ESIG
Large Loads
Task Force

Transmission Planning with Large Loads

CURRENT PRACTICES AND RECOMMENDATIONS

A Report by the
Energy Systems Integration Group's
Large Loads Task Force

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Transmission Planning with Large Loads: Current Practices and Recommendations

A Report by the Energy Systems Integration Group's Large Loads Task Force

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Disclaimer

This report was produced by a project team 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.

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PHOTOS

Preface to ESIG Large Loads Task Force Reports

This report is one of 11 reports by the ESIG Large Loads Task Force, which was formed to assist the power industry in addressing new challenges introduced by the rapid proliferation of large electronic loads such as data centers, as well as other large loads including manufacturing, electric vehicle fleets, and hydrogen production. The titles of the reports are as follows:

- Grid Integration of Large Loads: Introduction to the Large Loads Task Force, Data Needs, and Flexibility
- Forecasting for Large Loads: Current Practices and Recommendations
- Interconnection Processes for Large Loads: Current Practices and Recommendations
- Large Load Performance Requirements: Current Practices and Recommendations
- Large Loads: Behaviors, Capabilities, and Limitations
- Reliability Impacts of Large Loads
- Large Load Disturbance Events
- Large Load Modeling for Dynamic Studies: Current Practices and Recommendations
- Transmission Planning with Large Loads: Current Practices and Recommendations
- Resource Adequacy with Large Loads: Planning for Flexibility to Accelerate Integration
- Wholesale Market Design and Operations for Systems with Large Loads: Current Practices and Recommendations

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Executive Summary

Electricity systems across the United States are experiencing a surge of proposed large loads that is materially different in both scale and speed from historical load growth. These new loads include data centers, artificial intelligence (AI) facilities, advanced manufacturing, and other large electricity users. The pace, scale, geographical concentration, and uncertainty associated with large load development are placing unprecedented pressure on transmission planning processes, which were largely designed around slower, more incremental patterns of load growth.

Unlike historical loads, new large loads often seek interconnection within a few years, far faster than transmission planning, permitting, and construction timelines can typically support. Some large load facilities can reach gigawatt scale, cluster in the same areas, and materially affect local and regional system needs. In addition, many proposed projects may not ultimately materialize, and the operating characteristics of completed projects can introduce additional uncertainty for planners. In many regions, near-term interconnection and reliability needs are increasingly driving large, expensive, and long-lasting transmission investments that may solve immediate problems but do not create durable headroom for other new loads and generators or address long-term transmission needs.

The dramatic growth in large load interconnection requests calls for a new approach to transmission planning. This report from the ESIG Large Loads Task Force's transmission planning project team examines how large loads are exposing structural weaknesses in current transmission planning and offers practical steps to shift planning from reactive responses to more integrated, durable, cost-effective outcomes.

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Why Current Planning Processes Are Not Well Suited to Large Load Growth

Much of the current transmission planning effort in the United States is focused on meeting regional reliability and load-growth needs over a 10-year horizon following applicable North American Electric Reliability Corporation (NERC) and regional planning criteria.

Because these processes are designed to address immediate study needs and usually do not weigh broader system costs and benefits, they tend to select the lowest-cost project that solves the immediate and specific transmission need, even when a different solution would provide greater overall system value. More than 90% of transmission investment is still driven by these near-term, reliability-at-the-lowest-cost planning processes rather than through proactive, long-range, multi-value planning processes.

Under traditional load growth conditions, this combination of near-term reliability planning, separate interconnection studies, and project-by-project transmission development worked reasonably well for discrete, localized needs. Large loads strain current planning processes because they can trigger broader regional needs and require

trade-offs across longer planning horizons, larger geographies, and a wider range of solution types.

Three Structural Challenges

Silos

Transmission planning in the United States is fragmented by function, time horizon, study method, and institutional and geographical boundaries. Load interconnection, generator interconnection, reliability planning, economic studies, asset management, and long-range planning often are separate planning processes with different timelines, tools, assumptions, and decision paths. The fragmentation of transmission planning extends across jurisdictions and geographies. Utilities, regional transmission organizations (RTOs) and independent system operators (ISOs), and state agencies operate with different responsibilities and approval paths.

The impact of a proposed large load can extend across a regional system and affect several of these planning functions. The same system need can therefore be examined several times in different ways by different teams on different schedules without producing one clear, comprehensive transmission plan for the area. The lack of planning consistency and communication across the planning silos makes it easier to move forward with the transmission projects developed to address the initial need—typically narrower-scope, local projects—rather than broader regional solutions that can provide greater overall value. Broader solutions avoid a string of piecemeal incremental upgrades that would come at a higher total cost.

Timing Mismatch

Large load development timelines, especially for data centers, are often measured in months to a few years. By contrast, transmission planning and development operates on 5- to 10-year planning, regulatory, siting, and construction timelines. This timing discrepancy leaves transmission planning largely reactionary and constantly in catch-up mode, which can bias planners toward projects that can move most quickly through the clearest study frame and approval path. That pressure can make near-term, narrowly scoped interconnection or local reliability fixes more likely, even when the underlying needs are broader and longer term.

Uncertainty

Large loads introduce a radically different level of planning uncertainty, one that current planning processes cannot address. Large load development is lumpy, location-specific, fast-moving, and highly contingent on commercial, technological, and policy decisions outside the control (and sometimes knowledge) of system planners. The result is substantial uncertainty about ultimate transmission needs, facility development rates, locations, configurations, and the extent of co-located generation/storage or self-supply. This makes it very difficult to establish a base case demand forecast and difficult to determine how much, when, and where transmission will be needed.

Updating Planning Practices to Meet the Needs of Both Large Loads and the Grid

These planning deficiencies are structural and call for a range of responses that can be implemented on different timelines. Some actions can be taken now to improve visibility into where the grid can serve load, make better use of existing capacity, and reduce the risk that near-term decisions lock in poor long-term outcomes. Other changes require more substantial adjustments to planning methods, study assumptions, and transmission development practices.

Urgent Actions

Determine and Make Visible Where the Grid Can Serve New Large Loads–Now and in the Future

Large load planning benefits from a clear view of where the grid can serve new loads now, where that capability can be expanded quickly, and how those near-term actions fit into likely longer-term transmission development. Headroom studies and system-capacity maps can make that information visible by distinguishing between transmission capacity available now and capacity that could be created quickly with targeted actions. This information can steer large load requests toward locations that are more likely to be workable and reduce the likelihood that the same system limitations are rediscovered through multiple serial project interconnection requests.

Use Tools to Expand Fast-Service Options

Advanced transmission technologies can complement new transmission lines by creating near-term capacity and expanding interconnection headroom while larger transmission solutions are still being planned, permitted, and built. Operational tools, including remedial action schemes, can also increase effective headroom or usable transfer capability under defined conditions on either a temporary (bridge) or a permanent basis. These measures belong in the candidate solution set alongside more conventional transmission options.

Short-lead-time measures are most useful when they help address near-term needs while preserving room for efficient long-term solutions.

Make Co-location and Load Flexibility Real, Visible, and Usable

Large load flexibility, co-location with generation and storage, and self-supply can reduce transmission upgrade requirements, accelerate transmission service, and create a more manageable operating envelope, but only if those characteristics are clearly defined, visible, controllable, and enforceable in grid operations and the interconnection and transmission planning studies that rely on them.

Large load flexibility and options for co-located resources can be included in planning assumptions only when they are operationally credible and reflected in operating procedures, interconnection agreements, and applicable tariff and market rules. These arrangements can materially increase interconnection headroom and reduce the need for transmission expansion. As such, planners need to prioritize codification of the grid-operating rules defining large load flexibility and co-located resources.

Use a Coordinated Set of Assumptions and Information Across Studies

Current planning for large loads breaks down in part because different planning functions often use different study assumptions, have disconnected workflows, and address different versions of the same underlying problem. A coordinated planning response requires one set of facts: shared assumptions, shared data, and shared cases. Planners across different functions can work to develop a common large load dataset, common scenario definitions across studies, and linked analytical workflows across interconnection studies, reliability planning, economic studies, and longer-horizon planning.

Using a common assumptions log, a needs-and-constraints list, and a large-load data repository can help align studies across planning functions, enabling comparisons of multiple transmission solutions and supporting the selection of a more consistent regional portfolio solution.

