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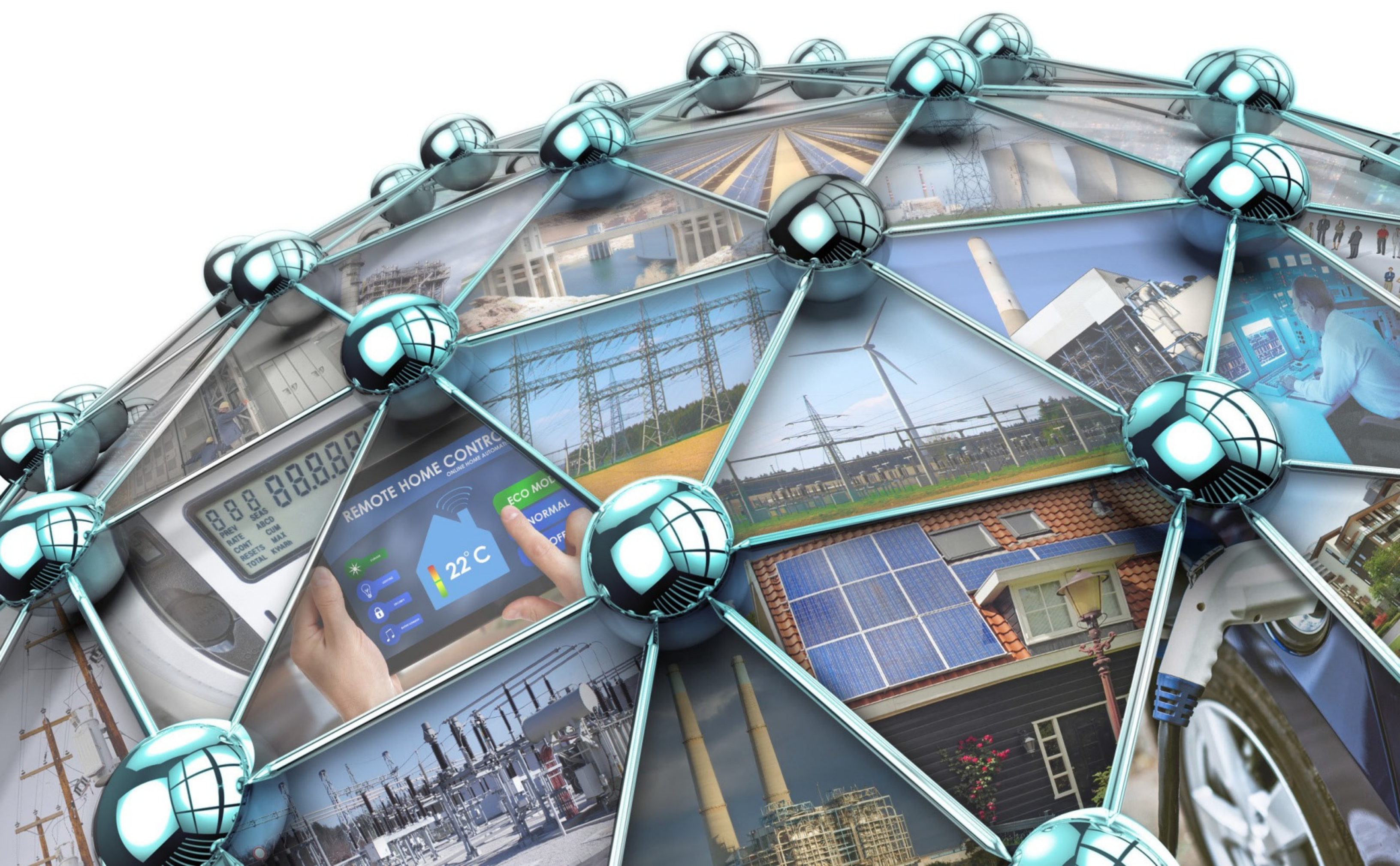
THE INTEGRATED GRID
A BENEFIT-COST FRAMEWORK



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A BENEFIT-COST FRAMEWORK

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EXECUTIVE SUMMARY

STATEMENT OF PURPOSE

The role and operation of the electric power system is evolving to accommodate changes in the ways electricity is produced, delivered, and used. Through a combination of technological improvements, policy incentives, and consumer choices in technology and service, the framework of the industry is changing.

Consumers have increasing choice and control over their electricity service. The range of choice is diverse: Owning or leasing generating systems (such as photovoltaic [PV], solar, thermal, wind, and biomass), and using storage options and technology to manage when and how they use electricity to manage costs. In this report these *distributed energy resources* are referred to collectively as *DER*.

Center stage is the increased integration of energy resources as part of strategies to make the power system more flexible, connected and resilient. Utilities are balancing daily and long-term strategies; the need to ensure that existing assets perform effectively while the utilities adapt their assets to a changing grid, and also create new technologies for a genuinely Integrated Grid.

Distributed Energy Resources

Distributed Energy Resources (DER) are electricity supply sources that fulfill the first criterion, and one of the second, third or fourth criteria:

1. Interconnected to the electric grid, in an approved manner, at or below IEEE medium voltage (69 kV).
2. Generate electricity using any primary fuel source.
3. Store energy and can supply electricity to the grid from that reservoir.
4. Involve load changes undertaken by end-use (retail) customers specifically in response to price or other inducements or arrangements.

The concept of an Integrated Grid was outlined by EPRI[1] noting the goals to realize the full value of a transformed power system – its diverse inputs, efficiencies and innovation. An Integrated Grid should make it possible for stakeholders to identify optimal architectures and the most promising configurations, recognizing that solutions vary with local circumstances, goals, and interconnections.

[1] *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources.* EPRI, Palo Alto, CA: 2014. 3002002733.

The question is about the ways in which DER interacts with the power system infrastructure. The formula for this answer has multiple dimensions. Beneficial and adverse circumstances can arise at differing levels of DER saturation. The interaction is dependent on the specific characteristics of the distribution circuits (design and equipment), existing loads, time variations of loads and generation, environmental conditions, and other local factors. Benefits and costs must be characterized at the local level and the aggregated level of the overall power grid.

EPRI recognizes the need for the industry to systematically and thoroughly address the implications of DER. This requires adopting planning protocols and operating procedures that see interconnected assets from end to end, and that operate the system in an integrated manner. This systematic approach to DER benefit-cost assessment is the focus of this report.

AN INTEGRATED PERSPECTIVE AND APPROACH

DER are typically connected to the radial arms of the grid; however, they have repercussions that resound throughout the electric system. Kilowatts generated on a distribution line can affect the performance of that circuit (and maybe adjacent circuits), the operation of the interconnected transmission system, and how the central generation fleet is dispatched. The influence extends to how the system is designed and built, what assets are added, and what assets were anticipated but no longer needed (avoided capital expenditures). Those effects, or impacts, include both benefits and costs. Enumerating and quantifying them requires a departure from conventional, function-centric planning and operation practices to look at the electric system as a whole—an Integrated Grid that extends beyond the retail meter and affects many new interests throughout the economy.

INTEGRATED GRID BENEFIT-COST FRAMEWORK

EPRI's benefit-cost methodology, described in this report, defines the tools, protocols, and methods necessary to conduct consistent, repeatable, and transparent studies to anticipate and accommodate DER. The framework is rooted in the fundamentals of power system engineering and economics, making the methods applicable to all regions, systems, markets, technologies, and research questions. Widespread application of EPRI's Integrated Grid framework brings essential coherence, consistency, and accuracy to evaluations of the net benefits that result from the proliferation of DER.

By using a common evaluation methodology, utilities and other stakeholders can compare and contrast studies and articulate their findings in ways that make the results understandable and applicable to others. It accelerates developing a comprehensive understanding of the impacts of DER adoption at low and high levels, on distribution systems with different loads and designs, and serving different electricity demands in all electricity markets. The effort and resources required to properly conduct an integrated grid analysis are substantial. Coordinated efforts employing a common evaluation framework accelerate the pace of understanding of the net benefits of DER and how to maximize them. They do so at a fraction of the cost and time compared to studies being conducted in isolation using different approaches and reporting results differently.

The Integrated Grid framework described in this report is summarized in Figure ES-1.

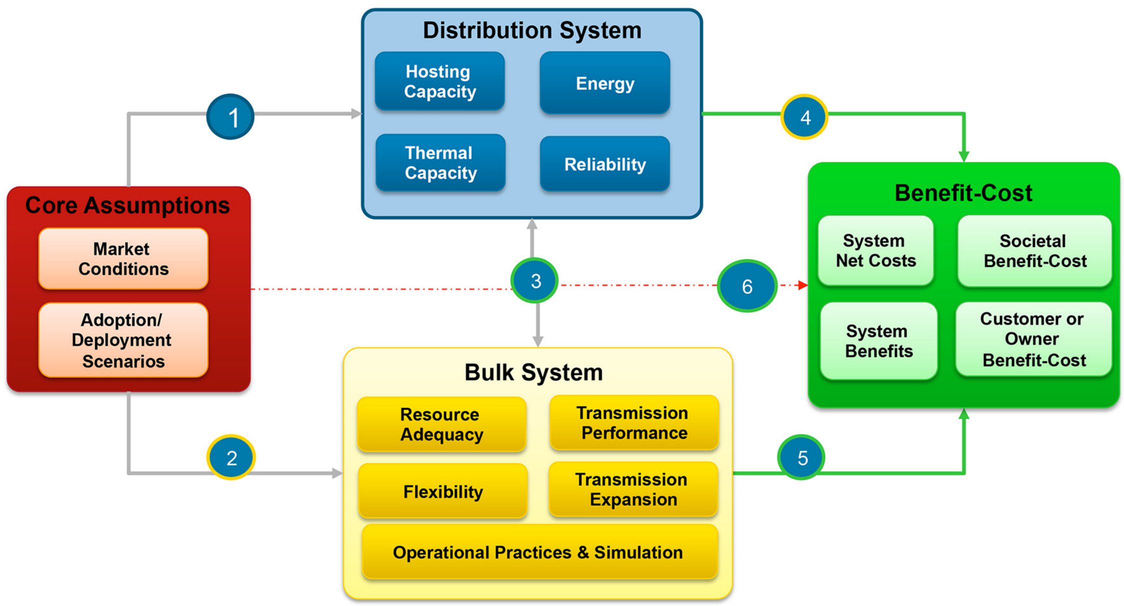

Figure ES-1
The EPRI Integrated Grid framework

The framework is composed of four core analytic elements that correspond to the steps undertaken to conduct a fully integrated system study. It begins by specifying the Core Assumptions: market conditions, DER adoption, and scenario definitions. These data populate and parameterize the analyses conducted to identify and quantify the impacts of DER on the distribution system and on the bulk power system.

A study of DER integration begins by identifying and quantifying the distribution system impacts attributed to interconnected DER. This is accomplished by conducting hosting capacity studies that determine the level of DER interconnection that can be locally accommodated without impacting the quality of supply for the existing infrastructure. Subsequently, energy, capacity, and reliability analyses are undertaken to identify designs and approaches that take advantage of the DER benefits while avoiding adverse impacts.

The bulk power system's focus begins with resource adequacy, making sure that sufficient resources are available to meet electricity demand. Next, transmission expansion studies determine whether the power generated can be delivered to the distribution system without a drop in service reliability (including the benefits and impacts of distributed resources). Three additional analyses—transmission performance, system flexibility, and operations practices and simulation—ensure that all system benefits and impacts are considered.

As depicted in the figure, distribution and bulk power system analyses might be construed as separate endeavors. That is not the case. The analyses are performed sequentially and, in some cases, iteratively. The distribution studies describe how power flows change at the substation—where the two elements of the electric system come together. The first pass through an integrated analysis of DER accommodation calculates the distribution impacts and passes them for analysis to identify benefits and impacts at the bulk power system level. The analyses at this level may suggest that the best way to maximize DER benefits involves making changes to the distribution system. For example, utility control of DER inverters may provide a more cost-effective means to manage distribution voltage levels while achieving additional, collateral system benefits.

The Benefit-Cost step is where the accumulated impacts are processed and measures of net benefits are constructed. It anticipates that a study requires a reference case to establish a basis for comparing DER interconnection cases. The reference case may omit DER or include DER connected only at the time of the study. Alternatively, the study may stipulate a level (or levels) of DER adoption and determine the impacts that result. Either approach launches a study that exposes the implications of different levels of DER adoption on distribution circuits, as well as different approaches for the related system design modifications.

Many of the impacts identified in the distribution and bulk power system analyses are costs or costs saved—the former incurred to mitigate adverse impacts, and the latter those that would have otherwise been incurred but are avoided. These are aggregated categorically, making a distinction between benefits and costs. Other impacts define changes in the system that are tangible and should be identified and quantified but that are not readily monetized because they are not transacted in the electricity (or any) market. Emissions associated with electricity generation, changes in delivery reliability, and changes in the economy (such as employments and wages) are examples of externalities for which there are no market transactions to definitively set a value for their level.

From a societal perspective, as many benefits and costs as possible should be monetized so that the net benefits derived are all-inclusive to reflect the utility's and its customers' interests as well as those of all economic sectors and all citizens. Alternatives for doing so are proposed in the framework. Studies that focus on a utility's production costs and associated financial implications typically include only those costs that the utility incurs. These are accommodated in the framework by the careful categorization of costs and benefits in terms of how they apply to specific decision criteria.

NEXT STEPS: INDUSTRY COORDINATION AND COLLABORATION

Integrated Grid Framework Application and Maturation

EPRI's benefit-cost framework is ready for widespread application, but it is a work in progress. The methodology employs available power system and economic models, methods, and data to construct a complete, end-to-end portrayal of how DER impact the electric system, how to translate those impacts into changes in utility cost, and how those impacts generate societal benefits. This report also points out shortcomings in modeling the electric grid as an integrated power system.

The complexities brought about by DER integration require the development of new planning tools and operating methods. Better estimates of DER output are essential to ascertaining system needs and meeting them cost-effectively. Communication with and control of field devices to improve system response to state changes such as voltage fluctuations tax current modeling capability to simulate their operation. Improved modeling capability is essential for devising operational strategies that realize the benefits that are possible.

Storage and demand response—which are DER by virtue of their impact on actual generation requirements—can mitigate some of the adverse impacts of DER, but how they affect distribution system operation must be better characterized and incorporated into dynamic system models. Standards can play a significant role in DER accommodation in the distribution system, but finding the necessary consensus on what they entail requires substantial impact and implications modeling support.

The temporal nature and nuances of the bulk power system require dynamic load modeling and forecasting capabilities along with probabilistic capacity adequacy analyses to account for the inherently intermittent nature of supply of some DER. The same holds for assessing impacts on the transmission system. Distribution planning models need to be integrated with those of the bulk power system for planning to be truly integrated.

A better understanding of the wants and needs of customers as well as when and how they use electricity is paramount to achieving the Integrated Grid vision. DER are installed by customers to serve their interests. Knowing the key drivers to the DER adoption decision—and forecasting how electricity demand changes as a result—are the first steps toward forecasting how much and what kinds of DER are likely to be interconnected.

EPRI seeks and welcomes ongoing collaboration with industry stakeholders to improve on the Integrated Grid framework to ensure that it develops intelligently and purposefully and is accessible to and used by the industry at large as well as by those who study the operation and performance of the electric system.

Technology Pilots

Creating a robust grid modeling framework is essential, but it is not enough—it's just the first step. The technologies developed and operating procedures formulated must be subjected to rigorous, in situ field testing to ensure that they perform as intended. Coordinated technology pilots implemented by utilities and others fulfill that obligation. EPRI proposes that pilots be launched to test technologies such as the following:

- Utility-scale PV, with and without storage. These are centrally controlled and dispatched renewable supplies attached to the distribution system. Pilots are needed to confirm the level and timing of the output of the PV system and to ensure that interconnection and grid coordination systems operate as designed—and that the design itself achieves effective integration. Coordinated storage system operating performance needs to be verified in a production environment, and strategies for maximizing its value need to be verified or shortcomings revealed and resolved.
- Distributed storage (customer-side systems) operated in conjunction with intermittent DER. Field tests are needed to confirm that storage coordination strategies that appear to be beneficial to the customer and the grid, based on simulations, are in fact beneficial when operated on consumers' and businesses' premises to serve their interests.
- Microgrids serve local customers' needs for greater electric service reliability and resiliency. They can also serve as a system support asset, but the benefits are speculative until confirmed in practical applications in which systems are fully interconnected with and operated in coordination with the grid.
- EV charging infrastructure can be built to serve the needs of electric vehicles but operated to achieve grid benefits as well. Because the frequency of use of these facilities is a matter of conjecture, therefore so are the impacts and benefits. The operation of at-scale facilities will resolve how the system is impacted, verify operating strategies, and inform refinements.
- Customer-side technologies, such as PV (with and without storage) and devices used by customers to control when and how much electricity they use. The relatively high rate of adoption of PV in some areas provides a testing ground to resolve both technical and behavioral questions about how DER affect the electric system. In areas in which adoption has been light, pilots that install and monitor systems will provide the data and experience needed to prepare for adoption should it accelerate in the future. Devices that control electricity may be adopted and used to advance the interests of the customer, or some aspects of that control can be made available to the utility to deploy for system operating purposes. Both situations warrant rigorous studies to quantify the impacts and implications for the operation of the electric grid.

Technology pilots are expensive to implement if they are designed to answer questions about performance and integration to a high degree of resolution. This is especially the case when rigorous experimental protocols are employed to attach a high degree of credibility to the findings and result in inference that extends to many other circumstances. Collaboration in the design of these pilots ensures findings that are useful across the industry.

Collaboration Is Key

The transition to the Integrated Grid is beyond the scope of any one organization. It requires careful collaboration among multiple parties sharing a mutual interest in DER integration. EPRI intends to promote and support ongoing technology assessments and performance documentation efforts in conjunction with other stakeholders. It plans to work with utilities in the United States and around the globe to coordinate system pilots, deployments, and modeling efforts that contribute to the improved understanding of how to accommodate DER. EPRI intends to engage with utilities around the world, the National Association of Regulatory Utility Commissioners (NARUC), Institute of Electrical and Electronics Engineers (IEEE), International Council on Large Electric Systems (CIGRÉ), and U.S. Department of Energy (DOE) and its network of national laboratories, trade associations {including Edison Electric Institute (EEI), the National Rural Electric Cooperative Association, the American Public Power Association (APPA)} and other organizations to both apply and hone the Integrated Grid benefit-cost framework.

A GUIDE TO READING THE REPORT

This report is organized as follows:

- Section 1 introduces the concept of an Integrated Grid, identifies who benefits from using it, and describes how they would employ it.
- Section 2 identifies issues that must be addressed to employ DER efficiently and effectively, laying the groundwork for devising an Integrated Grid study.
- Section 3 provides an overview of the Integrated Grid framework's components—the distribution, bulk power system, and cost-benefit analysis—and how they are employed.
- Section 4 provides an overview and primer on DER characteristics and their impact on grid operation. The characteristics of the distribution grid, including items such as voltage regulation and protection coordination are described, as are impacts on the bulk power system of DER—how resource adequacy and the flexibility of the bulk power system are affected.
- Section 5 introduces the concept of hosting capacity, a measure of a circuit's ability to accommodate DER without an adverse impact on its reliable delivery of power to all connected loads.

- Section 6 defines ways to increase the hosting capacity when DER penetration reaches the accommodation threshold.
- Section 7 describes how DER impacts to the bulk power system are identified and analyzed.
- Section 8 discusses how to mitigate adverse impacts of DER to the bulk power system to maximize the net benefit realized from power supplied by DER.
- Section 9 describes how impacts identified in the modeling stages are organized into a benefit-cost framework to support several perspectives on net benefits attributable to DER.
- Section 10 discusses the next steps for advancing the Integrated Grid initiative.

A good grasp of the Integrated Grid concept and its application requirements can be acquired by skipping the most technical sections (Sections 5–8). Those desiring an in-depth discussion of the technical details of the Integrated Grid framework and its application will find that in those sections. Section 9 describes how costs and benefits are characterized and monetized and the summary metrics constructed to summarize case studies, which will be of interest to all readers of the report.

1 INTRODUCTION

The role and operation of the U.S. electric power system are undergoing profound changes driven by the spread of distributed energy resources (DER). Today's electricity consumers have ever-increasing choice and control over their electricity usage, including owning or leasing intermittent generating systems (such as photovoltaic [PV], solar thermal, wind, and biomass) so that they can produce some of their electricity themselves, on their premise; managing storage when they use grid-supplied electricity; and managing when and how they use electricity to reduce their electricity costs. In this report, these are collectively referred to as DER.

The proliferation of DER means that electricity is no longer supplied exclusively and entirely from central generation facilities. Instead, transmission and distribution (T&D) networks are incrementally interconnecting a wider variety of resources that operate at customer premises or are connected to the lower-voltage parts of the electric grid. Although these nontraditional resources are being interconnected to the grid, they are not yet fully integrated into its planning and operational strategies. This may be acceptable for low penetration levels of DER installed on robust distribution circuits. However, an integrated approach to grid development and management is needed in order to accommodate the anticipated growth of these technologies throughout all areas of the network. The proliferation of these systems depends on many factors, such as system costs and policies that foster adoption by reducing that cost and the availability of the intermittent DER. Many of these factors are outside utility control. Accommodating widespread DER interconnection requires revising planning methods to anticipate the impacts that result.

EPRI launched its Integrated Grid initiative to address this need. It involves a three-phase effort to define the key requirements for effective assimilation and coordination of DER onto the electric power system. The EPRI Integrated Grid initiative seeks to foster collaboration in five core efforts:

- Grid modernization to support DER integration
- Strategies and tools for grid planning and operation
- Interconnection rules and standards
- Pilots to verify and refine DER integration protocols
- Informing policy and regulatory discussions

EPRI's Integrated Grid initiative seeks to provide industry stakeholders and policy makers with information and tools germane to these core areas. It was launched in the spring of 2014 with the publication of a defining concept paper, supporting documents, and knowledge transfer efforts.[2] The ongoing Phase II involves three interrelated initiatives: 1) develop an Integrated Grid benefit-cost evaluation framework, 2) prepare for discussion and eventual adoption interconnection technical guidelines, and 3) prepare recommendations for grid operations and planning to accommodate DER. These efforts position EPRI for the next phase, which will support developmental research, proof-of-concept projects, and pilots to amass the learnings and data the industry needs to design and operate an integrated grid.

This report—part of the Phase II initiative—introduces EPRI's benefit-cost framework and describes its conceptual underpinnings and application to utility planning and operations.

[2] *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources.* EPRI, Palo Alto, CA: 2014. 3002002733.

DEFINING DER

For the purposes of this report, *DER* are defined as fulfilling the first criterion (Item 1), in addition to any one of the second, third, or fourth criteria as follows:

1. They are interconnected to the electric grid, in an approved manner, at or below IEEE medium voltage (69 kV).
2. They generate electricity using any primary fuel source.
3. They store energy and can supply electricity to the grid from that reservoir.
4. They involve load changes undertaken by end-use (retail) customers specifically in response to price or other market-based inducements.

The first criterion means that the resource can inject power into the local utility company grid because it complies with the utility's (stakeholder-approved) interconnection rules and procedures. The second excludes almost no generation device (although scale economies may make some impractical) and includes all renewables.[3] The third refers to electric storage because it can inject electricity into the grid, even though its ability to do so depends on electricity generated previously by another technology. Finally, the fourth criterion recognizes that some end-use loads are dispatchable—that is, the rate and level of premise usage can be adjusted specifically in response to grid conditions.

WHY A BENEFIT-COST FRAMEWORK?

As outlined in EPRI's Phase I concept paper, there is a growing need to develop processes and best practices for integrating DER into the power system. Numerous technical challenges and policy considerations must, however, be addressed to help conform today's electricity system to the shifting nature of how electricity is produced and delivered to end-users.

Technology, business, and policy initiatives that foster DER integration are already under discussion throughout the United States and abroad. For example, an array of benefit-cost studies have been performed to date by utilities, consultants, national laboratories, commissions, and others evaluating the wisdom of new technology investment in everything from advanced metering to dynamic rate structures.[4] Yet despite their common underlying objectives and intents, these

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[3] Much of the current focus on DER is on those that use renewable fuels, storage (including electric vehicle batteries), and demand response. Under this definition, *DER* include other technologies such as natural gas fuel cells, combined heat and power facilities, heat pumps, and microgrids (which are a collection of DER operating as a virtual distribution system).

[4] Examples of value-of-the-grid studies include *A Review of Solar PV Benefit and Cost Studies*, Rocky Mountain Institute eLab, September 2013, T. Bradford and A. Hoskins; *Valuing Distributed Energy: Economic and Regulatory Challenges*, Princeton Roundtable, April 2013, J. Keyes and K. Rabago; and *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation*, Interstate Renewable Energy Council, October 2013.

studies collectively offer little consensus on what constitutes the level and character of the net benefits of DER because of the different methodological approaches employed and insufficient rigor and consistency in how impacts are identified and monetized.

An Accommodation Philosophy

The EPRI Integrated Grid framework is constructed to determine how best to accommodate DER. This focuses the study on determining the technical implications of a specified interconnected DER and from that, deriving the impact after the system has been adjusted to eliminate impacts that would adversely affect reliability. This approach allows the study organizers to specify a level of DER penetration, consider a range of levels, and determine the best locations for a specific level of DER on individual feeders. In addition, under each approach, the hosting capacity is derived and, when a mitigation strategy is required, one is specified and the cost accrued. This ensures that the scenario benefit-cost comparisons are made on an equivalent basis.

Consequently, no universally accepted methodology is employed to test and verify study results or compare results across multiple studies. Without a rigorous framework, studies that attempt to quantify the value of DER are prone to semantic interpretations that result in misunderstanding and confusion or missing or double-counting costs and benefits—or measuring them inaccurately. This gap is being addressed by focusing first on measuring impacts on specific feeders by some utilities, at the system level in California and New York, and more generally by the industry in the United States and abroad. DER's influence starts at the point of interconnection—and so should a study of their impacts on the electric system.

EPRI's benefit-cost framework, described in this report, seeks to define the tools, methods, and thought leadership necessary to create a consistent, repeatable, and well-documented approach to conducting studies to anticipate and accommodate DER. The framework is rooted in the fundamentals of power system engineering and economics, allowing the methods to be applicable to all regions, systems, markets, technologies, and research questions. If this methodology is widely employed, the results of studies conducted under a variety of circumstances can be compared because the assumptions employed are identical, or differences are made explicit—so their impacts can be isolated. As studies accumulate, their findings provide a library of case studies that inform the way in which subsequent studies are conducted and, in some cases, eliminate the need for such a study because the findings are transferable and inferential.

This report is a methodology, not an analysis or finding. The goal is not to develop a one-size-fits-all number or metric to measure the net benefit of DER, but rather to develop a framework for examining the impact of new resources and methods on the power system to promote an open discussion around the benefits and costs of different ways to accommodate DER.

WHAT'S UNIQUE ABOUT EPRI'S METHODOLOGY?

Many benefit-cost studies involve different levels of system analysis (for example, distribution, bulk power system, and economic) to quantify the net benefits of DER proliferation. Each of these studies contributes insights, but because there is no broad consensus on what constitutes the best way to conduct such studies, the wide range of findings is more confusing than useful for formulating policies or devising DER accommodation strategies.

EPRI's benefit-cost methodology strives to provide a framework that if widely adopted will provide objective, reproducible, and actionable findings for studies conducted over a wide range of circumstances. It employs the best available engineering analysis tools and recognizes and defines the need for better ones. Employing benefit-cost protocols ensures that DER impacts are viewed from a societal perspective and that the cost and benefit values generated comport with how utility revenue requirements are calculated. The former facilitates looking at the big picture, not just the utility-specific implications. The latter accommodates deriving the retail rate implications.

Construction of Study Scenarios

An Integrated Grid study involves comparing the results of accommodating a level of DER penetration, on a circuit or on a system, with a base case. The base case defines the way in which the circuits, assets, or their operation would have changed over the study period, absent the DER accommodation. Several different scenarios result from a study that alters the level of DER adoption or exogenous factors such as conventional fuel cost and DER adoption costs. The rigor of the framework ensures that such comparisons are made cognizant of—and isolating the impacts of—the underlying assumptions.

EPRI's Integrated Grid Benefit-Cost assessment framework builds on EPRI's research in developing the concept of *hosting capacity*, which defines the amount of DER that may be accommodated on a distribution circuit without degrading reliability and power quality. Basic research—verified through field applications—has demonstrated that a detailed study of DER at the feeder level is necessary to fully understand the consequences of DER adoption and to define the best accommodation strategy. The framework describes how to conduct screening studies that capture important nuances that determine how many DER can be accommodated while providing results that can be extrapolated to an entire system with hundreds or even thousands of distribution feeders.

The framework recognizes and describes how to extend the results of hosting capacity studies conducted at the distribution level to the bulk power system. This approach recognizes the interdependent nature of the DER impacts on system generation planning criteria (resource adequacy), operational criteria (such as provision of operating reserves), and transmission system design and operations.

The benefit-cost analysis component of the framework incorporates methods previously developed by EPRI's Smart Grid program to establish categories of impacts and convert them into costs and benefits so that a single-value metric (net benefits and benefit/cost ratio) can be derived that allows comparisons among case studies.[5]

LIMITATIONS OF THE FRAMEWORK

EPRI's benefit-cost framework is a work in progress that will be continuously refined as experience is gained in its application under diverse circumstances. Users should keep in mind:

1. As with any benefit-cost assessment, the focus is on comparing alternatives. Analyses developed under this framework facilitate comparing the net benefits of different scenarios against a reference case.
2. Because the contributing elements of EPRI's benefit-cost methodology are rooted in engineering and economic analyses, generalized results may not be available until several simulations have been completed. Consequently, significant effort is required in order to achieve meaningful results.

Who Should Use This Framework?

Beneficiaries of wide-scale adoption of this framework include the following:

Utilities

- Planning how to accommodate DER
- Anticipating DER impacts at various levels of adoption
- Evaluating new business strategies
- Justifying new investments in grid infrastructure to support DER
- Developing rates and tariffs to collect accommodation costs

Regulators and utility commissions

- Evaluating policy decisions regarding DER
- Interpreting the DER studies from different jurisdictions
- Evaluating the relative benefits and costs of DER integration
- Determining what constitutes the best locations for DER

Electricity sector stakeholders

- Selling DER to end-use customers
- Considering investments in DER production and sales
- Evaluating the consumer economics of DER adoption

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[5] *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*. EPRI, Palo Alto, CA: 2010. 1020342.

3. Likewise, various methods that make up the overriding methodology require comprehensive levels of data in order to be effective. Knowledge of the prevailing power system architecture, renewable resources, system planning procedures, and operational policies are just a few of the major categories of items needed to properly evaluate scenarios.

As with any benefit-cost methodology—especially those that consider long-lived assets typically located throughout power systems—results depend on the assumed actions of multiple stakeholders. These future behaviors cannot be known in advance, especially considering the 5- to 25-year study time horizon.

HOW TO USE THE INTEGRATED GRID FRAMEWORK

EPRI has identified three target audiences for this methodology: utilities, regulators and utility commissions, and third-party stakeholders.

EPRI proposes a framework for evaluating how to accommodate DER. Individual studies will have a significant level of variety, owing to the difference in the scope and scale of the technologies included and the issues studied. Navigating through the EPRI benefit-cost process involves four main steps:

1. Defining a question and determining relevant assumptions (addressed in Section 2)
2. Assessing distribution-level impacts (Sections 5 and 6)
3. Assessing transmission-level impacts (Sections 7 and 8)
4. Monetizing impacts using an overall benefit-cost analysis (Section 9)

Each of these steps is discussed in detail in the sections that follow.

A Guide to Reading This Report

The report is arranged to provide a thorough understanding of the characteristics of DER and the existing grid, identify impacts that may result with grid integration of DER, define how those impacts can be mitigated, and translate those impacts into economic terms in a way that facilitates comparison of alternative DER situations and market circumstances. Following is an outline of the report's sections and their content:

- Section 2 offers an overview of the fundamental components necessary to apply the Integrated Grid framework to a variety of situations, whether hypothetical or actual. It discusses guiding questions that, with proper attention to detail and planning depth, can be addressed by the framework. In addition, it discusses some of the inherently subjective or situation-specific study factors—dictated by users of the methodology—that will influence the study.

- Section 3 provides an overview of the Integrated Grid's analytical framework. It first briefly characterizes the features of a model that are required to adequately account for the full effects of DER on the grid and, in turn, on power system economics. It then outlines the overarching framework and its component parts, setting the stage for a more detailed discussion of each component's makeup and implementation in successive sections of the report.
- Section 4 provides an overview of power system operation and characterizes, at a high level, the impacts that DER can have on the electricity network. It emphasizes the inextricable tie between the distribution and bulk power systems and makes the case for a system-wide view of DER integration.
- Section 5 focuses on the distribution aspects of the overall Integrated Grid framework, providing the necessary inputs to the methodology's bulk power system and benefit-cost analysis components to properly account for the value streams and the costs associated with integrating DER into the grid.
- Section 6 serves as a succinct primer of current and future technology-related strategies for supporting greater grid-connected DER at the distribution level. It is intended to provide a range of options that can be employed to enable transition to an Integrated Grid.
- Section 7 details five core methods that comprise the way in which the Integrated Grid framework considers bulk power system planning and operations, building on previous EPRI research to account for the nature of DER.
- Section 8 describes the bulk power system mitigation actions and associated benefits. It categorizes the technologies that can be used into three broad areas: system operations improvements, flexibility resources, and transmission technologies.
- Section 9 lays out the benefit-cost analysis approach that EPRI has developed to allow for monetization and comparison of DER interconnection scenarios, each consisting of results from the distribution and bulk power system processes described in Section 5 and 7, respectively.
- Section 10 describes EPRI's efforts to coordinate the development and advancement of an integrated grid assessment framework in cooperation with others through collaborative pilot projects.

OTHER PRODUCTS OF PHASE II DEVELOPMENT OF THE INTEGRATED GRID

Two additional work products are being developed under Phase II of the Integrated Grid initiative.

Recommendations for Interconnection Standards

The ratification and adoption of IEEE 1547 in 2003 served as a positive step toward the greater grid integration of DER.[6] However, the unanticipated technological change and consumer acceptance of DER (especially PV) have undermined the standard's usefulness and applicability. DER subject to the enacted standard were, for instance, barred from providing voltage and frequency support to the grid or from riding through momentary disturbances. In addition, provisions for communication and coordination with the grid operator were not stipulated in the protocol.

The pronounced growth of DER-produced generation that is contributing to the power supply has made it necessary for DER to perform the very functions that IEEE 1547 originally prohibited. Revisions were made to the standard in May 2014 that allow DER to be configured to support the grid; they are permitted, but not required. A working group of IEEE is considering revisions to the standard to address issues that have arisen since its adoption.[7]

EPRI, under the broader Integrated Grid initiative, is producing a series of white papers for utilities, standards organizations, and state commissions detailing its recommendations for DER support of the grid—including ride-through, voltage support, communications, and coordination of DER. These documents will be sequentially released to the public.

Distribution and Transmission Operator Coordination

With a new focus on DER accommodation, renewed emphasis is being placed on more tightly coordinating the activities of the DER owner, distribution owner, and transmission system operator (TSO). The result is the emergence of new technical requirements that facilitate coordination among different operating entities and, in turn, result in greater system reliability. These novel requirements affect many areas:

- Resource (day-ahead) scheduling
- Real-time balancing
- Integrated markets
- System planning

[6] IEEE 1547-2003, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

[7] IEEE 1547a-2014, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems, Amendment 1.

- System operation
- Integrated modeling

To promote thought leadership and discussion in this area, EPRI and EEI conducted a workshop to discuss ways in which DER impact electric system planning. Participating organizations included independent power producers, equipment manufacturers, integrated utilities, independent system operators (ISOs), distribution companies, national laboratories, government offices, and research organizations. EPRI expects to conduct additional workshops over the next 18–24 months to propose and discuss strategies for accommodating DER.

2 DEVELOPING QUESTIONS AND CONTEXT FOR AN INTEGRATED GRID

The Integrated Grid framework described in this report employs a system-level approach for determining the physical impacts of grid-interconnected DER on the power system. Informing investment and policy decisions, however, requires specifying the study objectives and contextual questions as well as making many assumptions that inform the analyses undertaken. Successful application of the framework requires practitioners to carefully define the specific issues to be addressed. Otherwise, the many complex relationships and modeling elements involved will produce a landslide of results that are difficult to interpret.

This section describes the questions that, with proper attention to detail and planning depth, can be addressed by the framework.

KEY ISSUES AND QUESTIONS ABOUT INTEGRATING DER

The transition to an integrated grid requires that the electricity industry ask and reflect upon new questions regarding the way in which the power system is built and operated. They should be constructed to recognize the issues challenging the industry's ability to maintain a high level of performance and reliability while meeting or exceeding safety standards. Interconnected DER challenge conventional planning techniques that assume one-way energy delivery from power plants to consumers. New planning methods are needed to account for how DER affect existing distribution and bulk power delivery equipment and how to address adverse impacts while maximizing the value that DER provide to the system. It should not be a foregone conclusion of an integrated grid DER impact study that net benefits accrue or that they do not—a well-designed study answers that question.

There is growing interest among utilities, government agencies, consultants, developers, DER owners, and consumer groups to address concerns about the consequences of increasing amounts of DER interconnected to the power system. Over a dozen value-of-the-grid studies have been undertaken to assign a monetary value to DER. Most employ a top-down methodology that begins by establishing categories of possible benefits that might be attributed to DER and searching through the utility tariffs to identify attributable savings. This approach relies on the ability to establish avoided costs individually by category, rather than calculating them systematically by examining the system as a set of complex physical and financial interrelationships.

Establishing benefit and cost categories is essential to ensuring that the analysis finds them all—and counts none twice. The EPRI framework employs this strategy, and this categorization is close to what others have proposed.[8] The difference is that EPRI proposes identifying and quantifying impacts attributable to DER through a bottom-to-top analysis of the power system. The complex engineering and economic relationships that define the electric system are examined to identify and quantity impacts that are due solely to DER interconnection. Those impacts include benefits (such as avoided costs) and DER accommodation costs—costs that otherwise would not have been incurred by the utility.

