2024 White Paper

Designing Distribution Systems to Enable Deep Decarbonization

An Introduction to Right-sizing the Distribution System to Meet Future Needs

TABLE OF CONTENTS

A CALL TO ACTION

The electrification of buildings and transportation and the integration of distributed energy resources are key contributors to societal decarbonization plans. For clean electricity to be a customer's preferred energy source, power delivery must be reliable, increasingly resilient, and affordable. A transition from fossil fuels to clean electricity in these sectors could more than double existing peak power demands in some regions of the country within the next few decades, and significant investment on the distribution system will be required to meet these increasing demands.[1] While the impacts of decarbonization plans broadly impacts the entire power delivery system—electric transmission, generation, end even natural gas - this paper focuses on the potential impacts to the electric distribution system of aggressive electrification goals, and the critical role the distribution system plays in enabling this future.

The scale and pace of change impacting electric distribution systems requires rethinking how the electric grid will be planned, designed and operated going forward. Utilities will need to evaluate numerous factors that drive grid needs, including capacity, reliability, and degrading asset condition. Developing distribution plans that best integrate multiple objectives over the coming decades will require a long-term strategic outlook, effective planning, and efficient implementation. Enhancing distribution system capabilities at scale will be the result of many individual project implementations over time. Decisions distribution utilities are making today will impact grid readiness to enable future objectives. Therefore, we must ask ourselves—**what can we do now to prepare the distribution grid?**

As an initial step, the U.S. Department of Energy (DOE) and EPRI are working together to identify the planning criteria, distribution designs, and operational capabilities needed to "right-size" distribution systems throughout the decarbonization transition. In early 2024, a workshop was held with utility planners from electric distribution companies from across the United States. Workshop discussions identified these initial areas of opportunity:

- Advance distribution planning processes that ensure capacity enhancements meet near-term needs and align with long-term strategic objectives.
- Identify distribution design standards that cost-effectively benefit a broadening array of stakeholder objectives.
- Develop communication and change management strategies that foster consensus on a path forward and facilitate the progression of an expanded portfolio of infrastructure projects and customer program offerings.

This paper serves as a *call to action* for utilities and stakeholders to align on a path forward that enables deep decarbonization of the energy sector in a reliable

1 *LCRI Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis.* EPRI, Palo Alto, CA: 2022. 3002024993.

and cost-effective manner. Recognizing there are significant differences across utilities, this paper highlights common opportunities to move the industry forward. **Ultimately, the goal is to identify actions now that better prepare us for the future**.

WHAT DOES IT MEAN TO RIGHT-SIZE THE DISTRIBUTION SYSTEM?

A right-sized distribution system is one which meets the needs of utility customers while achieving mid- and long-term societal decarbonization objectives in an affordable and reliable manner. Right-sizing strategies seek to ensure deployment of distribution capacity and capabilities of the **right scope, at the right time, and in the right place**.

Identifying future grid needs must be sufficiently proactive considering implementation lead times for tasks such as regulatory approval, financing, permitting, material/resource procurement and project implementation. This will require taking action proactively, even with increasing uncertainty about the magnitude, timing, and location of load growth. To mitigate risks associated with these uncertainties, utilities must continue to advance distribution planning practices that evaluate a range of potential outcomes through scenario and probabilistic analysis with appropriate risk management techniques.

From a risk perspective, Table 1 outlines the potential bilateral consequences of a failure to right-size. A good right-sizing plan includes specific metrics to monitor these areas of risk and guide the prioritization of investment portfolios.

Right Scope

A well scoped mitigation plan integrates suitable technologies at a scale sufficient to meet forecasted capacity needs, enhance reliability, and enable long-term objectives. Planning criteria should establish thresholds for loading that identify:

1. When enhancements are warranted
2. Post-mitigation loading expectations, considering future load growth and the costs of premature asset replacement.

A right-scoped project is achieved through careful consideration of benefits, costs, and residual risks of multiple alternatives.

Right Time

Ideally, capacity enhancement projects are placed in service just in time to meet evolving grid needs. To do so, capacity enhancement efforts must be initiated ahead of the actual need date to accommodate project implementation lead times. An appropriate planning horizon should consider the key factors that drive the expected lead time for each project alternative. Factors considered may include load growth rates, project initiation activities (alternative assessments, project approvals, engineering, funding, permitting), and resource (labor and supply chain) constraints. Today, implementing projects at the "right time" is getting more challenging as infrastructure lead times have increased due to supply chain constraints for the procurement of power system equipment. In the future, solutions that leverage customer sited resources will require sufficient time to design programs, achieve regulatory approval, and procure the appropriate mix of utility and/or third-party resources.