Near-Term Fixes

In addition to the immediate actions listed above, planners need methods that can test multiple plausible futures, identify scalable options, and compare how different transmission strategies perform when realized conditions differ from expectations.

Use Scenario-Based and Least-Regrets Planning

Scenario planning can explicitly address the uncertainty posed by large load development by testing how transmission plans perform across a range of plausible futures. A least-regrets approach allows for the selection of solutions that perform well across several plausible futures while limiting negative consequences when reality diverges from expectations. Flexible, scalable transmission solutions can be designed to preserve options rather than narrow them.

In fast-growing areas, planners need to assess whether proposed solutions are effective across a range of plausible futures and whether the consequences of underbuilding may outweigh the cost of spending more at the outset. These trade-offs can be quantified using a scenario-based least-regrets planning framework, which can compare serial local fixes, staged regional reinforcements, larger regional or more flexible solutions, and combinations of transmission and operating measures.

Design Near-Term Projects for More Robust Long-Term Outcomes

Upgrades to address near-term needs must be tested not only for whether they solve the first identified constraint but also for how well they preserve cost-effective expansion paths if load growth continues, clusters more tightly, or materializes faster than expected. The cost of responding to uncertain large load build-outs can be reduced through more flexible solutions, such as staged construction, higher-voltage-ready structures, transmission paths and substations designed for future expansion, and technologies that can be repurposed or augmented over time. A "future-fit" check can help keep a near-term transmission project from inefficiently limiting future options by testing whether it preserves attractive expansion opportunities if load in the area continues to grow.

Longer-Term Structural Solutions

New large loads are often large enough, fast enough, and uncertain enough that the planning process needs to be able to identify longer-term comprehensive transmission needs before repeated project-level decisions lock in inefficient outcomes.

Shift from Project-by-Project Upgrades to Proactive Long-Term Planning

Transmission planning should evaluate near- and longer-term, region-wide transmission needs more comprehensively across multiple planning processes. The Midcontinent Independent System Operator's (MISO's) Long Range Transmission Planning process is an example of a study that evaluates multiple transmission needs over a 20-year horizon on a multi-benefit basis. A similar approach can be applied to planning for large loads, using robust scenario development and analysis of least-regrets transmission solutions. Scenario-based, multi-benefit, long-term planning is also required by Federal Energy Regulatory Commission (FERC) Order 1920.

Reducing the separation between siloed planning functions is a related but distinct improvement. The

Southwest Power Pool's (SPP's) proposed Consolidated Planning Process is one example of a more explicit effort to bring the different planning tracks together. Full consolidation is not the only way to improve the process, though. Stronger coordination, shared assumptions, better hand-offs, and broader evaluation across existing planning processes can also move regions in the right direction. Together, these changes can move planning away from repeated short-term fixes and toward transmission solutions that better meet overall system needs.

Use Location Signals and Development Zones to Guide Growth

Consideration of the interplay between planning decisions and future large load interconnection requests can reduce unrealistic queue growth, improve siting decisions, and distinguish between places where load can be served now, where near-term tools can create access, and where larger transmission development will still be required.

States, utilities, RTOs/ISOs, transmission owners, regulators, and other stakeholders can work together to identify likely large load development zones and support development of the transmission capacity needed to proactively meet future interconnection requests in these locations. Texas's Competitive Renewable Energy Zones (CREZ) process provides an example of such a locational-development approach. The CREZ process identified generation development areas in advance and proactively built transmission to reach them, rather than waiting to serve projects one interconnection request at a time. The highly localized clustering of large load interconnection requests suggests that a similar approach could support more timely, cost-effective transmission solutions for large loads.

Use Comprehensive and Coordinated Planning to Inform Transmission Decisions

More efficient, coordinated, and consolidated processes can preserve planners' ability to evaluate scalable, multi-driver solutions instead of relying on incremental fixes that narrow the options for more efficient future grid solutions. Multi-driver, multi-benefit, and portfolio-level evaluations are especially useful when the same part of the system is simultaneously affected by reliability, interconnection, congestion, resilience, and broader regional needs.

Regional and interregional transmission solutions can create significant transmission capacity for load and generator interconnections, address future transmission needs, reduce congestion and losses, improve resilience, and reduce regional resource adequacy requirements. The Joint Targeted Interconnection Queue study by SPP and MISO illustrates this point. It identified upgrades to support 9 GW of existing generator interconnection requests and enable another 20 GW near the seam at about half the cost of the regions' more incremental queue-driven processes. MISO's long-range multi-value portfolios provide another example of broader, multi-benefit evaluation, with estimated benefit-cost ratios of 1.8 to 3.8 and support for roughly 136 GW of generation.

A More Proactive, Coordinated, Long-Term Approach

Large loads do not simply create more demand. Their size, speed, concentration, uncertainty, and configurations require fundamental changes to grid planning. Meeting these new challenges necessitates transmission planning processes that can address near-term needs without losing sight of the longer-term system they are shaping.

Introduction to Transmission Planning and Large Loads

Electricity systems across the United States are experiencing a surge of interconnection requests from large loads that is materially different in both scale and speed from historical load growth. These new loads include data centers, artificial intelligence (AI) facilities, advanced manufacturing, and others. The pace and scale of their development, their geographical concentration, and the uncertainty around each of these dimensions are placing unprecedented pressure on transmission planning processes, which were largely designed around slower, more incremental patterns of load growth. Existing planning processes are struggling to accommodate these requests, and near-term interconnection and reliability needs are increasingly driving large, expensive transmission investments, with long-lasting consequences. These investments may be planned around the immediate request without fully considering broader and longer-term system needs.

New large load requests differ from historical load growth in several important ways. These new customers often seek interconnection within a few years, far faster than transmission planning, permitting, and construction timelines can typically support. Some facilities, particularly data centers and AI facilities, can exceed a gigawatt in scale and can materially affect local and regional power flows, voltage performance, and resource adequacy. Their development is often geographically concentrated, but many proposed projects may not ultimately materialize, creating significant uncertainty for planners. In addition, many large loads have complex operational characteristics, including power electronics–based interfaces and dynamic demand profiles. Together, these factors complicate both forecasting and planning decisions, as planners must assess how to serve many gigawatts of prospective load while maintaining reliability, controlling costs, and avoiding stranded transmission investments.[1]

Utility forecasts indicate that U.S. electricity use will increase by about a third by 2030, with data centers accounting for about 55% of peak-demand growth (Wilson et al., 2025). Lawrence Berkeley National Laboratory also estimates that data centers' share of U.S. electricity use could reach 15.3% by 2030, up from 4.7% in 2024 (Smith et al., 2026). Figure 1 (p. 2) illustrates the geographical concentration of the large load challenge (Fletcher, 2025). Since data centers account for the majority of new large load interconnection requests, this report primarily addresses the challenge of planning for this type of large load, but the discussion here applies to all large loads.

