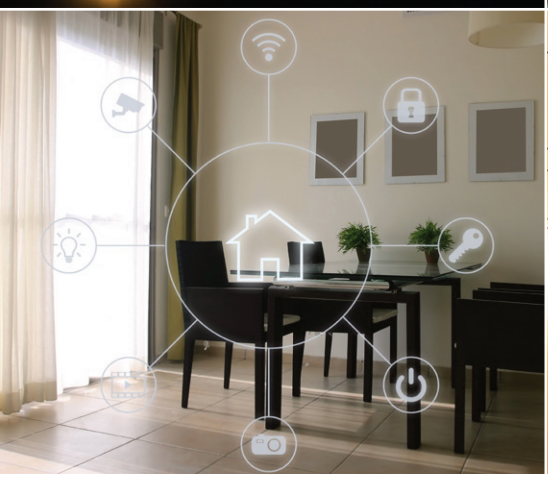
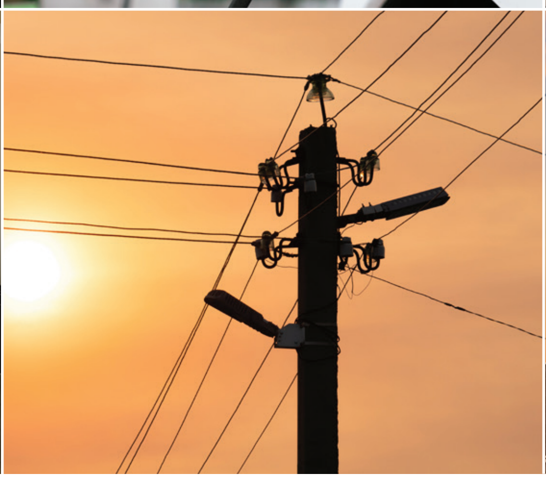
Optimization for Integrated Electricity System Planning

OPPORTUNITIES FOR INTEGRATED PLANNING IN CAPACITY EXPANSION MODELS




A Report by the
Energy Systems Integration Group's
Integrated Planning Task Force

June 2025

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Optimization for Integrated Electricity System Planning: Opportunities for Integrated Planning in Capacity Expansion Models

A Report by the Energy Systems Integration Group's Integrated Planning Task Force

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Disclaimer

This report was produced by a task force made up of diverse members with diverse viewpoints and levels of participation. Specific statements may not necessarily represent a consensus among all participants or the views of participants' employers.

Suggested Citation

Energy Systems Integration Group. 2025. *Optimization for Integrated Electricity System Planning: Opportunities for Integrated Planning in Capacity Expansion Models*. A report by the Integrated Planning Task Force. https://www.esig.energy/integrated-planning/.

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Executive Summary

A confluence of factors is now driving electricity system planners to consider the need for deeper integration across traditionally siloed planning processes, models, and—in some jurisdictions—organizations. These factors include rapidly accelerating load growth, technological evolution, growth in inverter-based resources, and power sector decarbonization goals. Integrated planning methods hold the promise of meeting generation, transmission, distribution, and customer/distributed energy resource (DER) system needs at lower costs through a comprehensive planning approach. Historically siloed planning processes are no longer sufficient for today's power system, where investments such as energy storage and flexible loads can serve multiple functions for resource and grid needs across planning domains. Initial integrated planning efforts have broadly focused on increasing links between existing planning siloes and facilitating a two-way flow of information between models and planning domains. Additionally, some co-optimization of generation, transmission, storage, and/or DERs has been performed. This report focuses on the technical opportunities and challenges for a theoretical expanded full-system capacity expansion optimization, as well as practical recommendations for moving planning processes toward more optimal solutions.

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Initial efforts at integrated planning may start by assessing process gaps and aligning key inputs and scenarios into siloed processes, progressing toward more advanced approaches to integrated analytical methods. At a minimum, comprehensive planning involves iterative feedback loops between existing siloed processes, where even adding a single iterative loop can improve results. Taken further, co-optimization methods hold the promise of applying a least-cost optimization framework across a broader set of planning needs and potential solutions. Increasing the scope of the widely used generation (G) capacity expansion optimization provides a potential starting point for co-optimization of transmission (T), distribution (D), and customer/DER (C) investments alongside the optimal generation plan. Such an approach could support the identification of capacity investments in each planning domain, though additional models would still likely be needed to fully co-optimize the system due

At a minimum, comprehensive planning involves iterative feedback loops between existing siloed processes, where even adding a single iterative loop can improve results. Taken further, co-optimization methods hold the promise of applying a least-cost optimization framework across a broader set of planning needs and potential solutions.

to limits in computation and mathematical formulations. These include the need for deeper modeling of resource adequacy, operational flexibility, power flow, system stability, protection schemes, and other detailed complementary analyses, which may require additional process iterations.

To explore the key steps and options involved in moving toward a more integrated, comprehensive planning paradigm, the Energy Systems Integration Group convened a task force of experts from utilities, system operators, research organizations, national laboratories, consultants, and other planning practitioners. Three reports were produced which contribute to the nascent knowledge base of integrated planning practices.[1] The first report, *Foundations of Integrated Planning,* defines integrated planning and why it is needed, followed by a broadly applicable framework for comprehensive planning. The second report, the *Integrated Planning Guidebook*, provides practical recommendations for today's electricity system planners to advance toward increasing levels of integration through a walk/jog/run approach. This is the third report, *Optimization for Integrated Electricity Planning*, focusing on the opportunities and current challenges in using economic optimization–based capacity expansion modeling to consider a broader set of integrated planning constraints and investment opportunities. Key points made in this report are the following.

The benefits of a full-system capacity expansion optimization include the potential for endogenous identification of integrated planning solutions, lower-cost integrated system plans, and fewer iterations between planning models.

For example, co-optimization can support the identification of where to build out the transmission grid for new bulk-grid investments, where to optimally site energy storage resources, and the value of DER versus bulk-grid resource investments. However, there are also major challenges to a full-system capacity expansion optimization. It requires significantly more granular resource, load, and grid constraint data, which leads to computational tractability challenges at scale. It also may lead to unrealistic outcomes or false precision, where value-stacked integrated solutions are maximized further than their real-world feasibility. Current decision-making venues and processes may not be ready to implement a fully optimized plan across multiple planning domains.

Bulk-grid generation and transmission co-optimization methods are rapidly evolving, with multiple tractable methods for co-optimization.

These broadly include using either (a) aggregated zonal topology for dispatch with detailed transmission deliverability limits and upgrade costs for new resources, or (b) various levels of more detailed dispatch topology—such as multiple sub-zones or a full nodal representation—with transmission upgrades represented as flow constraints between zones or nodes. The former is adept

1 All three reports can be found at https://www.esig.energy/integrated-planning/.

at capturing deliverability upgrade requirements and the latter at capturing the impacts of congestion. They may be used individually or in tandem to co-optimize G and T investments.

Optimizing local grid investments faces higher hurdles, as it is not tractable to model load and resource balance down to the distribution system level, let alone down to the customer.

Recognizing the limits of capturing granular distribution system values, DERs and flexible loads can be directly optimized against G+T investments or indirectly optimized through process iterations, subject to a few key considerations. Methods that can align the valuation for supply-side and demand-side resources can enable the identification of the least-cost resource mix needed to meet generation and grid needs. Optimizing DERs necessitates significant data development and bundling to create tractable DER supply curves. DER and flexible load performance must be measured relative to a clear baseline so that their incremental value to the system can be properly assessed. Planners need to consider whether existing DER sourcing mechanisms—such as utility programs, tariffs, or solicitations—are sufficient for sourcing the optimized system and/or local needs modeled, or whether additional real-world validation is needed. Additionally, least-cost optimization has important limitations when compared to the broader cost-effectiveness frameworks often used in customer DER planning and rate design, which consider multiple stakeholder perspectives. In general, planning frameworks for DERs will need to match the decision frameworks used by utilities and regulators to determine DER investments and incentives.

Alternative approaches exist to a single full-system optimization that can tractably capture key interactions across planning domains.

Three alternative approaches to a single full-system optimization are presented in this report (Table ES-1). First, hourly avoided costs from bulk-grid G+T planning and distribution system planning can be used to align DER valuation with system and local displaceable investments. Second, distribution system planning optimization models can be used to assess grid versus DER investments, incorporating bulk avoided costs from a G+T co-optimization to evaluate the net value of new DERs in local grids. Third, marginal distribution system costs can be created and parameterized in reduced form as inputs into a G+T+C capacity expansion model, and this process can be iterated to converge on the appropriate mix of resource versus wires investments.

A walk/jog/run framework supports a phased approach for continual improvement that provides a tractable pace of change management.

Recognizing both technical and practical challenges for being able to model and implement a "theoretically optimal" planning solution, this report shares specific recommendations for planners to make incremental progress toward the fully integrated analytical models presented. The format for the suggested steps in the conclusion is a walk/jog/run framework, which supports a phased approach for continual improvement that provides a tractable pace of change management (Table ES-2, p. x).

TABLE ES-1
Three Alternative Approaches to a Single Full-System Optimization

Option 1: Hourly avoided costs	Option 2: Many local system optimizations	Option 3: Bulk grid and DER optimization
Develop hourly avoided costs for all distributed energy resource value streams based on an optimized bulk-grid generation and transmission solution, supplemented by additional detailed transmission and distribution studies to inform locational values	Optimize a single bulk-grid generation and transmission solution that informs the bulk-grid value for distributed energy resources studied in many local integrated distribution system optimizations against distribution upgrade needs	Use a parameterization of marginal distribution system costs to inform a generation, transmission, and distributed energy resource co-optimization

Source: Energy Systems Integration Group.

TABLE ES-2

Incremental Stages of Progress Toward Fully Integrated Analytical Models

Incremental Stage of Progress Toward Fully Integrated Analytical Models	Planners' Tasks
Walk	Planners align objectives, assess key gaps, and harmonize inputs and scenarios. These low-hanging fruit can enable initial integration stages with minimal new data or model development and set the stage for later phases.
Jog	Planners address the gaps assessed in the *walk* phase. This involves creating new data needed for integrated planning, building new modeling capabilities, and creating an integrated planning process through which these new data can be incorporated into expanded modeling and decision-making processes.
Run	Planners use expanded capacity expansion optimization models and/or tightly coupled iterative processes to coordinate investments across generation, transmission, distribution, and customer programs and DERs.

Source: Energy Systems Integration Group.

In the *walk* stage, planners focus on aligning objectives, assessing key gaps, and harmonizing inputs and scenarios. These are key low-hanging fruit that can enable initial integration stages with minimal new data or model development and set the stage for later phases. In the *jog* phase, the gaps assessed in the prior phase are addressed. This involves creating new data needed for integrated planning, building new modeling capabilities, and creating an integrated planning process through which these new data can be incorporated into expanded models and decision-making processes. In this phase, spatially and temporally granular data are generated for loads, grid constraints, grid upgrades, and supply- and demand-side resource options, and combined generation, transmission, and energy storage capacity expansion is possible.

In the *run* stage, planners will use expanded capacity expansion optimization models and/or tightly coupled iterative processes to coordinate investments across generation, transmission, distribution, and customer loads and DERs. This may include either varying degrees of fully combined optimization using appropriately parameterized datasets or carefully designed iterative loops between planning processes.

As planners approach the final phase of integrated planning, they will have new data available and new modeling capabilities to support advanced and/or novel analyses. In the *run* stage, planners will use expanded capacity expansion optimization models and/or tightly coupled iterative processes to coordinate investments across generation, transmission, distribution, and customer loads and DERs. As outlined in this report, this may include either varying degrees of fully combined optimization using appropriately parameterized datasets or carefully designed iterative loops between planning processes such as the use of marginal avoided costs; either approach can be sufficient.

The practical methods outlined in this report provide a framework for planners to increase integration of their analytical processes. The methods support efficiently identifying comprehensive planning solutions that facilitate informed decision-making, lower-cost outcomes, and continuous improvement. These methods are broadly accessible today through careful coordination and data exchange between modeling tools. As computational capabilities and new methods evolve, tighter integration, more seamless data interaction, and increased automation may become feasible.

By taking the steps outlined here, energy system planners can advance the integration of generation, transmission, distribution, and customer DER planning, paving the way for a more integrated electricity system that supports the development of a reliable and affordable 21st century power system.

Introduction

A confluence of factors is now driving electricity system planners to consider the need for deeper integration across traditionally siloed planning processes, models, and—in some jurisdictions—organizations. These factors include rapidly accelerating load growth, technological evolution, growth in inverter-based resources, and power sector decarbonization goals. Within power system planning, the traditionally siloed planning processes include the following domains, which interact with related functions such as strategy, finance and capital planning, and other related organizations (Table 1).

TABLE 1

The Four Main Power System Planning Domains

Planning Domain	Description
Generation planning (G)	Economics-focused near- and long-term optimized capacity expansion, production cost, and resource adequacy studies to meet reliability and policy goals
Transmission planning (T)	Economic and physics-based studies to identify near- and long-term* transmission investment needs for capacity, reliability, stability, congestion relief, and other factors
Distribution planning (D)	Physics-based studies to identify typically near-term distribution system investment needs relative to planning criteria
Customer program and DER planning (C)	Economics-informed studies or fixed incentive budgets to support distributed energy resource solicitations, customer programs, and rate/tariff design

* "Long-term" has historically meant different things to different planners. For example, long-term generation planning in integrated resource plans may consider up to 20 (or more) years into the future, whereas long-term transmission planning has historically looked out 10 years into the future.

Source: Energy Systems Integration Group.

An integrated approach to planning is now necessary as the scale of new investment in the electric power system continues to increase and new investments have key interactions across the traditionally siloed planning domains. For instance, investment in remote generators must be paired with necessary transmission infrastructure, battery storage can serve both generation and grid needs, and distributed energy resource (DER) values are increasingly driven by the generation and transmission investments they can avoid. The cost of continued siloed planning would be a higher-cost power system with many missed opportunities.

To explore the key steps and options involved in moving toward a more integrated, comprehensive planning paradigm, the Energy Systems Integration Group convened a task force of experts from utilities, system operators, research organizations, national laboratories, consultants, and other planning practitioners. A series of task force meetings were held, culminating in three reports to contribute to the nascent knowledge base of integrated planning practices.[2] The first report, *Foundations of*

2 *Foundations of Integrated Planning*, the *Integrated Planning Guidebook*, and this report can be found at https://www.esig.energy/integrated-planning/.

Integrated Planning, defines integrated planning and why it is needed, followed by a broadly applicable framework for comprehensive planning. The second and third reports focus on the practical elements of carrying out integrated electricity system planning. The second report, the *Integrated Planning Guidebook*, provides practical recommendations for today's electricity system planners to advance toward increasing levels of integration through a walk/jog/run approach. This is the third report, *Optimization for Integrated Electricity Planning*, focusing on the opportunities and current challenges in using economic optimization–based capacity expansion modeling to consider a broader set of integrated planning constraints and investment opportunities.

Traditional Capacity Expansion Optimization

Capacity expansion optimization is a fundamental tool for generation planning, providing a structured approach to determining the least-cost mix of generation resources needed to reliably meet projected electricity demand over a long horizon. These models typically solve for investment decisions in new generation assets and retirement decisions for existing assets by minimizing system-wide costs while ensuring compliance with resource adequacy standards, policy targets, and operational constraints. Capacity expansion models rely on assumptions about load patterns and growth, public policy goals, resource adequacy needs and resource contributions, fuel prices, technology availability, and technology costs to determine the optimal mix of resources. Figure 1 provides an overview of the typical generation capacity expansion optimization problem: key inputs that define system needs and resource options, a net present value (NPV) cost-minimizing objective function considering fixed and variable system costs, constraints that ensure that all portfolios produced meet reliability and policy goals, and key outputs provided from the optimization including resource portfolio changes, dispatch results, system costs, and carbon emissions.

FIGURE 1
Traditional Economic Optimization Practices

Key Inputs

- Load/distributed energy resource forecasts
- Load/distributed energy resource shapes
- Baseline resources
- Planned additions and retirements
- Capital, operations and maintenance, and fuel costs
- Resource potential
- Resource operating characteristics
- Reliability need and resource contributions

Objective Function: Minimize Costs

Fixed resource costs

- Generation capacity (thermal, hydro, renewables, etc.)
- Energy storage
- Demand response, energy efficiency, etc.
- Transmission (if modeled)

\+

Variable operating costs

- Fuel and variable operations and maintenance costs
- Start-up costs
- Carbon costs
- Etc.

Constraints

Reliability/operations

- Hourly load/resource balance
- Operating reserves/flexibility
- Resource adequacy
- Resource build limits
- Resource operating limits
- Transmission flow limits

Policy

- Renewable portfolio standard targets
- Greenhouse gas limit and/or carbon price

Key Outputs

- Generation capacity additions and retirements
- Generation by resource
- Achieved renewable portfolio standard
- Achieved greenhouse gas emissions targets
- Costs
  - Modeled costs (annual and net present value)
  - Shadow prices (energy, reserves, capacity, renewable portfolio standard or greenhouse gas emissions targets, etc.)

Within traditional economic optimization frameworks for capacity expansion, key inputs include load forecasts and costs, the objective function seeks to minimize fixed and variable costs, and the model is subject to a variety of constraints such as renewable portfolio standard goals and resource build limits. Once the model solves, key outputs of interest include capacity adjustment decisions (i.e., builds and retirements) as well as the overall cost of the system.

Source: Energy Systems Integration Group.

A wide variety of capacity expansion models are used today, each with unique attributes and capabilities. Additionally, each generation planning process is generally set up in a customized manner based on the needs of the planners, the input received from stakeholders, and the constraints of related regulatory processes. All capacity expansion modeling processes solve for bulk-grid generation needs, and some may also consider additional system needs.

