platform that uses traditional DR signals to customers via text or email message.

POTENTIAL SOLUTIONS FOR DISCUSSION AT THE WORKSHOP

Recap of core challenges and themes

- Underutilization of operational assets manifests in several ways, such as actual usage deviating from proposed usage, lack of integration with other assets and utility staff, no reliability, economic, or other customer benefits.
- Investments in subsequent operational assets are often made without achieving even minimal integration of preceding assets, which can cause poor integration of new assets.
- There are multiple causes for underutilization of assets ranging from technical, regulatory, and management factors, such as poor change management.
- Effective asset utilization can be described in general terms—such as improvements in reliability indices, improved physical asset load and utilization factors, integration into operators' practices—or in asset-specific ways.

Potential "early" solutions

The ideas below draw from the material above.

- Framework for regulators and utility leadership for evaluating effective utilization of existing assets, which can be independent of the various applications and use cases

- Checklist of questions for regulators and utility leadership for evaluating new investments, which can include a component of demonstrating effective use of existing operational assets and a description of use cases/applications for new assets
- Strategies for utility process improvements to maximize asset utilization
- Modular implementation of new assets that is connected to specific use cases

Open questions and other solutions

- What are the core drivers that contribute towards low asset utilization?
- What are the approaches to improve asset utilization, taking into account the diversity of drivers for low utilization (encompassing regulatory, technical and management factors)?
- Are the operational asset tiers a meaningful construct for evaluating utilization of existing and proposed new operational assets?
- How can minimal, good and advanced asset utilization achievement be defined?
- What are the modular ways for implementing operational assets and for different use cases?

READING LIST

Preworkshop suggested reading

- CHARGED, Inaugural Convening Report (Distribution operations and Grid connection chapters), 2024 chargedinitiative.org/wp-content/uploads/2025/12/CHARGED-Inaugural-Convening-Report-2024-2.pdf
- EPRI, Utility Strategies for Implementing Distributed Energy Resource Management Systems (DERMS), 2024, www.epri.com/research/products/000000003002031038
- Department of Energy, Voice of Experiences: Leveraging AMI networks and data, 2024 www.energy.gov/sites/default/files/2024-02/01-03-2019_doe-voe-leveraging-ami-networks-and-data-report_508_0.pdf
- Department of Energy, Voice of Experiences: Insights into advanced distribution management systems, 2015 www.energy.gov/sites/default/files/2024-02/11-02-2015_doe-voe-insights-into-advanced-distribution-management-systems-report_508_0.pdf
- Department of Energy, Voice of Experiences: A system in transition: the influence of next generation technologies, 2022 www.energy.gov/sites/default/files/2024-01/20-06-2022_doe-voe-a-system-in-transition-report_0.pdf

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- Department of Energy, Distribution grid orchestration, 2024 www.energy.gov/sites/default/files/2024-12/2024-11-18%20Distribution%20Grid%20Orchestration_Clean.pdf
- SEPA, Encyclopedia of DERMS functionalities, 2023 sepapower.org/resource/encyclopedia-of-derms-functionalities
- Department of Energy, Modern distribution grid report, Volume II: Advanced technology maturity assessment Version 2.0, 2019 gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_II_v2_0.pdf
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HOLISTIC APPROACHES TO GRID ASSET UTILIZATION

CONVENING DISCUSSION

WORKING GROUP OBJECTIVES

Original objectives from the Briefing Document

Develop implementation guidance and best practices on how to maximize utilization of operational grid assets. This working group will focus on extracting maximum value from distribution system monitoring and controls technologies, and identifying technology and process improvements that enable better grid asset utilization to achieve the objective of CHARGED, which is to enable reliable and affordable electrification.

Working group alignment

Based on the above objectives, the working group aligned on the following three objectives for the convening discussions:

- Identifying challenges and defining success metrics to better utilizing operational assets to improve grid utilization
- Exploring illustrative use cases to assess benefits, tradeoffs, and dependencies for operational assets
- Building project outlines for implementation based on research products, tools, or process changes needed to bridge the gap between current state and desired end state

ASSET UTILIZATION DEFINITIONS AND SCOPE

Definitions

Working group participants agreed to two key definitions to facilitate conversations:

TERM	DEFINITION
Grid Assets	Physical grid infrastructure including poles and wires, distributed energy resources (DERs), transformers, substation equipment, loads, etc.
Operational Assets	Utility software platforms that enable and support the core operational and technical functions of a utility's electric grid. These assets facilitate network modeling, situational awareness, control, data management, and coordination across grid assets. Examples include advanced energy management systems (ADMS) and distributed energy resources management systems (DERMS).

Using the above definitions, the working group focused on how to better use ***operational assets*** to extract maximum value from ***grid assets***, so as to enable more cost-effective electrification while maintaining reliability.

Scope

As outlined in the briefing document, the scope of this working group was limited to grid and operational assets. Topics such as IT infrastructure, cybersecurity, and data protocols were considered out of scope for this session. However, several participants noted that IT infrastructure is a major issue that is important to examine in future work.

IDENTIFYING KEY CHALLENGES TO ASSET UTILIZATION AND DEFINING SUCCESS

The first goals of the working group were to identify the challenges around asset utilization and to define success. Participants independently identified challenges and metrics for measuring success in asset utilization. They then compared results and reflected on the exercise as a group to capture additional insights.

Key challenges

Participants organized the challenges into three key categories: technical, regulatory, and management.

Key challenges identified by working group participants

TECHNICAL CHALLENGES	REGULATORY CHALLENGES	MANAGEMENT CHALLENGES
• Utilities lack a single source of truth for their grid assets • Utilities experience system integration and interoperability challenges across operational assets • Several participants described issues of vendor product interoperability; getting the correct software licenses for product modules; and gaps between functionality some vendors promise and the capabilities of the products when deployed.	• Regulators lack an aligned vision and clear success metrics for ideal end state • Utilities have misaligned incentives for deploying and fully using operational assets	• Utility management often lacks a clear vision, business cases, success metrics, and processes for operational assets • Utility management sometimes takes a technology-driven approach instead of a problem-solving driven approach (defining the use case or problem and then selecting the solution) • Utility departments often operate in silos with a lack of visibility into cross-functional efforts

Defining success

Participant suggested qualitative and quantitative metrics across four different categories for measuring success:

- **Increased grid utilization:**
  - Increased utilization factor of grid assets
  - Increased hosting capacity
- **Streamlined utility processes:**
  - Reduced staff time
  - Smooth data flow between operations, planning, and program teams
  - Breaking down silos between utility departments

- **Improved customer experience:**
  - Reduced interconnection queue wait times for both load and DERs
  - Improved DER application approval rates
- **Positive impact on rates:**
  - Accommodation of additional load and DER for little to no grid infrastructure investment should result in rate stabilization/reduction.

In reflecting on the exercise of defining success, participants raised the following two takeaways: First, defining success is difficult for both operational and grid assets, particularly given the lack of clear definitions, industry alignment, or widespread adoption of success metrics. Second, both qualitative and quantitative metrics are needed to gauge successful operational and grid asset utilization. Qualitative metrics show up in utility process improvements and customer experience, while quantitative metrics are more relevant to tracking increased grid utilization.

APPROACHES FOR IMPROVING ASSET UTILIZATION

Classifying operational assets

The working group examined the operational assets from the Briefing Document and were invited to challenge the classification of each asset as **Foundational**, **Primary**, **Secondary**, or **Tertiary** tiers. Participants either accepted the original classification of each operational asset or reclassified the operational asset to a different tier. In addition, several new operational assets were proposed by participants and assigned to tiers before the group voted on classifications.

Working group collective classifications of operational assets

TIER	OPERATIONAL ASSETS	WORKING GROUP OBSERVATIONS
Foundational	**Accepted as Foundational:** Outage management system (OMS), geographic information system (GIS), supervisory control and data acquisition (SCADA), data historians, communication framework **Reclassified to Foundational:** asset management system (AMS), work management system (WMS), DER registry, ADMS (partially), advanced metering infrastructure/meter data management system (AMI/MDMS)	Participants did not reclassify any Foundational assets identified in the briefing document to a different tier. Participants were split on classifying ADMS. Some recommended reclassifying ADMS as Foundational if a utility already had it, while others felt it was Primary if the utility had not adopted ADMS yet.
Primary	**Accepted as Primary:** Powerflow **Reclassified to Primary:** DERMS (partially), ADMS (partially)	Participants were split on classifying DERMS. Some recommended reclassifying DERMS as Primary, while others felt it was Secondary
Secondary	**Accepted as Secondary:** None **Reclassified as Secondary:** DERMS (partially)	Participants did not leave any initially proposed operational assets in the Secondary tier. Assets were either elevated or lowered.
Tertiary	**Accepted as Tertiary:** AI tools, Digital Twins, Market Integration systems, EV detection algorithms **Reclassified to Tertiary:** Real-time Forecasting Engine	Participants were unsure where to classify AI tools. Currently the tools are Tertiary but could be elevated in the future depending on their development.

Use case exploration

Participants explored the possible suite of operational assets required using two illustrative use case examples:

1. Dynamic flexible interconnection (“Flex IX”) for DERs to manage grid constraints
2. Locational demand flexibility to shape peak demand on targeted circuits/substations that are overloaded

The objective of the activity was to test assumptions on what is necessary vs nice-to-have by focusing on the problem to be solved rather than working backwards from a presumed solution. Participants approached the use cases with polar opposite cost frameworks. Half of the participants were instructed to develop a best-in-class implementation (the “Luxe EV”) that ignored cost considerations but instead would be the ideal solution for the scenario. The other half of the participants developed bare minimum implementations (the “Beater Car”) that were optimized for lowest cost and were encouraged to include feature compromises if needed to meet requirements.

Scenario 1: Dynamic Flex IX for DERs

Problem Statement: Implement dynamic flexible interconnection for DERs to manage substation thermal constraints

LUXE EV VERSION	BEATER CAR VERSION
Workflow: • Assume a "closed loop" design in which the utility can confirm and measure individual DER performance when an event is called. • Assume DER sites have relay gateways, and speak a protocol like DNP3. • GIS provides an updated network model to the ADMS system • ADMS performs state estimation and captures secondary effects • Forecasting tools, advanced communication, and AMI-level data feed into DERMS for control decisions • DERMS controls DERs and load, using utility-grade communications to dispatch resources. • An optimal powerflow (OPF) engine redispatches resources	Workflow: • This version has two options, which are both one-way communications with DERs. Individual performance cannot be confirmed or measured, but SCADA can be used to monitor whether the constraint has eased. • **Option 1:** SCADA measures a constraint, a "pre-DERMS" calculates curtailment for individual devices, emails & texts are sent to customers on a public communication system with a curtailment schedule or request (direct communication may be used for larger DERs), and SCADA measures the updated constraint • **Option 2:** SCADA measures a constraint, a "pre-DERMS" tool is used to calculate voltage point, Load Tap Changer (LTC)/ regulation tries to manage the constraint. If that doesn't work, DERs are disconnected using a simple volt-watt approach until the constraint improves

Scenario 2: Targeted Demand Flexibility

Problem Statement: Implement locational demand flexibility to shape peak demand on specific overloaded circuits/substations

LUXE EV VERSION	BEATER CAR VERSION

Workflow:
• The forecasting engine or AMI 2.0 provides forecasts
• ADMS serves as the core intelligence, dynamically optimizing grid constraints and selecting the best option to address the specific grid constraint, including:
  - Edge DERMS (e.g., managed charging, vehicle-to-grid)
  - Utility-owned controllable grid assets (e.g., battery energy storage systems)
  - Enterprise DERMS (e.g., community solar)
• Automated switching and distribution automation schemes are also used where tie-feeder capacity is available
	Workflow:
	• Use GIS to identify asset location
	• Planners use SCADA and Data Historian to run forecasting studies and establish the peak period
	• Scheduler portal triggers customer communications (email / text)
	• Operators uses SCADA in real time to assess whether load constraints are being alleviated or remain binding

Key takeaways from the activity

Participants highlighted several key takeaways from the exercise:

- **"Beater Car" versions can work.** Many utilities already have the tools to construct a Beater Car version of a flexible interconnection program or a locational demand flexibility program.