The Role of Transmission Planning in Effective Large Load Integration

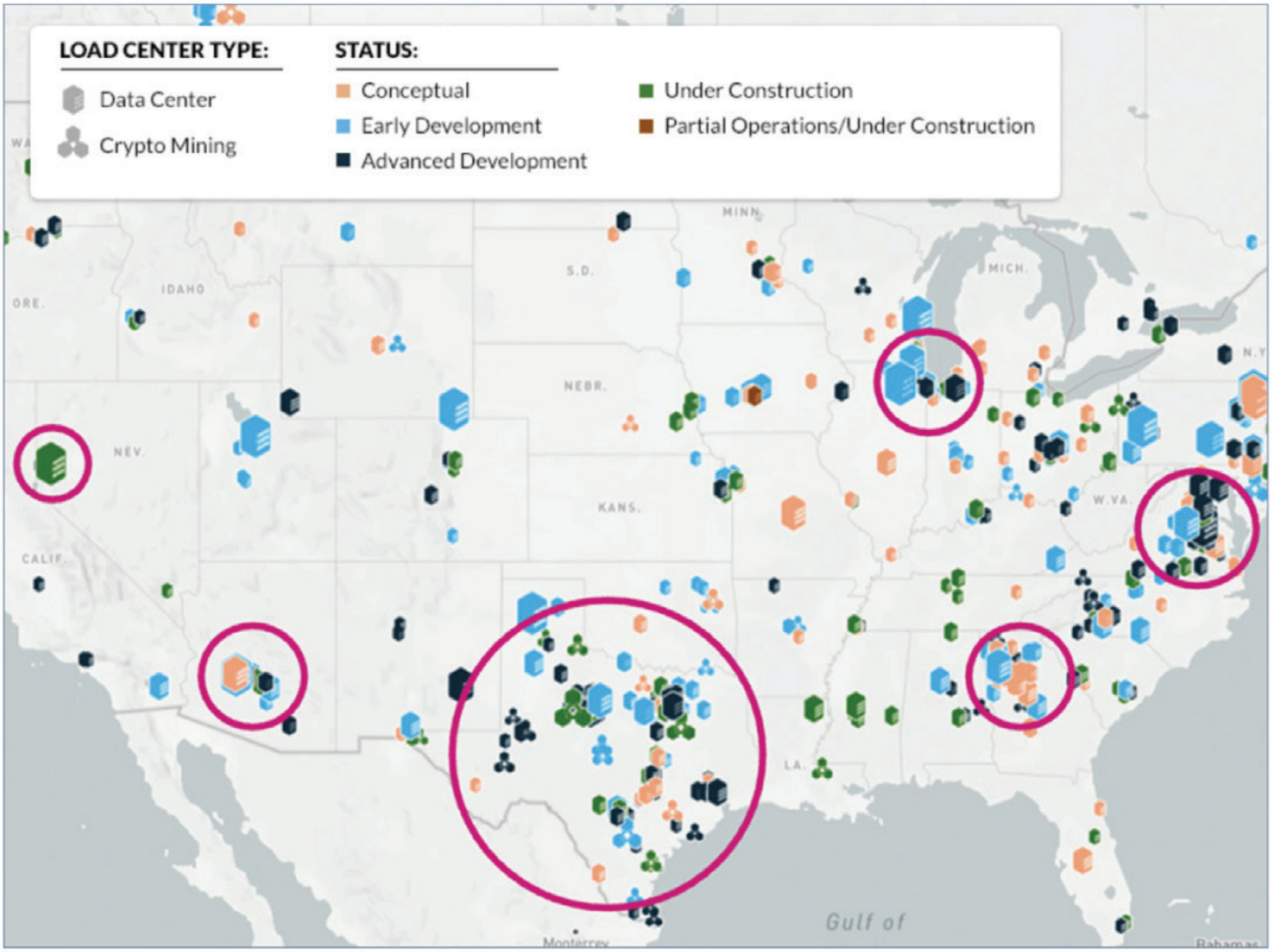
Transmission plays a critical role in meeting the electricity needs of all generation and end-use customers, connecting customers and allowing grid operators to operate the grid securely and reliably. If transmission capacity is insufficient, the result can be power outages, possible damage to customer and generator facilities, and potential delays in connecting new loads and generators.[2] The grid is able to reliably serve predicted levels of new load and generation using both excess transmission capacity and timely transmission expansion. But if the transmission system is

1 See the ESIG white paper "Historical and Modern Large Loads: Characteristics, Context, and Industry Actions to Meet Grid and Customer Needs," https://www.esig.energy/reports-briefs/historical-and-modern-large-loads.

2 Most state and federal utility regulatory regimes give utilities an obligation to serve every customer, but to date they do not impose that requirement upon customer loads that have not yet been interconnected to the transmission or distribution system, nor do they place a time limit on how quickly new customer loads must be served.

FIGURE 1

High Levels of Geographically Concentrated Data Center Grid Interconnection Demand, as of December 2025

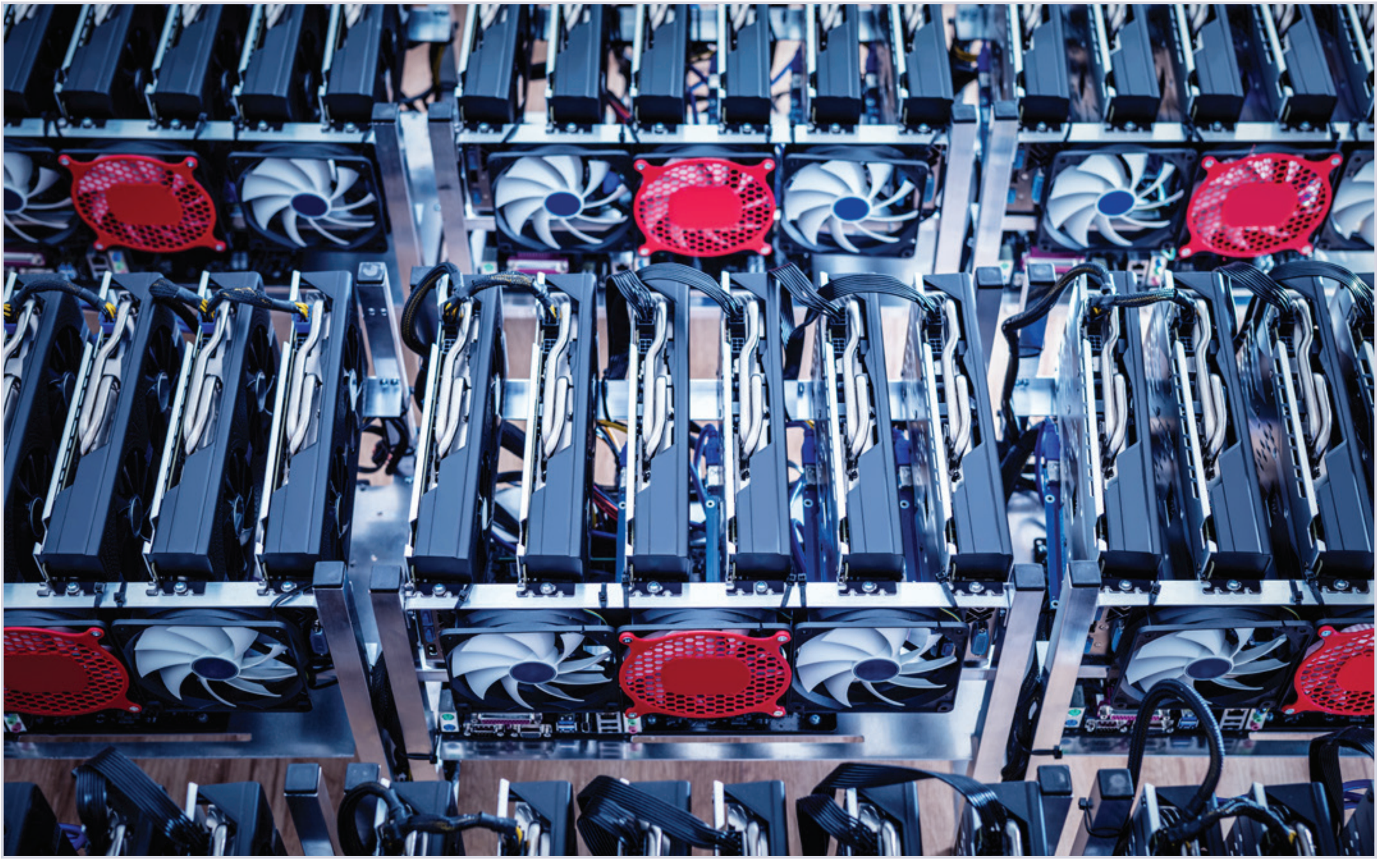


Source: Yes Energy's Infrastructure Insights, https://www.yesenergy.com/products/infrastructure-insights.

not expanded proactively as new loads and generators are added, reliability problems can arise during high-demand periods such as winter or summer peaks. Insufficient transmission capacity can also increase congestion costs, raising the cost of delivered energy to consumers. Many studies have affirmed the value of and need to expand the nation's transmission system to serve new demand, integrate additional resources, and support grid reliability (Mai et al., 2026a).

Transmission planning decisions, however, must be made well in advance of actual system needs because new transmission projects can take up to a decade to plan and build. Transmission investments are often expensive and construction slow, and new lines require rights-of-way that may displace other land uses, so poor planning decisions can be costly. Investments in new transmission require thoughtful analysis of need, costs, and societal benefits.[3]

3 Transmission system designs, infrastructure builds, and performance are closely regulated by state and federal agencies and subject to strict consensus-based reliability standards developed and administered by the North American Electric Reliability Corporation. Transmission owners and regional grid operators must adhere closely to these standards. If through evolving conditions or insufficient effort a transmission owner or grid operator finds that it is violating one or more of these standards, it must cure each violation promptly, both to protect the bulk power system and to avoid compliance penalties.



