ELECTRIC POWER
RESEARCH INSTITUTE

THE INTEGRATED GRID

PHASE II:

A BENEFIT-COST FRAMEWORK

DRAFT

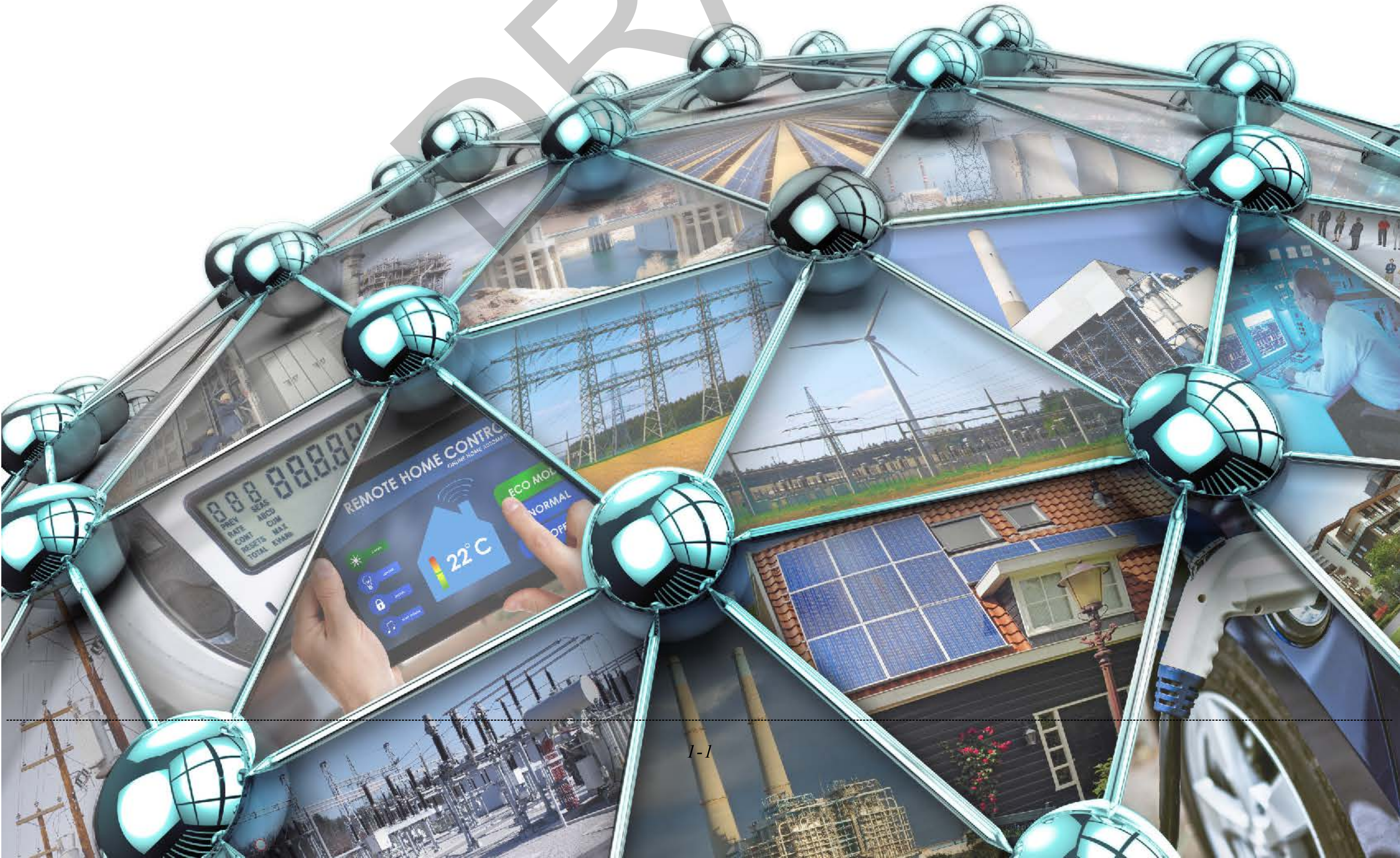


TABLE OF CONTENTS

EXECUTIVE SUMMARY

As articulated in a February 2014 concept paper, the electric power system has evolved through large, central power plants interconnected through grids of transmission lines and distribution networks that feed power to customers.[1] However, it is beginning to change—rapidly in some areas—with the rise of distributed energy resources (DER) such as small natural gas-fueled generators, combined heat and power plants, electricity storage, and solar photovoltaics (PV) on rooftops and in larger arrays connected to the distribution system. In many settings, DER are, in fact, already impacting the operation of the electric grid. Moreover, through a combination of technological improvements, policy incentives, and consumer choices in technology and service, the role of DER is likely to become more pronounced in the future.

Yet the successful integration of DER depends on the supportive capabilities of the existing electric power network. In its current form, today's grid—especially its distribution systems—are not designed to accommodate a high penetration of DER while sustaining high levels of electric quality and reliability. The technical characteristics of certain types of DER, such as variability and intermittency, are quite different from those of central power stations. To fully realize the value of distributed resources and to serve all consumers at established standards of quality and reliability, the need has arisen to integrate DER into grid planning and operational processes and to expand the system's scope to include broad-based DER operation—what the Electric Power Research Institute (EPRI) calls the *Integrated Grid*.

The electricity system as we know it is expected to change in different, perhaps fundamental ways, requiring careful assessment of the costs and opportunities of various technological and policy pathways forward. Changes are also expected to affect the grid's accrued value to utilities, their customers, new stakeholders—including DER investors and owners—and society at large. To this end, EPRI has developed a detailed, actionable framework for assessing the benefits and costs of transitioning to a more integrated grid. Based on user-defined scenarios, the framework offers a holistic approach for identifying the technical impacts of DER—both adverse and beneficial—on the interrelated distribution and bulk systems and monetizes them to inform least-cost strategies.

This report, part of the second phase in a larger initiative aimed at charting the transformation to the Integrated Grid, describes the fundamental changes that increasing levels of DER impose on the electric power system along with existing and future tools

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

and processes intended to address associated impacts. Amid this backdrop, this report details EPRI's turnkey method for determining cost-effective approaches for integrating DER onto the power system.[2]

Characterizing the Framework

In EPRI's view, DER influences the operation of the electric grid and can, in turn, benefit all customers—not just those who install and operate distributed technologies. However, realizing these benefits requires accepting that the greater adoption of DER will fundamentally change power system engineering as we know it. Addressing the anticipated (and unforeseen) issues raised by DER in a timely manner is a fundamental prerequisite to realizing all of the benefits that DER has to offer.

Sufficient capability exists today to begin to identify and quantify DER impacts and characterize important cause-and-effect relationships that can help utilities adapt system requirements in the near term. More complex models and methods, however, are required in order to understand what will be needed in the not-too-distant future to accommodate a more diversified and larger portfolio of DER sited throughout vaster portions of the power system. Many utilities are, in fact, currently tasked with addressing the impacts of elevated DER adoption levels.

The Integrated Grid framework described in this report provides a more comprehensive understanding of DER impacts to, in turn, present a more nuanced range of cost-effective integration strategies to utilities and grid operators. It uses what we know now about distributed energy resources using tools presently available to assess DER impacts and provides a first-order calculation of their benefits and their costs.

The questions explored through the Integrated Grid framework are intended to be broader in scope and scale than those considered in conventional planning, which are more narrowly defined. The latter seeks to identify the best investments and enact operational changes to accommodate anticipated electricity demand at least cost. Historically, with power centrally generated and delivered to individual end users, electricity demand forecasting has involved understanding changes in the number of consumers and businesses as well as when and how they will use electricity.

DER alters the historical equation by introducing complex dynamic effects and interdependencies on power delivery that must be accounted for so that utilities can anticipate and accommodate new uses of the distribution system. In addition, DER initiates changes that are not fully contained at the distribution level. For example, changes in

[2] The framework focuses on DER integration, but the analysis is mindful of the ways in which DER and grid integration can affect energy efficiency and demand response: these, too, could have large effects the affordability, reliability, and environmental cleanliness of the grid.

power demand that result on some feeders have ramifications for the operation of the bulk power system. Changes can, for example, occur in transmission system loads (and directional flows) as well as in the composition and usage of the generating portfolio to meet electricity demand. Dramatic changes (benefits and costs) are possible even at relatively small levels of DER interconnections. At larger levels, DER effects can more definitively influence system performance.

EPRI's proposed methodology aggregates all of the technical impacts experienced throughout distribution, generation, and transmission to thoroughly account for the complex effects that DER introduces and translate them into financial terms. It does so in a consistent, repeatable, and transparent manner in an effort to facilitate the delivery of accessible results that can help move the industry forward.

How Is the Framework Structured?

The EPRI framework, illustrated in Figure ES-1 and informed by core user-provided questions and assumptions, employs distribution and bulk system impact assessments and benefit-cost analysis methods and protocols to convert technical impact data into distilled financial metrics. Through its use, greater information can be derived surrounding the relative merits of alternative DER integration approaches. EPRI anticipates that as applications of the Integrated Grid framework are undertaken, many aspects will be refined. However, the basic structure is robust and ready for immediate use.

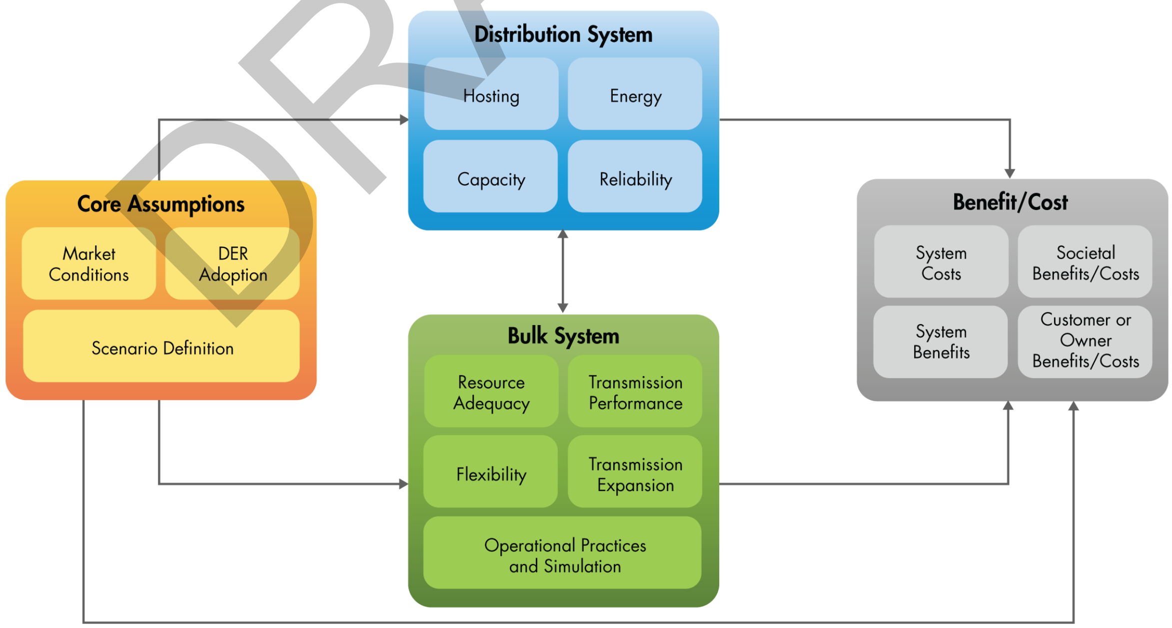


Figure ES-1
The EPRI Integrated Grid framework

An analysis based on the Integrated Grid framework considers incremental impacts, costs, and benefits resulting from DER additions as well as related power system modifications. Figure ES-1 provides a high-level overview of the analytical framework. It is defined by four core components: framing assumptions, DER impact evaluation on local distribution, aggregate DER impact assessment on bulk system operations, and DER impact monetization using an overall benefit-cost analysis.

- **Core Assumptions module.** A study starts by defining a specific question to be answered by the framework along with related assumptions that bound the analysis. This process is represented by the Core Assumptions block. Items in this block range from general parameters, such as a study's timeframe or anticipated interest rates, to specific items such as market structures or land-use constraints. Together, groupings of assumptions define the various scenarios that will be analyzed in order to answer research questions of interest. Therefore, the core assumptions share a direct link with each of the other primary components of the overarching benefit-cost methodology. If research questions require an iterative solution, the core assumptions may need to be modified with prior outputs from the framework.
- **Distribution System module.** Once assumptions are defined, the logical next step is to characterize the way in which the presence of DER affects the operation of the local distribution feeders to which they are connected. The Distribution System process considers incremental impacts—both positive and negative—that result from DER additions. Information supplied by the core assumptions about the physical and performance characteristics of the circuits being studied is a pivotal underpinning for this analysis. Beneficial as well as adverse impacts can be identified using commercially available distribution system power flow models. After impacts are calculated, results are collected for processing at the bulk power system level or in the synthesizing benefit-cost step.
- **Bulk System module.** Beyond the local distribution system, there is also a system-wide impact of DER that must be taken into account. The Bulk System process considers the way in which the operation of the both the transmission system and generation fleet is affected. Certain core assumptions—submitted by users of the framework—are fed directly into this analysis, along with changes in power flow at various substations, which form the natural boundary between the distribution and the bulk electricity system. With an understanding of the expected changes in system load and available resources under a given scenario in hand, various metrics are then used to evaluate the adequacy, flexibility, and performance of existing bulk system assets. Once the necessary adjustments to the bulk system are evaluated, changes in capital costs, such as central generation or transmission, as well as variable costs, such as fuel or maintenance, may be passed on to the overall benefit-cost process.

Although the distribution and bulk system analyses are treated separately in this methodology, there is a definite need to analyze the mutual influence these components have on one another. This is represented in the figure as a bidirectional arrow between the two processes. If, for example, transmission constraints limit options for accommodating DER on distribution, some iteration may be required to produce a valid solution for a given scenario. Ideally, both processes could be unified in a single analysis—but suitable tools are not currently available in commercial software products to accommodate this approach.

- **Benefit-Cost module.** As a final step, the methodology employs a benefit-cost process to summarize the impact of DER in financial terms. Input from the core assumptions is directly incorporated into this step of the framework, including information on utility finances or cost of capital. Recognized changes in benefits and costs derived from the distribution and bulk system processes are recorded, and impacts that have not been monetized in previous steps of the framework are assigned financial terms. Most importantly, impacts are categorized based on the perspective of various entities, including the utility, customer, and society at large. The results of the benefit-cost block comprise the financial outputs that are generally looked upon as the answers to the various questions explored through the Integrated Grid framework.

In some respects, the overarching Integrated Grid approach is similar to an end-to-end system planning analysis—though rarely is system planning done serially, or in the order shown in Figure ES-1. Nevertheless, because the integration of DER implies costs and benefits at multiple levels, this process is necessary in order to properly quantify results and reduce the likelihood of double-counting. Although the order of operations is unique, everything done in the Distribution and Bulk System analysis portions of the methodology includes some form of economic analysis in the usual utility planning style, for example, selecting a least-cost solution among alternatives to solving a problem.

Although the portrayed framework comports with the way in which utilities plan to serve electricity demand, the actual analyses may be complicated by several factors. To analyze a variety of potential outcomes, some research questions will require significant iteration at various points; therefore, the actual process may not be as linear as described. In addition, important details may emerge during analyses that require special treatment and recognition in the economic analysis and potentially circumvent portions of the framework. This is especially true when corporate or market boundaries interfere with an otherwise unhindered process. Though EPRI's framework is based on currently available data and tools, information and expertise from different areas of a utility's organization may be required in order to produce accurate results.

What Can You Do with EPRI's Benefit-Cost Framework?

Equipped with an understanding of system infrastructure issues and DER deployment expectations, the EPRI framework addresses several new research questions that extend beyond the capabilities of conventional planning:

- What are the benefits and costs of adding new DER to the power system?
- How can energy storage be deployed effectively?
- How much can integration costs be reduced by guiding DER deployment?
- What are the most cost-effective solutions to DER integration problems?
- Will it cost more to invest incrementally in the grid as opposed to being proactive?

Effectively addressing these emerging questions requires a perspective grounded in the fundamentals of power system engineering and analysis. Potential DER benefits must always be weighed analytically against their associated costs. If new technologies are to be deployed, the EPRI framework provides methods for evaluating a range of investment options based on DER integration scenarios, distribution system characteristics, and stakeholder objectives. With the entire system modeled and the most cost-effective solutions determined, system-wide integration costs can be determined under the EPRI framework for a variety of DER deployment scenarios.

What's Unique About the Framework?

Numerous benefit-cost studies exist today that inform different levels of analysis (distribution, bulk system, economic, and so on) for various technologies and policies. Each of these studies has independent merit, but there is no broad cohesion among the group as a whole. EPRI's benefit-cost methodology incorporates multiple types of studies to analyze the true impacts of introducing new technologies on the grid. By harmonizing existing methods under one approach, EPRI's methodology offers a way to inclusively assess impacts at a greater technical depth across both the distribution and transmission systems.

There are also features unique to specific components of the framework that are intended to enhance insights. For example, unlike other methods governing distribution impact studies used in the industry, the method proposed by EPRI accounts for static, topological characteristics of each feeder as well as their unique operational response to DER, the location of the DER within the distribution system, and the DER technology itself in interaction with the grid. Rather than examining only a few select feeders, EPRI's proposed methodology examines all feeders throughout a distribution system. It somewhat uniquely takes into consideration the unique response of feeders by characterizing each feeder individually.

EPRI's overriding methodological approach is founded on solid power system engineering and economic principles, allowing the procedure to be adaptable to a changing system. The approach begins with a balanced assessment of the physical effects associated with rising levels of DER. As they are available, new grid management technologies and schemes are also considered for their impact on the distribution and bulk systems. The framework then offers guidelines for determining the associated benefits and costs in various regions, systems, utility service areas, and research questions to, in turn, promote greater industry coordination. As a partial outcome, the framework's results have the potential to support both business and policy decision makers.

What's Next?

The final phase of the Integrated Grid effort—to be launched during the latter half of 2014—will focus on the demonstration of the benefit-cost methodology described in this report. It will also document findings derived from new technologies, including their performance characteristics, application issues, and overall costs. The goal is to develop a greater understanding of the framework and the various technology options available to better integrate distributed energy resources.

Phase III of the Integrated Grid project will involve the following:

1. **Methodology application.** This task will develop a particular set of research questions for a single utility or region along with a corresponding analysis based on the EPRI benefit-cost framework. The required resources and potential scheduling will be subject to scope and availability.
2. **Technology demonstrations.** This task will inform analyses by characterizing emerging technologies and collecting experimental data from the actual deployments. As part of this type of demonstration, EPRI will support the fielding of new equipment, data collection and analysis, and the feedback of information to relevant modeling and benefit-cost efforts.

We look forward to working with utilities, the National Association of Regulatory Utility Commissioners (NARUC), IEEE, the International Council on Large Electric Systems (CIGRÉ), the U.S. Department of Energy and its network of national laboratories, utilities, and numerous other stakeholders from around the globe to mutually facilitate system demonstrations, deployments, and modeling efforts—and to plugging results into EPRI's assessment framework for ongoing evaluation. Together, we can realize the vision of an Integrated Grid.

1 INTRODUCTION

The electric power system's fundamental nature is changing. Today's electricity consumers have ever-increasing choice and control over their electricity usage and are better positioned than ever before to own (or lease) generating assets. Power is no longer supplied entirely from central generation to the customer; instead, transmission and distribution (T&D) networks are incrementally interconnecting a wider variety of resources. 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 scenarios in which distributed energy resources (DER) are installed on isolated parts of the electric power system. 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.

EPRI launched its Integrated Grid initiative to address this need. It involves a three-phase effort intended to align power system stakeholders around the key requirements for effective assimilation and coordination of centralized and distributed power sources onto the T&D network. To this end, the Integrated Grid effort seeks to promote and foster global collaboration along four main areas:

- Grid modernization
- Strategies and tools for grid planning and operations

- Interconnection rules and standards
- Enabling policy and regulation

Integrated Grid research is intended to provide stakeholders with information and tools germane to these four core areas. The initiative is sequentially structured to provide more immediate insights that can be further refined.

Launched in spring 2014 with the publication of a defining concept paper, supporting documents, and knowledge transfer efforts, EPRI's Integrated Grid project has progressed to a second phase.[3] Phase II's primary outputs are a benefit-cost framework, interconnection technical guidelines, and recommendations for grid operations and planning with DER. These efforts position EPRI for the final phase of the initiative, which will support global demonstrations and modeling to provide comprehensive data that stakeholders will need for transitioning to an Integrated Grid.

This report, part of the Phase II undertaking, introduces EPRI's benefit-cost framework. Although it is intended to accommodate multiple stakeholder questions, it focuses on demonstrating—for illustrative purposes—the way in which the framework can help facilitate the greater grid integration of DER.

How Is DER Defined?

For the purposes of this report, *DER* is defined as fulfilling the first criterion (Item 1) in addition to any one or more of those that follow it:

1. It is interconnected to the electric grid, in an approved manner, at or below IEEE medium voltage
(69 kV) and
2. It generates electricity using any primary fuel source or
3. It stores and can supply electricity to the grid from that storage or
4. It involves load changes undertaken by end-use (retail) customers specifically in response to price or other market-based inducements to do so.

The first criterion means that the resource can inject power into the local utility company grid because it complies with the utility's interconnection rules and procedures. The second excludes

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

almost no generation device (although scale economies may make some impractical) and includes all renewables. The third refers to electric storage of any type because it can inject electricity into the grid—even though its ability to do so may depend on electricity generated elsewhere—as well as its delivery through the grid interconnection. Finally, the fourth criterion recognizes end-use loads that are dispatchable; that is, the rate and level of usage can be adjusted specifically in response to grid conditions. It includes loads that are dispatched by an external entity under a contract agreement as well as load changes undertaken by the end user to realize a benefit.

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 and policy challenges must, however, be addressed to help conform today's electricity system to the shifting landscape.

Various technology, business, and policy pathways for 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 on everything from advanced metering to dynamic rate structures. Yet despite their common underlying objectives, these studies collectively offer little consensus because of their often unique methodological assumptions and general lack of transparency. Consequently, no universally accepted process exists to test and verify study results or to evaluate results across multiple studies. Without a standard process, these studies are prone to semantics, either misunderstanding or confusing the perspectives of multiple parties (utility, customer, society) and thus potentially missing or double-counting costs and benefits.

EPRI's benefit-cost methodology, described in this report, is designed to provide the tools and thought leadership necessary to create a consistent, repeatable, and transparent approach to organizing and evaluating such studies. As a result, future studies built on this proposed framework can be 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. The results of multiple studies can then be compared and assumptions cross-referenced and assessed for impact and accuracy. As studies accumulate, their results will be compared and assumptions cross-referenced to revise and further improve upon the initially proposed methods and practices.

The framework described in this report is a **methodology**, not an analysis. The goal is not to develop a one-size-fits-all number or metric, but rather to develop the necessary framework for examining the impact of new resources and methods on the power system—to promote an open discussion around the costs and benefits of different pathways forward. As such, this work product is not intended to be resource- or system-specific; it should be thought of as a set of guidelines for conducting a consistent, accurate analysis.

What's Unique About EPRI's Methodology?

Numerous benefit-cost studies involving different levels of analysis (distribution, bulk system, and economic) have been conducted in order to inform the efficacy and impacts of various technologies and policies. Independently, each of these studies has its own degree of merit, but there is no broad cohesion of approaches among the collective group. This in mind, EPRI's benefit-cost methodology does not attempt to correct or supplant any one study—but rather to incorporate the multiple types of studies performed to date and to analyze the true impact(s) of new technologies on the grid more holistically.

In harmonizing existing methods under one approach, EPRI's methodology offers a way to inclusively assess impacts across both the distribution and transmission systems. Although the methodology's technical depth is distinctive, it is largely founded on established techniques that are not unique to EPRI but that have been modified to address the characteristics of the Integrated Grid. The framework itself builds on years of prior research findings from EPRI's distribution, operations and planning, renewables, smart grid demonstration, and other research and development (R&D) programs. Each component of the overarching framework is rooted in engineering and/or economic perspectives informed by decades of industry experience.

The methods for determining the benefit-cost impacts of DER on distribution build on EPRI's leadership on the topic 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 impacts is necessary to fully understand the consequences of DER adoption. The impacts have been generalized and extended so that results can be applied to entire systems with hundreds or even thousands of distribution feeders using screening protocols that identify where issues are most likely to arise. In turn, analyses can illustrate the impact of new technology on hosting capacity and on conventional benefit categories, such as loss reduction or asset deferral, over a broad swath of utility footprints.

The methodology also shows the way in which five interlinked elements of generation and transmission planning can be combined to assess the aggregated impact of DER at the bulk system level. This approach recognizes the interdependent nature of the functionally different elements of the power system (distribution, transmission, and generation) by considering the effect of DER on planning criteria (such as resource adequacy), operational criteria (such as operating reserves), and transmission system performance.

As is the case with the distribution analyses, impacts of DER on bulk system levels are initially defined by their physical properties and, where possible, monetized as either benefits or costs; corresponding monetary values have not yet been assigned. As such, the benefit-cost analysis component of the framework incorporates methods previously developed by EPRI's Smart Grid program that allocate value metrics according to a classification of different stakeholder perspectives.[4]

What Are the Limitations of the Framework?

EPRI's benefit-cost framework is a work in progress that is intended to be continually refined—after all, its ultimate objective is to be applicable to the industry at large. Several limitations, however, should be noted:

1. As with any benefit-cost assessment, there is no absolute measurement. Analyses developed under this framework will only be able to compare the costs and benefits among different scenarios against a reference case. No value judgment (for example, whether an individual resource is good or bad) will be substantiated based on the EPRI framework.
2. Because the contributing elements of EPRI's benefit-cost methodology are rooted in engineering and economic analyses, general results may not be available until several simulations have been completed. Consequently, significant effort is required in order to achieve meaningful results.

[4] 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.

    a. 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 time horizons of different studies.

Who Should Use This Framework?