The Integrated Grid framework offers a way to fill this industry gap by informing public and internal planning efforts with additional perspective, grounded in the fundamentals of power system engineering and analysis. It employs a methodical and systematic approach using methods that are accurate, consistent, and reproducible. It is designed to address a wide range of pertinent research questions, including the following:

- **What is the value of DER to the rest of the system?** DER can deliver value in many ways (for example, intrinsic, economic, and financial), as evidenced in recent DER studies conducted in Austin, Texas and the state of Minnesota.[9, 10] A common practice in value-of-solar studies is to first establish benefit categories and then to search for contributions in the form of avoided costs—for example, avoided generation, T&D, and distribution capital costs

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[8] EPRI's benefit and cost categorization system is a derivative of work done (by EPRI and DOE) to devise a system to support benefit-cost studies of Smart Grid technologies (*Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects, Volumes 1 and 2: Measuring Impacts and Monetizing Benefits*. EPRI, Palo Alto, CA: 2012. 1025734).

[9] K. Rabago et al., "Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator," *Proceedings of the World Renewable Energy Forum 2012*. Denver, CO.

[10] *Minnesota Value of Solar: Methodology*. Minnesota Department of Commerce, St. Paul, MN. April 2014.

calculated in long-term planning studies. However, if the studies did not model the characteristics of DER contributions to meeting electricity demand and did not identify the electric system costs incurred to accommodate those resources, the attributed avoided costs fall short of portraying the complete net benefit picture. That representation becomes even less credible if the location (on the grid) and type of DER are not accounted for explicitly. The EPRI framework involves conducting a systematic, bottom-to-top simulation of the impacts associated with a specified level of DER connected to a specific location of the distribution grid.

- **How many DER can be accommodated without making further infrastructure investments?** Planners need to be able to anticipate the level at which DER penetration on a circuit will require changes to reliably accommodate more DER. This is of particular concern for interconnected DER that inject power into the grid (using renewable resources and fuel cells, for example) and may be an issue with virtual power supplies such as storage and demand response. The Integrated Grid's hosting capacity methodology answers this question directly by establishing the DER accommodation level for each circuit individually.
- **What will be the cost to integrate and accommodate additional DER based on their location?** A successful DER integration impact study identifies the benefits and costs on an individual feeder basis. A variation on doing this by systematically increasing the DER interconnected to a feeder is illustrated in a 2012 Southern California Edison study that examined the difference in accommodation cost between utility-directed PV (located to minimize accommodation cost) and that based on individual customer adoption decisions (cost incurred to interconnect).[11] Researchers from the PV Grid initiative in Europe have been investigating benefits, costs, and potential barriers to deploying advanced technologies for increasing DER hosting capacity.[12]
- **What are the costs and benefits of different operational strategies for deploying DER?** One consequence of DER is that they can adversely affect circuit voltage, which requires mitigation costs. Alternatively, smart inverters to support additional two-way power flow reduce or eliminate infrastructure upgrades. If the DER inverter is controlled by the local system operator, there may be benefits that accrue locally or at the system level that should be accounted for in the determination of net benefits.

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[11] The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System, Southern California Edison (SCE), Rosemead, CA, May 2012.

[12] "Prioritisation of Technical Solutions Available for the Integration of PV into the Distribution Grid," *PV Grid*. 2013.

- **What utility business strategies are applicable to DER?** What are the advantages of utility ownership of DER located on customers' premises? What if the utility owns the inverter or pays the customer for net benefits its operation provides to the system? What are the advantages of community-owned solar? All require a detailed accommodation study.
- **How does integration cost change as penetration of DER increases?** EPRI's research indicates that the level of hosting capacity of a circuit is a function of many interrelated factors. For instance, integration costs can arise even from a low penetration of DER (5%) because of an adverse impact on the circuit's voltage or protection system. Other feeders can accommodate a high penetration of DER (50% or more). Hosting capacity studies resolve the accommodation threshold for individual feeders.
- **Does an incremental, accommodating investment cost more than a preemptive accommodation?** Would it be more cost-effective (that is, have a higher benefit-to-cost ratio) to take action on a feeder where DER growth is anticipated (but not assured) before the systems are installed? An integrated grid study classifies circuits according to hosting capacity. The results will help distribution system planners establish priorities for various levels of DER adoption across the system as part of how they plan the timing of upgrade investments and what that upgrade should involve.
- **What is the theoretical upper limit to distributed generation on the system?** Even at this early stage of transition to DER, there is justification in asking about the upper limits to DER accommodation for the system or its constituted elements. The answers require hosting studies to be conducted at the distribution level followed by a determination of how the bulk power system is affected—which is what the Integrated Grid framework facilitates and directs.

Defining the research questions is the first step to employing the Integrated Grid methodology. As organizing principles, they determine how the methodology is employed effectively and efficiently.

3 OVERVIEW OF THE INTEGRATED GRID ANALYTICAL FRAMEWORK

This section provides an overview of the Integrated Grid's analytical framework as a series of connected, functionally oriented analyses that quantify the impacts and implications for the entire electric power system of DER interconnected to the distribution system. This sets the stage for the more detailed discussion of each analysis component in Sections 4–8.

FRAMING THE INTEGRATED GRID PROCESS

Table 3-1 lists the assumptions and data required to conduct a DER accommodation study, organized according to the functional elements of the study. The first two categories—General Assumptions and Utility Business Regulatory Policy—define the business and financial environment in which the utility operates and characterizes factors that affect how revenues and retail rates are determined, respectively. The third category, Societal Value, defines important impacts that are measurable—framing variables that are used to interpret and monetize impacts attributable to DER. The last three categories define the variables required to model DER impacts on bulk power assets and operations, transmission system assets and operations, and distribution system assets and operations.

The requirements are extensive: the scope of an integrated grid study is end-to-end. All elements of the physical operation of the utility are examined in detail to ensure that all DER impacts are identified. Sections 4–9 describe in detail the models that use these physical and market characterization data. This section emphasizes the importance of establishing scenarios; otherwise, modeling a system this large with this level of detail would overwhelm the goal of isolating DER impacts to inform and direct utility investment and operational decisions as well as public policies that would foster DER.

Table 3-1
Integrated Grid study assumptions and input requirements

General Assumptions	• Timeframe of study • Inflation/escalation rates • Investor/utility cost of capital
Utility Business and Regulatory Policy	• Locational value • Tariff options • Utility obligations – Responsibility to serve – Renewable portfolio standards – Customer incentives (technology-related) – PV, microgrids, storage, combined heat and power, demand response • Utility incentives – Reliability and resiliency – Infrastructure investment incentives – Electrification incentives
Societal Value	• Electrical reliability standards and requirements • Grid resiliency requirements • Customer service options and choices • Energy efficiency investments • Externalities – Reduced generation carbon emissions – Macroeconomic impacts
Bulk System Assets and Operations	• Market characteristics – Energy – Capacity – Ancillary services – Flexibility – Fuel diversity incentive • Resource mix and projections – Generation type: for example, coal, nuclear, hydro, wind, PV, natural gas, or other renewable • Capacity resources – Energy storage – Demand response • Locational availability • Fuel availability and deliverability

Table 3-1 (Continued)
Integrated Grid study assumptions and input requirements

Transmission System Assets and Operations	• Constraints
	• Planning methods
	  – N-1 contingency
	  – Risk-based planning
	• New build limitations
	  – Land use
	  – Policy/regulator
	• Availability of new technologies
	  – High-voltage direct current (HVDC)
	  – Flexible AC transmission system (FACTS)
	  – Phasor measurement units (PMUs)
	  – Demand response and energy storage
	• Operations and maintenance
	• New infrastructure build costs
	• Wide-area monitoring capability

Distribution Assets and Operations	• Interconnection requirements
	• Distributed PV projections
	• Electrification and load growth
	  – Electric transportation
	• Technology options
	  – Conservation voltage reduction, energy storage, distribution automation, dispatchable DER, microgrids, demand response, electric vehicle (EV) charging (including vehicle-to-grid)
	• Communication systems
	• Distribution optimization objectives
	  – Reliability
	  – Resiliency
	  – Efficiency
	  – Power quality

A high-level representation of EPRI's analytical framework is depicted in Figure 3-1. It is composed of four components: Core Assumptions, Distribution System and Bulk Power System impact analyses, and Benefit-Cost protocols to provide an overall financial characterization of how DER affect the power system and society.

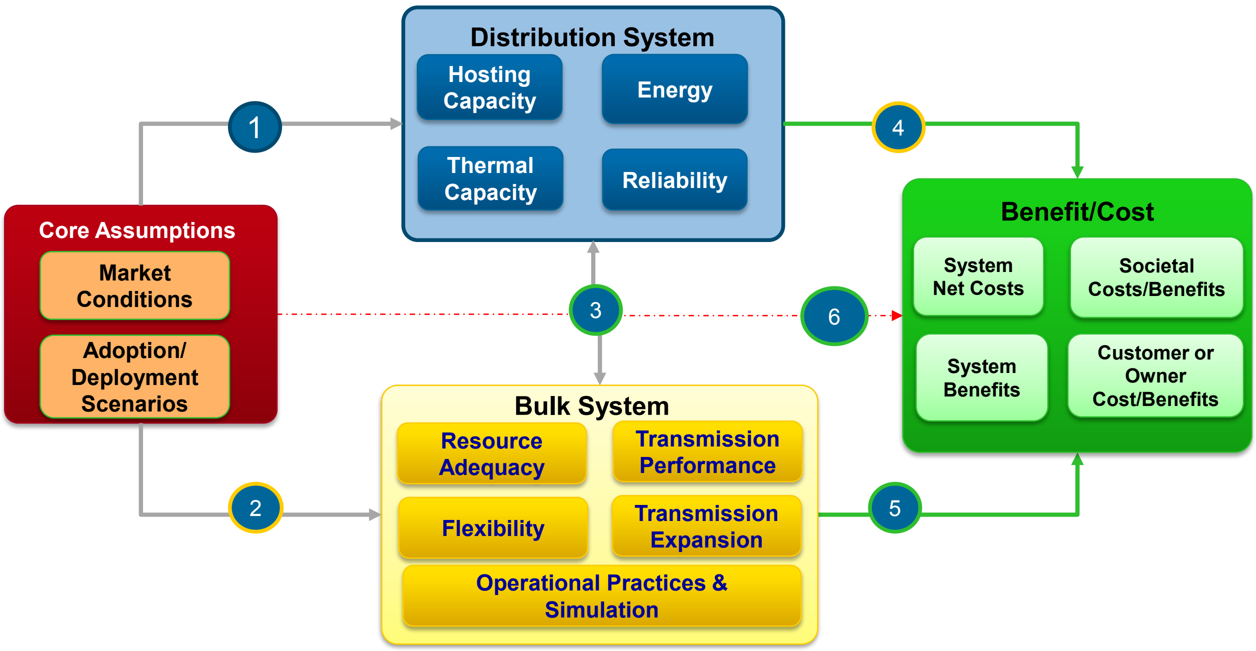

Figure 3-1
Overview of the benefit-cost methodology

CORE ASSUMPTIONS

As discussed in Section 2, a study starts by defining questions to be answered and issues to address using the framework along with related assumptions that bound the analysis. This process is represented by the Core Assumptions block in Figure 3-1. It is composed of three categories of data and assumptions:

- **Market conditions.** Utilities operate in electricity markets where they sell their electricity output. The price they receive is influenced by electricity demand—locally and in interconnected markets—as well as state and federal regulations. Specifying the price formation process is a key factor in conducting the study. Retail rates determine revenues for retail sales, which in turn affect wholesale electricity prices. Costs are driven by policies that determine what type of fuels can be burned, when, and in what quantities. Changes in the market structure influence wholesale rates. All of these are subject to considerable uncertainty that must be taken into account in the analysis.
- **DER adoption.** The EPRI framework was developed to evaluate DER impacts systematically, but it can accommodate studies driven by exogenous forecasts of DER adoption. In either case, a study requires specifying the size, operation, and performance of the DER technologies being studied.

DER performance characterization includes the hourly (or more granular) output of the system, distinguished by how much is consumed at the premise and how much (if any) is fed into the distribution system throughout the study period. The study's analyst must decide which devices to include along with their size and output. These will vary by DER type according to the resource's availability and the efficiency of the device.

The EPRI approach to conducting hosting capacity modeling, on an individual distribution circuit basis, is to establish a detailed characterization of the electrical operation circuit to establish a baseline. DER are then added in increments until a violation is encountered, defined by the deterioration of service below established standards. Mitigation strategies are evaluated; one is selected and implemented, which restores the circuit to acceptable operation, and additional DER are added until another violation occurs. This sequential-load DER penetration approach establishes for each circuit the threshold for DER adoption before accommodations are required and defines the cost to extend that threshold.

Alternatively, the study can specify a forecasted level of DER over the study period, and the hosting capacity analysis would indicate whether violations would result and when—and specify the mitigation costs. Such a study would externally define the relationship between the adoption encouragements and the level of adoption and then establish corresponding cases of scenarios with alternative adoption levels that can then be evaluated using the framework as described above.

In either DER characterization mode of analysis, EPRI's hosting capacity method can be used to determine how a specified level of DER would be optimally distributed across a circuit or among circuits of a system.

- **Scenario development.** The Integrated Grid framework is designed to compare alternative states of the world by establishing a base or reference case, altering the amount of DER that is interconnected to create study scenarios, and comparing the outcomes. The base case defines how the system under study is expected to be built out and managed over the study life—with and without DER. Establishing a base case requires specifying values for all of the factors listed in Table 3-1 and possibly more, depending on the distribution, bulk power system, and financial models employed.

  Scenarios are alternative versions of the future distinguished by how key parameters and assumptions differ from those of the baseline and among study scenarios. Because so many technical, economic, and financial variables are involved—each of which can take on many different levels—the combinations, permutations, and possibilities are overwhelming—beyond what an individual study or even many coordinated studies could accomplish within a reasonable time and budget. The study's designers must find a way to limit its scale and scope and still produce results that inform the issues it was chartered to address.

Study situations to evaluate are defined by establishing the questions the study will address and developing scenarios accordingly. The previous section emphasizes the need to establish hypotheses and questions to provide direction to the study.

Focusing the study on answering specific questions about how DER impact the electric system provides structure and defines how to populate scenario assumptions. A scenario specifies the study area and period: the former defines the distribution circuits to be studied and the market and bulk power system's assets and its planning and operational practices. In most cases, there are available (and fully outfitted to conduct multiyear studies) models of each. It also defines the utility enterprise operating environment and the associated financial and regulatory circumstances, which in turn provide a source for establishing key economic assumptions such as fuel price forecasts, interest rates, load growth, revenues, and rates.

Planning and operations models are available to define a base case that corresponds to already established planning scenarios and ranges of values for key drivers of utility operation, investment, and finances. Employing these characterizations of what's coming (as the base or reference case) is vital to isolating the effects of DER. Planning scenarios embody the way in which the utility intends to respond to changes in electricity demand and how it is affected by the economy. They include expectations about when distribution circuits are likely to require an investment and what actions will be undertaken. Likewise, planning scenarios stipulate generation and transmission capacity requirements and how changes in those needs will be met. Already developed and tested planning scenarios provide a way to establish a multiyear, business-as-usual base case.

- **DER penetration.** How many DER and where they are interconnected are key assumptions that the directors of the Integrated Grid DER impact study must establish. This can be accomplished by identifying time-delineated and location-specific DER adoption scenarios, or the study can use the screening methodology developed by EPRI.

  EPRI's DER distribution impact screening methodology employs a hosting capacity methodology to define how many DER a circuit can accommodate before modifications are required along with what intermediating investments in assets and operational practices are required to remove that threshold. The way in which DER impact a circuit is a function of many factors that vary considerably across circuits and involve complex cause-and-effect interrelationships that are not well-understood. As result, each circuit must be evaluated individually. EPRI's hosting capacity screening process has devised streamlined procedures that use commercially available distribution models (to which most utilities have access). Sections 5 and 6 describe these methods in detail.

- **Study results.** The result is a study that provides a complete screening characterization of the distribution topology, circuit by circuit, for the specified DER technology. This expands distribution and bulk power system planning criteria to include DER specifically as an important factor to measure and have strategies ready to be undertaken when circumstances warrant. An additional perspective is gained by using the protocols developed by EPRI to determine the best locations for DER on and among circuits—an essential element of the study based on exogenous forecasts of DER.

EPRI proposes that utilities undertake screening of all distribution circuits using DER hosting capacity; however, as described previously, the screening can also be employed to assess the impacts (system benefits and costs) of specific DER adoption forecasts.

METHODOLOGICAL COMPONENTS

Distribution Analysis

Quantifying circuit hosting capacity is the core of the distribution analysis process, focusing on accommodating DER while maintaining established standards of reliability and power quality. *Hosting capacity* is defined as the amount of DER a feeder can support under its existing topology, configuration, and physical characteristics. When the hosting capacity is reached, any further DER additions will result in a deterioration of service until remedial actions are taken.

The most common constraints that require evaluation are steady-state voltage, protection coordination, and thermal overload. They are affected by several factors (discussed in Section 5), including feeder construction, voltage regulation strategy, and DER deployment. Section 5 also describes the manner in which hosting capacity may be calculated for several feeders as well as the data and tools required in performing both detailed and general assessments.

Understanding the hosting capacity under the system's current arrangement is, however, only a partial solution. To provide the proper analytical perspective, traditional study methods must be augmented with new features that accomplish the following:

1. Analyze alternative asset additions and operational changes to expand hosting capacity
2. Investigate the benefits that distributed energy resources provide to the distribution system

Many of these questions require that the hosting capacity of distribution feeders be extended beyond that currently allowed by its current operating constraints, requiring one or more of several different technical solutions (discussed in Section 6). The strengths and weaknesses of each solution are presented in that section, along with instructions on how a resource may be incorporated into the base hosting capacity analysis. In addition to hosting capacity, special treatment is required to consider potential benefits of DER on the distribution system—

specifically, loss reduction and deferral of upgrades. The methodology exports the costs associated with increasing hosting capacity, specifying when in the study period they are projected to be made, directly to the economic analysis. The derived change in power flow is reported to the bulk power system analysis as a procedural input.

By maintaining system operation to conform standards of reliability and power quality according to established performance criteria, the hosting capacity method essentially assumes that reliability and power quality remain within accepted ranges. If reliability were allowed to deteriorate, there would be a cost to customers. Under the EPRI hosting capacity method, the circuit is upgraded to maintain reliability and power quality, which appear as a cost in the utility cost function.

Bulk Power System Analysis

Bulk power system analysis involves the joint study of transmission and generation planning to ascertain the impacts of DER interconnected at distribution. As with distribution system analysis, bulk power system analysis employs a series of metrics that measure the system's reliability and performance. Given the potential for impacts in the form of costs and benefits, the operation and future planning of the bulk power system are evaluated to determine what adjustments are needed to maintain performance at acceptable levels while maximizing the value of the interconnected DER. Through an iterative process, candidate solutions can be evaluated for economic efficiency in terms of their capital expense and operating cost. Evaluating these metrics requires five interlinked processes, described in Section 7:

- Resource adequacy
- Flexibility
- Operational scheduling and balancing
- Transmission system performance
- Transmission expansion

Using currently available simulation tools, the framework shows how these core processes are connected as well as the data requirements and exchanges for each. As DER growth continues, new solutions may be required at the bulk power system level to ensure that the system continues to meet performance metrics. Section 8 identifies several traditional and upcoming technology options and weights their advantages and disadvantages. The output of the bulk power system analyses is composed of a series of infrastructure and operating costs, which feed into the overall economic analysis.

Benefit-Cost Analysis

Results derived from the distribution and bulk power system analysis steps of the framework comprise a set of impacts. Some are monetized when posted to the benefit-cost analysis by virtue of their being cost (or avoided cost) that is an output of the impact analyses. The benefit-cost step monetizes the remaining impacts and adds them to the accumulated costs and benefits to produce summary benefit-cost metrics. In addition to consolidating results, the economic analysis traces how costs and benefits arise among various entities, including customers and society.

Conventional system planning techniques—and the business and regulatory analyses they inform—evolved in a world of one-way energy delivery from power plants to consumers. Two-way power flow on the distribution system requires new planning methods that produce new views of the world, new investments and actions to consider, and new goals to strive for. Utility stakeholders see these issues from different perspectives. Some are rooted in business and regulatory principles that have been adhered to for decades. Others are shaped by economic or financial considerations. Still others reflect a belief in pursuing environmental or social objectives.

In order to understand one another and seek common ground, it is essential that stakeholders compare alternatives from an objective assessment of the impacts associated with policies and actions. The Integrated Grid benefit-cost analysis framework employs a comprehensive and objective engineering and economic approach to inform multiple perspectives.

A variety of economic analysis techniques are available to compare and contrast alternative courses of actions associated with accommodating DER. All are relevant and useful in an integrated grid world, but they are useful in different ways to different stakeholders:

- **Benefit-cost analysis asks: Is the activity beneficial to society?** A societal view examines alternative projects or courses of action in terms of net benefit to society as a whole. It considers all costs and all benefits, regardless of their level and to whom they accrue. If the benefits outweigh the costs, the project is considered a benefit to society.
- **Financial analysis asks: Is an investment profitable for utility investors?** Financial analysis represents the perspective of investors. An investor (which may be an individual or corporation) is primarily concerned with whether the monetary returns from a prospective investment are commensurate with their risk as well as how those returns compare with other investment opportunities. If the returns are too low relative to their risk (that is, the probabilistic spread of possible outcomes), the investor will look elsewhere to invest. Societal costs and benefits are not included in the financial analysis because they are not costs the utility incurs and charges to consumers.

- **Utility financial planning analysis has two perspectives that must be addressed:**
  1. **How does the utility minimize cost of service while meeting service obligations?** Utility planning analysis is a special case of economic analysis constrained by the utility's obligation to serve. This imposes obligations such as extending service and maintaining safety and reliability within standards. Because they must invest to meet those requirements, the utility's shareholders are granted an opportunity (not a guarantee) to earn a return on prudently invested equity capital, commensurate with the risk. In exchange for that opportunity, the utility is obligated to choose investments that minimize customer costs within constraints that regulators or policy makers impose. Planners are focused only on costs incurred by the utility in meeting its obligations.
  2. **How are shareholder interests balanced against those of regulators and customers?** This involves reconciling the societal and financial perspectives. What planners determine to be the least-cost option may not be the most pragmatic or practical one for utility investors. Utilities must consider how investments and expenditures affect their financial health; are responsive to regulatory concerns and initiatives; fulfill customer's wants, needs, and expectations; and responsibly reflect environmental concerns. When no available course of action can fulfill all of these considerations, the utility has to determine how to balance them.
- **Unregulated entities ask: How do I benefit?** For-profit firms conduct business in the electricity industry without an obligation to serve (beyond contract obligations they enter into) and also without the competitive or territorial protections afforded monopolies. Competitive independent generators and demand-response providers are examples of this type of firm—as are DER manufacturers, distributors, and operators. They take on investments only when the expectation of returns on the investment is commensurate with the risk involved. They are not required to reveal their risk preferences or to represent other interests. Competitive firms have a well-defined perspective on benefits: they care about costs they incur and revenues they receive.
- **The societal perspective asks: What is best for citizens collectively?** Today we are seeing stakeholders with a variety of perspectives about DER. For some, the goal is increasing the use of renewables because it contributes to environmental improvement. They generally adopt a societal perspective on what constitutes a proper benefit-cost analysis. Others want to create robustly competitive markets or allow customers a larger degree of self-determination in how they meet their energy needs. They may adopt a societal perspective, but they are concerned with policies that include DER subsidies that undermine the efficient operation of the electricity sector.

Utility planning for the integrated grid requires acknowledgment of all of these stakeholder perspectives. New technologies and analysis practices are required in order to provide an integrated, enriched portrayal of the consequences of policies and actions that affect the degree to which DER are interconnected to the grid. The consequences of alternative courses of action must be portrayed in a variety of ways so that stakeholders can evaluate them for their perspective and understand the position taken by others. In this way, decisions can be made based on both facts and consideration of interests. The EPRI Integrated Grid framework provides the means for meeting these needs.

4 SYSTEM OPERATING IMPACTS: CAPABILITIES AND CONSIDERATIONS FOR ACCOMMODATING DER

Determining the costs and benefits attributable to DER requires identifying how these resources impact both the local distribution and the bulk electricity system. Impacts are identified through a comprehensive and systematic study of the electric system infrastructure and operational approaches (and their costs) that must be consequently adapted. Because DER influence emanates from where the resource is interconnected, a bottom-up approach is required to identify the impacts and trace their consequences without double-counting or missing key effects.

This section provides an overview of power system operation and characterizes the impacts that DER can have on the electricity network. It emphasizes the inextricable tie between the distribution and bulk power systems that is needed to study and characterize DER integration that provides a framework for assessing DER impacts and their benefit and cost consequences. It lays the groundwork for determining cost-effective DER grid management strategies by summarizing the following:

- Resource characteristics inherent to DER that impact the power system
- Distribution and transmission system-specific impacts that may result from DER penetration

- The implications of higher DER penetrations for overall system performance given the interconnected nature of the T&D systems

With this foundational information established, successive sections (5–8) provide a further characterization of DER impacts on distribution and transmission for the interested reader; they then present current and future technology-related options and processes that can be harnessed to help assimilate DER into an integrated grid.

The focus in this and the next four sections is on identifying DER impacts as well as the physical changes in the electric system infrastructure—and how it is operated—that result from DER interconnections. Section 8 describes the way in which impacts are monetized to provide a unified portrayal of the net benefit of DER integration.

THE NEED FOR INTEGRATED PLANNING AND OPERATION

As depicted in Figure 4-1, AC power systems have traditionally been designed to flow energy produced at central station generators through the bulk transmission system to distribution substations, which in turn distribute electricity to end users through radial feeders emanating from the substation. This function-specific and serial planning approach has allowed planners and operators to focus on managing the reliability and affordability of electricity delivery as separate entities, without specific consideration of how the two subsystems interact.

Adding DER as a resource changes this. The interrelation of the distribution and bulk power system components of the electricity grid necessitates that the operating impacts of DER be examined through the electric system so that potentially cascading and collateral impacts are captured and reported.

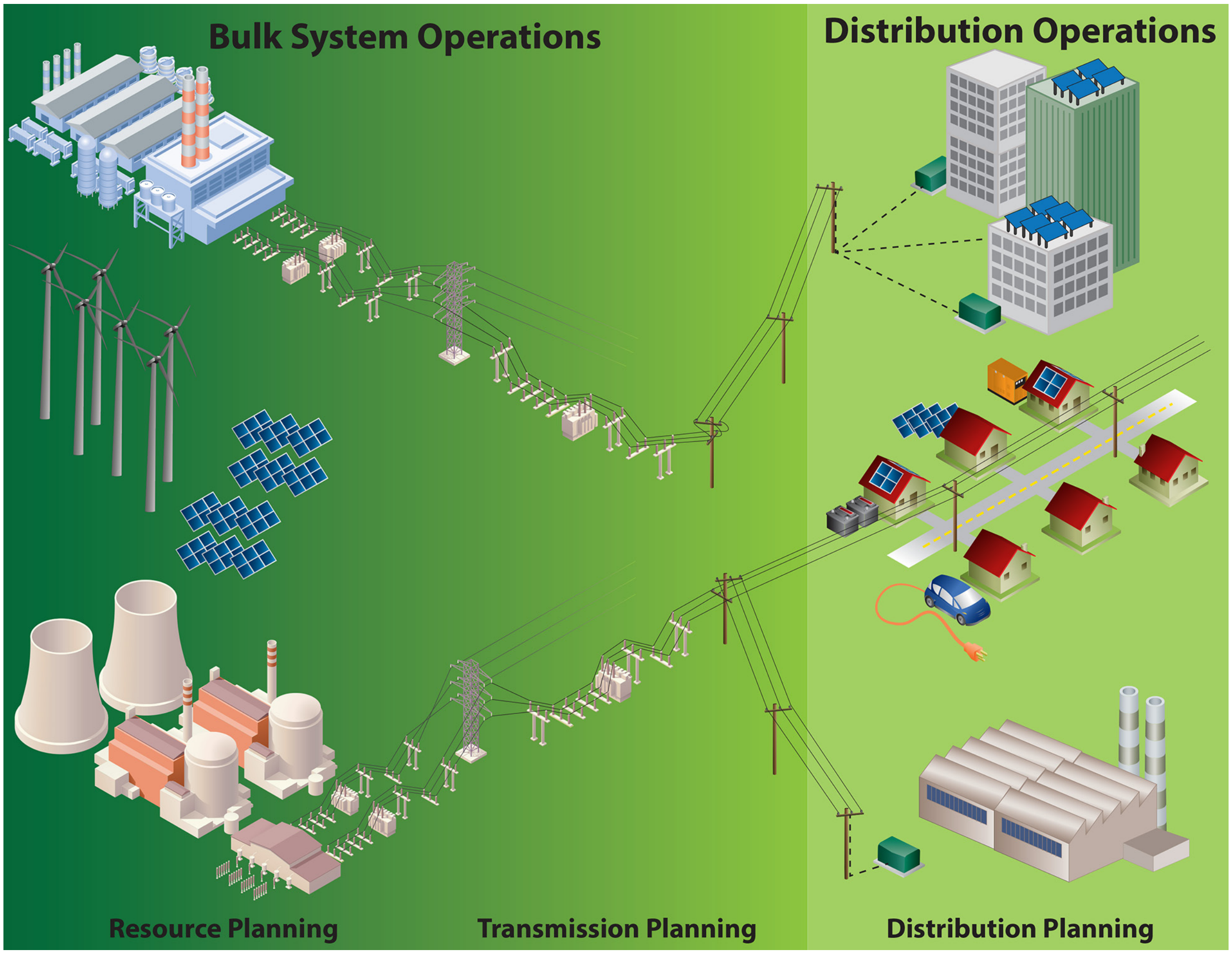

Figure 4-1
Interconnection of the bulk power system and the traditional isolated planning and operations functions that are challenged by increasing DER levels

Transmission planners have traditionally been able to consider the distribution system as aggregate loads as each bulk transmission voltage-level bus and ensure that power from large central station generators is reliably delivered from the transmission system to that bus. Similarly, distribution planners assume that the transmission system is an infinite source of power delivering sufficient voltage and frequency at the high side of the distribution substation transformer. They design the local delivery system assuming that there is sufficient delivery capability to reliably supply individual loads across the system. Both take load as given, although stochastic models are used to account for uncertainty. Both design for power to flow downstream, from central generation sources to end-use loads.

However, with increasing DER levels across broader distribution areas, distribution and transmission can no longer be planned and operated in isolation. For example, DER interconnections create the potential for power to flow from the distribution system back into the transmission system and for the distribution system to more significantly contribute to system dynamics in response to disturbances. The potential also exists that during certain periods, substantial levels of load may be served either locally behind the meter or, to a greater extent, by DER exporting energy to the grid—displacing central station generation that has traditionally provided voltage and frequency support functions to the transmission system. Beyond directly influencing the usage patterns of existing centralized assets and reserves interconnected to transmission, DER incorporated onto distribution may also delay or entirely mitigate the need for generation and wires infrastructure upgrades and alter operations and maintenance (O&M) protocols and frequencies.

The interconnected nature of T&D systems, along with growing potential for distributed energy and ancillary services to be provided from the distribution system, requires that the overarching T&D network be planned and operated as an integrated and interactive system when DER penetration becomes substantial. Increasing DER levels increases the need for integrated approaches to T&D modeling. Those needs include the exchange of information that can be used to simulate and evaluate the aggregate system reliability, affordability, sustainability, and safety implications of various system developments, investments, and technology choices.

What constitutes a substantial level of DER? EPRI research has established that distribution system impacts can arise at relatively low levels of penetration on individual circuits but other circuits can accommodate very large penetrations. Establishing the distribution impacts requires the study of individual feeders, which EPRI proposes be done using its DER hosting capacity methodology. The level at which aggregated DER at a substation affect the bulk power system depends on the nature of both systems. EPRI's Integrated Grid framework provides a way to anticipate those impacts and identify system asset and operation accommodations.

DER Characteristics That Drive System Impacts

Because of their unique attributes, the greater grid penetration of DER technologies is poised to produce new potential benefits as well as challenges to the entire power system. Distribution systems have been operated with and accommodated the interconnection of traditional, non-variable DER technologies such as reciprocating engines and combustion turbines (CTs), including microturbines, for decades. The sources of benefits and adverse reliability impacts of traditional DER have been well-documented for these technologies.[13, 14] These included benefits

[13] Roger C. Dugan and Thomas E. McDermott, "Distributed Generation and Power Quality," PQA 2000: Power Quality Performance for the Millennium, Memphis, TN, May 16–18, 2000.

from the deferral of T&D investment, reduced line losses, and reduced congestion. Reliability and safety concerns include managing distribution feeder voltage regulation, protection system interactions, and unintended islanding. The potential for increased adoption of nontraditional (variable), grid-connected DER technologies across larger geographic regions, however, raises concerns about the impacts of DER that migrate up through the bulk electric system.

Table 4-1 provides a comprehensive list of the major DER characteristics that impact T&D operations and planning. Each of the characteristics summarized in the table is further discussed in the subsection that follows, although not all characteristics listed may apply to all DER technologies.

Table 4-1
Major DER characteristics that impact operations and planning

Characteristic	Potential Impacts
Point of interconnection impacts	• Medium-voltage/low-voltage location drives potential benefits that include delivery system upgrade deferral, congestion relief, and delivery system loss reductions. • Location also drives potential challenges, including protection and voltage regulation concerns and operational reliability risks resulting from competing T&D project needs (for example, ride-through).
Visibility and controllability	• Lack of T&D system operator visibility of customer-owned resources adds uncertainty to the load served from the system. • Lack of controllability impairs operator ability to manage power flows, maintain supply-and-demand balance, and uphold reliability standards.
Inverter interface	• Requires system protection and control schemes that differ from traditional synchronous machine-interfaced resources. • Active and reactive power control schemes can support voltage and frequency performance beneficially and more efficiently than those provided by synchronous machines.
Output variability and uncertainty	• Voltage regulation and frequency issues. • Greater need for flexibility in other resources. • Additional operating and planning reserves to ensure that sufficient energy is available to serve load.
Environmental compatibility and fuel costs	• Low or no fuel costs for certain technologies; high for others. • Low or no emissions for certain technologies; high for others.

[14] Roger C. Dugan and Thomas E. McDermott, "Operating Conflicts for Distributed Generation on Distribution Systems," IEEE 2001 Rural Electric Power Conference, IEEE Catalog No. 01CH37214, Little Rock, AR, May 2001, Paper No. A3.

Point of Interconnection Impacts

As defined in this report, DER interconnect to the power grid through the medium-voltage distribution system or below, behind the customer meter for customer-sited facilities. In contrast to traditional bulk power system interconnected generation resources, the proximity of the DER to load served on the circuit determines the extent of beneficial and adverse impacts. The beneficial impacts of interconnection at the distribution level are the same regardless of whether one is considering traditional or emerging DER technology; they are driven to a significant extent by the ability to serve load locally. Serving load from DER as opposed to serving load from more traditional central station generation may offer the following advantages:

- Deferral and avoidance of delivery system upgrades (transmission and/or distribution)
- Congestion relief, which relates to the deferral of delivery upgrades
- Reduction of delivery system losses

The location of DER within the distribution system creates the possibility of reliability impacts, which can be positive or negative. The distribution delivery system in North America is predominantly radial, with power flowing one way from generation source to end-use load. DER may negatively impact protection and voltage regulation because they open the possibility of the flow of power in the other direction. For safety and protection, distribution-connected generating assets have been required to disconnect from the system during abnormal system voltage or frequency conditions. Some standards and regulatory requirements have been established that statutorily require disconnection of DER under specified circumstances. As DER penetration levels continue to increase, the consequences of DER dropping off create significant system reliability risk.

Visibility and Controllability

Improved visibility and controllability of DER deployments contribute to the resource's potential to positively affect the system. In many regions, a large number of existing and anticipated DER deployments are customer-owned resources located behind the customer meter. This is true for rooftop PV, customer-sited energy storage, electric vehicles (specifically, the battery), and all demand-response resources. The inability of T&D system operators to continuously monitor DER resources for their output adds uncertainty to system load calculations and regarding the portion of system load that must be served from the power system if DER become unavailable.

Operator decisions are made based on estimations and forecasts. If the quality of that information is inaccurate or misleading, operator decisions will deviate from the optimal outcome. As DER become a larger portion of the resources serving local or electric system load, the inability to directly control these intermittent resources will hinder the effectiveness of T&D operator efforts to supervise power flows, maintain a supply-and-demand balance, sustain must-run generation during low load periods, and generally uphold reliability standards.

Some DER—especially those involving controlling end-use customer loads—may be aggregated through programs in which a third-party entity or "aggregator" manages how the resource interacts with the distribution system. This aggregation model has been used for bidding demand-response resources into energy and ancillary service markets. However, in these situations, the visibility and controllability of an actual resource at a given location within the electrical grid are quite coarse. Demand-response resources are directly controlled by the utility, but additional uncertainty surrounds the visibility and controllability of these resources because of their dependence on customer behaviors that can be influenced by price sensitivities, convenience, comfort, and/or other incentives.

Inverter Interface

Some of the DER technologies projected to deploy at high penetration levels—including solar PV, battery storage, and electric vehicles—interface electrically to the electric grid through an inverter (demand response is the exception because it only draws power). As a result, these resources do not interact with and respond to the power system in the same way as traditional synchronous machines. The inverter's power electronic interface creates challenges to system operation in addition to offering opportunities to harness new controls.

The system integration challenges posed by inverter-based resources stem from how they respond to system disturbances compared with those of traditional synchronous machine-interfaced resources for which system protection and control schemes were primarily designed. For example, the inverter decouples the DER from system frequency. Consequently, it does not provide inertial response to correct frequency excursions like a conventional generator does. Similarly, inverter-based resources don't have the same type of primary frequency controls or voltage controls as synchronous generators, which have traditionally been used to support key system reliability functions.

Inverter-based resources, however, offer unique capabilities to control both active and reactive power much more quickly than traditional synchronous machines if so designed. With appropriate control schemes, DER may be able to support voltage and frequency performance, correcting any adverse impact they induce and mitigating system-origination disturbances. Pilots and early implementations of inverter-based energy storage technologies have, for example, displayed the ability to provide higher quality frequency regulation services so that the required total regulating reserve is reduced along with the associated ancillary service costs.[15]

[15] http://www.ieee-pes.org/presentations/td2014/td2014p-000675.pdf; http://www.ercot.com/content/mktrules/pilots/frrs/Preliminary_Report_on_Fast_Responding_Regulation_Service_Pil.ppt.