Table 1. *Consequence of failure to right-size*

CHARACTERISTIC	CONSEQUENCE
Wrong Scope	**Too Small** = unable to meet customer energy needs, degraded reliability requiring additional future upgrades **Too Big** = underutilized investment and increased customer costs
Wrong Time	**Too Late** = delayed customer connections and declining reliability **Too Soon** = underutilized investment and increasing customer costs
Wrong Place	**Wrong Place** = degraded reliability, underutilized investment and increasing customer costs

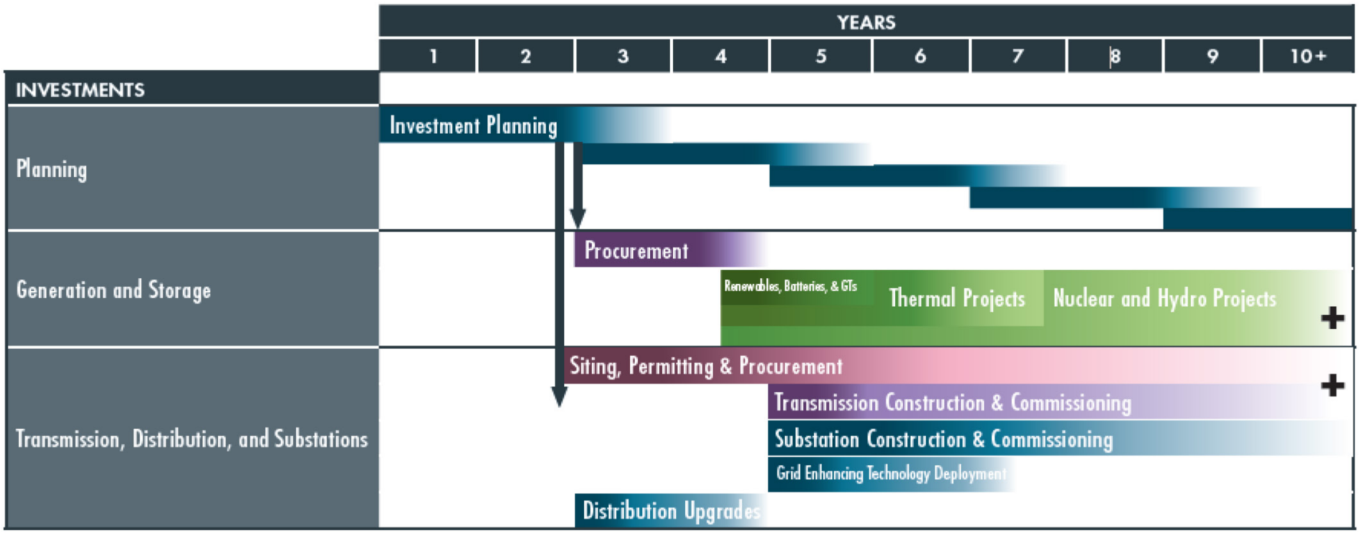

Figure 1. *Typical lead times for electric power system infrastructure projects*

Figure 1 highlights project implementation timelines for various types of utility infrastructure projects.[2] As presented in this figure, lead times for major distribution projects can be five years or longer. If regulatory approval is required, the time frame for planning can extend significantly. Therefore, commitment to a plan can be required several years in advance of forecasted need.

Right Place

The delivery of reliable power requires continuous physical connectivity from at least one power source to every customer connection. Allocating load to the exact point of connection on the distribution system is often the most uncertain element of load forecasting. Locational uncertainty creates risk. Certainty of locational forecasting generally declines as granularity increases and is lower at the individual customer meter than at the substation or feeder head.

The geographic range over which capacity can be leveraged is a key consideration when proactively enhancing capacity. The locational risk associated with making an infrastructure investment is impacted by the area over which the installed capacity can be leveraged. For example, capacity added to a substation can be leveraged over a wider area than capacity added on a single feeder, within a subdivision, or at a customer-level service transformer. However, adding capacity at the substation will not mitigate a constraint that arises downstream, such as a feeder overload that results from a new cluster of electric vehicles (EVs) or heating loads.

At the neighborhood level, service transformers and secondary systems are designed for the capacity requirements of specific premises with an expectation that they will be in service at that location for 30+ years. As such, initial installations at the service level should be sized to accommodate the potential usage of the properties served or designed in such a way to facilitate future upgrades.