- The main compromises were in two-way communications with grid assets, the delivery method of the price signal, and a reliance on calculated or forecasted values instead of real-time data.
- Participants noted utilities do not currently implement Beater Car versions because they are not incentivized to do so.

- **Utilities should be considering middle ground options** between the Beater Car and the Luxe EV, which are bookend solutions. Approaches may lean towards the Beater Car side of the spectrum but should include a clear pathway to evolve towards Luxe EV capabilities.
- **Is an asset truly foundational if it is not used in Beater Car versions?** Several operational assets classified as Foundational were not used in the Beater Car versions, prompting some to reconsider which assets are truly foundational.
  - Participants asked what capabilities utilities could do without and still be successful in these scenarios. This prompted closer scrutiny of the capabilities of operational assets like ADMS and DERMS and whether the value of some features is always clear.

Defining the role of DERMS in increasing grid utilization

In this activity participants examined the importance of DERMS, taking a randomly assigned position as either a "cynic" or a "believer" in DERMS investments. This activity built on discussions and assumptions about DERMS that surfaced in the use case exploration.

Participants debated whether DERMS is critical to increasing grid utilization in a cost-effective and reliable way. After the debate, some participants remained split on the importance of DERMS for asset utilization. This lack of consensus helped motivate the proposed **Project 2** listed in the Potential implementation steps section.

Advantages and disadvantages of DERMS, as identified by group "cynics" and "believers"

DISADVANTAGES OF DERMS	ADVANTAGES OF DERMS

• Deploying DERMS is expensive and has a long implementation lead time
• DERMS has an opaque/unclear definition, with mismatches between vendor promises and real-world performance
• Many functions attributed to DERMS can be achieved through alternative pathways, including:
  - Forecasting, communications, and dispatch of DERs using existing systems
  - Aggregators and third party vendors managing DER assets
  - Using IEEE 1547 settings to manage DER behavior
• There is currently no true OPF DERMS, implementations are only rule-based
	• DERMS enables direct DER control, thus assures reliability
	• DERMS is the only technology dedicated to maximizing grid utilization
	• DERMS unlocks real-time pricing
	• DERMS enables virtual power plants (VPPs) and unlocks customer participation in markets

Next steps: potential projects

The working group generated several ideas for future projects using "Shark Tank"-style pitches from each participant. Participants described the project, the challenge it addresses, and its measurement metrics. Each participant then voted to prioritize their top three project ideas for further development. The collectively prioritized projects are shown in the table below.

Collectively prioritized projects, as pitched and voted on by the working group

POTENTIAL PROJECT TITLE	OBJECTIVE	TARGET END STATE	INITIAL ACTIONS
Project 1: SPARK (System Performance + Asset Repository of Knowledge) Developing Technical Metrics for Grid Utilization	Develop quantitative metrics for benchmarking and reviewing utility performance on grid utilization	A regulator-approved metric like System Average Interruption Duration Index (SAIDI)	• Create stakeholder group • Identify and collect data • Conduct a "regulatory roadshow"
Project 2: Developing Success Framework for Utilization of Operational Assets	Define success measures for improved utilization of foundational operational assets by developing an evaluation framework for internal utility use to track asset performance and identify pathways to extract benefits.	A framework adopted by multiple utilities to assess their internal processes and operational assets	• Identify initial target utilities • develop questions and surveys for initial interviews and knowledge-gathering
Project 3: Dynamic Operating Envelopes (DOE) Simulation Exercise	Devise and conduct a tabletop simulation of DOEs on select constrained feeders/ substations within a utility that coordinates actions across operators and other relevant utility teams	Implement this simulation exercise in 1-2 host utilities to test a utility-tailored proof of concept. Ultimate goal is to deploy dynamic operating envelopes in reality for targeted use	• Develop high-level implementation strategy of DOE simulation • Identify host utility and tailor to their proposed grid scenario and available suite of operational assets

In reflecting on the Convening exercises and how to advance this work, several themes were echoed by multiple participants:

- **Defining metrics and measuring utilization is complex**
  - Participants emphasized the importance of building consensus on what success looks like and how to measure it
  - Clear metrics are critical for enabling appropriate regulatory oversight, which in turn can drive adoption of best practices
- **The value of the minimum viable product ("Beater Car") should not be underestimated**
  - Most utilities already have the operational assets needed to deploy a minimum viable version of these programs
- **Vision and management buy-in is crucial**
  - Without utility-wide alignment and buy-in, it is difficult to implement change
  - Honest reporting and assessment are important
  - Some participants suggested integrating a product management role into operations

PROGRAM HARMONIZATION AND STREAMLINING

BRIEFING DOCUMENT

OVERVIEW

Objective: Develop principles and strategies for how utilities can harmonize and streamline multiple customer programs along the dimensions of design and operation, to address differentiated distribution system needs across a utility territory, while recognizing bulk system needs, and support beneficial electrification.

Relevance to CHARGED: Customer programs are central to CHARGED, enabling demand-side flexibility that supports electrification and offsets traditional infrastructure investments. However, a proliferation of DR and DSM programs can confuse customers, inhibit participation and scale of adoption, and regulatory processes may further complicate the landscape (e.g., mandates for new VPP programs). Utilities face challenges in dispatching flexible resources and balancing bulk versus distribution system benefits. Lack of harmonization may limit scale of adoption and limit cost-effectiveness and application of DSM programs specifically for electrification and distribution benefits.

Program harmonization definition: For purposes of this working group, program harmonization is defined as an **alignment and/or consolidation** of utility load flexibility programs that results in **efficiencies and improvements** in program delivery and desired outcomes from both the individual customer and grid / utility perspective at the distribution system level.

This chapter is organized into five sections:

1. ***Connections to Previous CHARGED Efforts***, which describes how the group topic relates to previous and ongoing CHARGED activities, including from the 2024 Inaugural Convening.
2. ***Scope***, which describes what topics are considered in and out of scope.
3. ***Challenges and Emerging Practices***, which discusses current challenges, emerging practices to deal with these challenges, and provides examples of emerging practices.
4. ***Potential Solutions for discussion at the workshop***, which includes a recap of core challenges, and solutions that span near-term and longer-term components, along with open questions that would benefit from discussion during the Convening.
5. ***Reading List***, which includes suggested pre-workshop reading and additional references for those that are interested.

For context, the development of this chapter, and all materials in the briefing document, were based on several perspectives within the internal CHARGED team.

CONNECTIONS TO PREVIOUS CHARGED EFFORTS

Potential solutions that can serve a program harmonization objective were highlighted at the Inaugural Convening, in particular through the Targeted and Integrated Deployment group, which highlighted solutions 'co-deployment' and the development of data sharing platforms to enhance program performance—particularly for locational value—and to support planning.

- Least-regrets solutions
  - Improving coordination among programs, planning, and rates (e.g., processes, data management and sharing, cross-training of staff)
  - Promoting co-deployment of DER and EE programs with load management programs (e.g., coupling DR programs with heat pump water heaters deployment through rebates)

  These 2 solutions were ranked 1st and 2nd by convening attendees among the list.

  - Partnering with aggregators or allow them to bid into residential and commercial programs (e.g., interruptible tariffs), since they have visibility into deployed measures that are controllable (orig 6, new 7-8)
- Longer-term solutions - Data sharing platforms that support advanced program design by leveraging existing program data, and support customer targeting to address grid conditions

CHARGED is standing up an implementation activity working directly with a utility partner focused on improving program alignment to deliver grid and customer benefits.

SCOPE

The information in this chapter provides a broad background and context for the working group. For purposes of a manageable scope and ensuring successful outcomes of the Convening, we have topics that are within and outside of the working group scope.

In scope: The following topics represent priority themes for program harmonization.

- Load flexibility programs
- Dispatch hierarchy between bulk system/wholesale programs and distribution grid services
- Streamlining the customer experience
- Incentives and compensation structure
- Dispatch

Out of scope: The following topics have been identified as out of scope topics—these issues are important but may detract from progress on priority themes.

- Electrification incentive programs
- Wholesale market structures and regulatory processes
- Locational valuation methods (as this is a part of the locational DSM working group)
- General program design and improvement (as this was a focus of the 2024 Convening)
- Data sharing mechanisms and platforms (as this is a part of the data working group)

CHALLENGES AND EMERGING THEMES AND PRACTICES

Drivers of a lack of program harmonization

- A multitude of factors have resulted in the current state of program "unharmonization" across the industry, such as the following.
  - **Policy and regulatory drivers:** Utilities may have multiple programs that have significant overlap, in part, because of policy directives to design new programs which are often technology driven. For example, some utility commissions and state agencies have directed utilities to design "virtual power plant" (VPP) programs, when historically VPPs have been implemented by utilities via existing program and rate structures.
  - **Dual participation in wholesale and retail markets and inconsistent price signals:** For example, resources may participate in wholesale market DR programs; resources will be dispatched for system benefit, which may not be aligned with distribution benefits. Incentives between retail and wholesale programs may not align.
  - **Utility silos and data sharing challenges:** Some programs, due to their technological focus, do not cleanly fall within one department over another within a utility. For example, some utilities may have multiple portfolios that could assume a managed charging program, such as flexible load or transportation. This creates management silos, which has further consequences for intra-utility data sharing across departments.
  - **Organic program growth and proliferation:** Related to planning, the development of these programs often happens organically and reactively, responding to immediate needs and innovations. There has been a lack of a holistic perspective that may require a restructuring of programs and operations. Over decades, multiple programs targeted to specific needs, customer types and market conditions have been implemented.
  - **Varying technological measures:** Different technological measures across programs inherently create different approaches for resource participation and performance measurement. For example, performance measurement of load reduction/demand response programs is typically done through baseline comparison calculations (vs. storage or non-dispatchable PV that can be directly measured.)
- Given the current state of the utility program ecosystem—incredible **breadth and diversity of utility programs**—it will be a challenge to develop a comprehensive roadmap on how utilities can harmonize and streamline customer programs.

Characterizing program harmonization and defining program scope

- By nature, program harmonization is cross cutting and requires a holistic, whole-system perspective. Achieving program harmonization starts with defining which programs might be included and how they are tied to other utility activities, which is a challenge in and of itself.
- Programs could include price-based control (rate) approaches, flexible load programs, demand control approaches, and targeted efficiency—where programs are aimed (or should be aimed) at controlling costs for the purpose of affordability and enabling electrification.
- Most time varying rates (TVR) could be considered a program based on actual use/applicability. When needed, the utility will call a critical peak pricing (CPP) or a peak time rebate or a behavioral demand response (no payment) event. It is possible that a utility may experience different peaks across their system at different times, suggesting that

multiple time-varying rates are needed, which may be difficult to manage or coordinate. Time of use rates (TOU) may be a different situation because, if well implemented and mandated across the service area, they would modify the baseline, creating a new normal.