Variability and Uncertainty of Output

Many of the DER technologies projected to deploy in the near future, such as distributed PV generation, have variable and less certain output profiles at any specific time. For example, the output of a given solar PV resource depends on solar insolation and varies as the sun rises and sets or as clouds pass overhead. Wind generation varies as the underlying wind resource fluctuates. Some of this variability can be mitigated by aggregating the output of many DER across increasing geographic footprints: the variation in smaller localized regions can impact voltage regulation and frequency for less expansive, islanded power systems, even if the variability is fully known.

This variability also impacts the need for flexibility in other resources. The production uncertainty of some DER technologies at any given time creates additional challenges related to the coordination of adequate generation with existing load. For variable output DER, additional operating reserves must be maintained to ensure that sufficient energy is available to serve load when forecast errors materialize—this leads to additional production costs. Output uncertainty also impacts planning reserves. If the output of DER (as is the case with any generation resource) is uncertain during high-risk hours for serving load, additional supply and/or delivery capacity may be required to guarantee that load can be served at established risk tolerance levels. DER are subject to sources of uncertainty different from those of conventional generation and require acknowledgment and analysis.

Environmental Compatibility and Fuel Costs

DER offer the potential to reduce total electric power emission. Some DER technologies, such as PV, are relatively low emitters of greenhouse gases compared to many conventional generating units. The variability and uncertainty issues from renewable DER result from their dependence on sunlight and wind as their fuel source—which also means that these resources have zero fuel cost and zero emissions. Energy storage can be charged from lower cost and potentially lower emission central station energy resources during off-peak energy periods. Electric vehicles provide significant opportunities for reducing emissions from burning gasoline in internal combustion engines. Demand response that reduces overall electricity output, or changes when grid-supplied electricity is used, may reduce the overall level of emissions.

As mentioned previously, although DER offer the potential to reduce total system fuel costs, they may increase other aspects of total system production costs as a result of increased ancillary service costs. In addition, although renewable energy has zero fuel cost, the energy price paid for renewables may be higher than the marginal cost of energy from other resources because of guaranteed payments, tax credits, or subsidies. What is important is the net outcome after all cause-and-effect relationships play out.

The Importance of Distribution System Characteristics

The extent to which DER deployment can beneficially or adversely impact the distribution system depends on the characteristics of the DER technology as well as those of the grid to which it is interconnecting. The main considerations that account for the overall impact include the following:

- **Local distribution system characteristics and operating constraints**, such as voltage class, radial vs. networked arrangement, conductor type, geographic topology of the feeder, regulation equipment used, and operating characteristics such as voltage planning limits and protection schemes.
- **Amount and location of DER**, principally the location of individual DER devices along the distribution system and the aggregate amount of DER on the circuit.
- **DER characteristics**, such as inverter-based vs. machine-based DER, fixed vs. intermittent output, and the time at which DER provide power or energy to the grid (coincidence with load).

Determining the capacity of a distribution circuit to accommodate DER is the cornerstone of EPRI's proposed Integrated Grid methodology for determining DER impacts to the distribution system. EPRI defines a circuit's ability to accommodate DER without the need for mitigating cost or actions, as hosting capacity, expressed as MW or as a percentage of the total load served by the circuit.

An example of distribution hosting capacity results, from EPRI research, is illustrated in Figure 4-2; it indicates the extent to which widely varying amounts of PV can be accommodated on distribution feeders with differing characteristics.[16] The feeders studied are listed on the vertical axis and the megawatts of hosting capacity on the horizontal axis. The color coding for each feeder indicates the amount of capacity the feeder can handle, in three categories. Green indicates no problem accommodating the indicated level of PV; yellow indicates that the location of PV on the feeder at that level becomes the determining factor, so that aspect must be considered. Red indicates the feeder load range over which no (or no more) DER can be accommodated without increasing the possibility of adverse impacts to local loads and perhaps at the bulk power level.

Some feeders can host large amounts of PV (for example, R1, R2, R3, G1, and G2 in the figure). Others (G3, D1, D2, and D3) are limited in the amount of DER that can be accommodated (that is, hosted) if grid upgrades are not performed. Hosting capacity represents a consistent method for determining how much PV (or DER) can be accommodated without necessitating grid upgrades.

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[16] *Distributed Photovoltaic Feeder Analysis: Preliminary Findings from Hosting Capacity Analysis of 18 Distribution Feeders.* EPRI, Palo Alto, CA: 2013. 3002001245.

Hosting capacity analysis has been applied to a relatively wide range of distribution feeders throughout the United States that served as the basis for the methods described next.

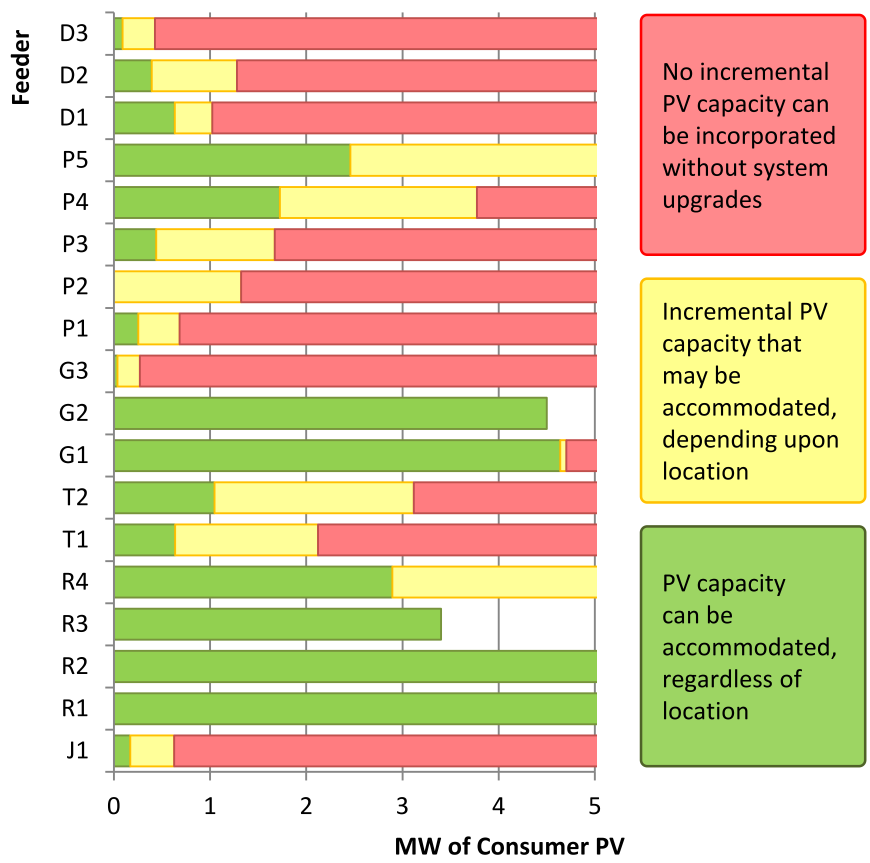

Figure 4-2
Sample distribution hosting capacity results

Table 4-2 lists by category the impacts that DER can have on the distribution system and the contextual factors that determine the extent of each impact. Below, further elaboration on several of the factors that determine a system response to DER are presented in relation to individual impacts.

Table 4-2
Sample DER impacts to distribution and the influencing factors

DER Impact	Influencing Factor(s)
Voltage regulation	• Voltage limits • DER amount and location • Feeder construction characteristics • Regulation equipment
Voltage support	• Communication and control capability and coordination • DER amount and location
Protection coordination	• The degree to which DER raise fault current, affect protection equipment short-circuit ratings, and/or cause sympathetic trips • DER amount and location
Energy losses	• DER energy profile characteristics • Feeder construction • DER amount and location
Energy consumption	• Local load energy profile • DER energy profile • Feeder regulation characteristics • Secondary/service characteristics • DER amount and location
Capacity	• Asset and system operation constraints • Existing and future load • DER amount and location • DER temporal generation/demand characteristics • DER availability and controllability
Reliability	• System configuration and design • Existing and future load • DER amount and location • DER availability, visibility, and controllability

Voltage Regulation

The potential impact of DER on distribution voltage is very much driven by location. In some cases, this can be problematic, while in others it can be beneficial. Utilities design the distribution system to maintain primary voltages within specified ranges, which define standards. The most common standard adopted in North America is ANSI C84.1,[17] which stipulates that under normal conditions, primary voltages are kept within ±5% nominal rating. Some utilities are mandated (by state regulation) to maintain voltages to a tighter upper ceiling to reduce end-use energy consumption (referred to as *conservation voltage reduction*, or *CVR*). In such cases, utilities operate so that the upper bandwidth on voltage is +3% to +4% instead of +5% above the 120-V basis.

DER technologies that inject power into the distribution grid (for example, distributed generation and distributed storage) have the potential to change voltage along a distribution feeder because of the power injected into the grid. Because most distribution systems are radial, feeder voltages typically drop the farther they are from the distribution substation.

The injection of active power from DER on a distribution feeder causes a voltage increase at the generator terminals, regardless of where the DER are located. The extent to which the DER cause voltage rise, however, depends on the size of the DER and where they are interconnected to the grid. The two main factors that determine the impact are short-circuit strength and reactance-to-resistance (X/R) ratio at the point of interconnection. The larger the DER relative to the strength of the system, the more likely the DER will be able to raise the system voltage during increased output. Conversely, if the system strength is large with respect to the rating of the DER, voltage is less likely to be impacted. Likewise, a feeder with a low X/R ratio is more susceptible to DER causing unacceptable voltage fluctuations because of active power changes and less likely with higher X/R. DER located toward the end of a distribution feeder can have both low short-circuit strength and low X/R, which is the reason they can cause unacceptable voltages farther away from the substation.[18]

[17] ANSI C84.1, American National Standard for Electric Power Systems and Equipment—Voltage Ratings (60 Hertz), 1995.

[18] *Power Factor Guidelines with Distributed Energy Resources: Using Reactive Power Control with Distributed Energy Resources.* EPRI, Palo Alto, CA: 2013. 3002001275.

Overvoltage

The addition of DER and the potential voltage rise that can result have the potential to cause overvoltage on the distribution system. The overvoltage situation could be highly locational as follows:

- On secondary systems where DER are connected to a low-voltage portion of the grid (as is the case with most customer-connected DER)
- On primary systems if the aggregate amount of DER is large enough with respect to the strength of the grid

Whether the additional voltage rise caused by DER results in overvoltage is determined by the location of the DER and by localized power flow characteristics. The location determines the relative change in voltage caused by the DER (short-circuit strength and X/R) as well as how much "headroom" is available at the location before a voltage limit is reached. This ability to move the voltage without causing overvoltage is commonly referred to as *voltage headroom* and varies along a distribution feeder as illustrated in Figure 4-3. As the voltage (the solid varying line in the figure) drops over the length of the circuit, so does headroom. In the illustration, a voltage regulator is located strategically so that at the end of the line, voltage is at an acceptable level.

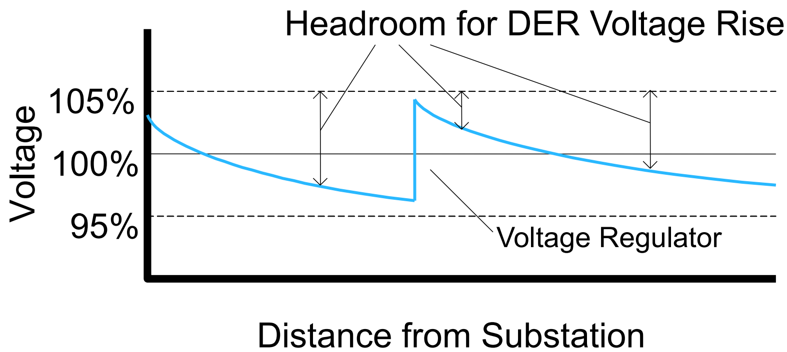

Figure 4-3
Voltage drop along a distribution feeder and the *headroom* concept

Localized power flow characteristics determine the direction in which the power is flowing. Normally, active power flows from the distribution substation radially to loads. However, with DER, the potential arises for power to flow in the opposite direction—particularly during low load periods. This change in flow direction can result in overvoltage.

Voltage Fluctuations

Distribution feeder voltages fluctuate on a daily basis as transmission system voltage and customer loads vary. Distribution utilities deploy regulation equipment such as load-tap changers (LTCs), line regulators, and switched capacitor banks to help regulate the voltage to within acceptable limits.

Individual customer load variations are smoothed throughout a feeder as a result of customer diversity. Variable generation driven by a common resource such as solar PV and wind can be more correlated, particularly for resources in close proximity to one another, resulting in solar resources that can ramp up and down coincidently.[19] This causes sudden changes in output, leading to troublesome voltage fluctuations on the distribution system.

Frequent regulation to mitigate voltage changes can lead to power quality problems or cause additional wear and tear on regulation equipment such as LTCs and line regulators, potentially shortening their useful life.

Voltage Support

DER can also provide advantageous services to the grid, such as voltage support. Some DER can regulate output—active power, reactive power, or both—and mitigate many of the voltage issues that arise on a circuit. The response time of inverter-based generation can regulate output much more quickly than traditional voltage control devices. If the DER output is coordinated with existing utility voltage control and provides voltage support when needed, adverse impacts are reduced or even eliminated.[20] With communication and control capability, DER that can regulate their output can also potentially coordinate with CVR programs and help control customer voltages to reduce customer consumption.

[19] *Variability of PV on Distribution Systems Analysis of High-Resolution Data Measured from Distributed Single-Module PV Systems and PV Plants (0.2 kW to 1.4 MW) on Three Distribution Feeders*. EPRI, Palo Alto, CA: 2012.1024357.

[20] Rylander, M., Abate, S., Smith, J., and Li, H., "Integrated Control of Photovoltaic Inverters to Improve Distribution System Performance," accepted for presentation at CIGRE Canada 2014 Conference, September 2014.

Protection Coordination[21]

Utilities must retain the ability to detect and isolate faults as well as provide service restoration to all customers in a timely fashion. Additional DER can impact the utility's ability to perform these functions. Potential impacts from the integration of DER include the following:

- **Nuisance fuse blowing, particularly related to fuse-saving schemes affected by the added current supplied by the DER.** Fuse/breaker coordination for faults downstream of a fuse can be affected if the fault current passing through the fuse is significantly increased by the addition of DER units on the distribution system.
- **Misoperation by upstream breakers, reclosers, sectionalizers, or fuses resulting from downstream DER generation.** The impact of DER on fault currents can be significant. A synchronous generator would typically inject 4 to 8 times its rated output current for 5 to 7 cycles during a fault. Inverter-based generation, however, typically contributes much less—on the order of 1.2 to 2 times rated current. If the DER raise the level of fault current, a fuse may no longer be coordinated with the main feeder circuit breaker, or the feeder breaker's ability to "see" the fault may be reduced—potentially reducing the utility's ability to detect and isolate faults.
- **Increased short-circuit current on the distribution system caused by large levels of DER.** In areas where feeder equipment is near its short-circuit ratings, DER may raise the levels beyond the equipment's capability.
- **Sympathetic tripping of the feeder or line reclosers on its circuit caused by a large generator near a substation.** This happens when a fault occurs on adjacent feeders serviced by the same substation to which DER are connected. This sympathetic trip is caused by DER feeding the adjacent feeder's fault with sufficiently high current to activate the instantaneous overcurrent-protection device on the previously unfaulted feeder. This condition can be prevented by adding directional overcurrent relays and, in some cases, adjusting standard overcurrent relays at the substation. Similar situations can also be seen with fuses, reclosers, and sectionalizers.

Energy Losses

DER have the potential to reduce distribution losses because the generation is provided closer to where the energy is actually consumed (customers). The extent depends on the location of the resource and when the energy is provided to the grid. When sited closer to the customer, the electrical resistance between the generation source and the customers is decreased, reducing the resistive losses in the distribution lines. If the generation resource output is coincident with the

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[21] *Engineering Guide for Integration of Distributed Storage and Generation*. EPRI, Palo Alto, CA: 2012. 1023524.

needs of the local loads and can provide the energy when the local load is consuming energy, losses can be lessened further. However, if the DER are not coincident with the feeder's load or are not located electrically close to loads, resistive losses can increase the extent to which overall losses increase as a result of adding DER.

Energy Consumption

Customer-based DER can increase voltage and therefore counteract the benefit of CVR. This can occur when increased levels of DER interfere with the CVR equipment's ability to bring voltages down to reduced levels. In some cases, this can result from an increase in the consumer's voltage because the DER are located on the same premises with load. If, however, the DER have some form of Volt/VAR (volt-ampere-reactive) control capability, increased customer voltages can be avoided. If the DER can be coordinated closely with the local voltage reduction mechanisms, the DER can potentially be used to assist in CVR and further reduce energy requirements.[22] Communication and control are necessary for this to be realized.

Capacity

A potential benefit of integrating DER into the distribution system is reduced net feeder demand that relieves capacity on existing distribution infrastructure, potentially deferring distribution capacity upgrades. For a resource to provide distribution capacity relief, it must be available during peak load periods when feeder assets are most constrained and capacity becomes the limiting factor. The ability for intermittent DER, such as PV, to reduce feeder peak demand may abate at high penetration levels if the load peak shifts outside the time of PV.

Reliability

Reliability measures the number or duration of interruptions of electrical service experienced by consumers. DER have the potential to improve reliability, but the technology must be dependable and sited in a location on the distribution system where it can effectively deliver power during system failure events.

Properly sited and configured DER can assist in the restoration of service after storm-related outages and power delivery component failures from other causes. Utilities often switch isolated feeder sections to alternate feeds at such times. Occasionally, there is insufficient capacity in the alternate feed to supply the load required to restore service to all consumers on the affected feeder section. The ability to support some of the load from DER output sited on the affected section may improve feeder reliability.

[22] *Advanced Voltage Control Strategies for High Penetration of Distributed Generation: Emphasis on Solar PV and Other Inverter-Connected Generation*. EPRI, Palo Alto, CA: 2010. 1020155.

If the DER can operate without the presence of the grid, they can be used to help restore power to sections of the distribution system that are completely isolated from the bulk power system (for example, as a result of storm damage). This is often referred to as a *microgrid* that can provide increased localized grid resiliency. It can consist of one large DER device or several DER devices operated with a common control and servicing an electrically interconnected premises, buildings, and electric clouds. A microgrid is designed to remain operational when the grid is deenergized—perhaps for several days.

As with capacity, DER output must be available at the time of need to improve distribution reliability. However, power must be available at the time of a failure that causes an interruption of service. If faults occur at night or during stormy periods with overcast skies, solar PV generation would not be available to assist with feeder reconfiguration or to power microgrids that do not have charged storage.

BULK TRANSMISSION SYSTEM IMPACTS OF DER

DER affect bulk transmission system operations, especially at higher penetration levels, primarily because they change the load at the substations that serve as the interface to the distribution system. Despite the fact that individual DER technologies differ with regard to controllability, extent of communications interfaces that impact observability, and other characteristics, high penetrations of DER impact the reliability, cost, and environmental contribution of the bulk transmission system in similar ways.

High levels of DER impact the bulk transmission system across five organizing categories: resource adequacy and expansion, resource flexibility, transmission expansion, operational scheduling and balancing, and transmission system performance. They are described and differentiated in Table 4-3. The general impacts of DER on these five areas of bulk transmission system operations and planning are described following the table. The analytical framework required to quantify the detailed impacts on each of these processes for a given scenario is described in Section 7. The analysis framework described must be comprehensive and sufficiently robust to consider the nuances summarized for each of the bulk power system impact areas delineated next.

Table 4-3
Impacts of high-penetration DER on the bulk transmission system

Organizing Category	Definition	Factor(s) Influencing DER's Impact
Resource adequacy and expansion	Resource availability that can sufficiently meet customer demand at all times and at least cost.	• DER availability, output variability, and production level during high-risk system hours
Resource flexibility	Resource availability that can aggregately provide sufficient operational flexibility to follow the cyclic nature of the load through the day and year.	• Degree to which DER affect the variation in the shape of the daily load that must be served from the transmission system
Transmission expansion	Transmission infrastructure required to sufficiently serve load.	• Degree to which loads can be locally served by DER, particularly during system peak delivery times • Degree to which DER may adversely impact reliability, requiring additional transmission
Operational scheduling and balancing	Resource supply dispatch that can sufficiently provide energy and required ancillary services to balance load in the near term and at least cost.	• The aggregate emissions and fuel costs of the DER dispatched to meet load • The additional operating reserves required through dispatchable thermal generation to manage DER variability and output uncertainty
Transmission system performance	Transmission system operation within established reliability criteria.	• DER location and level of power flow reduction across the transmission system • Level of central station generation and associated voltage and frequency support that is replaced by DER • DER response level to system voltage and frequency disturbances

Resource Adequacy and Expansion

Establishing resource adequacy involves developing and maintaining sufficient resources, at the least cost possible, to ensure that the likelihood of not being able to meet customer demand at all times meets the established criteria (for example, the "1 day in 10 years" standard). As part of the resource adequacy planning process, evaluations of projected future load levels are conducted using the expected probabilities of availability for supply and demand resources to determine 1) whether additional resources are needed to serve load at an acceptable system reliability (that is, probability of not serving load) and 2) the optimal mix of resources to provide the needed capacity at the least cost.

The impacts of DER on resource adequacy are complex and not necessarily intuitive. The extent to which any new resource contributes to undermining resource adequacy depends on the extent to which the resource is available and produces energy during high-risk system hours, when the margin between available supply and demand is the lowest. The uncertainty and variability characteristics of some DER described previously may reduce their contribution to resource adequacy because the probability of their output levels during high-risk hours may be lower. This means that the benefit of DER to resource adequacy depends on the certainty with which the DER can be depended on to contribute when the system most needs capacity. With increasing penetrations of DER, the hours during which the system is at highest risk may be altered. For example, PV may at first contribute significantly to a daytime summer peaking system, but as soon as the net peak shifts, the contribution from PV declines to zero without storage of sufficient duration or other means to shift demand.

DER may not be able to replace certain conventional generation resources on a one-to-one basis or even up to the value of their capacity contribution: the need for other operational reliability services may require that other resources remain connected or available. To the extent that DER offset central station generation, DER may lower capacity costs—assuming that the DER can supply all of the bulk power system reliability contributions of the replaced resources. Even if they can't provide resource adequacy, the reduction in energy required may mean that a low-capital, high-energy cost peaking resource is now more suitable.

Typically, DER are less flexible than the dispatchable, central station generation that they might replace because, regardless of dispatchability for capacity or energy, most DER technologies are limited in their ability to provide reactive power support or frequency support to the transmission system. Further, some DER such as wind and PV have relatively low capacity factors, requiring more megawatts of installed capacity to meet energy requirements. Other DER such as demand response may have limitations on their use, such as only within certain hours of the day or months of the year or a limited number of calls per year.

Resource Flexibility

The portfolio of resources available to the TSO must include sufficient operational flexibility (ramping, cycling, minimum generation levels, and so on) to follow the cyclic nature of the load through the day and across seasons. Some DER, primarily solar PV, increase the need for system flexibility because they increase the variation in the shape of the daily load that must be served from the transmission system as it offsets load by serving it locally.

Figure 4-5 shows the observed net load served from the ENEL (Italian utility) transmission system in Southern Italy for an August day over three successive years across which the levels of distributed PV increased significantly. By August 2012, the system load curve exhibited a step drop (ramp down) at around 800 hours and a step increase (ramp up) starting at 1500 hours.

The plot illustrates the need for increased ramping capability from other system resources to be able to follow the net load and to balance supply and demand. Further, the plot illustrates the growing need to lower remaining system resource output levels midday—either by reducing online output levels or by cycling generators offline. In this case, DER are increasing system flexibility requirements as well as the cost of reliably operating the system through greater O&M to handle the ramping and cycling of existing resources and by adding new resources to manage the increased flexibility requirement.

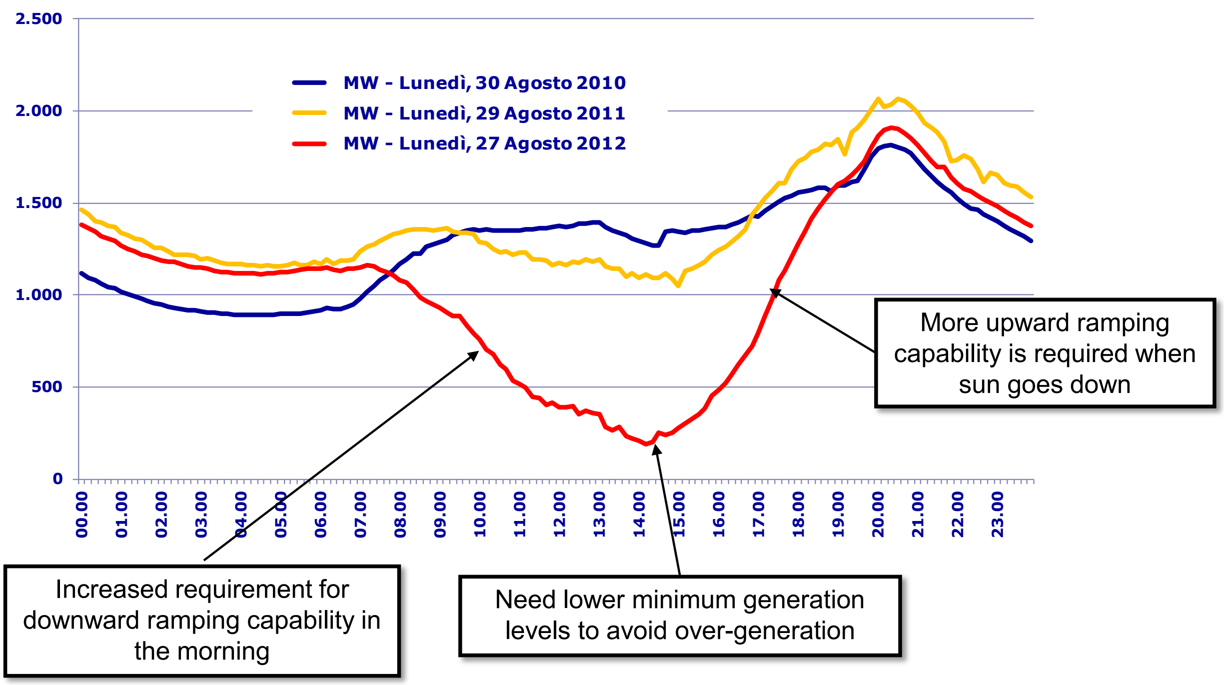

Figure 4-4
Illustration of increased system flexibility requirements (MW) over the day, resulting from high levels of distributed PV in the southern Italy region of the ENEL system

DER impact on transmission system flexibility is not just adverse. DER such as demand response and energy storage have already been shown in many regions to be effective operational flexibility resources used for balancing the variations in system load caused by bulk power system interconnected wind generation.[23] Flexibility can sometimes be considered a part of the overall

[23] S. H. Huang, J. Dumas, C. González-Pérez, and W. J. Lee, "Grid Security Through Load Reduction in the ERCOT Market," *IEEE Transactions on Industry Applications*. Vol. 45, No. 2, March/April 20, 2009.

resource adequacy framework; for example, a flexibility deficit could be met by building a new baseload plant, thereby freeing up a more flexible resource. Similarly, the addition of specialized flexible resources, such as storage and certain kinds of demand response, will likely contribute to resource adequacy as the level of operational timeframe uncertainties increases in a system.[24]

Transmission Expansion

DER impact on the need for new transmission is similar to their impact on resource adequacy. Serving more of the load locally from DER decreases the need for transmission delivery capacity and defers otherwise needed transmission upgrades, other things being equal. As with resource adequacy, however, the extent to which DER contribute to transmission delivery capacity depends on the extent to which DER reduce the transmission system peak delivery requirement.

Just because DER reduce the total energy consumed downstream of a given transmission corridor does not necessarily imply that the capacity required to supply and deliver energy reliably across that corridor decreases proportionally—or at all. Transmission planners must determine the certainty with which they can depend on DER to reduce peak delivery requirements in order to determine whether DER actually reduce transmission investment costs.

Operational Scheduling and Balancing

TSOs use sophisticated optimization algorithms to commit and dispatch supply resources to provide energy and ancillary services so that sufficient supply is available to balance load over the near-term horizon at the lowest possible cost. Production cost tools are used to perform simulations of these decisions in a planning framework. They can also be used to evaluate the aggregate emissions of the resources dispatched to meet load. As noted in describing the unique characteristics of DER, distributed wind and PV generation have zero fuel cost—generally, they reduce the overall production cost because they displace conventional thermal generation that burns fuel. Similarly, renewable DER are zero-emission resources: they also reduce overall emissions because they displace fossil-fueled generation.

The fuel cost and emission benefits of DER may be lessened, however, by the additional operating reserves that may need to be carried on dispatchable thermal generation to manage the additional variability and uncertainty in output wrought by renewable DER. Additional regulating reserve, spin and non-spin reserves, and possibly load-following reserves may be required. In addition to the higher level of reserves that may need to be carried and the associated increased

[24] *Power System Flexibility Metrics: Framework, Software Tool, and Case Study for Considering Power System Flexibility in Planning*. EPRI, Palo Alto, CA: 2013. 3002000331.

production costs, thermal units that are required to be online for reliability reasons may be operated at less efficient operating points—resulting in higher emissions than when operated nearer full load. These fuel cost and emissions savings must be determined through detailed analytical simulations, discussed in Section 7.

Transmission System Performance

TSOs are responsible for operating the transmission system within established reliability criteria. The operators dispatch generation and transmission resources to ensure that all system components are loaded below their thermal ratings and that system frequency and voltages are maintained within established limits. In addition, operators must ensure that sufficient resources are available to arrest and return the system to acceptable operating conditions after a system disturbance.

DER impact transmission system performance in multiple ways. First, because of the locational effect discussed previously, DER tend to reduce the power flow across the transmission system—which reduces losses and the total bulk power system cost of delivering power. The reduced power flow across the transmission system would also tend to improve voltage stability, if not for a related impact of the DER displacing central station generation that provides both voltage and frequency support. Any improvement in voltage stability associated with reduced flow levels may be more than offset by reduced reactive capability and voltage control if conventional central station generation is committed offline because reduced load levels are being served from the transmission system.

Similarly, these same central station generators also provide inertia and primary frequency response to oppose and arrest disturbance-driven frequency excursions such that frequency performance may also be impacted by high levels of DER. So, the aggregate impacts of DER—whether beneficial or adverse—must consider the full breadth of how the system operates with the DER on the system.

Another potential reliability impact of high levels of DER is the response of DER to system voltage and frequency disturbances. IEEE Standard 1547, Interconnecting Distributed Resources with Electric Power Systems, requires DER to disconnect for abnormal system voltage or frequency conditions. Although a recent amendment (1547a, 2014) altered the standard so that it does not prohibit voltage and frequency ride-through, the standard still does not require those features. Detailed system power flow, voltage stability, and dynamic stability evaluations are needed to fully understand the impacts of a given DER scenario on system transmission performance. A detailed description of the required analyses is provided in Section 7.

THE INTERCONNECTED NATURE OF TRANSMISSION AND DISTRIBUTION SYSTEMS

AC power systems were designed to transfer energy produced at central station generators through the bulk transmission system to distribution substations. They then distribute electricity to end users through radial feeders emanating from the substation. This approach has allowed planners and operators to focus on managing the reliability and affordability of electricity delivery for separate portions of the system without substantial consideration of the system as a whole. Doing so required understanding the magnitude and dynamic behavior of the aggregate load. Beyond that, however, planners and operators have had little need to understand details about the medium-voltage system or about the loads (or resources) fed from that system because of the one-way direction of power flow. Consequently, there was essentially no other impact of the distribution system on the transmission.

The only aspect of the distribution system that TSOs have traditionally focused on has been the magnitude of the aggregate load at the distribution-substation interface. Based on the present and near-term forecasted loads, the TSO has traditionally ensured that sufficient supply resources are scheduled and operated to deliver power across the system with satisfactory voltage and frequency levels. Distribution system operators (DSOs) have then managed the voltage from the low side of the distribution substation transformer down to individual delivery points without considering which resources are providing the energy or any impact—positive or negative—that their systems might have on the bulk transmission system.

As the levels of DER increase across broader distribution areas, distribution and transmission can no longer be planned and operated in isolation. As DER penetrations increase, the impacts spread beyond the distribution system to the bulk transmission system. As the relative percentage of the load served from DER increases, many bulk power system issues must be considered, given the lack of visibility and controllability of a large portion of the supply resource serving load at a given time.

Because of the interconnected nature of the transmission and distribution systems and the increasing potential for distributed energy and ancillary services to be provided from the distribution system, the overarching T&D network will increasingly need to be planned and operated in a much more closely coordinated manner. Increasing DER levels will drive the need for integrated T&D models and for exchange of information that can be used to simulate and evaluate the aggregate system reliability, affordability, sustainability, and safety implications of various system developments, investments, and technology choices.

Sections 5 through 8 describe analysis frameworks for evaluating the impacts of these choices across both transmission and distribution and further emphasize the manner in which they must be considered together. EPRI is conducting a separate and parallel Integrated Grid effort to define the required interactions of T&D operations and planning functions that will provide additional detail and insight into these needs.

NEED FOR DER INTERCONNECTION REQUIREMENTS

The potential transmission performance impacts described in the previous section point to the need for DER interconnection requirements that provide for DER capabilities supportive to bulk transmission system operation. Some of the adverse impacts of DER on transmission system performance may be mitigated with appropriate interconnection requirements. For example, the need for voltage and frequency ride-through could be satisfied with appropriate interconnection requirements, and it should be noted that IEEE 1547 is undertaking a full revision that considers such ride-through requirements.

In addition to simply not harming transmission reliability, some DER may also be able to support system frequency performance with appropriate requirements. EPRI is conducting a separate, parallel Integrated Grid effort to recommend needed DER interconnection requirements for guaranteeing both transmission system and distribution system reliability. The series of white papers being produced from that effort should be referenced for more detailed discussion of DER interconnection requirements.

Sections 5 through 8 take a deeper look at DER impacts from both a distribution-centric view (Sections 5 and 6) and a bulk energy system–centric view (Sections 7 and 8).

5 CHARACTERIZING THE IMPACTS OF DER ON DISTRIBUTION

DER, by definition, physically connect to the grid through the distribution system—either at the primary, medium-voltage level or through the secondary, low-voltage, customer-side level. It follows that the appropriate frame of reference to assess the impacts of DER is the distribution system. Once these impacts have been identified and quantified, an integrated grid perspective extends the study to ways in which the bulk power system is affected.

This section focuses on the distribution aspects of the overall Integrated Grid framework, providing inputs and data to the methodology's Bulk Power System and Benefit-Cost analyses to properly account for the value streams and the costs associated with integrating DER into the grid.

DER produce electricity that is nearer to the consumer, reducing the amount of power supplied by distant central power stations. Two main value streams associated with DER originate on the distribution system:

- **Distribution system losses.** Because DER are connected closer to the load, they have the potential to reduce delivery losses across the distribution system.25
- **Upgrade deferral.** With DER that can guarantee production during constrained periods, upgrades, operations, and maintenance relief can be realized.

There are other implications for the performance of the distribution system associated with DER-supplied power that result from reverse power flow across the circuit and DER output variability, leading to two factors to take into account in summing up impacts:

- **Voltage regulation.** The distribution infrastructure, which includes voltage regulation equipment, methods, and planning tools, was designed for one-way power flow. Integration and accommodation of DER must account for operational and cost implications of two-way power flow.
- **Protection.** Distribution circuit protection schemes have been designed for one-directional fault current. With DER, faults can arise that the existing protection system does not sense or cannot counteract. Additional relaying and modification of schemes and practices are necessary when DER reduce the effectiveness of existing equipment.

As discussed in Section 4, several factors determine the overall effect of DER, both in terms of value streams that can be derived and issues that can arise that require mitigation. The Distribution System Analysis component of the framework uses inputs from the Core Assumptions module, as defined in Section 3, and detailed modeling of the physical system to identify and quantity impacts to the distribution system. The impacts are assessed through four types of analysis: hosting capacity, energy, thermal capacity effects, and reliability.

The remainder of this section is organized as follows:

- Accounting for the Distribution System: Unique Factors That Shape Responses to DER
- Distribution Analysis Methodology: A Brief Overview
- Hosting Capacity Analysis and Solution Identification
- Energy Analysis
- Thermal Capacity Analysis

[25] Distribution losses and the potential reduction depend on when and where the DER are providing energy to the grid with respect to the load. DER located electrically close to the load have greater potential to reduce delivery losses.

ACCOUNTING FOR THE DISTRIBUTION SYSTEM: FACTORS THAT SHAPE RESPONSES TO DER

As discussed, distribution systems are designed differently based on many physical and environmental factors as well as the load served. It follows that distribution feeders are affected by DER in different ways and to different degrees and that an individual feeder is affected by the type of DER connected. This section summarizes these factors, listed in Table 5-1, and associated distribution system impacts attributable to interconnected DER. The diversity of factors and effects that can be confronted justifies the need to model each feeder individually; there is insufficient understanding of the interactions among the effects to justify organizing feeders into clusters or groupings to simplify the analysis.

Table 5-1
Key feeder characteristics that determine how DER impact the grid

Feeder topology	Radial vs. networked
Voltage class	Size and location of DER
Regulation equipment	Electrical proximity to other DER
Short-circuit strength and X/R ratio	DER response characteristics
Operating criteria	DER control

Feeder Topology

Utilities serve customers using varying types of distribution systems. Some are composed of several compact, urban feeders, while some utilities serve customers primarily through long, rural distribution systems. Many have both types of circuit arrangements, but to various degrees. Each system was designed in the most cost-effective manner to reliably serve customers. As a result, many systems are considerably disparate. Take, for example, the graph shown in Figure 5-1, which illustrates the total three-phase circuit miles for two investor-owned utilities' feeders in California. One utility's infrastructure consists mostly of 20 miles of three-phase backbone, while almost 50% of the other's circuits are twice that size. Findings that circuit length is not the only factor that impacts other correlations have been verified.[26]

[26] *Distributed Photovoltaic Feeder Analysis: Preliminary Findings from Hosting Capacity Analysis of 18 Distribution Feeders*. EPRI, Palo Alto, CA: 2013. 3002001245.