Developing a Right-sizing Strategy

Right-sizing requires putting it all together:

Right-sizing = Right Scope + Right Time + Right Place

Distribution systems must have the capacity to meet customer/stakeholder demands, whenever and wherever they occur. Historically, with limited visibility into the distribution system, this has been accomplished by conservatively forecasting an annual peak load by summing non-coincident load contributions and discounting the impacts of DER, load management, and advanced grid management capabilities. The on-going integration of enhanced communication and control technologies are creating opportunities to better understand the variability of net loads and more precisely forecast distribution system capacity requirements, including the potential impacts of DERs and a more flexible grid.

Right-sizing strategies should consider a breadth of solution alternatives, including non-traditional solutions as they become available and are technically and economically viable. Currently, the most common non-traditional solutions consider tariffed pricing or program incentives to encourage

2 *Enhancing Energy System Reliability and Resiliency in a Net-Zero Economy.* EPRI Palo Alto, CA: 2022. 3002023437.

distributed generation and actively managed resources such as demand response, energy storage, and microgrids. These non-traditional solutions could be either third party or utility owned and operated, depending on statutory restrictions.

Though non-traditional alternatives are being developed and tested, traditional infrastructure investment currently remain the most common solution to meet location specific customer demands. At present, capabilities to leverage variable energy resources in support of distribution system capacity needs are in the early stages of maturity and require a resilient interconnection to the grid to enable their capabilities and realize their value. Additional pilot-scale implementations are needed to quantify performance results and communicate the lessons learned. To apply novel solutions at scale with confidence, planning and operating criteria will need to be developed considering the availability and reliability expectations of variable energy resources, considering the level of utility oversight being employed. In addition to the technical capabilities numerous terms and conditions issues need to be codified, including legal and regulatory governance, assignment of liabilities, performance expectations and financial settlement. Without these criteria, it will be challenging for non-traditional solutions to be routinely considered a reliable mitigation alternative by the planners.

Temporal and spatial forecast uncertainties create risk and can inhibit commitment to proactive project implementations. Project lead times can vary and are often shorter for smaller-scale projects than they are for larger-scale projects. For a major project, like a new substation, lead times can exceed 5+ years, while a simple service transformer can be upgraded within a fiscal year. A substation project will require customized designs, permitting, equipment procurement, and specialized construction with minimal scheduling flexibility once the project is initiated. In contrast, proactive service transformer upgrades can be managed as an operational program in which the scale of transformer upgrades is planned and funded in advance, inventory is maintained to ensure stock is available to progress the anticipated volume of work, but the design and implementation of numerous small projects can be flexed based on evolving needs. A utility's distribution work plan generally consists of a portfolio of planned projects of various sizes and proactive planning is beneficial for all project types to secure necessary funding approvals and achieve maximum supply chain efficiencies.

Even with the best of planning, there will be times when large customer service requests result in capacity needs sooner than a full-scale project can be implemented. To be responsive to these more immediate needs, utilities should maintain readily available interim solutions if capacity needs can be met in stages. Examples of interim solutions may include non-wires alternatives that defer the need date of major infrastructure projects, and the deployment of modular or mobile equipment, which can be rapidly installed and subsequently relocated following the completion of a more comprehensive project.

With deep decarbonization targets, it becomes increasingly important for electric distribution planning to be coordinated with broader planning activities across the energy spectrum. As technical capabilities evolve, utilities may economically mitigate load constraints across all levels of the power system, from generation to the customer premise, with an increasing suite of flexible resources controlled by multiple entities. ***Planning will need to be nimble and transparent, clearly articulating distribution system risks, opportunities, and the criteria that guide decision-making.***

ENABLING THE TRANSITION TO CLEAN ENERGY

The scale of change is great with many hurdles to overcome, and there was consensus amongst the workshop participants that ***we need to do something, and we need to start now.*** To do so, utilities will need regulatory support and predictable cost recovery for proactive grid investments. To mitigate inherent uncertainties, utilities are seeking support from entities such as EPRI and DOE to better understand the scope and scale of potential grid impacts associated with decarbonization initiatives. Opportunities for initial collaboration may include efforts to:

- Identify and promote nationally recognized distribution system load forecasting methodologies and planning criteria to streamline planning reviews and approvals
- Establish capability requirements for non-traditional solutions to be considered a reliable distribution resource
- Define performance metrics and processes for multi-objective decision-making to facilitate prioritization and measure progress towards desired outcomes

A more detailed discussion of common themes and needs identified to facilitate the transition to clean energy is presented in the following sections.