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

This framework is intended for **utilities** involved with the following:

- Planning for new types of resources, especially DER
- Anticipating the ways in which DER might influence the electric system at various levels and concentrations
- Developing business strategies considering an ever-changing power system
- Justifying new investments in grid infrastructure to support DER
- Developing rates and tariffs based on cost causation

It is intended for **regulators and utility commissions** involved with the following:

- Studying existing or upcoming policy decisions with respect to DER
- Seeking to interpret the DER studies from different jurisdictions
- Evaluating the relative costs and benefits of DER integration proposals by utilities and/or other stakeholders

It is intended for **third-party stakeholders** involved with the following:

- Selling DER to end-use customers
- Considering investments in DER production and sales
- Evaluating the consumer economics of different program designs, policies, or rate structures

How Should the Framework Be Used?

Although the material presented in this report is detailed, it remains a **framework**. Individual benefit-cost studies will still have a significant amount of variety, based on the technologies or other custom issues studied. Navigating through the EPRI benefit-cost process involves four main steps:

- Defining a question and determining relevant assumptions (addressed in Chapter 2)
- Assessing distribution-level impact (Chapters 5 and 6)
- Assessing transmission-level impact (Chapters 7 and 8)
- Monetizing impacts using an overall benefit-cost analysis (Chapter 9)

Each of these steps is discussed in detail in their individual sections.

A Guide to Reading This Report

The report itself is logically arranged to provide a thorough understanding of the characteristics of DER and the existing grid, the potential impacts that may result with greater grid integration of the resource, and how those impacts translate in economic terms. Following is an outline of the report's individual chapters and their content:

- Chapter 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 conveys some of the informative factors, dictated by users of the methodology, which will influence analytical conclusions.
- Chapter 3 provides an introductory overview of the Integrated Grid's analytical framework. It first briefly characterizes the necessary features of a model that can 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.
- Chapter 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 systems and makes the case for a system-wide view of DER integration.

- Chapter 5 focuses on the distribution aspects of the overall Integrated Grid framework, providing the necessary inputs to the methodology's Bulk System and Benefit-Cost analysis components to properly account for the value streams and the costs associated with integrating DER into the grid.
- Chapter 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.
- Chapter 7 details five core methods that comprise the way in which the Integrated Grid framework considers bulk system planning and operations, building on previous work to account for the nature of DER.
- Chapter 8 describes the mitigation actions and associated benefits. It categorizes the technologies that can be used into several broad areas: system operations improvements, flexibility resources, and transmission technologies.
- Chapter 9 lays out the benefit-cost analysis approach that EPRI has developed to allow for monetization and comparison of scenarios, each consisting of results from the distribution and bulk system processes described in Chapters 5 and 7, respectively.
- Chapter 10 conveys EPRI's desire to coordinate the development and advancement of an Integrated Grid assessment framework in cooperation with others and with collaborative demonstration efforts.

What Else Is EPRI Producing as Part of Phase II 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. However, the unanticipated technological change and consumer acceptance of DER (especially PV) have undermined the standard's usefulness and applicability. Distributed energy resources 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 ironically made it necessary for DER to perform the very functions that IEEE 1547 originally prohibited. Consequently, revisions were made to the standard in May 2014 that now allow DER to support the grid. These behaviors are only permitted, however—not required.

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 the power supply now spanning both the transmission and distribution systems of many jurisdictions, new emphasis is being placed on more tightly coordinating the activities of the DER owner, distribution owner, and transmission system operator. The result: the emergence of new technical requirements that coordinate among different operating entities and, in turn, support greater system reliability. These novel requirements affect many areas:

- Resource (day-ahead) scheduling
- Real-time balancing
- Integrated markets
- Planning
- System operation
- Integrated modeling

In an attempt to promote thought leadership and discussion in this area, EPRI is conducting a series of workshops on these topics for DER, transmission, and distribution owners and operators. Participating organizations include independent power producers, equipment manufacturers, integrated utilities, independent system operators (ISOs), distribution companies, national laboratories, government offices, and research organizations. The core aim of these workshops—anticipated to occur over the next 18–24 months—is to identify common objectives and approaches for meeting them. Technology transfer is expected to be provided in a series of white papers.

2 DEVELOPING QUESTIONS AND CONTEXT FOR AN INTEGRATED GRID

The Integrated Grid framework described in this report employs a holistic, system-level approach for determining the physical impacts of distributed energy resources on the power system as well as their associated costs and benefits. Its value in informing investment and policy decisions, however, is dependent upon user-defined objectives, contextual questions, and stated assumptions that inform the methodology's various steps to produce meaningful outcomes. Hence, successful application of the framework requires practitioners to carefully consider a range of issues—including the nature of the general inquiry driving analysis, reference cases, scenario development rationales, and related input assumptions—that will color results.

This chapter briefly describes 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 conveys some of the informative factors, dictated by users of the methodology, which will influence analytical conclusions.

Posing New Questions to Integrate DER

The transition to an Integrated Grid requires that the electricity industry begin to ask and reflect upon new questions. These questions are intended to recognize the emerging issues challenging our ability to adhere to the system's high functioning performance, reliability, and safety standards. Growing deployment of DER is, for example, increasingly taxing the capabilities of conventional planning techniques that assume one-way energy delivery from power plants to consumers. As a result, newer approaches are needed that are better suited to inform electric system asset investments and prepare the electric grid for greater distributed energy resource integration.

There is growing activity among utilities, government agencies, consultants, developers, DER owners, and consumer groups to tackle the issues posed by the movement toward a more decentralized model. Most of these efforts are, however, often proprietary in nature and/or limited to specific focus areas and unique approaches. Consultants and other third parties often develop their own unique analyses, making it difficult to compare and contrast findings. As an overarching consequence, there has been sparse sharing of results, and in turn, little industry consensus despite the common purpose many of these studies share.

The Integrated Grid framework offers a means for filling this industry gap by informing public and internal planning efforts with additional perspective, grounded in the fundamentals of power system engineering and analysis, around DER and its system-wide effects. Its standardized approach adheres to methods that are accurate, consistent, repeatable, and transparent to confidently justify investment or operational decisions based on a more holistic viewpoint. Like all benefit-cost methods, however, its meaningful application relies on the development of well-thought-out planning questions that consider the changing electricity landscape and its constituent dynamics. This initial exercise—clearly defining a problem and developing requisite question(s) intended to help elicit solutions—falls to the users of the Integrated Grid methodology and drives the entire benefit-cost process.

There is, of course, a wide range of pertinent research questions that can be adapted to meet expressed objectives using the methodology, a sampling of which follows.

- **Is investment in DER justified and/or cost-effective?** Although not a new question—cost justification has always permeated utility rate cases and decision-making processes—new types of assets beyond poles and wires, such as distribution management systems (DMS), have unique cost and benefit metrics by which they are evaluated. With the growth of DER, these types of investments may conceivably move from a class of discretionary, non-required investments to the most cost-effective methods for integrating distributed resources.

- **What is the value of a given resource to the rest of the system?** "Value of Solar" discussions have, for example, occurred in many jurisdictions over the past two years that attempt to define the derived utility or societal value of customer-adopted photovoltaic (PV) generation. There are, however, many types of value (intrinsic, economic, financial, or otherwise) to consider that can be used to set resource procurement targets or inform ratemaking, as seen in recent developments in Austin, Texas and the state of Minnesota.[5, 6]
- **How much DER can be accommodated without making further infrastructure investment?** Wind integration studies, which typically address bulk system concerns, and PV hosting capacity studies, which typically focus on distribution issues, attempt to address this question. In both types of studies, the current physical infrastructure is assumed fixed while the distributed resource deployment is increased. This process continues until some planning or operational criteria are violated and the limit defined. The Integrated Grid methodological approach can go beyond the purview of typical wind integration and PV hosting capacity studies by assessing the system-wide impacts of DER on the unified transmission and distribution (T&D) networks.
- **What will be the cost to integrate and accommodate additional DER into the current electric power system?** This question allows for different infrastructure investments to be applied in order to increase DER integration limits. With many options available, a successful study in this area needs to compare both the benefits and costs associated with different technology or operational pathways across the entire system. A narrowly defined example from Southern California Edison in 2012 examined the difference in costs between utility-guided PV versus organic growth based on individual customer decisions.[7] In other efforts, 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.[8]
- **What are the costs and benefits of different methods for deploying DER?** This type of question focuses on locational and operational efficiencies that may be gained or sacrificed with changes in deployment strategies for DER. Determining the costs and benefits of deploying DER with "smart inverters" or of strategically installing DER in "sweet spot" locations that can support additional two-way power flow without major infrastructure

[5] 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.

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

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

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

upgrades are examples of this type of inquiry. With the recent 1.3-GW energy storage mandate in California,[9] increasing numbers of stakeholders are likely to evaluate specific locational values associated with the resource.

- **What new business strategies are applicable to DER?** This question is typically a product of high-level planning for utilities and other stakeholders and still implies the need to evaluate operational efficiencies and the best uses of capital expenditure. For instance, is it profitable for utilities to own DER? Can DER be profitable in an energy or capacity market? Should stakeholders pursue individual- or community-owned solar? What new utility services can be marketed specifically to owners of DER?
- **How does integration cost change as penetration of DER increases?** Most third-party studies typically project integration costs based on a system's existing architecture and consider the amount of DER expected to come on-line only over the next few years. However, as projections progress into the future, the increasing number of DER interconnections will produce different kinds of integration costs to the utility. For instance, integration costs with a low penetration of DER now arise mostly in the form of voltage constraints that may be mitigated with smart inverters or by resizing certain distribution equipment. However, systems with larger amounts of variable DER may require changes in system protection, controls for substation LTCs, or bulk system items such as synchronous condensers to provide inertia. Future-proof studies will incorporate methodologies that dynamically adjust in order to consider the full system impact of increasing DER adoption.
- **Does incremental investment cost more than a preemptive accommodation?** This question requires a combination of operational, technical, and policy regimes in order to investigate a more detailed problem of proactively addressing the changing nature of a system with DER. Discerning that some system investments can benefit greatly from consistent implementation and economy of scale, can some system improvements be better addressed before they are considered compulsory requirements to preserve system reliability? From a regulatory standpoint, does it make economic sense to allow utilities to invest in anticipation of future DER growth, just like load growth?
- **What is the theoretical upper limit to distributed generation?** Can an entire power system be created and supported by DER? What are the upper limits to DER growth that can be accommodated while still creating a reliable power system? What is the economic benefit-cost relationship for more fundamental quantities such as inertia, frequency, and voltage performance? Are there economic barriers that must be considered in advance of technical

[9] "Decision Adopting Energy Storage Procurement Framework and Design Program," Public Utilities Commission of the State of California, Sacramento, CA, October 2013.

ones, or vice versa? The answers to this overarching curiosity would likely require many test cases to evaluate the potential of resource mixes and mitigation options.

These and other crafted questions represent a first key step to using the Integrated Grid methodology. As organizing principles, they directly determine the manner in which the methodology can be employed to accomplish targeted ends. This in mind, when framing a new research question, two important points are important:

- **Benefit-cost analyses are always relative.** The positives and negatives of any scenario will always be relative to those of another scenario. Questions answered by the framework must involve one or more scenarios that are compared to a reference case.
- **More general questions require analysis of many scenarios.** Typically, questions that are loosely defined require either large numbers of scenarios, or many assumptions, for the framework to arrive at a conclusion. Careful definition of a research question will involve trade-offs between the applicability of the analysis and its level of complexity.

Informing the Benefit-Cost Framework

Providing context to a research question in the form of scenario assumptions and other situational factors is a vital next step to informing the benefit-cost framework. A number of variables will affect the methodology's calculation as well as its output, such as geography, available resources, or other system characteristics. As such, considering a universe of relevant, value-laden assumptions and inputs to the benefit-cost model is an integral component to producing sought-after results. Following is a narrative sampling of such considerations.

- **Renewable resource availability.** Renewable resource availability in a specified region can significantly affect the outcome of any study. For example, DER technology adoption in solar-rich portions of the American Southwest could be significantly different from those in the Northeast or Northwest, which have significantly less solar irradiance. Consistently sunny locations will allow for higher solar resource capacity factors, along with different alignments between solar production and system load. In a similar vein, cold winter temperatures may affect the uptake and behavior of customer-sited combined heating and power (CHP) systems.
- **Customer behavior.** The manner in which end users evaluate the viability of customer-sited DER investments is key to understanding DER adoption potential. Even if the solar resource is plentiful and PV panel costs are low, customers may still elect to forgo installation for a variety of reasons. Meanwhile, as energy storage becomes more economic (relative to utility-supplied energy and capacity), a greater number of customers may elect to have these devices installed in their homes or businesses. Will they be operated to shift load or to avoid paying a

demand charge? Will customers elect to use these devices (or flexible load) to participate in demand response programs? Customer behaviors governing these decisions are likely to be influenced by the regulatory and policy climate along with technology availability and cost.

- **System architecture.** Though each utility in a given region has to provide for generation, transmission, and distribution of electricity, the scale and scope of these facilities range significantly, as does the technology employed. A small rural utility may have only a few transmission lines, with long distribution feeders serving a small number of customers each mile. Meanwhile, an urban utility may have a strongly interlinked transmission backbone, along with short, possibly networked, distribution feeders serving a dense customer population. The type and age of available central generation assets will also impact benefit-cost outcomes. Areas with large amounts of hydroelectric power will differ from systems that rely on coal or nuclear for baseload generation. The age of these central plants also affects their efficiency (or heat rate) as well as their flexibility and forced outage rate.
- **Electricity market organization/management.** The organization and management philosophy of the local utility and system operator will also affect outcomes. Is generation in a service area participating in an organized market? Can DER participate in the market, either individually or through an aggregator? Is there a requirement or opportunity for DER to provide ancillary services? If there is no organized market, is there possibility for DER owners to establish bilateral contracts or enter into power purchase agreements (PPAs) with the local, vertically integrated utility?
- **Policy and regulatory climate.** Positions established by both legislative and regulatory bodies must also be accounted for. Is local, state, or federal government attempting to promote renewable energy through a renewable portfolio standard (RPS)? If so, is it implemented in such a way as to prefer central or distributed renewable sources? How are individual DER installations metered and compensated for their generation? Does the customer use DER to supply part of their own load behind the meter, or is the installation in a buy-all, sell-all relationship with the local utility? How are the rates structured in a given area or customer class? Are rates structured to incentivize energy conservation, such as with volumetric rates, or perhaps to promote the installation of distributed solar (with a high feed-in tariff)?

Table 2-1 illustrates a range of assumptions that may be incorporated as boundaries to the analysis. It is intended to provide a greater scope of representative issues that bear consideration for completing various types of assessments.

Note: Only specific assumptions will be applicable based on the nature of the inquiry posed to the methodology.

Table 2-2-1
Snapshot of Assumptions

General	• Timeframe of study • Inflation/escalation rates • Investor/utility cost of capital

Regulatory Policy	• Locational value
	• Tariff options
	• Utility obligations
	  – Responsibility to serve
	  – RPS
	• Customer incentives (technology-related)
	  – PV, microgrids, storage, CHP, demand response, etc.
	• Utility incentives
	  – Reliability and resiliency
	  – Infrastructure investment incentives
	  – Electrification incentives

Bulk System Operations	• Market characteristics
	  – Energy
	  – Capacity
	  – Ancillary services
	  – Flexibility
	  – Fuel diversity incentive
	• Resource mix and projections
	  – Generation type: coal, nuclear, hydro, wind, PV, natural gas, other renewable, etc.
	• Capacity resources
	  – Energy storage
	  – Demand response
	• Locational availability
	• Fuel availability and deliverability

Table 2-1 (Continued)
Snapshot of Assumptions

Transmission Characteristics and Planning	• 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), PMUs, demand response, energy storage
	• Operations and maintenance
	• New infrastructural build costs
	• Wide-area monitoring capability

Distribution Characteristics and Planning	• 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, EV charging (including vehicle-to-grid)
	• Communication systems
	• Distribution optimization objectives
	  – Reliability
	  – Resiliency
	  – Efficiency
	  – Power quality

Societal Value	• Electrical reliability • Grid resiliency • Customer choice • Energy efficiency • Environmental – Reduced carbon emissions

Obtaining Precision Through the Integrated Framework

Though high-level objectives described above can be defined fairly easily, addressing the specific components of the evaluation at scale can be fairly complicated. For instance, assessing the hosting capacity of one distribution feeder may be straightforward and accomplished with a high degree of detail. Applying that same solution to an entire distribution system that may have thousands of feeders may, however, be challenging and of questionable value. Many benefit-cost studies produced to date use a top-down approach, beginning with general categories of costs and benefits.

In contrast, the methods espoused in this report all begin at an engineering level and work their way up. As a result, these methods may require much more specific data than a top-down analysis, leading to simulations that are much more detailed. Items that are not defined as assumptions, or provided by external input, must be derived from the analysis. Therefore, the range of potential scenarios is more extensive and the analysis more involved. Because the number of technology or policy mechanisms is numerous and unintended secondary impacts are possible, it may be difficult to achieve precision with just one run through the analysis. Often, precision will be achieved by working through several reference cases or sensitivities to establish a range of outcomes. These types of "runs" will also likely reveal gaps in existing modeling processes that will require additional tools with which to reduce simulation runs and achieve greater accuracy.

Evolving the Integrated Grid Framework to Address Future Questions

The power system is changing as a result of factors that include the growth of DER, the shifting nature of customer behavior, and the adaptation of policy and regulatory frameworks. Today, the majority of planning questions are attempting to address the emerging impacts of initial DER grid integration, assuming that the vast majority of the electricity network remains static. However, as system characteristics continue to evolve, a basic benefit-cost framework needs to consider future states and contain a degree of flexibility that is able to address incipient and/or as yet unrecognized questions. A work in progress, the Integrated Grid methodology is positioned—with input from stakeholders—to be adapted to address potential future planning needs.

Growing familiarity with the Integrated Grid approach and its incremental, consensus-based refinement should allow for its application in an increasing variety of ways. In the near term, documented examples of its use are intended to help impart the range of questions, assumptions, and processes that can be employed to derive an array of results.

3 OVERVIEW OF THE ANALYTICAL FRAMEWORK

A complete and actionable analysis of how DER affects electric system operation requires using an assortment of planning tools and processes to address a range of user-defined questions discussed in the previous chapter. EPRI's Integrated Grid framework incorporates many existing analysis methods to arrive at outcomes that are broader in scope and scale than those that can be derived from individual planning studies performed in isolation. In this way, the framework is designed to move beyond the more narrowly defined parameters governing conventional planning methods (which typically select investments and enact operational changes that accommodate anticipated load growth). It is instead equipped to more comprehensively explore the physical and financial impacts of varying penetrations of DER on the entire electricity network.

This chapter provides an introductory overview of the Integrated Grid's analytical framework. It first briefly characterizes the necessary features of a model that can 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.

Framing the Integrated Grid Process

A high-level representation of EPRI's analytical framework is depicted in Figure 3-1. It considers incremental impacts, costs, and benefits resulting from DER additions as well as related power system modifications. It is defined by four core components: framing assumptions, DER impact evaluation on local distribution, aggregate DER impact assessment on bulk system operations, and DER impact monetization via an overall benefit-cost analysis.

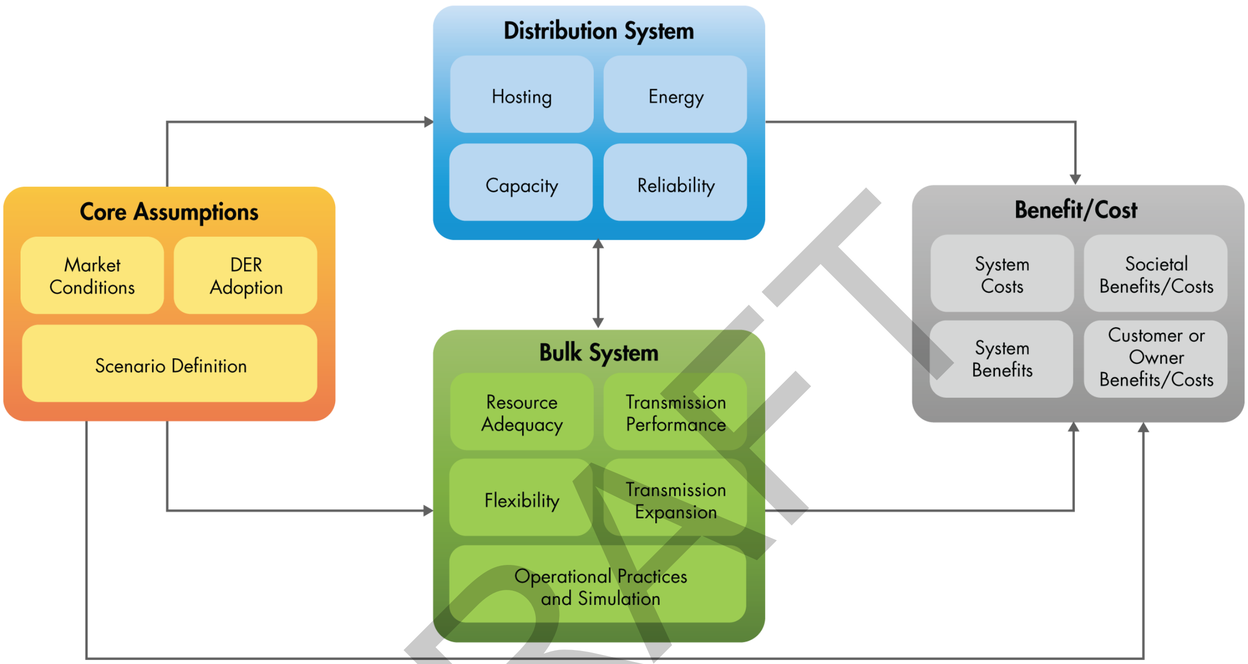


Figure 3-1
Overview of the benefit-cost methodology

As discussed in Chapter 2, a study starts by defining a specific question to be answered by the framework, along with related assumptions that bound the analysis. This process is represented by the **Core Assumptions** block in Figure 3-1. Items in this block range from general parameters, such as a study's timeframe or anticipated interest rates, to specific items like market structures or land-use constraints (see Table 2-1 for an example list). Together, groupings of assumptions define the various scenarios that will be analyzed in order to answer research questions of interest. The core assumptions therefore share a direct link with each of the other primary components of the overarching benefit-cost methodology. If research questions require an iterative solution, the core assumptions may need to be additionally modified with prior outputs from the framework.

Once these assumptions are defined, the logical next step is to characterize how the presence of DER affects the operation of the local distribution feeders to which they are connected. The

Distribution System process considers incremental impacts, both positive and negative, resulting from DER additions. Information supplied by the core assumptions about the physical and performance characteristics of the circuits being studied is a pivotal underpinning for this analysis. Chapter 5 of this report demonstrates how beneficial and adverse impacts are identified using commercially available distribution system power flow models. Chapter 6, meanwhile, provides additional information about methods for enhancing beneficial distribution system impacts—and mitigating adverse ones. After impacts are calculated, results are collected for processing at the bulk power system level, or in the synthesizing benefit-cost step.

Beyond the local distribution system, there is also a system-wide impact of DER, which must be taken into account. The **Bulk System** process considers how the operation of the both the transmission system and generation fleets is affected. Certain core assumptions, submitted by users of the framework, are fed directly into this analysis, along with changes in power flow at various substations, which form the natural boundary between the distribution and the bulk electricity system. With an understanding of the expected changes in system load and available resources under a given scenario in hand, various metrics are then used to evaluate the adequacy, flexibility, and performance of existing bulk system assets. These methods are described in detail in Chapter 7.

If the performance of the bulk system using existing resources is inadequate or anticipated network expansion is insufficient to preserve reliability, a series of mitigation options at the bulk system level are identified and defined in Chapter 8. Once the necessary adjustments to the bulk system are evaluated, changes in capital costs, such as central generation or transmission, as well as variable costs, like fuel or maintenance, may be passed on to the overall benefit-cost process.

Although the distribution and bulk system analyses are treated separately in this methodology, there is a definite need to analyze the mutual influence these components have on one another. This is represented in Figure 3-1 as a bidirectional arrow between the two processes. If, for example, transmission constraints limit options for accommodating DER on distribution, some iteration may be required to produce a valid solution for a given scenario. Ideally, both processes could be unified in a single analysis, but suitable tools are not currently available in commercial software products to accommodate this approach. Chapter 4 of this report more fully describes the interrelated nature of the distribution and bulk systems as well as the general impact that DER can have on both components of the Integrated Grid.

As a final step, the methodology in Figure 3-1 employs a benefit-cost process to summarize the impact of DER in financial terms; this process is detailed in Chapter 9 of this report. Input from the core assumptions is directly incorporated into this step of the framework, including information on utility finances or cost of capital. Recognized changes in benefits and costs derived from the distribution and bulk system processes are recorded, and impacts that have not been monetized in previous steps of the framework are assigned financial terms. Most importantly, impacts are categorized based on the perspective of various entities, including the utility, customer, and society at large. The results of the benefit-cost block comprise the financial outputs that are generally looked upon as the answers to the various questions explored through the Integrated Grid framework.

In some respects, the overarching Integrated Grid approach is similar to an end-to-end system planning analysis—though rarely is system planning done serially or in the order shown in Figure 3-1. Nevertheless, because the integration of DER implies costs and benefits at multiple levels, this process is necessary to properly quantify results and reduce the likelihood of double-counting. Although the order of operations is unique, everything done in the distribution and bulk system analysis portions of the methodology includes some form of economic analysis in the usual utility planning style, such as to select a least-cost solution from several alternatives to solving a problem.

Although the portrayed framework comports with how utilities plan to serve electricity demand, the actual analyses may be complicated by several factors. To analyze a variety of potential outcomes, some research questions will require significant iteration at various points—so the actual process may not be as linear as described. In addition, important details may emerge during analyses that require special treatment and recognition in the economic analysis and potentially circumvent portions of the framework. This is especially true when corporate or market boundaries interfere with an otherwise unhindered process. Though EPRI's framework is based on currently available data and tools, information and expertise from different areas of a utility's organization may be required to produce accurate results.