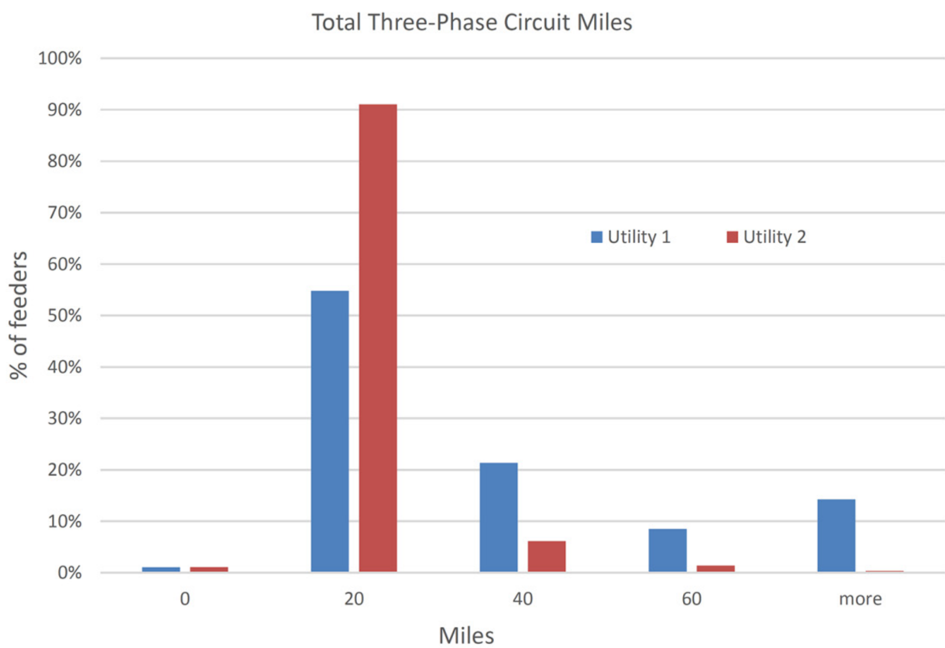

Figure 5-1
Distribution feeder lengths (total miles) for two investor-owned utilities

Voltage Class

System voltage level can have a greater determination than topology on system performance. The higher the system voltage, the greater the short-circuit strength (stiffness) of the system—short-circuit strength increases with the square of the voltage. All other things being equal, the higher the short-circuit strength, the less impact DER output has on system voltage.

Regulation Equipment

The use of regulation equipment within a distribution feeder can also determine how many DER that particular feeder can accommodate, based on impact to system operation.

The use of regulation equipment, such as LTCs, feeder regulators, and switched capacitor banks, has been adopted in various ways throughout the world. Some utilities' distribution substations do not use LTCs, while others do (or use feeder regulators at the feeder head). Other utilities use feeder regulators and/or switched capacitor banks or a combination thereof.

The vast majority of voltage regulation methods consist of mechanically switched devices that operate on the order of 45–90 seconds, while longer time delays are often associated with capacitor bank switching. The introduction of DER has the potential to interact with existing regulation control in an undesirable way—either through excessive switching/tapping of the device outside its normally intended range, resulting in loss of life, or possibly causing inadvertent voltage conditions as a result of variations in DER output.

Short-Circuit Strength and X/R Ratio

The relative impact on system voltage caused by DER power injection is also related to the grid's short-circuit strength and X/R ratio.[27] The ability for DER to move system voltage is dependent upon the relative short-circuit strength (MVA) of the grid with respect to the capacity of the DER. In addition, the X/R ratio with respect to the amount of active and reactive flow from the DER determines the ability of the DER to change system voltage.

Operating Criteria

The manner in which the feeder is operated must also be taken into account, specifically in terms of allowable voltage range of operation. For example, most system planners' design is based on meeting ANSI C84.1, which specifies a limit of ±5% nominal (defined as 114 V to 126 V on a 120-V base). The wide band accommodates the effect of extreme load and weather on circuit voltage. Some utilities have adopted the use of conservation voltage management to reduce system energy consumption. For these circuits, the planning limits for voltage response are often much narrower than the ±5% target because the equipment employed adjusts to exigent circumstances: the upper limit may be reduced from 5% to 3%. However, this tighter band can become a more limiting factor. A voltage rise from DER could result in unacceptable voltages under CVR conditions unless accommodating actions are undertaken.

Radial vs. Networked

Whether the circuit is radial or networked plays an important role in system impacts of high penetration, especially for distributed generation. This is largely related to protection of the system rather than to voltage impacts. Special consideration must be given to spot and urban networks—even a small amount of reverse power through a network protector could cause it to trip and adversely impact other customers.

Size and Location of DER on the Distribution Feeder

The size and location of the DER are perhaps the most critical DER-specific factors that must be taken into account and can directly impact hosting capacity, especially for variable output technologies such as PV and wind. Large-scale DER systems interconnected to distribution near the substation (or through express feeders) have a significantly different impact on grid voltage than if they were connected near the end of the feeder. This is illustrated in Figure 5-2, which

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[27] The *X/R* of an electric system is the ratio of its total reactance to its total resistance. The higher the *X* value, the more inductive the system is.

compares the hosting capacity of two feeders (labeled P3 and P5) at different levels of PV penetration. The bottom feeder (P3) reaches the point of requiring PV accommodating upgrades at a penetration of less than 2 MW, while the other can handle 6 MW before upgrades are required.

The relative stiffness of the system near the substation with respect to the size of the DER system is much higher and would therefore have much less impact on system voltage. Farther from the substation where the system impedance is much higher (lower short-circuit current), the DER system will more likely impact system voltage—possibly adversely. Location impact is directly tied to many of the factors discussed previously, including topology, regulation equipment, and X/R.

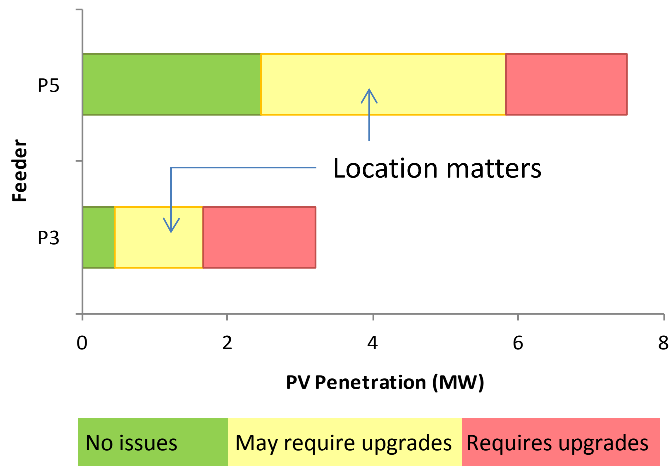

Figure 5-2
Sample results illustrating locational dependency of hosting capacity

Electrical Proximity to Other DER

With DER, some diversity in output is expected as, for example, solar PV systems geographically dispersed throughout a distribution feeder. However, as noted in prior EPRI research, to a certain extent the PV systems can be correlated at certain time resolutions, particularly if they are more proximate to one another.[28] This fact is compounded the closer the PV systems are located electrically. For example, a few customers connected to the same service transformer would have

[28] *Variability of PV on Distribution Systems: Analysis of High-Resolution Data Measured from Distributed Single-Module PV Systems and PV Plants (0.2-kW to 1.4-MW) on Three Distribution Feeders*. EPRI, Palo Alto, CA: 2012. 1024357.

well-correlated solar PV output profiles. Because of the electrical proximity of the solar PV systems to one another, the PV systems are more likely to impact system voltage (similar to a single point of connection). The same concept can be applied to larger scale systems connected throughout a distribution feeder.

Combinations of DER technologies with complementary output characteristics (for example, variable DER combined with energy storage) are also affected by their electrical proximity to one another.

DER Response Characteristics

Variable generation such as wind and solar can have widely varying impacts on system response when compared to fixed or dispatchable DER. Differences are due to the timing, extent, and frequency of changes in output relative to local electricity demand characteristics. The coincidence of peak DER production with load level is also an important factor to take into account. Three generalities can be drawn about the association of DER output and local electricity load:

- DER output coincident with load is more likely to reduce peak demand and lower capacity requirements.
- DER output coincident with load is more likely to decrease system losses.
- DER output not coincident with load is more likely to result in voltage issues, particularly peak output production during light load periods, potentially causing an overvoltage condition.

The specific DER technology employed is also a factor; for example, rotating machines and static inverter interfaces have different impacts on system protection. Rotating machines can provide as much as 5–6 times rated current during faulted conditions, while inverter-based DER are likely to be significantly less (1–2 times rated current).

DER Control

The type and extent of control the system operator has over DER also changes system impacts. If the DER are dispatchable, some of the grid’s need for voltage and/or power support can potentially be met by DER. In some cases, DER may not be fully dispatchable; however, their reactive power can be controlled either autonomously or remotely in a way that contributes to mitigating any DER-caused impacts or in response to system needs. In such cases, the DER may also contribute to voltage regulation. Operating the DER system at either a slightly inductive power factor (absorbing VARs) or under Volt/VAR control can help mitigate many of the voltage concerns.[29] This mitigation can extend to supporting the grid—the effects of which can be revealed using Volt/VAR control simulations.[30]

DISTRIBUTION ANALYSIS METHODOLOGY: A BRIEF OVERVIEW

A key driver in determining the overall impact of DER on the distribution grid is structural diversity, but it also poses the greatest methodological challenge to quantify. A utility's distribution system consists of hundreds to thousands of distribution feeders—each designed and operated to meet local conditions, so each responds differently to DER. Because of the possible widely varying responses across feeders that result in different types and levels of impact to be accommodated, an integrated grid evaluation requires that all feeders be modeled—at least to establish the basic properties and type.

A detailed analysis of each and every feeder requires a large amount of data, modeling and output processing, and extensive engineering staff time. To circumvent this issue, some have proposed modeling representative feeders (selected based on their topological characteristics) and extrapolating the results to all members of the cluster. This allows engineers to query geographic information system (GIS) and cluster feeders based on static characteristics (for example, voltage class, peak load, and length of lines). Doing so significantly reduces engineering time and allows a smaller subset of feeders to be analyzed.

But is this a wise course to follow? Complex interrelationships among the static feeder characteristics pose a challenge to creating robust clusters. This combined with the possibility of unobserved (sometimes dynamic) factors makes finding meaningful clusters challenging. The consequences of errors in measuring the impacts of a representative member of a cluster become quite large because the results are attributed to all members of the cluster.[31]

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[29] *Power Factor Guidelines with Distributed Energy Resources: Using Reactive Power Control with Distributed Energy Resources.* EPRI, Palo Alto, CA: 2013. 3002001275.

[30] *Advanced Voltage Control Strategies for High Penetration of Distributed Generation: Emphasis on Solar PV and Other Inverter-Connected Generation.* EPRI, Palo Alto, CA: 2010. 1020155.

[31] *Cluster analysis* refers to numerical methods for classifying members of a population according to observable and measurable characteristics, with the objective of devising objective and stable classifications that support prediction and inferences (Everitt, B., Landau, S., Leese, M, and Stahl, D., *Cluster Analysis*, Fifth Edition. Wiley West Sussex, UK, 2012, p. 4). They rely on there being strong association among characteristics and actions that are not observable directly, but can be identified using powerful numerical processes. A shortcoming is that because they are empirical in nature, they may produce specious associations, and as a result underlying cause-and-effect relationships are not necessarily revealed and verified.

EPRI proposes a method that acknowledges the importance of differences in static and topological characteristics for each feeder as well as their unique operational performance to connected DER, the location of the DER within the distribution system, and the DER technology's interaction with the grid. Rather than examining only a few select feeders, EPRI's proposed methodology examines all feeders that make up a distribution system, taken into consideration by modeling each feeder individually.[32]

Methodology for Distribution Analysis

The previous section describes how DER can affect the operation of the distribution system, focusing on the system's physical characteristics that determine power delivery. The discussion identifies several aspects that shape or condition the DER impact on a distribution feeder. Influencing factors are specified to draw an association between physical feeder characteristics and how they impact the delivery of power from substations (connected to the bulk power system) to end-use customers—the engineering physics of electricity (Table 4-2). The ensuing discussion sorts these impacts into four root cause categories: DER impact on voltage, protection, energy, and thermal capacity.

The preceding discussion focuses on sub-elements of each root-cause impact individually to describe how grid performance is influenced, laying the foundation for identifying both adverse and beneficial impacts. It does not reveal, however, the complex interrelationships among the forces that determine how electricity flows in a conventional distribution system—and that DER producing two-way flows alter those fundamental cause-and-effect relationships. The location and size of the DER are considerations that are interdependent with system strength and customer loads. A change in voltage caused by DER can improve feeder performance or result in the need for an investment to mitigate an adverse effect. Complex associations and cause-and-effect relationships abound. A thorough and actionable evaluation of DER must take all of these factors into account, individually and collectively.

EPRI has developed and piloted methods for conducting feeder-specific analyses that account for all of these factors and thereby provide a complete characterization of the impacts attributable to DER. EPRI's OpenDSS simulation platform has served as the foundation for these analyses.[33] It employs dynamic and stochastic simulation techniques to establish power flows in a feeder under current conditions and to quantify the impacts of adding DER in any amount to any part of the feeder for a range of adoption scenarios. EPRI has also used similar techniques for plug-in

[32] A utility may apply screening criteria to identify those areas and feeders where DER are most likely to be connected and treat them as the study area, thereby reducing the size of the analysis. The downside is that some feeders have little tolerance for DER, so accommodation issues can arise in areas where DER penetration is light. A valuable advance to studying DER impacts would be the development of more reliable DER adoption models.

[33] EPRI OpenDSS, Open Distribution System Simulator, Sourceforge. http://sourceforge.net/projects/electricdss/files/.

electric vehicle (PEV) adoption, energy storage analysis, and distribution efficiency studies (Green Circuits).[34, 35, 36] Techniques developed and applied throughout these efforts—involving more than 100 unique distribution feeders—serve as the basis for the analysis methodology described in this section.

These studies show that accounting for the complexity of power flows is critical to understanding how DER impact feeders; they are affected differently at different levels of DER interconnection, other factors being constant. However, the level of the determining factors is seldom discrete and constant—hence the need for dynamic simulation. Interactions among factors can be fully accounted for only by recognizing that their outcomes are uncertain, not discrete. An insightful analysis must consider the mean impact over the distribution of these factor outcomes.

Technically complete results come at a high price. Modeling the dynamic aspects of any feeder requires a large amount of characteristic data that the utility must supply. Moreover, the simulations require substantial analysis computational resources to fully examine how a feeder is impacted.

Based on findings from detailed individual feeder analyses, EPRI has developed a methodology for characterizing the impacts of various levels and arrangements of DER on all of a utility's feeders. A DER impact assessment requires using software to simulate feeder performance, with and without DER. EPRI's Integrated Grid Benefit-Cost framework employs commercially available analysis tools for determining hosting capacity (a definition of which follows). Several commercial tools used by utilities for system planning can be used for this analysis. Using these systems saves time and resources because the models have already been developed to represent the utility's feeders. Perhaps most importantly, it means that a utility can conduct the analyses using commercially available distribution analysis tools—which most of them have—and repeat the hosting capacity analysis process when conditions warrant.

EPRI's method for characterizing DER impacts to distribution is depicted in Figure 5-3. It involves five major analysis activities, denoted by the rectangles in the center of the figure distinguished by capital letters:

- Characterization of distribution feeders and DER (A)
- Hosting capacity analysis (B)
- Energy analysis (C)

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[34] J. Taylor, A. Maitra, M. Alexander, D. Brooks, and M. Duvall, "Evaluation of PEV Distribution System Impacts," IEEE General Meeting, Power Engineering Society, Minneapolis, MN, July 2010.

[35] *EPRI Framework for Evaluating Energy Storage Within Distribution Systems: Energy Storage Integration Council (ESIC) Application Working Group (WG1)—Reference Guide*. EPRI, Palo Alto, CA: 2013. 3002001553.

[36] *Green Circuits: Distribution Efficiency Case Studies*. EPRI, Palo Alto, CA: 2011. 1023518.

- Thermal capacity analysis (D)
- Reliability analysis (E)

Inputs to the analysis are defined to the left of these processes: Feeder Models, Load Data, and DER Data. The outputs of these analyses go to Bulk System Analysis (top box on the right of the figure), defined as substation impacts on load, or to the Benefit-Cost Analysis (the bottom right-most box), which tracks costs incurred to accommodate DER and cost savings provided by DER discovered in the analyses.

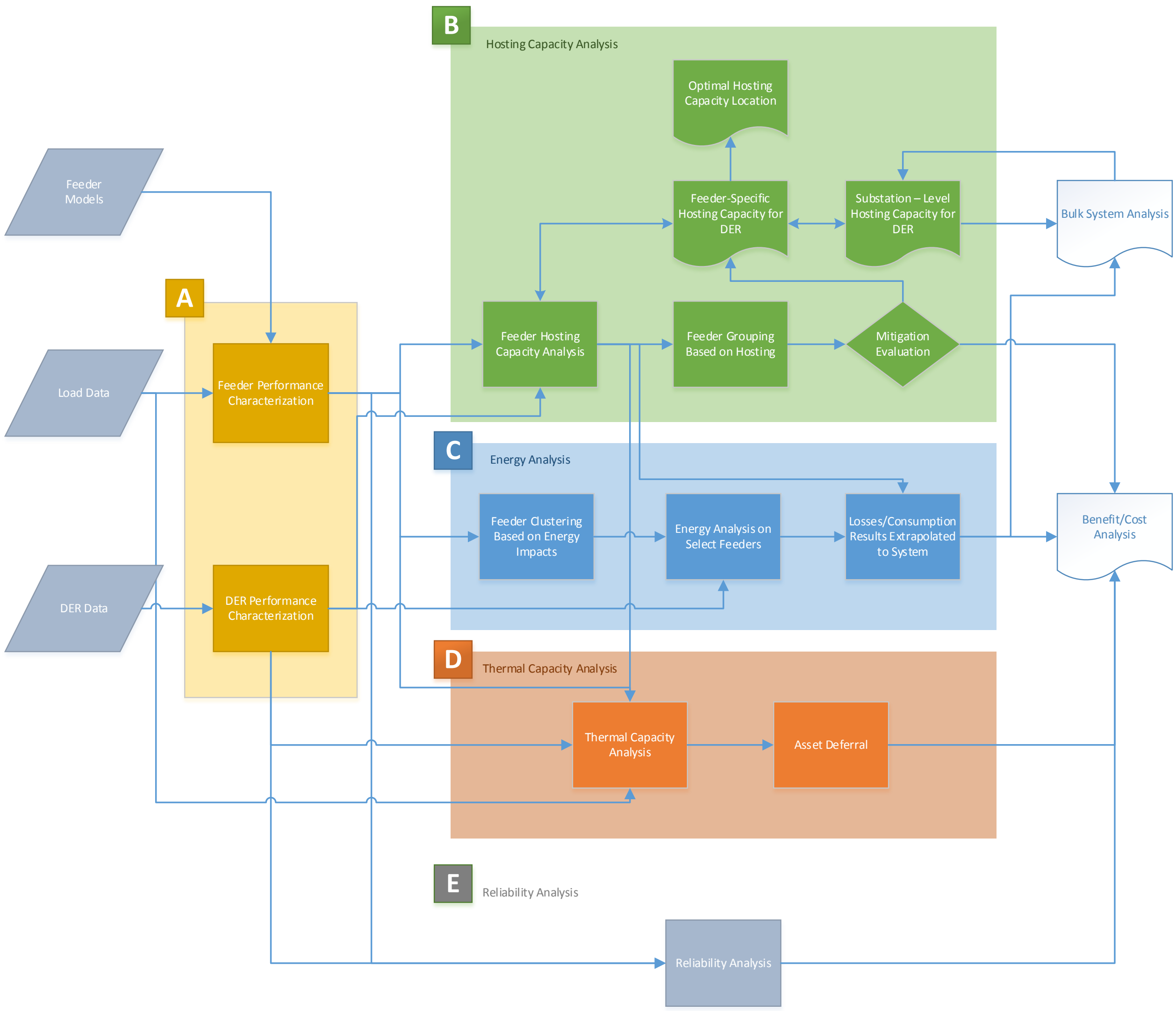

Figure 5-3
EPRI's Integrated Grid distribution analysis framework

Distribution Feeder and DER Characterization

The first step in the methodology is to characterize the distribution feeders and DER. The methodology uses the input data (denoted as the boxes in Group A in the figure) to undertake a basic analysis of each individual feeder in the distribution system by performing a load-flow and short-circuit analysis. The Feeder Performance Characterization provides voltage, short-circuit, or loss information that can be used as an input to the next analysis step. The DER Performance Characterization step defines the DER's electricity output characteristics (for example, fixed vs. intermittent, dispatchable vs. non-dispatchable, production profile, energy capability, and voltage control capability).

Hosting Capacity Analysis

A key to this methodology is its hosting capacity approach for determining how many DER can be accommodated prior to necessitating system upgrades, illustrated in the top rectangular box (labeled B) in Figure 5-3. Recall that *hosting capacity* is the amount of DER that can be accommodated without adversely impacting power quality or reliability. These are procedures that take advantage of the findings from detailed studies to establish a way to determine, for each feeder studied, the level of DER adoption at which a critical system state requirement is violated.

As discussed previously, the important criteria for evaluation are voltage and protection. The hosting capacity protocols define how hosting capacity can be determined by individual feeders using commercial software tools. Using previously developed feeder models of the distribution system, simulations are run to define the hosting capacity on each feeder and determine whether a voltage and/or protection violation occurs. Once these are established, the feeders can be grouped—by hosting capacity, type of violation, and other physical characteristics. The groupings are used to determine what, if any, mitigation strategies are necessary and at what penetration level these are needed.

An immediate output for each feeder is the first-order DER hosting capacity limit, which defines the level (MW) of DER on the feeder at which a violation occurs—in the form of a voltage disruption, circumstances that interfere with protection equipment operating at its established settings, or both. Any violation compromises the reliable operation of the feeder and has adverse consequences for customers served by the feeder, and perhaps implications for maintaining reliability at the bulk power system level.

The hosting capacity limit becomes an input to bulk power system analyses. Based on the initial Bulk Power System Analysis results, if local transmission constraints limit the amount of DER that can be accommodated in the area, this constraint is then passed back down to the substation and eventually to the feeder level to reduce overall DER levels.

Distribution feeders that experience a violation require additional analysis to determine the best way to resolve a violation, which defines the equipment and procedures employed and the associated mitigation cost. A detailed mitigation analysis is required only for a few representative feeders from each group at this point (*Feeder Grouping* in the figure).

The results of Mitigation Evaluation (the diamond-shaped figure in the bottom right of the Hosting Capacity Analysis box) for each representative(s) feeder are extrapolated to the group and then aggregated to the system.

Energy Analysis

The change in losses is an additional consideration in evaluating DER accommodation: the loss reduction is a benefit that results in both reduced generation requirements and lower bills to customers. The Energy Analysis (labeled C in Figure 5-3) estimates the change in loss and energy consumption response for each feeder studied. Similar to the hosting capacity approach, feeders are grouped based on their loss performance (among other metrics), and detailed analysis of select (representative) feeders is performed. This detailed analysis determines loss bands at increasing DER penetration levels that can then be extrapolated to the other feeders in the group to produce system-wide changes in losses.

Thermal Capacity Analysis

Thermal Capacity Analysis, the third level of impact modeling (portrayed as Rectangle D in the figure), requires specific information regarding system fleet thermal characteristics and associated load profile characteristics and projected load growth. Therefore, capacity is modeled separately for each feeder to identify potential benefits (asset investment deferral) arising from power being generated locally as well as any adverse consequences of two-way power flows on feeder carrying capacity. (Details regarding how this analysis would be performed are not included in this report because they are specific to each utility's planning methods and vary from utility to utility.)

Reliability Analysis

The analysis of feeder reliability is by nature probabilistic because failures have a high degree of uncertainty. DER with variable output such as wind and solar generation add another degree of probabilistic variability to the problem. There are many other factors to consider, such as the coincidence of DER output with load, the location of failures, and the topology of the circuit. Researchers have developed several approaches to probabilistic planning that, for the most part, have not been embraced by utility planners. Utility distribution planners prefer more deterministic methods based on average failure rates, assuming predictable interactions between circuit components. However, they do not portray the extent of the risk of failure, masking low-probability but high-impact failures—and therefore may result in mitigation actions not being taken and exposing the circuit and its customers to outages.

There is no consensus on the approach to follow for reliability analyses as part of the Integrated Grid planning framework. The selection of a generally accepted approach may require several years of research. However, the methods used to determine hosting capacity determine the amount of DER that can be accommodated without degrading existing reliability performance, and this is sufficient to screen circuits for their ability to accommodate DER.

Outcomes of the Distribution Analysis

The methods described facilitate conducting DER accommodation studies for the entire distribution system in an automated fashion. Efficient implementation also enables qualified users to evaluate mitigation solutions on a feeder-by-feeder basis. As the distribution system changes over time, the assessment method can be repeated as needed to account for changes to the distribution system, such as reconfigurations implemented (absent a DER accommodation prerogative) to accommodate load growth or for contingency reasons. This aspect is critical when there is a need to understand the impacts (in terms of cost and value) of DER spread across an entire distribution service territory.

Key findings from each feeder can be provided, including the following:

- **Feeder-specific hosting capacity.** This is the amount of DER that can be accommodated without violating feeder voltage and protection performance thresholds. These results can then be aggregated up to the substation level and provided to the transmission planners for the bulk power system analysis, providing the necessary information for the bulk power system analysis described in Sections 7 and 8.
- **Substation-level hosting capacities.** These improve visibility into substation-level capacity for accommodating PV connected to the feeders it serves.
- **Identification of least-cost locations for integrated DER along a feeder.** Issues with location-based information regarding likely locations along a feeder may arise as well as locations where DER can be integrated in a least-cost fashion.
- **Mitigation solutions.** The issues derived from the hosting capacity analysis help determine the range of mitigation options for allowing higher penetration levels of DER to be accommodated.
- **Loss impacts.** This addresses changes in feeder losses as DER are deployed at increasing penetration levels.
- **Energy consumption.** This addresses changes in energy consumption as DER are deployed at increasing penetration levels.
- **Asset deferral.** This addresses capacity reduction resulting from DER and the potential to defer asset upgrades.

The discussion that follows provides greater detail about these analysis protocols.

HOSTING CAPACITY ANALYSIS AND SOLUTION IDENTIFICATION

A core component of the distribution methodology is that it quantifies how many DER can be accommodated on a distribution feeder without violating feeder performance thresholds, referred to as *hosting capacity*—that is, the amount of DER that can be accommodated on a feeder without adversely impacting operations, power quality, or reliability. The term *hosting capacity* has been used synonymously with *penetration limit*. However, EPRI uses this terminology to describe the range of DER levels that can be integrated on a distribution feeder while taking into account both the size and location of the DER.

The potential impact of DER on distribution system performance—and ultimately a feeder's hosting capacity—depends on many factors, primarily the distribution feeder characteristics, the location of the DER along the feeder, feeder operating criteria and control mechanisms, and the electrical proximity of DER on the circuit to other DER systems. Some distribution circuits can accommodate considerably higher levels of DER before operating criteria are violated, while others hit violation at lower levels of DER. DER interconnected at the head of the feeder have a lesser impact on system performance than if they are connected farther from the substation, where the feeder is weaker. For example, short distribution feeders and/or those built entirely of larger conductors can, in some cases, accommodate significant levels of DER without resulting in system voltage violations. By contrast, other feeders serve customers over a wider geographic footprint and "taper" conductor size as the conductor extends outward from the substation and use line regulators to regulate voltage.

Purpose

The primary objective of this task is to determine hosting capacities for all feeders in a service territory or a specified study area. The hosting capacity results describe locations where DER are more easily accommodated and those where DER are more of an issue. The results also describe the level of interconnected DER at which system reliability issues begin to arise. The secondary objective of this task is to determine the mitigation needed to increase the hosting capacity by alleviating potential adverse issues.[37]

Input

The system under study (all system distribution circuits or a subset thereof) must be modeled in the host utility's distribution analysis software to apply the hosting capacity screening method for each feeder. The power flow models used in the study will not be altered other than to adjust load levels and automatic control equipment as needed. The appropriate load adjustments for peak, off-

[37] For a detailed, step-by-step description of hosting capacity protocols and methods, see *Streamlined Methods for Determining Feeder Hosting Capacity for Solar PV*. EPRI, Palo Alto, CA: 2014. 3002003278.

peak, and midday conditions must be inherent to the model or derived from supervisory control and data acquisition (SCADA) measurement data. Methods particular to the utility for running the power flow must also be used so that the models are properly simulated. The resultant solutions provide the necessary information to apply the hosting capacity screening methodology. This information primarily includes voltage and impedance profiles along with power flow reports for each feeder and is available in EPRI report 3002003278.[38]

Process

The amount of DER that can be accommodated system-wide can be determined through a streamlined hosting capacity assessment method designed to calculate the amount of DER that can be accommodated on each feeder. This process allows the evaluation of hundreds to thousands of distribution feeders to determine the amount of DER that can be accommodated at the local level before adverse issues with voltage and protection occur. For each issue, a hosting capacity value is estimated to identify the load level at which the issue can potentially begin to occur on a feeder. The location and exposure to the issue help determine the mitigation needed to relax the hosting capacity constraint and accommodate higher levels of DER. Results can then be aggregated at the substation and beyond for bulk power system analysis.

The hosting capacity analysis can be divided into two main steps:

1. **Hosting capacity evaluation.** This step involves analyzing the potential impact of DER on voltage and protection.
2. **Mitigation evaluation.** This step involves evaluating ways to accommodate higher levels of DER while maintaining system reliability and power quality.

Hosting Capacity Evaluation

The hosting capacity evaluation assesses distribution system performance with respect to voltage and protection impacts. For each feeder, the first step is to estimate the level of hosting capacity that does not require system upgrades.

Voltage Analysis

Voltage-based hosting capacity is calculated by determining the impact of DER on primary and secondary voltages across a feeder. This includes voltage headroom for accommodating DER as well as reverse power conditions and voltage fluctuations at regulation equipment (such as LTCs and line regulators) that result. Voltage magnitude issues occur when the primary or secondary voltage exceeds a specified limit. The voltage limit takes into account whether standard ANSI limits are applied or whether more stringent requirements associated with CVR programs (using

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[38] *Streamlined Methods for Determining Feeder Hosting Capacity for Solar PV*. EPRI, Palo Alto, CA: 2014. 3002003278.

regulation equipment) must be used. Voltage fluctuations experienced by regulation equipment can cause excessive tapping or switching of mechanical devices or create susceptibility to allowing DER to adversely regulate voltage. Identifying how many DER can be accommodated without causing adverse voltage impacts is the goal of this part of the hosting capacity analysis.

Protection Analysis

Protection-based hosting capacity is calculated for feeder breaker equipment trips caused by changes in fault current resulting from DER. Several key items are addressed in this methodology:

- **Sympathetic breaker tripping.** Sympathetic tripping of the feeder breaker is a concern when a fault occurs on a parallel feeder and the ground fault current relay on the studied feeder trips as a result of DER contribution.
- **Increased fault current.** Incidental tripping is also a concern on parallel feeders when the total fault current from the bulk power system and local sources increases. In addition, many feeders—especially in urban areas—have little margin for additional fault current. DER increase the total available fault current, and the resulting levels may exceed the capacity of the short-circuit protection equipment. The farther from the high-voltage or low-voltage substation, the greater the importance of percentage change in fault current. A large change is often an indication that the protective relays are no longer coordinated.
- **Breaker reduction of reach.** This issue involves reduced sensitivity of the feeder breaker. Reduced reach results when local DER supply sources contribute fault current that reduces the amount of fault current flowing through the feeder breaker.
- **Open-phase conditions.** Open-phase fault conditions may occur on utility distribution systems as a result of blown fuses, damaged conductors, connector failure, or bad splices. These conditions are associated with DER on an isolated section where severe overvoltage or unstable load voltages may occur on the open-phase conductor.
- **Reverse power flow.** In some cases, DER-induced reverse power flow can cause inadvertent tripping of protection equipment, requiring the use of direction-based protection schemes (that is, directional relaying).

Some utilities also specify load/generation ratios that ensure that unintentional islands do not occur. This metric is used, when applicable, in the overall protection analysis.

Mitigation Evaluation

Feeders that have encountered a hosting capacity limit are grouped by the particular issue found. Mitigation of these issues is based on detailed studies of mitigation options, which include replacement of equipment, reconductoring, and other options as described in the next section. From this analysis, a range of technical solutions for each feeder is provided along with the extent to which the solution is needed.

To determine the mitigation solutions, three tasks are performed:

1. **Hosting capacity grouping.** Feeders are grouped based on their hosting capacity response. The number of groups is determined by the hosting capacity threshold and the issues that arise; the hosting capacity determined is then compared to the DER penetration scenario (the desired threshold level) being evaluated. Feeders are then sorted into groups based on whether the target is above the hosting capacity limit and mitigation solutions are needed, or the hosting capacity limit is above the target and no solution options are necessary. For the feeders that require mitigation, Steps 2 and 3 are carried out to determine what improvements must be made to raise the threshold to the desired level.

2. **Detailed mitigation solution analysis.** A few feeders are selected from each response group to be representative of all members of the group, and mitigation options for accommodating higher levels of DER are evaluated. Mitigation options that technically remedy the issue are critically assessed at increasing penetration levels of DER. For each feeder, an incremental MW-capacity of DER that can be accommodated per solution is determined.

3. **Hosting capacity improvement allocations.** The incremental MW-capacity value is then used as a basis for determining the extent to which additional upgrades are needed on the corresponding feeders in each group. This approach allows consideration for other feeders in the group that may require similar mitigation solutions, but the extent to which the mitigation is needed is established for each feeder using the incremental MW-capacity value determined in Step 2. This metric can be used either to approximate the level of improvement needed for the remaining feeders to reach a certain hosting capacity or to determine the upgrade required to reach the next limiting hosting capacity constraint. In some cases, multiple mitigation measures may be necessary, depending on the issues that arise. For example, a feeder may be susceptible to both voltage and protection issues—both of which would need to be remedied.

As the process is repeated and more experience is gained, rules of thumb regarding incremental MW-capacity per mitigation solution will mature and can be used in place of detailed simulations.

The amount of DER that can be accommodated at this point is then aggregated to the substation level for input to the bulk power system analysis. In some cases, high levels of DER could potentially alleviate local transmission constraints. However, the opposite may be the case (that is, there is an upper limit on the DER that the substation can accommodate), in which case the limit is passed back down to the local substation/feeder level. Feeder hosting capacities and associated mitigation solutions are then adjusted (scaled) to account for any local transmission constraints.

Output

The output of the hosting capacity screening methodology provides an estimate of the hosting capacity for each issue on each feeder. The most limiting hosting capacity of each feeder provides the total potential DER penetration levels with the current system conditions. Results from the feeder level are then aggregated at the substation level to provide hosting capacity limits for the bulk power system analysis. The mitigation options to increase hosting capacity are output from this task and used in the economic evaluation.

The locational impacts of DER (see Figure 5-4) are also provided through the hosting capacity screening method. This output consists of location-based information regarding optimal and non-optimal DER deployments that can reduce the need for infrastructure changes and/or upgrades. DER can be accommodated on some locations with no issues arising—the circuits coded as *No Issues* (green) in Figure 5-4. Other circuits are more vulnerable, and DER penetration may be problematic—the circuits classified as *Possible Issues* (yellow) in Figure 5-4 (generally those farther from the substation). Some circuits are designated as *Probable Issues* (red in Figure 5-4) and require some form of mitigation.

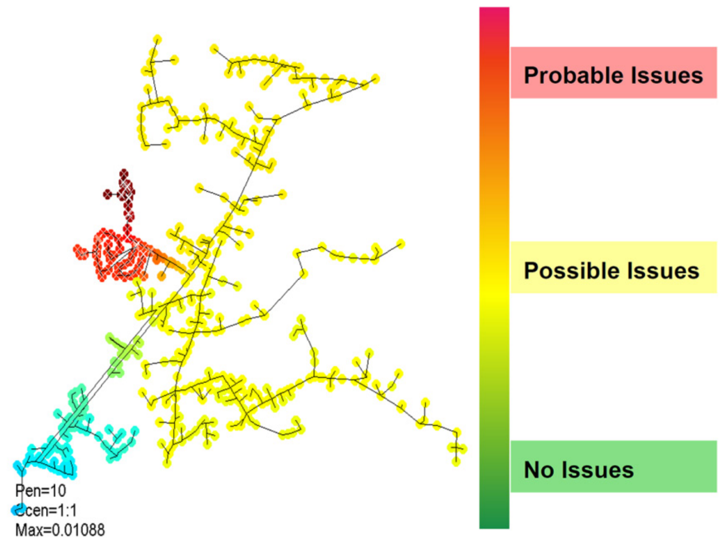

Figure 5-4
Distribution feeder heat map illustrating location-based impacts of DER

The hosting capacity analysis also provides input to other distribution analyses steps by providing feeder-specific hosting capacity values to both the energy and capacity analyses.

Advantages and Disadvantages of the Method

The primary benefit of the hosting capacity analysis methodology is that it considers the utility's entire distribution system on a feeder-by-feeder basis. Hosting capacity values and the associated mitigation options are determined at the feeder level. System-wide assessments at the substation level can then be made by aggregating the responses from each feeder. To make the methodology applicable to the entire system, however, a complete set of models of the distribution system feeders must be available for the approach to be applied and executed. Although the most critical feeder characteristics and issues are considered, research may identify other factors that must be accounted for. These variables as well as additional hosting capacity issues will be addressed as the methodology matures.

ENERGY ANALYSIS

Purpose

The objective of the energy analysis is to quantify the DER impact on distribution losses and energy consumption.

Input

The following information is needed for the energy analysis to be carried out:

- Basic power flow model of each feeder in the utility service territory
- Detailed power flow model of select feeders
- 8760 load measurement data on select feeders (typically at the feeder head only)
- 8760 DER output profile
- DER hosting capacity values for each feeder

Process

The overall loss methodology can be described in five main steps:

1. **Characterize distribution feeder voltage and loss performance.** The first step in this process is to characterize all distribution feeders by performing a power flow simulation to capture the following:
   - **Peak line losses.** Because most distribution feeder models are developed for peak load conditions, the peak line losses can be extracted from the model. Although peak load losses are not indicative of annual energy losses, they can be used as input to characterize distribution feeders for grouping purposes.
   - **Voltage profile information.** Voltage characteristics such as maximum voltage drop across the feeder, voltage headroom (up and down), and average voltage can be used to characterize each distribution feeder individually.