- Across these programs, there is not a clear alignment on a preferred approach between technology-neutrality and technology-specificity for flexible loads and devices. There are emerging preferences for rates and programs that can be technology-agnostic.
- There are multiple dimensions to program harmonization that should be considered as we illustrate in the table below.

Dimensions of Program Harmonization (Not meant to be exhaustive)

DIMENSION	EXAMPLES
Utility considerations	• Program design and management effort • Operations and dispatch • Co-optimization across multiple grid services
Customer experience	• Enrollment complexity • Codeployment options • Dual participation limitations • Vendor / aggregator roles
Grid services	• Bulk system energy • Bulk system capacity • Distribution system capacity • Ancillary services
Customer market segment	• Residential • C&I • Low income / DAC
Dispatch signal	• Passive • Active
Impact measurement	• Verified on / off • Baseline impact estimation • Sub-metering
Payment terms	• Upfront incentive • Fixed monthly payments • Performance based payments
Load characteristics	• Whole building • Specific flexible loads such as EVs, storage • Occasionally interruptible loads (HVAC) • Process loads (industrial, data centers) • Dispatchable • Non dispatchable
Wholesale market interaction	• Customer enrolled in retail DR and wholesale DR • Customer enrolled in only retail DR program • DR is included in LSE demand bids into wholesale markets

- It might be possible to harmonize programs that have common elements across these dimensions (and possibly disparate elements).

Multiple perspectives on multiple customer programs

- **Utilities**, due to redundancies or conflicts in program designs, may find it hard to predict customer behavior and responses to varying incentives. This, in turn, can make it hard to incorporate these impacts into planning processes beyond operations, which has consequences for investing efforts in maximizing program outcomes.
  - From a program perspective, different parameters might need to be set for different technological measures. There are measures that have dispatchable-like capability like batteries, thermostats, etc., and others that are better candidates for load shifting like managed charging or thermal storage.
  - Additionally, trying to do a DR program with a customer's asset that is already engaging in a different program like TOU-EV rates can be troublesome and wasteful.
- **Customers** are often dealing with imperfect information and program confusion. The proliferation of programs can make it difficult for a customer to determine where to invest the time, effort, and finances to enroll in a program that would maximize their return.
  - Customers also face participation eligibility challenges as utilities have a significant amount of leeway to impose terms and penalties. If a customer cannot participate in a program due to these requirements, the customer might lose interest, particularly if the incentive is relatively small. This has consequences for the utility to scale.
  - Customers are not provided with the resources or informational access at a utility that would help alleviate this enrollment and make participation easier. Without support, the multitude of options can lead to decision paralysis and participation attrition.
- **Third-party aggregators** both face and present new challenges.
  - They can create opportunities for streamlining participation and enrollment, including across diverse programs by managing the navigation of incentives and simplifying decision-making and payments for customers. For example, if multiple programs all had the same incentive metric (e.g., hourly price per kW) and these were communicated to third-parties agents and customers, it could streamline programs significantly.
  - On the other hand, it's possible that the involvement of third-party agents creates new sources of confusion and/or dilutes the value proposition for customers. It's also possible that there are aggregators that only specialize in a particular technology, which could lead to customers having to engage with multiple aggregators.
  - Streamlining program design can also negatively affect third-party aggregator business models, where the simplification of program participation is a value sell.

Interoperability and data communication

- The lack of interoperability requirements and standardization of communication protocols may prove to be a significant hurdle to program harmonization.
- Achieving interoperable communications protocols that enable efficient, technology- and vendor-agnostic aggregation has proven challenging.
- Europe has made substantial strides in requiring common standards and interoperability. By not following suit, the US may continue to see a highly fragmented, unscalable market structure.

Dual participation in utility programs and varying payment mechanisms

- In trying to align programs, utilities may be faced with the challenge of reconciling different approaches to payment valuation mechanisms. For example, event-based DR, TOU rates, and managed charging programs all have different approaches for calculating incentives/payment.
- Additionally, there may be the risk that the customer is being double-paid or overpaid for DER participation in multiple programs. Avoiding this is critical to avoid cost shifts that will likely impact LMI customers more than non-LMI customers.
- The interaction with time-varying rates is challenging because the timelines for rate cases are much longer than for program design and implementation.
- Relatedly, there may be some concern of customers and market participants gaming the system through cost-shifting. As such, there needs to be clear guidelines for mitigating unwanted customer behaviors and unintended market signals.

Examples of challenges presented by lack of program harmonization

- A new construction mixed use project in San Jose, CA was designed to reduce load during the peak window (4-9pm) daily. The TOU rate arbitrage opportunity is much smaller than the event-based wholesale market or retail DR programs; however, the DR programs require establishing a baseline energy use during the peak window and only value load reduction, not exports. So the development which can shift load daily out of the 4-9 pm window (since the homes have solar, batteries, and thermal storage), and export to the grid during that time, does not have a way to be paid for those services (aside from the TOU rate arbitrage), deflating the value proposition.
- In an Indiana IOU program, customers can only enroll their water heater in the DR program if they are enrolled in the AC cycling program. Such customers who may want to enroll their water heater, but not their HVAC system, will be unable to do so.

Examples of efforts to harmonize programs

- National Grid presented at the 2024 Peak Load Management Association (PLMA) conference. Per their presentation, National Grid aggregates all measures under one program and has a hierarchy of action (though it appears there may be only two measure types—thermostats and batteries). Additionally, the C&I portion has 2 different programs to choose from.
- Puget Sound Energy provides a singular program entry to customers via the Flex program, which several measures qualify for. However, customers have to sign up for the Flex program for each measure by technology-type; as such, the program does not streamline enrollment hurdles.
- The peak saver pilot from FortisBC similarly is one program with several measures. After this, the Power Hours Rewards Program was launched with thermostats and EV off-peak charging.

POTENTIAL SOLUTIONS FOR DISCUSSION AT THE WORKSHOP

Recap of core challenges

- Drivers of a lack of program harmonization include policy challenges, utility silos, data sharing challenges, poor planning, organic program growth, and varying technological measures.

- The resulting breadth and diversity of utility programs present a challenge for producing a comprehensive harmonization roadmap.
- Defining the scope and type of the programs that might be included in a program harmonization effort is a critical and challenging first step. This includes aligning on the technology-bent of the program (whether harmonization should be in pursuit of tech-agnosticism).
- The proliferation of multiple programs presents challenges and opportunities for the utility, the customer, and third-party agents.
- Successful harmonization of programs across a utility may require greater interoperability and data communication requirements in order to avoid continued fragmentation.
- Dual participation in utility programs and varying payment mechanisms inherently arise as a challenge when harmonizing programs that have different approaches to valuation. These may require additional guardrails to protect against double-counting and cost-shifting.

Potential near-term solutions

- **Co-deployment:** At the 2024 Inaugural Convening, the targeted deployment working group highlighted "co-deployment" between different types of BTM programs as a least-regrets solution (e.g., ensuring electrification and efficiency measures are tied to some type of flexible load program or rate). It was determined that the utility should engage the customer at the point of sale of the device to be controlled.
- **Customer program scope and focus:** In terms of program types to focus on for harmonization, one of our utility implementation partners has suggested an immediate need to focus on flexible load programs as utilities are budget constrained and the easiest way to capture customers to enroll in flex load programs is during measure implementation.
- **Automatic enrollment across relevant programs:** A potential low-threshold approach for streamlining enrollment and participation is automatic enrollment for customers enrolling in one incentive measure, across relevant programs that are harmonized with said measure. For example, if a customer purchases a measure with a utility incentive and has the potential for load flexibility, the customer is automatically enrolled in the load flexibility program. This could reduce steps to enroll and engage customers, increase participation, and increase willingness to participate.
- **Similarly, utilities could institute an opt-out rate for DER customers:** If DER customers want to take advantage of program incentives, it could be required that they enroll in a time varying retail rate. This would make enrollment simpler and doesn't require a baseline calculation.
- **Establish a hierarchy of needs:** The value of load flexibility is not well defined and the value of DR will be different for wholesale and distributed benefits. To avoid issues of participation and selection a hierarchy level should be established. There are several approaches to consider:
  - Co-optimization of dispatch is an economist's ideal approach, but many consider distributed LMP to be functionally intractable as it deals with too many nodes.
  - Another approach would be to simply dispatch for distribution system contingencies as first priority and bulk system as a second priority. Theoretically, this could encompass reducing the resource adequacy benefit for customers, which can contribute to non-mitigation of bulk system emergency shortages. This approach would need to reconcile that the system value can often be higher than the distribution system value.

- Alternatively, some suggest programs should prioritize system level benefits first, and then any distribution specific issues to minimize overlaps.
- Another approach towards program design (and incentive development) would be to assess the marginal cost tradeoffs (or avoided costs). In New York, for example, future programs are likely to continue to emphasize bulk system benefits because marginal generator costs (associated with clean firm power) will be more expensive relative to distribution equipment capacity costs, which continue to be relatively cheap.
- A hierarchical design, which specifies dispatch protocols, may not be needed altogether if incentives can internalize desired grid outcomes —hourly prices can be set for bulk system energy and emissions and capacity value can be hourly adders or $/kW-Mo. These payment structures inherently signal which needs are met first.

- **Periodic evaluation of needs:** As grid needs change and as new resources are introduced in the system, the hierarchy could be re-evaluated with integrated resource and distribution system planning cycles in order to properly address the challenge of effective program planning. This evaluation would track DR value at different levels and, if there are any significant changes, then update the incentive payment accordingly.
  - An evaluation of DR benefits at the different uses of the resource (wholesale and distribution) is critical. Ensuring the program structure incorporates multiple types of grid services and communicates a price for each based on priority and value for DR, hierarchical responses could naturally follow (e.g., the Connected Solutions program in the northeast may be expanded this summer with a Dx Grid Services adder for certain hours when local constraints are expected).
- **Technical assistance coordinator at a utility:** In order to mitigate customer confusion and imperfect information, both of which risk low customer interest and participation attrition, utilities may consider having dedicated customer engagement staff. This individual would help coordinate programs internally and would help customers navigate their options and make program enrollment choices that bring both the customer and the utility the most value.
- **Potential program design considerations include:**
  - Aligning price signals and structures across programs, and reconciling up-front (often technology specific) incentives with ongoing incentives (which would ideally be technology agnostic and are pay for performance). There is a need to strike a balance of up front and performance based incentives to encourage customer adoption with some predictable payments, but also to require continued participation and performance to receive payments. The upfront incentives attract customers while the pay for performance reinforces good behavior and helps retain customers.
  - Grounding incentive mechanisms in the value of service constructs. The incentive mechanism should be capped at whatever it would otherwise cost ratepayers (e.g., if a $100 million grid upgrade was avoided, that should be considered the total program cost or incentive cap).
  - Developing incentives based on the value of DR for the use. Understanding the value will help shed light on the right incentive level.
  - Paying per kW and kWh, not per device, which in turn would require more flexible baseline and impact calculations, with after/before testing and statistical baselines (and not just historical data), as well as allowing impacts to be calculated with less expensive sub-metering.