The following section presents a more detailed description of the framework's core components. These key processes are comprehensively elaborated upon in Chapters 5–9.

Methodological Components

Distribution Analysis

The concept of *hosting capacity* forms 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 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. These criteria are impacted by several factors discussed in Chapter 5, including feeder construction, voltage regulation strategy, and DER deployment. Chapter 5 also describes the manner in which hosting capacity may be calculated for several feeders, as well as the data and tools required to perform 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:

1. Analyze the ability to expand hosting capacity through a series of mitigation options.
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 Chapter 6). The strengths and weaknesses of each solution are presented 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 then exports options for potential system upgrades, including their respective timing, directly to the economic analysis; associated change in power flow is reported to the bulk system analysis as a procedural input.

By maintaining standards of reliability and power quality according to planning criteria, the method essentially assumes that reliability and power quality remain within accepted ranges. That is, reliability is not allowed to deteriorate, which would appear as a direct cost to customers. Rather, the system is upgraded to maintain reliability, which appears as a cost in the utility cost function. The same is true for power quality, which will be maintained by physical means.

Bulk System Analysis

Bulk system analysis refers to the joint study of transmission and generation planning for systems that are subject to DER growth at the distribution level. As with distribution system analysis, bulk system analysis is governed by a series of metrics that reflect the system's reliability and performance. Given the adoption of DER and the potential for mitigation at the distribution level, the operation and future planning of the bulk system must be adjusted to maintain core system metrics at acceptable levels. 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 Chapter 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 system level to ensure that the system continues to meet performance metrics. Chapter 8 outlines several traditional and upcoming technology options, their advantages and disadvantages, and their respective impacts on the framework's major processes. The output of the bulk 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 system analysis steps of the framework comprise a set of impacts, some monetized and others not. The economic analysis monetizes the remaining impacts and tabulates costs and benefits. In categorizing these expenses, specific care is taken to identify the type of expense (capital or operating) and its related timing. In addition to consolidating results, the economic analysis traces how costs and benefits arise among various entities, including customers and society.

Tracing the flow of costs and benefits requires an understanding of the corporate and market structures that govern the behaviors of utilities and that may influence their customers. Although many power system questions can be resolved from a customer-cost perspective, some economic questions must be evaluated in a societal economic framework. Utility planning analyses support power system investment and operation decisions based on costs that are incurred in doing so and revenues that arise from power supply and delivery.

However, the use of societal resources to produce electricity can have effects that ripple out (or sometimes cascade) to sectors of the economy and affect rate payers in different ways (as well as citizens who are not rate payers). Some impacts are typically externalized in keeping with regulatory and public policy. EPRI's analyses include all quantifiable impacts, however, especially when evaluating cost causation and benefit causation. EPRI's purpose is to provide analysis that informs utilities, regulators, and public policy makers on matters that may affect cost allocation, rate design, and other policy issues relevant to electricity. Therefore, the framework characterizes costs and benefits from both societal and utility-customer perspectives.

4 SYSTEM OPERATING IMPACTS: CAPABILITIES AND CONSIDERATIONS FOR ACCOMMODATING DER

Recognizing the unique characteristics of DER that impact both the local distribution and the bulk electricity system is essential to determining the costs and benefits associated with greater adoption of these resources. Identified impacts likewise inform the infrastructure and operational approaches (and their costs) that must be consequently adapted.

This chapter 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 two systems and makes the case for a system-wide view of DER integration. To this end, it lays the groundwork for determining cost-effective DER grid management strategies by summarizing the following:

- Resource characteristics inherent to DER that drive the potential to positively and/or negatively impact the power system
- Distribution and transmission system-specific impacts that may result from high DER penetrations

- 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 chapters (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 Shift to More Holistic Planning Paradigms

The interrelation of the distribution and bulk system components of the electricity grid necessitates that the operating impacts of DER be examined in a holistic manner so that potentially cascading and conjoined effects can be appropriately captured and reported. 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 conventional 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.

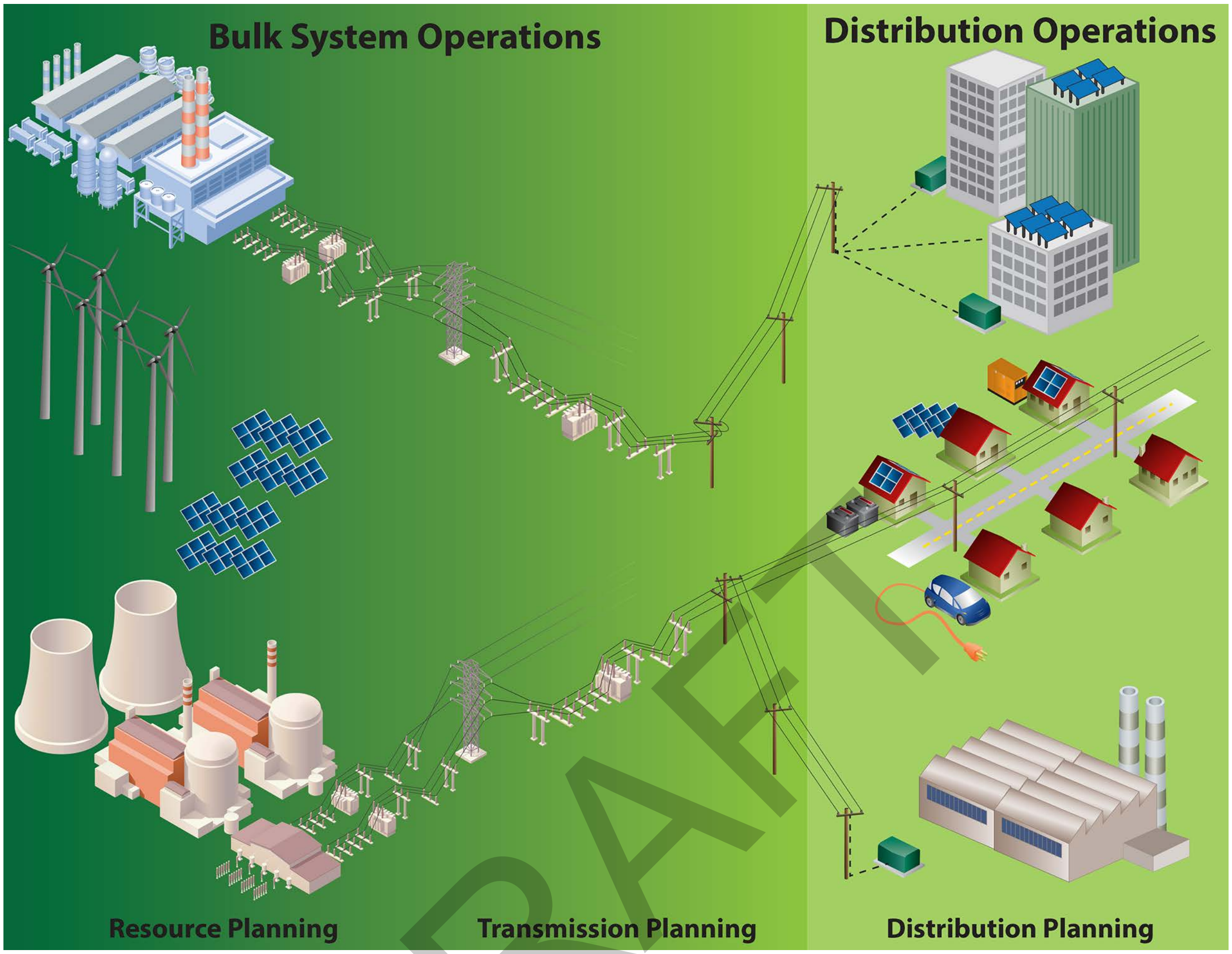


Figure 4-1
Interconnection of the power system and the traditional isolated planning and operations functions that are challenged by increasing DER levels

As such, transmission planners have traditionally been able to consider the distribution system as a lumped load at the appropriate 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 have been able to assume that the transmission system is an infinite source delivering sufficient voltage and frequency at the high side of the distribution substation transformer from which they ensure that sufficient delivery capability exists to reliably supply individual loads across the system.

But with increasing DER levels across broader distribution areas, distribution and transmission can no longer be planned and operated in isolation. For example, rising DER penetrations elevate 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, as well as alter operations and maintenance (O&M) protocols and frequencies.

All told, the interconnected nature of the T&D systems and the growing potential for distributed energy and ancillary services to be provided from the distribution system require that the overarching T&D network be planned and operated as one rather than in parts. Increasing DER levels will increase 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.

DER Characteristics That Drive System Impacts

Historically, for utility planners DER has been a distribution-centric consideration. Distribution systems have been operated with traditional DER technologies—such as reciprocating engines and combustion turbine (CT), including microturbines—for decades. In these circumstances, the potential benefits and adverse reliability impacts of traditional DER have been well documented.[10, 11] Identified benefits include deferral of T&D investment, reduced line losses, and reduced congestion. Commensurate reliability and safety concerns include 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 is, however, driving a growing need to reassess the impacts of DER up through the bulk electric system as well. Because of their unique attributes, the greater grid penetration of DER technologies is poised to produce both new potential benefits as well as challenges to the entire power system.

[10] 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.

[11] 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.

Table 4-1 provides a summary overview of the major DER characteristics that drive the benefits and challenges that DER represents to transmission and distribution operations and planning. Each of the characteristics summarized in the table is further elaborated upon in the subsection that follows.

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

Point of Interconnection Impacts

By definition, *distributed* energy resources interconnect to the power grid through the medium-voltage distribution system or below, often behind the customer meter. Relative to traditional bulk system interconnected generation resources, the locational aspect of DER—the fact that it is located at or near the load without having to be delivered through the transmission system—introduces the potential for both beneficial and adverse impacts. The potentially 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. As a result, serving load from DER as opposed to more traditional central station generation may provide 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

At the same time, DER's location within the distribution system creates the possibility for potential reliability impacts, which can be positive or negative. The design of the distribution portion of the power delivery system in North America is predominantly radial, with power flowing one way: from source to load. As a result, the introduction of DER into the distribution system may negatively impact protection and voltage regulation. For safety and protection, distribution-connected generating assets have traditionally been required to disconnect from the system during abnormal system voltage or frequency conditions to the point that some standards and regulatory requirements have been established to statutorily require disconnection. As DER penetration levels continue to increase, however, so too does the prospect that DER resources might fail to ride through system disturbances—creating significant system reliability risk.

Visibility and Controllability

Improving visibility and controllability of DER deployments contributes to the resource's potential to positively affect the system. 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-owned energy storage, electric vehicles, and all demand response resources. As such, T&D system operators are typically unable to monitor DER resources at any given time, adding uncertainty to system load calculations and regarding the portion of system load that must be served from the power system if DER becomes unavailable. It should also be noted that for the transmission system operator, even DER resources owned and operated by distribution utilities may not be visible.

As DER becomes a larger portion of the resources serving load at any given time, the inability to directly control these 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. 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.

Some DER resources may be aggregated through programs in which a third-party entity or "aggregator" pays consumers for the ability to manipulate customer loads or on-site generation to dispatch the aggregate resource according to system operator direction. This aggregation model has been used for bidding demand response resources into energy and ancillary service markets. But even in these situations, the visibility and controllability of an actual resource at a given location within the electrical grid are quite coarse. Some 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

Many 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. 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 majority of potential challenges posed by inverter-based resources stem from their differing method of response 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 resource from system frequency. Consequently, it does not inherently provide inertial response to oppose frequency excursion. 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 do, however, offer unique capabilities to control both active and reactive power much more quickly than traditional synchronous machines. As a result, with appropriate control schemes, DER resources may be able to beneficially support voltage and frequency performance. Demonstrations 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.

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 will vary as the sun rises and sets or as clouds pass overhead. Wind generation also varies as the underlying wind resource fluctuates. Although some of this variability can be mitigated by aggregating the output of many distributed energy resources 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. Furthermore, 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 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. To the extent that the output of DER (or any other 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.

Environmental Compatibility and Fuel Costs

Generally, DER offers the potential to reduce total electric power emission. Certain 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 resources result from their dependence on sunlight and wind as their fuel source—which also means that these resources also 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.

Similarly, DER offers the potential to reduce total system fuel costs, but may increase other aspects of total system production costs as a result of increased ancillary service costs as mentioned previously. And 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.

The Importance of Distribution System Characteristics

The extent to which DER deployment can beneficially or adversely impact the distribution system depends on the combined characteristics of the DER itself as well as 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 usage, geographic footprint of the feeder, regulation equipment used, and operating characteristics such as voltage planning limits and protection schemes.
- **Amount and location of DER**, such as the location of individual DER devices along the distribution system as well as the aggregate amount of DER.
- **DER characteristics**, such as inverter-based vs. machine-based DER, fixed vs. intermittent output, and the time at which DER provides power/energy to the grid (coincidence with load).

Determining the hosting capacity of DER is one of the key elements of the proposed methodology for determining DER impacts to the distribution system. Sample distribution hosting capacity results from EPRI research are provided in Figure 4-2 to illustrate the extent to which widely varying amounts of PV can, for example, be accommodated on distribution feeders with differing characteristics.[12] The feeders studied are listed on the vertical axis and the MW of hosting capacity on the horizontal axis. The color coding for each feeder indicates the amount of capacity the feeder can handle. Green indicates no problem accommodating that level of PV; yellow suggests that the location of PV on the feeder at that level becomes the determining factor. Some feeders can host large amounts of PV (for example, R1, R2, G1, and G2 in the figure), while others (G3, D1, D2, and D3) are more or less limited 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. This approach has been applied to a range of

---

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

distribution feeders throughout the United States and is the basis for much of the methodology described in this report.

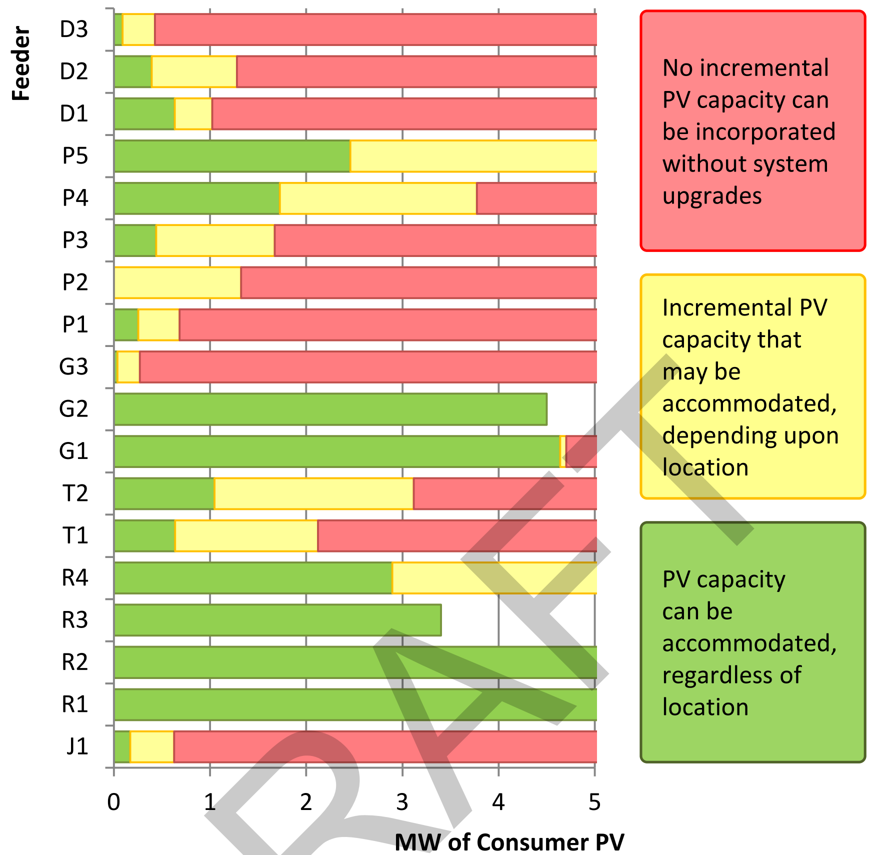


Figure 4-2
Sample distribution hosting capacity results

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 raises fault current, affects protection equipment short-circuit ratings, and/or causes 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

Utilities design the distribution system to maintain primary voltages within standard ranges. The most common standard adopted in North America is ANSI C84.1,[13] which specifies that under normal conditions, primary voltages are kept within ±5% nominal rating. Some utilities in certain states are mandated to maintain voltages to a tighter requirement in order to reduce customer energy consumption (also known as *conservation voltage reduction*). In such cases, utilities plan for the upper bandwidth on voltage to be +3 to +4% instead of the typical +5%.

DER has the potential to change voltage along a distribution feeder because of the power injected into the grid. As noted previously, most distribution systems are radial; therefore, distribution feeder voltages typically reduce the farther they are from the distribution substation.

The injection of active power from DER on a distribution feeder will cause a voltage increase at the generator terminals, regardless of where the DER is located. The extent to which the DER causes voltage rise, however, depends on the size of the DER and where it is 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 size of 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 why it can cause unacceptable voltages farther away from the substation.[14]

As a result, 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.

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

[14] *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 caused by the additional resource has the potential to cause overvoltages on the distribution system. This overvoltage could occur on either of the following:

- Secondary systems where DER is connected to a low-voltage portion of the grid (as is the case with most customer-connected DER)
- 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 overvoltages 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 overvoltages is commonly referred to as voltage *headroom* and varies along a distribution feeder as shown in Figure 4-3.

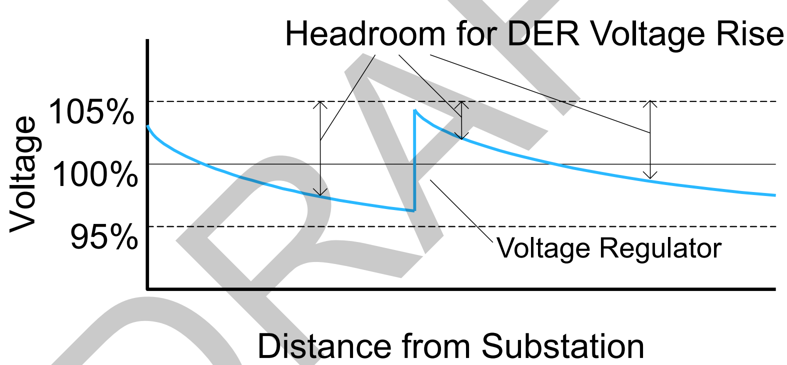


Figure 4-3
Voltage drop along a distribution feeder and the “headroom” concept

The localized power flow characteristics determine the direction in which the power is flowing. Normally, active power flows from the distribution substation radially toward 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 overvoltages.

Voltage Fluctuations

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

Unlike customer load variations that are smoothed throughout a feeder as a result of customer diversity, variable generation such as solar PV and wind can have much more correlated output—particularly at close distances to one another within a distribution system. Although some diversity exists across a distribution feeder footprint for solar and wind, the relatively small area associated with distribution feeders results in solar resources that can ramp up and down in coincidence.[15] As a result of these sudden changes in output, variable generation such as solar and wind can cause excessive voltage fluctuations on the distribution system.

Inappropriate regulation 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—either active power, reactive power, or both—and as a result can mitigate many of the voltage issues that arise. The response time of inverter-based generation can regulate output much faster than traditional voltage control devices. If the DER can coordinate with existing utility voltage control and provide voltage support when needed, value to the distribution system can be realized.[16] With communication and control capability, DER that can regulate output can potentially also coordinate with conservation voltage reduction (CVR) programs and help control customer voltages to reduce customer consumption.

---

[15] 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.

[16] 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[17]

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. Common 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 raises 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 desensitizing 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 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 for which DER is 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 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, or sectionalizers.

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

Energy Losses

DER has the potential to reduce distribution losses because the generation is provided closer to where the energy is actually consumed (customers). The extent to which DER can reduce distribution losses depends on the location of the resource and the time for which 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 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 generation resource is not coincident with the load or is not located electrically "close" to the load on the feeder, resistive losses can actually increase.

Energy Consumption

Customer-based DER can increase voltage and therefore counteract the expected benefit of CVR programs by increasing consumer loads. This can occur when increased levels of DER inhibit a utility's ability to bring voltages down to reduced levels. In some cases, this can occur from a simple increase in the consumer's voltage because the DER is located on the same premises with load. If the DER, however, has some form of Volt/VAR (volt-ampere-reactive) control capability, increased customer voltages can be avoided. If the DER can further coordinate with the local voltage reduction mechanisms, the DER can potentially be used to assist in CVR.[18] Communication and control are necessary for this to be realized.

Capacity

Distribution systems are designed to provide service to all customers, even at peak load periods when assets are most constrained. 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 any resource to provide distribution-capacity relief, it must be available during peak load periods when assets are most constrained and when feeder capacity is a limiting factor. The ability for a DER such as PV to reduce feeder peak demand may tend to saturate at high penetration levels if the load peak shifts outside the time of PV influence.

[18] 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.

Reliability

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

Properly sited DER with appropriate capabilities 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 sited on the affected section can be helpful and will improve reliability statistics.

If the DER can operate without the presence of the grid, it can be used to help restore power to sections of the distribution system that are completely isolated from the bulk power system as a result of storm damage, for example. This is often referred to as a *microgrid* and is a popular idea for grid resiliency research. It can consist of one large DER device or several DER devices operated with a common control. A microgrid would be expected to remain operational for perhaps several days when extensive damage is done. This limits the applicable technologies to a subset of resources that supply high energy and capacity needs with no disruptions.

As with capacity, DER output must be available at the time of need to improve distribution reliability.

Although capacity and reliability are related, the contribution of DER power to reliability improvement 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 with powering microgrids that do not have charged storage.

Bulk Transmission System Impacts of DER

DER affects bulk transmission system operations, especially at higher penetration levels, primarily because it changes 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, in aggregate high penetrations of DER impact the reliability, cost, and environmental contribution of the bulk transmission system in several ways.

Figure 4-4 provides an example illustration of how increasing DER penetration in individual distribution areas aggregately impacts bulk system transmission functions such as voltage and frequency performance, operating reserve levels, and the flexibility of other system resources required to follow the aggregate load shape served from the bulk system. Certain areas of the world, including parts of the United States, are in fact beginning to observe the way in which high penetrations of DER—particularly PV—affect the bulk system.

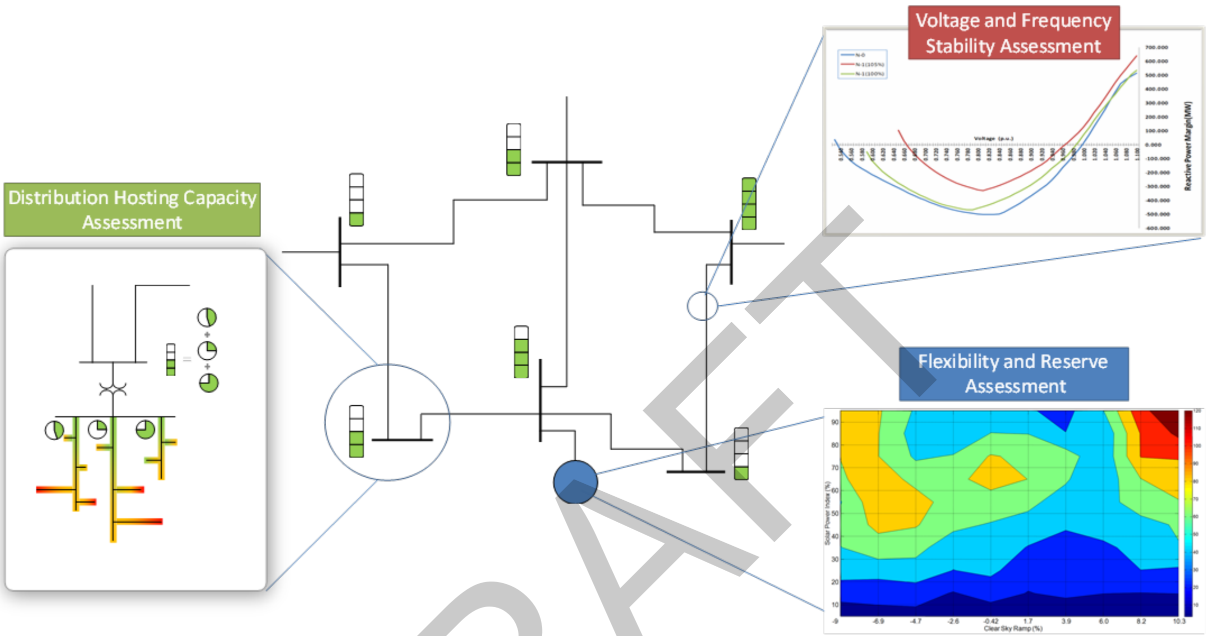


Figure 4-4
Illustration of the impacts of DER up through the bulk systems as DER levels increase

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

Table 4-3
Impacts of high penetration DER to 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 affects the variation in the shape of the daily load that must be served from the transmission system
Transmission Expansion	Transmission infrastructure required to sufficiently meet load.	• Degree to which loads can be locally served by DER, particularly during system peak delivery times
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

Resource adequacy is the process of 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 is very small and below established criteria. As part of the resource adequacy planning process, evaluations of projected future load levels are used along with expected probabilities of availability for supply and demand resources to determine 1) whether additional resources are needed to serve load at an acceptable 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 resource adequacy generally depends on the extent to which the resource is available and produces during high-risk system hours, when the margin between available supply and demand is the lowest. Therefore, to the extent that DER resources contribute during the high-risk hours, DER increases resource adequacy. The uncertainty and variability characteristics of some DER resources 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 resources 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 will decline to zero without storage or other means to shift demand.

The impact of DER on the cost of providing resource adequacy is also not straightforward. To the extent that DER resources offset central station generation, DER may lower capacity costs—assuming that the DER can supply all of the bulk system reliability contributions of the replaced resources. Even if it can't provide resource adequacy, the reduction in energy required may mean that a low-capital, high-energy cost peaking resource is now a more suitable resource. Typically, DER resources are less flexible than the dispatchable, central station generation that they might replace in that regardless of dispatchability for capacity or energy, most DER technologies are limited in providing reactive power support or frequency support to the transmission system. Further, some DER resources such as wind and PV have relatively low capacity factors, requiring more megawatts of installed capacity to meet energy requirements. Other DER resources 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.