In past decades, relatively slow growth in customer demand gave transmission planners adequate time to plan for the expected system needs over a 3- to 10-year time horizon. In many regions, utilities rely on near-term studies to identify the lowest-cost transmission solutions within their footprint to address defined, localized reliability issues. Long-term planning studies may be conducted to assess potential future system needs, but these studies are used primarily to inform near-term utility infrastructure plans. Existing processes often do not evaluate broader system costs, future interconnection needs, or ways that near-term fixes may constrain longer-term outcomes.[4]

The proliferation of new large load project interconnection requests exacerbates the deficiencies of these local, piecemeal approaches and is contributing to disruptions in the balance between current planning practices and a rapidly evolving grid. The dramatic growth in large load interconnection requests calls for a new approach to transmission planning specifically designed to proactively meet the needs of new large load customers.

Report Organization

The ESIG Large Loads Task Force examined how large loads are exposing structural weaknesses in current transmission planning and identified practical steps that can move planning from reactive responses toward more integrated, durable, cost-effective outcomes. This report focuses on three central challenges: siloed planning processes, timing mismatches between large load development and transmission expansion, and uncertainty about the scale, location, and operational characteristics of future demand. It also examines the roles of load flexibility, co-location, and interregional planning, and concludes with recommended planning practices.

4 See Energy Systems Integration Group, *Modernizing Transmission Planning: Integrating Silos to Deliver Multi-Driver, Multi-Value Outcomes*, a report by the Integrating Transmission Silos Task Force, December 2025, https://www.esig.energy/wp-content/uploads/2025/12/ESIG-Integrating-Transmission-Silos-report-2025.pdf.

Overview of Existing Transmission Planning Processes

Much of the current transmission planning effort in the United States focuses on meeting local and regional reliability and load-growth needs over roughly a 10-year horizon, in accordance with applicable North American Electric Reliability Corporation (NERC) and regional planning criteria. These reliability studies typically analyze transmission adequacy using a base case forecast of demand growth and resource changes under a limited set of stressed system conditions (such as summer and winter peak hours). These analyses are used to develop actionable transmission plans that meet current reliability criteria. Over the last decade, as NERC planning requirements have expanded, planning organizations have devoted more study capacity to meet those requirements and avoid NERC compliance penalties.

Transmission owners and regional planning organizations conduct parallel studies to determine how to integrate new supply resources and new demand customers. In many regions, long-term studies, interregional studies, and other efforts complement these core reliability planning studies.

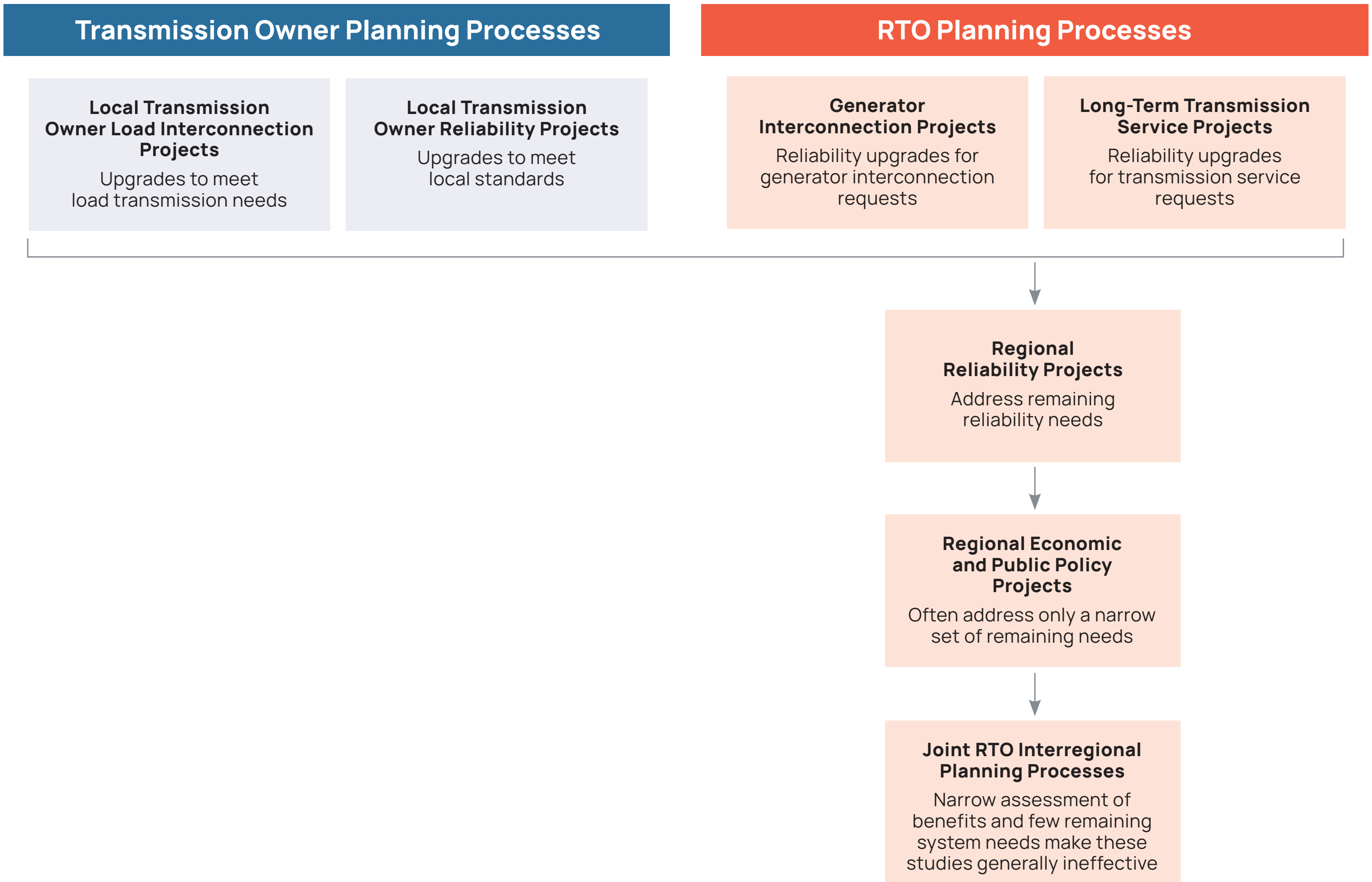
Reliability-Driven Approach Focused on Localized Near- and Medium-Term Needs

Transmission planning processes vary by region, but generally follow the process illustrated in Figure 2 (p. 5). In independent system operator (ISO) and regional transmission organization (RTO) regions, the reliability-driven planning processes in the first two rows of Figure 2 are focused either on responding to load or generation interconnection requests or on addressing near- and medium-term reliability needs. Outside of ISOs/RTOs, many of the same planning functions are performed by transmission owners with some coordination through regional transmission planning organizations.

At present, in most regions, the local and regional reliability projects planned through the channels shown in the first and second rows of Figure 2 account for more than 90% of the approximately $25 to $30 billion invested each year on new transmission across the U.S. (Pfeifenberger, 2025a). These transmission planning processes evaluate project costs but typically do not assess broader grid-wide costs and benefits. As a result, most current planning studies identify the lowest-cost project for the specific system need under study rather than identify the most cost-effective and highest-value transmission, supply, and demand solutions. Under historical load-growth conditions, these reliability-driven planning frameworks conducted by the local transmission owner worked reasonably well for discrete, localized, near-term reliability needs.

FIGURE 2

Illustration of Separate Planning Tracks and the Sequential Evaluation of Transmission Needs in Regional Transmission Organizations



Transmission needs are often evaluated through separate local and regional study tracks, which can narrow the set of options considered before broader regional or interregional solutions are evaluated.

Source: Pfeifenberger, J. P., K. Spokas, J. M. Hagerty, and J. Tsoukalis, *A Roadmap to Improved Interregional Transmission Planning* (The Brattle Group, 2021), https://www.brattle.com/insights-events/publications/brattle-economists-author-report-on-the-benefits-of-expanding-interregional-transmission/.