  - Providing tariff riders for additional services so that payments can be added onto existing tariffs and programs rather than creating a new program.
- **Price signal considerations for third-party agents:**
  - For third-party agents, day-ahead, hourly prices, or dispatch could be very implementable and provide 90% of the value. There could also be real-time signals for select, large customers or customers with the right technology (including prosumers).
  - Being transparent in the calculation of DR event value in the hierarchy is very important. There is discussion to be had regarding whether this value should reflect a dynamic or static, average approach that covers each of the event categories. Dynamic pricing might discourage response in events that do not meet a minimum threshold because the real value is low but in aggregate and in the long run the utility would benefit. On the other hand, a dynamic rate (such as the ACC export rates or the dynamic pricing pilots in CA) can be coupled with event-based programs focused on emergency scenarios only (for which prices are often capped to not fully reflect).
- **Approaches for performance assessments** may include statistical methods, after/before testing, and comparing participating and non-participating customers to reduce reliance on year long EM&V studies. It could also involve increased active monitoring of distribution grid status, congestion, and operation as electrification and DG deployment increase. Reassessments should be conducted while DSP/IRP is being developed.
- **Shifting towards demand-side participation in ISO markets:** For utilities that participate in ISO markets, incorporating customer flexibility into their demand side bids into wholesale markets, such that customers do not "dually" participate in both wholesale and retail load flexibility programs, may be one way to harmonize along the lines of bulk and distribution system needs.

Open questions

- What constitutes successful program harmonization? Is full harmonization of programs realistic and desirable? What are the risks of not harmonizing programs?
- Are there particular dimensions by which to harmonize programs? (Based on the "Dimensions of program harmonization" table above)?
- What do we do with the programs that are currently successful?
- What do the crawl, walk, run approaches for a program harmonization framework look like? How do these steps differ for utilities in and outside of wholesale markets?
- How frequently should grid needs, grid value, and incentive levels be re-evaluated to prevent misalignment between wholesale and retail price signals?
- What should a hierarchy of grid needs look like? How should programs be designed to follow a hierarchy?
- Do third party providers feel that there should ultimately be one large customer program, or should there still be multiple different programs available (e.g., differentiated by customer type, dispatch method, technology type, grid service) and why?
- How can program harmonization leverage the unique attributes of third-party agents?
- What behavior for third-party agents needs to be incentivized in order to achieve a desired aggregation of several measures and assets?
- How do utility operations and planning factor into this discussion?

Potential longer-term solutions

- **Interoperability and standard communication protocol requirements** could be enforced to enable multiple aggregators and devices to participate in programs. This could be requiring standard communication protocols, or allowing for any communication protocol capable of ingesting certain grid signals.
- **Technology-agnostic compensation for flexible load programs:** Specific rates could be designed for the aggregator, not the customer. The aggregator can then manage a portfolio of customers to minimize the aggregator bill. The value of DR per event type or category would need to be defined, with the measures categorized in buckets and existing programs transitioned to align with this approach.
- **Case-making analysis on post-harmonized budget:** During potential modeling studies, the cost of administration of a program goes in each of the individual programs modeled affecting cost effectiveness, as well as the cost of marketing and outreach. Would program harmonization "free up" money to reinvest in actual measures for adoption or payments for load flexibility? In other words, do several programs need more budget than one program?
- **Other longer-term program design considerations:**
  - Shortening contract/program length
  - Preferencing DLM over price based control
  - Allowing impacts to be calculated with less expensive sub-metering
  - Moving rates to be more fixed- and demand charged-based to allow more dynamic variable rates without cost shift.

READING LIST

Preworkshop suggested reading

- CHARGED, Inaugural Convening Report (Targeted and integrated deployment chapter), 2024 chargedinitiative.org/wp-content/uploads/2025/12/CHARGED-Inaugural-Convening-Report-2024-2.pdf

Additional references

- Brattle, New York's grid flexibility potential, 2025, www.brattle.com/insights-events/publications/brattle-experts-conduct-a-study-to-determine-new-yorks-grid-flexibility-potential-in-2030-and-2040/

PROGRAM HARMONIZATION AND STREAMLINING

CONVENING DISCUSSION

WORKING GROUP OBJECTIVES

Original objectives from the Briefing Document

Develop principles and strategies for how utilities can harmonize and streamline multiple customer programs along the dimensions of design and operation, to address differentiated distribution system needs across a utility territory, while recognizing bulk system needs, and support beneficial electrification.

Working group alignment

The working group aligned on the following four objectives for the convening discussions.

1. Align on a definition of program harmonization and develop a shared understanding of the opportunity it poses
2. Identify under what circumstances harmonization is useful/possible
3. Prioritize the most impactful program design elements around which to harmonize for load flex programs to include distribution grid services
4. Identify what is needed for implementation of harmonized programs

PROGRAM HARMONIZATION DEFINITION AND OUTCOMES

Definition

For the purpose of this working group, program harmonization is defined as an alignment, consolidation, and/or optimization of a given utility's portfolio of load flexibility programs across various dimensions.

The group provided further definitions of consolidation, alignment and optimization:

- **Consolidation:** Fewer separate programs
- **Alignment:** Harmonization along complementary dimensions to work together
- **Optimization:** Ensure resources are maximally used for delivering value to the grid and customers

Throughout the working group discussions, the group emphasized that program harmonization is not exclusively consolidation, although much of the working group's discussions were focused more on consolidation, rather than alignment, or optimization. In many situations, consolidation might be a primary motivation for exploring harmonization (for example, if a utility has a very large number of load flexibility programs).

Desired outcomes of program harmonization

The working group went through an exercise to understand the benefits of program harmonization for each type of stakeholder group. The table below lists the desired outcomes from each perspective.

Desired outcomes of program harmonization *(Not meant to be exhaustive)*

UTILITIES	AGGREGATORS	CUSTOMERS

• Higher customer engagement, adoption
• Flex resource value maximization
• Streamline regulatory compliance
• Maximize grid utilization and program impact
• Reduce costs and administrative burdens
  - Affordable rates
  - Simplified dispatch
• Ensure reliability and grid stability
  - Accommodate load growth
	• Clarity of rules and incentives
	• Less confusion on dual participation
	• Standardize technical requirements
	• Consistent price signals and rules
	• Administrative efficiency
	• Revenue maximization and compensation predictability
	• Streamlined access to utility data
	• Ability to stack opportunities
		• Ease in navigating utility programs
		  - Can lead to increased adoption
		  - Reduced effort for dual participation
		• Reliability
		• Affordability
		• Equitable shares of system costs with allowances to LMI
		• Ability to adopt and install tech
		• Pursue sustainable technologies

TESTING THE CONCEPT WITH A SCENARIO ACTIVITY

Scenario description

Participants were divided into two groups. Each of the two groups were given a hypothetical scenario in which the respective hypothetical utility had 3 programs that the group would explore harmonization. The two scenarios are described below.

Utility company Watt's Up Electric is currently offering the following 3 programs

	PROGRAMS		
	C&I DR PROGRAM	SMART THERMOSTAT PROGRAM	BATTERY PROGRAM
CHARACTERISTICS			
Customer segment	C&I	Res and small businesses	Res and commercial
Grid Service	Bulk system capacity	Bulk system capacity	Bulk system capacity
Equipment type	Any	Thermostat smart	Battery
Dispatch type	Event-based	Event-based	Continuous (daily/weekday)
Compensation	Capacity ($/kW) and energy payment ($/kWh during an event)	Enrollment bonus + ongoing payment (fixed $/mo)	Ongoing payment (fixed $/mo)
Quantification of load reduction	Customer baseline	Customer baseline	BMS submeter
Utility dispatch signal	Passive	Active	Active

Utility company Amped and Ready Electric is currently offering the following 3 programs

	PROGRAMS		
	PEAK TIME REBATE PROGRAM	**WATER HEATER PROGRAM**	**MANAGED CHARGING—OFF PEAK CHARGING**
CHARACTERISTICS			
Customer segment	Res	Res	Res and C&I
Grid Service	Bulk system capacity	Bulk system capacity	Bulk system capacity
Equipment type	Any	Water Heater	EVSE
Dispatch type	Event-based	Event-based	Continuous (daily/weekday)
Compensation	Bill credits $/kwh	Enrollment bonus + ongoing payment (fixed $/mo)	Fixed $/month for off peak period charging at least 80% of the time
Quantification of load reduction	Customer baseline	Customer baseline	EVSE submeter / AMI
Utility dispatch signal	Passive	Active	Active

For each scenario, the participants were asked to consider the following questions:

- Is harmonization possible? If so, which factors are more critical to harmonize around/ which are less important? What challenges arise?
- Does the decision differ if the utility is part of an ISO?
- Given the programs are targeting bulk system peak, how would you layer in distribution system services? What factors need to be considered? How would you set up the program?
- Are there any program characteristics that are important to consider for program harmonization not included in the table?

Scenario exercise results

Across both groups, the discussions focused on program consolidation, rather than alignment or optimization. While both groups determined program harmonization (i.e., consolidation) was possible, one group struggled to identify how to streamline and consolidate programs given the attributes of the hypothetical programs. Both groups identified preferences for technology agnostic programs.

Watt's Up Electric

- Group determined program harmonization is possible
- Decided the compensation structure should be aligned with the grid service and program should be technology agnostic
- Challenges included baselines and delivering effective price signals to customer segments; the group noted aggregators could be helpful in achieving that goal
- Regarding ISO existence, would need to explore how to layer in additional value but the same program structure could apply

Amped and Ready Electric

- The group initially decided program harmonization is possible but later struggled with the approach; at a minimum programs 1 and 2 could be consolidated in terms of equipment
- Decided the grid services application is the most important factor
- In that context, utility dispatch signal and customer type were determined to be the most important considerations
- A key challenge noted was active vs. passive control in that the utility may not want to give up control: group decided this could be a differentiating factor to harmonize against

APPROACHES FOR PROGRAM HARMONIZATION

Dimensions of program harmonization

The working group began with the list of dimensions articled in the briefing document and went through a ranking exercise of these dimensions, along with additional ones added at the convening. This activity was based on the hypothesis that certain dimensions may be used to harmonize multiple programs, which could include consolidation, alignment or optimization (for example, would it be appropriate to consider consolidation of multiple programs that address the same customer types?).

The table below shows the outcomes of an exercise in which the dimensions were discussed in terms of their importance to harmonization. Although a ranking exercise was conducted, the group was not comfortable indicating numbers.

Dimension prioritization activity

DIMENSION	
Stakeholder perspectives Grid services Compensation structure (as distinct from the magnitude/level of compensation) Level of control	The working group was in general agreement that these four dimensions are salient dimensions as a "place to start" exploring program harmonization. How best to harmonize around these dimensions remains an open question.
Intra-utility program eligibility Quantification / measurement of impact Dispatch type Equipment type / load Customer segment Interaction with wholesale market	

The activity identified two broad sets of dimensions—one set that includes priority dimensions as a "place to start" program harmonization exploration, as compared to the second set of dimensions. Although the group noted these four dimensions are perhaps highest priority dimensions, how best to harmonize around these dimensions remained an open question.

Additional considerations on the program harmonization dimensions include the following.

- The "stakeholder perspectives" is not truly a dimension but an overarching consideration
- The results of this exercise are not meant to be prescriptive and are not definitive

- Certain dimensions in the lower set of dimensions, such as dispatch type, have a relationship with other "priority" dimensions, such as level of control
- Participants emphasized that while the discussion about dimensions was weighted towards consolidation, program harmonization is not solely consolidation.

When to preserve uncoordinated programs

The working group discussed conditions in which harmonization may not be warranted.