As such, DER resources 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. Additional revenue streams may need to be required—either through new capacity products or operational reliability ancillary service products—to ensure that these units are available when needed for resource adequacy and/or operational reliability.

Resource Flexibility

The resources available to the transmission system operator must aggregately have 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 resources, primarily solar PV, increase the need for system flexibility by increasing 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 that had to be served from the ENEL transmission system in Southern Italy for an August day in three successive years across which the levels of distributed PV increased significantly in the region. The plot shows 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 on-line output levels or by cycling generators off-line. In this case, DER is increasing system flexibility requirements as well as the cost of reliably operating the system through greater operations and maintenance (O&M) to handle the ramping and cycling of existing resources and by adding new resources to manage the increased flexibility requirement.

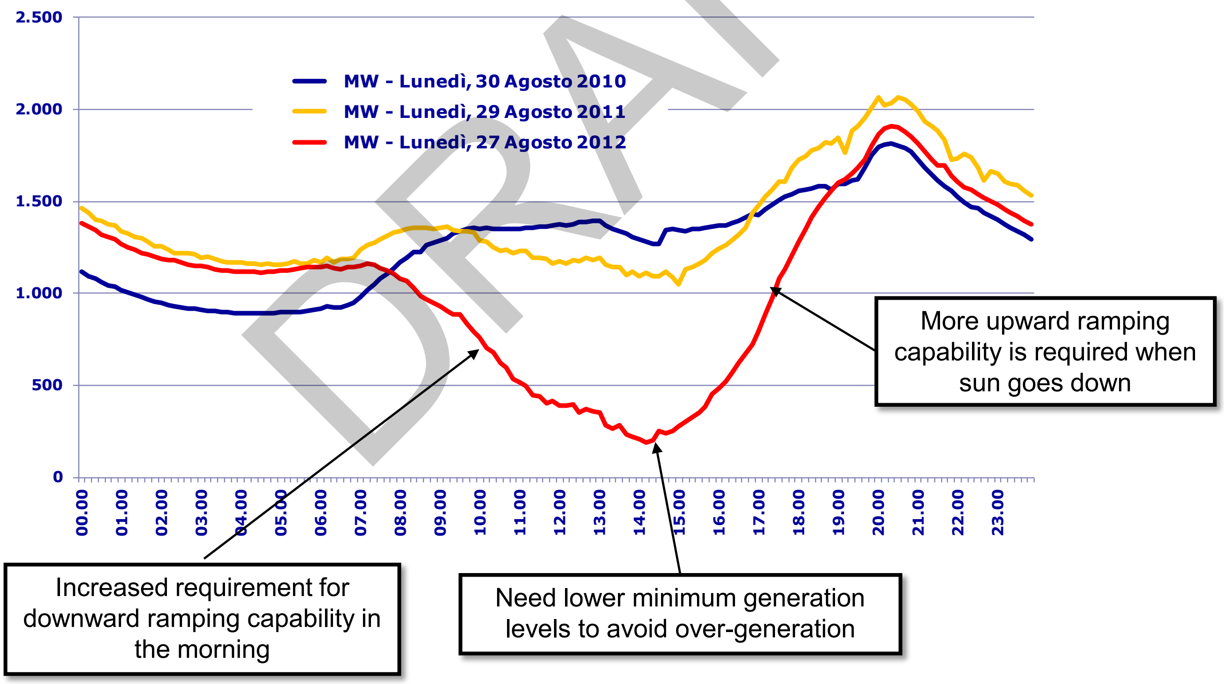


Figure 4-5
Illustration of increased system flexibility requirements resulting from high levels of distributed PV in the southern Italy region of the ENEL system

DER's impact on transmission system flexibility is not, however, one-sided. DER resources 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 system interconnected wind generation. In addition, demand response has been shown to not only be effective in providing certain balancing functions, but also to be cost-effective in providing those capabilities relative to building new conventional resources that incur an opportunity cost when holding capacity for reserve capabilities. Flexibility can sometimes be considered a part of the overall resource adequacy framework; for example, a flexibility deficit could be met by building a new baseload plant—if it frees up a more flexible resource. Similarly, the addition of specialized flexible resources, such as storage and certain kinds of demand response, is likely to contribute to resource adequacy.

Transmission Expansion

DER's impact on the need for new transmission is similar to its impact on resource adequacy. In general, serving more of the load locally from DER would seem to decrease the need for transmission delivery capacity to defer otherwise needed transmission upgrades. As with resource adequacy, however, the extent to which DER contributes to transmission delivery capacity depends on the extent to which DER reduces the peak delivery requirements of the system. Just because DER reduces 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 provides a benefit to transmission investment costs.

Operational Scheduling and Balancing

Whether in a market or a traditional vertically integrated region, transmission system operators use sophisticated optimization algorithms to commit and dispatch supply resources to provide energy and the required ancillary services to ensure 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. The same production cost optimization tools can also 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 distributed energy resources 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 reserve that may need to be carried and the associated increased production costs, thermal units that are required to be on-line 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 Chapter 7.

Transmission System Performance

Transmission system operators are responsible for operating the transmission system within established reliability criteria. The operators will 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 impacts transmission system performance in multiple ways. First, because of the locational effect discussed previously, DER tends to reduce the power flow across the transmission system—which reduces losses and the total bulk 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 off-line 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.

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, required 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 Chapter 7.

The Interconnected Nature of Transmission and Distribution Systems

AC power systems have traditionally been 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 (see Figure 4-4). 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. They 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.

Similarly, the only aspect of the distribution system that transmission system operators have traditionally needed to understand has been the magnitude of the aggregate load at the distribution-substation interface. Based on the present and near-term forecasted loads, the transmission system operator 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 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 T&D 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 as a whole rather than in parts. 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.

Chapters 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 resources 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 requirement needs.

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

5 CHARACTERIZING THE IMPACTS OF DER ON DISTRIBUTION

DER, by definition, physically connects to the grid through the distribution system, either at the primary, medium-voltage level, or through the secondary, low-voltage customer level. For this reason alone, it is essential to assess the impacts of DER on the distribution system to recognize the potential benefits and challenges associated with greater DER integration. This chapter focuses on the distribution aspects of the overall Integrated Grid framework, providing the necessary inputs to the methodology's Bulk System and Benefit-Cost Analysis components to properly account for the value streams and the costs associated with integrating DER into the grid.

There are two main value streams that can be derived from DER that occur on the distribution system:

- **Reduced distribution system losses.** Because DER is connected closer to the load, it has the potential to reduce delivery losses in the distribution system.[19]

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

- **Upgrade deferral.** With DER that can guarantee production during constrained periods, upgrades, operations, and maintenance relief can be realized.

Meanwhile, some of the hurdles associated with greater DER integration result from reverse power flow and output variability. As a result, DER tends to adversely affect two things:

- **Voltage regulation.** The distribution infrastructure—which includes voltage regulation equipment, methods, and planning tools—was designed for one-way power flow. Proper integration of DER must account for two-way power flow.
- **Protection.** As with voltage regulation, many protection schemes have been designed for one-directional fault current. Additional relaying and modification of schemes and practices are necessary when DER interferes with existing protection.

As noted in Chapter 4, several factors determine overall distribution response to 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 Chapter 3, and—based on the particular objectives—evaluates the aforementioned value streams and impacts across a distribution system. The value streams are assessed through four key analyses: hosting capacity, energy, capacity, and reliability analysis. What follows is a more detailed look into how particular DER characteristics determine overall distribution system response.

The remainder of this chapter is laid out 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
- Capacity Analysis

Accounting for the Distribution System: Factors That Shape Responses to DER

As discussed, distribution systems are designed differently based on a myriad of factors; in turn, distribution feeders uniquely respond to DER. This section provides a brief summary of these factors, listed in Table 5-1, and associated impacts due to DER.

Table 5-1
Driving factors that determine how DER impacts with the grid

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

Feeder Topology

Many distribution utilities serve customers using widely varying types of distribution systems. Although some utilities' distribution systems may consist of compact, urban feeders, other utilities may primarily serve customers through long, rural distribution systems. 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 utility serves customers through 40 miles or longer of three-phase lines. Although this is not the only factor that impacts distribution system response to DER, strong correlations with respect to characteristics such as overall feeder length have been found.[20]

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

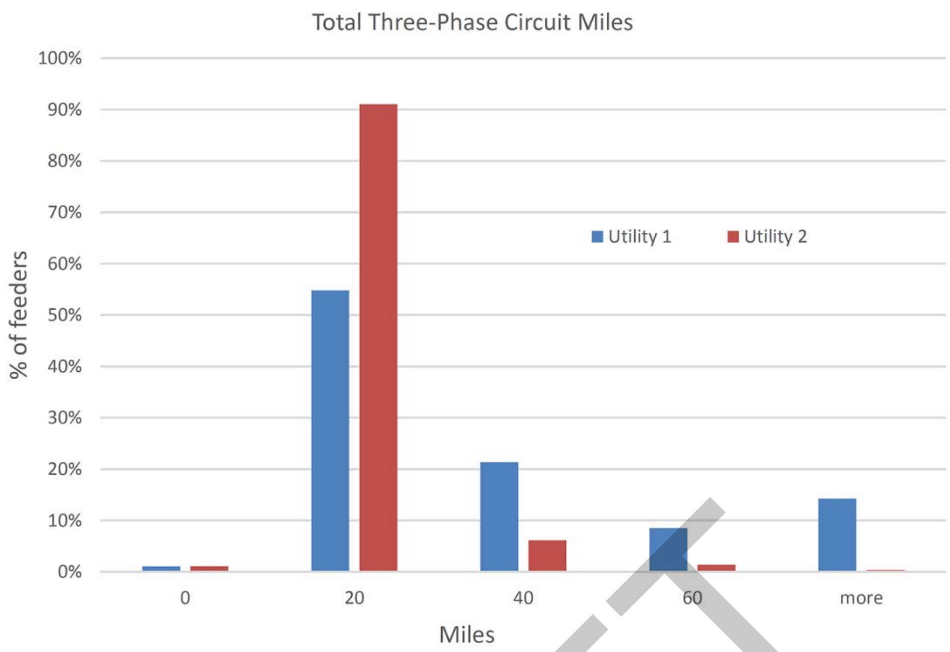


Figure 5-1
Distribution feeder lengths (total miles) for two investor-owned utilities

Voltage Class

System voltage level can have a greater determination than topology on system performance. The higher the system voltage, the stiffer the system—and stiffness increases with the square of the voltage. Therefore, the stiffer the system, length constant, the less impact variations in DER output will have on system voltage.

Regulation Equipment

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

The use of regulation equipment—such as load-tap changers (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 may commonly 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.

X/R Ratio

The relative impact on system voltage caused by DER power injection into the grid is also related to the system's X/R ratio. If the PV injection into the grid is all active power, with the DER operating at unity power factor, the voltage variation is primarily driven by the amount of current injected into the grid and the system real impedance (resistance). At medium voltage, typical distribution systems in the United States have X/R ratios around 2 to 4, with the majority of that determined by the conductor configuration (for example, overhead vs. underground).

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 (114 V to 126 V on a 120-V base). However, many utilities have adopted the use of CVR to reduce system energy consumption. For these circuits, the planning limits for voltage response are often much narrower than the ±5% target. The upper limit may be reduced from 1.05% per unit to 1.03% per unit. If that is the case, voltage rise from DER could easily result in unacceptable voltages under CVR conditions.

Radial vs. Networked

Whether the circuit is radial or networked plays an important role in system impacts of high-penetration PV.

This is, however, mostly related to protection of the system rather than 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 (see Figure 5-2). Large-scale DER systems' interconnected to distribution near the substation (or through express feeders) will have a significantly different impact on grid voltage than this same system connected near the end of the feeder. The relative stiffness of the system near the substation with respect to the size of the

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

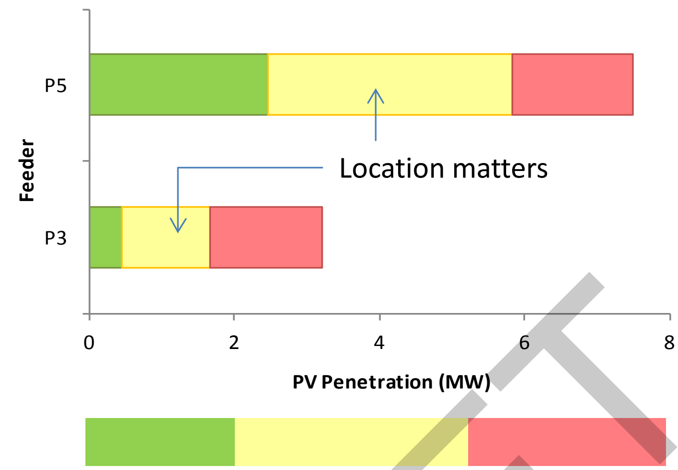


Figure 5-2
Sample results illustrating locational dependency of hosting capacity

Electrical Proximity to Other DER

With DER, there is expected to be some diversity in output 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.[21] This fact is then compounded the closer the PV systems are located electrically. For example, a few customers connected to the same service transformer would have solar PV output profiles that are very well correlated. 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.

[21] 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.

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. The differences primarily emanate from the timing, extent, and frequency of changes in output with respect to local demand characteristics. The coincidence of peak DER production with load level is also an important factor to take into account. More specifically:

- DER output coincident with load is more likely to reduce peak demand.
- DER output coincident with load is more likely to decrease system losses.
- DER output non-coincident with load is more likely to result in voltage issues—particularly peak output production during light load periods, potentially causing overvoltages.

For these reasons, it is important to consider the relationship between load and DER production. The specific DER technology employed is also a factor. Rotating machines and static inverter interfaces have different impacts on system protection, for example. Rotating machines can provide as much as 5–6 times rated current during faulted conditions, while inverter-based DER can be significantly less (1–2 times rated current).

DER Control

The type of control that is used for DER also changes system impacts. If the DER can be controlled and is dispatchable, the needs of the grid in terms of voltage and/or power can potentially be met with the use of DER. In some cases, DER may not be dispatchable; however, the reactive power can be controlled either autonomously or remotely. In such cases, the DER can potentially mitigate issues that may arise regarding DER-induced voltage rise. Operating the DER system in either a slightly inductive power factor (absorbing VARs) or under Volt/VAR control can help mitigate many of the voltage concerns.[22] This mitigation can be furthered by helping support the grid, as illustrated using Volt/VAR control simulations.[23]

1. [22] Planning Methodology to Determine Practical Circuit Limits for Distributed Generation: Emphasis on Solar PV and Other Renewable Generation. EPRI, Palo Alto, CA: 2010. 1020157.

[23] 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.

Distribution Analysis Methodology: A Brief Overview

One of the key drivers that can determine the overall impact of DER on the distribution grid—structural diversity—also poses the greatest methodological challenge. A typical utility's distribution system consists of hundreds to thousands of unique distribution feeders, each designed and operated differently with its own unique response to DER. Because of the widely varying responses that can be realized, it is necessary to consider in any evaluation of an entire system the range of possible feeder types.

To date, a detailed analysis of each and every feeder has not been performed because of the vast amount of data, processing, and engineering time needed to perform such a large-scale task. To circumvent this issue, some approaches have been proposed in which sample feeders are selected based on their topological characteristics. This allows engineers to query geographic information system (GIS) feeder information to cluster feeders based on static characteristics (for example, voltage class, peak load, and length of lines). This method significantly reduces engineering time and allows a smaller subset of feeders to be analyzed.

Unlike other methods used in the industry, the method proposed in this report accounts for static, topological characteristics for each feeder as well as their unique operational response to 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 throughout a distribution system. It somewhat uniquely takes into consideration the unique response of feeders by characterizing each feeder individually. Additional detailed analysis on select feeders is performed only when necessary.

Methodology for Distribution Analysis

The previous section describes, among other things, how DER can affect the operation of the distribution system, focusing on the physical characteristics of the system that determine power delivery. The discussion identified several aspects that shape or condition the DER impact on a distribution feeder. Influencing factors were 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 sorted these impacts into three root cause categories: DER impact on voltage, protection, and energy.

The preceding discussion focused on sub-elements of each root cause impact individually to describe how grid performance is influenced, thereby laying the foundation for identifying both adverse and beneficial impacts—what the DER adoption benefit-cost calculation requires. It reveals, however, the complex interrelationships among the forces that determine how electricity flows in a conventional distribution system, and how that complexity becomes more involved when DER produces two-way flows. The location and size of the DER are considerations that are interdependent with system strength and customer loads. A change in voltage caused by a DER can improve feeder performance or result in the need for an investment to mitigate adverse effect. Complex associations and cause-and-effect relationships abound. A thorough and actionable evaluation of DER must take all of these into account.

EPRI has developed and demonstrated methods for conducting feeder-specific analyses that account for all of these factors and subsequently provide a complete characterization of the impact DER adoption can have at any level. EPRI's OpenDSS simulation platform has served as the foundation for these analyses to date.[24] 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 electric vehicle (PEV) adoption, energy storage analysis, and distribution efficiency studies (Green Circuits).[25, 26, 27] Techniques developed and applied throughout these various efforts, involving over 100 unique distribution feeders, serve as the basis for much of the analysis methodology described in this chapter.

Those studies show that attending to the complexity of power flows produces detailed results that are critical to understanding DER. Feeders are affected differently at any level of DER and by different levels of DER, other factors constant. However, those factors are seldom constant—hence the need for dynamic simulation. These 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, and the simulations require substantial resources to fully examine how a feeder is impacted.

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

[25] 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.

[26] 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.

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

Based on findings from detailed individual feeder analyses, EPRI has developed a practical methodology that characterizes the impacts of various levels and arrangements of DER on all of a utility's feeders. It facilitates using commercially available analysis tools for most of the steps, in particular, the hosting capacity (a definition of which follows). A DER impact assessment requires using software to simulate feeder performance, with and without DER. There are several commercial tools used by utilities for system planning that can be used for this analysis. This means that the models have already been developed to represent the utility's feeders; using these systems saves time and resources. Perhaps most importantly, it means that a utility can conduct the analyses with current analytical resources.

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: Characterization of Distribution feeders and DER (A), Hosting Capacity Analysis (B), Energy Analysis (C), Capacity Analysis (D), and Reliability Analysis (E). Inputs to the analysis are defined to the left of these processes: Distribution Feeder Models, Load Data, and DER Data. The outputs of these analyses go to Bulk System Analysis (at the top), defined as substation impacts on load, or to the Benefit/Cost Analysis (the right-most box), which involves costs incurred and cost savings discovered in the analyses.

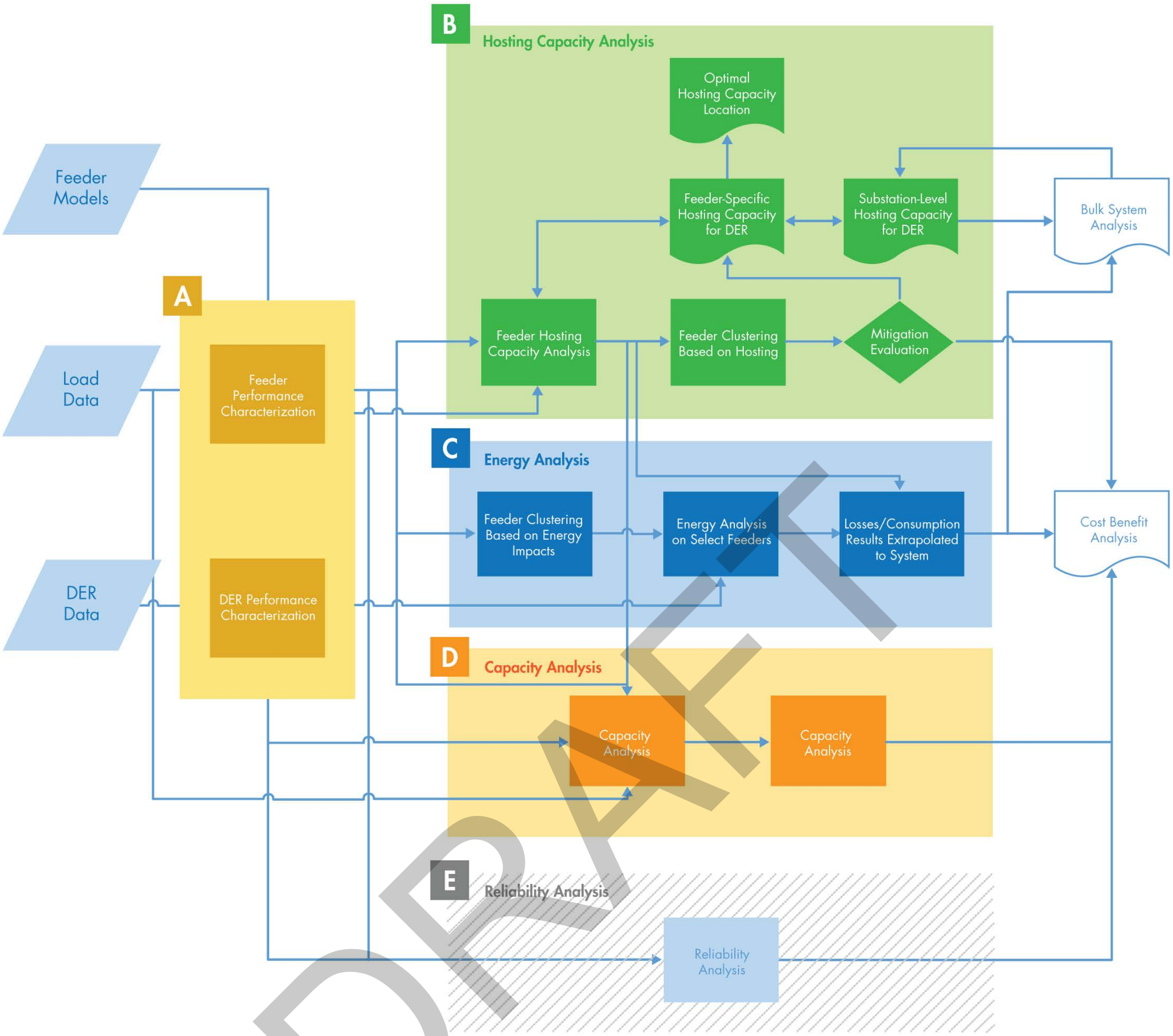


Figure 5-3
Overall distribution analysis framework

Distribution Feeder and DER Characterization

The first step in the methodology is to characterize the distribution feeders and DER. This portion of the methodology uses the input data to perform a basic analysis of each individual feeder in the distribution system by performing a load-flow and short-circuit analysis. The Feeder Characterization will provide voltage, short-circuit, or loss information that can be used as an input to the next analysis step. The DER Characterization step considers the DER's unique response in terms of output characteristics (for example, fixed vs. intermittent, dispatchable vs. non-dispatchable, production profile, energy capability, and voltage control capability). The DER characterization will determine how certain aspects of the next steps are carried out.

Hosting Capacity Analysis

A key to this methodology is its Hosting Capacity approach for determining how much DER can be accommodated prior to necessitating system upgrades, illustrated in the top rectangle box (labeled *B*) in Figure 5-3. These are procedures that take advantage of the findings from detailed studies to establish a way to determine for each feeder at what level of DER adoption 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. An analyst creates a data set for each feeder from readily available data. Simulations are run to define the hosting capacity on each feeder and determine whether a voltage or protection violation occurs. Once these are established, the feeders can be grouped—by hosting capacity, type of violation, and other physical characteristics—into Hosting Capacity clusters. 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 is passed on to bulk system analyses. Based on the Bulk 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. Subsequent analysis determines the best way to resolve a violation (the mitigation cost). However, a detailed analysis is required only for a few representative feeders from each cluster at this point (*Feeder Clustering* in the figure). The results of Mitigation Determination (the right-side triangle in Rectangle A) for each representative(s) feeder are extrapolated to the cluster and then aggregated to the system.

Energy Analysis

There are additional considerations in evaluating DER accommodation: the loss reduction (a benefit that results in reduced kWh generation requirements) and the impact on feeder capacity—how much load it can serve. These are expected benefits. The final outcome is an estimated loss and energy consumption response for each feeder throughout an area. Similar to the Hosting Capacity approach, for the Energy Analysis (labeled *C* in Figure 5-3), feeders will be grouped based on their loss performance (among other metrics), and detailed analysis of select feeders will be performed. This detailed analysis will determine loss bands at increasing DER penetration levels that can then be extrapolated to other feeders within the group for system-wide determinations.

Capacity Analysis

Capacity Analysis, the third level of impact modeling (portrayed in 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.

Reliability Analysis

Quantifying the impact of DER on reliability is a difficult task even when the DER is dispatchable. The analysis is by nature probabilistic because failures have a high degree of uncertainty. DER with variable output such as wind and solar generation adds another degree of probabilistic variability to the problem. There are many variables to consider, such as the type of DER, the coincidence with load, 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.

There is no consensus on a single approach that might be recommended to the Integrated Grid planning framework at this time. The selection of a particular approach is expected to take several years of research and is beyond the scope of this immediate effort.

Outcomes of the Distribution Analysis

For the entire distribution system analyzed as part of this process, 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 performance thresholds. These data can then be aggregated up to the substation level and provided to the transmission planners for the bulk system analysis. This portion of the project will actually provide the necessary information for the bulk system analysis described in Chapters 7 and 8.
- **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 will 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 is deployed at increasing penetration levels.
- **Energy consumption.** This addresses changes in energy consumption as DER is 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 much DER can be accommodated on the distribution system without violating feeder performance thresholds, referred to as *hosting capacity*—that is, the amount of DER that can be accommodated into the grid 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 a wide number of sizes and locations for DER.

The potential impact DER can have on distribution system performance—and ultimately a feeder's hosting capacity—depends on many factors, including 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 will have lower limits. DER interconnected at the head of the feeder has a different impact on system performance than if it is connected farther out 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. This can be contrasted against other feeders that serve customers over a wider geographic footprint that “taper” conductor size farther from the substation and use line regulators to regulate voltage.