   These simulation results are available in all commercially available distribution analysis platforms.
2. **Determine loss factors for each feeder.** Once the distribution feeders have been characterized based on performance, loss factors can be calculated for each feeder that take into account loss density and loss per unit length.
3. **Perform feeder grouping and subset selection.** Grouping of feeders based on loss factors, static topological data, and voltage performance is next performed. Unlike other methods for grouping, this approach includes feeder performance as modeled, which reveals associations that are subsequently used to create the grouping. A subset of feeders that represents each group is then identified.
4. **Perform a detailed loss analysis.** Next, a detailed loss analysis is performed on one feeder from each subset. This analysis includes 8760 simulations (annual analysis at hourly resolution) that capture the annual energy and peak demand performance of the distribution feeders under varying DER penetration levels and deployment scenarios. From this analysis, loss bands at varying penetration levels for one year for each subset representative feeder are determined (see Figure 5-5). Because most distribution feeder models do not contain secondary lines and service transformers, these data need to be added to the select feeders for the detailed analysis.

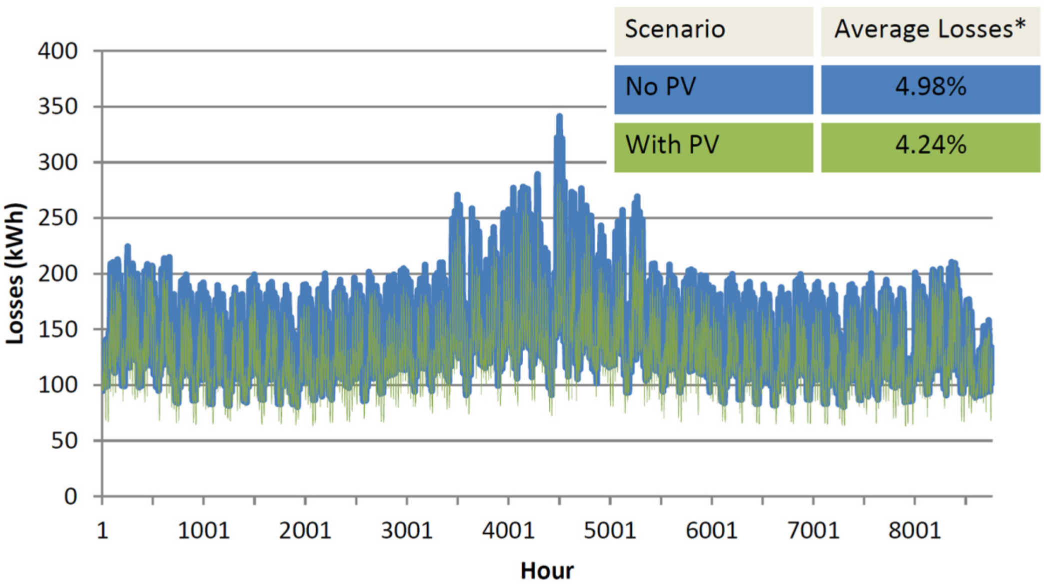

Figure 5-5
Example feeder loss reduction with DER

5. **Extrapolate loss bands.** Using the results from the detailed analysis, loss band changes can be extrapolated to the remaining feeders in each group. Feeder hosting capacity information along with loss band information can be used to estimate loss impacts on each feeder.

Output

The results of this analysis provide input to both the bulk power system and benefit-cost analyses, including 1) detailed loss results at increasing penetration levels for select feeders and 2) estimated losses at hosting capacity limits for all feeders across the utility.

Advantages and Disadvantages of the Method

Although topological data can be used to group feeders, feeder performance characteristics should also be considered to better group the feeders and apply detailed results from select feeders to the broader system. However, most distribution system models do not take into account the effects of distribution service transformers and secondary circuits. Therefore, the detailed analysis results need to be used to approximate secondary/service losses on the remainder of the system.

Although this approach specifically applies to system losses, the same approach can be applied to the analysis of energy consumption.

THERMAL CAPACITY ANALYSIS

Purpose

DER can have a marked effect on power flows and therefore system capacity, determined by the amount of DER interconnected. This analysis quantifies the influence of varying DER real and reactive power flows and portfolios (of location and penetration combinations) on distribution system capacity with regard to asset thermal ratings and the potential deferral of capacity upgrades. The details regarding how this analysis would be performed are not covered in this report—they are specific to the each utility's existing planning methods and vary from utility to utility. However, a general procedure is provided. This is an area that merits research to devise a more universal methodology.

Input

The analysis requires the following:

- Characteristic load class profiles (for example, residential and commercial) for each feeder and/or historical substation loading measurements
- System-specific load growth measurements (feeder level, if available)
- Thermal characteristics of feeder/substation assets for evaluation
- System asset fleet statistics (such as transformer ratings and current load levels)

Process

The assessment methodology develops daily and yearly asset loading profiles representing projected load conditions combined with varying DER portfolios. The profiles are then used to quantify the impacts to asset thermal ratings while accounting for different combinations of asset thermal characteristics, load mix, and projected load growth. Figure 5-6 illustrates the results for a PV study, indicating that feeder load was reduced between the hours of 800 and 2100. The extent to which this translates into distribution capacity avoidance depends on the coincidence of the reduction and the feeder load.

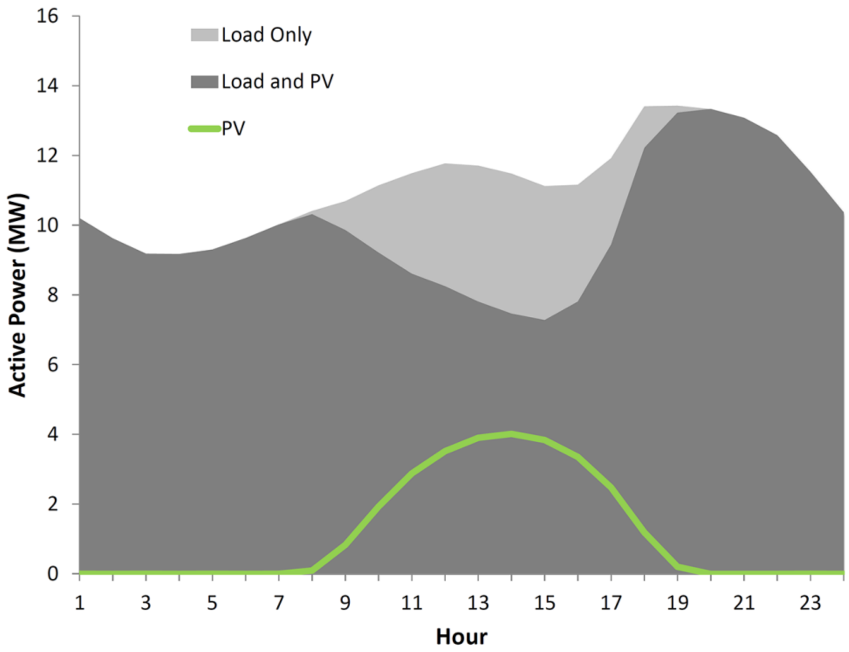

Figure 5-6
Illustration of contribution of distributed PV to reducing feeder net load

Finally, the quantified thermal ratings impacts are used to project the potential capacity upgrade deferrals across system assets.

Output

Findings from the assessment are provided to the benefit-cost analysis in terms of the relationships among various DER operations and asset ratings as well as quantification of the upgrade deferrals.

Advantages and Disadvantages of the Method

The evaluation considers the temporal and spatial influence on thermal ratings and potential asset deferral benefits. Ramifications to distribution system reliability are not quantified but can be addressed qualitatively.

6 SUPPORTING GRID-CONNECTED DER: TECHNOLOGY OPTIONS AT THE DISTRIBUTION LEVEL

DER at some level of penetration require modifications to the distribution infrastructures, changes in operating practices, or both to maintain local service reliability and quality for all customers served by the feeder. As discussed in Section 5, that level (the hosting capacity) depends on several factors as does the type of mitigation required. Once the issues to address are identified, the next step in the Integrated Grid framework is to determine which mitigation strategy to employ.

Several technology options are available to accommodate DER at almost any level of penetration. They are listed in Table 6-1 and range from relatively straightforward and low-cost actions such as upgrades to distribution equipment to costly measures such as reconductoring. Another recourse for the mitigation of some issues is to reconfigure the DER so that they become a part of the distribution system, at least to the extent that some of their operation can be managed by the system operator through the inverter (the device that converts DER DC output to AC compatible with the electric system).

Table 6-1
Technology options for supporting grid-connected DER

Line/transformer upgrade (line reconductoring)
Voltage upgrade
Voltage regulation
Smart inverters
Protection system upgrade
Dispatchable resources
Communication and control

LINE RECONDUCTORING

One of the most common issues arising from the integration of DER into distribution is an adverse impact on primary voltage, manifested as either overvoltage or unacceptable voltage fluctuations. This is more prevalent at higher DER penetrations; however, as demonstrated in Section 5, the hosting capacity of some circuits is low compared to the load served and the number of premises that could adopt and interconnect DER.

The extent to which DER increase voltage depends on the capacity of the system relative to the DER as well as the X/R ratio of the grid. Reconductoring of a distribution system is one way to increase the short-circuit strength and increase X/R. Larger conductors have lower resistance and slightly lower reactance. If the voltage fluctuation is caused by changes in active power, replacing the conductors (the distribution lines) will help—but if the voltage fluctuations are the result of reactive power changes, it will not. Reconductoring is a substantial undertaking in time and cost, which reaffirms the need for an in-depth hosting capacity study on a circuit to identify issues before committing to this action.

TRANSFORMER UPGRADE

Voltage rise at the secondary level can occur during lightly loaded conditions as the result of interconnecting DER. This can result in voltage at some premises above the accepted level and interfere with CVR equipment installed to lower voltage across the circuit, reducing electricity demand.

Replacement

One solution for mitigating a customer-induced secondary overvoltage is to replace the service transformer with a larger one, increasing grid capacity at the customer level. This is effective, but it comes at a relatively high cost if no upgrade were otherwise anticipated for the circuit.

No-Load-Tap Adjustment

Some service transformers have no-load-tap adjustment settings. Changing the tap to a lower setting could mitigate overvoltage. However, care would need to be taken to ensure that lower settings do not result in unacceptable undervoltage, especially if DER are being installed on the circuit at a rapid pace.

VOLTAGE UPGRADE

Increasing system voltage increases the capacity of the grid. System capacity is determined based on the square of the voltage (V) over the system equivalent impedance (Z): Capacity = (V^2/Z). If the voltage of the system were increased by a factor of 2, the capacity of the system would increase by a factor of 4 (2^2), resulting in a significantly higher capacity on the system—and increasing the feeder's hosting capacity for DER when voltage is the limiting factor. Upgrading the system voltage requires new assets such as insulators, arresters, switches, and transformers, all of which must be installed—a potentially expensive undertaking.

VOLTAGE REGULATION

Several technologies are available that can help regulate voltage on a distribution feeder with DER, including traditional, mechanically switched regulation equipment (line regulators) as well as advanced, static-controlled regulation (such as DSTATCOM) to increase hosting capacity. In some instances, this may be the least-cost mitigation strategy.

Mechanically Switched Regulation

On voltage-constrained feeders where the distribution system is serving customers on long, rural lines, utilities often deploy line regulators along the feeder to maintain voltage with the specified tolerance. These devices follow the load variations throughout the day and operate anywhere from just a few times up to 30–40 times per day with a response time of 45–90 seconds. Although not intended to regulate voltage changes resulting from DER, most of these regulator banks have a "cogeneration" model that allows for regulating voltage when power flows in both directions. This can be a relatively inexpensive approach to regulating adverse voltage conditions caused by DER. However, highly variable DER such as wind and PV can result in daily operations at a much higher rate that decreases the life expectancy of the regulation device, resulting in increased capital expenditure/operations and maintenance (O&M) costs to the utility.

Static VAR Control

More advanced technologies are available for regulating voltage along the feeder. For example, inverter-based reactive power control allows the utility to regulate potential adverse voltage changes that can be caused by load or DER. These technologies have been used to mitigate voltage flicker issues caused by rapidly varying loads such as chippers, arc furnaces, and car crushers.

Because this technology is inverter-based, it can regulate voltage much more quickly than mechanically based regulation. In addition, it is not subject to the same wear and tear as found in regulators. On the other hand, the up-front cost for such equipment may be higher.

SMART INVERTERS

Reactive Power Control

One approach to mitigating many of the voltage issues caused by DER is to allow the DER to provide power factor, or reactive power (VAR) control. Nearly all large three-phase DER interconnecting to the grid have power factor control capability. Vendors of smaller single-phase units are developing such capability. In addition, the IEEE 1547 Working Group has recently voted to allow DER to provide reactive power control if the local utility allows for it.[39] The inclusion of such technologies may require additional reactive power sources such as substation capacitors.

Active Power Control

When high DER output and low load cause feeder voltage to rise too high, reducing the active power output of the DER may reduce overvoltage. In some cases, where a large number of customers served by the same distribution transformer have DER, local service voltage may exceed limits—at least sometimes. This can result in DER systems not "turning on" (generating power) because of the overvoltage situation. Therefore, reducing the active power output of DER systems through localized voltage conditions may allow more of the PV to "share" the voltage headroom on the distribution transformer. One example of such control is Volt-Watt control, which provides a flexible mechanism through which a general Volt-Watt curve could be configured.

[39] "Coordination with and approval of, the area EPS and DR operators, shall be required for the DR to actively participate to regulate the voltage by changes of real and reactive power." Excerpt from IEEE P1547a/D2, *Draft Standard for Interconnecting Distributed Resources with Electric Power Systems*, Amendment 1, June 2013.

PROTECTION SYSTEMS

When interconnected with an electric utility system, DER become a functioning part of the system. Successful integration requires effective coordination of DER with the system protection design. DER on the electric power system can interfere with the desired operation of overcurrent-protective devices that constitute the feeder's protection system. Impacts that arise from the integration of DER include the following:

- Nuisance fuse blowing, particularly those related to fuse-saving schemes adversely affected by the added current supplied by the DER
- False tripping operations by upstream breakers, reclosers, sectionalizers, or fuses as a result of downstream DER generation
- Failure of sectionalizers to operate when they should because the DER keep a line energized
- Desensitization of breakers and reclosers as a result of unplanned DER currents
- Increased operating duty on existing breakers that shortens equipment life

The largest impact that DER have had on existing protection practices is on the coordination of feeder relaying. Most utilities have implemented changes or limitations on their existing substation manual switching procedures as a result of DER.[40] Some of these changes are safety-related, resulting from concern over the presence of active (but not anticipated by workers) generation on the feeder. This can create a voltage hazard after the circuit is opened, resulting in unsafe working conditions.

These conditions inhibit the utility's ability to maintain a safe and reliable system. Therefore, modification of existing protection equipment and practices and/or additional equipment is necessary. Options include the following:

- Additional relaying
- Adaptive relaying
- Communication
- Modifications to existing protection settings
- Advanced relaying schemes
- Breaker replacement

[40] *EPRI Survey on Distribution Protection: Emphasis on Distributed Generation Integration Practices*. EPRI, Palo Alto, CA: 2013. 3002001277.

DISPATCHABLE DER: ENERGY STORAGE AND DEMAND RESPONSE

Dispatchable DER, such as energy storage and demand response, can be used for a variety of value-enhancing purposes on distribution systems. Storage can be used to provide backup power to individual premises or to a collection of co-located premises. It can also be used to store the output of intermittent resources such as PV for local economic purposes (to minimize grid-supplied power) or operated specifically to supply services to the bulk power system. Demand response includes customers acting in their best interest by responding to dynamic usage prices and call options of customer loads that are dispatched specifically to support system reliability. Neither is a generation resource, but they can be managed in a way that supplements generation and delivery resources by adjusting electricity demand so that it better aligns with the cost of supplying reliable power.

Capacity

Dispatchable resources can increase distribution system capacity by supplying power during peak demand periods. Figure 6-4 shows a simulation designed to determine the feasibility of using distributed battery storage to shave the peak feeder demand load each day using energy stored during off-peak hours. It illustrates the importance of forecasting the time of the daily peak when the storage resource is limited.

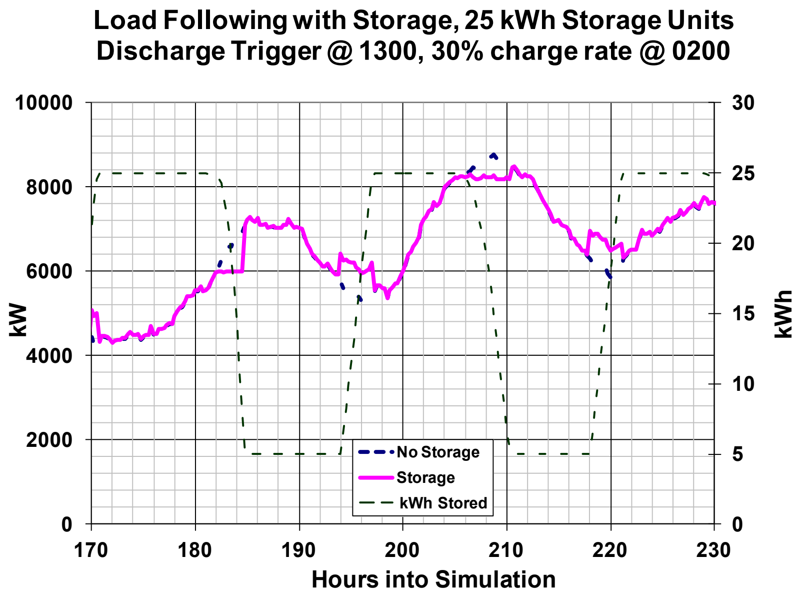

Figure 6-4
Using storage for daily peak shaving

Design of the storage element capacity along with specification of the energy storage dispatch control objectives and settings is extremely important. If the storage is triggered "on" too quickly, it can be depleted prior to the peak—and the full benefit from shaving the peak or having acquired stored energy at a substantially lower cost cannot be realized. This outcome occurs on the first of the two days shown in Figure 6-4. Storage is dispatched around Hour 195 to counteract the growing peak load and starts to recharge at about Hour 210, to be available the next day to serve the same purpose.

Variable/Renewable DER Integration

Another application for dispatchable resources is to improve the integration of other DER. Dispatchable resources do so by addressing directly some of the temporal uncertainties of renewable DER and by mitigating adverse impacts. For example, energy storage can be used to store energy generated by renewable resources at times when loads are relatively low and supply it to the system during peak demand periods. In this fashion, storage can be used to solve the lack of coincidence between the time of peak solar generation output and that of peak load on residential feeders.

Separately, dispatchable resources can be paired with renewable generation to mitigate inherent fluctuations in renewable generation output. In certain cases, these fluctuations may result in voltage concerns and increased operation of voltage regulation devices. Time-sequential simulations are generally required to fully capture the system response to the proposed storage and control functionality. Renewable generation with and without the storage is illustrated in Figure 6-5, which shows a storage control algorithm. In this case, the energy storage is dispatched based on anticipating when loads will peak to maximize the value of the stored energy.

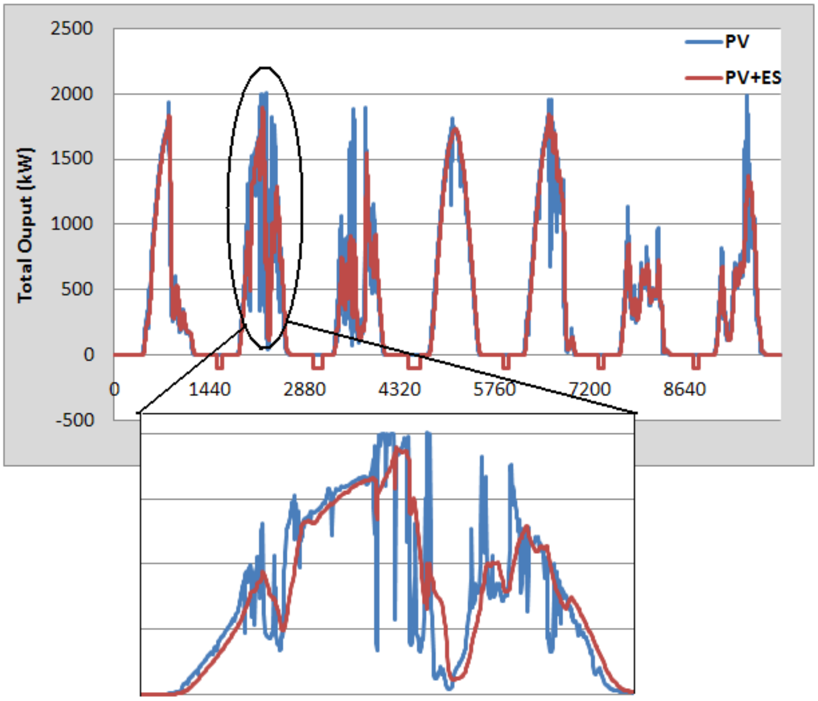

Figure 6-5
Smoothing variation in DER generation

COMMUNICATION AND CONTROL

Communication and control infrastructure is a critical component of coordinating the technology required to successfully integrate DER into the grid. Many of the challenges surrounding the integration of DER pertain to the following:

- Lack of monitoring capability
- Lack of knowledge about how to coordinate with existing automation and controls
- Lack of manageability
- Lack of adherence to open standards

Monitoring and management capability between the DER and the distribution system operator can alleviate many of these issues. Awareness of DER operation at any given time would assist in performing load transfers to avoid problems. If coordinated with existing utility voltage regulation, DER issues involving voltage problems can be remedied—or at least somewhat abated. Moreover, if DER can provide needed services when called upon, they could also provide beneficial support to the grid.

To fully realize these advantages, the following components must be in place:

- DER with communication and control capability so that the system operator can monitor their output and, if allowed, manage them to the system's best interests
- Distribution grid communication infrastructure, for example, suitable field area networks, distributed energy resources management systems (DERMS), and distribution management system to provide supervisory control of all aspects of the system's operation and integrate DER effectively
- Common functions and communication protocols for DER so that the system can be used anywhere
- Common services and protocols for DER enterprise integration so that planners and operators deal with a homogeneous set of interconnections
- Planning and operational tools that account for DER grid support capability to take advantage of services that DER can offer to the distribution and bulk power systems

7 CHARACTERIZING THE IMPACTS OF DER ON THE BULK POWER SYSTEM

The bulk power system provides supply and delivery of electricity to meet demand as well as sufficient capacity and ancillary services to ensure reliability. Section 4 discusses the general characteristics of DER and the beneficial and adverse impacts they may have on the bulk power system. This section extends that discussion by describing an analysis framework through which the effects of DER can be comprehensively assessed. The results of the analysis, combined with those from the distribution analysis described in Section 5, produce the impacts and costs needed to conduct a benefit-cost assessment, as described in Section 9.

This section describes five core methods, with modifications and extensions to account for the nature of DER, that constitute how the Integrated Grid framework considers bulk power system planning and operations:

- **Resource adequacy.** This planning process ensures that sufficient generating capacity is available to meet demand.
- **Flexibility assessment.** This operational process ensures sufficient balancing capability.
- **Operational scheduling and balancing.** This operational process ensures successful balancing of supply and demand.

- **Transmission system performance and deliverability.** This planning process ensures stable, high-quality power supply delivery.
- **Transmission expansion and deliverability.** This operational process ensures sufficient network capacity.

Planning refers to looking forward in time to determine how to adjust the stock of system assets to meet forecasted demand. The five core bulk power system planning and operational processes are not independent; rather, they are interrelated and interdependent. The decisions made in one process can significantly impact the outcome of other processes. The bulk power system analysis framework takes these interactions into account when identifying and quantifying the benefits and impacts of DER integration.

The bulk power system must also be seamlessly and constantly interacting with the distribution networks connected to it, as described at a high level in Section 4, because DER's impacts are manifested first at the distribution circuit to which they are connected. Comprehensive understanding of the effects of accommodating a new technology, such as DER, requires iterative evaluation and reevaluation of the system's behavior in each of the aforementioned core processes as well as the interaction between the integrated bulk and distribution systems.

Figure 7-1 shows EPRI's five core processes and the interactions among them. An important aspect of this framework is that the impacts are relative. They are determined by comparing the results of an assumed level of DER penetration on individual distribution circuits relative to how the system would have been built and operated in the absence of the DER—for example, a DER build-out or adoption scenario compared against one "business as usual."

As discussed next, such an analysis requires the development of a fully configured base case for the way in which the generation and transmission system is configured today and how it is expected to evolve absent DER. Doing so provides a comprehensive portrayal of the impacts attributable to DER.

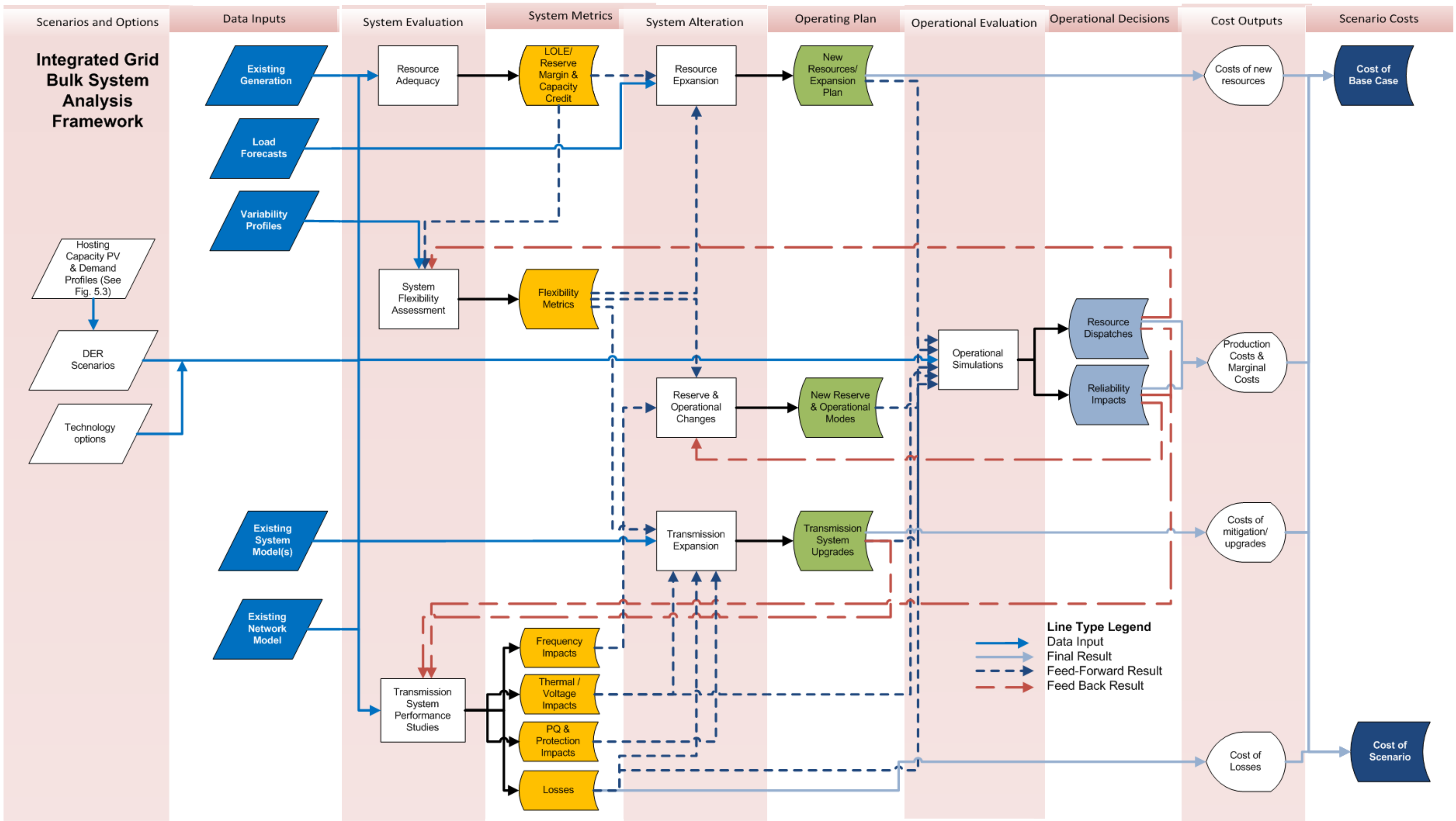

Figure 7-1
Integrated Grid bulk power system analysis framework

Implementing the framework starts on the left-hand side of Figure 7-1 with identifying input data requirements—some of which are outputs from the distribution system analysis—and defining the scenario(s) to be studied. The bulk power system analysis proceeds to the right in the figure through a series of steps in which costs and impacts are evaluated. The extent to which the full framework can be applied depends on both the availability and the quality of the data available. Most of the data required is available to some degree from existing planning and operational processes at both the transmission and distribution system levels. However, measuring DER impacts in the bulk power system challenges the tools available, as discussed next.

The bulk power system framework includes assessments of the transmission network as well as central generation and system operation. A full study will include long-term reliability evaluation, system alteration, operational evaluation, and cost calculation stages (the colored columns 3, 5, 7, and 9 in Figure 7-2). The stages mirror the sequence in which power system planning is carried out—starting with the examination of long-term investment needs and finishing with the evaluation of operating procedures. A complete analysis requires conducting all five stages but not necessarily sequentially. Findings of any stage of the analysis might require returning to and repeating a previous stage.

Information required as an input into one of the processes may be the outcome of another bulk power system process that is fed backward or forward. These flows are depicted in the framework diagram (Figure 7-1) as dashed red (back flows) and blue (forward flows) lines, respectively. Iteration between analyses of the bulk power system and distribution system analyses may be necessary because a bulk power system finding may define a limit to how many DER can be accommodated at the system level or motivate exploration of how to better use DER to improve overall system performance. This is consistent with the Integrated Grid framework philosophy: identifying the key areas of interaction between DER and the bulk power system to provide direction for the development of what will become detailed modeling and analysis procedures.

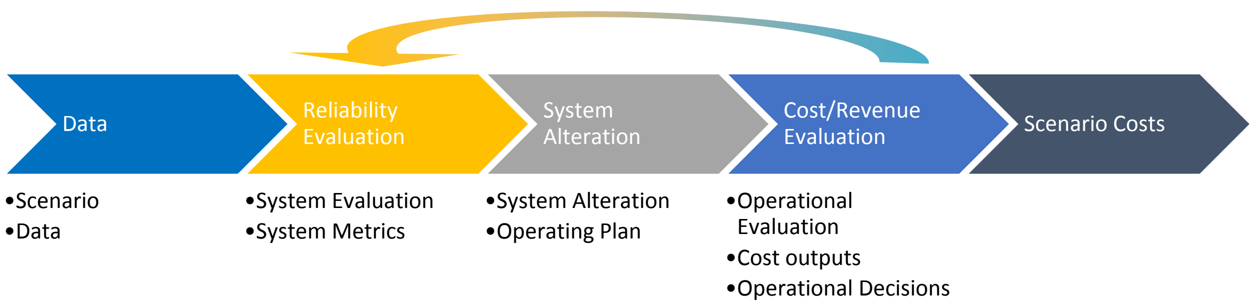

Figure 7-2
High-level framework flow for each scenario

The outcome of each analysis process is either a cost or a technical impact. For example, the outcome from operational simulation is production cost changes and the generator dispatches that caused them as well as outage profiles (technical outputs) that serve as a check against sufficiency. Both of these outputs are useful: cost outputs are accumulated and passed to the benefit-cost framework; technical outputs are performance measures or requirements that are inputs into other core processes. The next subsection explores each of these core processes in detail and discusses their relevance to the Integrated Grid bulk power system analysis framework.

The remainder of this section provides detailed information on bulk power system analysis processes, looking at the inputs, outputs, processes, and DER impacts along with study guidelines for resource adequacy, flexibility assessment, operational simulations and practices, and transmission system performance and expansion. Most of the practices discussed are used today by system planners. EPRI proposes that where DER are involved, such studies must be directly tied to distribution studies that characterize how local load is affected before the bulk power system impacts are studied. Planning processes that were once independent must now be integrated.

CORE BULK POWER SYSTEM ANALYSIS PROCESSES

Resource Adequacy Process

Purpose

The resource adequacy analysis is the starting point for an integrated assessment. It includes two main functions carried out by TSOs, reliability coordinators, utilities, and investors:

- Supply adequacy: an assessment of system reliability to ensure that sufficient supply will be available to meet forecasted demand over the study period
- Resource expansion planning: to determine what new resources are required to meet the adequacy criterion

These two functions are grouped together (as shown Figure 3-1) describing the framework because there is strong interaction between the two.

The purpose of the supply adequacy assessment is to determine whether the electric system (a utility, market, or region) will have sufficient generating capacity available to meet forecasted demand at the established level of system reliability. In the United States, there is no national standard in terms of the level of reliability; many jurisdictions use the traditional “1 day in 10 years” loss of load expectation (LOLE) criterion. However, this criterion varies internationally, and DER studies must be adjusted accordingly.

The outcomes from supply adequacy assessments indicate when additional generation capacity is required. If additional capacity is needed, a resource expansion analysis is conducted to determine which generation or other resource to add to a system to ensure that the resource adequacy reliability standards are met.

Inputs

The data required to conduct a supply adequacy assessment include the following:

- Forecasts for demand over the planning horizon, including system peak demand and demand shape. Some methods use chronological load information (for example, hourly 8760 time series) while others use load duration curve information. The level of resolution must be specified in the definition of the study scenario.
- Detailed generator characteristic data for units expected to be available for operation in the planning horizon, including forced outage rates, planned maintenance requirements, minimum and maximum generating levels and run times, and production cost data such as heat and ramp rates. These data can come from the scenario definition and are outputs of the distribution hosting capacity and energy analysis.
- Network representation to provide at least a high-level understanding of the deliverability of supply between and within load zones. This information must be specified in the definition of the study scenario and may be modified by the transmission expansion process.

Long-term demand forecasts use a wide range of underlying information, including macroeconomic modeling, historical demand data, and historical and long-range forecasted weather data. Several demand forecast scenarios may need to be analyzed, including some extreme events—for example, a hot summer, a cold winter, high demand growth, and the extent and nature of demand reduction. More sophisticated methods use decades of historical weather information to portray extremes in temperature across seasons of the year, providing a comprehensive representation of potential load scenarios when combined with the other factors. Historical weather information is also used in determining the expected output levels of hydro generation and other variable generation, for example, wind and solar generation and demand response.

Probabilistic methods that capture the wide variety of possible scenarios with the associated uncertainty are becoming more prominent as a way to quantify supply adequacy.

Recent EPRI research has also shown that for regions with high levels of variable generation, estimates of the operational (day-ahead or hour-ahead) forecasts at hourly time resolution or higher may also be required and individually established for each technology type.[41] Generally,

[41] *Power System Flexibility Metrics: Framework, Software Tool, and Case Study for Considering Power System Flexibility in Planning*. EPRI, Palo Alto, CA: 2013. 3002000331.

data that better characterize the availability and production of supply resources over time will be needed, including data on demand response, temperature-dependent impacts on conventional generator equivalent forced outage rate (EFOR) values, and impacts of gas deliverability constraints during cold periods.

Resource expansion uses the same inputs as the resource adequacy analysis along with additional information on the operational parameters of each existing resource and capital and operating costs.

Process

Resource supply adequacy measures the availability and ability of the system's resources (existing or added) to meet the expected demand. There are a variety of processes to actually determine resource adequacy, ranging from relatively simplistic reserve margin calculations based on the sum of derated resource capacities relative to forecast peak load, to rigorous probabilistic assessments that use detailed, historical, and chronological load data along with generation and network availability data to provide composite generation/transmission adequacy assessments. An integrated grid approach to resource adequacy employs methods that represent all resource technologies likely to be subject to assessment to the degree of detail required.

Methods such as the probabilistic LOLE method adopted by the IEEE Task Force on Capacity Value[42] are necessary because they assess the contribution of each resource to reducing the risk of insufficient generating capacity over a planning period, rather than their contribution at a single point in time—such as system peak, which may represent only a fraction of the overall risk. The LOLE and energy not served (ENS) metrics compare the distribution of available generating capacity (based on the EFOR for each generation type) to the distribution of the net load (that is, load remaining after variable generation for a range of scenarios) to determine the likelihood and extent of insufficient supply. Probabilistic methods such as LOLE also more appropriately value the capacity contribution of variable resources relative to simple considerations such as the output during the peak hour or over a subset of hours deemed to be of high risk.

More advanced techniques are required to assess the resource adequacy of the system when considering the restrictions associated with energy-limited resources such as energy storage and demand response.[43] Because the capacity contribution of energy-limited resources depends on the energy reservoir available when the capacity is needed, resource adequacy calculations

[42] Keane, A., Milligan, M., Dent, C. J., Hasche, B., D'Annunzio, C., Dragoon, K., Holttinen, H., Samaan, N., Soder, L., and O'Malley, M., "Capacity Value of Wind Power," *Power Systems, IEEE Transactions on*. Vol. 26, No. 2, pp. 564–572, May 2011.

[43] Madaeni, S. H., Sioshansi, R., and Denholm, P., "Estimating the Capacity Value of Concentrating Solar Power Plants: A Case Study of the Southwestern United States," *Power Systems, IEEE Transactions on*. Vol. 27, No. 2, pp. 1116–1124, May 2012.

should model this behavior to reflect this state-specific aspect of availability. The assumptions that govern the operation of energy-limited resources from the scenario definition should be reflected as part of this process.

If the system is shown to be short of capacity or flexibility (discussed next), a resource expansion assessment is required. A resource expansion assessment may also be conducted to evaluate potential resource development scenarios or to reduce overall costs. The resource expansion assessment process is focused on the optimization (cost minimization) of the resource additions required to meet stated reliability criteria. The actual process of determining the optimal set of new resources to add to a system can vary significantly from system to system and range from simplistic screening curve approaches to advanced simulation.[44, 45] Another consideration is how the market is organized and operated: as a vertically integrated utility, as an ISO/RTO market, or as another arrangement between power generation and retail delivery.

Some resource adequacy tools provide both adequacy and expansion capabilities, but the representation of resources and the network is generally less detailed in the expansion planning analysis than in operational simulation. A separate expansion analysis considers a predefined set of technology options (for example, conventional generators, variable generation, and demand response) for which operational characteristics data are specified.

It is important that the expansion planning process include a representation of resources in external systems and the transmission capability to deliver resources from one region to the next. Although full security-constrained AC power flow capability is not necessarily required, including inter-area transfer limits between regions within the expansion model allows the expansion planning process to properly leverage economic resources in regions with excess supply or to determine where new resources are needed.