Historically, this process has been focused nearly exclusively on *generation* planning. Transmission constraints have been considered in a simplified or exogenous manner, limiting the ability to fully capture system-wide interactions. Local transmission interconnection costs are often considered, but broader grid constraints to reliably deliver power across peak and off-peak conditions have often been excluded or simplified in capability expansion modeling. This is due to either (1) new resources requiring minimal transmission expansion, (2) the difficulty of developing those constraints and their solutions, (3) the reliance on a one-way flow of information from generation studies to downstream transmission studies, or (4) computational constraints. Not accounting for transmission grid needs can potentially lead to sub-optimal generation and energy storage selection and siting.

Despite the impetus for early "integrated resource planning" efforts to better optimize demand-side resources directly against bulk-grid investments, there has been limited success across the industry in incorporating customer programs and DERs into capacity expansion models. Technical capabilities exist to do so. Some planners have performed the extra input development work to create DER supply curves and have used these to optimize DERs—including energy efficiency, demand response, distributed solar, and others—against supply-side resources. However, there are institutional barriers in some cases to using least-cost optimization models for DER program design. There can also be technical barriers to capturing the full level of detail required to consider the local grid costs and benefits that may tip the scales in favor of local versus bulk-grid additions. One key technical barrier—addressed in detail in this report—is the challenge of capturing the needs of the distribution grid and the ability for new DER investments to avoid future distribution system investments.

This historically siloed approach to generation capacity expansion can result in inefficiencies, where expansion decisions are made without fully considering bulk-grid transmission impacts or local-grid needs and resource investment opportunities. These inefficiencies could ultimately lead to a higher-cost electric grid. As electric grids evolve with growing loads and increasing levels of renewable energy, energy storage, demand-side resource options, and emerging technologies, there is a growing need for capacity expansion models to broaden their scope beyond generation planning alone in support of integrated planning that ensures the right investments, at the right times, in the right places.

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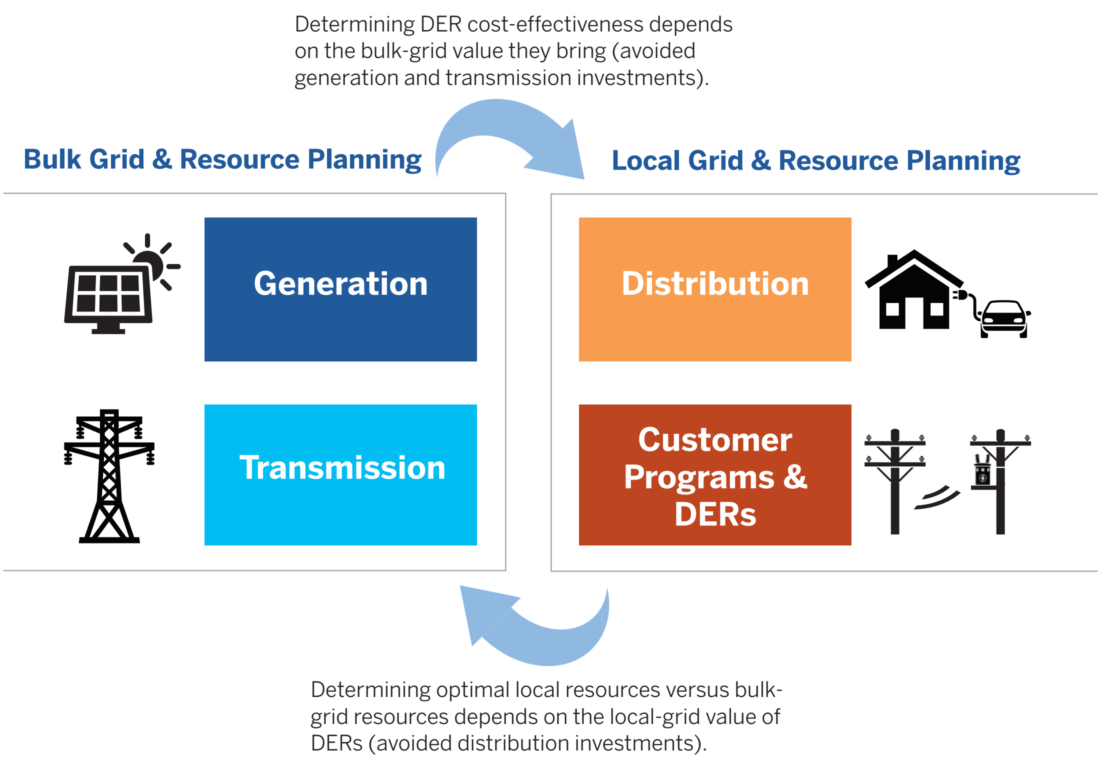
Opportunities for Full-System Capacity Expansion Optimization

This report explores the concept of a full-system capacity expansion optimization, together with viable/promising incremental steps to move planning processes *closer* toward the theoretically optimal solutions a full-system optimization would allow. In theory, a full-system optimization approach has significant advantages by allowing for the endogenous identification of capacity investments across generation, transmission, distribution, and DERs and taking into account the interactions between those four planning domains. By jointly optimizing these components, planners can better capture meaningful interactions across planning domains including the impact of transmission constraints on bulk-grid generation costs, the strategic siting of energy storage, and the trade-offs between DER deployment and bulk-grid investments. As illustrated in Figure 2, the decision to invest in bulk-grid versus locally sited resources depends both on the value of avoided bulk-grid generation and transmission as well as the costs and benefits to local distribution grids. Since capacity expansion models represent the most fully formed tractable capacity optimization models used in power system planning, they form a natural starting point for the consideration of how enhanced representation of generation, distribution, and customer DERs could enable a more integrated approach.

By jointly optimizing generation, transmission, distribution, and DERs, planners can better capture meaningful interactions across planning domains including the impact of transmission constraints on bulk-grid generation costs, the strategic siting of energy storage, and the trade-offs between DER deployment and bulk-grid investments.

FIGURE 2

Theoretical Bulk and Local System Capacity Expansion Optimization



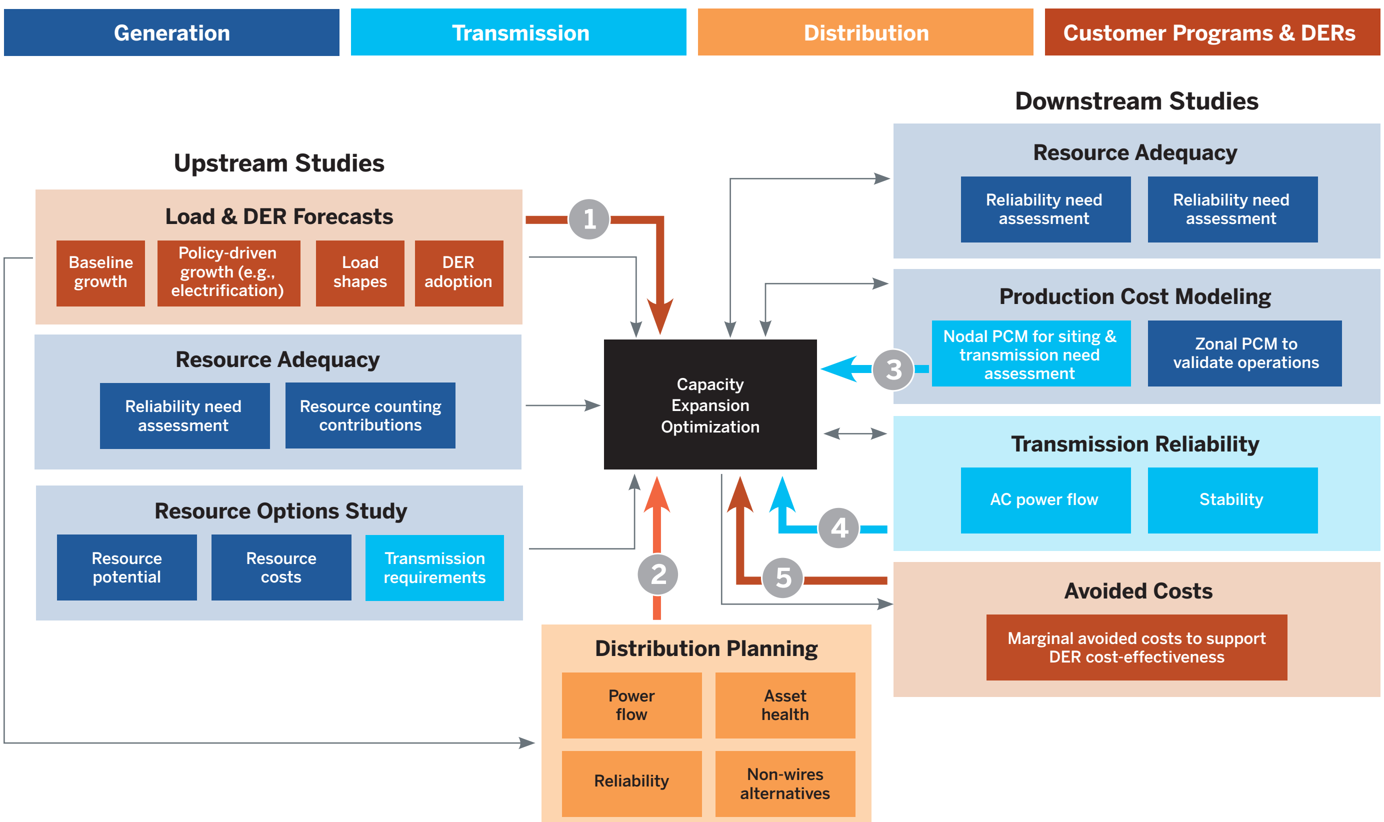
Flow diagram of information to visualize theoretical full-system capacity expansion optimization of bulk and local systems.

Source: Energy Systems Integration Group.

Within a power system planning process, there are upstream and downstream analyses that could be incorporated into a full-system capacity expansion optimization process. Upstream processes that inform capacity expansion include load and DER forecasts, resource adequacy modeling, and a resource options study. Downstream models use outputs from a capacity expansion analysis, including resource adequacy validations, production cost modeling for operability and congestion analysis, transmission reliability studies, power flow studies, and the estimation of avoided costs for DER cost-effectiveness analysis. The large light orange, dark orange, and blue arrows in Figure 3 indicate the upstream and downstream analyses that could theoretically be incorporated into a full-system optimization process. A comprehensive optimization approach has the potential to lower total system costs by avoiding suboptimal, siloed decision-making and reduce the need for iterative adjustments between separate planning models.

FIGURE 3

Upstream and Downstream Processes That Inform a Full-System Capacity Expansion Optimization



1. Make DER forecasts endogenous to the capacity expansion optimization by modeling them as candidate resources
2. Reflect distribution constraints, upgrade needs, and non-wires alternatives within a valuation of local grid resources (DERs) as candidate expansion options
3. Endogenously capture transmission congestion that may impact optimal generator and storage siting, renewable curtailment, and optimal dispatch
4. Inform transmission investment needs or dispatch constraints for resource deliverability and/or system stability
5. Ensure consistent valuation between supply- and demand-side resources by allowing that valuation directly within the expansion optimization

The larger dark orange, light orange, and light blue arrows represent additional information that would be used in the capacity expansion tool as part of a full-system capacity expansion optimization. The benefits of incorporating each are detailed in the numbered list below the graphic.

Notes: LOLP = loss-of-load probability; PCM = production cost model.

Source: Energy Systems Integration Group.

Challenges of Full-System Capacity Expansion Optimization

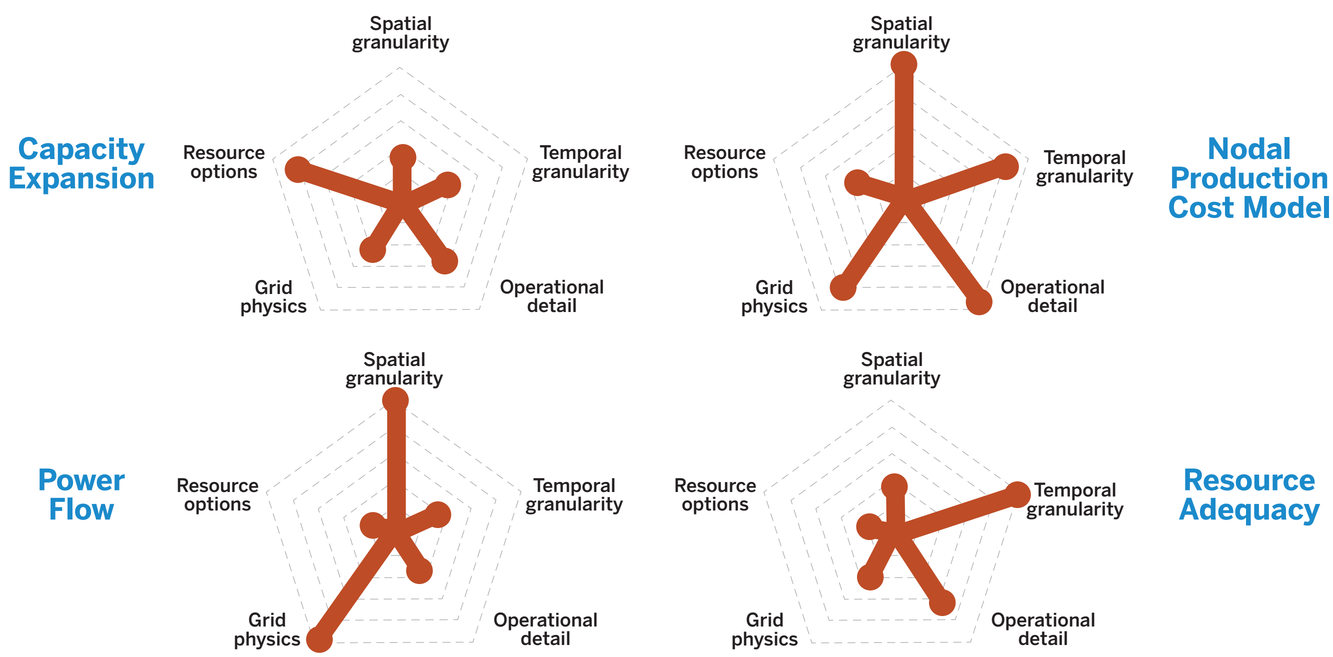
There are a number of challenges to implementing a full-system capacity expansion optimization framework. One is the need to integrate and extend more granular data, such as locational forecasts of load, resource availability, and grid upgrade costs. This level of data can be difficult to generate and may introduce false precision or over-optimization, where an intricately integrated solution may not actually be feasible to deploy. Additionally, simultaneously optimizing across multiple system layers is computationally complex. Tractability challenges emerge as optimization model runtime and computational costs increase nonlinearly with increasing numbers of decision variables and constraints.

Current capacity expansion models already make trade-offs along multiple dimensions to create tractable optimization problems, and these trade-offs are important to understand, as a full-system optimization would require increasing the level of detail captured in spatial granularity, grid physics, and resource options, to capture where to site resources and where (and how) to expand the grid. The trade-offs used in many of today's capacity expansion models include the following (see Figure 4):

- **Spatial granularity:** This is often modeled at a zonal level with nodal resource siting addressed in downstream models.
- **Temporal granularity:** Representative days or weeks for hourly dispatch are selected from broader multi-year load and weather datasets.
- **Operational detail:** Approximations of unit commitment and economic dispatch are used.
- **Grid physics:** Limited detail is considered, with simple zone-to-zone transfer limits and no power flow.
- **Resource options:** Multiple candidate resource technologies are modeled, typically with some level of aggregation and often as linear (not integer) decision variables.

FIGURE 4

Level of Detail Captured Across Five Key Dimensions in Various Power System Planning Models



Each power system planning model comes with its own trade-offs with respect to temporal and spatial granularity, operational detail, resource options, and grid physics. The length of the lines on each dimension represent the level of detail captured in each modeling process, with long lines indicating a high level of detail being captured.

Source: Energy Systems Integration Group.

Capacity expansion models also often use linear programming approaches that simplify discrete investment and dispatch decisions to enable computational feasibility.

Finally, while co-optimization enhances coordination across planning domains, it cannot fully eliminate the need for iterative processes, as economic optimization models have inherent limitations in their ability to capture factors such as grid physics, system stability, resilience, and consumer behaviors. These challenges highlight the need for careful consideration to balance the benefits of full-system co-optimization with the practical challenges of implementation.

Full-System Capacity Expansion Optimization vs. Iterative Approaches

Integrated power system planning methods come in multiple forms. In an integrated planning process, when making decisions about infrastructure in one planning domain, information is incorporated from other planning domains that may impact the overall optimal decisions to be made. One approach to integrating planning processes relies on iterative models and processes. Here, outputs from one model are used as inputs to another model, and there is a two-way flow of information to downstream models, then back upstream to consider adjustments to prior models. One example is the siting of a new generation portfolio on the transmission grid. If capacity expansion is performed zonally, downstream models including nodal production cost analysis can inform refinements to resource siting and may even change the resource portfolio itself. Another example is refinements of grid needs obtained from production cost, resource adequacy, or power flow models that flow back into generation capacity expansion operational constraints.

While this iterative approach has been used successfully in early integrated planning processes, there is increasing interest in co-optimized approaches. Co-optimized approaches require more upstream studies to populate a broader range of options for an expanded system optimization to select. These approaches allow the optimization software to make cost-effective infrastructure decisions, reduce the decisions made in downstream models, and may decrease the number of iterations required to converge on the optimal integrated planning solution. While the full-system co-optimization approach relies on co-optimization for all system needs, a spectrum exists between the two bookends described above and shown in Figure 5 (p. 8). For instance, in the middle of this spectrum, some investments can be co-optimized (e.g., generation and transmission) while other investments are addressed in downstream models that iterate with the expansion optimization as needed.