These same largely reactive and piecemeal transmission planning processes form the default planning framework for handling large loads interconnection today.[5] Current regulatory and planning structures tend to encourage the development of interconnection solutions by local utilities through siloed processes. Utilities are obligated to study the impacts of new customers on the grid, and they understand the customers' desired interconnection time-lines. However, large loads strain that approach because they can trigger broader regional needs and require trade-offs across longer planning horizons, larger geographies, and a wider range of solution types.

Only a few regions have mature long-term, multi-value planning processes. And even where broader, proactive planning exists, it is often not well connected to the near-term planning tracks where large load requests are evaluated and where upgrade decisions are often made. The emphasis on near-term planning is likely to continue to drive most large load–related transmission decisions

5 This planning focus on the near and medium term and base cases will have to expand since the recent adoption of FERC Order 1920, which requires performance of multi-value benefit-cost analysis using scenario analysis. This is discussed on page 6.

until local planning tracks are better coordinated or integrated with longer-term, region-wide, multi-value processes that address large load needs along with grid reliability and economics.

Given the large size of some new loads, even a single large load interconnection request can trigger significant regional network upgrades, including new extra-high-voltage transmission. Projects of this scale often cannot be integrated into the grid by an individual utility using existing near-term reliability and interconnection processes because the grid impacts from this one customer request can extend well beyond the utility's service territory. Even so, many large load interconnection decisions are currently being made at the local level rather than through a coordinated assessment of regional or even interregional system needs.

Figure 3 shows that most transmission projects completed in 2024 were at a voltage of 138 kV or below, likely designed to meet localized reliability needs or interconnect new generation (FERC, 2025a).

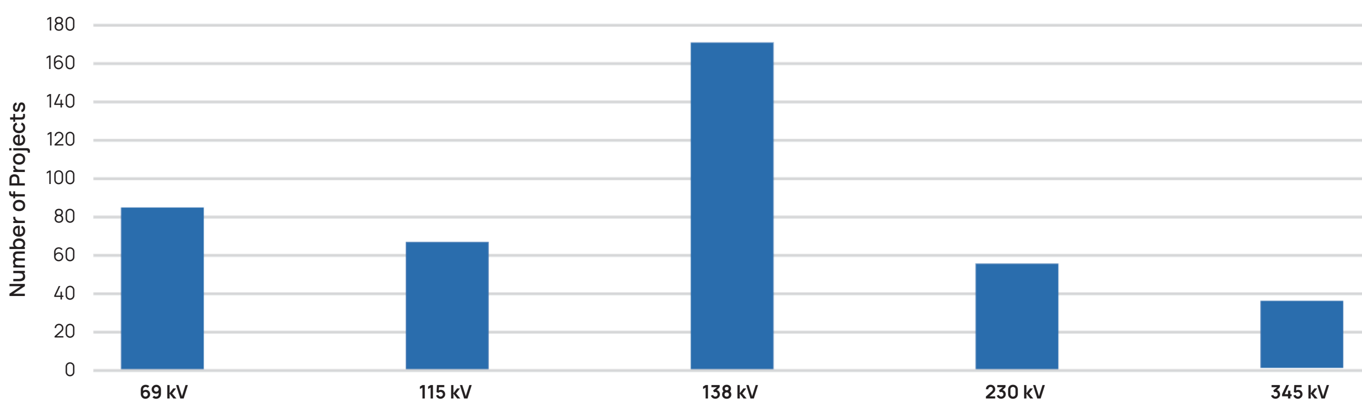
Planners are beginning to see that current planning processes are inadequate to meet the challenges presented by the recent wave of large load interconnection requests, that the current reliance on incremental upgrades alone is insufficient, and that planners and planning processes need to increasingly focus on larger regional solutions to meet emerging grid needs.

The emphasis on near-term planning is likely to continue to drive most large load-related transmission decisions until local planning tracks are better coordinated or integrated with longer-term, region-wide, multi-value processes that address large load needs along with grid reliability and economics.

Regulatory requirements are changing as well. FERC Order 1920, adopted in May 2024, requires regions to conduct long-range planning with at least three defined scenarios, quantify seven types of benefits for identified projects, and define a pathway for projects identified in the long-range planning to potentially be endorsed for completion (FERC, 2025a).

Many of the requirements in FERC Order 1920 build on existing examples of long-term, multi-driver planning for broader regional economic and public policy objectives. While these examples account for only a small share of most regions' total transmission investments, they provide promising practices that can be formalized and more widely implemented, as discussed below. These include the California Independent System Operator's (CAISO's) Comprehensive Transmission Planning Process, with economic benefits evaluated through its Transmission Economic Assessment Methodology; Southwest Power

FIGURE 3
2024 Transmission Projects by Voltage



Source: YesEnergy—Infrastructure Insights: Electric Transmission and Distribution Database; published in Federal Energy Regulatory Commission, *2024 State of the Markets,* 2025, https://www.ferc.gov/media/state-markets-report-2024.

Pool's (SPP's) Integrated Transmission Planning process; the Midcontinent Independent System Operator's (MISO's) Multi-Value Project and Long-Range Transmission Planning processes; the Electric Reliability Council of Texas's (ERCOT's) Competitive Renewable Energy Zones, 2024 Regional Transmission Plan (RTP) 345 kV Plan, and Texas 765 kV Strategic Transmission Expansion Plan (ERCOT 2025a); and New York's Public Policy Transmission Planning Process (Pfeifenberger et al., 2021b). Recent planning cycles have approved major transmission facilities, including new 500 kV and 765 kV lines and at least one high-voltage DC (HVDC) project, in part to address emerging system needs associated with rapid load growth.[6]

Nevertheless, even when long-term needs are addressed more proactively and comprehensively, near-term reliability and interconnection needs are still addressed through separate functional planning processes at individual utilities that typically do not consider long-term needs or impacts on costs beyond the immediate project being studied. Even in areas where these studies are reviewed by staff at a regional planning organization, the grid interconnection department is likely siloed from other planning staff. As a result, broader long-range and economic planning processes typically operate behind, rather than in place or ahead of, the near-term reliability and interconnection processes that determine load-driven transmission projects.

Cost Allocation of Transmission Projects

Many of the changes in planning procedures recommended in this report will likely require reconsideration of some cost allocation policies. In many regions, the reason a transmission project is needed determines which customer(s) will pay for the project. Because the siloed planning process is what establishes that need, it effectively determines who pays for it. Transmission cost allocation is an important regulatory consideration that

6 SPP's 2024 Integrated Transmission Planning approved the region's first recommended 765 kV project, with rapid load growth identified as a major driver of the 2024 Integrated Transmission Planning portfolio (SPP, 2025d). MISO's Long-Range Transmission Planning Tranche 2.1, approved in 2024, includes the creation of a 765 kV transmission backbone to support high system transfers and resolve reliability and congestion needs (MISO, 2024a). ERCOT's 2024 Regional Transmission Plan compared a 345 kV plan and the Texas 765 kV Strategic Transmission Expansion Plan. It concluded that the region's demand growth requires major transmission build-out and identified the 765 kV backbone as part of the statewide reliability solution (ERCOT, 2025b). PJM's 2025 Regional Transmission Expansion Plan Window 1 process evaluated and recommended major transmission proposals including 500 kV and HVDC solutions to address reliability needs associated with forecast load growth in multiple parts of the footprint (PJM, 2026a; PJM, 2026b).

is inextricably tied to the technical issues addressed in this report; however, the implications of the report's findings on cost allocation procedures are outside of its scope.

Why Large Load Growth Is Incompatible with Current Planning Processes: The Core Challenges

Today's new large loads differ in fundamental ways from the historical demand growth that existing transmission planning processes were designed to serve. Unlike traditional demand growth, individual large load projects can exceed 1 GW, large numbers of projects tend to cluster within small geographical areas, they seek rapid interconnection (within a year or two), their electrical demand patterns and operational capabilities can have significant impacts on the regional grid, some projects are planned with co-located resources that may serve all or most of their demand, and competition between projects for timely grid interconnection creates uncertainty regarding which projects will be realized and which will be cancelled.

For example, as of January 2026, the ERCOT large load interconnection queue totaled approximately 233 GW, including 92 projects each exceeding 1 GW and collectively representing more than 140 GW of proposed demand. By comparison, the grid's record peak demand is approximately 86 GW. By April 2026, the queue had grown to approximately 410 GW, of which roughly 90% were data centers (ERCOT, 2026c; ERCOT, 2026d).[7] The impacts of clusters of large loads can extend beyond the service territories of local transmission utilities and even beyond the boundaries of the regional planning authority, RTO, or ISO.