- When things are not broken
  - If there is no unrealized value; move to harmonize lacks positive outcome
  - When enrollment is completely saturated
  - No overlapping dimensions or unrealized value
- When customer considerations are prohibitive
  - When customer types are different
  - When a program serves a need specific to a customer type
- When the temporal dimensions are not aligned
  - If there are too many customer changes in too short of a time
  - When implementing a pilot
- When regulatory lift is prohibitive
  - If administrative will for separate programs is strong
  - If regulatory lift is prohibitive

If these conditions exist, it may not make sense to harmonize programs.

Next steps: potential implementation process

The working group went through an implementation exercise where the broader working group was divided into three groups. Each group was asked to develop key steps to explore program harmonization within a specific utility. Each group was set up to have at least one utility participant. Both groups' results were aligned in terms of the broad steps:

- Build internal utility alignment and structure to address portfolio wide load flex goals
- Inventory portfolio of programs along dimensions to identify opportunities for harmonization
- Create an action plan for harmonization

RISK MANAGEMENT TOOLS FOR PROACTIVE INVESTMENT

BRIEFING DOCUMENT

OVERVIEW

Objective: Define implementation strategies for risk management tools, such as performance incentive mechanisms, for proactive investment, addressing both the technical dimensions (e.g., a utilization metric) and the regulatory dimensions.

Relevance to CHARGED: Proactive capacity investments are intended to occur ahead of confirmed new loads and are generally based on more uncertain forecasts over longer time horizons. This additional uncertainty increases the risk that investments may be underutilized or disallowed by regulators, and may put an inequitable amount of risk on all ratepayers with no real discernment for who benefits the most. Checks and balances are needed to help shift the burden of over investment (and stranded assets) from ratepayers exclusively to utilities. This effort could be split into two aspects—the first in which technical aspects on how to "measure" performance (such as through system utilization metrics) are discussed—and a second in which processes or tools to mitigate risk are discussed.

This chapter is organized into four sections:

1. ***Connections to Previous CHARGED Efforts***, which describes how the group topic relates to previous and ongoing CHARGED activities, including from the 2024 Inaugural Convening.
2. ***Challenges and Emerging Practices***, which discusses current challenges, emerging practices to deal with these challenges, and provides examples of emerging practices.
3. ***Potential Solutions for discussion at the workshop***, which includes a recap of core challenges, and solutions that span near-term and longer-term components, along with open questions that would benefit from discussion during the Convening.
4. ***Reading List***, which includes suggested preworkshop reading and additional references for those that are interested.

For context, the development of this chapter, and all materials in the briefing document, were based on several perspectives within the internal CHARGED team.

CONNECTIONS TO PREVIOUS CHARGED EFFORTS

The Inaugural Convening included a workstream on distribution system planning. In that workstream, planning challenges were discussed and ranked, followed by discussions on least-regrets solutions and longer-term solutions. Several of these are relevant to this working group objective, including the following.

- Least regrets solutions associated with load forecasting:
  - Improved load forecasting, such as better understanding load growth for large customers, especially fleets
  - Considering managed charging, demand response, and other DSM programs in investment planning
  - Using AMI data, where available, in load forecasting and planning
- Least regrets solution – planning for operational flexibility
- Longer-term solution – utility and regulatory framework for proactive investment
- Longer-term solution – Develop performance-based incentive mechanism for proactive investments that can be used in multiple jurisdictions

Currently, solutions are being developed in three ongoing CHARGED virtual-format "ideation" working groups, which will conclude in Q4 of 2025. One of these is focused on proactive investment frameworks and was inspired by the longer-term solution of the same name identified in the Inaugural convening. Draft materials from this working group are being included as part of the pre-read for this working group to facilitate leveraging the work completed so far. Several members of the "Risk management tools for proactive investment" (hereafter referred to as the "risk" working group) are participating in the "Proactive investment framework" working group.

The inspiration for this risk working group is the longer-term solution on developing performance-based incentive mechanisms for proactive investments, for which a short description is included below, taken from the Inaugural Convening Report.

> ***What is the project?*** *Develop a performance-based incentive mechanism for proactive investments that can be used in multiple jurisdictions and tied to measures of asset utilization and performance with respect to electrification outcomes. The mechanism could be tied to a specific set of investments or a bounded portfolio of projects specifically for enabling electrification, and could have thresholds for incentives that allow utilities to scale back efforts without incurring too large of a penalty. The upside could be structured as shared savings and the downside as a return on equity haircut on the specific capital investments. This kind of incentive could provide a means to build trust between utilities and regulators and stakeholders, establishing a forum for learning and tracking the outcomes of early strategic proactive investments. In discussion, the group raised questions about the need for and design of incentive mechanisms, and whether this project might be able to be bundled into the third project (framework for proactive investment).*

The *risk* working group objective has been broadened from the original conceptualization in order to build on the efforts achieved in the ongoing proactive investment framework working group, and to allow for regulatory tools that go beyond performance-based incentives.

This chapter is organized broadly into challenges and solutions around two broad questions:

- How can technical success of proactive investments be measured?
- What are the regulatory tools for incentivizing technical success?

CHALLENGES, EMERGING THEMES AND PRACTICES

Measuring technical success

- One of the underlying principles of CHARGED is that both "supply-side" solutions (i.e.,

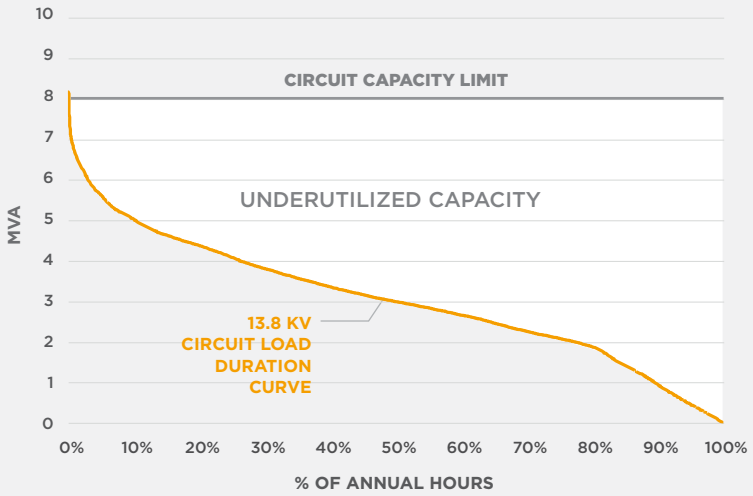
infrastructure to deliver more energy) and "demand-side" solutions (i.e., programs or pricing to shape load and reduce peak demand) should be leveraged to address anticipated load growth and facilitate affordable and reliable electrification. Measurements of technical performance should consider both types of solutions.

- In summary, to measure technical success of proactive investments, key metrics could include a combination of historical and projected load and utilization factors, coupled with complementary metrics. We describe load and utilization factors, then complementary metrics.
- **Distribution Load Factor** and **Utilization Factor** are potential metrics that are suitable for assessing the effective use of demand-side and supply-side measures. In both cases, higher values indicate higher utilization.
  - **Load Factor** is a measure of the "peakiness" of the load served by an asset, and by flattening the peak (increasing load factor), costs are reduced. Similar to a customer load factor (used by commercial and industrial or C&I customers to manage and minimize demand charges), the Distribution load factor for an asset can be improved by lowering peak demand and/or increasing delivered energy (usage) during off-peak hours. It is calculated by dividing the total MWh delivered by an asset in a designated period (typically a year) by the product of the maximum demand MW (or MVA) and the number of hours in the period.
  - **Utilization Factor** is a measure of how much of an asset's total available capacity is utilized throughout the year. This is not just the ratio of an asset's peak load to its capacity (which many utilities track today) but incorporates an energy component by dividing the total MWh delivered by an asset in a designate period (typically a year) by the product of the asset's capacity rating in MW (or MVA) and the number of hours in the period.
  - The **example below** (see callout box) demonstrates how these metrics, when calculated simultaneously, can provide a quantitative assessment of how peak loads are minimized and the degree to which investments are right-sized to address a capacity need.
  - Both Load Factor and Utilization Factor can be calculated for a substation, substation transformer, circuit, or distribution service transformer.
  - Overall, these calculations are accessible today for most utilities, leveraging a combination of information from common utility operational computer systems (SCADA, work management systems, billing or GIS).
  - However, there are some challenges to calculating these metrics. Configuration changes that precede the new investment can render the calculation process to be more complex—for example, if a new substation is constructed, existing circuits may be transferred to this substation and load growth across the new and old circuits would need to be tracked. SCADA data alone may not provide the needed information; configurations could be manipulated to artificially amplify utilization factors. Finally, determining the appropriate timing for assessing utilization and load factors is challenging for assets with 30-50 year lives.
  - Critics may question the importance of utilization factor in an environment of high load growth with the argument that it's more efficient in the long run to overbuild once, rather than having to add additional capacity later. It is possible that utilities may be inclined towards load factor because of their obligation to serve and regulators towards utilization factor as it reflects better utilization of capacity.

LOAD AND UTILIZATION FACTOR EXAMPLE

Load Factor is calculated by dividing the total MWh delivered by an asset in a designated period (typically a year) by the product of the maximum demand MW (or MVA) and the number of hours in the period. Utilization Factor is calculated by dividing the total MWh delivered by an asset in a designated period by the product of the asset's capacity rating in MW (or MVA) and the number of hours in the period. Calculations for a simplified hypothetical circuit are below.

Typical Distribution Circuit Asset Utilization



- Circuit capacity = 8 MVA
- Peak load = 8.2 MW
  - 5 hours > 8MW
- Annual energy delivered = 26,800 MWh

LOAD FACTOR =
26,800 MWh/(8.2 MW x 8,760 hours) = 37.3%

UTILIZATION FACTOR =
26,800 MWh/(8 MW x 8,760 hours) = 38.2%

For this hypothetical circuit, assume that the utility forecasts a potential 1.5 MW load addition with a load factor of 65% in Year 3. The utility has identified a set of programs and pricing to shift 0.75 MW of peak demand to off-peak by Year 3. An additional proactive capacity expansion project (reconductoring) would increase the circuit's capacity by 2 MVA by Year 3. In addition to the forecasted 1.5 MW load addition, the utility assumes a load and peak demand growth rate of 1% annually. The assumptions used by the utility in its analysis of the proactive upgrade are summarized below:

Today's circuit capacity (MVA)	8.0
Annual increase in peak demand and usage	1.0%
Forecasted load addition in Year 3 (MW)	1.5
Forecasted load addition in Year 3 (MWh)	8,500
Forecasted load addition in Year 3 load factor	65%
Proactive investment incremental capacity (MVA)	2.0
Potential load/demand shifted to off peak in Year 3 (MW)	0.75

To demonstrate that a proactive investment may be justified, the utility would first calculate the existing and forecasted Load and Utilization factors in the "Do Nothing" scenario (i.e., with no load shifting, load additions, or proactive investment), shown as Scenario 1 below.

SCENARIO 1 ▸ "Do nothing" (No load addition, no load shift, no proactive investment)

	CIRCUIT CAPACITY (MVA)	PEAK DEMAND (MW)	ENERGY DELIVERED (MWH)	LOAD FACTOR	UTILIZATION FACTOR	OVERLOAD RISK
Circuit today	8.0	8.2	26,800	37.3%	38.2%	<0.2 MW for 5 hours
Year 1	8.0	8.3	27,068	37.3%	38.6%	<0.3 MW for 7 hours
Year 2	8.0	8.4	27,339	37.3%	39.0%	<0.4 MW for 7 hours
Year 3	8.0	8.4	27,612	37.3%	39.4%	<0.4 MW for 7 hours
Year 4	8.0	8.5	27,888	37.3%	39.8%	<0.5 MW for 9 hours
Year 5	8.0	8.6	28,167	37.3%	40.2%	<0.6 MW for 12 hours

Note that in Scenario 1, the circuit's Load Factor remains constant since both the peak demand and energy delivered grow at a constant 1% per year. The circuit's Utilization Factor improves each year as more energy is delivered while the circuit capacity remains constant at 8 MVA. Overload risks occur for 7 hours or fewer each year through Year 3.