Outputs

The resource adequacy assessment is typically the first analysis conducted as part of an integrated assessment of bulk power system impacts. The resource expansion process can also be triggered by a change in the available generation, demand, or variable generation profiles or by a change in the transmission infrastructure or operating practices. A re-computation would be necessary, for example, when generation is added or subtracted from the system as a result of the subsequent analysis step to ensure flexibility adequacy or transmission operational performance.

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[44] Stoft, S., Power System Economics: Designing Markets for Electricity. Wiley, 2002.

[45] *PRISM 2.0: Regional Energy and Economic Model Development and Initial Application, US-REGEN Model Documentation.* EPRI, Palo Alto, CA: 2013. 3002000128.

Whether an initial adequacy assessment or subsequent iterations, the outputs of the supply adequacy assessment include the following:

- Reliability metrics such as LOLE, ENS, planning reserve margin (percent of peak load), or other indices
- Capacity value associated with each generating resource, often calculated using methods such as the effective load-carrying capability technique

These outputs become inputs into the subsequent resource expansion assessment process, which determines the nature (technology type, size, and operating configuration) of the required new capacity. The output of the resource adequacy process is a set of generation resources that will be used in the sequential core analysis processes. The costs associated with making a change to the generation portfolio will feed into the benefit-cost assessment.

DER Impacts

As noted in Section 4, DER impact the resource adequacy process in multiple, and in some respects non-intuitive, ways. Generally, all other things held constant, adding any new supply resource to the system increases resource adequacy. The extent to which the new resource increases adequacy depends on the availability of the added resource during high-risk hours when supply-demand margins are tight. The impact of DER on resource adequacy calculations depends on the DER technology type: all are, to some degree, intermittent in output, and that output is subject to considerable variation. This distinguishes them from conventional, central station generation resources in terms of availability.

The availability of the DER must be determined based on their availability as defined at the distribution feeder where the resource is connected. This includes the outage rate of that feeder and the DER resource's own availability. If the DER resource is solar or wind generation, the resource adequacy calculation should include the stochastic nature of each resource's availability, which can vary widely among DER. The same is true for energy-limited DER devices, such as storage and most demand response. Ensuring that the performance over time, and at any time, is adequately represented is critical to understanding the contributions of DER to resource adequacy and the resulting reduction in other new capacity additions that might otherwise be required.

All other things being equal, adding a new resource—DER or otherwise—improves adequacy. However, many things change when DER are added to the system. DER provide energy and capacity to the system in ways that may impact the economic viability of conventional generation. Some may operate so few hours that they are not economic to maintain, resulting in closure of existing generators. Adding high-energy, low-capacity resources to the system may result in some currently available, conventional resources being used at levels below the threshold for their being economic—but their availability is essential to maintaining system reliability. If this is the case, market arrangements must be made to ensure that these essential resources remain available and perhaps dispatchable in new ways.[46]

Integrated Grid Study Guidelines

The resource adequacy evaluation process involves meeting the following criteria:

- Meets reliability standards across the range of future scenarios, considering uncertainty in weather, demand, and technology using probabilistic methods.
- Minimizes total expected costs over a range of future scenarios, including capital and operational costs.
- Selects from a wide range of technology options, including choosing between conventional and nontraditional generation to reveal the implications for policies that stipulate a required amount of the latter, for example, 33% renewable resource–fueled generation.
- Captures the operational capability limitations of each technology type:
  - Both transmission- and distribution-connected resources are considered.
  - For variable generation, the distribution of available capacity should be based on multiple years of historical data. At least 10 years of historical or simulated variable generation production data is recommended. If transmission networks are included in the model, the location of the DER (on which distribution circuits and to what extent) is important to the analysis.
  - For the capacity contribution of energy-limited resources, the selected method should account for the feasible operational modes under which the resource can be operated. This guidance links to the initial scenario definition and the energy profiles from the DER under evaluation.
- Considers a wide variety of possible future scenarios:
  - Probabilistic/scenario-based approaches are preferred.
  - Captures the stochastic nature of variable generation, which may influence capacity needs.
  - Considers different electricity market structures.
  - Incorporates the variability of demand, fuel supply and cost, and other factors that contribute to market prices and utility revenues.

[46] EPRI is developing methods for recognizing the more complex implications of DER on utility revenue and merchant plant revenues and revenue adequacy.

- Considers the implications on capacity adequacy of early generator retirement or mothballing of units because they are no longer economic but that may be essential or whose replacement cost is substantially higher.

These processes may implicitly include system simulations over a variety of horizons as well as resource adequacy calculations to determine the optimal or most likely future generation mix. Where resource adequacy calculations are embedded in other processes, they should also comply with these recommendations.

Flexibility Assessment Process

Purpose

The purpose of the flexibility assessment is to ensure that the system has sufficient capability to balance the expected aggregate variability (ramping) and uncertainty (forecast error) of demand and variable generation in the study scenario. Power system operational flexibility has increased in importance as a result of rising penetrations of variable wind and solar generation.

The flexibility assessment process determines potential shortages in flexibility over operational time horizons (from minutes to hours), which informs decisions on new transmission or generation resource expansion, requires changes to operational practices, or both. This is distinct from regulation services that are dispatched in very short time intervals (seconds) and affect resource adequacy differently. Flexibility assessment may be conducted along with that of resource adequacy if the resource adequacy tools sufficiently impose operational flexibility requirements.

Inputs

The scope and substance of a system flexibility assessment can vary from simple screening based on installed resources to a detailed assessment of expected resources committed and dispatched over time, taking into account transmission deliverability. The data requirements increase with the complexity of the analysis conducted. The minimum requirements for screening-type assessments include the following:

- Chronological time-series electricity demand and variable generation profiles for the time period being studied. Historical data are needed to estimate future load and variable generation output levels using advanced forecast models. Wind and PV output profiles and short-term forecasts for plants that do not yet exist must be synthesized through advanced numeric weather prediction models.[47] These data originate from the initial scenario definition and are informed by the distribution energy analysis.

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[47] Development of Eastern Regional Wind Resource and Wind Plant Output Datasets, NREL, Golden, CO: 2014. Accessed online: http://www.nrel.gov/electricity/transmission/pdfs/aws_truewind_final_report.pdf.

- Generation and demand resource characteristic data that define the operational flexibility of the resources such as capacity, ramp rates, minimum output levels, minimum uptimes and downtimes, and startup times. This information must also be specified in the scenario definition.

For more detailed assessments, the data requirements include the following:

- The chronological (hourly or even shorter time interval) production output from each generator to model its flexibility. If dispatch information is not available, the generator cost information required to conduct commitment and dispatch modeling simulations to obtain the generator outputs is needed.
- A network (transmission) model to ensure the deliverability of the available flexibility for a given load and power flow scenario.[47] If a network model is used, generator locations along with the demand and production profile of DER at each transmission substation are needed. These data are provided by the distribution energy analysis. Short-term forecasts will also need to be synthesized for each location.

Process

As noted, the process of calculating a system's flexibility adequacy can vary in complexity. Three levels of analysis should be performed:

1. Basic analysis as resource adequacy
2. Mid-level analysis as operational simulation
3. Detailed analysis after generation and transmission expansion and operational simulation are concluded

A reference analysis should be carried out first to provide a basis for comparing the variability of the net load (demand not met by variable generation) to the average or worst-case available flexibility for a given time horizon (for example, 10-minute, 1-hour, or 3-hour ramps). The available flexibility can be based on assumptions about the dispatch capability of the resources based on operator experience or a cost-based ranking. Some utilities and system operators are implementing these types of flexibility assessment techniques in planning studies.[48]

Flexibility can also be studied in greater detail in resource adequacy proceedings.[49] Mid-level flexibility assessment can be carried out after dispatch schedules are established for each resource from the operational simulation core process. Dispatch information is used to determine

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[48] Integrated Resource Plan 2013, Appendix G, Puget Sound Energy, Bellevue, WA: 2013. Accessed online: https://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppG.pdf.

[49] Flexible Resource Adequacy Criteria; Must Offer Obligation, California Independent System Operator, Folsom, CA: 2014. Accessed online: http://www.caiso.com/Documents/BusinessRequirementsSpecification-FlexibleResourceAdequacyCriteriaMustOfferObligationver1_1.pdf.

the flexibility a resource can offer at each point in time after its dispatch positions are considered.[50] For example, a flexible generator dispatched to its maximum capacity 100% of the time cannot provide any upward flexibility, but it may provide downward flexibility—which is equally valuable in some hours of the day. Mid-level flexibility assessment involves post-processing of resource dispatches or can use Monte Carlo–type scheduling and dispatch calculations within the flexibility assessment.

As mentioned, the available flexibility can be determined from the resource dispatch, which is then compared in either a deterministic or probabilistic manner to the net load variability and uncertainty. The broader industry trend of shifting from deterministic to probabilistic approaches is mirrored in flexibility assessment. Periods of flexibility shortage are less predictable than those of capacity shortage. As a result, single-point or deterministic assessments are less suitable than probabilistic methods. EPRI recently released a white paper on the subject of flexibility metrics that provides greater detail on the individual options available. [51]

Detailed flexibility analyses examine the role of the transmission network in delivering the flexibility available from resources to load centers during periods of variability. This analysis should be carried out as a validation step when transmission and generation expansion and operational simulation are complete. Establishing deliverability consists of determining whether the thermal limits of the power system are violated when all resources are re-dispatched to deploy the maximum flexibility. [50, 52, 53] This can be done through power flow analysis or by optimizing the maximum amount of flexibility that can be delivered through an alternative form of the optimal power flow algorithm.

Outputs

The output of the flexibility assessment process is a series of derived flexibility metrics. Whereas there are well-established metrics for traditional resource adequacy, the metrics for flexibility are less well-established.[54] These metrics report the frequency and severity of flexibility shortages over the study time horizon for both upward and downward ramping directions.

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[50] *Power System Flexibility Metrics: Framework, Software Tool, and Case Study for Considering Power System Flexibility in Planning*. EPRI, Palo Alto, CA: 2013. 3002000331.

[51] *Metrics for Quantifying Flexibility in Power System Planning*. EPRI, Palo Alto, CA: 2104. 3002004243.

[52] Chen, Y., Gribik, P., and Garner, J., “Incorporating Post-Zonal Reserve Deployment Transmission Constraints into Energy and Ancillary Service Co-Optimization,” *IEEE Trans. Power Systems*. Vol. 24, No. 2, 537–549, March 2014.

[53] Lannoye, E., Flynn, D., and O’Malley, M., “Transmission, Variable Generation, and Power System Flexibility,” *IEEE Trans. Power Systems* (in press).

[54] *Metrics for Quantifying Flexibility in Power System Planning*. EPRI, Palo Alto, CA: 2104. 3002004243.

The outputs are inputs to both the generation and transmission expansion processes, imposing additional requirements or constraints for new investments in supply and/or delivery resources. In addition, the calculated flexibility metrics may be used to inform evaluations of operational process changes that are assessed in the operational simulation core process. Flexibility assessment can be initiated at multiple points in the framework as data become available (for example, resource dispatches) or because the physical or operational characteristics of the system change (for example, generation profile or reserve requirements).

DER Impacts

The impact of DER on flexibility adequacy depends on the nature of the supply technology. Distributed wind and solar generation will have impacts similar to those of transmission-connected variable generation: increased variability and uncertainty, resulting in more frequent generator cycling[55, 56] and increased reserve requirements.[57] Transmission-connected variable generation production is routinely forecasted in time periods such as day-ahead, but forecasting the production from distributed generation is not yet as widely practiced.

Until the short-term production forecast accuracy of both distribution- and transmission-connected generation is of equal magnitude, considerable uncertainty is associated with DER output—and it may be considerable either generally or at specific times. This in turn will require additional system flexibility to balance the system. Because of the increased diversity of DER, distributed systems may eventually be easier to forecast than central station variable generation.

The coordination of the response of the DER to bulk power system requirements is in accounting for the effect of DER on available flexibility. If DER can be dispatched by a system operator—directly or indirectly, and in a timely manner—they will contribute to the flexibility of the system, subject to the limits of the distribution system. For example, demand response is already used in some regions to provide flexibility-related reserve functions.[58] Distributed energy storage may also be a dispatchable resource, possibly increasing the availability of system flexibility. The way in which DER are modeled depends on the underlying technology and the degree to which they can be dispatched by the system operator.

[55] *Power System Operational and Planning Impacts of Generator Cycling Due to Increased Penetration of Variable Generation*. EPRI, Palo Alto, CA: 2013. 3002000332.

[56] *Impact of Cycling on the Operation and Maintenance Cost of Conventional and Combined-Cycle Power Plants*. EPRI, Palo Alto, CA: 2013. 3002000817.

[57] *Stochastic Optimal Power Flow for Reserve Determination: Enhancement of Dynamic Reserve Procurement*. EPRI, Palo Alto, CA: 2012. 1024348.

[58] *Load Participation in the SCED*, ERCOT, Austin, TX: 2014. Accessed online: http://www.ercot.com/content/services/programs/load/laar/DSWG_Loads_in_SCEDv1_Refresher_042314.pptx.ppt.

Integrated Grid Study Guidelines

Because flexibility assessment is a relatively recent development in system planning, most of the proposed methods are suitable for inclusion in an integrated grid study. Many of these flexibility assessment approaches can be conducted jointly with the resource adequacy process. Regardless of the method employed, the following guidelines should be followed:

- Examine both upward and downward flexibility.
- Examine flexibility needs and adequacy over all operational time horizons that are critical to the system being evaluated (for example, 10 minutes up to 10 hours).
- Include a time-series or probabilistic approach to capture multiple operating conditions.
- Include the appropriate level of detail in flexibility assessment, depending on the information available:
  - Carry out screening-type approaches after the resource adequacy process.
  - Carry out mid-level-type approaches after or at the same time as operational simulation, accounting for the way in which a system and/or market operates its resources.
  - Carry out detailed approaches when full network model and resource dispatches are available.
- Take into account the operational constraints associated with each resource type, for example, energy limits from storage and hydro and the ability to dispatch DER.

Operational Simulations and Practices Process

Purpose

Evaluating DER requires more accurate representation of system operations directly in planning. Certain operational details may not be represented because of data or computational limitations, but improvements to computational and data enterprise systems allow planners to better incorporate the way the system will operate as part of the planning analyses.

The operational simulations and practices core process involves two distinct but intrinsically linked analyses:

- **Operational simulation analysis.** The operational simulations described here involve more detailed production cost simulations at finer time resolutions than those associated with typical scheduling and dispatch functions. Detailed operational simulations can model the system's behavior on a second-by-second time scale, capturing the ability of the automatic generation control (AGC) actions to deploy reserves to balance load and maintain system frequency within limits.

- **Reserve and operational practices.** Production cost simulations are informed by the scheduling practices employed by the utility or planning entity. They include operating reserve products/categories and requirements, timing of scheduling decisions, use of operational forecasts, and other operational decisions. The second analysis in this core process is an analysis and refinement of these practices.

Inputs

Operational simulation ties together all aspects of the system: demand, generation, transmission, and operational practices such as reserve requirements. As such, the data requirement for simulation is intensive, requiring at least the following:

- Individual generator physical and cost characteristics (for example, heat rates, ramp rates, start times, and minimum up/down times) from the scenario definitions and the distribution hosting capacity and energy analysis.
- Chronological time-series load and variable generator output data for all time resolutions and horizons to be studied (for example, hourly resolution for at least one year; 6 seconds for AGC simulations) and associated operational forecasts for the same time period. These originate from the scenario definitions and the distribution hosting capacity and energy analysis.
- Representation of the transmission network (for example, pipe and bubble–type zonal models or DC network models). This comes from the scenario definition and may be altered by the transmission expansion process.
- DER controllability assumptions and operational characteristics from scenario definition.
- Distributed energy storage operational configuration.
- Scheduling operational structure and practices (for example, market utility scheduling structure, reserve requirements, emissions limits, and costs) from the scenario definition.

The simulation may also require information on how one system interacts with neighboring systems through the exchange of power.

Process

The operational practices and simulation analyses can be broken into three subtasks:

1. **Operating reserve determination.** As the generation portfolio changes to include a larger penetration of variable generation (both transmission- and distribution-connected), the risk to the system from demand and generation imbalances is likely affected. Selecting the right types of reserve in the appropriate quantities is an important input into the operational simulation of the given scenario. The types of reserve required depend heavily on how scheduling is carried out: coarse time-resolution dispatch instructions or dispatch decisions undertaken with low-quality, short-term forecasts (for example, hourly dispatch intervals set

more than 36 hours in advance) require a wider variety of reserves to cover variability over different time scales, and vice versa. The quantity of reserve required is typically determined using a variety of statistical techniques.59, 60, 61 These methods sometimes consider demand and variable generation variability and uncertainty and result in reserve requirements sufficiently large to meet a pre-specified risk level.

2. **Scheduling practices evaluation.** Although the timing and time granularity of scheduling decisions (for example, hourly scheduling vs. 15-minute or shorter interval scheduling) can significantly impact the operating reserves required to maintain reliability and the associated cost, they can have other implications for the operation of each resource type.62 As the level of within-day uncertainty in resource output increases, the benefits of shorter scheduling intervals increase. In addition, other scheduling practices are impacted by increased system uncertainty and should be examined as part of operational simulation. These impacts may include benefits from incorporating elements of stochastic commitment and dispatch63, 64 or developing new market formulations65, 66 that capture the capabilities of new resources or provide system services, such as flexibility. An emerging trend in operational practices is to share balancing responsibility across multiple systems or balancing areas.67, 68 Understanding the extent of such changes is important in determining the best practices and least-cost mode of operation.

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[59] Incorporating Wind Generation and Load Forecast Uncertainties into Power Grid Operations, Pacific Northwest National Laboratory, Richland, WA: 2010. Available online: http://www.pnl.gov/main/publications/external/technical_reports/pnnl-19189.pdf.

[60] Western wind and solar integration study, National Renewable Energy Laboratory, Golden, CA: 2012. http://www.nrel.gov/docs/fy13osti/55588.pdf.

[61] Ibanez, E., Krad, I., and Ela, E., A Systematic Comparison of Operating Reserve Methodologies. IEEE Power and Energy Society General Meeting, Washington, D.C., July 2014.

[62] Accommodating High Levels of Variable Generation, NERC, Atlanta, GA: 2010. Accessed online: http://www.nerc.com/files/ivgtf_report_041609.pdf.

[63] Tuohy, A., Meibom, P., Denny, E., and O'Malley, M., "Unit Commitment for Systems with Significant Wind Penetration," *Power Systems, IEEE Transactions on*. Vol. 24, No. 2, pp. 592–601, May 2009.

[64] *Stochastic Optimal Power Flow for Reserve Determination: Enhancement of Dynamic Reserve Procurement*. EPRI, Palo Alto, CA: 2012. 1024348.

[65] Flexible Ramping Constraint Operating Procedure, California Independent System Operator, Folsom, CA: 2014. Accessed online: http://www.caiso.com/Documents/2250.pdf.

[66] Chen, Y., Gribik, P., and Garner, J., "Incorporating Post-Zonal Reserve Deployment Transmission Constraints into Energy and Ancillary Service Co-Optimization," *IEEE Trans. Power Systems*. Vol. 24, No. 2, 537–549, March 2014.

[67] Business Practice Manual for the Energy Imbalance Market, California Independent System Operator, Folsom, CA: 2014. Accessed online: http://www.caiso.com/Documents/BusinessPracticeManual-EnergyImbalanceMarket-Draft.pdf.

[68] Market Network Codes, ENTSO-E, Brussels, Belgium: 2014. Online at: http://networkcodes.entsoe.eu/market-codes/.

3. **Production cost and frequency control simulation.** The production cost simulation of a system can be carried out using several different tools. These simulations are usually conducted at hourly resolution, or finer, over a one-year time horizon—providing the outage, commitment, and dispatch schedules for each of the generation resources. The simulations are typically designed to represent the actual market or utility scheduling processes, which may include multiple interval decisions ranging from long-start commitment runs, day-ahead scheduling, and real-time dispatch. As previously mentioned, new dispatch simulation tools are becoming available that can also take into account recent AGC action and area control error forecast accuracy on a second-by-second resolution, resulting in the longer horizon scheduling decisions.

Outcomes

The operational simulation and practices process provides the following outputs:

- Evaluations of the sufficiency of operating practices and procedures and insights on the benefits of potential changes to the design of the scheduling process, including scheduling times, time resolution, and frequency. DER scenarios may also change the type and quantity of reserves required as well as the process by which the reserve requirement is determined.
- A multitude of outcomes from the operational simulations provide specific insights for certain decisions and are inputs to other processes for other decisions. Cost outcomes such as energy or reserve prices and production costs are aggregated into the total cost for the scenario, which is an input to the benefit-cost analysis.
- Reliability impacts such as incidences of loss of load, insufficient reserve capability, or significant area control error are reported. Resource dispatches are required by several other core processes such as flexibility assessment and transmission system performance analysis and feedback, as appropriate. Cost consequences feed into the benefit-cost analysis.
- Emissions impacts can be determined from the operational simulation, including CO2, SOx, and, to a lesser degree, NOx. Cost and benefit implications are examined in the benefit-cost assessment.

Impact of DER

DER can have a substantial impact on operational activities. Depending on the specific technology and its associated dispatch capabilities and rules (for example, priority dispatch), DER may affect systems differently. Distribution-connected solar and wind generation will result in increased requirements for reserves at certain times of the day while potentially reducing them in others (although overall requirements are likely to increase). Demand response and storage may have a lesser impact and in fact contribute to reducing some of the adverse impacts of other DER.

DER may also offer the capacity for curtailment during specific hours to provide reserve services. The rules concerning DER participation in scheduling and dispatch play an important role in how they are included in the simulations: forecast accuracy and controllability are key features of DER that will determine how they are included in each case.

Integrated Grid Study Guidelines

The operational simulation and practices evaluation conducted as part of an integrated grid analysis should include the following:

- Processes and practices:
  - If no assumption on reserve requirements is included in the scenario definition, operating reserve requirements should be determined for each scenario evaluated; that analysis should accomplish the following within the context of existing system practices:
    - Be set to meet primary and secondary frequency control standards as well as the variability and uncertainty experienced between scheduling cycles (for example, day-ahead to real-time variability and uncertainty).
    - Be updated regularly in response to the forecasted conditions and associated uncertainty.
    - Cover a sufficient range of variability and uncertainty to ensure the reliability of the system.
  - Reserve provision should accommodate the range of providers that can reliably provide the defined services.
  - Additional reserve categories, such as those providing longer term flexibility, should be evaluated to determine if they can reduce system costs.
- Simulations:
  - Both demand and renewable production uncertainty should be included as forecasts with associated uncertainty at each decision stage.
  - Multi-cycle representation of system operations should be used. Each cycle (for example, day-ahead) should interact with the cycles that follow (for example, hour-ahead with real-time, and vice versa).
  - Systems that trade energy with other areas should model those interties with a sufficient level of detail to represent the impact on their own area.
  - Reserve procurement should be optimized with energy scheduling if it is done so in reality; if not, this would be a good scenario to study.

Transmission System Performance Process

Purpose

The purpose of the transmission system performance process is to ensure the reliable operation of the power system in delivering energy under different conditions and to assist in formulating new transmission expansion plans. The transmission system must be operated to maintain system power flows, voltages, and frequency within specified operating limits for any single contingency—or other credible contingencies beyond a single contingency—and to return the system to within operating limits without cascading outages.

This requires that planners conduct power flow analyses for reasonably expected potential operating conditions across known credible contingencies, detailed time-domain stability studies for critical contingencies, and short-circuit and transient studies to ensure proper system protection and adequate power quality. Planners should also conduct protection studies to ensure that the system is sufficiently robust to operate and recover during faults with power system equipment.

Inputs

The data required to conduct the transmission system performance analysis are categorized as follows:

- **Generator data.** Generator real and reactive power ratings, impedances, and time constants; inertia; excitation system parameters; and governor control parameters. These are specified in the scenario definition but may be altered in the resource adequacy (expansion) process—especially if DER become a prominent source of supply.
- **Transmission network data.** Voltage levels, impedances and ratings for lines and transformers, and shunt data. These are specified in the scenario definition but may be altered by the transmission expansion process.
- **Load data.** Real and reactive power levels and composition. These are specified in the scenario definition but may be altered at the substation level by the outcome of the distributed energy analysis (see Section 5).
- **System dispatch and external flows.** The load and generator operating levels and transmission topology must be specified based on the specific dispatch for the scenario being studied. In addition, any scheduled interchange with external areas must also be identified and modeled. These flows are determined in the system operational simulation core process.
- **DER data.** The capacity, location, output profile, and reactive control capability at the bulk power system for DER aggregated to transmission substations. This information comes from the distributed analysis processes.

The quality of the available data impacts the level of detail of the model used to represent any power system equipment. The objective is to produce a model that will provide results with sufficient accuracy to meet the scenario's goals and reach a solution in a reasonable amount of time.

Process

The process is executed in four steps:

1. Collect system data.
2. Develop the power system model.
3. Perform a system analysis.
4. Identify system weaknesses.

Two methods essential to analyzing the performance of a power system under different conditions are steady-state and dynamic simulation analysis. The models required can be categorized based on these two analysis methods. The power flow and dynamic models for traditional equipment (such as conventional generators, transformers and lines, and loads) are relatively well-established, with load models becoming more complex as end-use technologies that manage loads are adopted. Models to represent DER are just beginning to be developed and evaluated. In addition, short-circuit models and time-domain transient models may be required to study how to modify system protection strategies and maintain power quality, including consideration of harmonic levels and unbalance.

The impacts of high levels of DER on transmission system performance are best captured by using an integrated model of the T&D systems. However, this is a complicated process from a data and computational perspective because the distribution system is typically modeled with full three-phase representation along with the typical positive sequence model of the transmission system. Such a model may not presently be possible for large systems. As the capability to carry out these types of assessments becomes available in analysis tools, they should be adopted. In the interim, the best available approach is to use existing modeling tools that separately model transmission and distribution with appropriate protocols for the transfer of results between the tools to capture the effects of one system (that is, transmission or distribution) on the other. For example, aggregated DER are represented as a generator connected through a transformer and using impedance to characterize the distribution substation and feeder in transmission power flow studies. These aggregated models come from the analyses described in Section 5.

For both power flow and dynamic evaluations, an accurate representation of the effects of a new generation technology on transmission system performance can be determined only if the production from both DER and central station resources is appropriately dispatched to balance demand for each analysis.

Application to DER Accommodation Studies

Power flow and contingency simulations should be conducted for credible load and DER output scenarios. In each, aggregated DER can be represented as a constant active power and reactive power generator at each appropriate transmission bus. Based on the requirements of the region, the equivalent generator can be set to operate at unity or at a non-unity power factor to represent the reactive contributions and requirements of the DER and their effect at the substation. If advanced reactive power controls for DER (such as those associated with smart inverter functions for distributed PV) become commonplace, those capabilities should also be modeled and included in the analysis so that the benefits are recognized in the bulk power system analysis.

Using a power flow model, AC load-flow analysis tools should be employed to examine bus voltages, thermal loadings on transmission lines and transformers, power plants' real and reactive power output, and active/reactive margins at critical interfaces and buses in the power system. The voltages and flows should be compared to the desired operating ranges of the power system equipment. In this way, the operating point can be checked to make sure it is sustainable and realistic. The impact of DER on active and reactive power margins can be examined using advanced power flow techniques.[69] The power flow model can also be used to determine the extent to which DER affect transmission losses because they serve load locally. As penetration levels increase to the point that local DER at times exceed premise load, reverse flows into the transmission system occur (if allowed under interconnection rules), reversing the effect of DER on losses.

For dynamic transmission reliability studies (which are relatively short-term in nature), the simplest way to represent DER at any transmission load bus is by reducing the load value at that bus. For example, 1 MW of distributed PV connected to a 10-MW load bus would be represented by simply reducing the load (over the 8760 hourly profile) at the bus to 9 MW. In this simplified modeling approach, disconnection of PV resulting from a fault, for example, is emulated by increasing load back to its original value. No standard dynamic model is presently available for distributed PV; however, in many of the latest commercially available transmission planning software platforms, the existing large-scale PV dynamic models can be used to represent the aggregated distribution-connected PV at the bulk power system level behind the transformer and feeder impedance model described previously.

Using these models, a more realistic representation of DER impacts can be achieved because it captures PV's dynamic characteristics more accurately than the simplified approach. The fault ride-through characteristics of DER—voltage (and frequency) vs. time protection—can be represented using voltage and frequency generator disconnection relay models. These models are available as standard library models in most of the commercial transmission planning software.

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[69] Kundur, P., *Power System Stability and Control.* EPRI, McGraw Hill, 1994.

With the DER appropriately modeled in the dynamic system model—including dynamic load models—stability simulations are performed for contingencies such as transmission system faults and loss of generators. The stability simulations are performed to examine the impact of DER on transient voltage stability and primary frequency performance of the system. For transient voltage stability simulations, the system fault can be any contingency (or contingencies) with a widespread impact on voltage magnitudes; such contingencies will most likely result in a higher number of PV trips and can therefore have more adverse impact on transient voltage recovery. (Note that the allowable transient voltage recovery time can vary based on regional requirements.) The credible contingencies for transient voltage stability simulations can be selected based on experience and existing knowledge of the region. The "hot spots" (that is, regions with a high concentration of DER) should be monitored for the credible contingencies.

The frequency performance of the system is usually evaluated under the loss of largest in-feed (of a generator). The performance metrics typically used to assess the overall frequency response of the system are the frequency nadir, time to reach the frequency nadir, and the final steady-state frequency.

The most severe fault and generator loss contingencies should be studied for the same load and DER output levels identified in the power flow analyses. The behavior of the system during short-circuit conditions must also be studied as new technologies, such as DER, are connected to the transmission or distribution network.

Output

The outputs from the transmission performance evaluation include the following:

- Identification of operating limit violations, such as thermal overloads, voltage violations, or lack of dynamic reactive power support. System violations are inputs to the transmission expansion process where required transmission expansion plans will determine whether any bulk power system modifications are required.
- Impact on transmission system losses, which can be monetized and included in the overall benefit-cost module.

Impacts of DER

High levels of DER may displace conventional units in dispatch because of their lower marginal costs. However, conventional units provide reactive power support to the transmission system, and their absence can reduce the system's dynamic reactive capability. In addition, DER may degrade the power factor at the transmission load buses because the active power is supplied through the distribution network, and reactive power is still supplied through the transmission network (in North America, DER are typically not used to regulate voltage at the point of interconnection). This may alter the overall voltage performance of the system, especially in regions with a high DER concentration. As a consequence, there may be adverse effects on voltage magnitudes, line flows, system active and reactive power security margins, and transient voltage recovery.

In terms of steady-state impacts, the addition of DER themselves can cause a rise in local voltages, as realized at the transmission level, because of a decrease in net load. However, low voltages can occur as a result of displacement of conventional plants, which are responsible for providing voltage regulation at the transmission level. From a losses perspective, DER may reduce total losses—but power flow simulations are needed to quantify the actual impact on losses. Given the variability of output of some DER, probabilistic methods may be required to determine the proper commitment and dispatch levels of conventional generation and the associated power flows across the system.

In terms of dynamic impacts, because of the lack of dynamic reactive capability, voltage performance during a fault can deteriorate and lead to transient voltage instability. In addition, the lack of fault ride-through provisions in current North American standards may result in disconnection of DER due to a large voltage disturbance. This can have adverse impacts on transient voltage recovery.

In addition to voltage impacts, high levels of DER can impact system frequency performance following a loss of large in-feed as a result of displacement of traditional resources that provide frequency control. Although some DER technologies may be able to provide active power control to support system frequency, visibility and control of the DER as part of the overall bulk power system frequency control are complicated.[70] The disconnection of DER on a wide scale as a result of lack of ride-through capabilities can also impact system frequency, especially in small, isolated power systems.

Ongoing regional and industry efforts are seeking to establish updated interconnection requirements for distributed resources to support bulk power system reliability, such as revising the voltage frequency fault ride-through requirements on DER as stipulated in IEEE 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems). EPRI is supporting the development of guidelines as part of the Integrated Grid project. If such provisions are adopted, DER integration studies must be performed to calculate minimum voltage and frequency ride-through requirements for the study region. These settings could vary based on DER penetration levels and type of system (for example, meshed, radial, or isolated).

[70] EPRI is preparing a separate white paper that discusses how different types of DER contribute to system resource needs, which has implications for the composition of the conventional generation portfolio required to accommodate DER.

Integrated Grid Study Guidelines

The transmission performance evaluation is conducted as part of an integrated grid analysis and should include the following:

- Power flow and dynamics models that accurately represent DER and their impact on central station generation:
  - Aggregated DER as determined from distribution system analysis such as EPRI's distribution feeder hosting capacity interconnected at appropriate transmission buses.
  - Aggregated DER modeled as the most appropriate standard model (presently bulk power system PV models) connected through a transformer and impedance to represent the substation and distribution feeder.
  - Unit commitment and dispatch for load and DER output scenarios to determine availability and dispatch levels for conventional generators.
- Power flow simulations:
  - Should be conducted across credible contingencies for critical load/DER output scenarios. For example, evaluate combinations (coincidence) of the time of system peak and the time of solar noon peak during both summer and winter relative to less granular measures of DER output levels—full aggregate output, zero output, and expected output based on historical data.
  - Determine the extent and nature of thermal and voltage violations.
  - Determine the effect on losses.
  - Include advanced power flow analyses conducted to evaluate reactive power margins.
- Dynamic simulations:
  - Should be conducted for most significant faults and single worst contingences.
  - Disturbance ride-through characteristics of DER must be accurately represented.
  - Transient voltage recovery, voltage stability, and frequency stability for worst contingencies should be evaluated.
- Protection and power quality simulations/analysis:
  - Include short-circuit studies to determine protection settings.
  - Conduct harmonic analysis, potentially including simulations, to ensure voltage quality levels.

Transmission System Expansion Process

Purpose

The purpose of the transmission system expansion process is to determine the investments in the transmission system that are required either to address reliability concerns and load deliverability issues identified in the transmission performance evaluation process or to capture costs related to transmission congestion. The objective is to optimally (in a least-cost fashion) expand the transmission system to ensure that for forecasted load levels, the system is operated within limits, without load curtailment, while allowing for delivery of the most economic generation sources.

Inputs

Transmission expansion requires the following inputs:

- All of the inputs of the transmission performance process (such as generator dispatch, load forecasts, and transmission network data) from both the scenario definition and distribution analyses.
- The facilities with voltage and thermal and stability violations are identified in the transmission performance evaluation process.
- Production cost information for various scenarios from the operational simulation process to identify potential economic transmission projects.
- Technical, logistic, and economic characteristics of potential mitigation options, including information on the availability of rights of way for permitting and siting new transmission facilities and the costs of guiding the development of DER in certain areas. All of these data are provided from the scenario definition and the distribution hosting capacity and energy analysis.

Processes

The transmission expansion process is conducted for multiple planning horizons, including the following:

- Long-term planning over 10+ years, which results in relatively high uncertainty in load forecasts, technology development, and energy policy that impacts the power system requirements such that identified projects must be viable across many potential developments. Planning objectives may include accessing new and/or more economic resources, upgrading to a higher voltage level, improving overall system efficiency, and investing in new technologies such as flexible AC transmission system (FACTS) and high-voltage direct current (HVDC).

- Mid-term planning over 3–10 years where load and generation are subject to lower uncertainty. Planning objectives include identifying transmission projects to address specific reliability issues that tend to be localized.
- Near-term planning over 1–3 years where load and generation are known with relatively high certainty. Planning objectives include identifying temporary projects to cover potential reliability issues that have emerged without sufficient time to develop permanent transmission solutions. This may include limits or guidance of DER deployment at certain transmission substations.

Within each of these planning horizons, there are various processes to determine the transmission expansion plan for a given planning horizon. These include scenario-based expansion planning, optimization methods, and risk-based analysis. Each method of selecting the optimal expansion plan has its advantages and disadvantages, but all have the same objective function: to define a reliable transmission system at least cost. The benefit of multiple horizons is the development of prudent, harmonized, and strategic plans that can adapt—at minimal cost—to changes in planning assumptions.

Output

The outputs of the transmission expansion process include the following:

- New transmission expansion plan specifying investments that feed back as input into the resource adequacy, flexibility, and operational simulation process. If any remaining reliability impacts are identified using operational simulations (such as transmission congestion), the transmission expansion plan may need to be reviewed and/or modified.
- Capital and operating cost associated with identified transmission investments that are inputs to the benefit-cost methodology.

Impacts of DER

The transmission expansion process is complicated with increasing levels of DER because of the associated uncertainty surrounding the amount of DER expected to come online at any time, the location of those DER, and the potential variability in their availability and output. As noted in Section 4, DER have the potential to offset the need for new transmission projects by serving load locally and reducing thermal loadings of transmission facilities, depending on the extent to which the output of the DER coincides with system peak load periods.

The uncertainty regarding the actual output or availability of the DER for a specific study scenario must be considered when evaluating expansion plans because the timeline for developing transmission facilities requires specifying and committing to build transmission requirements several years prior to the time of need. DER may also impact transmission expansion planning through the potential displacement of bulk power system conventional generation that provides reactive support to the system (see the description of impacts in "Transmission System Performance Process" earlier in this section), requiring additional transmission facilities specifically to ensure voltage performance.

Integrated Grid Study Guidelines

The transmission expansion process conducted as part of an integrated grid analysis should include the following steps:

1. Address and mitigate all operating criteria violations identified in the transmission performance process.
2. Identify and evaluate potential long-term planning projects that are economically viable based on reduced congestion and generation cost differentials.
3. Consider a sufficiently broad range of planning scenarios either through traditional scenario analysis or emerging risk-based methods that use probabilistic methods to evaluate potential transmission needs and mitigation options.
4. Interact with generation system expansion and distribution hosting capacity processes to determine an optimal system development plan.

8 SUPPORTING GRID-CONNECTED DER: TECHNOLOGY OPTIONS AT THE TRANSMISSION LEVEL

The impacts of increasing levels of DER on the bulk power system, described in Section 7, may be minimized or entirely mitigated through investment in bulk power system technologies and resources or by adjusting existing system and/or market operational practices. These potential mitigation approaches have their own costs that must also be considered as part of the larger Integrated Grid methodology. In addition, there may be collateral benefits that arise from these actions that offset the costs. This section describes bulk power system technologies that can be used to accommodate three broad areas: system operations improvements, flexibility resources, and transmission technologies.