These factors, among others, must be taken into account when evaluating the impact of DER on distribution system performance. These factors inevitably determine how much DER can be accommodated before the system is pushed beyond acceptable limits. Several factors, including feeder- and DER-specific characteristics, determine the extent to which distributed energy resources impact grid performance.

Purpose

The primary objective of this task is to determine unique hosting capacities for all feeders within a service territory. The hosting capacity results describe locations where DER is more easily accommodated and those where DER is more of an issue. The results also describe the amount of DER at which 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.

Input

The complete system under study 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-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 will 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. Details regarding the methodology for performing hosting capacity screening will be published later in 2014.[28]

Process

The amount of DER that can be accommodated system-wide will be determined through a hosting capacity screening approach designed to calculate the amount of DER that can be efficiently determined on each feeder. This process will allow the characteristics of hundreds to thousands of distribution feeders to dictate 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 will be estimated that identifies at what load level the issue can potentially begin to occur on a feeder. The location and exposure to the issue will 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 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 will assess the 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 DER will have 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. Voltage magnitude issues occur when the primary or secondary voltage exceeds a specified limit. The voltage limit will take into account whether

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

standard ANSI limits can be applied or whether more stringent requirements associated with CVR programs must be used. Considering the potential voltage fluctuations seen by regulation equipment can also indicate potential voltage issues that may arise—causing excessive tapping or switching of mechanical devices or creating susceptibility to allowing DER to adversely regulate voltage. Identifying how much 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 on feeder breaker-level issues caused by the change in fault current resulting from DER. Several key items will be 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 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 system and local sources increases. In addition, many feeders—especially in urban areas—have little margin for additional fault current. DER will increase the total available fault current, and the resulting levels may exceed the capacity of the short-circuit protection equipment. Farther from the high-voltage or low-voltage substation, the percentage change in fault current is important. A large change is often an indication that the protective relays will no longer be coordinated.
- **Breaker reduction of reach.** This issue involves reduced sensitivity of the feeder breaker. Reduced reach can impact the feeder when local 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. There are conditions with DER on the isolated section in which severe overvoltages or unstable load voltages may occur on the open-phase conductor. This condition should be studied and protected against.
- **Reverse power flow.** In some cases, reverse power flow can cause inadvertent tripping of protection equipment, requiring the use of direction-based protection schemes (directional relaying).

Mitigation Evaluation

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

To determine the mitigation solutions, three tasks will be performed:

1. **Hosting capacity clustering.** Feeders will be grouped, or clustered, based on their hosting capacity response. The number of clusters will be determined by the hosting capacity responses and any issues that arise; the hosting capacity determined will then be compared with the intended penetration target for each feeder. Each feeder will then be clustered 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 will be carried out.
2. **Detailed mitigation solution analysis.** A few feeders can be selected from each response cluster to be representative of all members of the cluster, and mitigation options for accommodating higher levels of DER will be evaluated. Mitigation options that technically remedy the issue will be critically assessed at increasing penetration levels of DER. For each feeder, an incremental MW-capacity of DER that can be accommodated per solution will be determined.
3. **Hosting capacity improvement allocations.** The incremental MW-capacity value will then be used as a basis for determining the extent to which additional upgrades are needed on the corresponding feeders in each cluster. This approach allows consideration for other feeders in the cluster that may require similar mitigation solutions, but the extent to which the mitigation is needed can be estimated 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 system analysis. In some cases, high levels of DER could potentially alleviate local transmission constraints. However, in cases in which such constraints limit DER, these limits will be passed back down to the local substation/feeder level. Feeder hosting capacities and associated mitigation solutions will then be adjusted appropriately to account for any local transmission constraints.

Output

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

The locational impacts of DER (see Figure 5-4) will also be provided through the hosting capacity screening method. This output will consist of location-based information regarding optimal and non-optimal DER deployments that can reduce the need for infrastructure changes and/or upgrades.

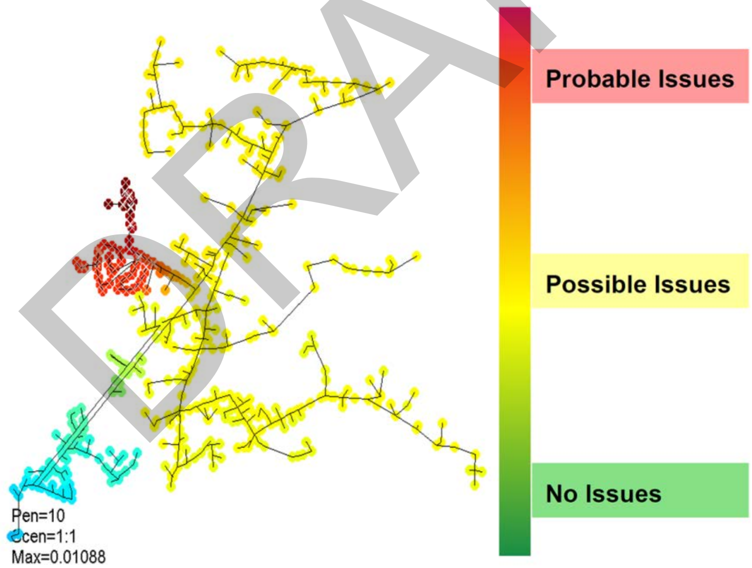


Figure 5-4
Distribution feeder heat map illustrating location-based impacts of DER

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, models of the distribution system must be available in order for the approach to be easily applied and executed. Although the most critical feeder characteristics and issues are considered, there will inevitably be outlying variables. 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 measurement data on select feeders
- 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 annual energy losses, they can be used as input to characterize distribution feeders for clustering 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 clustering and subset selection.** Clustering of feeders based on loss factors, static topological data, and voltage performance will next be performed. Unlike other methods for clustering, this approach includes feeder performance. A subset of feeders that represents each cluster will then be identified.
4. **Perform a detailed loss analysis.** Next, a detailed loss analysis will be performed on one feeder from each subset. This analysis will include 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 each type of feeder will be determined (see Figure 5-5).

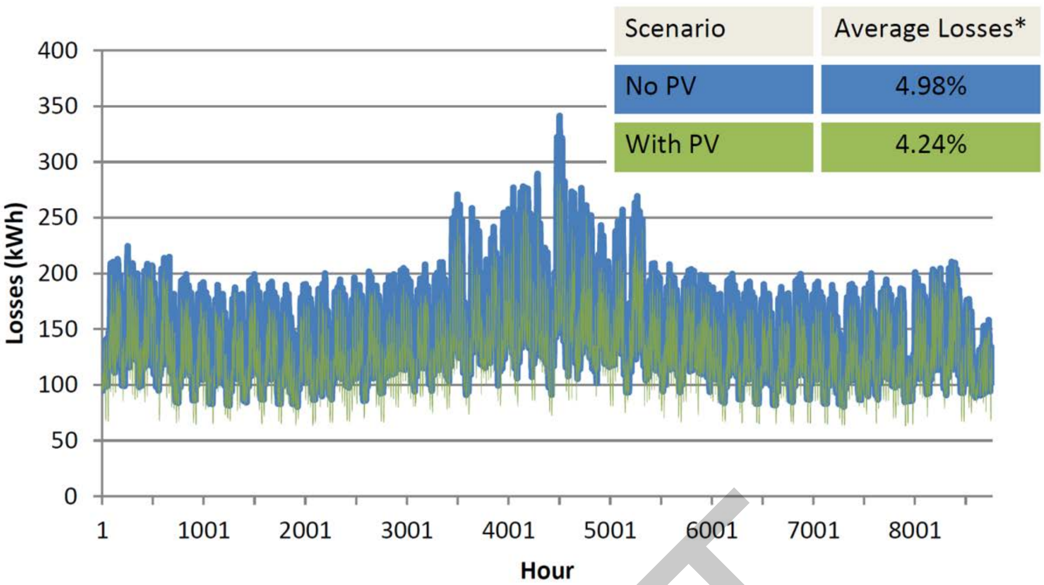


Figure 5-5
Example feeder loss reduction with DER

5. **Extrapolate loss bands.** Using the results from the detailed analysis, loss band changes can be extrapolated to the remaining feeders in each cluster. 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 system and benefit-cost analyses, including:

- Detailed loss results at increasing penetration levels for select feeders
- Estimated loss results 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, to better cluster the feeders and apply detailed results from select feeders to the broader system, feeder performance characteristics should also be considered. However, most distribution system models do not take into account the effects of distribution service transformers and secondaries. Therefore, the detailed analysis results will 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 for analysis of energy consumption.

Capacity Analysis

Purpose

At sufficient levels, DER can have a marked effect on power flows and therefore system capacity. This effort will assess the influence of varying DER real and reactive power flows and portfolios (of location and penetration combinations) on distribution system capacity with regard to the specification of asset thermal ratings and the potential deferral of capacity upgrades.

Input

Implementation of the proposed assessment method will require the collection and use of the following:

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

Process

The assessment methodology will derive a series of daily and yearly asset loading profiles representing projected load conditions combined with varying DER portfolios. The profiles will then be used to quantify the impacts to asset thermal ratings while accounting for different combinations of asset thermal characteristics, load mix, and projected load growth. Finally, the quantified thermal ratings impacts will be used to project the potential capacity upgrade deferrals across system assets. See Figure 5-6.

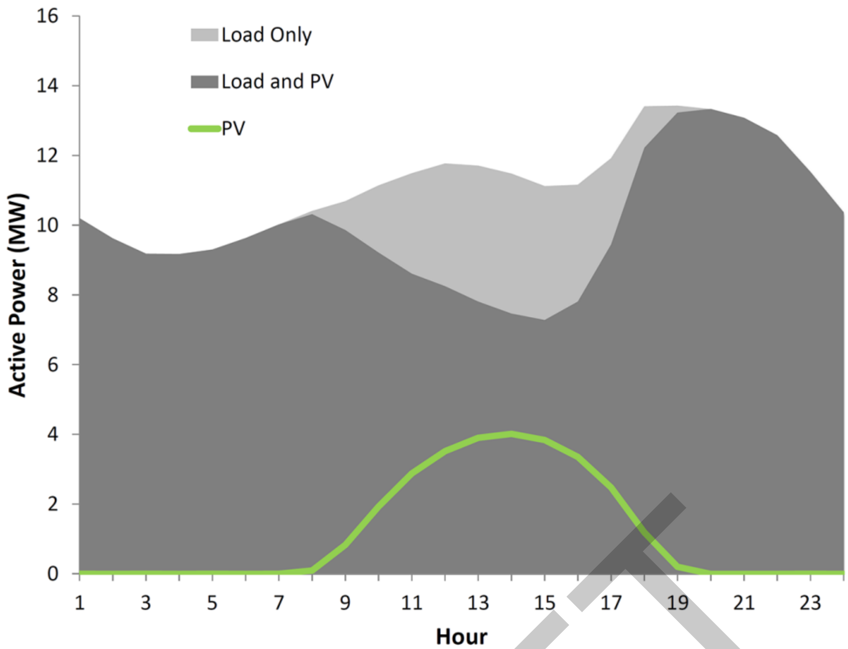


Figure 5-6
Illustration of contribution of distributed PV to reducing feeder net load

Output

Findings from the assessment will be provided to the benefit-cost analysis in terms of the relationships between various DER operations and asset ratings as well as quantification of the upgrade deferral durations.

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

Various technology options can be harnessed to help integrate DER into distribution, many of which are summarized in Table 6-1. This chapter 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.

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

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

Line Reconductoring

One of the more common issues arising from the integration of significant DER into distribution is the adverse impact on primary voltages, in the form of either overvoltages or unacceptable voltage fluctuations. As noted previously, the extent to which DER increases 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 method of increasing the short-circuit strength and increasing X/R. Larger conductors have lower resistance and slightly lower reactance. If the voltage fluctuation is caused by changes in active power, larger conductors will help—but if the voltage fluctuations are the result of reactive power changes, they will not.

Transformer Upgrade

Replacement

With customer-sited DER, potential voltage rise at the secondary level can occur during lightly loaded conditions. 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.

No-Load-Tap Adjustment

Some service transformers have no-load-tap adjustment settings. Changing the tap to a lower setting could mitigate overvoltages. However, care would need to be taken to ensure that lower settings do not result in unacceptable undervoltages.

Voltage Upgrade

Increasing system voltage is another method that can increase the capacity of the grid. System capacity can be estimated based on the square of the voltage over the system equivalent impedance (V^2/Z). If the voltage of the system were increased by a factor of two, the capacity of the system would increase by a factor of four (2^2). This could yield significantly higher capacity on the system and therefore increase a feeder's hosting capacity for DER. Of course, upgrading the system voltage requires new insulators, arresters, switches, and transformers—a potentially expensive proposition.

Voltage Regulation

One of the limiting factors associated with integrating DER into the distribution system is voltage. Several technologies exist 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).

Mechanically Switched Regulation

On voltage-constrained feeders where the distribution system is serving customers on long, rural lines, utilities will often deploy line regulators along the feeder to maintain voltage regulation. These devices typically 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" mode, allowing for regulation of voltage for power flowing in both directions. This can be a relatively inexpensive approach for regulating adverse voltage caused by DER compared to other solutions; however, highly variable DER such as wind and PV can cause excessive operations and decrease the life expectancy of the regulation device—resulting in increased capital expenditure/O&M 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 voltages 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 does not see the same wear and tear as found in regulators. On the other hand, the up-front cost for such equipment can be higher.

Smart Inverters

Reactive Power Control

One common 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 for smaller single-phase units are also adopting 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.[29]

Many VAR control options for DER are available that can be used to help mitigate voltage impacts as well as coordinate with existing feeder regulation control, including fixed power factor, Volt/VAR control, and voltage control.

The inclusion of such technologies may require additional reactive power sources such as substation capacitors.

Fixed Power Factor Control

The most common approach used in both small- and large-scale DER installations to mitigate voltage rise issues is to operate the DER at a constant (inductive) power factor. Although this method does not actively regulate the voltage at the point of common coupling (PCC), it does adjust the VAR flow based on the level of active power output—providing a form of regulation by reducing voltage variations caused by variations in active power output.

[29] "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.

Volt-VAR Control

The Volt-VAR control function allows each DER system to provide a unique VAR response according to 1) the voltage at the point of connection (the terminals of the DER system), 2) the available apparent power capacity of the DER at that time, and 3) the utility-defined Volt-VAR setpoints, as illustrated in Figure 6-1.

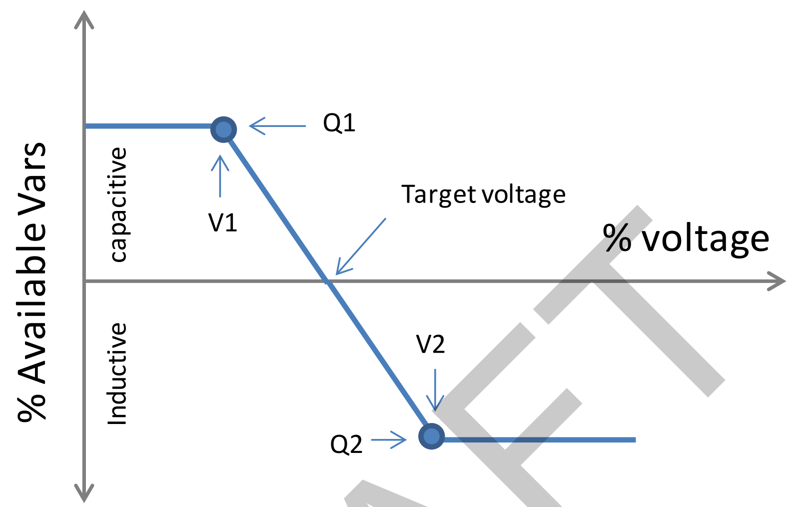


Figure 6-1
Example array settings to describe Volt-VAR behavior

Some of the uses of the Volt-VAR functionality attempt to maintain the voltage at the terminal of the DER system within ANSI limits for a variety of circumstances. Absorption of reactive power (inductive VAR) can be called upon if the voltage begins to exceed a predetermined upper level (as defined by the Volt-VAR curve). Conversely, if lower than normal voltages are present at the terminals of the DER system—due for instance to a reduction in active power output—reactive power can be delivered to the grid (capacitive VARs) to help boost the voltage back to normal levels.

The user may define a varying number of points in the form of a Volt-VAR curve. For example, the setpoints can be defined so that the inverter provides maximum possible reactive power at the full range of allowable voltage (V1 of 0.95 per unit [pu] and V4 of 1.05 pu) or possibly a more narrow range of setpoints to provide much tighter voltage regulation. The reactive power output values are defined as a percentage of available VARs given the present active power output and the full-scale apparent power rating of the DER system. The points can also be defined with or without a "dead band" so that the DER provides continuous VAR control from V1 to V4.

Voltage Control

Rather than the VAR level being determined by output power and/or a combination of voltage, direct voltage control responds to voltage only. The DER provides a VAR output based on its voltage setpoint plus or minus the bandwidth and provides reactive power up to its rated capability. This control method is traditionally found in bulk power system generation where the generator provides a certain amount of dispatchable active power at a given voltage and power angle setpoint (V/δ). Voltage control can be thought of as a variation of Volt/VAR control, but without the "curve" associated with the voltage response. The DER basically provides all the reactive power it can to bring the voltage back to within the bandwidth (see Figure 6-2).

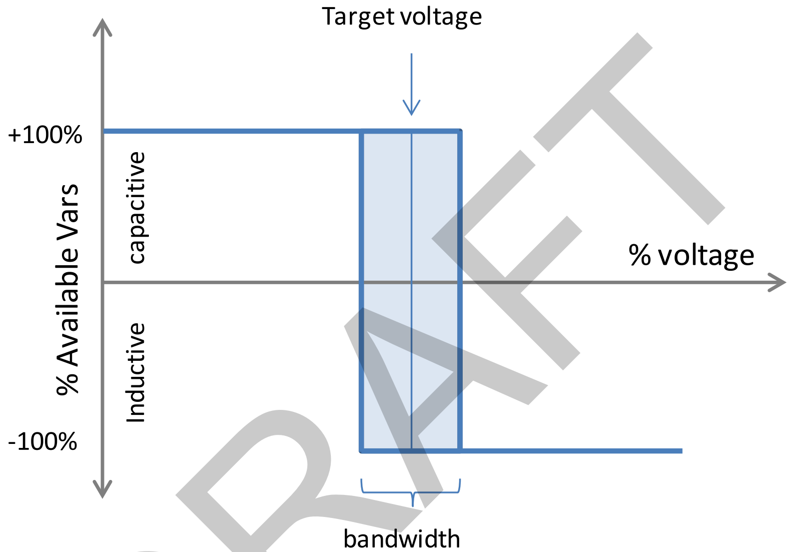


Figure 6-2
Example diagram illustrating voltage control

Active Power Control

When high DER output and low load cause feeder voltage to rise too high, the ability to reduce active power output may reduce overvoltages. In some cases, where a large number of customers served by the same distribution transformer have DER, local service voltage may exceed limits. This can result in certain DER systems not "turning on" as a result of overvoltage. Therefore, reducing active power output by 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 is a function intended to provide a flexible mechanism through which a general Volt-Watt curve could be configured. The user may define a set of voltage-active power (x, y) points that define the output of active power under various terminal voltage values (see Figure 6-3).The Volt-Watt function adjusts only the output of active power—it does not actively adjust reactive power output.

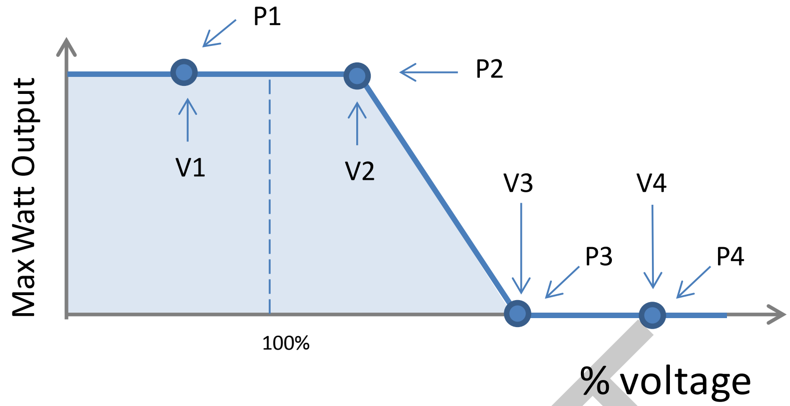


Figure 6-3
Example array settings to describe Volt-Watt behavior

Protection Systems

When DER is placed into service in an electric utility system, it becomes a functioning part of the system. Successful integration requires effective coordination of DER with the system protection design. The application of DER on the electric power system can influence the operation of various overcurrent-protective devices. Common 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
- 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 keeps a line energized
- Desensitization of breakers and reclosers as a result of unplanned DER currents
- Increased duty on existing breakers

In fact, the largest impact that DER has had on existing protection practices is on the coordination of feeder relaying. Most utilities have implemented changes or limitations into their existing substation manual switching procedures as a result of DER.[30] Some of these changes are safety-related, resulting from concern over the presence of active generation on the feeder. This can result in a voltage hazard after the circuit is opened and create unsafe conditions.

These conditions will continue to arise where additional DER on the system is found to 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

Dispatchable Resources: Energy Storage and Demand Response

Dispatchable resources such as energy storage and demand response may be used for a variety of purposes on distribution systems. For DER integration, dispatchable resources may be considered an independent resource or a way to facilitate integration of other DER. In this context, energy storage in general and thermal storage–based demand response programs would be tools to enable further DER integration.

Capacity

One potential operation of dispatchable resources is to 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. This simulation illustrates the importance of forecasting the time of the daily peak when the storage resource is limited.

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

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 all of the 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.

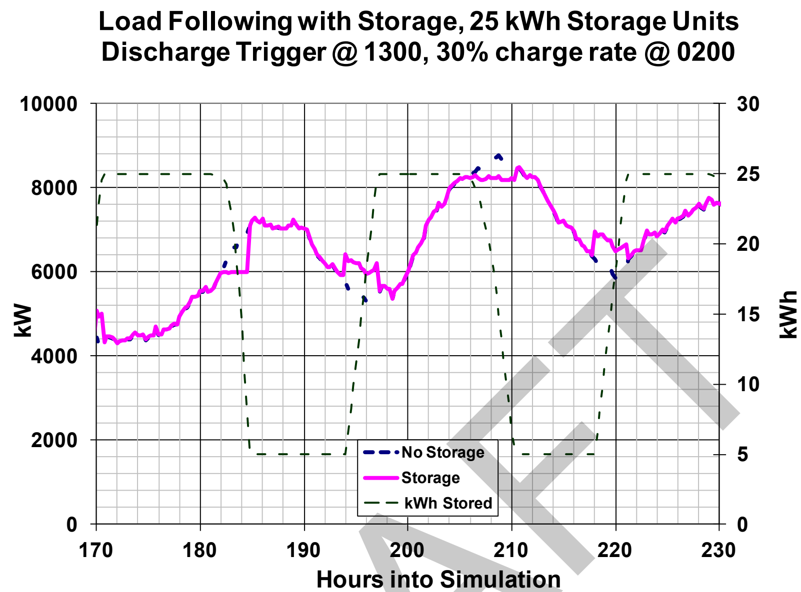


Figure 6-4
Using storage for daily peak shaving

Variable/Renewable DER Integration

Another commonly cited application for dispatchable resources is improved integration of other DER by addressing temporal uncertainties or by mitigating impacts. For example, energy storage can be used to store energy generated by renewable resources and then to supply this energy during peak demand periods. In this fashion, storage can be used to solve the common capacity problem of solar generation output frequently lagging the peak load on residential feeders by about 2 hours.

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 for one potential control algorithm. In this case, the energy storage is dispatched based on a moving average target. As is the case for any energy storage application, different resource capabilities, control schemes, and control settings will produce different results and will need to be designed and evaluated for each application.

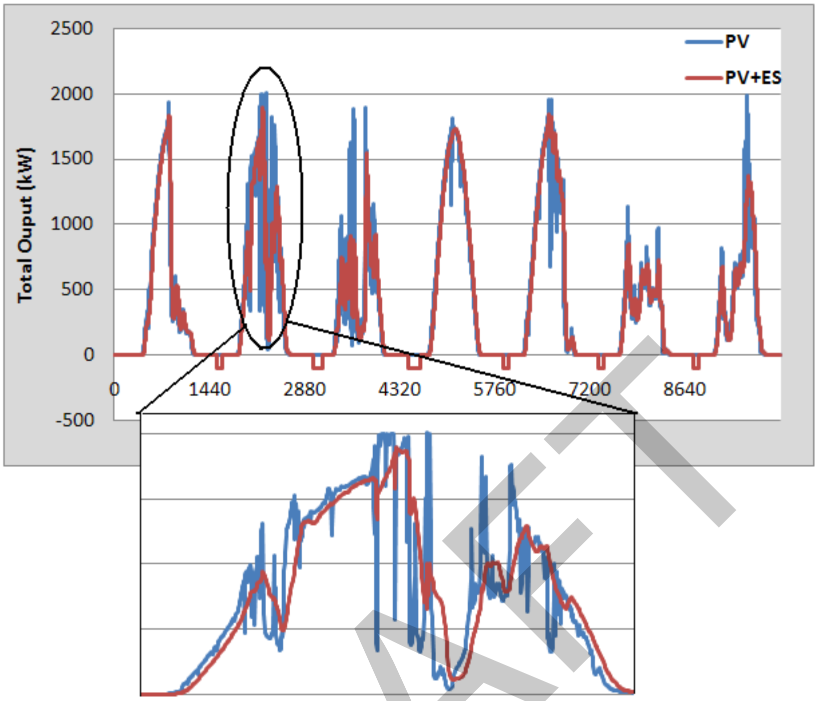


Figure 6-5
Smoothing variation in DER generation

Communications and Control

Communications and control infrastructure are critical components of coordinating the technology fixes 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 DSO can alleviate many of these issues. As previously noted, awareness of DER operation at any given time would assist in performing load transfers. If coordinated with existing utility voltage regulation, potential DER issues involving voltage problems can be remedied. Moreover, if distributed energy resources 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 communications and control capability
- Distribution grid communication infrastructure, for example, suitable field area networks, distributed energy resource management systems (DERMS), and DMS
- Common functions and communication protocols at the DER
- Common services and protocols for DER enterprise integration
- Planning and operational tools that take into account DER grid support capability

7 CHARACTERIZING THE IMPACTS OF DER ON THE BULK 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. Chapter 4 discussed the general characteristics of DER and the potential beneficial and adverse impacts they may have on the bulk system. This section dives deeper into those effects and presents an analysis framework through which the effects of DER can be comprehensively assessed. The results of the analysis are intended to be combined with those from the distribution analysis, described in Chapter 5, to produce an overarching benefit-cost assessment, outlined in Chapter 9.