Large load project timelines often move faster than transmission planning cycles, and developers frequently seek power on much shorter timelines than utilities believe they can meet. Large load developers are competing to gain market share while also trying to sign computing companies for tenants; a critical component of their marketing is approved grid access.

As large load interconnection queues grow across the U.S., it is widely acknowledged that many of the projects currently in the queues will likely be cancelled or significantly delayed. There is insufficient transmission capacity, long-lead-time interconnection transmission equipment, and generation resources to serve all the proposed large loads within developers' desired timelines. In addition, it is not known how many of these large loads will be able to provide load flexibility to help address grid reliability issues (which would reduce the need for new generation and transmission to serve them) or will self-provide some or all of their energy needs through co-located resources. As a result, planners face significant uncertainty around how much large load capacity to include in planning study forecasts. New large loads are fundamentally different from traditional industrial facilities, which have extended development timelines and critical-path signposts that give transmission planners credible development signals, followed by sufficient time to include the new demand in regional studies and to comprehensively evaluate system needs.

The inadequacies in existing transmission planning processes for integrating today's large loads are magnified by the scale, speed, and uncertainty of this load growth, revealing three structural weaknesses: planning silos, speed mismatch, and uncertainty.

Silos

Functional Silos

Transmission planning in the United States is organized around several planning functions, each with its own objectives, study assumptions, timelines, and approval processes. These functions include load interconnection, generator interconnection, local and regional reliability planning, economic planning, public policy–driven planning, and long-term planning. In practice, they are usually executed sequentially or in parallel, rather than through a unified analytical and decision-making framework.

Large loads turn this fragmentation from an inefficiency into a reliability and cost problem. When interconnection, reliability, economic, and long-range planning functions operate independently, they often use inconsistent assumptions across teams, organizations, and regions.

7 See ERCOT's March 2026 Monthly Outlook for Resource Adequacy (ERCOT, 2026f). The report shows approximately 185 GW of total installed resources and ~100 GW of expected available capacity, an estimate of capacity available after accounting for seasonal capability and other adjustments.

As a result, decisions made to accommodate large loads can shape and constrain regional infrastructure for decades without ever being properly evaluated against broader system needs, future flexibility, or total system cost.

These functional silos were more tolerable when customer demand growth was incremental, predictable, geographically diffuse, and more aligned with transmission planning and construction timelines. But today, a single new large load or a cluster of large loads seeking service within two years can simultaneously alter local reliability needs; cause regional power flow changes, congestion, and voltage constraints; and challenge long-term resource adequacy. Uncoordinated and inconsistent planning processes are ill-suited to evaluating these system-wide effects collectively and to identifying the most effective combination of interconnection and transmission solutions.

Ability of Siloed Sequencing to Foreclose Broader Transmission Options

In siloed planning, different planning functions study different needs. In addition, the order in which decisions are made and how solutions are evaluated can prematurely foreclose more comprehensive and efficient solutions. For example, a near-term reliability or interconnection study, operating within its own silo, may identify a local upgrade that resolves the immediate violation before broader planning processes have evaluated regional or interregional needs and solutions. An early local fix that addresses the transmission needs of a single large load can make broader transmission solutions seem less necessary or harder to justify. Once the local upgrade is approved and modeled into the future system, later studies inherit it as a fixed assumption, and the residual need appears as a smaller set of limiting elements—the broader solution, then, looks like an incremental add-on rather than the more complete and often more cost-effective answer it would have been. But addressing the local need has not made the broader need go away; it has only been partially, and less efficiently, addressed. This is especially problematic when those broader solutions have higher upfront costs but offer greater long-term benefits, such as improving market efficiency, improving resilience, or meeting public policy objectives.

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This bias is reinforced because siloed transmission planning functions often have different goals and proceed on different schedules. Reliability-driven projects (including interconnection projects) tend to advance first. System reliability studies focus on addressing specific NERC and regional reliability criteria violations at minimum cost, often based on analysis of a limited set of grid operating conditions (such as peak summer and winter demand).[8] New customer interconnection studies are scoped to identify the minimum required upgrades to serve the triggering interconnection project request. By contrast, long-range or multi-value planning evaluates a broader

8 NERC planning reliability standards, such as FAC-002-4 and TPL-001-5.1, impose compliance requirements on utilities and regional planning organizations to ensure reliability through interconnection and near-term (1- to 10-year) planning studies (NERC, 2024; NERC, 2023).

set of needs and benefits over longer time horizons, but is typically conducted after near-term reliability upgrades have already advanced. This can reduce the apparent system benefits from regional solutions that, if evaluated first, would have been far superior to the multiple local projects. As a result, planners may never identify and select larger local, regional, or interregional projects that could address multiple reliability, interconnection, deliverability, and economic needs more cost-effectively.

Given different timelines, input assumptions, and objective functions, it is even difficult for planners to assess whether their bias toward near-term projects is resulting in higher long-term transmission costs. Attempts to compare a set of near-term projects to a larger alternative developed using a longer planning horizon would be undermined by a lack of consistency in study scope, planning horizon, modeling assumptions, and evaluation criteria between the two sets of studies. In practice, there are few, if any, opportunities to directly compare projects developed by different study processes.

These dynamics are magnified for large load integration because of the size of the proposed facilities. The problem is especially acute when planners address large load requests one at a time, but similar dynamics can arise even in batch studies of multiple nearby facilities. Without planning procedures that consider long-term system needs and align interconnection studies with other comprehensive planning efforts, the pattern of incremental upgrades will only partially and reactively address system needs. Each individual upgrade may appear reasonable on its own, but the sequence makes multi-need solutions harder to identify, justify, and advance. Over time, the total cost of serial, reliability-driven upgrades will often exceed the cost of a long-term solution that would have addressed a wider range of known and plausible future system needs.

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Geographical and Institutional Silos

Siloed planning also suffers from a lack of coordination between different organizations within the same or adjacent planning regions. Transmission planning responsibilities are divided among transmission owners, ISOs/RTOs, and regional planning groups that are overseen by different state regulators and FERC. These entities have different geographical footprints, regulatory mandates,

In many cases, the planning scope available to any single utility, zone, or market footprint is not broad enough to entirely capture the system-level effects of new large load facilities, and an individual planning organization cannot effectively evaluate all reasonable infrastructure options.

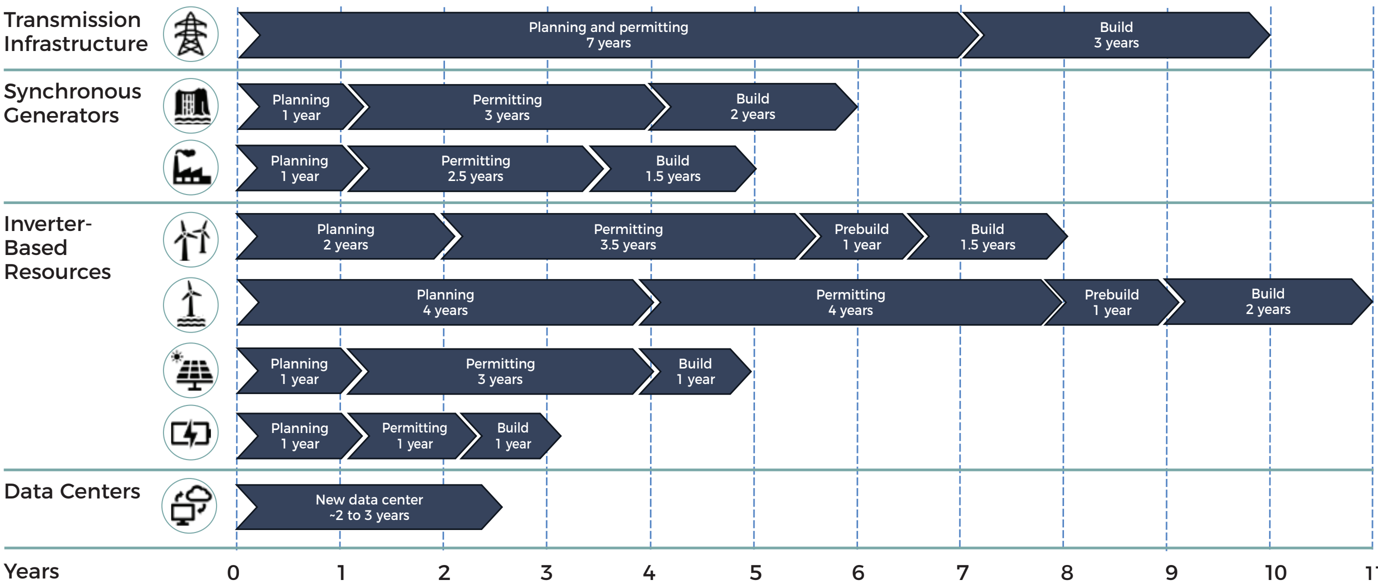
and incentives. But an individual large load project or cluster of projects can materially affect power flows, shift binding transmission constraints, and change transfer capabilities well beyond the point of interconnection, including across utility, state, and planning region lines.