The Value of Taking Incremental Steps Toward Full-System Optimization

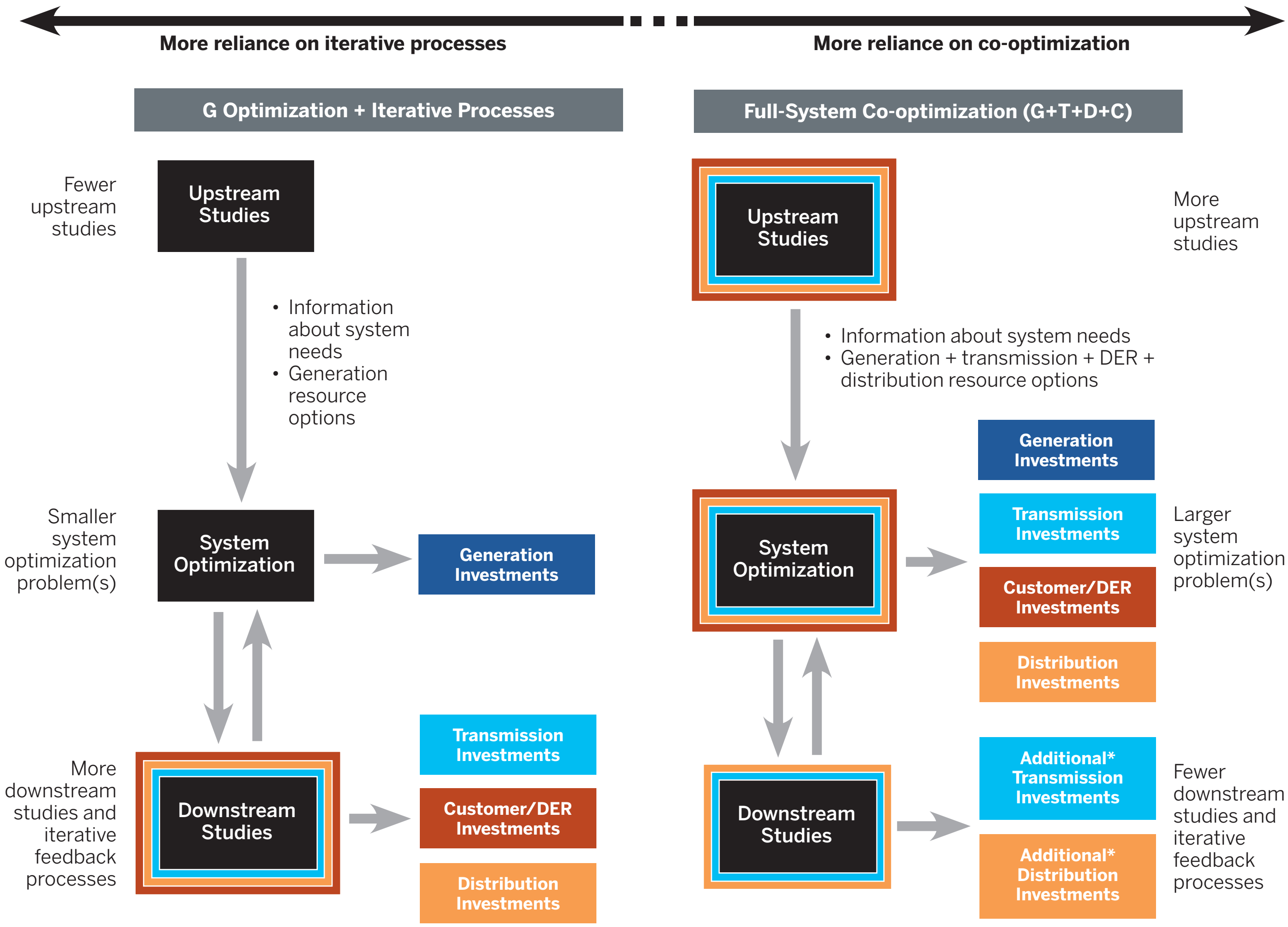
Most system planners today face substantial data development, model development, computational, and institutional challenges to a full-system optimization approach. For these reasons, an incremental approach to expanding the scope of traditional expansion optimization modeling is warranted. A walk/jog/run framework is presented in the key takeaways section of this report to support planners incrementally moving toward more optimal planning methods.

The sections that follow consider the opportunities and challenges of increasing levels of co-optimization for integrated planning:

- "**Bulk System Capacity Expansion Optimization**" discusses theoretical and practical approaches to optimizing bulk-grid generation and transmission capacity investments. Though multiple approaches exist, these methods to co-optimize bulk-grid investments are being applied today and therefore

FIGURE 5

A Spectrum from Iterative Integrated Planning to Full-System Co-optimization



As energy system planning moves toward more co-optimization, there will be a necessary increase in the upstream studies that flow into the optimization model, the size of the optimization problem itself will increase, and there may be less of a need for downstream studies and model iterations. "System optimization" may be a capacity expansion based model or a broader type of optimization model and/or set of models.

* The full set of T+D grid investments will need to be determined through more detailed and/or granular grid set of analyses (power flow, stability, protection, etc.) than can tractably fit into a system co-optimization.

Source: Energy Systems Integration Group.

represent low-hanging fruit for incremental improvements to most existing processes.

- **"Bulk + Local System Capacity Expansion Optimization"** explores theoretical and practical approaches to optimizing both bulk-grid generation and transmission capacity investments as well as DER investments and their costs and benefits for local distribution grids. These methods are less common today and therefore represent "higher-hanging fruit" with more significant data development and model development needs for most existing processes.
- **"Key Takeaways"** gives the current state of co-optimization approaches and recommendations offered for planners.

Bulk System Capacity Expansion Optimization

Before considering a full optimization across all planning domains, a combined optimization just within the bulk-grid domains (i.e., "G+T" or generation and transmission) is considered. There are multiple existing methods for co-optimizing the bulk power system considering generation resource needs, their locations, and their impacts on transmission system needs. The trend toward co-optimization of bulk-grid generation and transmission has been driven by a few factors. Regions with growing shares of renewable energy have seen new resource locations far from load centers, which require significant transmission infrastructure development. The growth of energy storage has created new opportunities for value stacking based on where storage is sited. Storage can be flexibly sited near load to minimize imports requiring transmission infrastructure or address local capacity needs in load pockets. It can also be sited near remote renewables to maximize new line utilization, thereby lowering transmission costs per delivered MWh. These types of interactions benefit from a co-optimization approach.

Theoretical Bulk System Capacity Expansion Optimization

A co-optimized approach to bulk generation and transmission planning seeks to endogenously determine the most efficient investment portfolio across both domains. Under this approach, bulk generation expansion decisions would be made in tandem with transmission infrastructure upgrades. This requires integrating detailed transmission input data into the capacity expansion optimization, including grid topology, granular load and resource location information, definitions of key transmission constraints, and candidate transmission upgrade costs. Unlike traditional planning methods, which have often treated transmission expansion as an exogenous downstream process or relied on iterative adjustments, co-optimization directly incorporates the economic and operational trade-offs between expanding generation in existing network-constrained areas versus investing in new transmission infrastructure to unlock remote resources. The optimization objective function would be updated to add transmission upgrade costs to the generation costs, and the constraints would be updated to include a characterization of physical transmission limits, with upgrades available to overcome existing network constraints. This approach has the potential to significantly enhance the efficiency of bulk system planning outcomes by optimally expanding the transmission grid in alignment with optimized generator and storage siting. The relevant changes needed to the capacity expansion optimization problem definition are shown in Figure 6 (p. 10).

FIGURE 6

Model Requirements for Adding Transmission Data to Generation Capacity Expansion Studies

Key Inputs	Objective Function: Minimize Costs	Constraints	Key Outputs
• Transmission topology • Granular load and resource location information • Transmission constraint definitions • Transmission upgrades and costs	• Transmission upgrade costs	• Transmission limits	• Resource locations • Energy storage siting locations • Selected transmission upgrades and costs

In addition to the modeling requirements of traditional economic optimization models for capacity expansion described in Figure 1 (p. 2), co-optimization of generation and transmission involves more inputs, objective function variables, constraints, and outputs.

Note: Transmission limits could be zone-to-zone or node-to-node flow limits, peak deliverability limits, or other limits depending on the types of transmission constraints being captured.

Source: Energy Systems Integration Group.

There are varying degrees of difficulty in generating and formatting the data for adding transmission optimization to a generation-focused capacity expansion model. Table 2 (p. 11) outlines the key considerations for each new data input and the level of difficulty of generating it. The difficulty of G+T co-optimization is highly system- and case-dependent. Factors impacting the level of difficulty include the level of spatial granularity used, the use of existing or novel system topology definitions, and the availability of information on candidate transmission options like new lines. The next section discusses practical approaches to balancing these factors, with multiple feasible implementation options.

Practical Approaches to Bulk System Capacity Expansion Optimization

Given computational and data limitations, practical approaches often involve balancing model complexity with computational tractability. Many bulk system planning models today employ zonal representations of the transmission system in simulating system dispatch, with varying degrees in the spatial granularity of candidate resources. The simplest approach for aligning transmission investments with zonal capacity expansion modeling is to iterate between the capacity expansion modeling, a mapping process to assign new resources to transmission busbars, and transmission analyses. Iteration, however, does not provide the same efficiencies as a co-optimization process, whereby the optimization finds the most efficient solution endogenously. The following sections therefore focus on co-optimization methods.

One co-optimization method for incorporating transmission needs into a zonal capacity expansion model is to add additional transmission constraints to candidate resources based on the ability of the existing transmission system to deliver the resources' output to load. This can be informed by deliverability studies, like

TABLE 2

Transmission Data Development Needs for Co-optimization

Data	Description	Key Considerations	Level of Difficulty
Transmission topology	How to define the zonal and/or sub-zonal transmission topology?	• Zones may be defined as balancing areas or with sub-zonal regions defined. • Resource-level or transmission zones' constraints can be defined for specific investments, separate from the broader system power flows. • Inter-zonal, intra-zonal, or nodal constraints can be defined to limit power flows.	**Low to high difficulty** Obtaining these data requires more effort if topology deviates from existing datasets or defines new zones (i.e., creation of renewable energy zones or aggregating nodes to form zonal limits).
Load and resource locations	How are system-level loads disaggregated and new resource options defined in the transmission topology modeled?	• Load forecasts are often done at the system level and typically may already be disaggregated for downstream grid modeling (nodal production cost model, power flow, distribution studies). • Detailed resource potential mapping involves technical potential, screening out environmental or societally sensitive sites, and mapping disaggregated potential to the transmission topology and upgrade options modeled.	**Medium difficulty** Methods exist, but there is significant work for detailed mapping of both load and resource datasets.
Transmission constraint definitions and limits	How to represent transmission system constraints in capacity expansion and what limits to place on them?	• Options include resource-level or transmission-level deliverability constraints, inter-zonal limits, intra-zonal limits, and nodal constraint definitions. • Planners need to weigh the trade-offs of increasing spatial granularity with computational tractability. • Each system has a unique set of transmission constraints and new resource options available, so there is no one-size-fits-all approach. • Data development may require nodal production cost or power flow modeling to determine the specific transmission system constraints (overloads, voltage, stability, etc.).	**Low to high difficulty** The degree of difficulty depends on the constraint modeled—existing path ratings are simple, new transmission zones or node aggregations are harder, and nodal constraints may require additional work vs. security-constrained limits in nodal production cost models.
Transmission upgrade options	What investment options alleviate constraints, and what do they cost?	• Solutions must be developed to constraint violations and then translated into candidate transmission upgrade options or mapped to candidate resources that drive those violations. • Feasibility screening methods may be required to ensure that upgrades are implementable (routing for new lines, siting and permitting challenges, etc.).	**Medium to high difficulty** Larger-scale upgrades like major new transmission lines require significant data development to ensure technical and practical feasibility.
How are candidate transmission options modeled?	Are upgrades modeled as linear or integer variables?	• Specific upgrade decisions are yes/no integer decisions. • Linearized ($/MW) upgrades can be useful to decrease model runtime and to allow for additional builds using generic $/MW costs (when costs are expected to scale linearly and costs can be informed by specific representative upgrades).	**Medium difficulty** Integer variables generally increase model runtime.

Significant data development is required to co-optimize generation and transmission, though the specific types of data are highly system- and use-case dependent. Factors impacting the level of difficulty of data development include the level of spatial granularity used, the use of existing or novel system topology definitions, and the availability of information on candidate transmission options like new lines.

Source: Energy Systems Integration Group.

One co-optimization method for incorporating transmission needs into a zonal capacity expansion model is to add additional transmission constraints to candidate resources based on the ability of the existing transmission system to deliver the resources' output to load.

those performed during the resource interconnection process. Deliverability limits and candidate transmission upgrades can be applied at the resource level or in transmission zones. The "renewable energy zone" (REZ) model for defining transmission zones has been used successfully for joint planning of new generation and transmission needs in California, Hawaii, Texas, and Australia. The benefit of a transmission zone–based approach is the ability to maximize transmission utilization by grouping new resources together, such as co-location of solar, wind, and battery storage. Deliverability constraints can be flexibly defined by transmission planners. For instance, the California Independent System Operator (CAISO) has designed deliverability limits used in the California Public Utilities Commission's Integrated Resource Plan process with up to three separate time windows (off-peak, partial peak, and on-peak) and with multipliers for each resource's contribution against those limits (solar, wind, battery storage, firm capacity, etc.). The resource plan with expanded transmission then goes through CAISO's transmission planning process, with its own set of detailed technical studies, stakeholder process, and FERC-regulated approval.

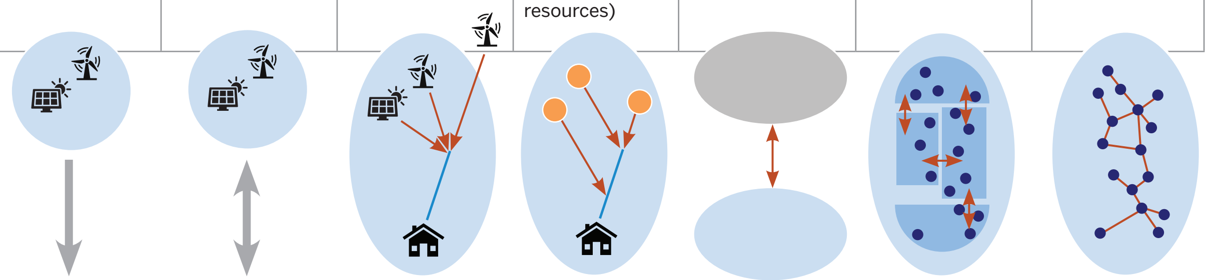
The most detailed approach to G+T co-optimization would be to use a full nodal representation of the transmission system—as is found in a nodal production cost model—in the capacity expansion model. This requires creating datasets of load growth, load shapes, baseline generators, and candidate resources mapped to each transmission node and creating candidate transmission upgrade options for the paths that connect each node to the larger system. This can be time-intensive to develop, computationally burdensome to implement, and practically challenging if each candidate option is later subject to routing, siting, and permitting challenges. Therefore, this approach may be feasible for some planning processes but not for others.

"Pipe and bubble" representations of the transmission grid that capture capacity limits but not power flow considerations allow the nodal capacity expansion to be flexibly applied to right-size the modeling approach for a given use case, capturing inter-zonal congestion effects while managing computational feasibility. New zone definitions with aggregated nodes can be used to reduce

FIGURE 7

Practical Methods for Co-optimizing Generation and Transmission Capacity Expansion

	Integrated Planning Approaches						
			Co-optimization Approaches				
	No integration	Iteration	Resource or transmission zone limits		Hourly flow constraints (pipe + bubble representation)		
	One-way flow	G ⟷ T Iterative Process	Resource-specific constraints	Transmission zones	Inter-zonal	Intra-zonal (aggregated nodes)	Nodal
Capacity expansion model dispatch	Zonal	Zonal	Zonal	Zonal	Inter-zonal	Intra-zonal (aggregation of full network nodes)	Nodal
Capacity expansion model transmission limits	None	None	Resource-level	Transmission zone–level (across resources)	Inter-zonal hourly flow	Intra-zonal hourly flow	Nodal hourly flow
	Downstream studies address all transmission needs from capacity expansion resource additions	Downstream studies address all transmission needs from capacity expansion resource additions, but include feedbacks to adjust the generation mix (or siting) based on results	Resource-level limits can vary from interconnection to new tie-lines and are useful for connecting a single resource type	Transmission zone–level limits allow for diversity to maximize utilization (e.g., adding solar, wind, storage together) and transmission studies for major renewable energy	Inter-zonal limits allow for study of large-scale interregional upgrades, including impact on investment and production costs	Intra-zonal limits capture intra-zonal constraints but aggregate nodes to limit data needs and runtime impacts	Nodal representation captures full network model nodal constraints; requires modeling nodal-level dispatch, which vastly increases runtime



Integrated G+T planning approaches are presented, ranging from iterations between generation and transmission analyses to more detailed co-optimization methods. Co-optimization methods are categorized into "resource or transmission zone limits" and "hourly flow constraints" with multiple options within each of these. These practical methods for optimizing generation and transmission are not mutually exclusive and can be combined based on data availability and desired granularity.

Source: Energy Systems Integration Group.

the spatial granularity captured while still maintaining an intra-zonal representation. Inter-zonal constraints and upgrades can also be modeled in considering the value of expanded links between balancing areas. Figure 7 provides an overview of practical methods for G+T co-optimization in use today. These methods are not mutually exclusive and can be combined, such as using detailed transmission zone constraints to address deliverability needs while also using inter-zonal constraints to address the impacts of congestion.

Current practical implementations of G+T co-optimization focus on staged improvements, leveraging increasing levels of integration while maintaining manageable model complexity. These approaches allow planners to capture the most critical transmission constraints while avoiding intractable computational burdens. By jointly considering generation and transmission investments, these methods can reveal cost-saving synergies, such as strategically siting generation to reduce congestion, co-locating storage and generation to maximize line utilization, and prioritizing transmission investments that enable broader system-wide efficiency.