This chapter describes five core methods that comprise how the Integrated Grid framework considers bulk system planning and operations, building on previous work to account for the nature of DER:

- Resource adequacy: the planning process to ensure sufficient generating capacity to meet demand
- Flexibility assessment: an operational process to ensure sufficient balancing capability

- Operational scheduling and balancing: an operational process to ensure successful balancing of supply and demand
- Transmission system performance and deliverability: the planning process to ensure stable, high-quality power supply delivery
- Transmission expansion and deliverability: an operational process to ensure sufficient network capacity

These five core bulk system planning and operation processes are not independent; rather, they are interrelated and interdependent. The decisions made in one process can significantly impact the other processes. Accordingly, the bulk system analysis framework takes into account these interactions when evaluating the benefits and impacts of DER integration. The bulk system also must be seamlessly and constantly interacting with the many distribution networks connected to it, as described at a high level in Chapter 4. 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 and the interaction between the integrated bulk and distribution systems.

Figure 7-1 shows EPRI's proposed bulk system analysis framework at finer resolution as well as the interactions among the framework's core processes when analyzing the impact of DER integration. An important feature of this integrated assessment is that the beneficial and adverse impacts of one future scenario are determined by comparing the results of that scenario (for example, costs, reliability, and emissions) to the results of a second scenario. Both should build out from the existing network. The assessments determined from this framework should always be the difference between two iterations of the analysis (for example, one DER build-out scenario compared against one "business-as-usual" scenario).

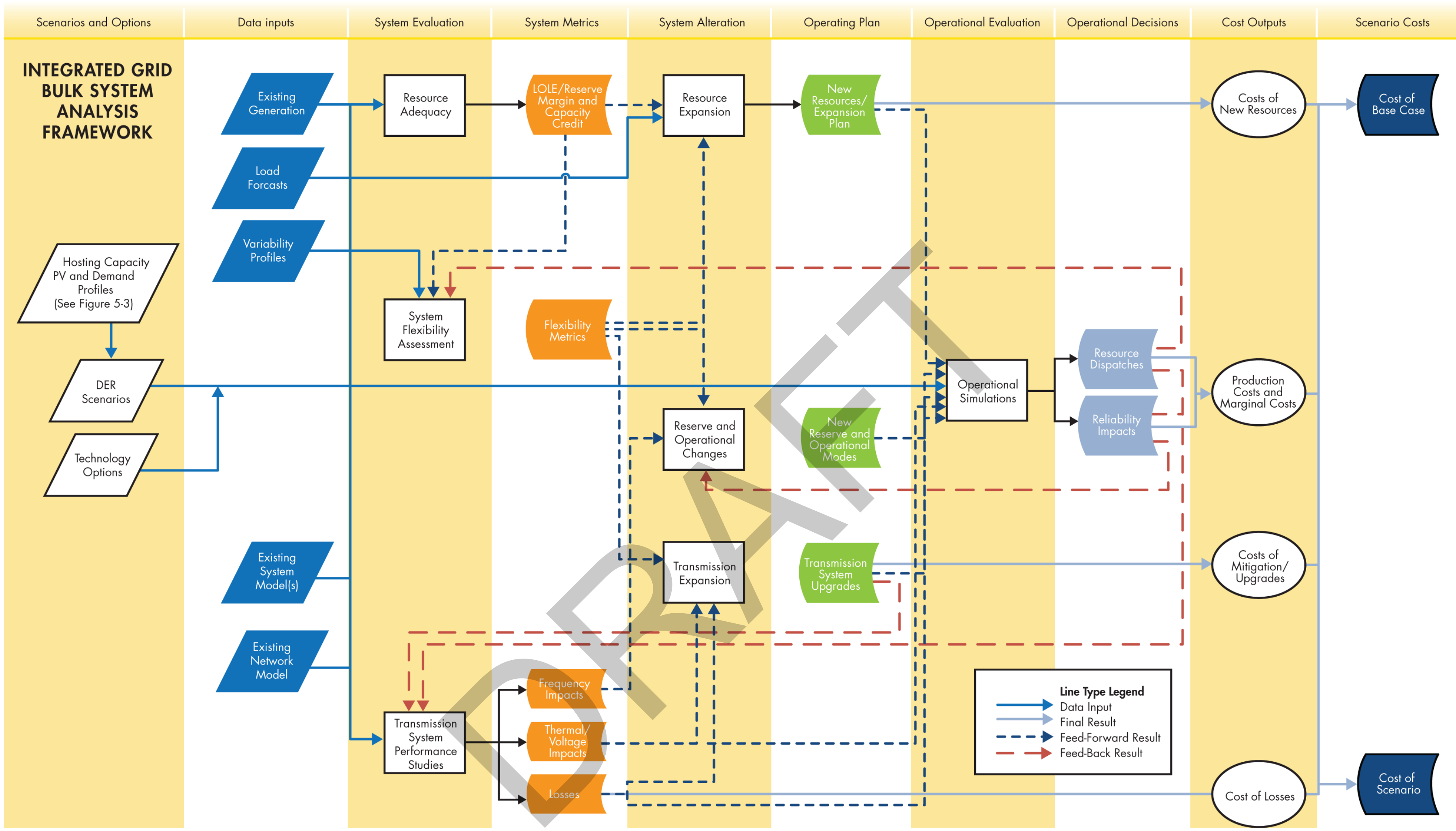


Figure 7-1
Integrated Grid bulk system analysis framework

The framework portrayal starts on the left-hand side of Figure 7-1 with the input data requirements, outputs from the distribution system analysis, and the definition of the scenarios to be studied. The bulk system analysis flows to the right 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 quality of the data available. If shortcomings in key data mean that specific core processes cannot be carried out, this has implications for the interrelated processes. The issue of data requirements and quality will be addressed later. However, most of the data required is available to some degree from existing planning and operational processes at both the transmission and distribution system levels.

The bulk system framework includes assessments that impact 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 (see Figure 7-2). The stages of the framework 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. Although the route through an integrated analysis is shown as passing through all stages, the progression is not necessarily linear. Information required as an input into one of the processes may be a result of another bulk system process that is fed back or fed forward. These are noted in the framework diagram (Figure 7-1) as dashed red and blue lines, respectively. Iteration between bulk system and distribution system analysis may also be necessary.

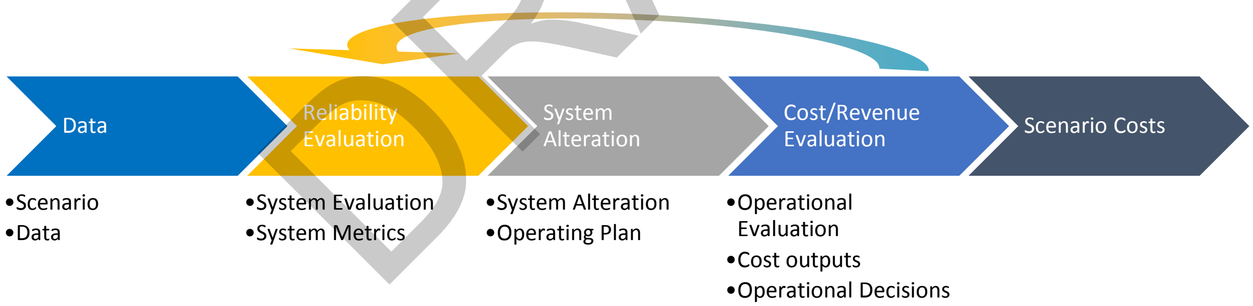


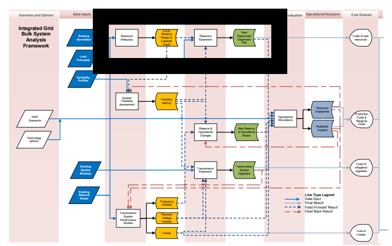
Figure 7-2
High-level framework flow for each scenario

The outcome of each analysis process can be classified as either a cost or a technical output, for example, the outcome from operational simulation in which the production costs are calculated as well as the generator dispatches or outage profiles (technical outputs). Both of these outputs are useful: cost outputs are accumulated into a single cost for the given scenario and employed in the benefit-cost framework, while technical outputs serve as 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 system analysis framework.

The remainder of this chapter provides detailed information on bulk system analysis processes, looking at the inputs, outputs, processes and DER impacts, and 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. What EPRI proposes is that a study of DER impacts on the bulk power system should pay attention to how DER affects distribution system load because they may result in the need for additional supply resources, different operating practices, or both.

Core Bulk System Analysis Processes

Resource Adequacy Process



Purpose

The resource adequacy is a core process that is the starting point for an integrated assessment. It includes two main functions carried out by transmission system operators, reliability coordinators, utilities, and investors:

- Supply adequacy: an assessment of the reliability to ensure that sufficient supply will be available to meet future demand
- Resource expansion planning: an assessment of the optimal new resources to add in order to meet a stated adequacy criterion

These two functions are grouped together in the framework (as shown in the inset figure) 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 to a standard level of 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.

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 the most suitable generation resources 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 actual chronological load information (for example, hourly resolution 8760 time series) while others use load duration curve information. This information must be specified in the definition of the study scenario.
- Detailed generator characteristic data for units expected to be in 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 rates and ramp rates. These data can come from the scenario definition as well as 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.

The generation of long-term demand forecasts is required and depends on 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, hot summer, cold winter, high demand growth, and demand reduction). More sophisticated methods use decades of historical weather information to capture extremes in temperature across different 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 applications such as determining the expected output levels of hydro generation and variable generation, for example, wind and solar generation (either transmission or distribution system connected) or 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 for each technology type.[31] Generally, 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 their capital and operating costs.

Process

Fundamentally, resource supply adequacy is a measure of the availability 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 should use methods that appropriately represent all resource technologies that are likely to be subject to assessment.

To this end, methods such as the probabilistic LOLE method adopted by the IEEE Task Force on Capacity Value[32] should be used 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 (load remaining after variable generation for a range of scenarios) to determine the likelihood and extent of insufficient supply. Probabilistic methods such as LOLE can also more appropriately value the capacity contribution of variable resources relative to simple considerations of output during peak or a collection of specified risk hours.

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

[32] 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.

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. Where significant storage capacity exists, more computationally intensive resource adequacy methods are more appropriate.[33] This is one area in which further research and development is required. Because the capacity contribution of energy-limited resources depends on the energy reservoir when the capacity is needed, resource adequacy calculations should model this behavior appropriately. 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. (Note that 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.[34, 35] The exact execution of this process should consider the assumptions on the operation of the system (for example, vertically integrated utility or ISO market).

Although some resource adequacy tools provide both adequacy and expansion capabilities, the representation of resources and the network is generally less detailed in the expansion planning analysis than in operational simulation. A separate expansion analysis will choose from a predefined set of technology options (for example, conventional generators, variable generation, interconnection, and demand response) for which the same operational characteristics data are required. 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.

[33] 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.

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

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

Outputs

The resource adequacy assessment will typically be the first analysis conducted as part of a holistic, integrated assessment. 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.

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 are inputs into the resource expansion assessment process, which determines the nature 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 cost associated with making a change to the generation portfolio will feed into the overall cost for the scenario and be fed into the benefit-cost assessment.

DER Impacts

As noted in Chapter 4, DER impacts 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. As such, 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.

For all DER, the availability of the resource must be determined based on its 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 its stochastic nature. The same is true of energy-limited DER devices, such as storage and most demand response. Ensuring that the performance over time is adequately represented is critical to understanding the contributions of DER to resource adequacy and the potential 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 is added to the system. DER provides energy and capacity to the system in ways that may adversely impact the economic viability of conventional generation. Some may now be operated so few hours that they are not economic to maintain, resulting in closure of existing generators or precluding the development of new generators. This revenue sufficiency of new and existing conventional generation must be considered when assessing the impacts of DER on resource adequacy and during resource expansion.

Integrated Grid Study Guidelines

The resource adequacy evaluation process should meet the following criteria:

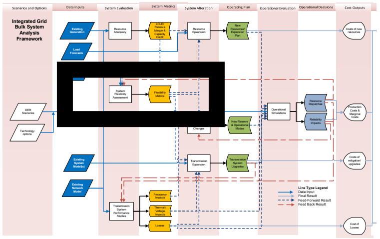
- Meets reliability standards across the range of future scenarios covering uncertainty in weather, demand, and technology using probabilistic methods
- Minimizes total expected costs over a range of future scenarios, including capital and operational costs
- Selects from a wide range of technology options, including the ability to choose between conventional and nontraditional generation while respecting policy priorities
- Captures the operational capability limitations of each technology type:
  - Both transmission- and distribution-connected resources considered
  - For variable generation, the distribution of available capacity should be based on multiple years of historical data, if available. 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 could be relevant to the analysis.
  - For the capacity contribution of energy-limited resources, the selected method should account for the competing operational modes in which the resource is being 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 favored
  - Captures the stochastic nature of variable generation, which may contribute to capacity needs if appropriately assessed

- Minimizes the risk of stranded assets and considers the impact on capacity adequacy of early generator retirement or mothballing for economic reasons
- Interacts with transmission system expansion processes to determine an optimal system development plan

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 guideline recommendations.

Flexibility Assessment Process

Purpose



The purpose of the flexibility assessment process 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 chosen scenario. Power system operational flexibility has increased in importance as a result of rising penetrations of variable wind and solar generation. In scenarios with high DER penetration, similar concerns exist.

The flexibility assessment process determines potential shortages in flexibility over operational time horizons (from minutes to hours), which feeds into decisions on new transmission or generation resource expansion, requires changes to operational practices, or both. Flexibility assessment can sometimes be included in the same step as resource adequacy. In this report, it is described separately, but there is potential for combination if the resource adequacy tools sufficiently capture operational flexibility requirements.

Inputs

The scope and rigor of a system flexibility assessment can vary from a simple screening based on installed resources to a detailed assessment of expected resources committed and dispatched over time with consideration of 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. Given that these assessments will be for future years, historical data provide the foundations to estimate future load and variable generation output levels based on 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.[36] These data originate from the initial scenario definition and are informed by the distribution energy analysis.

- 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 the availability of 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 scenarios. 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 is carried out
2. Mid-level analysis as operational simulation is carried out
3. Detailed analysis after generation and transmission expansion and operational simulation are concluded.

[36] 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.

Basic assessments should be carried out first in order to compare 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 on the dispatch of resources in each case. These assumptions are based on operator experience or a cost-based ranking. Some utilities and system operators are starting to implement these types of flexibility assessment techniques in planning studies.[37]

Flexibility is also being considered in greater detail in resource adequacy proceedings.[38] Mid-level flexibility assessment can be carried out once dispatches are available for each resource from the operational simulation core process. Dispatch information is used to determine the flexibility a resource can offer at each point in time after its dispatch positions are considered.[39] 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. Capturing these dispatch effects is an important aspect of flexibility assessment. 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 dispatches, 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 gives greater detail on the individual options available. [40]

The most 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 once transmission and generation expansion and

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

[38] 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.

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

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

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.[39, 41, 42] This can be done through power flow scenario 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 calculated flexibility metrics. Whereas there are well-established metrics for traditional resource adequacy, the metrics for flexibility are less well established.[43] These metrics report the frequency and severity of flexibility shortages over a range of time horizons and for both upward and downward ramping directions.

The outputs are inputs to both the generation and transmission expansion processes, providing 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 as the physical or operational characteristics of the system change (for example, generation profile or reserve requirements).

---

[41] 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.

[42] Lannoye, E., Flynn, D., and O'Malley, M., "Transmission, Variable Generation, and Power System Flexibility," *IEEE Trans. Power Systems* (in press).

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

DER Impacts

The impact of DER on flexibility adequacy depends on the nature of the supply technology type. 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[44, 45] and increased reserve requirements.[46] However, although transmission-connected variable generation production is routinely forecasted in time periods such as day-ahead, 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 may be associated with DER output. This in turn will require additional system flexibility to balance the system. Because of 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 system requirements is important when accounting for the effect of DER on available flexibility. The controllability of DER will be determined when the planning scenario is created. If DER can be dispatched by a system operator—directly or indirectly, and in a timely manner—it 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.[47] Distributed energy storage may also be a dispatchable resource increasing system flexibility; however, without some degree of control, DER may adversely affect the flexibility of the system in certain circumstances. As with many of the other processes, the precise way in which DER is modeled as part of the flexibility assessment depends on the underlying technology and the degree to which it can be controlled.

---

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

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

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

[47] *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.

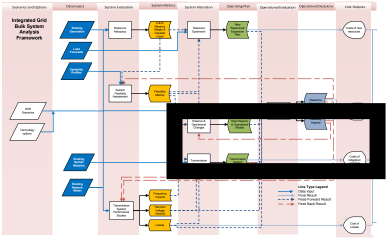
Integrated Grid Study Guidelines

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. As noted, many of these flexibility assessment approaches can be included together with the resource adequacy process—it is separated here to draw attention to the new requirements when considering DER integration. The exact process that can be included will vary, but in general the process followed should adhere to the following guidelines:

- Examine both upward and downward flexibility.
- Examine flexibility needs and adequacy over all operational time horizons that are critical for 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 how 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



System operational simulation is a key component of the evaluation process to determine the effects of integrating a new technology into the grid. It is increasingly recognized that evaluating many of these emerging technologies requires more accurate representation of the reality of system operations in a planning context. Certain operational details cannot be represented because of data or computational limitations, but improvements in utility computational and data enterprise systems allow planners to better incorporate the way the system will operate in the future as part of the planning analyses.

The operational simulations and practices core process is an amalgamation of two distinct but intrinsically linked analyses:

- **Operational simulation analysis.** Typically, production cost simulations include more detailed simulation 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 in each utility or system. These practices 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 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 1 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 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, resulting in the need for the same data for those systems.

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 may also change. Selecting the right types of reserve in the appropriate quantities through analysis of the future system 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 or more 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.[48, 49, 50] 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.** While the timing and time granularity of scheduling decisions (for example, hourly scheduling versus 15-minute or shorter interval scheduling) can significantly impact the operating reserves required to maintain reliability and the associated cost, it can have other implications for the operation of each resource type.[51] 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 with increased system uncertainty and should be examined as part of operational simulation. These may include benefits from incorporating elements of stochastic commitment and dispatch[52, 53]or developing new market formulations[54, 55]that capture the capabilities of new

---

[48] 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.

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

[50] 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.

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

[52] 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.

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

resources or provide system services, such as flexibility, which helps reduce costs in certain situations. A further developing trend in operational practices is to share balancing responsibility across multiple systems or balancing areas.[56, 57] Understanding the value of such changes to system operation is important in determining the best practices and least-cost mode of operation in a given scenario.

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, some tools are now emerging that can also model and interleave AGC action and area control error on a seconds resolution with 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 final costs that are aggregated into the total cost for the scenario, which in turn is an input to the benefit-cost analysis.

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

[55] 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.

[56] 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.

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

- Reliability impacts, such as incidences of loss of load, insufficient reserve capability, or significant area control error can also be reported and monetized. Resource dispatches are required by several other core processes such as flexibility assessment and transmission system performance analysis and feedback, as appropriate. These outcomes also feed into the benefit-cost analysis.
- Emissions can be determined from operational simulation, including CO_2, SOx, and to a lesser degree NOx. The cost and quantity of these emissions can be used in further analysis and as inputs to the benefit-cost assessment.

Impact of DER

DER has a significant impact on this set of analyses. Depending on the specific underlying DER technology and its associated dispatch capabilities and rules (for example, priority dispatch), DER may affect each system differently. Distribution-connected solar and wind generation will result in increased requirements for reserves at certain times of the day while potentially reducing it in others (though overall requirements are likely to increase).

DER may also offer 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 it is included in the simulations: forecast accuracy and controllability are key features of DER that will determine how it can be 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 exists as part of the scenario definition, operating reserve requirements should be determined for each scenario evaluated and 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 the associated uncertainty.
  - Cover a sufficient range of variability and uncertainty to ensure the reliability of the system.

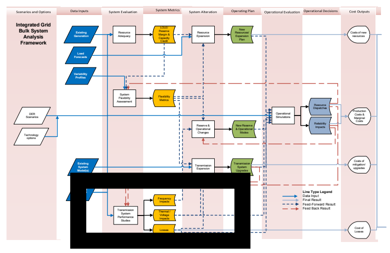
- Reserve provision should be technology-neutral and accommodate as wide a range of providers as is reliably capable of providing the defined services.
- Additional reserve categories, such as those providing longer term flexibility, should be evaluated to determine if they can reduce system costs required to maintain reliability with DER.

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 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 as well as detailed time-domain stability studies for critical contingencies. Planners should also conduct protection studies to ensure that the system is robust enough to operate and recover during faults with power system equipment.

Inputs

The data required to conduct the transmission system performance studies can be extensive but can be divided into five general categories:

- **Generator data.** Generator real and reactive power ratings, impedances and time constants, and inertia; excitation system parameters; governor control parameters. This is specified in the scenario definition but may be altered by the resource adequacy (expansion) process.
- **Transmission network data.** Voltage levels, impedances and ratings for lines and transformers, and shunt data. This is specified in the scenario definition but may be altered by the transmission expansion process.
- **Load data.** Real and reactive power levels; composition. This is specified in the scenario definition but may be altered at a substation level by the outcome of the distributed energy analysis (see Chapter 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 known and modeled. This comes from the system operational simulation core process.
- **DER data.** The capacity, location, output profile, and reactive control capability at the bulk 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 in a reasonable amount of time.

Process

The process is executed in four steps:

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

The two analytical methods that are essential to analyze 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 always evolving as end-use technologies emerge. Models to represent DER are just beginning to be developed and evaluated.

The impact of high levels of DER on transmission system performance would likely best be captured with an integrated model of the T&D systems. However, this is a complicated process from a data and computational perspective given the expansive distribution system that 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 is represented as a generator connected through a transformer and impedance representing the distribution substation and feeder in transmission power flow studies. These aggregated models come from the analyses described in Chapter 5.

For both power flow and dynamic evaluations, an accurate representation of the effect 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

With a specified level of DER in the scenario, power flow and contingency simulations should be conducted for credible load and DER output scenarios. For both analyses, 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. As advanced reactive power controls for DER (such as those associated with smart inverter functions for distributed PV) begin to proliferate, those capabilities should also be modeled and included in the analysis so that the benefits are transferred to and 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 on active and reactive power margins can be examined using advanced power flow techniques.[58] The power flow model can also be used to determine the extent to which DER affects transmission losses because it serves local load. As penetration levels increase to the point that local DER levels at times exceed load, reverse flows into the transmission system may occur, reversing the effect of DER on losses.

For dynamic studies, the simplest way to represent a 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. Although no standard dynamic model is presently available for distributed PV in many of the latest official release versions of GE's PSLF® and Siemens PTI's PSSE® transmission planning software platforms, the existing large-scale PV dynamic models can be used to represent the aggregated distribution-connected PV at the bulk system level behind the transformer and feeder impedance model described previously.

Using these models, a more realistic representation of DER can be achieved that 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.

With the DER appropriately modeled in the dynamic system model, stability simulations are performed for contingencies including transmission system faults and loss of generators. The stability simulations are performed to examine impacts of high penetrations 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) that has 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

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

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 (or 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. These system violations will be input to the transmission expansion process where required transmission expansion plans will be determined.
- 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 can reduce the system's dynamic reactive capability (that is, capability of the system to deliver reactive power during a fault). 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 (currently in North America, DER is 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 itself can cause a rise in voltages due to a decrease in net load as seen from the transmission level. 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 resources, 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 providing frequency control. Although some DER technologies may be able to provide active power controls to support system frequency, visibility and control of the DER as part of the overall bulk system frequency control is complicated. The disconnection of DER on a wide scale due to 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 system reliability, such as those efforts to revise 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. In the future, if such provisions are sanctioned, studies must be performed to calculate minimum voltage and frequency ride-through requirements for any given region—these settings could vary based on DER penetration levels and type of system (for example, meshed, radial, or isolated).

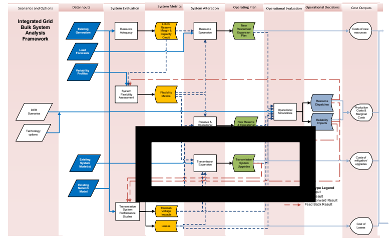
Integrated Grid Study Guidelines

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

- Power flow and dynamics models that accurately represent DER and its 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 most appropriate standard model (presently bulk 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:
  - Simulations should be conducted across credible contingencies for critical load/DER output scenarios (for example, combinations of system peak and solar noon peak during both summer and winter relative to various DER output levels—full aggregate output, zero output, expected output based on historical data, and so on).
  - Thermal and voltage violations.
  - Impact on losses.
  - Advanced power flow analyses should be conducted to evaluate reactive margins.
- Dynamic simulations:
  - Simulations conducted for most significant faults and single worst contingences.
  - Disturbance ride-through characteristics of DER must be accurately represented.
  - Transient voltage recovery and voltage stability and frequency stability for worst contingencies should be evaluated.

Transmission System Expansion Process

Purpose



The purpose of the transmission 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 set of facilities with voltage and thermal violations 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 or 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 analyses.

Processes

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

- Long-term planning over a time horizon of 10+ years where there is high uncertainty in load forecasts, technology development, and energy policy that impacts the power system requirements such that identified projects have to 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).