SYSTEM OPERATIONS IMPROVEMENTS

Operations improvements, such as software, communications and data infrastructures, and operational practices, can be employed to mitigate some of the adverse transmission system impacts of DER. The greater the level of DER interconnected, the more important it is to account for these costs. The technologies described next involve system operations improvements rather than new equipment.

System Operations Improvement #1: Increased Visibility and Controllability of DER

TSOs generally have direct communication channels with transmission-connected resources. This gives the TSO visibility to resource state, capability, and current output levels as well as the ability to issue dispatch instructions to the resource. TSOs do not currently have this same visibility and controllability of DER. Obtaining these capabilities may be essential to resolve the operational challenges associated with DER and thereby increase the net benefits realized.

Communications is a key component of improved visibility, data quality, and controllability. Several communications technologies (for example, fiber-optics, radio, cellular, and microwave) may be used. Establishing standards for these types of communications to DER—and perhaps among DER and other local market participants—will allow for greater deployment at lower cost and better interoperability between systems.[71] Communications also needs to be at a fine enough time resolution to be used for grid operational services and with sufficient accuracy to be able to track responses as required by operators.

One-way communication can provide either visibility or controllability. Two-way communication and control are preferred because the system operator not only knows what is happening, but it can also take control of the DER to take corrective action. This may require some form of aggregation of information from dispersed DER, either by the distribution utility or by a third-party aggregator. The type of aggregation is likely to depend on the service provided and the particular regulatory constraints in place. DSO/TSO interaction is therefore an important aspect of improved system operations.[72] EPRI is conducting research to establish the communication requirements; when vetted, they will be incorporated into DER studies.

Impacts Mitigated

Increased visibility and controllability can mitigate several adverse bulk power system impacts associated with DER, including the following:

- Managing the variability and uncertainty associated with DER. Operational visibility allows operators to measure resource production accurately and understand how it changes over time, allowing for more confidence in scheduling and dispatch decisions. This could result in a reduction in operating reserves and a more optimal dispatch, reducing production costs.

[71] A new focus in electricity market design is how the local distribution system can be organized and operated to accommodate a local market in electric services to better recognize the specific conditions of the local system and promote energy efficiency, DER and demand response, and electrification to take advantage of more efficient technology to provide energy-intensive services to consumers and businesses.

[72] DeMartini, P. and Kristvo, L. 2013.

- Controlling of active power output. This is essential because control over a large amount of DER would allow operators to better manage system ramping (ramp rate limitation). This may reduce reserve requirements and cycling of conventional plants, potentially reducing production costs—especially those associated with flexibility.
- DER unit visibility will inform the system operator of the amount of potential lost DER during fault conditions so that remedial action can be taken.
- Visibility will, over time, provide knowledge of the variability and uncertainty in the output of DER, allowing planners to better determine resource adequacy characteristics of DER and reduce costs.
- Controllability makes it possible for DER to provide ancillary services, including spin and non-spin reserves, regulating reserves, and new reserve products required in future systems.
- Improving DSO/TSO interfacing allows for more optimal system operations because all potential resources could be used according to their abilities and where and how they have their greatest value, which may reduce costs and improve reliability.

Consideration Within Framework

The benefits of DER visibility and control are primarily operational. Assessing visibility and control benefits and impacts within the analysis framework is primarily accomplished in operational simulation, transmission performance, and flexibility adequacy processes. Reserve determination and operational simulations reveal the implications for the increased confidence operators would have with existing reserves and potentially lower operating reserves. A similar benefit is derived for dispatches examined in power flow and stability simulations. Visibility and control may also reduce flexibility requirements, contributing to meeting flexibility needs. Modeling and simulating in a way that accounts for all of these factors are not easily accomplished; some system development is required.

Cost Considerations

The potential benefits of DER visibility and control must be considered along with the costs of obtaining this capability. The following are some of the more important aspects to consider in the benefit-cost framework:

- Cost of communications infrastructure for the TSO, DSO, third-party aggregator, and DER owners, which may include costs of software, hardware, and labor. Some of these investments may result in other benefits that offset the DER accommodation-incurred cost.
- Payments to DER owners for provision of services.
- Costs of additional technology needed to provide the services through DER. This sometimes requires only a software upgrade but, in some cases, may require additional equipment to interact with the communications network.

System Operations Improvement #2: Forecasting the Output of Variable Generation

TSOs use short-term forecasting to determine how variables associated with power system operations are expected to behave. Forecasting allows for more optimal decision making, improved reliability, and reduced costs. More accurate and detailed forecasts of DER output will reduce the impacts of DER on operational scheduling and transmission operation performance, particularly for solar PV, and for energy storage and demand response (by changing usage patterns for air conditioning, for example).

Forecasting can be performed for DER in several ways, as shown in Figure 8-1 for solar forecasting.

As shown, a variety of technologies can be used, depending on the particular function being addressed. The need for data on shorter time horizons requires using more field sensors (such as pyranometers or total sky imagers that measure irradiance), capturing cloud movement, and measuring and conveying other weather conditions. Longer term forecasts rely on more detailed atmospheric modeling as well as some input from sensors to predict climatic changes that have longer term implications for electricity demand and DER output. Day- to week-ahead forecasting generally starts with numerical weather prediction (NWP) models to predict physical flows of energy over the atmosphere that are used in most weather-related industries (for example, aviation).

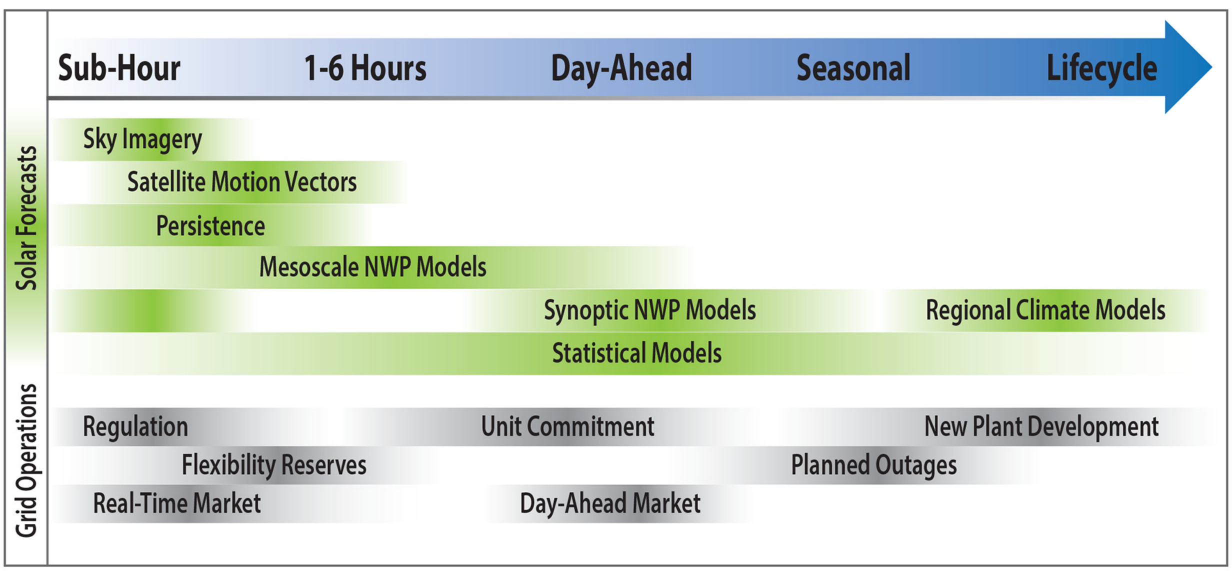

Figure 8-1
Solar forecasting on various time horizons showing forecasting model used and power system operations impacted

Government-funded forecasts are used as a basis that commercial forecasters combine with proprietary physical and statistical models to produce resource output forecasts. Closer to real time, accuracy is significantly improved. For example, solar output is easier to predict 5 minutes ahead than 4 hours ahead because of the persistent nature of the resource. Probabilistic forecasting can be used to provide uncertainty information and to determine risk associated with a forecast as well as the implications for scheduling and dispatch decisions.

Impacts Mitigated

Better forecasting of DER output, particularly distributed PV, will help mitigate some of these impacts:

- **Uncertainty.** Understanding the future variability of the DER output will allow for more optimal scheduling and dispatch to occur. This is the result of improved scheduling as well as reduced operating reserve requirements. It may also allow TSOs to better manage unexpected power flows. These mitigations of the impact of uncertainty will reduce production costs and improve reliability.[73, 74, 75]
- **Reactive power.** Accurate forecasting of DER output will allow transmission operators to better plan reactive power requirements on the bulk power system and to schedule transmission outages.
- **Resource adequacy.** Previous EPRI research[41] has shown that operational timeframe uncertainty (day-ahead) associated with PV can have adverse impacts on realizing resource adequacy targets. With large forecast errors, sub-optimal commitment of generation may result in periods in which large ramps cannot be met by the generation that is online. This results in greater likelihood of loss of load or curtailment of generation (depending on the direction of ramp).

Consideration Within Framework

The benefits of DER forecasting are primarily operational and are considered in the operational simulation process of the framework. The reduction in reserve requirements and improved operations can be measured using production simulation tools in the operational simulations process. This provides cost impacts as well as improved reliability impacts. Different forecasting time scales will impact production costs in different ways. Improved short-term forecasts (less

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[73] Ahlstrom, M., Bartlett, D., Collier, C., Duchesne, J., Edelson, D., Gesino, A., and Rodriguez, M., "Knowledge Is Power: Efficiently Integrating Wind Energy and Wind Forecasts," *Power and Energy Magazine*. IEEE, 11(6), 45–52, 2013.

[74] Hodge, B. M., Brinkman, G., Ela, E., Milligan, M., Banunarayanan, V., Nasir, S., and Freedman, J., Economic evaluation of short-term wind power forecasts in ERCOT: Preliminary results. National Renewable Energy Laboratory, 2012.

[75] Lew, D., Milligan, M., Jordan, G., and Piwko, R., "The value of wind power forecasting," *91st AMS Annual Meeting, 2nd Conference on Weather, Climate, and the New Energy Economy Proceedings*. Washington, D.C., January 2011.

than 1 hour) may be able to slightly reduce regulating requirements, while day-ahead forecasts may significantly improve the unit commitment. Resource adequacy may also need to consider forecast improvement, depending on the detail represented in the modeling tools used, where operational uncertainty can impact the ability to meet peak demand.

Cost Considerations

The costs for forecasting depend on the technology being used. For shorter term forecasts in particular, a large amount of technology must be deployed in the field (for example, pyranometers and total sky imagers), which may be expensive. Ideally, all PV systems would have these technologies, but that is almost certainly cost-prohibitive. A major consideration is how much it is worth spending on such technologies, which will depend on the benefits seen by improved forecasting in the relevant time scale. For the NWP models, improvement can be made in the forecasting of cloud movement, which could require significant government investment. The cost to acquire commercial forecasts ranges from several hundred to several thousand dollars per month per site. Savings are substantial if DER can be aggregated over geographic areas, without loss of specificity—for example, distributed PV might be defined as all PV connected to a distribution substation (or similar sized area). As a result, only one weather station's forecasts are required.

System Operations Improvement #3: Adjusted Operating Practices

Traditional operating practices may also be adjusted to more successfully integrate DER. Operating practices in use today have evolved over time based on several factors: the resources on the system and their needs (for example, the location both on the grid and spatially, dispatchability, and so on), the computational and software capabilities available to system operators (for example, power flow solution methods and processor speed for online calculations), the data available, and the risk preferences of both utility/ISO operators as well as society (as captured by regulatory rules).

With DER on the system, operating practices must evolve to better integrate these resources. Improvements in computation and software, data collection, and changing regulatory and utility/ISO requirements are already underway—so accommodating DER may require only modifications to these planned investments.

Adjustment to the following practices may have beneficial impacts for DER integration:

- **Reserve determination processes.** Increased requirements to manage variability and uncertainty on all timeframes result in increasing reserve levels. New methods to determine reserve requirements and/or new reserve categories may reduce the cost of providing reserves for DER and other variable resources. Dynamically determined reserve requirements based on current operating conditions (for example, more operating reserves may need to be carried during the middle of the day for solar PV or during cloudy periods) may reduce the impact of additional reserve requirements relative to traditional static reserve requirement processes.

Similarly, new reserve categories (often developed as market products in market areas), such as the flexible ramping product in CAISO, may ensure that uncertainty over a period from 10 minutes to 1 hour is taken into account without interfering with the deployment of, and reducing the need for, conventional—and more expensive—regulating reserves.[76] Reserve procurement mechanisms may need to be adjusted to reflect the fact that certain DER are able to provide faster, more accurate response compared to traditional providers of these services. This is particularly true for fast frequency regulation and fast frequency response services.[77]

- **Scheduling processes.** Consideration of the stochastic nature of solar PV and other renewables in determining system commitment and dispatch may also reduce potential reliability and production cost impacts. In addition, increased DSO/TSO interaction will require scheduling and dispatch practices to be able to communicate results as needed across various parties. DER also displace traditional generation sources of inertia and primary frequency response, which are important after a fault. Although DER may be able to artificially replicate some of these qualities, the operators will need new tools to ensure that the system operator has sufficient inertia and that the contribution, if any, from DER is accurately estimated for such tools.[78]

Impacts Mitigated

The new reserve requirement and scheduling operating practices described may be useful for mitigating the following impacts:

- Improved system response to and management of variability and uncertainty, which will reduce operating cost impacts and increase reliability without requiring significant capital investment. Many of these impacts cannot be totally mitigated using operational practices.
- Reduced operating reserves and more optimal scheduling may also reduce the need for flexible capacity.

Consideration Within Framework

The benefits of improved reserve requirements and scheduling are primarily operational and will mainly be considered in the operational simulation and practices process of the framework. Improvements in those practices are measured in terms of production cost and reliability

[76] California ISO, Revised Straw Proposal – Flexible Ramping Product including Fifteen Minute Market and Energy Imbalance Market, available at http://www.caiso.com/Documents/RevisedStrawProposal_FlexibleRampingProduct_includingFMM-EIM.pdf. Accessed August 25, 2014.

[77] ERCOT Concept Paper: Future Ancillary Services in ERCOT, Draft Version 1.1, November 1, 2013. http://www.ercot.com/content/committees/other/fast/keydocs/2014/ERCOT_AS_Concept_Paper_Version_1.1_as_of_11-01-13_1445_black.doc.

[78] Eirgrid, DS3: Wind Stability Assessment Tool, available at http://www.eirgrid.com/media/DS3%20WSAT.pdf. Accessed August 25, 2014.

improvements that are outputs of the operational simulation. As noted, the flexibility adequacy process may also be used to evaluate the benefits of the reserve requirement and scheduling improvements on the flexible capacity required for various timeframes.

Cost Considerations

The cost of changing operating practices requires examining how complex operations are affected, including the following:

- Computation cost to run more advanced software closer to real time.
- Software development and deployment. Because software often needs to be customized for specific systems, these costs could be significant. Deployment of the software may also require significant training or possibly newly hired expertise.
- The additional costs noted for implementing the advanced reserve and scheduling must be weighed against the cost savings resulting from more optimal operations. The costs and benefits associated with these new operating practices are also driven by the level of DER penetration and the technical and geographical spread involved in DER deployment. Low penetrations may be easy to accommodate, but there comes a breaking point at which large costs become essential.

FLEXIBILITY RESOURCES

Improvements to the operational flexibility of the system may be necessary—especially for high DER scenarios—to support balancing of supply and demand and to address increased flexible operation. These improvements may be derived through adding new sources of flexible resources or by obtaining additional flexibility from existing resources. Regardless of the source, they are expected to be able to provide enhanced ramping capabilities.

Flexibility Resource #1: Conventional Generation

Much of the flexibility needed by power systems is provided by thermal and hydro generators. Operational requirements of such plants—the ability to ramp quickly, operate across a wider output range, and start up and shut down more quickly—are essential for managing system variability. In existing power plants, there is a trade-off between increased flexibility and a combination of operating efficiency and/or capital costs. How these services are accommodated affects how they are provided.

Increased flexibility can be obtained in new plants and through retrofitting of existing generation. New plants, particularly combined- and simple-cycle gas turbines, show extremely flexible characteristics. They have the ability to operate at low minimum output with good efficiency, high ramp rates, and low start times. Retrofitting specific components and/or processes of coal, nuclear, gas, and hydro generators is being considered for increasing flexibility of existing units.

All types of plants should be considered for their ability to adjust operational practices to derive more flexibility from the existing plant. EPRI is studying nuclear plants to determine how best to operate them so that they can provide some types of flexibility—maybe not all time scales, but at least to some extent. Coal plants have already been retrofitted in some areas to provide lower minimum output and higher ramp rates.[79] Hydro can be retrofitted in two ways: by improving speed of response or, more significantly, by adding pump-back capability to reservoir hydro so that system load can be increased as well as decreased more rapidly. Hydro operations are also being examined to determine whether altered scheduling practices can improve the flexibility of the hydro fleet.

An important aspect of more flexible operations from a conventional plant is the potential impacts of increased cycling of the generation plants operating today. This includes start-stop operations, moving to new modes of operation (for example, moving from baseload to on/off cycling), and increased ramping. These operations can result in increased wear and tear on conventional plants that increases maintenance costs and outage rates and may reduce equipment lifetime and efficiency.

Impacts Mitigated

Several impacts can be mitigated, directly or indirectly, with a more flexible conventional fleet:

- Variability and uncertainty can be managed more efficiently with improved ramping capability and by better managing ramps. Reduced turndown and start times mean that the plant can be more easily reduced to a lower level and accommodate more variable generation—or quickly turned off and on again to respond to increases and decreases in variable generation.
- More flexible generation may improve resource and flexibility adequacy on the system because the likelihood of loss of load resulting from insufficient capacity being online is reduced.
- With reduced minimum-run generation requirements, more generation can be kept online while still efficiently accommodating DER, resulting in an improvement in frequency and voltage stability.

Considerations Within Framework

Conventional plant operation must be considered in all aspects of the framework. More flexible generation will most obviously impact the operational simulations area, with significant changes to production from conventional generation and associated costs, emissions, and reliability. However, conventional generation flexibility will also change the dispatches that need to be

[79] J. Cochran, D. Lew, and N. Kumar, *Flexible Coal: Evolution from Baseload to Peaking Plant*. National Renewable Energy Laboratory, 2013.

included in transmission system analysis, and more flexible conventional plants may result in alterations to potential transmission expansion. When considering flexibility adequacy, increased flexibility from new or retrofitted conventional plants will reduce the need for other flexible resources. The framework can examine the impacts of making existing plants more flexible or adding new flexible capacity by performing simulations with and without the flexibility being provided.

Cost Considerations

The cost considerations here can be broken down into capital investment and operating costs:

- **Capital investment.** The costs will include either the costs of new generating resources or the cost of retrofitting the existing plant. An important consideration regarding the costs of new, flexible generating capacity is that it likely will not be driven solely by DER expansion—normal load growth or plant retirement will induce the need for new capacity even without DER. What needs to be captured is the cost of the additional flexibility needed to manage DER integration relative to the capacity that may have been developed for other reasons. As described in the following subsection, DER such as demand response and distributed storage may themselves contribute to system flexibility. In such cases, DER may reduce the portion of the investment needed for conventional generator flexibility.
- **Operating costs.** The provision of flexible operation services from conventional plants increases maintenance costs, for example, from increased parts replacements and labor. Other costs may be associated with increased labor and training of operators as well as potentially increased compliance costs—particularly for nuclear. An increased outage rate may also be a consequence, resulting in reduced revenue to the plants and higher system supply costs because more expensive generation is used.

Flexibility Resource #2: Demand Response

Advances in communication and controls technologies, especially increased latency and lower costs, are expanding the ability of end-use customers to respond to system operator directives quickly and predictably—providing the potential to use demand response as a flexible resource. The capabilities for demand response to contribute to system flexibility obviously depend on being visible, controllable, and reliable. Some systems are using demand response to provide flexibility.[80]

[80] S. H. Huang, J. Dumas, C. González-Pérez, and W. J. Lee, "Grid Security through Load Reduction in the ERCOT Market," *IEEE Transactions on Industry Applications*. Vol. 45, No. 2, March/April 2009.

Impacts Mitigated

Using demand response as a flexibility resource has the potential to mitigate the following concerns associated with bulk power system impacts of DER:

- More efficient management of variability and uncertainty and improved balancing of active power. Provision of various balancing services, such as regulating reserves to non-spinning reserves, allows for improved integration of DER because conventional generation can then be used to provide energy or be turned off. In addition, the ability to increase demand—in particular, by charging storage devices—can result in a reduction of any potential curtailment of DER.
- Providing adequate capacity and, in combination with DER, reducing the need for more capital investment in conventional generation. To provide such adequacy, performance persistence must be verified so that the demand response can be relied on over several days and across several years.

Cost Considerations

Demand response involves inducing consumers of electricity to stop using electricity under certain conditions. To provide frequency services, the following attributes need to be established:

- Communication and control costs: what is required to satisfy the system operation need for visibility and control.
- Cost of metering and verification.
- Consumers' cost of purchasing and operating technologies that can respond to grid signals; dispatchable water heaters and thermostats are more expensive than typical water heaters.
- Increased complexity of system operations and associated computation and software costs. The cost to manage thousands of small devices located on customer premises may require considerably more effort and cost those that associated with acquiring flexibility services from a few large generating units.

Flexibility Resource #3: Energy Storage

Energy storage is by definition DER because of how it interconnects (to the distribution system). It can also accommodate intermittent generating DER. There are many forms of energy storage, including the following:

- **Pumped hydro** is the predominant form of energy storage in the electricity system today and typically is large in both capacity and energy stored. Suitable geological formations are required. Where available, this is a relatively inexpensive and well-understood technology. Newer technologies in this area include adjustable speed drives, which allow pumping levels to be altered.

- **Compressed air energy storage (CAES)** is a more widely applicable type of storage; it does not require specialized geographic circumstances. Traditional CAES uses gas with pumped air to produce energy more efficiently than gas alone (not counting for the power used to pump the air). Adiabatic CAES, still under development, does not need gas and instead keeps air warm for use later at high efficiency.
- **Battery storage** includes a variety of technologies, such as lead-acid, flow batteries, sodium-sulfur, Ni-Cd, and lithium-ion. They use different chemistries to store the energy and release it later. Batteries tend to respond quickly and accurately, and many technologies can be scaled to fit a wide range of needs—though most are currently small-scale. They tend to have short lifetimes, are relatively expensive, and have lower efficiency in terms of round-trip losses.
- **Electric vehicles** are batteries that are not stationary. These can be used by the grid in two ways. The first is to use smart charging to ensure that the batteries are charged at a time most useful to the grid while ensuring that the user charges his or her vehicle in the desired timeframe. The second uses vehicle-to-grid technology to provide power back to the grid from the battery.
- **Flywheels** use mechanical inertia to provide power for short periods—these are high-power, low-energy resources. Electricity is stored and then released as kinetic energy.
- **Thermal storage** involves the collection of excess thermal energy from a process or applications at a building, community, or even city level that is used later to provide power when needed. A variety of materials can be used, including solar thermal, ice, and earth.

Impacts Mitigated

Energy storage can help mitigate a large number of the impacts of DER, including the following:

- Provide power to the system quickly and reliably (within capacity) to both increase and decrease net load; this results in an extremely useful resource for managing variability and uncertainty more efficiently.
- Storage can be co-located with other intermittent DER to mitigate adverse impacts or located where it best serves system needs.
- The fast response of some forms of storage can reduce the need for regulating reserves because better dispatch performance accuracy means that fewer reserves need to be procured.
- Reduction in curtailment due to over-generation by storing the energy to be used later (particularly for high-energy applications).

Considerations Within Framework

Storage can be considered in all parts of the framework. To assess the benefits, the system should be examined with and without storage to determine overall production costs, capacity needs, and transmission needs. It is important to consider the particular nature of storage when assessing the impacts. Storage does not originate electricity output—it holds electricity produced for use at a later time, so the timing of charging and discharging is important to the benefits realized. During peak times on the transmission substation, storage that provides capacity for transmission deferral is not available to provide other services, for example, to abate fluctuations in the output of intermittent DER. Evaluating the role and benefit of storage requires establishing its best use, considering all the ways it can be dispatched and the fact that it is an exhaustible resource—for example, co-optimizing storage with energy and ancillary services over the relevant timeframes in unit commitment and ensuring that storage behavior, particularly inverter-based battery storage, is properly represented in transmission planning models.

Cost Considerations

Storage is a relatively expensive resource to procure. However, it can displace the need for a large variety of capacity (both transmission and generation), energy, and ancillary service needs. When considering storage costs, both capacity ($/MW) and energy ($/MWh) value need to be considered. System lifetime should also be considered: it tends to be short for battery storage and very long for pumped hydro.

TRANSMISSION RESOURCES

These are resources that can be added to the transmission system to accommodate DER.

Transmission Resource #1: FACTS and HVDC

HVDC (high-voltage direct current) is used to transfer power—typically over long distances—by converting power generated as AC to DC, transmitting the power, and then converting back to AC using power electronics. HVDC can be economically viable over longer distances (especially for undersea routes) because it requires a smaller right of way—resulting in lower transmission losses—and can be more easily controlled than AC transmission. In addition, HVDC is used to form a back-to-back link to interconnect systems with different frequencies. FACTS devices include static VAR compensators (SVCs), static synchronous compensators (STATCOMs), unified power flow controllers (UPFCs), and thyristor-controlled series compensation (TCSC). These are used to control voltage/reactive power to improve system performance. UPFCs can be used to control both active and reactive power.

Impacts Mitigated

FACTS and HVDC can help mitigate a large number of the impacts of DER, including the following:

- High levels of DER can alter power flows at the transmission level. HVDC can be used to sustain the desired power flow and provide more control to system operators.
- The planned retirement of conventional plants or their displacement to accommodate a high level of DER injection can impact the dynamic reactive capability of the system. FACTS devices such as SVCs can provide dynamic reactive support to the system.
- Because HVDC can control exact power flow in either direction, it can provide primary frequency control by channeling active power from regions with high reserves to regions in which load generation imbalance results from a frequency event.
- FACTS devices can help improve angular stability. For example, they can help improve damping of oscillations, which may increase as a result of displacement of synchronous units to accommodate DER injection.
- Because HVDC can block the propagation of AC disturbance, it may reduce the number of DER trips in a given area caused by low voltages.

Interaction with Framework

Most of the consideration is in transmission studies because the applications of FACTS are intended to improve voltage and frequency performance. However, the operations simulations may also be impacted. If less must-run generation is required, operating reserves requirements may be reduced. Resource adequacy may also be affected because generation otherwise required as a must-run resource can be retired.

Cost Considerations

FACTS is generally seen as an expensive technology and should be compared against other less expensive conventional solutions, considering the additional capabilities offered by the FACTS device, for example, better voltage control and coordination, improved reliability, and the ability to solve multiple system issues. From the perspective of DER integration, costs should be assessed to DER if the DER displace conventional generation, resulting in a choice among three options: keeping the conventional generation must-run, obtaining services from DER (if possible), or building new FACTS or HVDC devices.

Transmission Resource #2: Increasing Transmission Capacity

Congestion limits the way in which available transmission capacity can be used. Transmission congestion patterns are likely to change with increased DER, which must be taken into account in determining the kinds of transmission that need to be built, and where. From a technology perspective, the variability and uncertainty associated with DER may result in the need for larger transmission balancing areas or increased coordination between balancing areas, creating the need for significant transmission upgrades. It may also mean the use of higher voltages than have traditionally been used or the use of HVDC as described previously.

Impacts Mitigated

Transmission capacity expansion can mitigate potential negative impacts of DER, including the following:

- Voltage and transient stability problems may be remedied by building transmission, which reduces loading on the system and provides access to other resources.
- The impact of variability and uncertainty can be lessened by reducing bottlenecks in the system and allowing the flexibility resources to be more efficiently used.
- Production costs can be reduced through the more efficient use of generation resources.

Interaction with Framework

Transmission studies (for example, transmission planning and stability analysis) are affected if new transmission is assessed to determine its impacts. Operational simulations should include a representation of transmission to examine the benefits of new transmission on the provision of energy and ancillary services, while resource adequacy may be impacted if more resources can be considered. As with other technologies, examining the system with and without the new transmission will allow impacts to be studied. The value of existing transmission will be more difficult to determine—this could be done for operational simulations by examining how much each line contributes to cost reduction or by examining the system as a “copper plate” to determine how much the transmission is costing the system. As before, care is needed to separate impacts of DER from impacts that would have been seen regardless.

Cost Considerations

Costs of transmission are well-understood. Upgrades happen frequently, and significant information is available. Care should be taken when examining cost impacts to separate DER impacts from transmission upgrades needed regardless.

Transmission Resource #3: Synchronous Condensers

Synchronous condensers (sometimes called *synchronous compensators*) are motors in which the shaft is not connected but spins freely. They do not provide electrical power but are instead used to provide reactive power and to improve power factor. Because they operate as a synchronous motor, they absorb real power from the system—resulting in additional losses. They could also provide inertia if required. Reactive power can be continuously adjusted, allowing synchronous condensers to be a good resource to ensure that reactive power is maintained at desired levels in certain locations, particularly near large loads or in "lighter" areas of the system. Many older generators that are not being used to generate power for many reasons (for example, reduced efficiency, degraded parts, or environment-related retirement) have been or could be converted to synchronous generators. These are not as efficient as capacitor banks, but they are more controllable and potentially less expensive.

Impacts Mitigated

Two sources of mitigation are available:

- The main impact mitigated is reactive power provision. Synchronous condensers have the advantage that they provide reactive support in a similar manner to conventional generators. However, for high DER situations in which only reactive power is needed, synchronous condensers may be more suited because they prevent oversupply and curtailment.
- With increased concerns about inertia, synchronous condensers can also provide these services—again improving reliability while reducing the amount of conventional plant power needed online.

Interaction with Framework

Most of the interaction with the framework comes in the area of transmission studies because the impacts of synchronous condensers are intended to improve voltage and frequency performance. However, the operational simulations may also be impacted because less must-run generation will be required for operational practices. This may also free up flexibility resources or, alternatively, put them offline—thus impacting flexibility assessment. The most suitable way to study this is to examine both with and without new synchronous condensers on the system.

Cost Considerations

The costs depend on whether a new synchronous condenser is being installed or existing generators are being altered. There is significant experience in both worldwide, so data should be available. The implications for other generation and total system production costs should also be considered as described previously.

9 OVERALL BENEFIT-COST FRAMEWORK FOR THE INTEGRATED GRID

The application of distribution and bulk power system impact analyses described in the previous section produces a large body of data that describes how the power system is impacted by DER adoption. It is an end-to-end analysis that starts with identifying individual feeder impacts and works outward to trace the consequence of those impacts through the bulk power system. At each stage, it identifies what changes in system design, assets, and operation are required to accommodate DER while maintaining reliability standards at least cost. The findings provide utility planners and operators with information to anticipate and understand how to maximize the net benefits from DER interconnections.

Feeders are affected differently by the same level of DER adoption, and the mitigation actions differ because of feeder circumstances and utility decisions about what constitutes the best accommodating actions. Extending the distribution impacts results to the bulk power system produces secondary impacts on system design and operation that must be taken into account. The framework for doing so is the same regardless of the system. The kinds and level of analyses required depend on the physical nature of the bulk power system, its interconnection with the distribution system, and the choices of how accommodations are made. They vary across utilities because of differences in business practices, regulatory oversight, and state and local policy goals. The Integrated Grid framework developed by EPRI anticipates a series of analyses that explore a variety of policies and actions driven by different assumptions about endogenous and exogenous factors and forces. DER accommodation study scenarios reflect important differences and uncertainties. Providing answers to the investment and policy questions requires a distillation of the system analyses in a way that facilitates strategic decision making: comparing and contrasting alternative portrayals of how many DER are adopted where, as well as how the distribution and bulk power system are modified to accommodate these distributed resources.

This section describes the benefit-cost analysis that EPRI has developed to summarize and compare Integrated Grid DER accommodation scenarios, each consisting of results from the distribution and bulk power system processes. The benefit-cost analysis enables comparison of investment alternatives by converting accommodation impacts into monetary streams over time and combining them into a single net-benefit metric—the difference between identified benefits and costs. The results inform the selection from DER integration alternatives that may have different approaches but lead to the same result: a safe, reliable system. They also inform the assessment and refinement of policy goals.

The Integrated Grid benefit-cost framework is a logical extension of benefit-cost analysis protocols being used to guide the transformation of the power grid in the United States and elsewhere.[81] It builds on previous research efforts—in particular, those of EPRI and DOE, described in the report *Methodological Approach for Estimating the Costs and Benefits of Smart Grid Demonstration Projects*.[82] The Smart Grid methodology begins by addressing measurement and verification issues associated with conducting physical pilot projects to establish the impacts of Smart Grid technologies; it then classifies them according to who is affected and monetizes them so that alternatives can be compared.

The Integrated Grid framework extends this analysis to assess the implications of a subset of Smart Grid technologies: DER. It describes a detailed analysis of how the power system is affected and proposes how such a study can be accomplished.

OVERVIEW OF THE BENEFIT-COST ANALYSIS METHODOLOGY

Distributed resources interconnected to, and integrated into, the grid can have beneficial impacts that are realized beyond the local delivery system. They can reach all the way to the bulk power system, where fuel costs may be saved, asset investments deferred or avoided, and emissions reduced. The Integrated Grid benefit-cost framework traces these benefit and cost streams from their point of emanation to their monetary manifestation.

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[81] Joint Research Centre of the European Commission, "Guidelines for conducting a cost-benefit analysis of Smart Grid projects," 2012: http://ses.jrc.ec.europa.eu/sites/ses/files/documents/guidelines_for_conducting_a_cost-benefit_analysis_of_smart_grid_projects.pdf.

[82] *Methodological Approach for Estimating the Costs and Benefits of Smart Grid Demonstration Projects.* EPRI, Palo Alto, CA: 2010. 1020342.

Exploring both benefit and cost causation paths related to DER informs utilities, regulators, and policy makers about the implications of proposed DER interconnecting policies, cost allocation methods, and rate design. A comprehensive analysis identifies how the physical system must change to accommodate DER. The EPRI Integrated Grid framework evaluates impacts, benefits, and costs in a way that allows utilities to individually tailor a study to their circumstances and assess the most relevant alternatives. It imposes structure that facilitates comparison of the results with what others have found. The framework does not stipulate which alternatives should be pursued or how the costs incurred from those that are pursued should be recovered—that is left to the responsible stakeholders.

Figure 9-1 illustrates the methodology EPRI has adopted for evaluating the benefits and costs associated with DER interconnection. The boxes on the left describe the categories of impacts, which are in outputs of the distribution and bulk power system analyses (as described in previous sections). The second column specifies the measured impacts associated with each category; they include costs and physical impacts that have to be monetized.

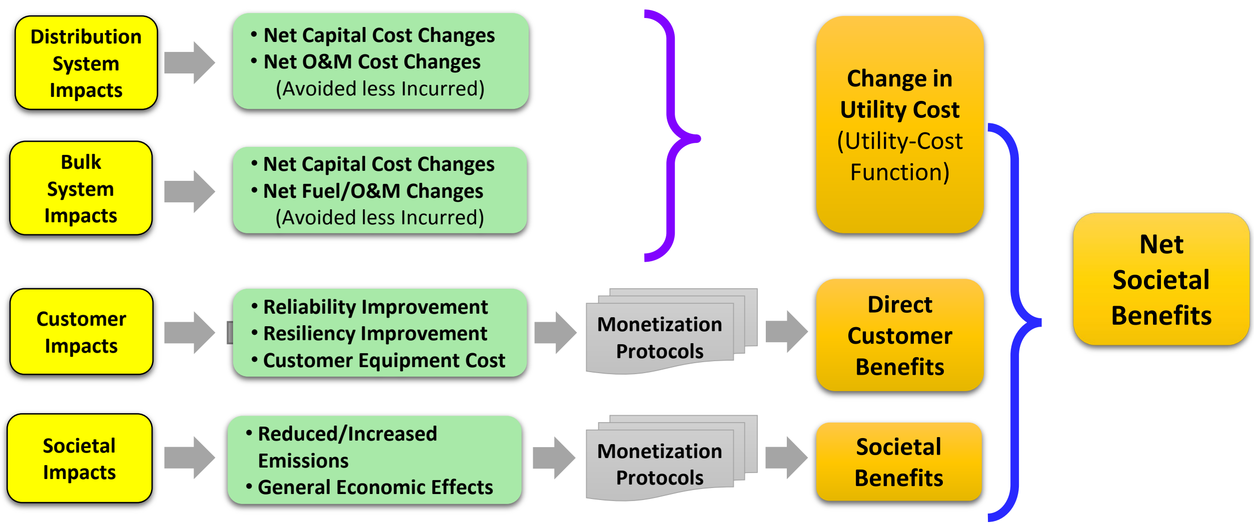

Figure 9-1
Detailed benefit-cost analysis methodology

The third column distinguishes benefits that must be monetized so that all salient impacts can be stated in monetary terms, including those associated with customer and societal impacts. These are referred to as *externalities* because they are not costs the utility incurs. Because these impacts are not transacted in the market, there is no unambiguous measure of their value or cost. Power plant emissions that are not subject to control limits (for example, carbon dioxide) have no market price (with some exceptions), so no cost is incurred by the utility for emitting them—and no cost is avoided when power is generated by renewable resources such as wind and PV.

The framework supports a variety of perspectives on DER accommodation. As described next, the benefit-cost analysis distinguishes between net costs incurred by the utility (the utility cost function) and are therefore collected in rates, and costs and benefits that accrue to customers and society and affect resource utilization—but are not priced by the market or administratively and are therefore not included in utility revenue requirements. Providing the utility perspective is essential because DER accommodation may require incurring costs to realize the benefits.

A societal perspective is warranted to inform policy decisions because:

> … what counts as a benefit or a loss to one part of the economy – to one person or group – does not necessarily count as a benefit or loss to the economy as a whole. And in cost-benefit analysis we are concerned with the economy as a whole, with the welfare of a defined society, and not any part of it.[83]

> … [Cost-benefit analysis] asks whether society as a whole will become better off by undertaking this project rather than not undertaking it, or by undertaking instead any number of alternative projects.[84]

Which externalities are monetized and which are left as measures of physical impacts is a jurisdictional decision. A decision whether to promote DER adoption through subsidies is a social policy question whose resolution would benefit from monetization of all benefits and costs to produce a single measure of net benefit, for a single policy or to compare alternatives. Otherwise, decision makers are left to make their own subjective assessment of the contribution of impacts that are not monetized. Alternatively, a decision by a utility and its stakeholders as to how best to accommodate DER—assuming that the amount of DER is exogenous to this determination—might focus solely on the utility cost function and its impact on rate payers because the influence of externalities has been rendered moot.