Technical Limits to Optimization Approaches

Bulk-grid co-optimization is possible using existing tools and methods, recognizing the challenges in data development and computational tractability noted above. However, even when transmission investments are linked in economic expansion optimization, there are fundamental limits to what can be captured in the capacity expansion modeling framework. Specifically, capacity expansion models have limited representation of operational detail and grid physics. This necessitates the continued use of downstream transmission planning models, even following a G+T co-optimized expansion. Additional required studies include:

- **Nodal production cost modeling**, as security-constrained economic dispatch and DC power flow in a full network model may reveal additional economic upgrades to address congestion
- **AC power flow studies**, to capture a more robust view of power flow dynamics and impacts on thermal overloading, voltage, etc.
- **Contingency analysis**, to capture grid impacts of G or T outage events (N-1, N-2, etc.) that may require additional investments to address
- **Stability studies**, which capture sub-second dynamic response during disturbance events, which can lead to additional investments (like synchronous condensers) or additional dispatch constraints (to model in up-stream production cost models or capacity expansion dispatch)
- **Resource adequacy and resiliency analyses**, which consider the resource adequacy or resilience value of transmission during extreme events not captured in the reduced temporal granularity in capacity expansion

These additional downstream transmission analyses lead to validation of the transmission investments selected in capacity expansion as well as identification of additional investments beyond those selected. They may also feed back to capacity expansion and production cost modeling inputs and constraints. Hence, even when using a G+T co-optimized expansion, an iterative approach may still be needed between that model and downstream models that capture more detailed physical constraints.

Bulk + Local System Capacity Expansion Optimization

Planners have been seeking ways to optimize local grid needs and resource options against the bulk system since the early days of integrated resource planning in the 1990s. The focus then was on the consideration of demand-side management resources such as energy efficiency, demand response, and cogeneration as potentially lower-cost alternatives to continued bulk grid expansion. Today, those traditional demand-side resources are still available, and, enabled by technology advancement and new types of load growth, many additional DER options are also of interest, including distributed solar, battery storage, flexible electric vehicle charging (V1G), bidirectional vehicle-to-grid charging and discharging (V2G), and many other types of load flexibility.

By co-optimizing DERs against bulk-grid generation and transmission, the bulk-grid avoided costs are endogenously captured. However, DER growth may have costs and benefits to local distribution grids as well. DER growth may impose integration costs on local distribution grids, and/or DERs may provide local-grid benefits by avoiding or deferring distribution grid investments. Co-optimizing bulk- and local-grid needs and resources in a full-system capacity expansion optimization would require fully endogenizing transmission and distribution grid needs together with bulk and local resource investment options into a single expansion problem. This full-system optimization is attractive because DER values depend on the bulk-grid generation and transmission investments they can avoid as well as their local-grid costs and benefits.

Co-optimizing bulk- and local-grid needs and resources in a full-system capacity expansion optimization would require fully endogenizing transmission and distribution grid needs together with bulk and local resource investment options into a single expansion problem.

Here, we first discuss how bulk- and local-grid needs and resources could theoretically be co-optimized. Then, since full-system capacity expansion optimization of the bulk and local grids remains infeasible today, we describe three alternative approaches that can approximate its benefits while maintaining tractability.

Theoretical Bulk + Local System Capacity Expansion Optimization

The largest challenge to co-optimizing bulk- and local-grid needs and resources in a full-system co-optimization is that each bulk power system has hundreds or even thousands of individual distribution grids, with unique distribution planning criteria that drive local-grid investment needs and their own uncertain noncoincident peak load forecast. For these reasons, it is not currently tractable to incorporate granular distribution system planning decisions into a system optimization; therefore, the focus on the theoretical local system optimization is centered on how DERs could be considered within a G+T+C co-optimization that considers locational value; the model requirements to do so are presented in Figure 8 (p. 16).

Optimizing DERs requires significant data development and new model functionalities, which have varying degrees of difficulty as shown in Table 3. First, it must be determined which DER resources should be forecasted via adoption models and which should be optimized as resource options within the capacity expansion. Operating characteristics, resource potential, and costs must be developed for all candidate DERs. Resource

FIGURE 8

Model Requirements for Adding DERs and Their Local-Grid Values to a Theoretical Bulk-Grid and DER Capacity Expansion

Key Inputs	Objective Function: Minimize Costs	Constraints	Key Outputs
• DER candidate resource options • Operating characteristics • Resource potential • Resource costs • DER resource adequacy contributions • Locational costs-benefits	• DER fixed costs • DER variable operating costs • DER locational costs or benefits	• DER potential • DER operating limits • Locational value limitations	• DER selected capacity • DER selected energy and dispatch

In addition to the modeling requirements of traditional economic optimization models for capacity expansion described in Figure 1 (p. 2), theoretical co-optimization of bulk-grid investments and DERs involves more inputs, objective function variables, constraints, and outputs.

Note: DER = distributed energy resource.

Source: Energy Systems Integration Group.

adequacy contributions need to be calculated and incorporated into the adequacy constraints in the expansion model.

Lastly, the most difficult data points to be developed are the locational costs and benefits of local resources on the distribution system. While it is simple to calculate avoided transmission line losses from siting generation at load nodes, it is very difficult to capture how costs and benefits vary across the distribution system and how load changes and packaging of multiple DERs impact local grid needs. Doing so for a single location is theoretically straightforward if sufficient distribution system data are available (typically many feeder models for a given transmission load node) and analyzed off-line. However, doing so for a large area quickly becomes computationally intractable and is hampered by the need for thousands of feeders of data typically from many different distribution utilities.

Key Considerations for DER Optimization in Capacity Expansion Modeling

This section presents six key considerations for optimizing DERs in capacity expansion modeling:

- DER optimization can endogenously capture the value of displacing supply-side investments.
- DERs' real-world constraints should be considered.
- Sourcing mechanisms can impact the ability to rely on DERs for certain grid needs.
- Many DERs need to be measured relative to a baseline.
- Least-cost optimization provides one perspective on customer DER cost-effectiveness.
- Locational costs and benefits are challenging to capture in a system-level optimization, so may require separate modeling.

DER Optimization Can Endogenously Capture the Value of Displacing Supply-Side Investments

The key opportunity of modeling DERs as candidate options in a capacity expansion model is to allow the

The key opportunity of modeling DERs as candidate options in a capacity expansion model is to allow the model to consider DERs as alternatives to supply-side options to achieve the lowest-cost solution.

TABLE 3

Data Development Needs for DER Optimization in Bulk + Local System Capacity Expansion Modeling

Data	Description	Key Considerations	Level of Difficulty
DER candidate resource options	What DERs will be optimized vs. forecast? What level of aggregation should be done?	Sourcing mechanisms can inform the approach (solicitations vs. tariffs vs. programs). • DER candidates can be modeled in place of or in addition to forecasts of cost-effective DERs and customer adoption. • Aggregation trades precision for tractability (e.g., bundling of energy efficiency measures).	**Low to medium difficulty** There are potential challenges for measuring DER incrementality if modeling on top of a forecast.

Operating characteristics	How can DERs contribute to meeting grid needs?	• Operating characteristics are highly DER-specific but these data generally capture output shape and/or the resources' ability to respond to grid needs, for example:
		  • Hourly savings of energy efficiency by measure type
		  • Demand response availability periods, duration, call limits
		  • Flexible loads (+ electric vehicle) baseline shapes, shift windows, hourly/daily limits, etc.
		  • Distributed solar hourly generation shapes
		  • Distributed storage operating limits/shapes (may differ for front-of-the-meter vs. behind-the-meter).
			Medium to high difficulty
			It can be difficult to develop data for new types of DERs (vehicle-grid integration) and for price signal responses (distributed storage, flexible loads).

Resource potential	What level of candidate DER capacity should be made available?	• Significant data development is needed via potential studies to map out technical, economic, and achievable potential for each DER. • Some DERs require ongoing investment to scale (e.g., energy efficiency programs). • Some DERs are substitutable for one another for specific value streams (e.g., distribution deferral), which can complicate the process of defining potential, decision variables, and values.	**Medium difficulty** Significant work is required but there are established methods for many DERs.
Resource costs	How much do DER options cost?	• Capacity expansion usually considers total resource costs (utility as well as customer costs and benefits). • Costs may be adjusted based on the use case, for example, customer adoption vs. utility system and/or local need sourcing.	**Low to medium difficulty** It is harder to develop data for DERs that require incentive payments, specifically, to determine what payment or tariff is necessary for what behavior.
Resource adequacy contributions	What reliability (resource adequacy) contributions are provided?	• Most DERs can be analyzed in a loss-of-load probability (LOLP) model and effective load-carrying capabilities (ELCC) can be developed. • DERs' interactive effects with other resources need to be carefully considered—for example, DERs with other DERs, distributed vs. bulk-grid solar or storage, flexible loads vs. bulk storage, energy efficiency and electrification impacts on load shape, etc.	**Medium difficulty** It may be difficult to capture some of the interactive effects.
Avoided losses	What avoided loss value do customer- or distribution-sited resources provide?	• Simple heuristics may be feasible to capture, such as applying avoided transmission and distribution losses.	**Low difficulty** Simple heuristics can be used.
Locational costs and benefits (location-specific)	What location-specific benefits can DERs provide (and when)?	• DER integration costs and benefits (such as distribution deferral) are location- and time-specific, DER-specific, and interactive with load and other DER changes.	**High difficulty** Very significant data development is required, and it may be hard to accurately capture spatial granularity and load/DER interactions over time within a system optimization.

Optimizing DERs requires significant data development and new model functionalities, with varying degrees of difficulty.

Source: Energy Systems Integration Group.

model to consider DERs as alternatives to supply-side options to achieve the lowest-cost solution. Notwithstanding the challenge of properly capturing the local-grid value of DERs, there are many bulk-grid values that can be considered when optimizing DERs within a bulk-grid generation (or generation + transmission) optimization. These include the following value streams that various types of DERs can provide:

- **Energy value:** DERs that provide energy (such as energy efficiency, distributed solar, and combined heat and power) may be able to support a system's meeting hourly energy demands at a lower cost than supply-side investments.
- **Capacity value:** DERs that provide resource adequacy capacity (such as energy efficiency, demand response, distributed storage, and flexible electric vehicle charging) can support meeting the resource adequacy needs captured in capacity expansion modeling. DER options should be appropriately measured with the same robustness as supply-side resource adequacy contributions, which includes considering both technical and behavioral factors that may limit these resources' availability during resource adequacy–constrained periods (for example, using effective load-carrying capability (ELCC) studies for DER accreditation).
- **Avoided transmission value:** If generation and transmission are co-optimized, then the value that DERs can provide by avoiding bulk-grid transmission investments will be endogenously captured.
- **Contribution to policy goals (such as clean energy):** Depending on how policies are defined, DERs can contribute in various ways. If renewable portfolio standard policies are defined based on retail sales of electricity, then reductions in energy consumption through increases in energy efficiency or behind-the-meter solar reduces the clean energy procurement obligation. DERs may also count directly toward policy goals, such as greenhouse gas–based policies. Endogenous treatment allows the capacity expansion model to determine the most cost-effective means by which DERs contribute to policy goals.
- **Flexibility/renewable integration value:** Some DERs provide flexibility that can offset bulk-grid investments and support renewable integration. These include distributed storage, flexible electric vehicle charging, and other flexible loads like space heating, space cooling, and water heating. These DERs can be modeled directly in capacity expansion dispatch with the appropriate constraints on their operations. For instance, flexible loads are subject to a baseline load shape, a cost to shift (such as program administrative or communications/control infrastructure costs), shift up and down limits, daily shiftable energy budgets, hour adjacency constraints, and daily energy neutrality constraints.

Note that these values are already assessed for similar bulk-grid resources in traditional capacity expansion modeling, with the exception of avoided transmission value in analyses without G+T co-optimization.

DERs' Real-World Constraints Should Be Considered

Like all resource options, DERs have their own technical operational constraints, such as the maximum discharge duration in a distributed battery. In addition, DERs may have their own unique constraints that impact their ability to support bulk-grid needs, including the following:

- Behavioral constraints that impact whether customers and their devices will be available to respond when called upon, such as availability of electric vehicles to flex and customers' willingness to respond to demand response events

- Market seams constraints that impact DERs' ability to see and respond to the bulk-grid needs modeled in capacity expansion studies, such as differences in real-time prices versus retail rate signals
- Value-stacking constraints that impact the ability for DERs to simultaneously solve bulk-grid, local-grid, and customer needs, such as the limitations for providing bulk-grid resource adequacy capacity, distribution grid deferral capacity, and customer peak load reductions

These additional constraints can be considered in capacity expansion models to the extent there are sufficient data to characterize them. Figure 9 shows key constraints used for modeling flexible loads in the California Public Utilities Commission IRP proceeding.

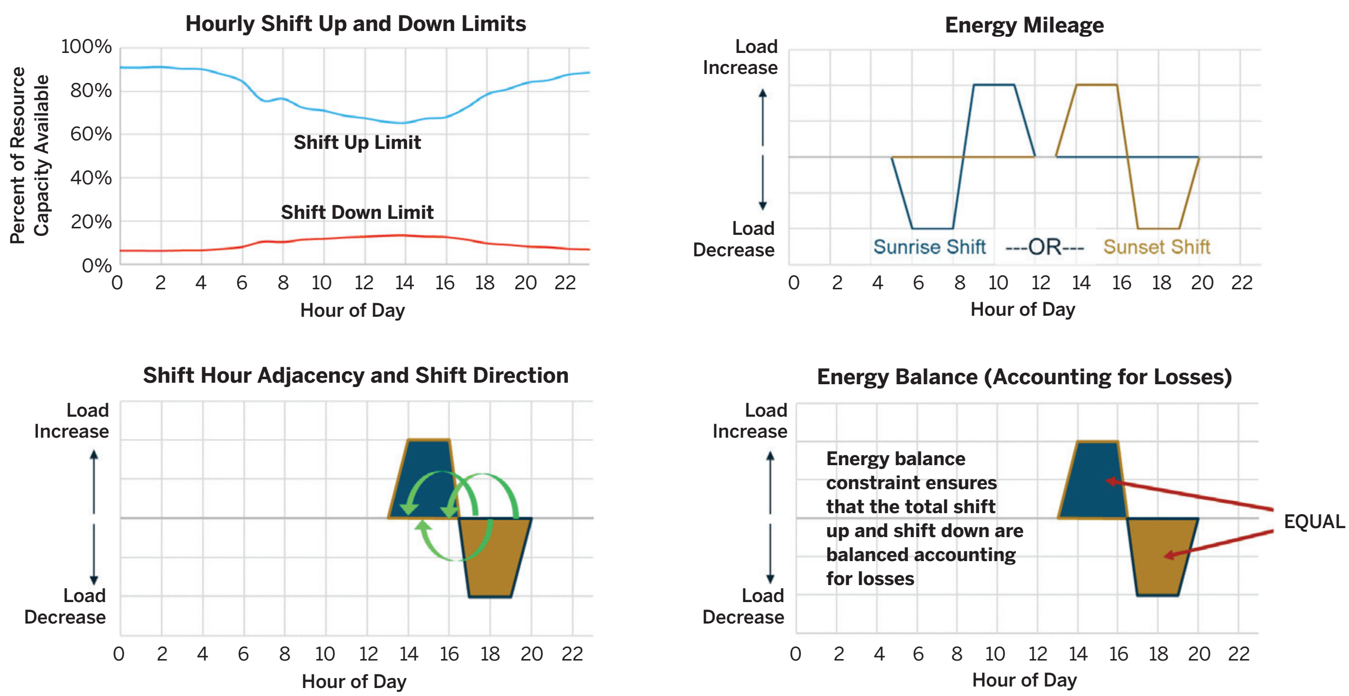
Sourcing Mechanisms Can Impact the Ability to Rely on DERs for Certain Grid Needs

Bulk-grid resources are typically sourced via either utility-owned construction, build and transfer arrangements, or a contract with a utility counterparty. Alternatively, these resources may enter the market in a merchant position based on expected wholesale market revenue. DERs have a unique set of sourcing mechanisms by which they are adopted, including the following (see Figure 10, p. 20):

- **Utility ownership and control:** In-front-of-the-meter resources that a utility self-builds which provide direct operational control; often sourced for specific grid needs (such as non-wires alternatives to traditional grid investments or to support reliability)
- **Competitive solicitations:** In-front-of-the-meter or behind-the-meter procurement via targeted solicitations (e.g., location- and attribute-specific non-wires alternatives) or all-source requests for offers (RFOs)

FIGURE 9

Example Modeling Constraints for Flexible Loads in Capacity Expansion Models



Visualization of the constraints necessary for flexible load implementation in capacity expansion modeling.

Source: California Public Utilities Commission, IRP Proceeding, 2023 Inputs & Assumptions (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/draft_2023_i_and_a_workshop_slides.pdf).

FIGURE 10

Suitability of Different DER Sourcing Mechanisms for DER Optimization Versus Forecasting

	Utility Ownership and Control	Competitive Solicitations	Customer Programs	Markets	Tariffs
Sourcing timeline and resource performance drivers	Utility construction timelines and distribution operational model	Utility procurement process and contract requirements	Customer adoption and behavioral response	Market clearing and wholesale price signals	Customer adoption and behavioral response
Uncertainty	**Low**	**Low-Medium**	**Medium**	**Medium-High**	**High**
Key use cases	Specific time-dependent grid needs (non-wires alternatives, etc.)	Specific time-dependent grid needs (non-wires alternatives, resource adequacy, etc.)	Identifying cost-effective measures, incentivizing customer adoption, enabling market transformation	Using market-based wholesale pricing (via energy or distribution services markets) to drive customer adoption and/or behavioral changes	Using wholesale or retail pricing (rates) to drive customer adoption and/or behavioral changes

Planners can be confident in optimizing ⟷ **Planners may need additional validation if optimizing**

Some DER sourcing mechanisms, such as utility ownership and control, are more adaptable for use in least-cost optimization than other DER sourcing mechanisms, such as tariffs. DERs that depend heavily on behavioral changes or retail rate incentives may need additional validation if optimizing so that operators can be confident in the level of response. Care should be taken to consider the feasibility and costs of relying on DERs sourced via different methods for certain grid services.

Source: Energy Systems Integration Group.