Right-Sizing Considerations

Distribution systems have incrementally expanded and evolved over time, resulting in a mix of old and new assets of varying capacity and operational capabilities from location to location. Investment to replace aging infrastructure has been a major component of utility capital investment plans. Recently, grid modernization has been another area of significant distribution investment. Modern technologies are creating new opportunities to better manage grid assets and DER. Integrating capacity, asset condition, and evolving modern grid capabilities presents a huge opportunity to maximize the value of future distribution plans.

COMMON THEMES	SPECIFIC NEEDS
• Integrating capacity, asset condition assessments, grid modernization plans, and DER opportunities can maximize the value of future investments • Agile planning practices will be required to manage uncertainty and pace of change • Common equipment standards could reduce procurement lead times, inventory, and enhance mutual aid amongst utilities • Planning, operating and performance expectations for actively managed non-traditional solutions need to be fleshed out further. • Clearly defined metrics and performance measures are critical to evaluating the effectiveness of solutions and track progress	• Identify planning criteria that considers managed resources in distribution plans • Identify appropriate benefit/cost methodologies, a standardized menu of value/cost metrics to select from, and the means to quantify key impacts for each project alternative with respect to achieving regional objectives through more transparent means. • Identify best practices in supply chain management and explore opportunities for standardization.

Envisioning Future State

Decarbonization, electrification and extreme weather resilience are commonly viewed as key drivers that will shape the needs of future distribution systems. While the scale and timing of these drivers may vary regionally, the design and operation of distribution systems will need to evolve significantly over the coming decades. A right-sized investment must ensure both reliability and affordability, striking a balance between risk mitigation, opportunity enablement, and cost effectiveness.

COMMON THEMES	SPECIFIC NEEDS
• Transparency and communication among stakeholders is imperative. • Longer planning horizons for distribution planning can facilitate integrated planning leading to more informed "right-sized" solutions • Techno-economic analysis is needed to better assess key initiatives, harmonizing policy goals and actual technology adoption trends. • Collaborative efforts to align practices across the industry where it makes sense, while recognizing state and local needs and objectives.	• Identify stakeholder engagement opportunities within the distribution planning process • Development/refinement of pathway scenarios to achieve regional electrification policy goals • Enhanced data and tools to strategically assess distribution system impacts of new technologies and customer programs.

Forecasting

With decarbonization policies as a backdrop, utilities will need to evolve distribution forecasting capabilities and be able to assess a customer's total energy requirement from all sources (electricity, natural gas, propane, oil, etc.) and determine if and when end use technologies may transition to electricity. Integrating jurisdictional decarbonization objectives into distribution load forecasts is important, both the propensity of technology adoption and the operating scenarios of how customers will use those technologies today and in the future.

COMMON THEMES	SPECIFIC NEEDS
• Forecasting methods will need to project load and DER with sufficient spatial and temporal granularity to assess substation and feeder level peaks and daily load shapes • Forecasting processes must be able to develop long-term load projections for multiple potential scenarios to enable a strategic assessment of a range of potential impacts across the distribution system • Forecasts must also support tactical planning and enable the development of specific project scopes	• Forecast technology adoption and peak potential demand • Develop hourly load projections for base load and individual forecast drivers for plausible operating scenarios for each forecast element • Develop planning scenario descriptions that define how forecast elements are aggregated for distribution needs assessments

Planning Design & Criteria

Today's distribution systems are comprised of numerous assets, installed over many generations based on standards applicable at that time. As a result, there is no "standard distribution system."

Long term electrification objectives create an opportunity to re-evaluate planning criteria and design standards holistically, both to new installations as well as the vast legacy asset base. It is important to recognize that the impacts of load growth due to electrification at existing customer locations may lead to more "upgrades" while load growth due to a growing customer base often leads to system "expansion". Planning criteria and design standards need to consider both avenues, as well as considerations for developing grid modernization capabilities and the potential to leverage DER and flexible resources.