The utility may also consider a scenario where it executes the peak load shift but not the proactive investment, and the anticipated load addition does not materialize (Scenario 2 below).

SCENARIO 2 ▸ Load Shift, No Load Addition, No Proactive Investment

	CIRCUIT CAPACITY (MVA)	PEAK DEMAND (MW)	ENERGY DELIVERED (MWH)	LOAD FACTOR	UTILIZATION FACTOR	OVERLOAD RISK
Circuit today	8.0	8.2	26,800	37.3%	38.2%	<0.2 MW for 5 hours
Year 1	8.0	8.3	27,068	37.3%	38.6%	<0.3 MW for 7 hours
Year 2	8.0	8.4	27,339	37.3%	39.0%	<0.4 MW for 7 hours
Year 3	8.0	7.7	27,612	40.9%	39.4%	None
Year 4	8.0	7.8	27,888	40.9%	39.8%	None
Year 5	8.0	7.9	28,167	40.9%	40.2%	None

Note that in Scenario 2 the overload risk is eliminated beginning in Year 3. The Year 3-5 Load Factor improves compared to the "Do Nothing" scenario since the circuit's peak demand is reduced while delivering the same amount of energy. The Utilization Factor is the same as the "Do Nothing" scenario since the circuit is delivering the same amount of energy with its 8 MVA capacity.

A third scenario that the utility may consider is where it executes the peak load shift, the load addition materializes, but the utility does not make a proactive investment. In Scenario 3, the circuit's Load Factor would increase with the load addition, however the utility risks a delay in connecting the new customer load as it must construct a reactive capacity upgrade solution.

SCENARIO 3 ▸ Load Shift + Load Addition, No Proactive Investment

	CIRCUIT CAPACITY (MVA)	PEAK DEMAND (MW)	ENERGY DELIVERED (MWH)	LOAD FACTOR	UTILIZATION FACTOR	OVERLOAD RISK
Circuit today	8.0	8.2	26,800	37.3%	38.2%	<0.2 MW for 5 hours
Year 1	8.0	8.3	27,068	37.3%	38.6%	<0.3 MW for 7 hours
Year 2	8.0	8.4	27,339	37.3%	39.0%	<0.4 MW for 7 hours
Year 3	8.0	9.2	36,112	44.8%	TBD	1.2 MW, delayed customer connection
Year 4	TBD	9.3	36,473	44.8%	TBD	
Year 5	TBD	9.4	36,838	44.8%	TBD	

Scenario 4 involves the peak load shift, materialization of the load addition, and the utility performing the proactive upgrade in Year 1. In this scenario, the overload risk is eliminated in Year 1 while both the Year 3-5 Load Factor and Utilization Factor improve compared to the "Do Nothing" scenario.

SCENARIO 4 ▸ Load Shift + Load Addition with Proactive Investment

	CIRCUIT CAPACITY (MVA)	PEAK DEMAND (MW)	ENERGY DELIVERED (MWH)	LOAD FACTOR	UTILIZATION FACTOR	OVERLOAD RISK
Circuit today	8.0	8.2	26,800	37.3%	38.2%	<0.2 MW for 5 hours
Year 1	10.0	8.3	27,068	37.3%	30.9%	None
Year 2	10.0	8.4	27,339	37.3%	31.2%	None
Year 3	10.0	9.2	36,112	44.8%	41.2%	None
Year 4	10.0	9.3	36,473	44.8%	41.6%	None
Year 5	10.0	9.4	36,838	44.8%	42.1%	None

Finally, the scenario where the utility executes the load shift and proactive investment, but the load addition does not materialize is illustrated below. In this Scenario 5, overload risk is eliminated in Year 1, Year 3-5 Load Factor improves due to the reduction in peak demand, however the circuit's Utilization Factor is significantly lower than the "Do Nothing" scenario.

SCENARIO 5 ▸ Load Shift , No Load Addition with Proactive Investment

	CIRCUIT CAPACITY (MVA)	PEAK DEMAND (MW)	ENERGY DELIVERED (MWH)	LOAD FACTOR	UTILIZATION FACTOR	OVERLOAD RISK
Circuit today	8.0	8.2	26,800	37.3%	38.2%	<0.2 MW for 5 hours
Year 1	10.0	8.3	27,068	37.3%	30.9%	None
Year 2	10.0	8.4	27,339	37.3%	31.2%	None
Year 3	10.0	7.7	27,612	40.9%	31.5%	None
Year 4	10.0	7.8	27,888	40.9%	31.8%	None
Year 5	10.0	7.9	28,167	40.9%	32.2%	None

As stated above, a regulator may view most favorably a proactive capacity investment that eliminates overload risks while simultaneously increasing an asset's Load and Utilization factors. As shown below, this only occurs in Scenario 4 for the sample circuit.

Comparison of Year 5 Load and Utilization Factors by Scenario

	YEAR 5 LOAD FACTOR	YEAR 5 UTILIZATION FACTOR	OVERLOAD RISK
SCENARIO 1 do nothing	37.3%	40.2%	Years 1-5
SCENARIO 2 load shifting, no load addition, no proactive investment	40.9%	40.2%	Eliminated in Year 3
SCENARIO 3 load shifting, load addition, no proactive investment	44.8%	TBD	Significant, potential customer delay
SCENARIO 4 load shifting, load addition, proactive investment	**44.8%**	**42.1%**	**Eliminated in Year 1**
SCENARIO 5 load shifting, no load addition, proactive investment	40.9%	32.2%	Eliminated in Year 1

- Complementary metrics could be considered for measuring technical success.
  - Supplemental benefits from proactive load-related capacity investments, such as faster customer connection times, improved safety, reliability, resilience, increased DER hosting capacity, and operational flexibility (such as flexible grid connections, advanced rates).
  - Supplemental information to load factor calculations, such as load forecast accuracy, load growth indicators such as new customer connections and service upgrades (which could provide objective information on load growth drivers).
  - Construction indicators for proactive investments such as actual vs. projected construction timelines and costs
- As one possible approach, to support a proposed proactive investment, a utility could provide the following information (in addition to existing capacity, forecasted incremental load additions).
  - Historical Asset level (substation/circuit/transformer) Load and Utilization factors, such as for the previous three years.
  - Projected Load and Utilization factors if it makes no proactive investment.
  - Projected Load and Utilization factors over the 3-5 years post-investment, accounting for the incremental capacity, forecasted incremental energy and peak demand (including steps to be taken to reduce or shift peak demand).
  - As part of the process, it's important that the utility demonstrates the cost-effectiveness of the proposed investment (i.e., the proposed solution(s) is/are the least-cost way of addressing the need while increasing Load and Utilization factors).
  - After making a proactive investment, the utility could report annually on the actual substation/circuit/transformer Load and Utilization factors compared to projections (with explanations for any material variances), and any complementary/supplemental benefits attributable to the proactive investment.
- To our knowledge, the Load and Utilization factors have been considered in some jurisdictions but are not currently tracked or reported by US utilities, either in the context of traditional (reactive) investments or proactive investments. However, some examples are worth noting.
  - Rhode Island's 2017 Power Sector Transformation report identified Distribution Load Factor as a metric worthy of tracking and reporting.[10]
  - A 2017 report by The Brattle Group summarized its assessment for the New York Joint Utilities of system load factor as a potential system efficiency earning adjustment mechanism (EAM). It concluded that a system load factor EAM will largely be ineffective because utility initiatives concerning the integration of DERs and the deployment of beneficial electrification are unlikely to have a meaningful and distinct impact on system load factor.[11] (It is worth noting that the Brattle report reached this conclusion prior to gas decarbonization efforts beginning in some jurisdictions as well as rapidly expanding energy storage and electric vehicles applications on the distribution system. These emergent factors may impact the findings.) Additionally, the system load factor (encompassing all of a utility's customers across its service territory) is not the same as a

10 State of Rhode Island Division of Public Utilities & Carriers Office of Energy Resources and Public Utilities Commission, Rhode Island Power Sector Transformation: Phase one report to Governor Gina M. Raimondo, 2017 ripuc.ri.gov/sites/g/files/xkgbur841/files/utilityinfo/electric/PST-Report_Nov_8.pdf, p. 28.

11 The Brattle Group, Assessment of load factor as a system efficiency earning adjustment mechanism, 2017 www.brattle.com/wp-content/uploads/2021/05/13775_assessment_of_load_factor_as_a_system_efficiency_earning_adjustment_mechanism.pdf, p. 2.

circuit- or substation-specific load factor, which a utility can influence. The Brattle report calls this a "Local Load Factor".[12]

- The Australian Energy Regulator reports utilization levels for its electricity distribution networks (not calculated the same way as in this document). See this blog[13] which argues for the need to begin measuring utilization at individual locations on the Australian networks.
- In Great Britain, utilities are regulated under performance-based regulation in which utilization metrics are leveraged, including a transformer utilization metric. An additional metric, the "transformer capacity released ratio", is a ratio of net capacity additions to the increase in peak load capacity which encourages that transformer capacity additions happen at locations where electric heating and transport load is added to the grid.
- Load factors are commonly used by C&I customers to manage usage and minimize demand charges.

Regulatory approaches

- There are a variety of strategies and known regulatory tools that can help mitigate risk to consumers for poorly made proactive investments. The most basic ones include the following.
  - A "no-regrets" risk mitigation strategy is to make sure proactive investments are right-sized and only used as needed; ensure utilities identify investments after using "best-in-class" distribution forecasting and planning methods, credibly seeking non-wires solutions when available, and using load flexibility where possible. Transparent processes are needed so stakeholders can assess this mitigation tool has been utilized.
  - Clear criteria on when the investment is deemed used and useful will manage utility expectations on timely, consistent cost recovery with customer risk.
  - Disallowances could be leveraged but should be viewed as the last resort for the worst case outcomes.
- Performance based regulation or ratemaking (PBR) is an overall regulatory approach that seeks to align utility incentives with the interests of customers and society. It does this by compensating utilities based on their performance against target outcomes rather than just costs—and by removing perverse incentives. PBR consists of multiple regulatory tools. Developing a robust, comprehensive PBR framework can be labor intensive.
- One PBR tool that could be used is performance incentive mechanisms (PIMs), which could be used to reward exceptional performance by the utility in maximizing asset utilization, interconnection timeline, and cost control. Performance incentive mechanisms can incentivize performance toward specific regulatory outcomes, but can be challenging to design well in practice. However, PIMs are easier to implement than more comprehensive forms of PBR given their relatively small impact to utility revenues, and thus can be more experimental. While PIMs, especially in the form of shared savings mechanisms, can support cost containment in targeted areas of utility spending, they are not able to more comprehensively incentive utility cost control compared to other PBR mechanisms.