- Midterm planning over a time horizon of 3–10 years where load and generation future uncertainty is more manageable. Planning objectives include identifying transmission projects to address specific reliability issues that tend to be localized.
- Near-term planning over a time horizon of 1–3 years where load and generation are basically known with 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 methods include scenario-based expansion planning, optimization methods, and risk-based analysis. The process selects the best option from a set of possible solutions that are defined by the planner. 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 change in planning assumptions. Midterm planning is the most significant horizon because long-term planning hinges on a greater deal of uncertainty.

Output

The outputs of the transmission expansion process include the following:

- New transmission expansion plan with identified 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 broader 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 on-line, the location of that DER, and the potential variability in its availability and output levels for some of the prevalent DER technologies. As noted in Chapter 4, DER has the potential to offset the need for new transmission projects by serving load locally and reducing thermal loadings of transmission facilities for a given load scenario—depending on the extent to which the output of the DER aligns 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 certainty in transmission requirements several years prior to the actual need. DER may also impact transmission expansion planning through the potential displacement of bulk system conventional generation that provides reactive support to the system (see the description of impacts in "Transmission System Performance Process" earlier in this section).

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

Some of the impacts of increasing levels of DER on the bulk power system, described in Chapter 7, may be minimized or entirely mitigated through investment in other system technologies/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. This chapter describes the mitigation actions and associated benefits and categorizes the technologies that can be used into 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 for high DER scenarios to mitigate some of the potentially adverse transmission system impacts of DER. The technologies described involve system operations improvements rather than new equipment such as energy, capacity, or power delivery resources.

System Operations Improvements 1: Increased Visibility and Controllability of DER

Transmission system operators (TSOs) generally have direct communication channels with transmission-connected resources that give the TSO visibility of resource capability and current output levels as well as the ability to issue dispatch instructions to the resource. TSOs do not presently have this same visibility and controllability of DER, but obtaining these capabilities through an operating agent would significantly improve some of the operational challenges associated with DER and increase its potential benefits.

Communications is a key component of improved visibility, data quality, and controllability. Several communications technologies (for example, fiber-optic, radio, cellular, and microwave) may be used. Establishing standards for these types of communications to DER resources will allow for greater deployment at lower cost and better interoperability between systems. Communications also need 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.

Although one-way communication can provide either visibility or controllability, two-way communications and control are preferred: the system operator knows what is happening and can also control the DER. This will likely require some form of aggregation, 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.

Impacts Mitigated

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

- Managing variability and uncertainty associated with DER: visibility allows operators to measure resource production accurately and understand how it is changing 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.
- Controllability of active power output, particularly if aggregated 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 allow for knowledge of the amount of potential lost DER during fault conditions (if such a problem exists).
- Visibility will, over time, provide knowledge of the variability and uncertainty in the output of DER, allowing planners to determine resource adequacy characteristics of DER.
- Controllability will allow suitable DER technologies to participate in the provision of various ancillary services, including spin and non-spin reserves, regulating reserves, and various potential new reserve products required in future systems.
- Improved DSO-TSO interfacing allows for more optimal system operations because all potential resources could be used according to their abilities, which in general has the potential to reduce costs and improve reliability.

Consideration within Framework

The benefits of DER visibility and control are primarily operational. As such, assessing visibility and control benefits and impacts within the analysis framework is primarily accomplished through the modeling and assumptions in the operational simulation, transmission performance, and flexibility adequacy processes. In particular, reserve determination and operational simulations will be altered to account for the increased confidence operators would have—potentially lower operating reserves. This would also impact the dispatches examined in power flow and stability simulations. Visibility and control may also reduce flexibility requirements and all DER to provide flexibility contributions. Examining a system with and without some aspects of visibility/controllability to quantify their benefits is difficult.

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.
- 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 Improvements 2: Forecasting 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, improving reliability and reducing costs. The ability to forecast their output will reduce the impacts of DER on operational scheduling and transmission operation performance, particularly for solar PV, but also potentially 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.

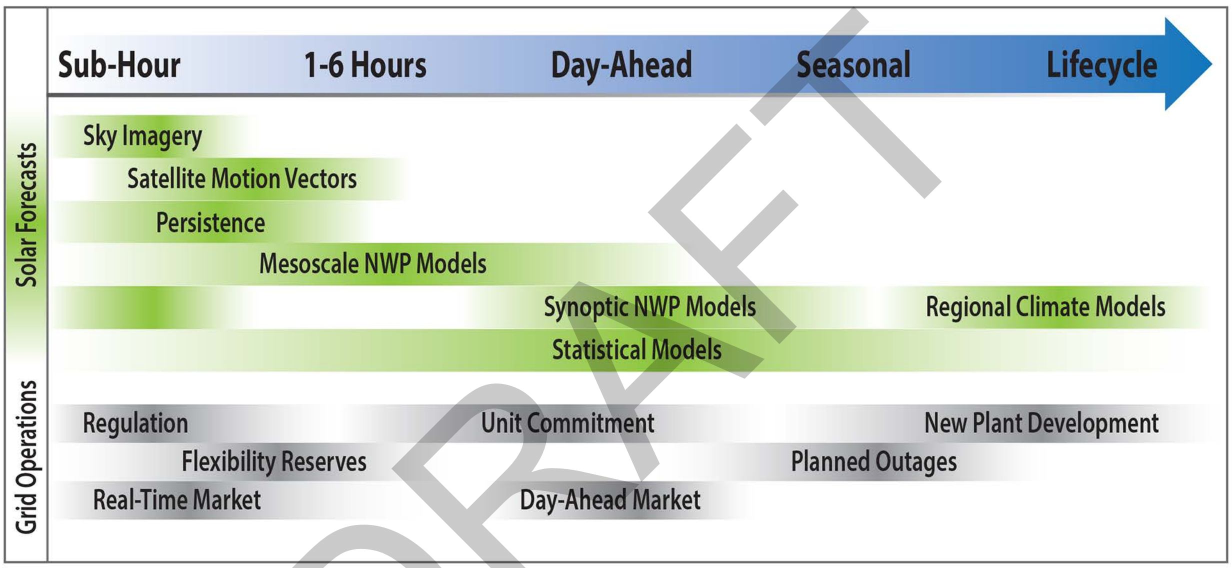


Figure 8-1
Solar forecasting on various time horizons showing forecasting model used and power system operations impacted

As shown, a variety of technologies can be used, depending on the particular function being addressed. Shorter time horizons tend to use more field sensors, such as pyranometers or total sky imagers, which measure irradiance, capture cloud movement, and so on. Longer term forecasts tend to use detailed atmospheric modeling as well as some input from sensors. For day- to week-ahead forecasts, these generally start with numerical weather prediction (NWP) models—these model physical flows of energy over the atmosphere and are used in most weather-related industries (for example, aviation). 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 is also used to provide uncertainty information and can therefore be used to determine risk involved and to improve scheduling and dispatch decisions.

Impacts Mitigated

Forecasting of DER, 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.[59, 60, 61]
- Accurate forecasting of DER output will allow transmission operators to better plan reactive power requirements on the bulk system and to schedule transmission outages.
- Resource adequacy: previous EPRI work[31] has shown that operational timeframe uncertainty (day-ahead) associated with PV can have significant impacts on resource adequacy. This is due to the fact that with large forecast errors, sub-optimal commitment of generation may result in periods when large ramps cannot be met by the generation that is on-line. This can result in potential loss of load or curtailment of generation (depending on the direction of ramp). For loss of load, this impacts resource adequacy.

Consideration Within Framework

The benefits of DER forecasting are primarily operational and will mainly be considered in the operational simulation process of the framework. The reduction in reserve requirements and improved operations can be measured using the 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 than 1 hour) may be able to only slightly reduce regulating requirements, for

[59] 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.

[60] 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.

[61] 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.

example, 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 being deployed in the field (for example, pyranometers and total sky imagers) could be very costly. Ideally, all PV systems would have these technologies, but that is almost certainly cost-prohibitive. Therefore, 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. Commercial forecasts of costs range from several hundred to several thousand per month per site—and so may end up being relatively impactful if aggregated over a system. (A "site" for distributed PV might be for all distributed PV connected to a distribution substation or similar sized area).

System Operations Improvements 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 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 new resources on the system, operating practices may evolve to better integrate these resources. It should be noted that, even without DER, many practices continue to evolve with improved computation and software, data collection, and changing regulatory and utility/ISO requirements. Adjustment to the following practices may have beneficial impacts for DER integration:

- **Adjusted reserve determination processes.** Increased requirements to manage variability and uncertainty on all timeframes have resulted 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 periods from tens of minutes to hourly uncertainty are covered without causing an undue burden on expensive regulating reserves.[62] These are better suited to short timeframes (less than 10 minutes). Reserve procurement mechanisms may need to be adjusted to reflect the fact that certain DER resources 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.[63]

- **Adjusted 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 displaces traditional 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 has sufficient inertia and that the contribution, if any, from DER is accurately estimated for such tools.[64]

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. Obviously, these impacts cannot be totally mitigated using operational practices.
- Reduced operating reserves and more optimal scheduling may also reduce the need for flexible capacity.

[62] 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 Aug. 25, 2014.

[63] ERCOT Concept Paper: Future Ancillary Services in ERCOT, Draft Version 1.1, Nov. 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.

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

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 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

As with other technologies, costs of changing operating practices are not easy to estimate. However, the most relevant implications include 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 new hired expertise.
- For new market products or changes to market rules, there may be significant time invested in stakeholder processes—the likely result may be something not fully optimal. Although this still reduces costs, the amount "left on the table" should be considered.
- 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

This section describes potential improvements to the operational flexibility of the system that may be employed for high DER scenarios to support balancing of supply and demand as well as potential adverse flexible operation impacts of DER noted previously. These improvements may be derived through adding potentially emerging flexible resources or by obtaining additional flexibility from existing resources. In particular, new or retrofitted resources are expected to be able to provide enhanced ramping capabilities.

Flexibility Resources 1: Flexibility from Conventional Generation

Much of the flexibility of power systems is currently provided by thermal and hydro generators. Operational flexibility of such plants—chiefly the abilities to ramp quickly, operate across a wider output range, and start and shut down more quickly—have become important considerations for managing system variability. Generally, there is a trade-off between increased flexibility and a combination of operating efficiency and/or capital costs. This increased flexibility has been obtained in new plants and through retrofitting of existing generation. New plants, particularly combined- and simple-cycle gas turbines, show extremely flexible characteristics—with 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.

In addition, all types of plants are examining methods to change operational practices to get more flexibility out of the existing plant. EPRI is examining nuclear plants to determine how best to operate them to provide some types of flexibility—this may not include all time scales, but it will allow nuclear plants to be operated in a more flexible manner. Coal plants have already been retrofitted in some areas to provide lower minimum output and higher ramp rates.[65] Hydro can be retrofitted in two ways: either by improving speed of response or, more significantly, adding pump-back capability to reservoir hydro so that system load can be increased as well as decreased. Hydro operations are also being examined to determine whether altered scheduling practices can improve flexibility of the hydro fleet.

An important aspect of more flexible operations from a conventional plant is the potential impacts of increased cycling of generation. 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, which increases maintenance costs and outage rates and may reduce lifetime and efficiency.

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

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 better managing ramps, while 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 on-line is reduced.
- With reduced minimum generation, more generation can be kept on-line while still efficiently accommodating DER, resulting in an improvement in frequency and voltage stability.

Considerations Within Framework

Conventional plant operations 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 considered 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 resources 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.** More flexible operations from conventional plants are mainly related to cycling costs. Increased maintenance costs can be quantified relatively easily—for example, increased parts replacements and labor. Increased outage rates result in reduced revenue and may also increase total system operating costs because more expensive generation has to be used. Reduced efficiency will result in reduced revenue and increased system costs, while reduced lifetime impacts the time period over which to recover capital costs and increases the need for new capital investment to replace the retired plant. For resources in which increased flexibility comes from altering operating practices, costs may be associated with increased labor and training of operators as well as potentially increased compliance costs—particularly for nuclear.

Flexibility Resources 2: Demand Response

Demand response resources are already being used by some system operators to provide increased operational flexibility. Advances in communications and controls technologies are expanding the ability of all types of consumers to respond to system operator directives, providing the potential to more broadly use demand response for flexible operations. The capabilities for demand response to contribute to system flexibility obviously depend on being visible, controllable, and reliable, but many systems are already successfully using demand response to provide such flexibility function.[66]

Impacts Mitigated

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

- Management of variability and uncertainty in a more efficient manner, improving balancing of active power. Provision of various balancing services—from 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 can result in a reduction of any potential curtailment of DER.

[66] 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.

- Demand response can also be used to provide capacity adequacy and, in combination with DER, could result in a reduced need for more capital investment in conventional generation. To provide such adequacy, persistence needs to be verified—that is, that the demand response can be relied on over several years in a planning horizon. To provide resource adequacy with increased DER penetration, demand response may also need to be able to respond to variability of PV and be available more frequently than traditional capacity adequacy programs and at various times of the day and year.

Cost Considerations

Because demand response is being considered for a wide range of technologies, identifying costs may mean examining each technology. In general, the following attributes need to be considered:

- Communications and control costs
- Installation costs of any technology, for example, advanced metering infrastructure
- Costs of aggregation (if the demand response is aggregated)
- Costs of enabling demand response technologies compared to existing technologies; for example, water heaters that can respond to grid signals are more expensive than typical water heaters
- Increased complexity of system operations and associated computation and software costs

Flexibility Resources 3: Energy Storage

Although energy storage—particularly localized energy storage (battery or thermal)—may itself be a DER, it may also help integrate other DER. There are many forms of energy storage, including the following:

- **Pumped hydro.** This 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; however, when they are 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).** This is also a larger form of storage; however, it is currently installed in only a few places worldwide. 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 the air warm for use later at high efficiency.

- **Battery storage.** This covers a variety of technologies, including lead-acid, flow batteries, sodium-sulfur, Ni-Cd, and lithium-ion. These use various chemistries to store the energy and then release it later. Batteries tend to respond quickly and accurately and can be scaled relatively easily, though most are currently small scale. They tend to have short lifetimes, can be relatively expensive, and can be inefficient in terms of round-trip losses.
- **Electric vehicles.** These are a particular subset of battery storage in which the battery is used to power electric vehicles. 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.** These 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.** This form of storage involves the collection of excess thermal energy at a building, community, or even city level; the energy can be used later to provide power when needed. A variety of materials can be used, including solar thermal, ice, and earth. Energy can be stored over long periods of time; inter-seasonal storage is sometimes used. Heat pumps shifting energy usage over a day can also be counted as thermal energy storage.

Impacts Mitigated

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

- The flexibility of energy storage—generally quick to respond, with the ability to both increase and decrease net load—results in an extremely useful resource for managing variability and uncertainty in a more efficient manner.
- T&D deferral can result from using energy storage in optimal locations on either network.
- The fast response of some forms of storage can reduce the need for regulating reserves because the 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 will need to 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, transmission needs, and so on. In addition, it is important to consider the functions being met by storage when assessing the impacts. For example, if storage is providing regulating reserves, ideally the accuracy of storage in providing this service is accounted for versus that of a conventional plant. During peak times on a particular transmission substation, storage that provides capacity for transmission deferral cannot be used to provide other services. Modeling of storage, particularly battery storage, is an area in which significant attention must be paid. This includes, for example, accurately 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. Whether storage is considered to replace other resources or added to an existing system will also be important: storage added to an already adequate system will not show as much value.

Cost Considerations

Storage can be an extremely expensive resource to procure. However, because it provides multiple services, these need to be carefully considered together. Storage 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) need to be considered. In addition, lifetime is important because 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 that may help with the integration of DER.

Transmission Resources 1: FACTS and HVDC

HVDC is used to transfer power—normally over long distances—by converting power to DC, transmitting the power, and then converting back to AC using power electronics. HVDC can be economically viable over longer distances (even more so if undersea routes are needed) because it requires fewer rights of way, lowers transmission losses, and can be controlled easily compared to 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 controller (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 obtain 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.
- FACT 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 interaction with the framework comes in the area of transmission studies because the applications of FACTS are intended to improve voltage and frequency performance. However, the operational simulations may also be impacted: there will be less must-run generation—and potentially fewer operating reserves—required for reliable operation. Resource adequacy may also need to consider a reduction in generation that was prevented from retiring because it was in a reliability must-run situation.

Cost Considerations

FACTS is generally seen as an expensive technology and should be compared against other less expensive conventional solutions. This comparison would need to consider the additional capabilities the FACTS device offers, 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 if DER displaces 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. It should be noted that these devices provide additional services not related to DER integration and therefore should not count as a DER-related cost.

Transmission Resources 2: Increasing Transmission Capacity

Transmission, although not a new technology, is extremely important in any power system and will continue to be relevant in a future with high DER penetration. For the purposes of this report, several aspects related to transmission are considered. Clearly, in the past few decades, it has become increasingly difficult to build transmission. Careful planning is needed, and various risks with any project therefore need to be assessed. This will include the likely deployment of DER and other resources that may impact the value of transmission, either to mitigate reliability constraints or to improve system economics. Increased complexity has led to a renewed interested in augmenting existing deterministic practices with risk-based or probabilistic techniques. These will better factor in the risk of future DER deployment, fuel prices, and resource expansion while also considering various outage risks and providing associated reliability and economic metrics.

Transmission congestion patterns are likely to change with increased DER; this will be important in determining which transmission needs to be built. From a technology perspective, the variability and uncertainty associated with DER may drive the need for larger balancing areas or increased coordination between balancing areas—which requires 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. Transmission is also important in reducing or removing voltage and transient stability issues; this will continue to be a factor but will have to be judged against other potential solutions, including DER.

Impacts Mitigated

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

- Voltage and transient stability problems can 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 more efficient use of generation resources.
- Higher voltage can allow power to be moved at lower costs and greater diversity brought to the system, reducing the overall resource requirements to meet resource adequacy needs.

Interaction with Framework

Although the most obvious area in which transmission will interact with the Integrated Grid framework is transmission studies (for example, transmission planning and stability analysis), where new transmission will be assessed for its impacts, it will also impact other areas. 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 accessed. 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 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 in order to separate DER impacts from transmission upgrades needed regardless.

Transmission Resources 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. They could also provide inertia if required. Reactive power can be continuously adjusted, allowing these 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, and 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, if they are not required to provide power, they may be more suited to areas with high DER penetration because it prevents 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 on-line.

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 off-line—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 numbers 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 distribution and bulk power system impact analyses described in Chapters 5 and 7 produce a large body of technical data that detail how the power system is consequentially affected by DER adoption. They also identify what changes in system design, assets, and operation are required to accommodate DER while maintaining reliability standards at least cost. The data provide utility planners and operators with valuable information to help them better understand and optimize system dynamics. Providing answers to the investment and policy questions that motivated the original study, however, requires a distillation of the system analyses in financial terms in a way that facilitates strategic decision making.

This chapter lays out the benefit-cost analysis (BCA) approach that EPRI has developed to allow for monetization and comparison of scenarios, each consisting of results from the distribution and bulk system processes. The BCA enables comparison of investment alternatives by converting all of their associated costs and benefits into monetary streams over time and combining them into a single net-benefit metric, or the difference between identified benefits and costs. This informs the selection from DER integration alternatives that may have different approaches but that lead to the same result: a reliable and safe system.

As a process, the benefit-cost framework component gathers its inputs from the core assumptions defined at a study's outset, as well as the distribution and bulk system framework modules. Changes in the power system infrastructure and operating conditions are classified as *impacts* and categorized according to the entities affected—among them, individual customers and society at large. As part of the BCA module, these physical impacts are then evaluated in monetary terms, as (net) benefits or costs, and then compiled and interpreted.

As the concept of the Integrated Grid evolved, EPRI recognized the need to assess system impacts holistically; the same holds true for analyses of DER accommodation, energy efficiency programs, or central power plant investments. Instead of a holistic assessment, many have opted for a piecemeal approach to estimating benefits (value), going category by category in search of benefits, but missing important complexities and interdependencies. This approach misses key effects and double-counts others.

The BCA framework for the Integrated Grid does, however, build on some previous research efforts—in particular, one jointly developed by EPRI and DOE, described in the report *Methodological Approach for Estimating the Costs and Benefits of Smart Grid Demonstration Projects*.[67] The smart grid methodology addresses measurement and verification issues associated with conducting physical demonstrations. The considered impacts and costs are limited primarily to the local distribution component of the power system. The Integrated Grid framework expands this analysis to include additional components of the power system, allowing the user to evaluate a much broader swath of available technology pathways.

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 generation level, where fuel and emissions may be saved. The Integrated Grid BCA framework traces these benefit and cost streams from where they occur to their monetary manifestation.

Exploring both benefit- and cost-causation paths related to DER aims to inform utilities, regulators, and policymakers about the implications of proposed DER interconnecting policies, cost allocation methods, and rate designs. A comprehensive analysis can identify how the physical system has to change to accommodate DER and must consider multiple accommodation methods. 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

[67] EPRI, Palo Alto, CA: 2010. 1020342.

relevant alternatives. However, the framework does not stipulate which alternatives should be taken or how the costs incurred from those that are taken should be recovered. That is left to the responsible stakeholders.

Figure 9-1 provides a detailed illustration of how the costs and benefits evaluated in the distribution and bulk power studies can be converted into monetary terms. The boxes on the left describe the inputs to the CBA process, which arrive from three different portions of the framework: the core assumptions and the distribution and bulk system processes. These items are then monetized and sorted by the entity to which they accrue. Some impacts identified by the distribution and bulk power studies are monetized before they arrive at the BCA module. Others require that they be converted to economic metrics independently during this step of the process. Overall, these costs and benefits can be classified into three categories:

- **Net system benefit (cost).** The change in capital cost and operating expenditures, incurred by the utility, that results from adding equipment or refining practices specifically intended to integrate DER.
- **Direct customer benefit.** The change in quality of service (including reliability) experienced by the customer as well as net changes in required equipment at the customer premises, such as DER.
- **Societal benefit.** The DER impacts that do not directly accrue to the utility or its customers: emissions variations, 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.

Once all of the impacts are monetized and categorized by the perspectives of interest, they are evaluated by several traditional benefit-cost metrics. Often, these outputs produce the result that is interpreted as the "answer" to the questions posed to the framework.

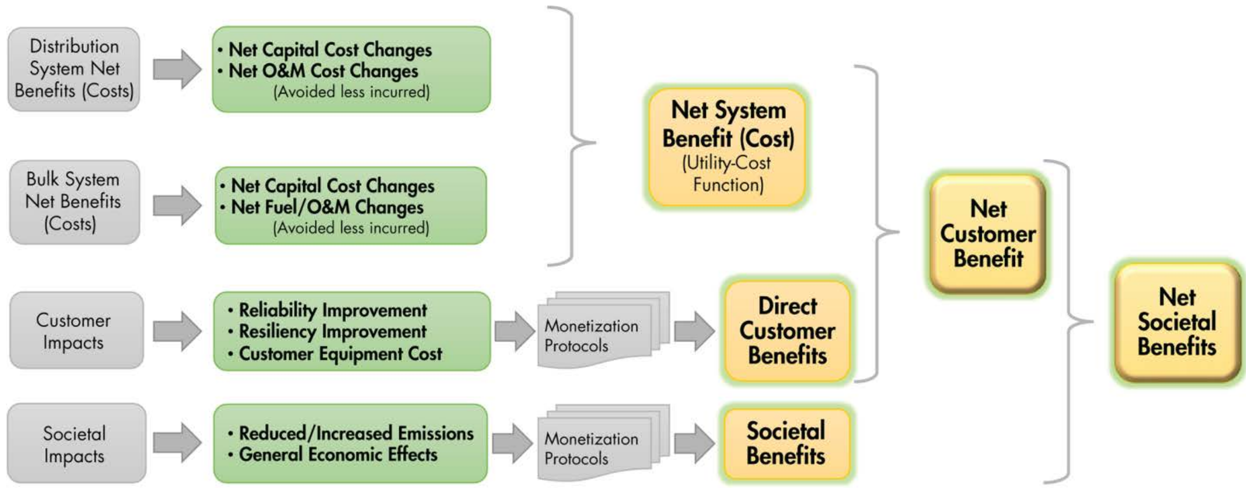


Figure 9-1
Detailed Benefit-Cost Analysis Methodology

Monetization Considerations

Impacts are the physical results of a change in the power system—for example, the addition of DER or changes in other power system equipment, such as new reclosers, upgraded transformers, and reconductored or re-routed distribution lines. Impacts should be measured or estimated relative to the state prior in order to derive the change. Although it is challenging to determine impacts on real power systems, they can be estimated using circuit models as well as production/market-simulation models described in Chapters 5 and 7.

Some impacts are links on a causal chain of impacts and involve costs or cost savings that are directly monetizable. For example, deferring a central generator investment or altering the generation mix (substituting one kind of generation for another) changes capital investment. However, once the deferral or mix change occurs, there may be countervailing changes in operations and subsequent costs. There may also be changes in fuel type that can change operating expenses over the long term. These are the interdependencies that the EPRI framework acknowledges and addresses. Only a complete, integrated analysis finds all benefits without double-counting.

Chapters 4–8 described these interdependencies in detail, making a compelling case for an integrated, end-to-end approach to measuring impacts. Until all impacts are accounted for, an assignment of value to an individual category (avoided cost, energy cost changes, customer benefits, societal benefits, general economic benefit, or improvements in national security) is fraught. Only by coincidence will the answer that results from a thorough analysis produce the same answer. There can be a high price to pay for taking shortcuts in determining how new uses of the distribution system affect overall system performance.

Costs and benefits are the monetary/economic equivalent of impacts. They are derived through a variety of monetization methods, as described in the following sections of this chapter. Impacts affect the utility business in a variety of ways, but financially they can be grouped into one of a few major categories that have natural association with cost causation or avoidance. Generally speaking, these costs and benefits are either internal to the utility cost function, or they are externalities.