COMMON THEMES	SPECIFIC NEEDS
• Need to holistically re-evaluate planning criteria • Evaluate changes to standard design based on long-term needs (i.e., transformer sizing, higher voltage levels, etc.) • Enhanced processes for comprehensive portfolio prioritization evaluations should be a part of transparent integrated planning	• Identify best practices in planning criteria and design standards. • Evaluate appropriate "capacity reserve" requirements of a distribution system as a function of hosting capacity, load growth, forecast uncertainty, reliability (contingency analysis), resilience, affordability, equity, and other factors. • Evaluate diversity factors for new technologies to be used in sizing distribution equipment for new developments, service transformers and secondary systems. • Evaluate relative benefit/cost impacts of various voltage transition approaches. • Identify the means to prioritize investments within a portfolio considering the breadth of short- and long-term objectives.

Operating Considerations

The utility of the future is envisioned to leverage flexible load and DER to optimize the utilization of distribution systems. For this future to be realized, sufficient manageable resources must be available in appropriate locations, and utilities must have the operational capabilities to utilize them.

COMMON THEMES	SPECIFIC NEEDS
• Need to ensure planning recommendations align with the operating capabilities available at the time of expected project implementation. • Need to integrate capacity, grid modernization, and customer pricing and program designs to ensure plans meet needs of future. • Ability to leverage DER for grid services will require better understanding of behavioral traits, ability to rely on those services, and grid modernization infrastructure to support its use	• Identify the operational pre-requisites for viable non-traditional solutions • Align grid modernization plans with operational pre-requisites and timing of needed DER services

WHAT CAN WE DO NEXT?

To keep the momentum going, EPRI and DOE plan to continue to investigate right-sizing opportunities and industry actions that will support grid readiness.

Near-term actions include:

- **Strategic Planning Framework:** Develop and demonstrate an industry-accepted and defensible, long-range distribution investment planning framework that holistically considers energy, capacity, reliability and resilience, and equity objectives.
- **Investment Strategies and Planning Criteria:** Identify strategies for investment priorities and planning criteria that guide when and where distribution upgrades are needed. Perform long-range distribution-level techno-economic case studies of multiple decarbonization scenarios in different regions of the country, and develop recommendations regarding new distribution planning criteria and grid design standards. These studies will review how investment decisions may vary based on time horizon, including horizons considered time.
- **Design Modernization and Standardization:** Identify opportunities to change existing designs and operating practices. Capture lessons learned from ongoing standardization activities around the world and collaborate with utilities and the vendor community to identify new distribution designs that are core to meeting future energy needs. Pursue consistency and standardization opportunities that have the best potential to meet future expectations, streamline implementation and reduce costs.
- **Identify Gaps and Opportunities to Enable Decarbonization Transitions:** Assess how various jurisdictional policies, rate designs, cost recovery and allocation mechanisms, and permitting practices may impact reliability, affordability, equity and the progression of utility action plans. Review practices across the US and globally to identify best practices.
- **Stakeholder Engagement and Workforce Development:** Elevate those who can enable the necessary changes by promoting transparency, broadening education, and developing the workforce of the future. This effort will identify leading communication strategies and practices to align across utility functions and with key stakeholders such as policy makers, regulators, and intervenors in regulatory proceedings. In addition, the effort will identify future workforce training needs and pathways for development.

CONCLUSION

The transition to a clean energy future offers an unrivaled opportunity to shape the utility of the future and have a positive impact on the lives of future generations. The initial steps toward deep decarbonization have begun and they will get steeper rapidly. If distribution utilities don't take action now, they run the risk of being an impediment to societal progress, policy expectations, and customer needs in a future that will likely come faster than we are accustomed. Please accept this call to action, as industry attention is needed to take a hard look at what can be done now to better equip the distribution system to meet these future needs.

ACKNOWLEDGEMENTS

The following organizations were instrumental in the development of this whitepaper. We would like to thank the following organizations and utilities for their participation in the January 2024 workshop and their edits and contributions to this paper.

- EPRI
- U.S. Department of Energy
- Lawrence Berkley National Laboratory
- Arizona Public Service
- Austin Energy
- Avangrid
- CenterPoint Energy
- Connexus Energy
- Consumers Energy
- CPS Energy
- Dominion
- First Energy
- LG&E and KU
- National Grid
- Portland General Electric
- Seattle City Light
- Southern California Edison
- Tampa Electric Company

The work described in this study was funded by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

About EPRI

Founded in 1972, EPRI is the world's preeminent independent, non-profit energy research and development organization, with offices around the world. EPRI's trusted experts collaborate with more than 450 companies in 45 countries, driving innovation to ensure the public has clean, safe, reliable, affordable, and equitable access to electricity across the globe. Together…shaping the future of energy.

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3002030782 **August 2024**

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