In many cases, the planning scope available to any single utility, zone, or market footprint is not broad enough to entirely capture the system-level effects of new large load facilities, and an individual planning organization cannot effectively evaluate all reasonable infrastructure options. Current transmission planning structures offer limited mechanisms for jointly evaluating, advancing, approving, and allocating the costs of transmission projects that provide significant benefits to multiple planning regions. As a result, utilities may default to using internal upgrades to address local interconnection and reliability needs because those are the only quickly available solutions, leaving broader interregional system inefficiencies unresolved.

In addition, large load clustering near constrained corridors, resource-rich development areas, or emerging industrial zones may create new complex transmission constraints or flow-gates that cut across multiple zones, utilities, or regional planning functions. These internally generated "seams" can be just as consequential as formal

FIGURE 4

Timelines to Develop and Build Grid Infrastructure and Large Loads



Data centers can be developed on relatively short timelines, much shorter than the time it takes to plan, permit, procure equipment for, and build transmission, distribution, and generation infrastructure to support these loads.

Source: R. Quint et al., *Practical Guidance and Considerations for Large Load Interconnections* (Elevate Energy Consulting and GridLab, 2025), https://gridlab.org/wp-content/uploads/2025/07/GridLab-Report-Large-Loads-Interim-Report.pdf.zip. Courtesy of GridLab and Elevate Energy Consulting.

interregional boundaries, yet they are often harder to recognize and harder to address because they fall between or across established responsibilities of utilities, transmission owners, and regional planning processes.

Timing Mismatch

Developers of large load projects, especially data centers, often want to start operation within a few months or years. These projects are highly capital-intensive and their funding may be sensitive to delay. In contrast, transmission planning and construction operate on multi-year analytical, regulatory, siting, and construction timelines. This mismatch creates structural friction that distorts interconnection sequencing, planning decisions, and investment outcomes. Figure 4 shows representative timelines from initiation to completion for transmission, supply resources, and data centers.

This timing mismatch and the back-up of new load projects in the interconnection queue creates persistent pressure to serve load faster than electricity system entities can plan, build, and ultimately provide interconnection and energization. If transmission planners treat grid capability as something determined only after project sites have already been selected and interconnection requests have been added to the study queue—as opposed to proactively maximizing existing capacity and developing new transmission infrastructure in advance of demand, guided by long-term scenarios of where and how much load growth is likely—the region may already be locked into repeated restudies, with growing competition for the same electrical locations and increasing pressure to solve near-term access problems with whatever measures can be advanced quickly.

The pressure on transmission owners to interconnect large loads quickly does more than compress planning schedules; it reshapes how planning problems are framed

The pressure on transmission owners to interconnect large loads quickly tends to shift planning questions away from the solution that best serves long-term system needs.

EXAMPLE 1

A Data Center Interconnection Request Responded to with a Small Upgrade Rather Than by Creating Durable Headroom

A 700 MW load seeks service within three years. The upgrade that would create durable headroom—transmission capacity that can support future load growth and other system changes beyond the immediate request—requires a new 345 kV transmission line that has a five- to seven-year development timeline. A smaller reconductoring and substation upgrade can satisfy near-term reliability criteria within two years. The smaller upgrade project moves forward because it fits the commercial window, even though it does not materially expand long-term capability. In this and many other cases, the fastest upgrade often wins, even if it is not the most durable one.

and which solutions remain viable. Under the pressure of time, planning questions can shift from "what solution best serves long-term system needs?" to "what can be approved and implemented soon enough to meet near-term demand?" See Example 1.

Uncertainty

Large loads introduce a fundamentally different kind of planning uncertainty. Unlike traditional demand growth, large load development is lumpy, location-specific, fast-moving, and highly contingent on commercial, technological, and policy decisions that are outside of system planners' control. As a result, there is high uncertainty about development rates, locations, and magnitude, and near-term "base case" assumptions become less reliable within months and years, much faster than reliability planning time frames.

Forecasts of anticipated loads over the next five years and beyond show an extraordinarily wide range of potential growth. Figure 5 (p. 13) illustrates the magnitude of large load uncertainties, with forecasts varying substantially even over just the next five years.

The range of uncertainty is similarly large within several U.S. regions. Texas provides one clear example. In April 2025, ERCOT reported an expected 2030 peak demand of 218 GW based on the transmission service providers' forecast. After discounting data center loads based on historical materialization rates, ERCOT adjusted the forecast to 145 GW, representing roughly 50 GW of large load additions. ERCOT used this adjusted forecast for its 2025 transmission planning cycle. Separately, large load interconnection requests in ERCOT exceeded 230 GW in late 2025 and, by April 2026, the grid operator reported that it was tracking approximately 410 GW of large loads seeking interconnection. These figures illustrate the core planning challenge: large load requests and forecasts can vary widely, but near-term reliability planning often still requires planners to select a specific forecast or limited set of cases that can materially affect which transmission needs and solutions are identified.

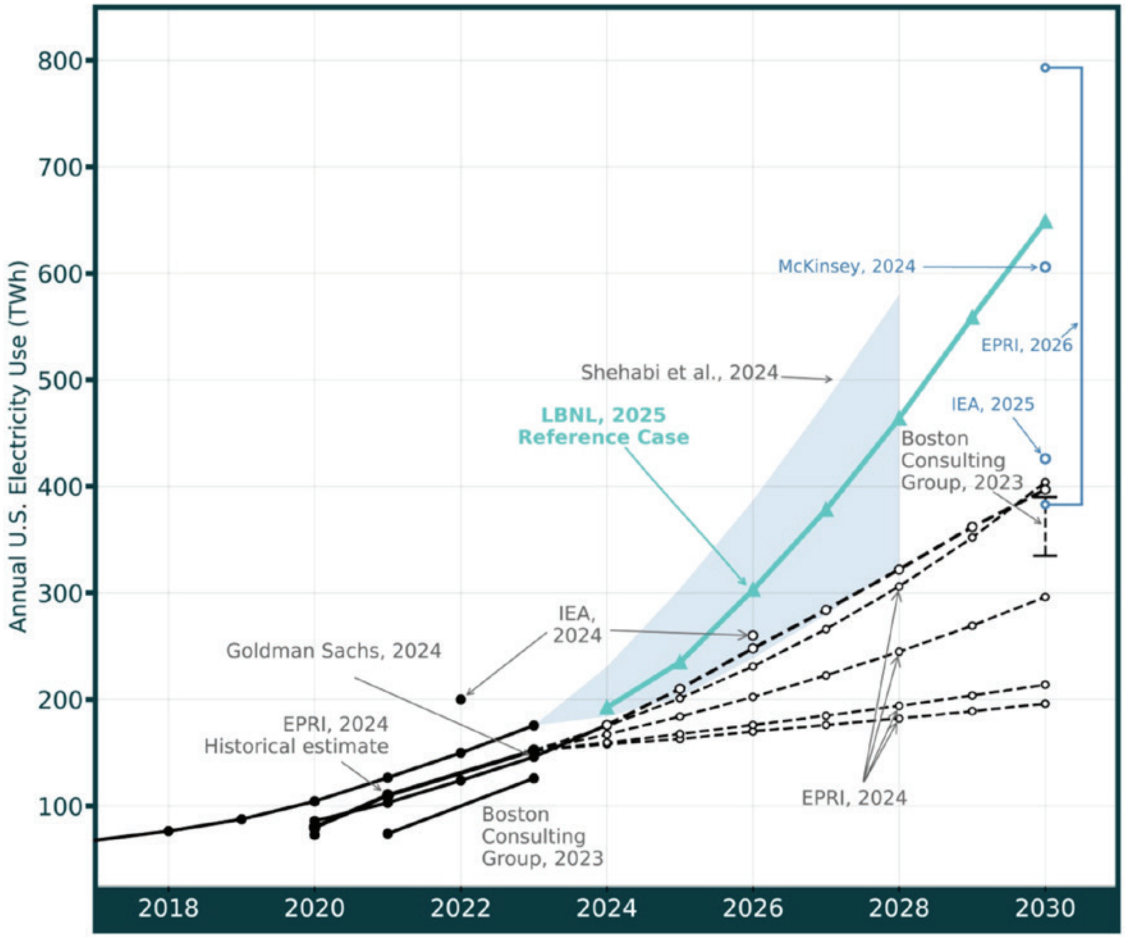
A single base-case forecast is no longer sufficient for even near-term transmission planning efforts in regions with a significant large load interconnection queue. Uncertainty must be treated as a core design constraint, and candidate solutions must be tested across a range of plausible outcomes. In one recent example from the SPP, planners approved a 765 kV backbone project based on the prevailing need case, yet by the following annual planning cycle, large load–driven reliability issues had worsened enough that SPP had to model the previously approved 765 kV line as if it were available earlier than its expected in-service date, effectively using a future project as a temporary modeling assumption to address reliability issues that had outpaced the near-term planning case.[9]