The last columns (on the right-hand side) of Figure 9-1 further distinguish benefits by whether they are realized by the customers of the utility or by society, which includes all consumers and all citizens. Costs and benefits are classified into two categories:

- **Change in utility cost.** The net change in capital ownership costs and operating expenditures incurred by the utility that results from adding assets (or avoiding expenditures on assets) or refining operating practices specifically intended to integrate DER.
- **Societal benefits.** The DER impacts that do not directly accrue to the utility or its customers, despite the fact that they may produce costs or benefit to society and its citizens. They include emissions, unpriced environmental and health-related issues, and general economic impacts such as job creation. Mechanisms for monetizing these impacts produce a total societal accounting, reflecting consideration of all costs and benefits, regardless of where (and to whom) in the economy they are realized.

[83] Mishan, E. J., *Cost-Benefit Analysis: An Informal Introduction.* Fourth Edition, Unwin Hyman, London, 1988. p. xxvii.

[84] Ibid p. xxix.

MONETIZATION CONSIDERATIONS

DER impacts are physical changes in the power system that result from interconnected DER, for example, changes in power system equipment—such as new reclosers, upgraded transformers, and reconductored or rerouted distribution lines—made to accommodate the DER additions. Although it is challenging to quantify all impacts on real power systems, they can be estimated using the methods and models described in Sections 5 through 8.

Impacts should be measured or estimated relative to a reference or base case. The Integrated Grid framework commences by defining a base case that defines key drivers to electricity demand and costs that are expected in the absence of DER. It includes distribution system investments that would be made and operational changes adopted to maintain system reliability. Likewise, the bulk power system base case parameters define the system as it is expected to unfold over the study period absent DER. This goes beyond describing the system as it is today because utilities are constantly assessing whether new investments are required to maintain reliability or to reduce costs. Some of these investments may increase hosting capacity (for example, reconductoring to meet anticipated demand growth) or result in tighter limits on the amount of DER that can be accommodated (for example, implementation of voltage management strategies that can be undermined or enhanced by interconnected DER).

Changes in the central generation mix are defined and monetized directly in the process of accommodating DER. Deferring a central generator investment or altering the generation portfolio (substituting one kind of generation for another) changes capital investment. Once the deferral or mix change occurs, countervailing changes in operations and subsequent costs may result. For example, there may be changes in fuel type that affect operating expenses over the long term, or there may be a requirement for new generation services (for example, flexible ramping) to accommodate DER. These interdependencies are anticipated and accounted for in the EPRI framework.

Costs and benefits are the monetary/economic equivalents of impacts. They are derived through a variety of monetization methods, as described in this section. Impacts affect the utility business in a variety of ways. Financially, they can be grouped into major categories that have natural association with cost causation or avoidance and further classified according to whether they are internal to the utility-cost function or externalities. Table 9-1 lists DER impacts categorically organized according to the system level at which they are incurred. The discussion that follows further describes monetization methods for impacts defined in Table 9-1.

Table 9-1
Impacts of DER accommodation and possible benefits and costs

Element	Impacts	*Benefit*	*Cost*
Distribution	Loss Reduction	x	
	Capacity Upgrade Deferral	x	
	Reconductoring		x
	Line Regulators/STATCOMS		x
	Relaying /Protection		x
	LTC accelerated wear		x
	Voltage upgrade		x
	Smart Inverters	x	x
	O&M		x
Bulk Power System	Generation Mix/Requirement Changes	x	x
	Deferral of Transmission Upgrades	x	
	Transmission losses	x	
	O&M	x	x
	Fuel Savings	x	
	Congestion	x	
	System Operations/Uncertainty		x
Customer	DER Investments		x
Societal	Emissions - CO2/GHG, Hg, SOx, NOx	x	
	Cyber Security	x	
	Health	x	
	Macroeconomic effects	x	

ELEMENTS OF THE UTILITY-COST FUNCTION

The utility-cost function defines costs incurred by the utility in providing electric service. These accounting costs are sometimes referred to as the *utility revenue requirement*.

Expenses and capital ownership costs are the differentiating main components of the utility-cost function, as follows:

- **Expenses.** These are expenditures for the routine costs of doing business within a specified period. Utility operating costs include fuel costs, employee payroll expenses, and O&M expenses. All expenses can be assumed to be incurred during the current period; they appear as current-year expenses on the utility's income statement and are included in the annual revenue requirement.
- **Capital ownership costs.** Capital expenditures for generation plants, T&D system equipment, metering and monitoring devices, and buildings and other utility property are converted through accounting rules into a stream of annualized capital-related expense items such as property and income taxes, depreciation (return of capital), interest on debt, and return on equity investment. The impact of investment tax credits and accelerated depreciation may also be included.[85]

  Annual expenses and capital ownership costs added together define the utility's annual revenue requirement, the utility-cost function, and what the utility needs to collect through tariffed rates.

Distribution System Impacts

- **Distribution loss reduction.** Distribution losses will be affected by the presence of DER on the distribution system. To the rest of the system, distribution losses look just like changes in load. Fuel is burned to supply losses, so loss reductions reduce fuel use and associated emissions (other things being equal). Distribution models used in the Integrated Grid framework calculate distribution losses directly. Incremental changes can be monetized using estimates of marginal energy cost and emissions, which themselves can be calculated on an hourly basis for a utility or market system.

[85] Investment tax credits and accelerated depreciation result in a revenue-requirement benefit for consumers. Each of these tax incentives creates a liability that offsets debt and equity investment, acting as a source of investment funds that carry zero cost to the utility. The overall effect is a reduction in revenue required from customers, so that customers receive the net benefits over the life of the investment.

- **Upgrade deferral.** In some cases, planned system upgrades to substations or circuits can be deferred because of loading reductions brought about by DER interconnection to distribution feeders. When this happens, the capital expenditures for the deferred upgrade are usually estimated to be higher than will be needed with DER. The upgrade may provide collateral cost savings or benefits, such as lower losses or other advanced features; these savings and benefits are additional deferred costs.
- **Reconductoring.** The penetration of DER may reach a level that requires a circuit to be reconductored (that is, some or all of the circuit's wires must be replaced by larger wires able to carry more current). The new conductors accommodate greater DER penetration on the circuit but may have other impacts as well. Most prominently, the circuit will have lower losses that produce collateral cost reductions that offset some (but not all) of the incurred capital costs.
- **New required equipment on the feeder or substation, such as voltage regulators.** Adding distribution equipment requires capital expenditures that will be converted into revenue requirements for analysis. There may also be secondary impacts on voltage or other O&M requirements that will lead to other changes in expenses, either increasing or reducing the net costs incurred.
- **Protection changes (relaying).** Protection system modifications undertaken to accommodate DER result in capital expenditures to replace relays and/or breakers. Usually there are no changes in losses associated with protection upgrades. Existing assets being retired early may affect revenue requirements.
- **Accelerated wear on load-tap changers.** LTCs and regulators routinely change settings, and each change causes wear—eventually, the contacts must be replaced. Shortened LTC equipment life from increased cycling duty caused by DER is an accommodation cost.
- **Voltage upgrades.** In some cases, the solution to accommodating DER on a low-voltage feeder is to raise the primary voltage level for the feeder by changing out all of the transformers (in addition to other changes). This requires a large capital expenditure producing smaller offsetting beneficial impacts such as lower losses.
- **Smart inverters.** Smart inverters for PV and storage may improve system stability and voltage control when DER reaches high penetration on a distribution feeder. Smart inverters may cost only slightly more than a conventional simple inverter and may become the norm. In some jurisdictions, smart inverters may be required as a condition of interconnection. The utility may be required to provide the inverter to its customers if the inverter is to be controlled by the utility. If the smart inverter is installed and owned by the utility, its cost is included in the utility-cost function. If owned by the customer or other provider, it is part of the customer's direct cost. However, the customer may be paid for services the device provides to the system, which adds to utility costs.

- **Energy storage.** Energy storage can be deployed to mitigate adverse DER impacts. If storage can be operated for purposes in addition to serving its primary goal (that is, providing the support or service that solves the original problem), system savings may result.

Bulk Power System Impacts

- **Generation mix changes.** Changes in generation mix affect capital expenditures. After the changes occur, however, there are also changes in operating costs owing to the differences in the generation portfolio. Changes in capital expenditures are treated in the revenue requirement framework described previously. The operational changes are derived by comparing the operation of the system with and without the changes, manifested as changes in fuel consumption, emissions, and O&M.
- **Transmission loss reduction.** Loss reduction in transmission lines is valued at marginal energy cost—the same way as small load and loss changes at the distribution level.
- **Operations and maintenance.** O&M is an expense item. Central station generating plants have substantial O&M expenses associated with the operation and maintenance of the plant. These expenses include labor, reagents, and consumables. Most of the O&M expenses for power plants are considered fixed (that is, they do not vary with plant output, at least in the short term). Changes in plant variable O&M costs are derived from generating system simulation models.
- **Fuel consumption.** Reductions in fuel consumption by central generators are cost savings associated with DER. Reductions in fuel consumption will also occur from reductions in losses on the generation and transmission system.
- **Congestion.** Congestion results when an optimal least-cost dispatch of generation resources is not realized because of transmission constraints. The constrained, sub-optimal dispatch is more costly because more expensive units (primarily fuel cost) are being used in lieu of lower cost units. From a broad system or societal perspective, any changes in congestion caused by DER may be accounted for in terms of these changes that may occur in total fuel cost, ignoring transfers among market participants.[86]

[86] In market systems, some market participants may benefit from congestion; others suffer costs. A whole-market or societal view that encompasses all participants would cancel out some of these divergent perspectives, but a narrower view that concentrates on customers in a load pocket, for example, would place great importance on the congestion that raises prices in that area. So where congestion is concerned, the scope of analysis is important.

Congestion is typically thought of as a transmission issue because the dispatch of resources is affected only by transmission constraints, but congestion could be said to occur on a distribution system if a distributed resource has to be curtailed because of distribution constraints. However, changes to the distribution system to accommodate DER are assumed to eliminate congestion among distributed resources on distribution feeders, so congestion remains a matter of constrained transmission where accommodation has taken place.

- **The value of DER** in a given location may be affected by congestion; in market systems, these values are already accounted for by differences in locational prices. DER value is lower if added in areas where prices are depressed by congestion. Conversely, DER value is higher if the DER are located in an area where prices are increased by congestion.
- **Congestion** may also be present within vertically integrated systems and may be affected by additions of DER. However, the integrated utility does not have locational prices for customers in different areas of its system, and all customers share in the higher fuel costs caused by the congested condition. This view of a congested system is similar to the whole-market view mentioned previously, in which the economic effects of locational differences are canceled out across the system—leaving only changes in fuel cost as an effect of congestion within the system. However, the same locational value for DER exists in a congested regulated system: DER additions may have different value in terms of production savings depending on where they are located. All of these congestion issues can be examined using models but only if the program models both transmission and generation systems, optimizing the dispatch within transmission constraints.
- **Emissions.** Emissions of gases and particulates can be estimated using production dispatch models. How they are accounted for depends on whether they are externalities or internalized operating costs. For regulated emissions, utilities or generators must buy allowances (or incur costs so that they operate within allowed emissions limits); the cost of these allowances is included in revenue requirements. The utility incurs no direct cost for its unregulated emissions, but they may create externalities that result in costs incurred by other entities or by citizens. Monetizing these requires accepting some reference price that reflects what a market would produce or is associated with costs incurred by others.

ELEMENTS EXTERNAL TO THE UTILITY-COST FUNCTION

Some impacts result in costs and benefits that are not included in the utility-cost function and are therefore not included in utility revenue requirements:

- **Customer costs and benefits.** Customer costs include long-lived purchases such as energy efficiency (EE) devices and investments such as storage and DER (for example, a rooftop PV system). Some costs, such as EE and PV, reduce the customer's electricity costs; others may improve the quality of service in terms of improved reliability or resiliency. Because the costs are incurred voluntarily by the customer, the purchases presumably have value to the customer.
- **Societal costs and benefits.** Impacts that affect society may be physically measurable but not unambiguously monetized. Two examples are 1) a reduction of emissions such as CO2 that results from DER replacing fossil-burning generation and 2) positive or negative changes in macroeconomic measures of social wealth, such as jobs and wages, which result from DER-supplied energy replacing the output of central generation resources.

Societal costs and benefits are externalities that do not produce cost that accrue to the utility or its customers. To estimate the social net benefit associated with DER requires that these impacts be monetized. Social cost rates associated with various emissions can be applied using the results of studies that seek to determine and monetize the damages associated with emissions.[87] As a proxy, prices can be applied from an emissions market, such as the Regional Greenhouse Gas Initiative (RGGI) emissions market of the northeast.

If DER result in changes in the frequency and duration of customer interruptions, the affected customers either incur a loss or gain a benefit in the form of reduced interruption costs. These are not costs paid to anyone in cash; rather, they are the economic costs of lost time, lost production, lost business, perhaps lost profits, and spoilage. These costs may or may not be known by most customers. Reliability has value, but it is not straightforward to put a dollar figure on it in every case. Regulators assign an implied value to reliability by requiring reliability standards for utilities to meet.[88]

The EPRI DER accommodation methodology identifies when and how reliability will be compromised and defines mitigating actions and their costs. These are counted as part of the DER accommodation cost. As a result, there are usually no adverse reliability impacts to be accounted for in the EPRI Integrated Grid framework.

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[87] Regulators can require a utility to include monetized emissions (or any other externalized impact) in its planning and operations decision making. The utility-cost function will eventually reflect additional costs because of changes in decisions, such as adding more expensive controls or burning more expensive fuel. The utility should expect full recovery only for incurred cost. The intent of such requirements would be for net social cost to be reduced, even though the utility-cost function would be higher than if the externalities were not accounted for in decision making.

[88] Recognizing the need for evaluation of interruption cost (and the value of interruption reduction) at the distribution level, DOE commissioned a study to quantify the cost of interruptions characterized over a variety of conditions in order to be appropriate for evaluation of distribution interruptions differentiated by time of week, day, and year. The end result of this study is a publicly available calculator known as the *Interruption Cost Estimator*, or *ICE*. The ICE model (available online at icecalculator.com) provides an estimate of interruption costs for a feeder, area, or company service territory based on input data that describe the types of loads and the reliability indices that characterize the reliability of the system evaluated. The basis for the interruption costs embedded in the ICE model is surveys taken by utilities over several decades. The process of converting these survey results into damage functions involved many compromises and estimates, but the results are documented and available on the calculator website.

COLLECTION AND INTERPRETATION OF RESULTS

The output of the benefit-cost analysis yields several measures of the financial implications of accommodating DER. A DER study will include several years of data on impacts producing vectors of costs and benefits for the study period. Applying a net present value (NPV) produces summary metrics:

- DER NPV, which is the difference between the NPV of study period benefits and costs
- NPV of the individual cost and benefit monetary streams study period
- The benefit-cost ratio (NPV of benefits divided by NPV of costs)
- Individual categorical benefits and costs as time-indexed vectors or compressed to NPVs

SUMMARY

EPRI has developed benefit-cost analysis methods and protocols to convert the technical impact data produced in conducting a detailed DER impact study into a summary metric of the net benefits. This informs decision makers of the relative merits of alternative DER integration approaches. An important distinction in comparing scenarios (different DER penetrations, for example) is between societal net benefits and utility revenue requirements. The former is appropriate for assessing public policy to ensure that scarce societal resources are used optimally. Externalities used in that calculation must be removed before comparing the implications for the utility revenue requirement and rates that recover it.

The goal of the EPRI Integrated Grid framework is to establish analysis protocols that are widely used so that comprehensive studies undertaken for a specific market convey information that provides insights for others. The protocols are intended for preliminary analyses. EPRI recognizes that utilities and their stakeholders will want to tailor the study to their circumstances, using the appropriate assumptions and established conventions for the way in which revenue requirements are structured and defined.

10 INDUSTRY COORDINATION AND NEXT STEPS

The Integrated Grid analysis framework described in this report supports the transition to a new electric industry paradigm in which centralized and distributed energy resources are fully interconnected to, and jointly coordinated with, the electric grid. A fundamental change in the way in which the industry plans for and operates the electric grid is essential to accommodate evolving customer preferences for how their electricity demand is met and to take advantage of new technologies to meet those demands. This involves planning and operating the electric grid as an integrated system, starting from the customer side of the meter all the way to central generation units and the control and operating system that manages those resources.

A key driver of the need for an integrated grid is the prospect of DER interconnected to the distribution system. The extent of DER interconnection will likely vary considerably over U.S. electric markets for some time. The rate of adoption of DER by customers (operating on their premise) and investments by utilities (located on the distribution system) will be driven by many factors, some of which are external to the utility—including technology advances and regulatory and public policy. DER either use intermittent resources (for example, PV and solar thermal) or act as resources that are intermittent by virtue of how they are dispatched (such as storage or demand response).

All regions of the country have the potential for some DER, so all utilities have an interest in developing the Integrated Grid concept and using some aspects of the analytical framework developed by EPRI. The demands on the design and operation of U.S. electric systems will change over the next decade in ways that cannot be predicted but whose consequences can be identified. EPRI's vision of an integrated grid is that with appropriate preparation, innovative planning and grid management techniques can be developed and adapted to accommodate the integration of DER into the power system.

The Integrated Grid methodology is built on power system engineering and economic principles applied in a consistent, repeatable, and transparent manner. Its approach is to identify and quantify the physical effects (impacts) that rising levels of DER can have on the distribution and bulk power systems. Because so many interrelated physical systems and processes are involved in supplying electricity to end-use demands, finding all of these impacts—and not double-counting any—requires a systematic and dynamic analytical process.

Identifying the physical impacts attributable to DER is not sufficient. Many are costs that can be calculated directly as an output of the distribution and bulk power system analyses and aggregated to portray the system level. Some of these impacts—for example, externalities such as certain generation emissions, reliability, and collateral economic effects on employment and wages—can be measured but are not transacted in any marketplace. Assigning a monetary value to these impacts requires stakeholders coming to agreement on how to accomplish that. If no monetary value is assigned, decision makers must decide what weight, if any, to apply to these impacts.

Widespread application of EPRI's Integrated Grid framework brings a degree of cohesiveness, consistency, and accuracy to evaluations of the net benefits resulting from the proliferation of DER. By using a common evaluation methodology, utilities and other stakeholders can compare and contrast studies and articulate their findings in ways that make the results applicable and useful to others. Doing so accelerates the development of a comprehensive understanding of the key drivers of the impacts of DER adoption at low and high levels, on distribution systems with different loads and designs, and in all electricity markets. The effort and resources required to properly conduct an integrated grid analysis are substantial, but through cooperative efforts using a common evaluation framework, utilities can accelerate the learning process at a fraction of the cost of each conducting its own study in isolation.

NEXT STEPS: INDUSTRY COORDINATION AND COLLABORATION

With the initial release of the Integrated Grid benefit-cost framework, focus now shifts to pilot projects and documentation of the Integrated Grid methodology and of new technologies and their associated performance characteristics, application challenges, and costs. Greater understanding of the framework and the various technology options available can inform the overarching assessment of investment options and scenarios that facilitate the integration of DER. Phase III of EPRI's Integrated Grid project involves two initiatives: 1) application of the framework to utility circumstances and 2) pilot projects to verify key interconnection and performance characteristics.

Integrated Grid Framework Application and Maturation

EPRI's benefit-cost framework is ready for widespread application, but it is a work in progress. The methodology employs available models, methods, and data to construct a complete, end-to-end portrayal of the way in which DER impact the electric system and how to translate those impacts into changes in utility cost and rates—as well as how the impacts generate societal benefits. The methodology also points out where there are shortcomings in modeling the electric grid and an integrated power system.

The complexities brought about by DER integration require the development of new distribution planning tools and operating methods. Better estimates of DER output are essential to ascertaining system needs and meeting them cost-effectively. Communication with and control of field devices improve the system operator's ability to respond to state changes, such as voltage fluctuations. Storage and demand can mitigate some of the adverse impacts of DER, but the way in which they affect distribution system operation must be better characterized and incorporated into dynamic system models. Standards can play a significant role in DER accommodation at the distribution level, but finding the required consensus on what they entail requires substantial impact and implications modeling support.

The dynamic nature and nuances of the bulk power system require dynamic load modeling and forecasting capabilities as well as probabilistic capacity adequacy analyses to account for the intermittent nature of DER. The same is true for assessing impact on the transmission system. Distribution planning models need to be integrated with those of the bulk power system for planning to be truly integrated.

A better understanding of the wants and needs of customers, and when and how they use electricity, is paramount to achieving the Integrated Grid vision. DER are installed by customers to serve their interests. Knowing the key drivers of the DER adoption decision is the first step toward forecasting how many and what kinds of DER are likely to be interconnected—so is forecasting how electricity demand changes as a result. How does free power affect how much customers use, and when, and is it a complement to or substitute for energy efficiency investments? Will DER adopters allow the utility to monitor DER output or let the utility operate the inverter to ensure smooth integration and perhaps use it as a system asset? In either case, will DER adopters expect compensation from the utility?

EPRI seeks and welcomes ongoing collaboration with industry stakeholders to improve upon the Integrated Grid framework to ensure that it develops intelligently and purposefully and is accessible to and used by the industry at large and those who study its operation and performance.

Technology Pilot Projects

Creating a robust grid modeling platform is essential, but it is not enough: it's just the first step. The technologies developed and operating procedures formulated must be subjected to rigorous *in situ* field testing to ensure that they perform as intended. Coordinated technology pilot projects implemented by utilities fulfill this obligation. EPRI proposes that pilot projects be launched to test technologies such as the following:

- **Utility-scale PV, with and without storage.** These are centrally controlled and dispatched generators that are attached to the distribution system. Pilots are needed to confirm the level and timing of the output of the PV system, that interconnection and grid coordination systems operate as designed, and that the design itself achieves effective integration. Storage system operating performance needs to be verified in a production environment and strategies for maximizing its value verified or shortcomings revealed and resolved.
- **Distributed storage (customer-side systems) operated in conjunction with intermittent DER.** Field trials are needed to confirm that storage coordination strategies that appear to be beneficial to the customer and the grid, based on simulations, are indeed beneficial when operated on consumers' premises by consumers.
- **Microgrids that serve local customers' needs for greater electric service reliability and resiliency.** These can also serve as a system asset, but the benefits are speculative until confirmed in practical applications in which systems are fully interconnected with and operated in coordination with the grid.
- **EV charging infrastructure built to serve the needs of electric vehicles but operated to minimize adverse impacts on the grid.** The frequency of use of these facilities is a matter of conjecture; therefore, so are the impacts. The operation of at-scale facilities will resolve the way in which the system is impacted and verify operating strategies or cause them to be refined.
- **Customer-side technologies, such as PV with and without storage as well as devices used by customers to control when and how much electricity they use.** The relatively high rate of PV adoption in some areas provides a testing ground to resolve both technical and behavioral questions about how they are used. In other areas in which adoption has been light, pilots that install and monitor DER systems will provide the data and experience needed to prepare for adoption if it accelerates.

Pilot projects are expensive to implement if they are designed to answer questions about performance and integration to a high degree of resolution. This is particularly the case when rigorous experimental controls are employed to produce measures of performance with a high degree of credibility and whose inference extends to many other circumstances. Collaboration in the design of these pilots ensures findings that are useful across the industry.

Collaborative Technology Assessment and System Pilots

EPRI is prepared to support designing pilots, establishing implementation plans and requirements, acquiring and coordinating the installation of equipment, conducting data collection and analysis, and providing a repository for the data collected to support analyses directed at improving the performance of the electricity sector.

The transition to the Integrated Grid is beyond the scope of any one organization—it requires careful collaboration among multiple parties sharing a mutual interest in DER integration. EPRI intends to engage with the National Association of Regulatory Utility Commissioners (NARUC), the Institute of Electrical and Electronics Engineers (IEEE), the International Council on Large Electric Systems (CIGRÉ), the U.S. Department of Energy (DOE) and its network of national laboratories, utilities, and numerous other organizations to both apply and hone the benefit-cost framework.

EPRI also aims to promote and support an ongoing technology assessment and performance documentation effort alongside other stakeholders. To this end, EPRI intends to work with utilities in the United States and around the globe to coordinate system pilots, deployments, and modeling efforts that contribute to the improved understanding of how to accommodate DER. EPRI intends to establish a data repository for technology information to provide data that can be employed in the Integrated Grid assessments to support a wide range of studies. The framework itself will evolve as more information about new technology options and economics is characterized.

EPRI's Integrated Grid Online Community: A Forum for Ongoing Industry Dialogue

As part of the Integrated Grid initiative, EPRI has created an online community to provide a forum for sharing concepts, ideas, and findings. Regular postings will offer a variety of insights and perspectives from the electric utility and stakeholder communities. Topics to be addressed on an ongoing basis include power system modeling; bulk power system operation; distribution planning; benefit-cost analysis; policy and regulatory framework for DER; and devices, standards, and testing.

EPRI invites all those with a stake or interest in providing reliable, safe, and affordable electricity to meet customer demands to become an active participant in this community. Within the boundaries of constructive conversation and healthy debate, participants are welcome to post comments, ideas, and differing points of view. For more information, visit http://integratedgrid.epri.com.

A GLOSSARY

The benefit-cost framework described in this report is intended to help the electric industry transition to a new paradigm in which centralized and distributed energy resources (DER) are interconnected and jointly coordinated to better accommodate customer preferences and usage options. EPRI's vision of an integrated grid is rooted in a fundamental conviction that, with appropriate preparation, innovative planning and grid management techniques can be adapted to address the impacts of integrating DER into the power system. Careful monetization of these impacts produces a measure of value—the net benefits.

The following terms and definitions are used in this report:

Ancillary services – Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the grid.[89]

Baseload generation – A generator whose expected operational duty will be to operate at relatively constant loads for much of the time with some load follow and with complete start/stop cycles limited to 3000 over the life of the unit.[90]

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[89] "Pro Forma Open Access Transmission Tariff," U.S. Federal Electricity Regulatory Commission (FERC). RM05-17-001.

Combined heating and power (CHP) – Local energy solutions that combine a primary generation source (such as a combustion engine or fuel cell) with a waste heat recovery system. The recovered heat can be used for space heating, hot water, absorption chilling, or other purposes. By recovering energy that would normally be lost, CHP systems are considered significantly more efficient than the primary source alone.

Combustion turbine (CT) – An internal combustion engine consisting of compressor, combustor, and turbine sections. Gas (normally air) from the compressor is mixed with combusted fuel and expands in the turbine, resulting in mechanical (rotational) energy.[91]

Conservation voltage reduction (CVR) – Process of reducing the voltage on a distribution feeder to reduce the consumption of connected loads.

Demand response – A consumer's ability to reduce electricity consumption at his or her location when wholesale prices are high or when the reliability of the electric grid is threatened. Common examples of demand response include raising the temperature of the thermostat so that the air conditioner does not run as frequently, slowing down or stopping production at an industrial operation, or dimming or shutting off lights—basically any explicit action taken to reduce load in response to short-term high prices.[92]

Discretionary investments – An investment that a utility is not compelled to make in order to meet established standards of service. These investments traditionally carry the burden of additional analysis to show a net customer benefit.

Distributed energy resources (DER) – Devices connected to the medium-voltage distribution network that generate or store electrical energy. This list includes photovoltaics, wind turbines, fuel cells, battery storage, small diesel or natural gas engines, and microturbines.

Distribution automation (D/A) – A technique used to limit the outage duration and restore service to customers through fault location identification and automatic switching.[93]

Distribution management system (DMS) – A set of control systems that actively monitor and control activity on the distribution systems. Various modules provide situational awareness, support market operations, and optimize voltage and reactive power profiles. Under local contingencies, these systems locate faults, isolate damaged segments, reconfigure networks, and provide feedback to grid operators.

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[90] IEEE Std C50.13™-2005, IEEE Standard for Cylindrical Rotor 50-Hz and 60-Hz Synchronous Generators Rated 10 MVA and Above.

[91] IEEE Std C37.106™-2003, IEEE Guide for Abnormal Frequency Protection for Power Generating Plants.

[92] Retail Electricity Consumer Opportunities for Demand Response in PJM's Wholesale Markets. PJM: http://www.pjm.com/~/media/markets-ops/dsr/end-use-customer-fact-sheet.ashx.

[93] IEEE Std C37.230™-2007, IEEE Guide for Protective Relay Applications to Distribution Lines.

Distribution system operator (DSO) – The entity responsible for operating, ensuring the maintenance of, and—if necessary—developing the distribution system in a given area and, where applicable, its interconnections with other systems. The DSO is also responsible for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity.[94]

Dynamic reactive support – Reactive power injection, typically required to adapt to rapidly changing conditions on the transmission system such as sudden loss of generators or transmission facilities. Examples that provide dynamic reactive support include generators, static VAR compensators (SVCs), static compensators (STATCOMs), other flexible AC transmission systems (FACTS), and synchronous condensers.[95]

Express feeder – A type of distribution circuit dedicated to specific loads or generators, which often bypasses other customers geographically closer to the substation.

Feed-in tariff (FiT) – A rate structure designed to promote the uptake of a range of small-scale renewable and low-carbon electricity generation technologies.[96] Implementations typically involve guaranteed grid access with long-term, guaranteed payments commensurate with the expected lifetime of the resource.

Flexibility – The ability of a system to deploy its resources to respond to changes in net load, where *net load* is defined as the remaining system load not served by variable generation.[97]

Generation and transmission (G&T) – The central network of large generators connected by a high-voltage transmission network; also referred to as the *bulk power system*.

Hosting capacity – The maximum amount of a particular resource that a system can accommodate without violating an established standard for reliability.

Inverter – A power electronic device that converts DC electricity into AC. It is the primary interface for many types of DER, including photovoltaics, battery storage, fuel cells, microturbines, and some wind machines.

Load-tap changer (LTC) – A selector switch device, which may include current-interrupting contactors, used to change transformer taps with the transformer energized and carrying full load.[98]

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[94] "Concerning common rules for the internal market in natural gas," European Parliament and Council Directive 2003/55/EC. June 2003.

[95] *Reactive Support and Control White Paper*. North American Electric Reliability Corporation (NERC). May 2009.

[96] Feed-In Tariff Scheme, Ofgem. https://www.ofgem.gov.uk/environmental-programmes/feed-tariff-fit-scheme.

[97] E. Lannoye, D. Flynn, and M. O'Malley, "Evaluation of Power System Flexibility," *IEEE Transactions on Power Systems*. Vol. 27, Issue 2, 2012.

[98] IEEE Std C57.12.80-2002, IEEE Standard Terminology for Power and Distribution Transformers.

Looped circuit (feeder) – A type of distribution circuit with two or more sources, usually separated by an open switch.

Networked feeder – A primary feeder that supplies energy to a secondary network.[99]

Network protector – An assembly comprising a circuit breaker and its complete control equipment for 1) automatically disconnecting a transformer from a secondary network in response to predetermined electric conditions on the primary feeder or transformer and 2) for connecting a transformer to a secondary network through either manual or automatic control responsive to predetermined electrical conditions on the feeder and the secondary network. [98]

Numerical weather prediction (NWP) – A science based on reducing the atmosphere to a series of mathematical equations to project the atmosphere forward into the future. The results are weather forecasts.[100]

Plug-in electric vehicle (PEV) – An electric vehicle that allows the user to charge its on-board storage prior to operation.

Photovoltaic (PV) – Sources that convert solar radiation into electric energy using semiconductor devices (referred to as the *photovoltaic effect*).

Power purchase agreement (PPA) – An agreement between a buyer (usually the utility) and seller for the purchase of generated energy, in whole or part, at a fixed price.

Radial circuit (feeder) – A type of distribution circuit fed from a single source.[101]

Reactance (X) – The imaginary part of an impedance; represents the quality of a line or load that absorbs energy during one half-cycle, returns it during the other half-cycle, and does no work.

Reactance-to-resistance ratio (X/R) – Typically a function of feeder construction (such as length, spacing, or wire diameter); this represents the ratio of feeder reactance to resistance.

Renewable portfolio standard (RPS) – A form of utility regulation that obligates electricity suppliers to produce a specific portion of their electricity from renewable sources, such as wind, solar, biomass, or geothermal.

Resistance (R) – The real part of an impedance; represents the quality of a line or load that dissipates energy.

Ride-through – The ability of a generator or load to remain operational during a disturbance of system frequency or local voltage.

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[99] IEEE Std 1234™-2007, IEEE Guide for Fault-Locating Techniques on Shielded Power Cable Systems.

[100] Regional Modeling: What Is Numerical Weather Prediction? U.S. National Oceanic & Atmospheric Administration (NOAA). http://www.esrl.noaa.gov/research/themes/regional/.

[101] IEEE 1610™-2007, IEEE Guide for the Application of Faulted Circuit Indicators for 200600 A, Three-Phase Underground Distribution.

Secondary network – An AC distribution system in which the secondaries of the distribution transformers are connected to a common network for supplying electricity directly to consumers. There are two types of secondary networks: grid networks (also referred to as *area networks* or *street networks*) and spot networks.[102]

Synchronous machine – Electrical equipment (either a motor or generator) that converts between electrical and mechanical energy, where the average speed of normal operation is exactly proportional to the frequency of the system to which it is connected.[103]

Synchronous condenser – A synchronous machine running without mechanical load and supplying or absorbing reactive power.[104]

Transmission and distribution (T&D) – Reference to the delivery infrastructure required to interconnect several generators and loads, using lines of various lengths and operating voltages.

Transmission system operator (TSO) – Entity whose responsibility it is to monitor and control the electric system in real time.[105]

Value-of-solar tariff (VOST) – Electricity distribution tariff designed to compensate PV owners for the computed value of their PV system to the utility (in avoided cost), customers, and society.

Variable generation – Generating technologies whose primary energy source varies over time and cannot reasonably be stored to address such variation.[106]

X/R ratio – See *Reactance-to-resistance ratio*.

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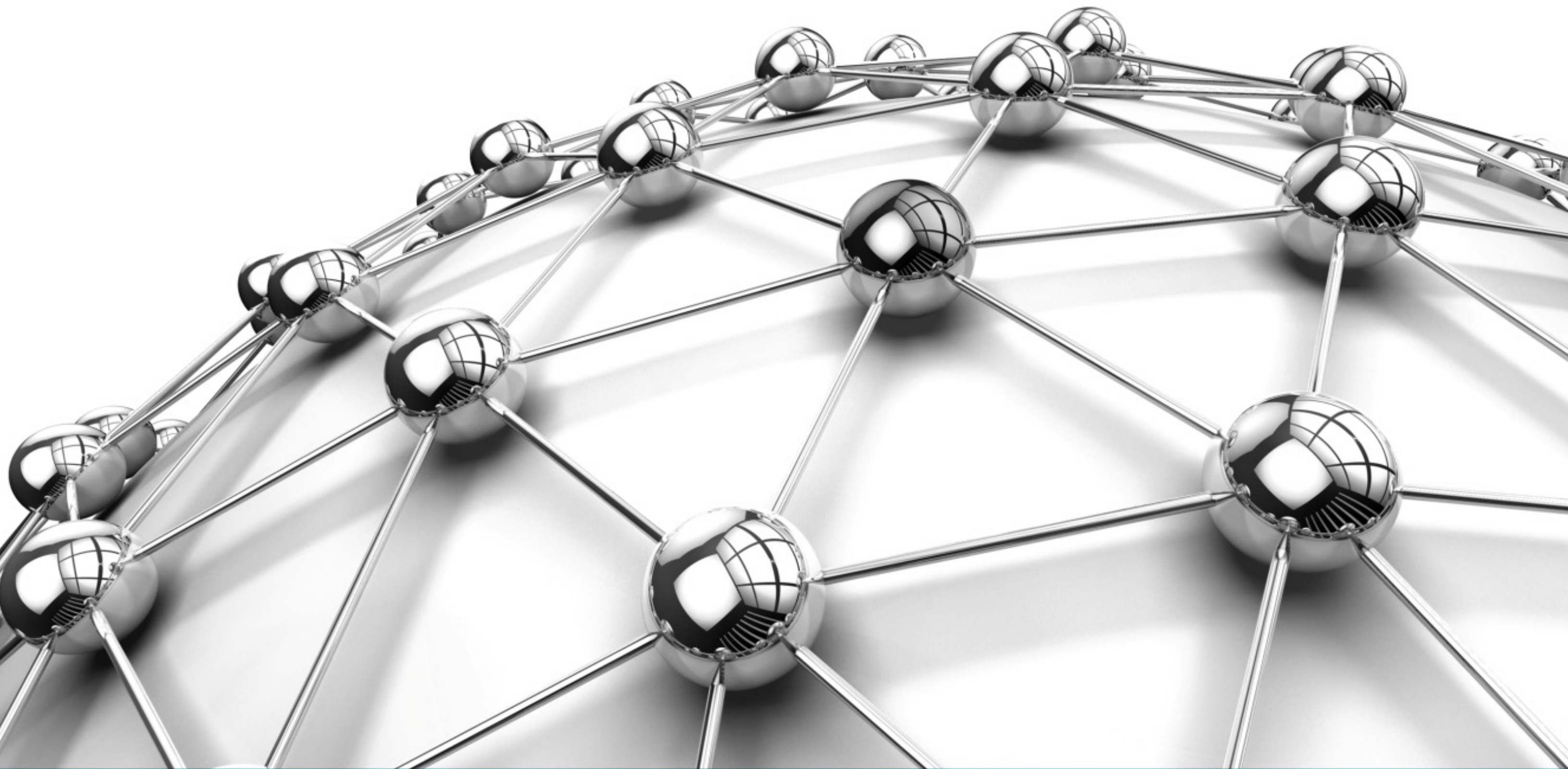
[102] IEEE Std 1547.6™-2011, IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks.

[103] IEEE Std 100-2000, *The Authoritative Dictionary of IEEE Standards Terms*. Seventh Edition.

[104] IEC 60050 International Electrotechnical Vocabulary – Section 411-34-03 (see *Synchronous condenser*).

[105] *Glossary of Terms Used in NERC Reliability Standards*. North American Electric Reliability Corporation (NERC), July 2014.

[106] *Accommodating High Levels of Variable Generation*. North American Electric Reliability Corporation (NERC), April 2009.



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