12 Ibid, p. 17

13 Energy Consumers Australia, Electricity distribution network utilisation – why it's important to consumers, and why we need to update how we measure it, 2023 energyconsumersaustralia.com.au/news/electricity-distribution-network-utilisation-why-its-important-to-consumers-and-why-we-need-to-update-how-we-measure-it

- Another PBR tool is multi-year rate plans (MYRPs), which can create a cost containment incentive if developed well, but there are numerous considerations:
  - MYRPs extend the window between rate cases beyond what is typical under traditional cost of service regulation (COSR). This means that once base rates are in place, they are not reset to reflect the utility's actual costs for several years (usually 3-5 years). If the utility manages to achieve savings in the costs recovered by those rates, it can benefit financially from those savings for longer than it would be able to under traditional COSR—creating an incentive for it to seek cost-savings opportunities.
  - MYRPs can have revenue or price caps over the life of the plan, though revenue caps are more common in the U.S. these days. These can be critical components to ensure that bill impacts are managed even when proactive planning is being used. Regulators need to have an understanding of the overall bill impacts to maintain affordability.
  - For MYRPs that adjust base rates according to multi-year forecasts, if proactive investments are approved as part of a forecasted budget, the utility has a pre-established budget with pre-determined rate impacts that they must optimize against to increase their return. If base rates are adjusted in MYPRs according to an index-based formula, proactive investments may still be able to be recovered through annual revenue adjustments.
  - However, if an interim rate adjustment is used to recover proactive investments beyond what is allowed to be recovered through annual base rate adjustments, the cost containment incentive introduced by a revenue or price cap is lost for the proactive investment unless there is another mechanism in place to incentivize cost containment (e.g., Hawaii's Collective Shared Savings Mechanism).
  - MYRPs can also be implemented alongside PIMs that measure performance over the span of the MYRP and can be focused on specific regulatory outcomes. PIMs frequently have annual targets and performance measures and are reset each MYRP.
- Regardless if MYRPs or more traditional rate cases are used to recover costs from proactive investments, interim rate adjustments may be considered as a way to encourage more timely investment and reduce regulatory lag. However, if used, these cost recovery mechanisms require careful consideration when being designed and implemented. Experiences with interim rate adjustments has shown that without specific cost recovery criteria or mechanisms to support cost containment, they remove cost containment incentives, reduce regulatory scrutiny, and are not usually tied to desired outcomes directly.
- Rate design can also be a useful tool. For example, demand charge alternatives have been used to encourage EV load through lower rates. This is good as long as rates trend upward in a transparent and predictable fashion. (Rate design was a focus of the Inaugural Convening)
- Overall, the industry has experience with these various tools. However, the results have been mixed and disparate, and this experience has not been in the context of proactive investments. Some examples (not meant to be exhaustive) are included.
  - Hawaii has a performance based regulation framework that includes an earnings sharing mechanism, however, the implementation of it has been complicated by the Maui fire. HECO recently reported a 14.5% ROE.
  - Connecticut is implementing a comprehensive PBR framework and aims to connect the distribution system planning process to the MYRP. Initial impressions are mixed.
  - Various jurisdictions have adopted MYRPs but have seen bills increase, such as in

Minnesota and Massachusetts (where bills have increased 40% in 3 years). In Maryland, a MYRP was rejected due to rate impacts and objections by consumer advocates. These jurisdictions are different in terms of their planning processes, which can improve stakeholder transparency and awareness, and support for MYRPs. Minnesota has had an integrated distribution planning process for several years and recently developed a proactive planning framework. Both Maryland and Massachusetts do not have distribution system planning processes.

- Past experience has shown that successful implementation of new regulatory tools (with desirable outcomes) requires that the regulator is committed to comprehensive regulatory changes (which tend to take more time than anticipated); otherwise they are often not worth it, as piecemeal changes can do more harm than good, and be viewed as helping shareholders and not ratepayers. This has been true of rate riders, MYRPs and PIMs.
- There are numerous considerations for regulators in selecting and designing a risk mitigation mechanism.
  - How these mechanisms impact the prudency determination and approval process, and the magnitude of the overall capital spend by the utility.
  - Design of these tools must be done in a way to ensure that incentives are appropriately aligned and cannot be misused or gamed.
  - The design must consider sequencing, pace, and cost containment. In some cases, changes were made very rapidly that have resulted in significant bill impacts.
  - Ensuring that foundation planning practices are established, investments are sequenced for lowest risk and cost, and planning incremental upgrades over a longer time period (or as load materializes) will help to mitigate bill impacts and pushback from stakeholders and the public.
  - It is important to ensure consumer advocates are comfortable with the changes so that they are not opposed as a matter of principle (which is often the case today).
  - How these tools are used should depend on the use cases motivating different proactive investment. There is more need for proactive approaches to provide new or upgraded service for EV fleets and public fast-charging locations, as those loads generally have the largest disconnect between timing of vehicle / EVSE procurement and timeline for necessary upgrades.

POTENTIAL SOLUTIONS FOR DISCUSSION AT THE WORKSHOP

Recap of core challenges

- Under investment in grid infrastructure can dampen electrification adoption while over investment can increase customer costs unnecessarily.
- Technical measures of success, which can be a part of risk mitigation tools, can incorporate traditional calculations such as load factor and utilization factor at the asset level, which together, encapsulate “demand” and “supply” side solutions. However, these have not been adopted in traditional ratemaking processes nor previously associated with proactive investment.
- Technical measures of success can track other objectives such as faster grid connection times, increased DER hosting capacity, safety, reliability and resilience, which are complementary to load factor and utilization factor.

- Even if distribution performance as it relates to proactive investment is measured, it is not obvious how these should be linked to regulatory incentives.
- However, various regulatory tools are available to incentivize desired performance and to mitigate risk. These range from basic approaches that emphasize right-sizing, robust planning approaches, leveraging flexibility (many of which were discussed in the Inaugural Convening), to multi-year ratemaking plans, to performance incentive mechanisms, and comprehensive performance based ratemaking.
- Each tool has pros and cons and very few jurisdictions have adopted them with 100% success; the more comprehensive the change is, the more committed regulators must be as piecemeal approaches can cause more harm than good.

Potential risk management solutions

- Requiring some level of Load and Utilization factor reporting, at the asset level, even in the context of traditional ratemaking; an early step can be to begin calculations of these metrics for specific assets and report for informational purposes. This information would be useful for internal utility planning exercises even if they are not tied to proactive investment approvals.
- Requiring a checklist of common elements of "no-regrets" planning approaches and metrics regardless of the ratemaking and approval process, such as elements from the CHARGED Inaugural convening least-regrets solutions identified in the planning workstream.
- Establishing rules for transparency in planning exercises, whether those are connected to newly established distribution system planning processes, or otherwise.
- Additional elements are discussed in the CHARGED proactive investment framework; a draft is being shared prior to the Convening.

Open questions and longer-term solutions

- What are the appropriate set of metrics or measures of technical success to ensure desirable outcomes from proactive investments?
- How feasible is it to consider load and utilization factors? What is a reasonable process for calculating and reporting Load and Utilization factors, historically and forward looking? (The previous section suggested calculations over 3-5 years post-investment with annual reporting, that compares actuals with projections.)
- What are some plausible mechanisms for proactive investment (e.g., ratemaking, PIMs) and what are some incremental steps and enabling conditions to move towards implementing these, including how they can be woven into regulatory processes, such as distribution system planning processes?
- What would the design of a "pilot" performance incentive mechanism for proactive investments look like that leverages the technical measures of success discussed?
- Are there common prerequisites and minimum criteria for designing a risk management mechanism for proactive investment, such as the example elements described in the preceding section?

READING LIST

Preworkshop suggested reading

- CHARGED, Inaugural Convening Report (Distribution planning chapter), 2024 http://chargedinitiative.org/wp-content/uploads/2025/12/CHARGED-Inaugural-Convening-Report-2024-2.pdf
- CHARGED, Draft Proactive investment framework from the ongoing CHARGED working group (shared as an attachment)

Additional references

- Lawrence Berkeley Laboratory, Unlocking load growth at the grid edge: Practices for managing, recovering, and allocating distribution system investments, 2025 eta-publications.lbl.gov/sites/default/files/2025-03/unlocking_load_growth_berkeley_lab_final.pdf (chapters 4 and 5)
- Minnesota Framework for proactive distribution grid upgrades and cost allocation for Xcel Energy, 2025 www.edockets.state.mn.us/documents/%7BE0831096-0000-CD13-930C-1797E172AFFA%7D/download?contentSequence=0&rowIndex=1
- Massachusetts Framework for the long term system planning process for distributed generation 2025 fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aechfbcaj?H2WP7YvZfmq7ZJ9JSMx8lDVOCwNmqkF7a2iSbK4sRtaPcSxI+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6ngIfa80wd3rxFD8G4j981M2Rna9aVTXA
- New York Joint utilities long-term proactive planning framework 2024 documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B60C3C193-0000-C42C-9162-2B10D1624579%7D
- New York Public Service Commission, Order addressing urgent upgrade filings, 2025 documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF05F6597-0000-C17B-B068-916CB5B91D67%7D
- Black & Veatch and EDF, Proactive Grid Investment Assessment Medium-and Heavy-Duty Vehicle Transportation Electrification, 2024 www.edf.org/media/new-study-suggests-preparing-grid-now-electric-trucks-buses-can-save-ratepayers-money
- RMI, How to restructure utility incentives, 2024 rmi.org/wp-content/uploads/dlm_uploads/2024/07/RMI_how_to_restructure_utility_incentives.pdf
- GridWorks, Smart Inverter Operationalization (SIO) working group report: Business cases and use cases, 2024, gridworks.org/wp-content/uploads/2024/02/Smart-Inverter-Operationalization-Working-Group-Report-Feb.1.24.pdf

RISK MANAGEMENT TOOLS FOR PROACTIVE INVESTMENT

CONVENING DISCUSSION

WORKING GROUP OBJECTIVES

Original objectives from the Briefing Document

Define implementation strategies for risk management tools, such as performance incentive mechanisms, for proactive investment, addressing both the technical dimensions (e.g., a utilization metric) and the regulatory dimensions.

Working group alignment

The working group revisited the central problem that has given rise to discussions of changing grid investment practices and timing:

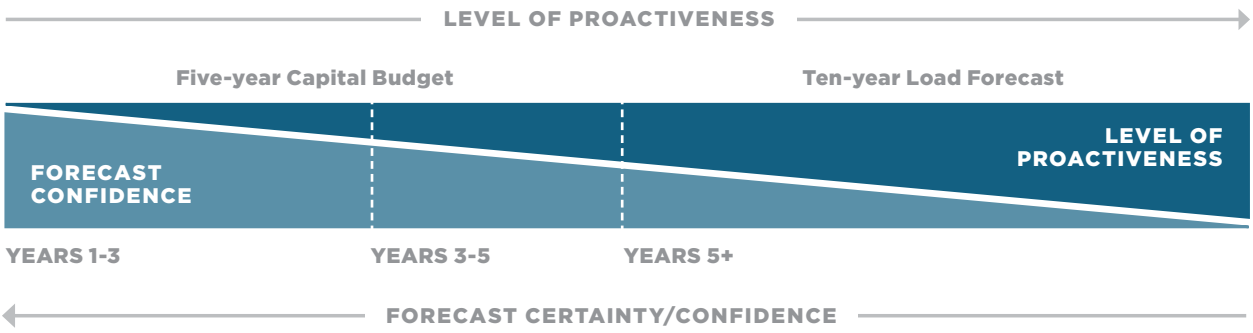
In an era of accelerating load growth, utilities may need to make targeted proactive investments in distribution systems to meet anticipated needs, but regulatory uncertainty—especially regarding cost recovery and timing—can inhibit such actions.