- **Customer programs:** Behind-the-meter resources or load changes sourced via utility (or third-party) programs that use financial incentives, marketing, and education to facilitate DER adoption; often planned in portfolios of programs using multiple measures of cost-effectiveness
- **Markets:** Wholesale energy markets may incent DER market entry, or specialized distribution system operator (DSO) markets may incent market entry for grid services[3]
- **Tariffs:** Usually behind-the-meter resources[4] adopted or behavioral changes driven by price signals such as retail rate design, net metering/billing, and feed-in-tariffs

The sourcing mechanism used depends on many factors. For example, it can be driven by the type of need identified. Solutions to customer-driven needs, such as bill reduction and building comfort, are often sourced by programs or tariffs. Solutions to system-driven needs or values, such as energy and resource adequacy capacity needs, can be sourced via customer programs, incentivized by aligning retail tariff design with system needs, or sourced via all source solicitations (such as a resource adequacy capacity all source RFO). Solutions to local needs, such as distribution deferral, are typically sourced by utility ownership or solicitations, though there is interest in using programs, markets, or tariffs. Sourcing models may evolve in the future, extending beyond these traditional approaches.

3 DSO-based markets are not common today. The United Kingdom currently uses DSO markets for flexibility to source DERs and load flexibility as a non-wires alternative. See https://www.flexiblepower.co.uk/downloads/1173.

4 Typically, tariff-based adoption refers to retail tariffs (i.e., electricity rate design), although in-front-of-the-meter resources can also be procured via wholesale tariffs, such as feed-in-tariffs.

When determining how DERs fit into a long-term planning process, planners will need to decide whether a DER should be forecasted or optimized. Here, it is important to consider which sourcing mechanism will be used to secure the DER, which can impact the level of utility control over the DER, its ability to provide specific grid services, and the sourcing costs.

Utility Ownership or Competitive Solicitations

Resources that will be directly procured via utility ownership or competitive solicitations allow planners to set very specific operational requirements in contracts, with clear financial penalties for non-performance and the option—in some cases—for direct utility control over the asset. This reduces uncertainty about the timeline to source the DER and the resource's performance once it is operational. These sourcing mechanisms therefore lend themselves better to optimization in capacity expansion studies.

Customer Programs

Customer program planning is often performed using assumptions of measure costs, utility and/or customer avoided costs, and the associated incentive payments required to incent adoption. Programs often set goals, such as energy efficiency savings goals, but they provide less certainty in the timeline of adoption and technology performance once adopted. This may be challenging if targeting specific grid needs, such as distribution investment deferral in specific locations. Therefore, planners should ensure that their modeled use case (e.g., avoided energy costs, system resource adequacy, and/or a location-specific grid need) is consistent with the confidence they have in sourcing those DERs through customer programs. Pilots, such as locationally targeted customer programs, can validate novel DER use cases and give planners more confidence in optimizing these resources.

Pilots, such as locationally targeted customer programs, can validate novel DER use cases and give planners more confidence in optimizing these resources.

Markets and Tariffs

Markets and tariffs are price-based mechanisms that may incent technology adoption at either the wholesale or retail level. Markets that may incent DERs include wholesale energy and capacity markets, as well as novel DSO markets that source DER flexibility for distribution grid services. Though limited today, distribution-level markets using the DSO model have emerged in the United Kingdom as another way to source the adoption of DERs and facilitate DER and load flexibility to support distribution grid needs. These markets allow third parties to respond to distribution network operator needs on a forward and real-time basis. They are dynamic and therefore have significant long-term uncertainty, making them challenging to forecast or optimize in long-term planning analyses. However, if markets prove that they can effectively source DERs for specific grid needs, planners can have more confidence in relying on DERs sourced through markets and optimizing their adoption in planning models.

Retail rate design is a key mechanism to incent customer behavior to align with grid value. Rates can encourage technology adoption and can encourage load flexibility of those adopted technologies, including electric vehicles, electrified water heating and space cooling/heating, and other end uses. Since tariffs lead to customer adoption or behavioral changes in uncertain amounts and on uncertain time horizons, they may be better suited for forecasting of adoption and behavioral shifts rather than modeling via candidate resources to optimize against specific grid needs. Wholesale tariffs (such as feed-in tariffs) are another tariff-based method for sourcing DERs that may provide more certainty for planners due to longer-term fixed payment structures.

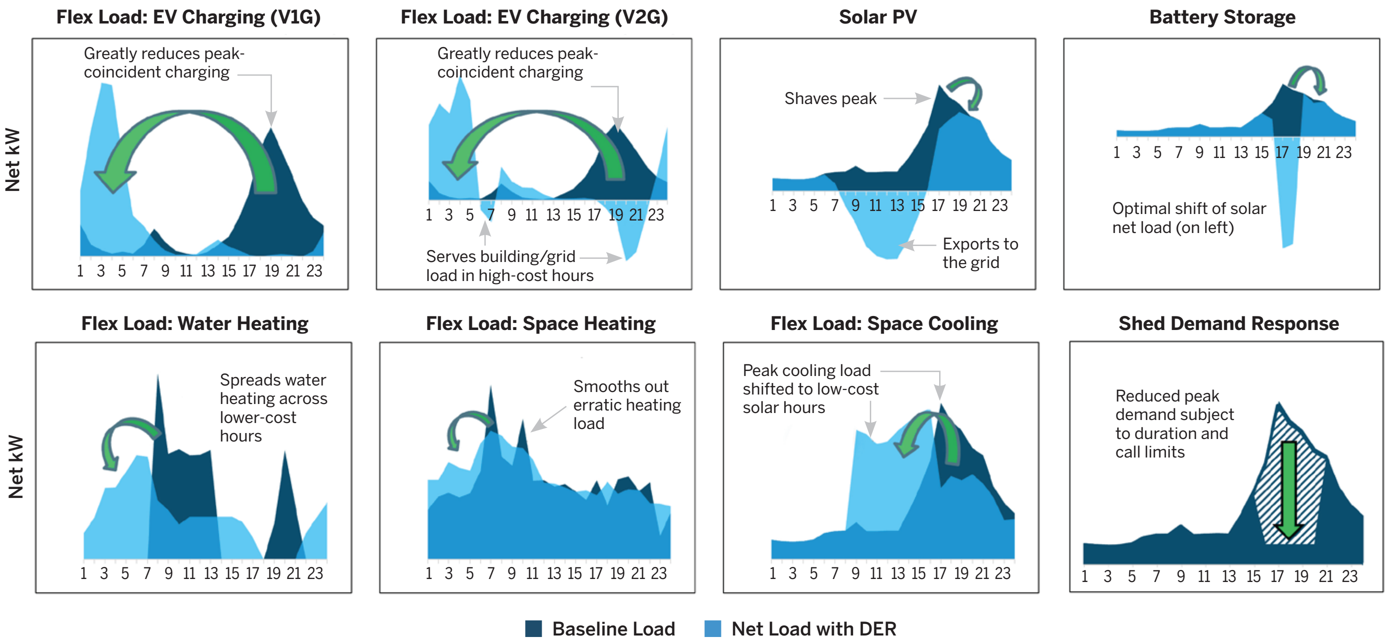
Sourcing mechanisms for DERs and flexible loads will continue to evolve as utility planners and policymakers continue to experiment with methods that support cost-effective DER adoption and operational flexibility that can maximize bulk grid and local grid value. Pilot programs for novel value streams, such as DERs for distribution grid deferral, can explore alternative sourcing strategies and provide planners with real-world validation of the feasibility and the costs of sourcing DERs for specific grid needs.

Many DERs Need to be Measured Relative to a Baseline

Behind-the-meter DER resources and load flexibility alter the loads that will be served by the bulk grid. When assessing the value of altering load shapes, planners need to measure these changes relative to a baseline load forecast. Some DERs may not require a baseline shape—for example, front-of-the-meter distributed storage that can be dispatched directly according to system needs and therefore does not have a clear baseline shape. Aligning baseline forecasts for loads, DERs, and load flexibility is important for integrated planning, to ensure the alignment of foundational inputs across planning processes. When quantifying the value of an additional DER or load flexibility resource—either endogenously in capacity expansion optimization or exogenously against a fixed stream of avoided costs—that value is measured relative to a baseline. At times, this requires challenging decisions by planners. For instance, planners need to decide what electric vehicle charging shape to assume in the load forecast, which determines what additional value may be created by managed charging programs for either one-way electric vehicle charging or two-way electric vehicle charging and discharging to the grid. These decisions should be carried through consistently into capacity expansion modeling, resource adequacy analyses, and grid planning models. This can be complicated by the need to map what might be full hourly sequences

FIGURE 11

Baseline Load Shapes and Net Load Shifted Shapes from DERs Modeled as Resources



When assessing the value of altering load shapes, planners need to measure these changes relative to a baseline load forecast. Flexible loads will have varying impacts on the net load-shifted shapes.

Source: Adapted from E. Cutter, J. Zhang, S. Spencer, F. Liu, B. Mahoney, H. Platter, P. Wild, and L. Bertrand, Glendale Water and Power's Plan to Increase Solar Adoption and Develop Additional Distributed Energy Resources: E3 Study Report. Energy and Environmental Economics (2024), https://www.ethree.com/wp-content/uploads/2024/11/E3-Study-Report_Glendale-Water-and-Power.pdf.

into representative periods often used in capacity expansion models. Figure 11 shows indicative baseline load shapes and shifted load shapes for a variety of DER and flexible load resources.

Least-Cost Optimization Provides One Perspective on DER Cost-Effectiveness

Most capacity expansion models operate using a cost-minimizing objective function. The scope of these costs may vary, but often it follows the application of the total resource cost (TRC) test that considers the economic costs and benefits to electricity ratepayers and society at large, or the program administrator cost (PAC) test that considers costs and benefits solely to electricity ratepayers. For instance, when considering a distributed generation investment, the TRC approach would value the benefits to utility grid operations and investment, such as avoided energy, capacity, and transmission and distribution costs, as well as the costs to utility customers and DER-adopting customers in the form of on-site equipment, installation, and interconnection costs.

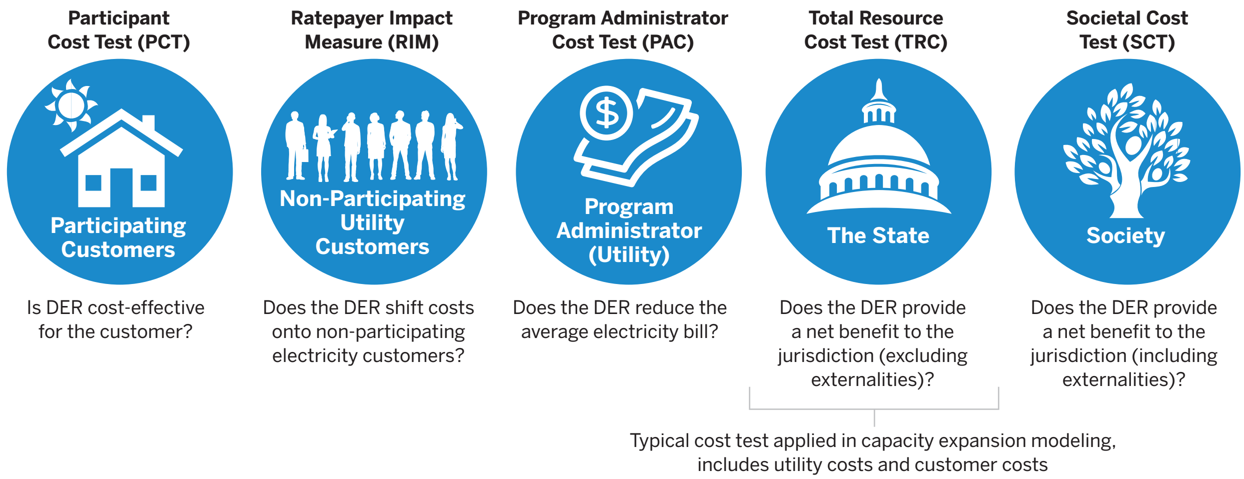
The Value of Employing Multiple Cost Tests

DER cost-effectiveness analysis, however, often considers multiple viewpoints captured via application of multiple different cost tests.[5] These consider the value of the DER from the perspective of the adopting customer, non-adopting ratepayers, the program administer, internalized costs in the jurisdiction, and internalized plus externalized costs in the jurisdiction. These perspectives are shown in the form of various costs tests in Figure 12 (p. 24). The primary test used for screening customer programs varies by jurisdiction. It is important to note that optimizing DERs in a capacity expansion model allows for a single cost test perspective in each optimization run and may not capture the same dynamics used

5 These cost-effectiveness tests apply generally to behind-the-meter DERs, not front-of-the-meter DERs that are sourced directly through utility procurement.

FIGURE 12

Cost Tests Used in DER Cost-Effectiveness Analysis



Some DER sourcing mechanisms, such as utility ownership and control, are more adaptable for use in least-cost optimization than other DER sourcing mechanisms, such as tariffs. DERs that depend heavily on behavioral changes or retail rate incentives may need additional validation if optimizing so that operators can be confident in the level of response. Care should be taken to consider the feasibility and costs of relying on DERs sourced via different methods for certain grid services.

Source: Energy and Environmental Economics (E3).

in existing, more detailed customer program evaluation practices. For instance, a resource may be cost-effective to the jurisdiction as a whole, while its adoption under current rate designs may result in unacceptable cost shifts between customer classes.

There are key equity concerns that are traditionally addressed in DER and rate design analysis, including consideration of how behind-the-meter DERs may shift costs from participating to non-participating customers. These factors have major, real-world impacts on the ability to scale DERs using certain sourcing mechanisms, especially retail tariffs like net energy metering. Equity factors also relate to programs that may not be cost-effective by PAC or TRC measurements, but address energy needs and affordability for low-income customers. Some DERs may be adopted due to retail rate incentives that make them cost-effective for participating customers (PCT), even if they would not be deemed cost-effective via a TRC-based least-cost optimization; it is necessary to forecast these DERs instead of optimizing them in a TRC-based framework.

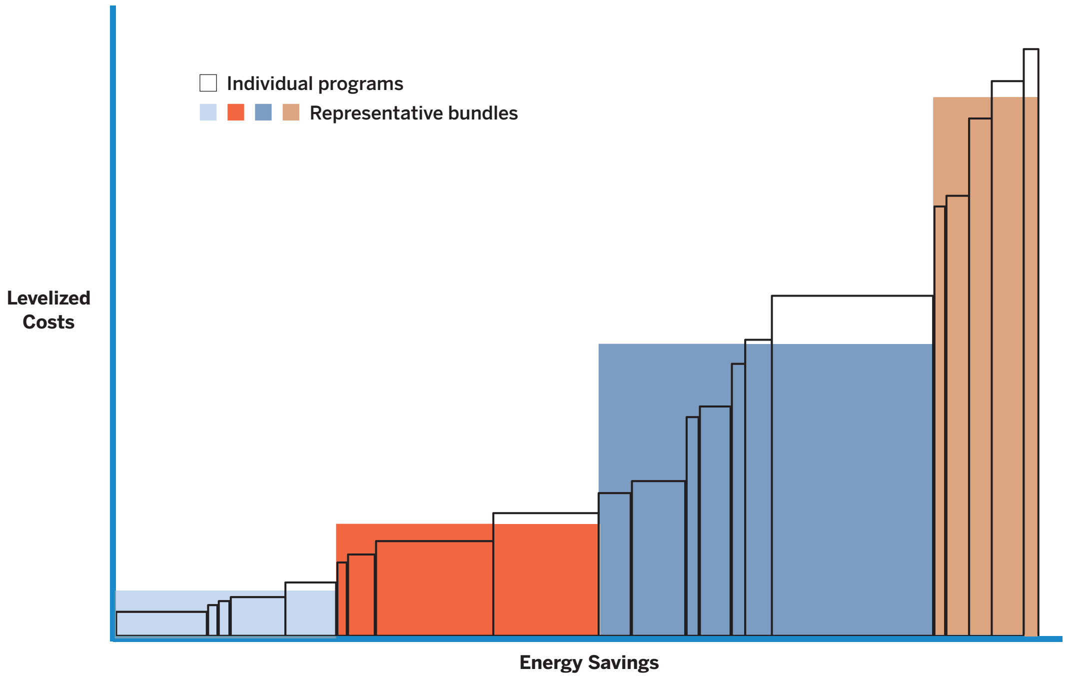
The Difference Between Measure-Level Planning and Portfolio-Level Planning

Another important consideration for how DERs are evaluated in capacity expansion models is whether they are modeled as individual measures or as a portfolio of measures. When planned by optimization in capacity expansion models, the DER is often modeled at the measure-level (or bundles of measures), which allows the model to pick the lowest-cost measures and leave off higher-cost measures. However, if they are planned at the portfolio level—as is often the case for energy efficiency measures—this allows low-cost measures like commercial lighting to offset other higher-cost measures that support low-income programs, market transformation, or other social objectives.

Individual customer program measures may number in the hundreds or thousands, which can increase data development and computational burdens during optimization. Grouping measures into bundles, as shown in Figure 13 (p. 25), provides a tractable means to reduce the number of DER candidate resources, although it also introduces subjectivity into how measures are bundled in

FIGURE 13

Bundling of Energy Efficiency Resources for Capacity Expansion Optimization



Due to the tractability challenges of modeling every individual distributed energy resource measure, bundling may be required. Illustrative bundling of an energy efficiency supply curve is shown here. Other methods of bundling could just as easily be applied, based on a combination of costs, sector, end use, and/or location.

Source: Energy Systems Integration Group.

ways that may ultimately impact those that are selected. For instance, bundles could include aggregation by costs, sector, end use, and/or location. In short, tractably including DERs in a system-level optimization requires reduced precision of the full details of their diversity.