Elements of the Utility Cost Function

Expenses and capital represent the primary means by which costs and benefits are recognized within the utility cost function:

- **Expenses.** *Expenses* are utility expenditures for routine costs of doing business within a specified period. All expenses are settled during the current period and appear as current-year expenses on the utility's income statement. Items of operating cost such as fuel cost and employee payroll are expenses. Expenses appear in each category of the utility cost function; for example, fuel costs are expenses in the system operations category, while O&M expenses are part of utility operations.
- **Capital.** *Capital expenditures* are investments in machines, equipment, devices, buildings, or any other utility property that endures and is used and useful for a period of years. Customers pay for the use of utility capital over time. In utility planning analyses, the amounts that customers are asked to pay are calculated over time, respecting standard accounting conventions. In addition, revenue requirements are calculated over time. That is, a capital investment is converted 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.[68]

  Capital-related expenses, which may be referred to as *ownership costs*, all fall within the system assets category of the utility cost function. These ownership costs combine with other expenses to constitute a utility's total "revenue requirements." However, it is generally not

[68] Investment tax credits and accelerated depreciation do not result in increased profits for shareholders. Rather, both tax incentives create liabilities that offset both 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.

necessary in utility planning analysis to calculate a utility's total revenue requirement. The analysis can concentrate on the investments and expenses that change between alternatives, evaluating only these incremental revenue requirements rather than the total.

Table 9-1 lists some of the potential impacts that DER additions can incur at the distribution and bulk system levels and which can be translated into costs and benefits that fall within the utility cost function.

Table 9-1
Potential impacts that DER additions can incur at the T&D levels

	Monetization of Physical Impacts into Costs and Benefits		
	Impact Category	**Nature of the Cost or Benefit**	**Cost-Benefit Category**
Distribution System	Loss reduction	Expense	System ops
	Upgrade deferral	Capital deferral	System assets
	Reconductoring	Capital, then loss reduction	System assets and ops
	New equipment (line regulators, STATCOMs)	Capital, then any ops changes	System assets and ops
	Protection changes (relaying)	Capital	System assets
	Accelerated wear-out of LTCs	Acceleration of capital and O&M	System assets and utility ops
	Upgrading voltage	Capital, then loss reduction	System assets and ops
	Smart inverters	Capital	System assets or customer cost
	Energy storage	Capital and operating savings	System assets and ops
Bulk System	Generator investment changes	Capital, then operating changes	System assets and ops
	Transmission loss reduction	Expense	System ops
	O&M	Expense	Utility ops
	Fuel consumption	Expense	System ops
	Congestion	Expense	System ops
	Emissions	Expense and social	Societal and system ops
	Forecasting activities	Capital and O&M	Utility ops and assets

A complication is that there may be joint costs involved. Joint costs result from an investment that serves more than a single purpose, and there is no unambiguous way to allocate the cost among these beneficiaries.[69] For example, there are likely large one-time investments that will be made, such as communications infrastructure or market design and IT upgrades, that aid in integrating DER but that would be made anyway. What part of that cost is assigned to actions intended to integrate DER? Alternatively, these investments may have been evaluated and determined to not be cost-effective but are required to accommodate DER. Should some of that cost be allocated to other beneficiaries? EPRI's BCA recognizes these complicating utility investment considerations so that decision makers can take them into account.

Elements External to the Utility Cost Function (Externalities)

As previously stated, some cost and benefit elements lie outside the utility cost function and are not specifically calculated as part of the other framework components:

- **Customer costs and benefits.** Customer costs and benefits are those that are not part of the utility's cost function and are not represented in revenue requirements. Customer costs may include long-lived items, such as out-of-pocket investments made in consumer-side equipment (for example, a rooftop PV system), less any utility or government incentives. They may also be identified in terms of the implied (by standards to which the system is built) quality or reliability of utility service as experienced by the customer.
- **Societal costs and benefits.** Social costs and benefits are not found in a utility's cost function and are not represented in revenue requirements. One social impact associated with renewable generation is a reduction of emissions such as CO_2. The societal costs related to these substances can be calculated proportional to the changes in emissions, using any of the variety of cost rates that have been estimated.

Classification of these costs and benefits serves to facilitate their monetization—not as a means for a shortcut, but to enable piecemeal evaluation of a single investment. Some of these items are clearly capital expenditures (which will be converted into ownership costs), though some of them are combinations of capital and expenses. Meanwhile, some of them are intermediate impacts that affect other impacts through a causal chain.

The following discussion further elaborates upon monetization methods of the system impacts denoted in Table 9-1.

[69] Cost-of-service studies encounter joint costs at every turn. They use accepted practices for allocating costs among functional service categories such as energy, demand, and customer. A BCA involves determining whether an investment is warranted, not how to divide accepted investment cost over categories—which is what cost of service accomplishes.

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, and they have the same follow-on effects as changes in load. Fuel is burned to supply losses, so loss reductions reduce fuel use and associated emissions (other things being equal). Distribution losses may, meanwhile, take on special importance to some distribution companies. For instance, a distribution company that buys energy and delivers it to customers will buy more energy than it sells, with the difference being losses. How these losses are accounted for may be important to distribution entities, so they will be kept apart from changes in losses in transmission.
- In accordance, the distribution models used by EPRI in the Integrated Grid framework provide for the changes only in distribution losses, so these numbers are available based on how the system is analyzed. These incremental changes can be monetized using estimates of marginal energy cost and emissions, which themselves can be calculated on an hourly basis within a utility or market system. Alternatively, they can be bundled with other changes in load so that their economic impact appears as changes in total production cost. Either method may be used, depending on the models and data available.
- **Upgrade deferral.** In some cases, planned upgrades to substations or circuits can be deferred because of loading reductions brought about by DER additions to distribution feeders. When this happens, the capital expenditures for the deferred upgrade are usually estimated to be higher than originally planned. But as they occur in the future, the present value of the upgrade's revenue requirements is often lower than the upgrade costs in the original plan. At the same time, there may be additional costs during the deferral period because of some advantageous impacts that the upgrade may bring, such as lower losses. In some cases, an upgrade may be deferred indefinitely; in that case, its entire revenue requirement stream is avoided.
- **Reconductoring.** On some feeders, a penetration level of DER may be reached that requires the circuit to be reconductored (that is, a length of the wires of the circuit must be replaced by larger wires able to carry more current than the original wires). The new circuit allows the greater DER penetration but will have other impacts as well. In particular, the circuit will have lower losses. The entire reconductoring package consists of a capital expenditure plus a stream of loss changes.
- **New required feeder or substation equipment, such as voltage regulators.** Just as with reconductoring, 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. Most of the secondary impacts will be aggregated with others, but each piece of new equipment will add O&M expenditures. This is an important consideration.

- **Protection changes (relaying).** Protection system improvements generally result in only capital expenditure changes, but they reduce the life of the replaced assets—thus impacting utility revenue requirements if written off (which is therefore disallowed).
- **Accelerated wear on load-tap changers.** LTCs and regulators routinely change settings, but each change causes wear and eventually the contacts must be replaced in a major maintenance event. Because these events occur only a few times during the life of the LTC, the expenses associated with these refurbishments are capitalized. Impacts of shortened life from increased cycling duty need to be monetized.
- **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 and making other changes. As with other upgrades, there is a large capital expenditure and smaller operating impacts such as lower losses.
- **Smart inverters.** Smart inverters may improve system stability and voltage control when DER reaches high penetration. As with other pieces of new equipment, smart inverters require capital investment, but these inverters may be owned by the DER owner or by the utility, depending on policy and regulator rules. Whether the cost of customer-owned inverters enters into the analysis depends on the economic question for the analysis. The expenditures for customer-owned inverters would not be converted into utility revenue requirements but would result in higher customer costs. (Notably, lower kWh output would also decrease customer benefits if uncompensated.)
- **Energy storage.** Energy storage is a possible solution to some problems on the distribution system. When it is considered as an alternative, a capital expenditure and a stream of operating changes are available if the storage can be operated for other purposes in addition to serving its primary aim (that is, providing the support or service that solves the original problem).

Bulk System Impacts

- **Generation mix changes.** As previously described, changes in generation mix impact 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 present in model results that compare the operation of the system with and without the changes. These system operations changes are manifested in 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. It is treated as a separate item here to emphasize its occurrence in an entity that may be separate from the distributor. In addition, the transmission models are separate from the distribution models.

- **Operations and maintenance.** O&M is an expense item by definition. 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 can be 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 the optimal least-cost dispatch of generation resources is not possible because of transmission constraints. The constrained, sub-optimal dispatch is more costly in terms of fuel. 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 constrained area, for example, would place great importance on the congestion that raises prices in that area. In this way, the analytical perspective matters.

  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, where the economic effects of locational differences are canceled out across the system—leaving only the change in fuel cost as an effect of congestion within the system.
- **Emissions.** Emissions of various gases and particulates can be estimated with production dispatch models. Monetizing changes in emissions is a simple matter of applying volumetric cost rates where regulation and associated pricing exists. For some pollutants, utilities or generators must buy allowances corresponding to their emissions, and the cost of these allowances is included in revenue requirements along with fuel cost.

Externally Monetized Impacts

Not every impact can be directly monetized as part of the framework. For instance, the impact of reliability lies outside of the utility cost function. Instead, when the addition of DER or other distribution-system changes result in changes in the frequency and duration of customer interruptions, its delivery customers receive value in the form of reduced interruption costs. These are not costs that are paid to anyone in cash; rather, they are economic costs of lost time, lost production, lost business, perhaps lost profits, and spoilage. These costs may or may not be tallied or known by most customers, although some industrial customers know well the cost of an inopportune interruption in the middle of a production run—and the presence of backup generation at many places of business is indicative of the value of continuous service. Reliability has value, but it is not simple to put a dollar figure on it in every case.

Recognizing the need for evaluation of interruption cost (and the value of interruption reduction) for the distribution level, DOE commissioned a study to quantify the cost of interruptions characterized over a variety of conditions so as to be appropriate for evaluation of distribution interruptions distributed at random across the year. The end result of this study is a publicly available calculator known as the *Interruption Cost Estimator*, or *ICE*. The ICE model (available for running 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 28 surveys taken by utilities over several decades. The process of converting these survey results into a consistent set of "damage functions" involved many compromises and estimates, but the results are documented and freely available on the calculator website.

Societal costs are generally externalities that do not accrue to the utility or its customers, either beneficially or adversely. A common example is unpriced emissions. Although there may not be direct pecuniary obligations on the utility, there are estimated social-cost rates associated with various emissions that can be applied, for example, from the Regional Greenhouse Gas Initiative (RGGI) emission markets of the northeast or from studies that seek to determine and monetize the damages associated with emissions.

Customer and Societal Perspectives

EPRI's *Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects* categorizes costs and benefits according to where they are typically recognized.[70] This approach is also espoused by the Integrated Grid's BCA methodology. Figure 9-2 illustrates impact categories to reinforce the customer and societal perspectives that are embedded in the BCA methodology.

Figure 9-2
Six areas of costs and benefits in utility benefit-cost analysis

As depicted in Figure 9-2, an electric utility's cost function (as it would be reflected in its balance sheet and income statement) comprises three distinct areas: utility operations, system operations, and utility assets.

Meantime, the customer perspective encompasses the reliability and power quality and direct customer costs and benefits associated with DER impacts. This view characterizes the electricity product as the customer perceives, controls, and uses the product.[71] The societal perspective extends the customer perspective by adding costs and benefits that are usually external to

[70] EPRI, Palo Alto, CA: 2013. 3002002266.

[71] *Power quality* can be considered a sub-area of reliability. Power quality problems may result in customer equipment damage or may cause interruptions of specific customer equipment. In either case, customers are exposed to costs and interruptions of their normal energy use. The problems, and often the solutions, are more local and specific than higher level reliability concerns, yet they are all problems in which customers' desired patterns of electric energy usage are interrupted.

customer-oriented utility benefit-cost analyses. These societal costs and benefits are usually not explicitly included in utility planning analysis because they are not economically applicable to the utility or to the customers in the present timeframe.[72]

Because societal costs and benefits do not flow through the utility cost function and are not incurred by customers, they are generally included in utility planning analysis only to the extent that the utility and stakeholders (policymakers and/or regulators) have determined that these considerations should affect the choices made by utilities on behalf of their constituents. For example, preference may be given to an energy efficiency investment over a generation investment, even if it is more costly to comply with a renewable portfolio standard (RPS) mandate. As a result, a constraint is placed on the planning process that raises the total current cost (or produces a benefit) the utility incurs.

The societal perspective provides useful information for policymakers who want to understand the wider economic implications of the policy alternatives they confront in regulating utility activities. It may influence some utility decisions, especially within government utilities in which there is close nexus to policymakers. It is not generally used in cost allocation or rate design, however, where the objective is the recovery of incurred accounting/financial cost.

Collection and Interpretation of Results

The output of the BCA yields several measures of the financial implications of accommodating DER. A DER study will include several years of data. EPRI proposes to produce vectors of costs and benefits in nominal or real dollar terms for each year of a study and to apply net present value (NPV) mechanisms to produce summary metrics. This requires specifying a discount or interest rate as well as an inflation rate. A database of values is available through EPRI for each of these as proxies; alternatively, a study sponsor can use its own values.

BCA outputs may include the following:

- DER scenario net present value, which is the difference between the NPV of benefits and costs
- Net present cost and benefit streams for an individual study's time period
- An overall benefit-cost ratio

[72] Societal costs may be present-value economic costs of forecasted future events, as in the case of carbon emissions and climate change.

- Individual categorical cost and benefit NPVs and streams
- Customer NPV, internal rate of return, or payback

In addition, the detailed cost and benefit streams developed in the study comport with those that utilities use for conducting financial analyses of investments. This facilitates the utility and its stakeholders undertaking a financial analysis that incorporates pertinent assumptions, such as the cost of capital and asset depreciation rates; proxy values in preparing the BCA are, again, available through EPRI.

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 metric to inform decision makers of the relative merits of alternative DER integration approaches. EPRI anticipates that as applications of the DER accommodation framework are undertaken, many aspects will be refined. However, the basic structure is robust and ready for immediate use.

10 INDUSTRY COORDINATION AND NEXT STEPS

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 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 those impacts produces a measure of value—the net benefits.

At its core, the overriding methodological approach is founded on power system engineering and economic principles that can be applied in a consistent, repeatable, and transparent manner. The proposed EPRI approach first provides a rationale for recognizing the physical effects (impacts) that rising levels of DER and associated new grid management schemes can potentially have on the distribution and bulk systems. It subsequently offers guidelines for determining the associated benefits and costs of contextual, scenario-based futures from multiple perspectives. In this way, the proposed method can be applied to various regions, systems, utility service areas, and research questions to, in turn, promote greater industry coordination.

It is ultimately hoped that the uniform application of EPRI's holistic Integrated Grid framework can bring a degree of coherence, consistency, and accuracy to future analysis activities. Empowered by a best practice methodology conferred with industry consensus, utilities and other stakeholders can be better positioned to compare and contrast methods and results in a way that is not possible through today's hodgepodge of largely proprietary, assumption-laden benefit-cost studies.

That being said, EPRI's benefit-cost framework is a work in progress. It is expected to be continually refined, particularly as issues become known with greater utility application of the methodology. Moreover, the approach contains inherent limitations and prerequisites that must be duly recognized before it is put to use. For one, the benefit-cost assessment does not provide an absolute measurement of net benefits; all results are relative. For another, it requires that an extensive amount of data be collected (for example, inputs surrounding power system architecture, renewable resource and system planning, and operational policies) and that simulations be performed to produce general results. Finally, it does not capture the impact of arbitrary stakeholder behaviors (for example, of end-use customers, utilities, and policymakers) that are subject to change over assumed power system planning time horizons.

EPRI welcomes ongoing collaboration with industry stakeholders to improve upon this benefit-cost methodology so that it can be made more relevant and accessible to the industry at large.

Summary Reflections and Perspectives

EPRI's holistic benefit-cost framework underscores several of the major opportunities and challenges facing the electricity industry today. Small distributed, interconnected generators that transmit power in two directions will affect all elements of the industry. The extent of this impact is an empirical issue that the EPRI benefit-cost framework is intended to answer for any utility, in any market, and for any change in the use of the distribution system. Foundational assumptions—many of which shape the essence of the power system and its management—will require adaptation and re-imagining in order to accommodate change. However, with this notable undertaking come manifold possibilities:

- New planning and operational questions being raised in the public space—many of them triggered by growing grid penetration of DER—offer an opportunity to bring the fundamentals of power system engineering and economics to a new audience and operating model.

- Moreover, these questions appear to indicate that a reliable electric grid remains critical; a well-functioning system network offers the best way to harness the unique advantages of every interconnected resource—whether generation supply, demand-side management, or process oriented.
- New analytical objectives offer the prospect to extend evaluation tools, such as hosting capacity and flexibility assessment, to increase their relevance and value. As the nature of the power system continues to change, these types of tools and their associated outputs can help inform equitable pathways forward.
- Technology development remains at the forefront, for both utilities and DER owners alike. There are tremendous opportunities for RD&D of new technologies if a net benefit can be demonstrated.

Of course, responses to several integral challenges facing the industry will significantly influence its future:

- Planning and operations still remain in individual silos, though it will be increasingly difficult for them to remain separate in the future. The holistic approach engendered by the Integrated Grid will require closer coordination than ever before.
- Many unknowns still remain for system planning. For example, considerable uncertainty surrounds the arbitrary nature of customer behavior and a largely unpredictable policy landscape, injecting a degree of difficulty into accurately arriving at long-term planning conclusions.
- The development of new tools is likely to make the process for arriving at an Integrated Grid more seamless. However, tight coordination with industry vendors and their commercially available products will be required in order to avoid unnecessary divisions and process steps.

Next Steps: Industry Coordination and Collaboration

With the initial release of the Integrated Grid benefit-cost framework, focus now shifts to demonstration and documentation—both of the methodology and of new technologies and their associated performance characteristics, application issues, 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. As such, Phase III of the Integrated Grid project will involve the following:

1. **Methodology application.** This involves developing a particular set of research questions for a single utility or region along with a corresponding analysis strategy based on the EPRI benefit-cost framework.

2. **Technology demonstration.** For the purposes of the Integrated Grid framework, many emerging technologies will be subject to field trials employing scientific methods, and collected experimental data will be used to inform benefit-cost discussions. As part of this type of demonstration, EPRI will support test design, fielding of new equipment, data collection and analysis, and the feedback of information to relevant modeling and benefit-cost efforts.

Technology Assessment and System Demonstration

The transition to the Integrated Grid is beyond the scope of any one organization, and it will require 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 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 will work with member utilities from around the globe to mutually facilitate multiple system demonstrations, deployments, and modeling efforts to provide a common data collection and repository for technology information that can be plugged into the assessment framework for ongoing system evaluations. 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

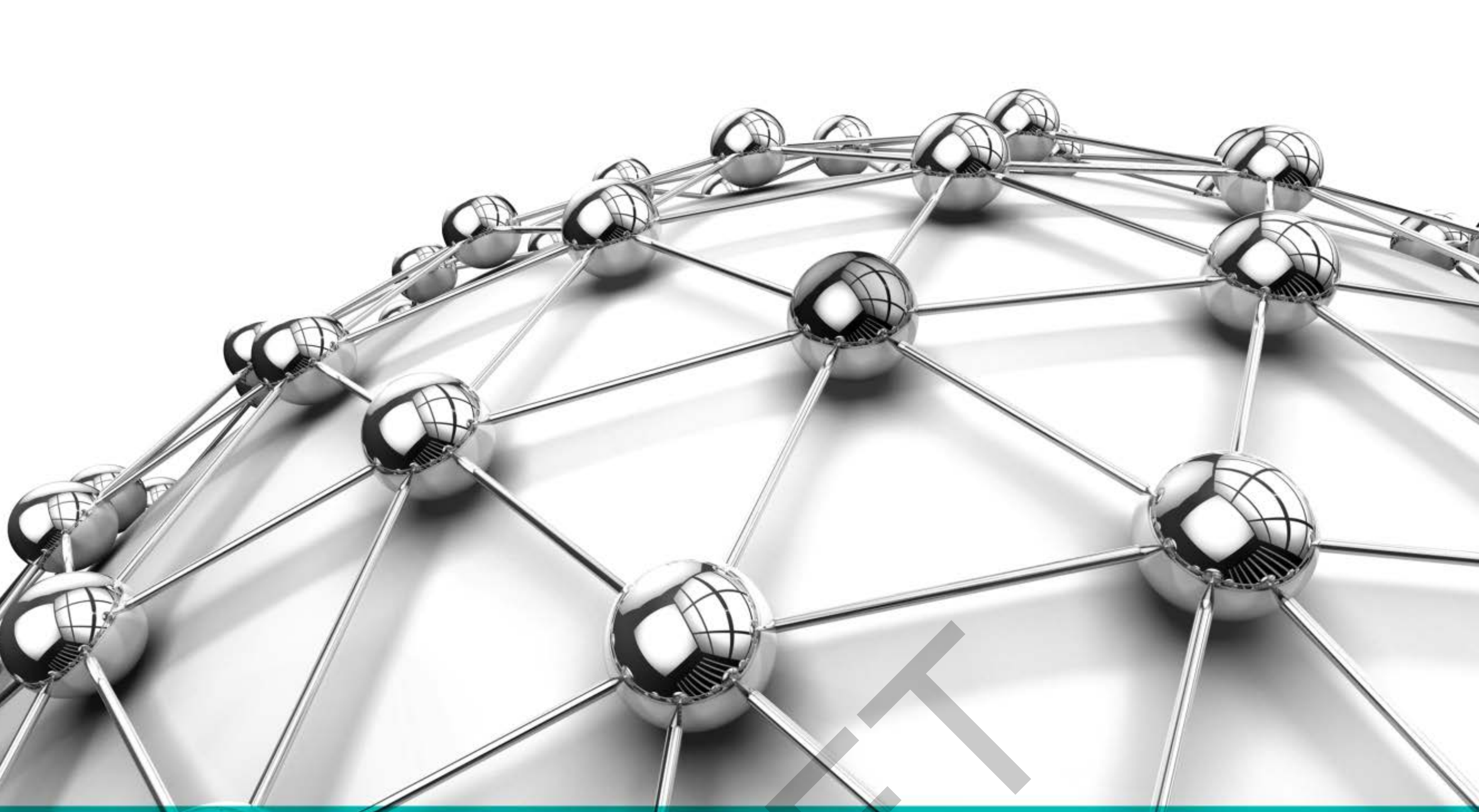
As part of the Integrated Grid initiative, EPRI has created a moderated online community that endeavors to provide a common ground for those who share an interest in all facets of the effort. A blog features informal insights from community experts on current and upcoming events, commentary on recent developments, and other industry observations. Each month, community experts initiate discussions designed to spark dialogue and foster ideas that can help shape the future of the electric power grid. Recurring topics include power system modeling, bulk system operation, distribution planning, benefit-cost analysis, policy/regulatory frameworks for DER, and devices, standards, and testing. From time to time, EPRI also leverages the community to elicit feedback on current and planned activities.

Furthermore, the community serves as a repository for papers, research and demonstration findings, presentations, webcasts, and other supporting materials.

EPRI invites you 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 Final Word

EPRI looks forward to further progressing the Integrated Grid initiative to align power system stakeholders around the key requirements for effective assimilation and coordination of centralized and distributed power sources onto the distribution and bulk systems. Through global collaboration—broadly around interconnection rules and standards, grid modernization, strategies and tools for grid planning and operations, and enabling policy regulation—EPRI is confident that the shift to an Integrated Grid can be cost-effectively achieved.



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 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 those impacts produces a measure of value—the net benefits.

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.[73]

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.[74]

[73] "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.[75]

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 their location when wholesale prices are high or 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/shutting off lights—basically any explicit action taken to reduce load in response to short-term high prices.[76]

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 that are 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.[77]

---

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

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

[76] 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.

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

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.

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. Also responsible for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity.[78]

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.[79]

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.[80] 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.[81]

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

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

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

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

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

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.[82]

Looped Circuit (Feeder) – A type of distribution circuit with two or more sources, usually separated by an open switch.[85]

Networked Feeder – A primary feeder that supplies energy to a secondary network.[83]

Network Protector – An assembly comprising a circuit breaker and its complete control equipment for automatically disconnecting a transformer from a secondary network in response to predetermined electric conditions on the primary feeder or transformer, and 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.[82]

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.[84]

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*).

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

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

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

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.[85]

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), it 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.

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.[86]

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.[87]

Synchronous Condenser – A synchronous machine running without mechanical load and supplying or absorbing reactive power.[88]

---

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

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

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

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.[89]

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.[90]

X/R ratio – See *Reactance to Resistance Ratio*.

[88] IEC 60050 International Electrotechnical Vocabulary – Section 411-34-03 (see "synchronous compensator").

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

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

B BIBLIOGRAPHY

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

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

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.

Minnesota Value of Solar: Methodology. Minnesota Department of Commerce, St. Paul, MN. April 2014.

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

“Prioritisation of Technical Solutions Available for the Integration of PV into the Distribution Grid,” PV Grid. 2013.

Decision Adopting Energy Storage Procurement Framework and Design Program. Public Utilities Commission of the State of California, Sacramento, CA, October 2013.

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

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

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

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.

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.

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

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.

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

Planning Methodology to Determine Practical Circuit Limits for Distributed Generation: Emphasis on Solar PV and Other Renewable Generation. EPRI, Palo Alto, CA: 2010. 1020157.

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

Smith, J., Rylander, M., Dugan, R., and Key, T., "Advanced Distribution Planning Tools for High Penetration PV Deployment," presented at the IEEE PES General Meeting, San Diego, CA, 2012.

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

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

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.

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.

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

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

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.

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

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

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.

Lannoye, E., Flynn, D., and O'Malley, M., "Transmission, Variable Generation, and Power System Flexibility," *IEEE Trans. Power Systems* (in press).

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

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

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

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

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.

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.

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

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.

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

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.

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

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.

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

Kundur, P., Power System Stability and Control. EPRI, McGraw Hill, 1994.

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

Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects. EPRI, Palo Alto, CA: 2013. 3002002266.

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) con- ducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engi- neers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent approximately 90 percent of the electricity generated and delivered in the United States, and international participation extends to more than 30 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together . . . Shaping the Future of Electricity

300200XXXX August 2014

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com