PROACTIVE INVESTMENT DEFINITIONS AND OBJECTIVES

Defining proactive investment and certainty spectrum dynamics

The working group began by working to define "proactive investment" as there is currently no set industry definition. Proactive investments are made ahead of confirmed loads and aim to enable future growth distinct from historical trends—for example, load from electric vehicles, which has increased substantially in recent years and is expected to continue growing quickly, yet is not well captured in historic trends.

Participants discussed how proactive investments differ from more traditional investments in timing, scale, and degree or type of uncertainty. They noted that the uncertainty associated with proactive investments is not necessarily greater, but different than that associated with more traditional investments, emphasizing longer time horizons and more variables. The group also discussed that some current investment practices already include a degree of proactive investment based on level of forecast confidence. With this in mind, proactive investments were framed in the discussion as being on a spectrum that transitions between higher near-term forecast confidence and a greater need for proactivity in the longer-term.



Source: Zach Pollock, Xcel Energy

Objectives for proactive investment

The objectives of proactive investment fall into four broad categories: energization, cost/rate savings, reliability, and policy goals. See the graphic below for more details about each of these categories.[14]

OBJECTIVE	DESCRIPTION
Energization	• Reduced connection timelines • Enabling electrification (customer plans) • Enabling electrification (policy goals) • Transparency into connection process, timeline, and cost • Flexible connections to energization
Cost/Rate Savings	• Deliver significant downward pressure on rates • Least cost least risk investments • Capex efficiency (“measure twice, cut once”) • Identify the best solutions to meet customer needs given more lead time to plan
Reliability	• Maintain reliability (and avoid overloads) • Ensure grid has adequate capacity • Resilience
Policy Goals	• Electrification • Gas decarbonization • Attract economic development loads (drive customers to certain areas / attract customers to utility/area)

CHALLENGES FOR PROACTIVE INVESTMENT AND MANAGING RISK

Risks of proactive investment

Discussing the risks of proactive investment, the group aligned on:

- Stranded assets (either because load does not show up, it shows up in a different area, or at a different time)
- Incorrect or unsuitable sizing of assets
- Poor coordination / sequencing of asset development
- Inappropriate cost allocation

14 Many of the objectives of proactive investment also apply to more traditional investments.

- Cost disallowance
- Affordability

However, the size of some of these risks varies based on geography. For example, in urban areas there is less risk of stranded assets as there are often ways for assets to be utilized even if it is for a different purpose than initially intended.

The group also acknowledged that there are also numerous risks to inaction or not investing proactively, including delayed energization, revenue loss or delay, missed policy objectives, degraded reliability, and a different form of unsuitable investment for utility assets.

The group highlighted the need for clear baselines of certainty, the overlap of risks between proactive and traditional investments, and a more refined understanding of technological and financial risk.

Measuring success: technical and complementary measures

A significant portion of the discussion focused on developing "measures of success" for proactive investments and how load and utilization factors could be usefully applied to projects (see the Briefing Document chapter for details on these metrics). Participants agreed that further use of these measures, also referred to as metrics, could provide opportunities for improved grid management and support the targeting and subsequent evaluation of proactive investments.

Several noteworthy conclusions included:

- **Practicality:** The data likely exists today for most utilities to calculate load and utilization factor on a feeder and substation scale.
- **Interaction with system operations:** When considering these metrics, it is essential to include larger system dynamics like load shift and load transfers to adjacent circuits.
- **Limitations:**
  - When proactive investments increasing capacity are made, utilization factor will decrease initially before potentially rebounding. It is important to consider this when deciding how this metric might be used, and how it should be paired with other metrics for a more complete picture.
  - Some form of cost metric will need to be brought in as a companion to these measures to enable better decision-making.
- **Use case:** Load and utilization factor could be used to assess an investment over its lifetime to see if it met projections. Some participants expressed that these measures should not be used to determine whether an investment should be approved for deployment.
  - Adhering to measures like these could slow down deployment of proactive investments. One suggestion was to utilize these metrics to review investments retrospectively and then apply learnings to assess future projects.
  - Careful thought needs to be given to the unit of analysis (individual assets vs. larger portions of the grid) for these metrics, as well as the time period over which they're being measured.
- **Value proposition of metrics:** For any metric proposed, it's necessary to make the case to the utility as to what the value proposition of that metric is for them (i.e., why should they bother tracking and potentially reporting that metric?).

- **Additional considerations:**
  - Need to balance potential for perverse incentives (e.g., potential disincentive for distributed generation)
  - How the true capacity of assets vs. the utility planning criteria (e.g., 75%, 100%) could influence capacity needs and technical measures
  - How to appropriately consider both supply- (traditional wires) and demand-side (e.g., load shifting / non-wires) options
  - An issue set aside for future discussion was native (gross) vs. net loads, and how they influence capacity needs

The group also discussed the need for complementary measures, which can help provide a more holistic view of proactive investments, specifically by reflecting impacts to customers/off-takers. The group developed a list of potential complementary measures to consider, spanning reliability, cost, operational flexibility, customer connection timelines, alignment with policy goals, and load forecast accuracy, among others.[15]

The group concluded that:

1. Technical metrics such as load and utilization factor will require pairing with other, complementary measures to tell a more complete story, and
2. Perverse incentives and unintended consequences must be considered in the design and use of any such evaluative criteria. For example, without careful criteria design distributed energy resources could be disincentivized due to their ability to decrease net utilization.

Ultimately, the group aligned around the need for multi-metric frameworks combining factors including asset utilization, reliability, affordability, and policy alignment, and that these more comprehensive approaches are preferred over single indicators. Open questions include:

- Whether and which of these measures would be reported publicly (vs. tracked internally by utilities and potentially regulators), and
- Whether they would be used prior to investments (ex-ante), after project development (ex post), both, or potentially in some other use case.

There will not be a one-size-fits-all approach and more work will be needed to understand what combinations of technical and complementary metrics are needed in what situations. The group underscored the importance of balancing technical and complementary metrics to avoid perverse incentives and ensure that proactive investments are evaluated not only by technical success but by their contribution to broader policy and customer outcomes.

APPROACHES FOR PROACTIVE INVESTMENT AND RISK MANAGEMENT

Managing risk through regulatory mechanisms

Expanding upon technical and complementary measures, the group explored how regulatory mechanisms—and most specifically, performance incentive mechanisms (PIMs) using these measures—can support proactive investments. In this discussion participants revisited the four

15 Discussion of complementary measures spanned many areas, and included cost (e.g., $/MVA added or served, $/kWh), economies of scale, reliability, resilience, operational flexibility, increased distributed energy resources (DER) hosting capacity, customer connection timelines, actual vs. projected costs and connection timelines, policy goal attainment, load forecast accuracy, and safety improvements.

overarching goals of proactive investments which could potentially form the basis for development of PIMs: energization and timelines, policy advancement, cost and rate savings, and reliability and grid capacity. Importantly the group acknowledged that no single PIM could address all of these goals, underscoring the need for a combination of mechanisms tailored to context and the use of different technical and complementary measures to undergird different PIMs. Additionally, as with the discussion of technical measures of success, the group discussed how perverse incentives must be considered. For example, absent thoughtful design a PIM based around utilization factor could result in artificial utilization increases on new, proactively developed infrastructure through load transfers.

Participants broke into two groups to discuss in additional detail potential PIMs around 1) energization timelines, and 2) cost and rate savings.

Energization

The energization-focused group discussed which portions of the energization timeline are directly within utilities' control and how to best measure improvements in energization timeline (e.g., time to energization, number of energized fleets, quantity of curtailment within flexible connections, interconnection cost over time, flexible connections, utilization, number of customers that could not be served). The central focus of the envisioned PIM was to tie incentives to reductions in service connection timelines. There was also discussion of whether additional incentives for customers (rather than utilities) to electrify and utilize proactively made capacity upgrades would be a useful strategy for reducing the risk of overbuilding and stranded assets.

Cost and Rate Savings

The cost and rate savings-focused group spent most of its time discussing which metrics would be most effective, durable, and fit-to-purpose for measuring the cost-effectiveness of proactive investments. Several of the salient parts of that discussion included:

- The potential for using a metric (likely in either $/MVA added or served) that captures a utilities' *long-term* capital efficiency.
- Opportunities to benchmark efficiency to peer utilities (potentially developing "frontiers of efficiency" to understand relative performance).
- Challenges in comparing very different projects between and across service territories (e.g., rural vs. urban capacity upgrades).
- Reducing capital bias by allowing utilities to earn a return on labor and expenses, and the beginnings of a discussion around TOTEX / larger systemic regulatory changes.[16]
- When metrics are useful for *decision-making* vs. when they are useful for *informational and transparency purposes*.

Across both breakout groups there was general alignment that establishing clear prerequisites for utility planning practices—such as best-in-class load forecasting—could enable more transparent and confident dialogue around proactive investments and the development of PIMs to support such investment. While further work is required to build out specific PIMs for use in different jurisdictions—and to meet different desired goals—the robust discussions in this convening present a helpful starting point for subsequent work.

16 Total expenditure ("Totex") ratemaking is an alternative regulatory approach to utility regulation, premised on the pooling of capital and operating expenses (to form "total expenses") to remove investor-owned utilities' bias towards capital expenditures given the guaranteed rate of return they earn for this category (unlike for operating expenses, which are passed through to customers).

Future directions

There were several topics not discussed during the convening which the group acknowledged are closely related and should be explored further. These include:

- **Cost allocation**, which was not discussed in great depth yet is an important component to consider when contemplating proactive investments.
- The **impacts on labor needs and operations and maintenance (O&M)** were raised multiple times. For example, one potential benefit of proactive investment is the opportunity to further spread out labor needs across years, avoiding a bottleneck in the workforce available to develop projects.
- Developing **a list of best-practices for utilities** that could be considered prerequisites for distribution system capacity planning that includes proactive investment proposals. This could help to reduce information asymmetry between utilities and other stakeholders such as consumer advocates.
- There was relatively limited discussion about **what steps *regulators* need to take to support proactive investment**, as the conversation primarily focused on the role of utilities. Further exploring the specific actions regulators can take to develop and/or support risk management approaches for proactive investment would be a productive follow-on exercise.

Throughout the convening the group recognized that there were several important voices missing from the conversation, including utility planners (vs. other functional roles) and consumer advocates. Both groups play important and unique roles and need to be further involved in future discussions of proactive investment and options for risk management.

Next steps: potential projects

When discussing opportunities to advance the implementation of these findings and methods for managing risk, the group identified two potential projects:

1. **Proactive Investment Metrics:** There is no standard approach for metrics to assess proactive investments, either to make investment decisions or for monitoring project success. A framework could detail different packages of metrics and when they should be used to (a) decide if a new proactive investment is needed and (b) assess if the proactive investment has been successful over time. A metrics framework could be highly impactful for making the case for increased proactive investment, and for allowing stakeholders to engage more comprehensively on proactive investment discussions.
2. **Distribution System Planning Best-Practices:** There is information asymmetry as external stakeholders (like consumer advocates) do not always have a clear way to assess whether utilities are implementing best practices for their distribution planning, and whether a utility is taking all appropriate precautions to reduce risk. This makes it more challenging for stakeholders to become comfortable with proactive planning and investment activities. A framework/checklist for utility best practices which can be applied in various scenarios and that has buy-in from utilities and consumer advocates could help to address this asymmetry.