Locational Costs and Benefits Are Challenging to Capture in a System-Level Optimization

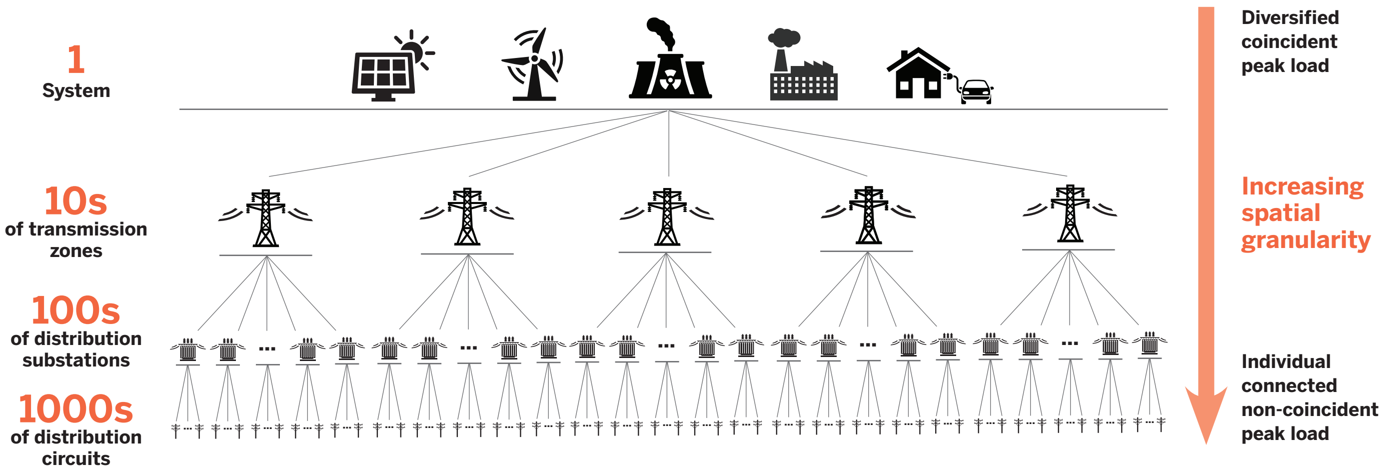
Considering the above discussion, it may be feasible to model DERs as resources within a capacity expansion optimization subject to the above key considerations (measure bundling, limited cost test views, operational constraints, etc.). One of the key benefits of modeling DERs is to allow bulk-grid and local resources to compete on a level playing field within the optimization by allowing them to be selected as part of the least-cost optimization to meet reliability and policy goals. One of the challenges to creating that level playing field is the challenge of parameterizing the locational costs and benefits for modeled DER options within a system-level optimization.

The Challenge of Capturing Distribution Circuit–Level Values

Figure 14 (p. 26) shows the relative scales of a system-level optimization, with a single load forecast and aggregated set of resources at the top, to a more granular transmission zone/node level breakdown with up to tens of load forecasts and resource zones, all the way to the granular distribution circuit–level breakdown, which requires hundreds to thousands of load forecasts and resource zones to model. This figure illustrates why it is currently computationally intractable to model detailed topology below the transmission grid level in a system-level optimization.

FIGURE 14

An Example of Relative Scales of a System-Wide Zonal Expansion Problem Versus a Granular Distribution-Level Expansion Problem

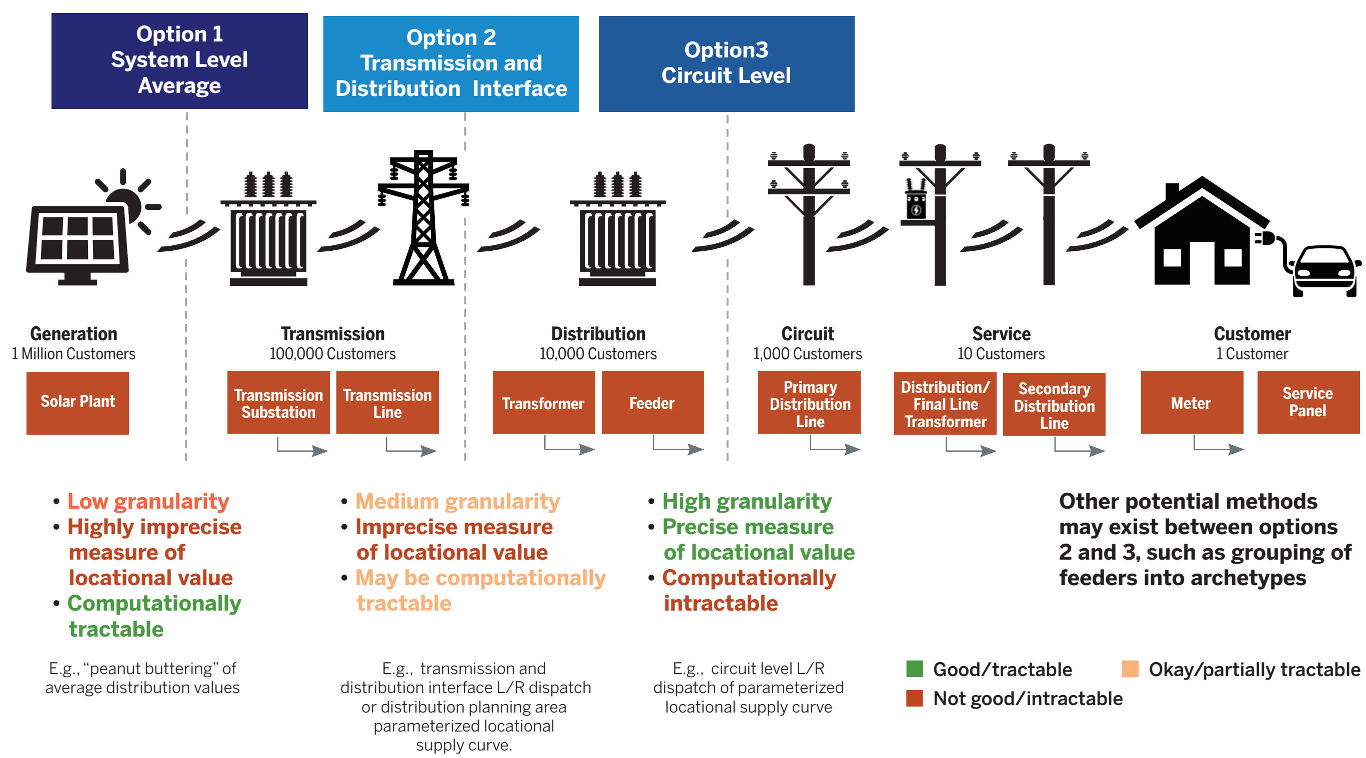


It is currently computationally intractable to model detailed distribution grid topology in a system-level optimization because it requires hundreds to thousands of load forecasts and resource zones to model.

Source: Energy Systems Integration Group.

FIGURE 15

Spatial Granularity Trade-offs in Capturing Local Grid Values



Higher spatial granularity increases precision of location distribution grid values but typically makes the optimization problem less computationally tractable.

Source: Energy Systems Integration Group.

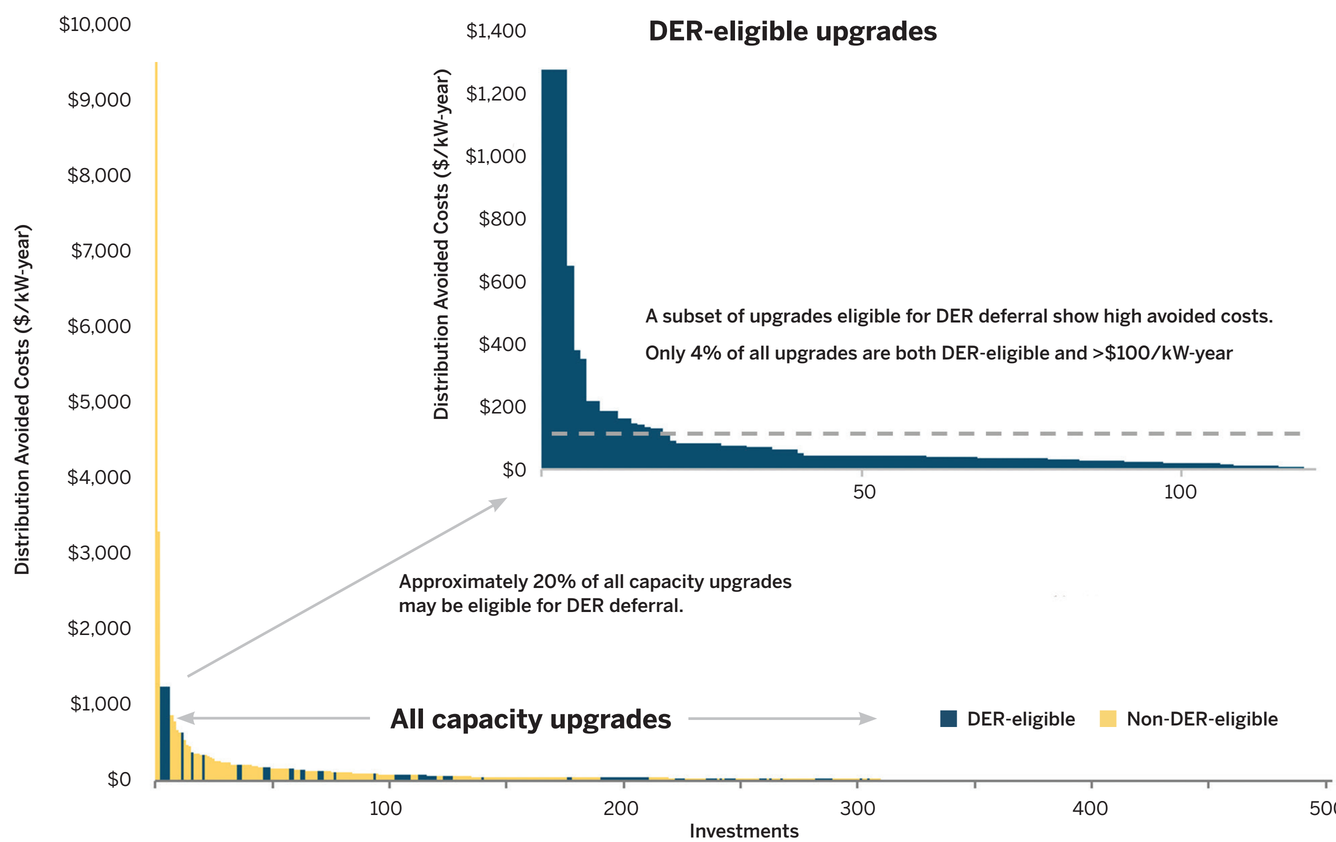
Trade-offs Between Methods of Aggregating Local Values

Since the full distribution-level topology is not readily captured in a system-level optimization, it is more tractable to incorporate a more aggregated approach for distribution system value of DERs. Figure 15 (p. 26) shows key trade-offs involved in more spatially aggregated approaches (options 1 and 2) than the circuit-level approach described above (option 3). Modeling with system-level averages is computationally tractable but is a highly imprecise measurement of locational value, meaning that DERs may be assigned values they could not actually realize. A middle point between these extremes could be to model flows at the transmission-distribution interface. But while this may be computationally tractable, it still provides an imprecise measurement of local value that might underestimate the local value opportunities and marginal avoided costs for some resources and overestimate them for others.

One key consideration for distribution upgrade deferral values is that values may be very high in some locations and then decline rapidly for most other locations on the grid. This points to the fact that most locations will have very low to moderate upgrade deferral values, while some specific locations have very high value and should be the focus for sourcing of non-wires alternatives, when feasible technically and commercially. This is shown in Figure 16.

FIGURE 16

Avoided Distribution Costs for California Investor-Owned Utilities



Higher spatial granularity increases the precision of location distribution grid values but typically makes the optimization problem less computationally tractable. Analysis of California investor-owned utility distribution capacity upgrades shows that most upgrades come at low cost, while a few upgrades come at very high cost. It also shows that only a subset of planned upgrades is estimated to be eligible for DER deferral and that only a further subset of those DER-eligible upgrades shows significant avoided cost.

Source: Energy Systems Integration Group; data from 2023 California utility grid needs assessment (GNA) and distribution deferral opportunity report (DDOR) datasets.

Parameterization of Local Value from Detailed Distribution Studies

One additional method is a parameterization of locational values from more granular distribution-level studies. This is a theoretically promising route, as many other key inputs to capacity expansion models are simplified into more computationally tractable parameters (e.g., the use of a planning reserve margin and effective load-carrying capabilities). Figure 17 shows an example of how a curve of locational net benefits can be calculated by combining the locational benefits and integration costs associated with increasing numbers of DERs on a distribution system. The challenge in this approach is that (a) each DER will have a different net benefits curve on each distribution system, (b) combinations of DERs and evolving load shapes have major interactions that impact locational values, and (c) deferral opportunities are time-dependent, so such a parameterization would also need to consider how the locational benefits change across the planning horizon—for example, if load grows and a substation is built before a DER solution can be implemented, then there is no longer an equipment deferral benefit. Ongoing research is needed to determine tractable methods to parameterize local value for capacity expansion modeling. A high-level method is proposed as part of the third alternative approach presented below.

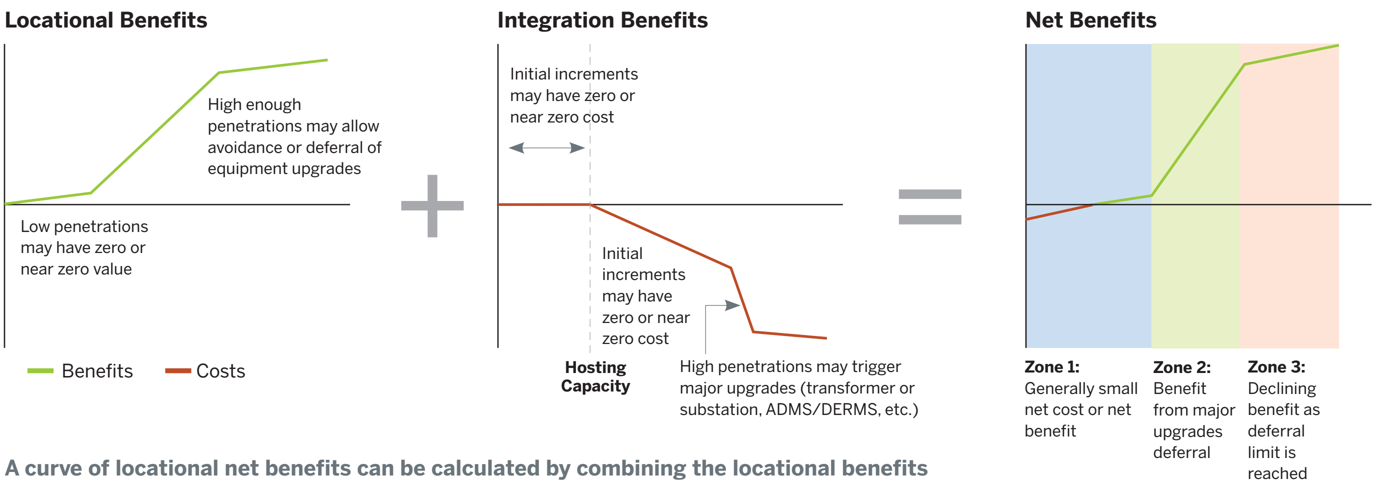
The factors described above have thus far limited the ability of most modelers to accurately capture the locational value of DERs in a capacity expansion modeling framework. DERs can still be modeled within a G+T co-optimization model, which allows for endogenous calculations of avoided generation and transmission investments from DER investment, but this approach would not allow for a measurement of their local costs or benefits to the distribution grid.

Practical Approaches to Capture Both Bulk-Grid and Local-Grid Values

Even as full-system co-optimization of the bulk and local grids remains infeasible today, there are alternative approaches that can approximate its benefits while maintaining tractability. These alternatives are generally meant as advanced, "run" stage analytical processes for organizations that have the technical resources to implement them (see the discussion in the concluding section on a walk/jog/run approach and the similar framework described in the second report in this series, the *Integrated Planning Guidebook*). In that context, there are many steps along the way to this level of integration that can provide substantial benefits; some specific steps along the way are presented in the final section of the report. While the

FIGURE 17

Theoretical Approach to Generating a Supply Curve of DERs' Locational Net Benefits



A curve of locational net benefits can be calculated by combining the locational benefits and integration costs associated with increasing levels of DERs on a distribution system.

Notes: ADMS = advanced distribution management system; DER = distributed energy resource; DERMS = distributed energy resource management system.

Source: Energy Systems Integration Group.

approaches outlined below are technically feasible now, there are typically additional practical, procedural, and institutional barriers to overcome when implementing these methods.

Three methods for capturing both bulk-grid and local-grid values are presented: (1) a marginal avoided cost–based approach, (2) many local-grid optimizations informed by a bulk-grid avoided costs approach, and (3) an approach using bulk grid + DER co-optimization with parameterized distribution values. These approaches leverage generally existing planning methodologies to improve coordination between bulk power system and distribution system planning without requiring full endogenization of all system components into a single optimization framework. However, some planning processes may need to be improved to produce the type of information exchanged in these processes (marginal hourly distribution-grid avoided costs, the ability to co-optimize DERs against distribution investments, etc.). Additionally, these methods are not all or nothing for each resource type. For instance, it may be useful to model some DERs that provide system value (such as interruptible load programs) in a generation capacity expansion, while other DERs can benefit from the more detailed treatment of avoided costs and/or locational values outlined below. These methods, as alternatives to full system optimization, all combine partial co-optimization of some planning domains with iterative feedback loops between processes either within or between planning cycles.

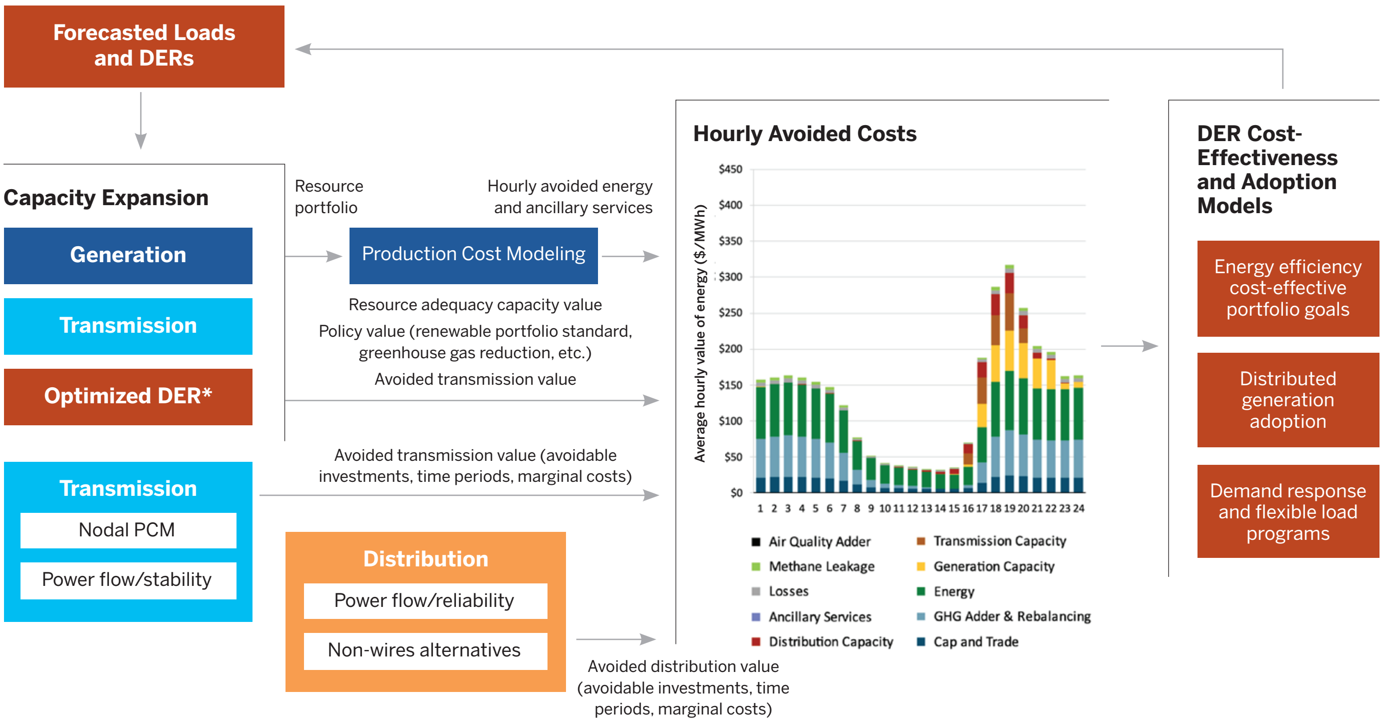
Alternative 1: Marginal Avoided Cost–Based Approach

The marginal avoided cost approach seeks to capture the value of DERs by calculating the cost savings they provide in avoiding or deferring bulk system investments in generation and transmission. Under this framework, capacity expansion and production cost models are used to estimate the marginal avoided costs of energy, capacity, ancillary services, and transmission, typically at an hourly level. These avoided cost estimates can then be used to inform DER procurement decisions, demand-side management program design, and distribution planning studies. This method is summarized in Figure 18 (p. 30).

One of the primary advantages of this approach is that it allows for more detailed economic valuation of DERs within an existing system planning structure. By using production cost modeling outputs to derive hourly avoided costs, planners can assess the potential contributions of

FIGURE 18

Overview of Marginal Avoided Costs Approach for Bulk and Local System Coordinated Planning



The marginal avoided cost approach seeks to capture the value of distributed energy resources (DERs) by calculating the cost savings they provide in avoiding or deferring bulk system investments in generation and transmission.

* Incremental DERs can still be optimized above forecasted DERs if desired.

Source: Energy Systems Integration Group.

DERs at different times of the day and year, capturing their ability to reduce system peak loads, provide reliability benefits, and defer large-scale infrastructure investments. Additionally, because many existing generation planning models already produce marginal values, such as loss-of-load probability simulations and ancillary service prices, the framework can be readily incorporated into existing processes.

However, there are things to consider when using the marginal avoided cost approach. It requires significant data development to generate hourly avoided costs, particularly for avoided transmission- and distribution-level investments. This approach typically produces just a single set of avoided costs used to inform DER planning. While developing multiple scenarios of avoided costs is possible using different capacity expansion scenarios or varying production cost modeling inputs like fuel prices, each scenario requires additional effort.

While the marginal avoided cost approach provides DER values for discrete bulk-grid futures that have specific levels of DERs embedded within them, a positive aspect of this approach is that it has an inherent feedback loop within it. Specifically, if DER forecasts used to develop the marginal avoided costs underestimate the amount of cost-effective DERs that will be adopted, this will be reflected in relatively high marginal avoided costs per adopted DER, which will then show a higher amount of cost-effective DERs that inform updated forecasts. If DER forecasts used to develop the marginal avoided costs *over*estimate the amount of cost-effective DERs adopted, this will be reflected in relatively low marginal avoided costs per DER adopted, which inform an up-dated forecast of cost-effective DERs that is lower than the starting forecast. Given the level of effort involved, existing examples of this approach (such as the Avoided Cost Calculator developed by the California Public Utilities Commission) apply this iterative feedback loop between planning cycles, though theoretically with enough time and resources it could be applied within an integrated planning cycle.

Alternative 2: Local-Grid Optimization with Bulk-Grid Avoided Costs Approach

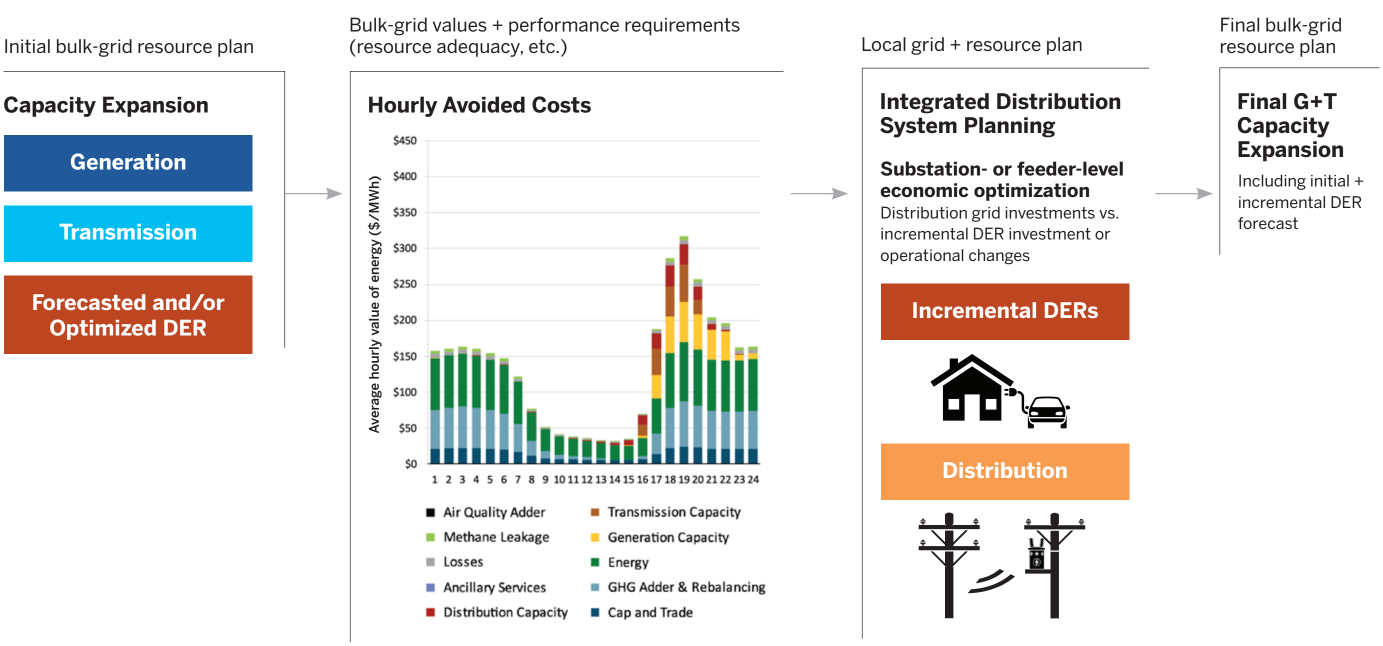
A related approach is to conduct localized distribution-system optimizations that incorporate bulk-grid avoided costs, as illustrated in Figure 19. Instead of attempting to integrate detailed local-grid constraints into a single system optimization, this method takes the results of the single system optimization and uses those, via bulk-grid avoided costs, as inputs into many parallel local-optimization problems that consider incremental DER investments or operational flexibility against distribution-system upgrade costs.

Under this framework, bulk-grid models first establish the system-wide avoided cost values for energy, capacity, ancillary services, and transmission, and for achieving policy goals. These values are then used as inputs into distribution-system planning models, which optimize investments at the substation and feeder level. Using this method, distribution planners can evaluate DERs for their ability to defer local grid infrastructure investments while discounting their costs by their bulk-grid value. Then, the incremental DER values and their operating shapes or limits are input into a final G+T optimization with fixed DER inputs to determine the final G+T+D+C solution.

This approach has several advantages. It allows distribution system planners to conduct more granular assessments of DERs while ensuring consistency with bulk system planning objectives. Additionally, because it does not require full endogenization of distribution constraints into capacity expansion models, it avoids the computational burdens associated with full-system optimization. By maintaining separate, but linked, modeling processes,

FIGURE 19

Overview of Bulk-Grid Avoided Costs Combined with Integrated Distribution System Planning for Bulk and Local System Coordinated Planning



Conducting localized distribution system optimizations that incorporate bulk-grid avoided costs takes the results of the single system optimization and uses those, via bulk-grid avoided costs, as inputs into many parallel local optimization problems that consider incremental DER investments or operational flexibility against distribution system upgrade costs.

Note: DER = distributed energy resource.

Source: Energy Systems Integration Group.

Alternative 2 allows distribution system planners to conduct more granular assessments of DERs while ensuring consistency with bulk system planning objectives and avoiding the computational burdens associated with full-system optimization.

planners can integrate DERs in a way that reflects both their local and bulk system value. This process also tends to align well with existing generation (integrated resource plan) and DER (avoided cost–based) planning and decision-making processes in use today.

This method also has key considerations. First, because it relies on sequential modeling rather than a fully integrated optimization, it requires assuming that DER investments are marginal price takers for avoided costs, though operations for distribution system value may change marginal energy prices (for instance, under different electric vehicle charging patterns). This can be mitigated by rerunning a bulk-grid generation and transmission co-optimization with fixed level and profile for DERs based on the integrated distribution system planning results. Second, it is possible that a value stack of avoided costs across G, T, and D may overestimate the value DERs can simultaneously provide. One example of this is where the provision of distribution deferral services may limit—either technically or contractually—a DER's ability to provide bulk system resource adequacy capacity. This can be addressed in the integrated distribution system planning stage by analyzing the alignment of local-grid needs with bulk system values and performance requirements (such as the critical hours of resource adequacy risk versus the output hours needed to avoid a local-grid upgrade).

Alternative 3: Bulk Grid + DER Optimization with Parameterized Distribution Values

A third alternative approach comes close to the ideal of co-optimizing all four planning domains by way of parameterizing the avoided distribution-grid value of DERs to make co-optimization of generation, transmission, and DERs tractable. This method begins with an assessment of detailed distribution-system capacity needs, using a forecast of loads and an initial forecast of DERs. As detailed in Figure 20 (p. 33), from this assessment one can produce a forecast of hourly marginal distribution system costs. To speed up this data development, this process can rely on a simplified hourly capacity balance of the distribution system instead of more detailed power flow modeling. It can also involve a screening assessment of non-wires alternatives to consider various factors that create or limit deferral opportunities. That forecast can be multiplied by the potential hourly shapes of DERs and/or flexible loads to calculate the marginal distribution-system avoided costs for each DER. The final step to model this value in a system-wide capacity expansion model requires a parameterization of the distribution-system value of each DER type in a manner that is tractable for the expansion optimization.

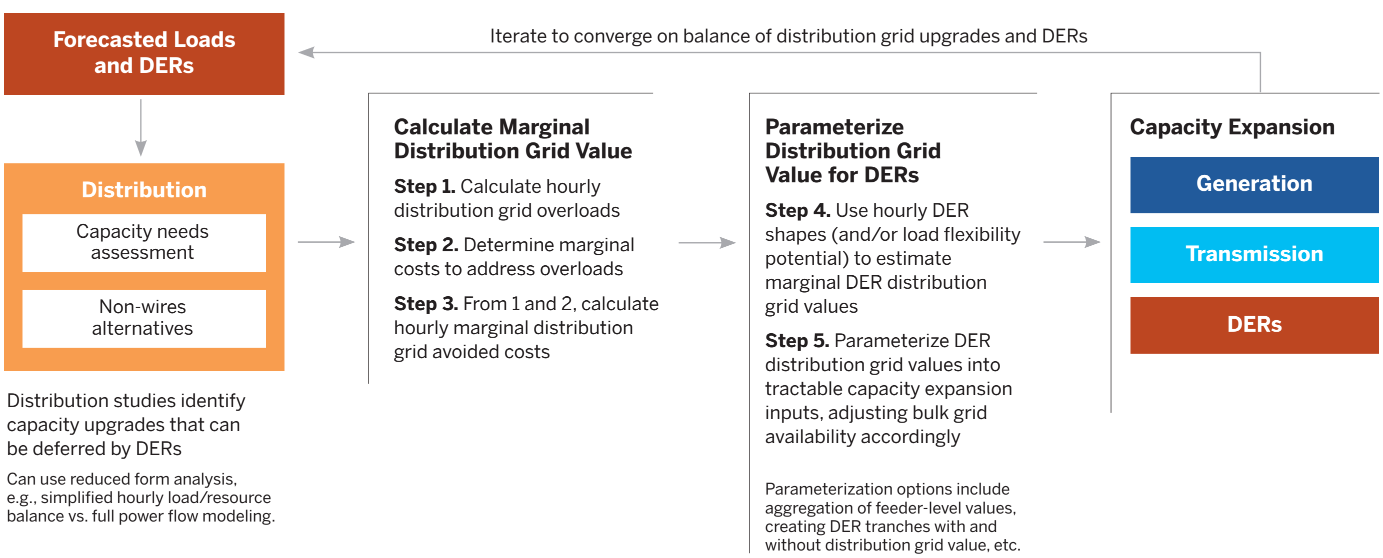
To date, no standardized method to perform the parameterization of granular distribution system values has evolved. One potential method involves aggregating feeder-level distribution avoided costs to a less granular portion of the distribution system and creating two tranches of DERs available within that area—one with avoided distribution costs, capped at the maximum deferrable MW, and another with no avoided distribution costs. This creates a vintaged DER supply curve that matches the maximum avoidable distribution amount and the associated economic value in each year. In theory, this process can iterate between the G+T+C capacity expansion and the distribution analysis to converge on the right balance of DERs versus distribution system investments. For instance, if the starting forecast includes few DERs, then the marginal distribution avoided costs of DER adoption will be relatively high, and many DERs will be selected. If those increased DERs are then fed back into distribution system analyses, then the marginal distribution avoided costs per DER will decline, resulting in fewer DERs being selected. The feedback loop can allow the process to converge on a least-cost mix of distribution upgrades and DERs that support both bulk system and local grid needs.

Conclusions of Bulk + Local Grid Optimization

While full-system capacity expansion optimization presents a theoretically ideal framework for fully integrating bulk and local system planning, some level of simplification is currently required to be computationally tractable for larger systems. This could take the form of simpler optimization with parameterized distribution system values or the use of alternative approaches such as marginal avoided cost–based planning and local-grid optimization with bulk-grid avoided costs. These latter methods leverage existing modeling frameworks to enhance coordination between generation, transmission, and distribution planning without requiring the computational and data-intensive challenges of full endogenization. By improving the flow of information between bulk and distribution system planners, they enable more efficient investment identification and better alignment of DERs with both local and system-wide needs. As we see continued improvement in computational capabilities, optimization techniques, and data availability, these approaches can be further refined to enhance their effectiveness, moving us closer to a more fully integrated electricity system planning process. To facilitate decision-making based on advanced integrated analyses, additional efforts will be needed to overcome institutional barriers, discussed in the next section.

FIGURE 20

Overview of Parameterized Distribution System Values and G+T+C Optimization for Bulk and Local System Coordinated Planning



Note: DER = distributed energy resource.

Source: Energy Systems Integration Group.

Additional Considerations for Integrated Decision-Making

The ESIG report *Foundations of Integrated Planning* presents a four-part integrated planning framework: the integration of inputs, integration of analysis, integration of actions, and integration with decision-making.[6] In the present report, the focus is primarily on the integration of inputs and integration of analysis, considering the opportunities for conducting more comprehensive planning with capacity expansion optimization as a foundation upon which to build. Here, we shift from the technical modeling details to broader questions of what the goal of integrated planning analysis is and what non-technical barriers stand in the way of integrating comprehensive planning analysis with decision-making processes.

This report focuses on the questions, what would a theoretical full-system co-optimization look like?, what are the challenges in doing such a co-optimization?, and what are alternative approaches that move the planning process closer toward that theoretical outcome? Figure 21 (p. 35) shows a schematic of the G+T+D+C solution space, highlighting the "theoretical optimal" planning solution. For clarity this is shown as a two-dimensional curve with the height representing costs and the points representing trade-offs between investment types.[7] As discussed in this report, there are key technical and computational challenges to implementing a single model that can reach this theoretical optimal outcome. Beyond the technical challenges, there are other practical challenges related to risk, uncertainty, feasibility, decision-making processes, and equity considerations.

Integrated planners would do well to focus on making incremental progress in the direction of the "theoretical optimal." Successive planning cycles can build upon past successes, and pilot projects can validate the feasibility of new, more comprehensive planning approaches and their associated operational and commercial models. As is often said, "do not let the perfect be the enemy of the good." In this spirit, a set of recommendations is proposed below within the walk/jog/run framework of incremental change.

Creating an Analytical Plan That Provides the Most Useful Information to Decision-Makers

Even the most sophisticated co-optimization models cannot fully capture all the procedural, institutional, or behavioral factors that influence organizational and individual infrastructure decisions in the real world. Decisions are necessarily made with incomplete information and limited time and resources for analysis. The best analytical plan is the one that provides the most useful

The best analytical plan is the one that provides the most useful information to decision-makers, including identifying a range of plausible solutions with limited impacts on affordability, considering risks and regrets across a range of alternative futures, and considering barriers to implementation or other qualitative factors that may lead to recommending a solution other than a least-cost optimal outcome.

6 https://www.esig.energy/integrated-planning/

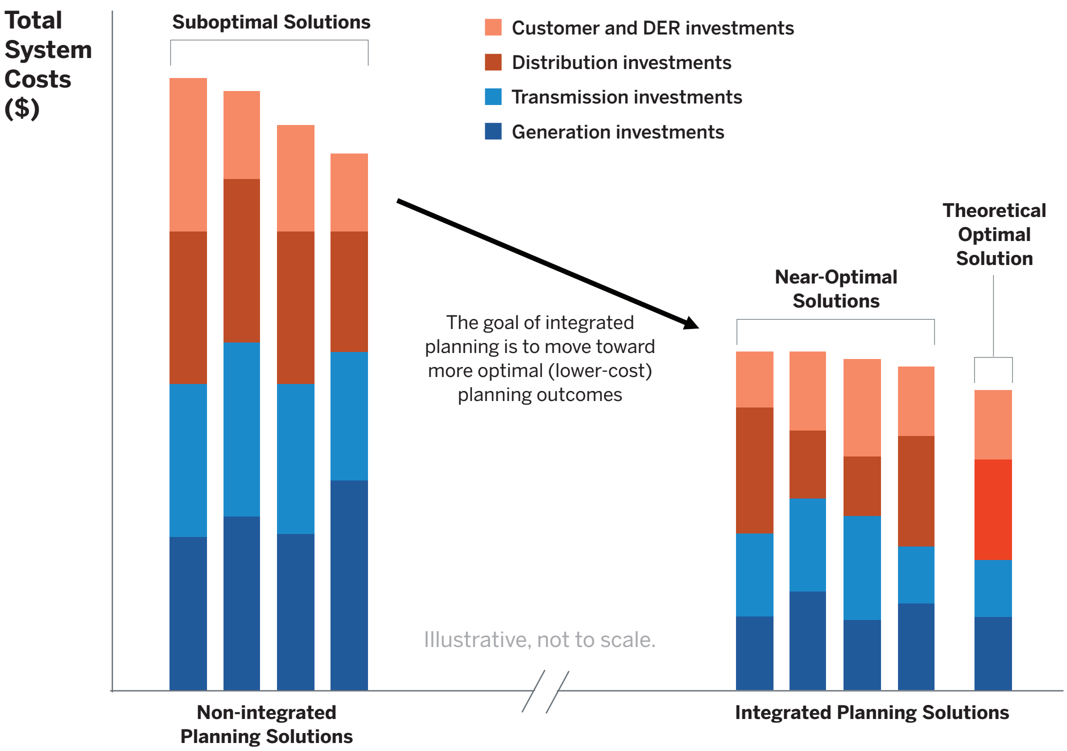
7 Note that the solution space for a full G+T+D+C co-optimization actually has many more than two dimensions of investments options.

information to decision-makers, including identifying a range of plausible solutions with limited impacts on affordability, considering risks and regrets across a range of alternative futures, and considering barriers to implementation or other qualitative factors that may lead to recommending a solution other than a least-cost optimal outcome.

Today, planning efforts often treat models as absolute prescriptive tools that dictate outcomes, leading to an underappreciation of the level of uncertainty in planning inputs, an overconfidence in modeling results, and gaps in understanding of the practical challenges to achieve modeled outcomes. This becomes apparent when examining plans from 5 to 10 years ago versus today's reality. In contrast to that approach, we recommend that planners both increase the technical sophistication of their models as detailed in this report and view models as inputs to a broader decision-making process that account for political, cultural, and institutional factors. Such

FIGURE 21

Integrated Planning Theoretical Optimal and Near-Optimal Solutions



There may be many different "near-optimal" solutions, requiring additional considerations:

- **Technical:** There may be analytical limits of full G+T+D+C co-optimization.
- **Uncertainty:** The optimal plan may be uncertain.
- **Risk:** Some plans are riskier, while other plans are more robust across possible futures.
- **Feasibility:** Feasibility may be affected by value-stacking limits, novel sourcing mechanisms, and build timelines.
- **Decision-making:** Institutional barriers may limit the implementation of the optimal plan.
- **Equity/affordability:** Not only least-cost, but the distribution of costs can also matter.

This diagram shows that (a) integrated planning activities can help move planners closer to the realm of more optimal (lower-cost) solutions, (b) there may be many near-optimal solutions with different investments than the theoretical fully optimized solution, and (c) in addition to the technical challenges of finding the fully optimized solution, decision-making amongst the range of near-optimal solutions requires additional considerations.

Source: Energy Systems Integration Group.

planning environments that treat model outputs as a starting point—and then layer on real-world constraints, stakeholder input, and policy context—will be better positioned to lead successfully to practical implementation of the modeled outcomes.

Designing Planning Processes to Complement Decision-Making Processes

Planning processes in power system planning can be designed to complement the related decision-making processes. As integrated planning inherently stretches across historically siloed planning domains, the solutions identified will also often stretch across disparate decision-making processes and even completely different regulatory regimes (e.g., regulated distribution vs. unregulated generation) or regulatory approval entities (e.g., a state public utilities commission versus a federal agency like FERC in the U.S.). This may call for adjustments to decision-making processes and timelines to allow for the implementation of more comprehensive planning solutions.

An example could be a behind-the-meter battery storage investment identified as providing bulk-grid energy and capacity value as well as local distribution system value. While this may appear a least-cost solution in a set of integrated planning models, many decision-makers across multiple teams or multiple organizations will be involved in approving and then making the investment in the behind-the-meter battery a reality: a distribution planning regulator to approve the resource as a sufficient and cost-effective non-wires alternative, a generation planning regulator to approve its inclusion in a long-term resource plan, retail rate designers to construct the associated retail tariff, wholesale market designers to create the process to capture additional wholesale value beyond what is captured in retail rates, an aggregator to sign up customers and market the associated grid services, and finally the customers themselves, who must agree to install the storage devices and allow them to be used for the grid services identified.

This example shows that even if a comprehensive value-stacked solution is identified in an integrated planning process, there can be important real-world barriers to feasibly implementing that solution. For example, regulatory approval can be a complex maze of venues and proceedings, with different proceedings, different timelines, different stakeholder processes, and different decision-makers in different venues.

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Without solutions to overcome some of the decision-making barriers, integrated planning analyses may be limited in the scope of investments they can ultimately secure. Solutions to overcoming these barriers will depend on local conditions and the regulatory environment, and may include:

- **Process alignment:** Better aligning planning and decision-making processes across planning domains can help facilitate the planning, approval, sourcing, and operations of integrated planning solutions. Alignment can occur across different venues (e.g., public utility commissions vs. FERC) or different proceedings at a single venue.
- **Process consolidation:** When possible, such as for vertically integrated utilities, instead of aligning processes, it can be preferable to simply consolidate them: consolidating decision-making with the integrated planning process would result in a single proceeding with one timeline, one set of stakeholder processes, and one set of decision-makers to approve the full integrated plan.
- **Organizational restructuring:** Sometimes even if external regulatory processes can be harmonized, business processes within an organization can prevent effective and efficient planning and decision-making. In these cases, reorganization may be beneficial.
- **Use of pilot projects to validate novel approaches:** As planners begin to consider more comprehensive and novel ways of integrating across planning domains, there is a need to validate the real-world feasibility of those approaches. Validation may be required for decision-making processes, new technology or operational models, and nascent methods for acquiring planning solutions (e.g., non-wires alternative solicitations). These pilots can support the validation of technologies modeled in planning tools as well as the processes to implement those technologies in the post-planning stage.

Even once these steps have been taken, it may still be the case that planning models can optimize investments across planning silos in ways that are inconsistent with feasible real-world outcomes. The use of a sequenced walk/jog/run approach to both modeling and post-planning implementation activities can facilitate a sustainable rate of change and avoid the modeling process outpacing reality.

Key Takeaways and Suggested Steps for More Integrated Planning Analyses

The use of an expanded capacity expansion modeling framework provides key opportunities for integrated planning as well as challenges. Such a framework offers a more optimal solution across planning needs and reduced iteration between models. The larger, more comprehensive view of potential solutions to system constraints allows the capacity expansion optimization model to determine a lower-cost portfolio and to endogenously identify innovative solutions across planning domains. This enables a platform for exploring innovative approaches such as using DERs as non-wires alternatives, using storage as a transmission resource, and making proactive grid investments in support of new loads. Here we offer key takeaways regarding how capacity expansion optimization modeling can be used for integrated planning and suggest steps for planners to incrementally advance in that direction.

Main Components of Expanded Capacity Expansion Optimization Modeling

For most planners, starting with the integration of bulk-grid investments of generation, storage, and transmission capacity represents the low-hanging fruit. Integrating local-grid needs and DER investments can be done via the multiple practical methods presented in this report. Though a fully integrated capacity expansion optimization for G+T+D+C remains broadly intractable today, combining partial co-optimizations with iterative feedback loops is a tractable alternative.

Generation + Transmission Capacity Expansion Optimization

Bulk-grid capacity expansion optimization methods provide a structured and efficient approach for optimizing generation, storage, and transmission investments across spatially granular regions. By integrating generation and transmission planning, system planners can achieve more cost-effective infrastructure deployment while accounting for key constraints such as resource availability, load growth, and network congestion.

Successful co-optimization will require the development of geographically detailed data sets, including baseline generation and transmission infrastructure, candidate resource options, transmission constraints, and candidate transmission options. The level of spatial granularity used in these models presents an inherent trade-off between precision and computational feasibility. To balance these considerations, planners can use practical methods such as zonal expansion with transmission constraints, pipe-and-bubble grid representations, or full nodal capacity expansion. These methods are not mutually exclusive and can be combined, such as applying a pipe-and-bubble approach with additional transmission zone deliverability limits. Downstream transmission studies will then be needed to validate optimized expansion plans, particularly to assess physical grid constraints and stability dynamics that are not possible to capture in economic capacity expansion modeling.

Bulk Grid + Local System Capacity Expansion Optimization

The optimization can then be extended to include both bulk-grid and local system resources. DERs can be integrated into a G+T co-optimization framework, allowing for an endogenous representation of the bulk-grid investments they can allow planners to avoid. However, it can be difficult to capture local distribution grid values and constraints with sufficient detail to accurately assess the locational costs and benefits of DERs. Key considerations for optimizing DERs and flexible loads include (1) measuring their potential relative to a baseline load forecast where relevant, (2) determining the sufficiency of sourcing mechanisms to achieve the optimized use cases whereby these resources provide maximum value to the full system, and (3) understanding the differences between least-cost optimization and traditional cost-effectiveness methodologies for customer DERs. While full integration—including fully detailed local grid values—remains difficult today, alternative approaches that rely on a marginal avoided cost framework or a parameterization of local-grid values provide the means to consider both bulk-grid avoided costs and local-grid values in DER planning. Using bulk-grid avoided costs within integrated distribution system planning can allow for tractable optimization of local-grid needs by comparing grid upgrade costs against DER costs minus their bulk-grid value.

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Suggested Steps to Move Toward More Optimal Planning Outcomes

Complementing the walk/jog/run framework used in the ESIG *Integrated Planning Guidebook*, a similar framework is presented below in the form of steps to incrementally move integrated planning analyses closer to more optimal planning outcomes.

Walk Phase: Align Objectives, Assess Gaps, and Harmonize Inputs and Scenarios

There are two critical components of beginning the integrated planning journey (Table 4, p. 40). The first is **objective alignment**, which involves holding discussions among the leaders of all involved planning organizations to determine the overall goals of an integrated planning process. These leaders may be executives from within a single large entity performing multiple planning functions (such as a vertically integrated utility), or they may be leaders from multiple organizations whose close coordination is paramount to a successful process. The second key component for getting started is a **gap analysis**. Existing planning processes should be reviewed to identify existing gaps within—or between—processes to bring them to current industry standards.

TABLE 4

Key Elements of the *Walk* Phase

The *Walk* Phase of Full-System Capacity Expansion Modeling of the Electricity System
Convene the leaders of all involved planning organizations to align objectives and determine the overall goals of an integrated planning process
Review existing planning processes to identify existing gaps within—or between—processes
Align key inputs, assumptions, and scenarios across planning processes

Source: Energy Systems Integration Group.

Among the lowest-hanging fruit in the *walk* stage is aligning key inputs, assumptions, and scenarios across planning processes. For instance, a common load and DER forecast (or set of load and DER forecast scenarios) should be used across all resource and grid planning processes. For some entities, this initial alignment may be a crucial first step for their inaugural integrated planning process, setting the foundation to build upon in later stages.

Jog Phase: Data, Model, and Process Development

The *jog* phase addresses the gaps assessed in the *walk* phase (Table 5). This often involves creating new data needed for integrated planning, building new modeling capabilities, and creating an integrated planning process through which these new data can be incorporated into expanded models and decision-making processes. This stage also involves careful examination and potential refinement of planning and decision-making processes, to facilitate real-world implementation of planning processes capable of identifying and securing optimal investments across generation, transmission, distribution, and DERs.

To improve the alignment of loads from the system-level down to each distribution feeder, planners will want to prioritize increasing the spatial granularity of load and DER forecasts. It is important to develop geospatially granular load and DER forecasts, informed by emerging statistical or machine learning–based methods. This can be done for specific transmission and distribution system locations in order to have a more precise representation of system needs and support the integration of generation and DER planning with transmission and distribution grid needs.

TABLE 5

Key Elements of the *Jog* Phase

The *Jog* Phase of Full-System Capacity Expansion Modeling of the Electricity System
Data and Model Development
Create new data needed for integrated planning including enhanced spatial granularity of load and DER forecasts, enhanced spatial resolution of candidate resource options, and candidate grid upgrades as investment options
Build new modeling capabilities including making generation and transmission co-optimization a standard practice
Process Refinement
Create an integrated planning process through which these new data can be incorporated into expanded models and decision-making processes
Carefully examine and potentially refine planning and decision-making processes
Increase the planning horizon of distribution planning processes, identify locationally defined grid needs, use hourly data to identify hourly overload amounts, and identify marginal distribution system costs

Source: Energy Systems Integration Group.

These analyses can support more proactive investments in new grid capacity. In support of this, distribution planning processes can increase their planning horizons, identify locationally defined grid needs, use hourly data to identify hourly overload amounts, and identify marginal distribution system costs. This type of granular grid-needs data is foundational to implementing any of the integrated planning approaches outlined in this report.

Planners can also enhance the spatial resolution of candidate resource options by using GIS-based tools to map new generation and storage resource options, incorporate realistic land use constraints and related feasibility screens, and link these resource options to specific grid interconnection points. With this spatial detail, planners can develop associated grid upgrade needs as candidate investment options to facilitate co-optimization.

For bulk system capacity expansion modeling, integrating generation and transmission co-optimization should become standard practice. By leveraging insights from transmission studies, including remote resource deliverability assessments and candidate transmission expansion projects, planners can move toward more efficient G+T co-optimization frameworks. The exact level of co-optimization reached will differ in each planning process, but creating a process for co-optimizing generation, transmission, and storage siting provides significant benefits for achieving a lower-cost comprehensive planning solution.

Developing an integrated planning process can support linking of previously siloed analyses. These links within and/or between organizations serve as the means to pass information between people and models. Model outputs from one process, such as avoided costs or candidate transmission upgrades, can serve as inputs into other processes to facilitate identification of comprehensive planning solutions.

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Run Phase: Fully Integrated Planning Analyses

As planners approach the final phase of integrated planning, they will have new data available and new modeling capabilities to support advanced and/or novel analyses. In the *run* stage, planners will use expanded capacity expansion optimization models and/or tightly coupled iterative processes to coordinate investments across generation, transmission, distribution, and customer loads and DERs (Table 6). As outlined in this report, this may include either varying degrees of combined optimization or carefully designed iterative loops between planning processes; either process can be sufficient.

DER and customer program planners will need to carefully evaluate the appropriateness of DER co-optimization or iterative processes within their planning processes. Some DERs may be more effectively forecasted based on customer adoption propensity, while others may be better suited for direct optimization against bulk-grid resource options within capacity expansion models.

TABLE 6

Key Elements of the *Run* Phase

The *Run* Phase of Full-System Capacity Expansion Modeling of the Electricity System
Use expanded capacity expansion optimization models and/or tightly coupled iterative processes to coordinate investments across generation, transmission, distribution, and customer loads and DERs
Consider DER co-optimization or iterative processes for DER and customer program planning that ensure consistent valuation of supply- and demand-side resources
Consider locational grid needs and related DER investment opportunities, such as distribution deferral
Use a comprehensive avoided-cost framework to inform retail rate design and align customer incentives with grid needs

Source: Energy Systems Integration Group.

Subject to data availability and scalable sourcing models, planners aiming to optimize the value of DERs should consider locational grid needs (such as distribution deferral), which for large systems likely need to be parameterized into a reduced form to fit into a capacity expansion optimization. DERs forecasted using cost-effectiveness tests should use hourly avoided costs or related methods to include bulk-grid value in DER valuation and forecasting. Avoided costs can also inform retail rate design to align customer incentives with grid needs.

Finally, distribution system planners should explore integrated distribution + DER system planning methods that incorporate the value of DERs for the bulk grid.

While these steps will require additional data development and new types of creative thinking, they are feasible to implement in today's planning models. As computational capabilities and new methods evolve, more advanced approaches may become practical, including full-system capacity expansion optimization, new optimization frameworks, and/or automated multi-model approaches. By taking the steps outlined here, energy system planners can advance the integration of generation, transmission, distribution, and customer DER planning, paving the way for a more integrated electricity system that supports the development of a reliable and affordable 21st century power system.

Optimization for Integrated Electricity System Planning: Opportunities for Integrated Planning in Capacity Expansion Models

A Report by the Energy Systems Integration Group's Integrated Planning Task Force

This report and its companion reports are available at https://www.esig.energy/integrated-planning/.

To learn more about ESIG's work on this topic, please send an email to info@esig.energy.

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

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