These three core challenges compound one another. Transmission planning silos make it harder to share information and compare system needs and solutions across planning functions and geographies. Speed pressure narrows the set of options that can be acted on quickly

9 SPP's *2025 Integrated Transmission Planning (ITP) Assessment Report* states: "Voltage collapse issues identified in the 2024 ITP, within SPS, persisted and worsened into the 2025 ITP, even after accounting for planned generation additions. SPP was forced to add the previously approved 765 kV line into models representing a point in time before the line is expected to be placed in-service" (SPP, 2025e, 90-91).

FIGURE 5

Comparison of U.S. Data Center National Electricity Demand Forecasts



The magnitude of large load uncertainties is large, with forecasts varying substantially over just the next five years.

Source: S. J. Smith, A. Hubbard, A. Newkirk, M. Ganeshalingam, B. Holecek, , D. Sartor, M. Mills, and A. Shehabi, *United States Data Center Energy Usage Report: 2025 Update* (Lawrence Berkeley National Laboratory, 2026), https://doi.org/10.71468/P1RP4F.

and favors the first actionable fix. Uncertainty around the pace, scale, and location of large load growth makes planning around a single base case less likely to develop and select desirable outcomes and raises the cost of getting the first move wrong. Together, these challenges push regions toward reactive, near-term, request-by-request quick fixes, and away from more prudent, durable, cost-effective long-term solutions.

Actionable Recommendations to Improve Transmission Planning

Multiple changes are needed to improve transmission planning to deal with the many challenges created by large loads and long-term reliability needs. Some immediate actions can make better use of existing grid capability and expand near-term options. Some require changes in how planners evaluate uncertain large load futures and how they choose near-term solutions that do not foreclose better long-term options. Others point to more structural changes in how planning processes are connected and how solutions are compared. The recommendations that follow are organized along those lines: immediate actions, near-term process fixes, and longer-term structural changes.

Improving Transmission Planning: Urgent Actions

The actions discussed in this section respond to the near-term mismatch between large load project schedules and the speed of transmission development, as well as the uncertainty around where and how new load will materialize. The goal of these near-term actions is to improve visibility into where the grid can serve load, widen the set of workable near-term options, and make flexible service arrangements that better support grid planning and operations.

Identify Where the Grid Can Serve New Loads Relatively Quickly

Today, available grid capacity for new large loads is often assessed and quantified only after developers have selected sites and entered the interconnection study process, where each request is evaluated through serial, project-specific studies. However, in regions with significant large load interest, planners need a clear up-front view of existing headroom, likely development areas, and the operating or transmission changes that would be needed to expand access in the near term. That means undertaking headroom studies to identify areas on the grid that can accommodate new large load projects quickly and determining which operating or transmission measures would be needed to expand that capacity. It also means tracking where large load developers are seeking interconnection, since those patterns can help inform future planning scenarios. Without such visibility, planners and developers will not be able to determine the best places to interconnect new projects quickly or assess how to make those interconnections happen without high costs or inefficiencies. Additional studies are also needed to examine where the grid is tight relative to where new large loads want to interconnect; these need to become the basis for later, longer-term, big-picture planning.

The combination of new headroom studies with desired development locations and batch interconnection studies will enable planners to distinguish between areas that can plausibly support fast service and areas that will require more substantive transmission development.[10] In places where the new load interconnection queue is not already clogged with many large load interconnection requests, planners could use these studies to recommend good locations for new large load projects. High-level headroom studies can also provide a critical initial linkage between the near-term interconnection study perspective and longer-term planning options.

In regions with significant large load interest, headroom studies of the existing system should not be limited to a single peak-hour view of the system. At a minimum, those studies need to reflect summer peak, winter peak, net peak, shoulder, light-load, and high-transfer conditions as relevant to the area being evaluated. The relevant question is not only whether a location can serve new large load projects under one assumed condition, but whether the area has room today under diverse, potentially challenging grid conditions, and how quickly the available transmission service capacity can be expanded for economically durable and reliable long-term service.

Provide Clearer Location-Specific Signals About Available Grid Capacity

Headroom information is most useful when it is available and visible early enough to affect large loads' siting

10 In batch or cluster interconnection studies are interconnection studies multiple projects are evaluated together, usually because they are geographically proximate, electrically related, or expected to come online around the same time. The purpose is to capture cumulative system impacts and reduce the serial restudies that often occur when projects are assessed one at a time

behavior. In a large load environment, that means giving load developers, system planners, and states clearer signals about where access appears feasible, where it depends on defined near-term measures, and where larger, long-term upgrades are likely to be required.

Addressing location-specific uncertainty requires more than tracking interconnection queues. Planners need to evaluate how infrastructure signals can shift development patterns over time and how locations that can be served more quickly evolve as upgrades are proposed, approved, delayed, or cancelled. This requires supplementing queue data with broader locational analysis and explicitly considering how alternative transmission investments might steer future siting behavior by creating or relieving local constraints (see Example 2).

Proactively Identify Preferred Development Zones for Large Loads and Generation

Planners can also reduce uncertainty by proactively identifying attractive locations for large loads and generation and steering developers toward those locations.[11] This would require close coordination between grid planners, industry groups, and state economic development agencies to identify economic development zones for large loads and generation development. Such a process could be similar to the designation of Texas's Competitive Renewable Energy Zones two decades ago (Cohn and Jankovska, 2020) or Illinois's Renewable Energy Access Plan (ICC and The Brattle Group). The identification of load and resource development zones would facilitate proactive grid planning to support more timely and cost-effective interconnection processes in the future.

Proactively identifying development zones does not mean publishing a single static hosting-capacity number or implying that all identified capacity is equally firm. It means providing locational signals in a form that reflects both different operating conditions as well as the difference between capacity that exists now and capacity that depends on additional measures or upgrades. Results should be published in a consistent, public, stakeholder-oriented format rather than remaining only in confidential project studies.

Clearer locational signals for large loads will not eliminate uncertainty. But they can reduce speculative queue growth, improve siting decisions, and help planners and large load developers distinguish between places where load can be served now, places where near-term tools can create access, and places where larger transmission development will still be required.

EXAMPLE 2

Transmission Headroom Information Changes Future Load Development Paths

A region studies upgrades to a 230 kV transmission line because it is one of the few circuits with apparent headroom and fast interconnection potential. Once the upgrade shows up in a public planning forum, two things can happen quickly: developers start marketing adjacent land as "grid-ready," and a second wave of load interconnection requests piles into the same electrical pocket. A year later, permitting or siting issues delay the transmission upgrade. Some projects may remain in the queue, while others may withdraw, and large load interest may shift toward other areas that had not previously attracted significant development interest.

This example illustrates why proactive planning should not be limited to the current interconnection queue. The queue provides useful information about where developers are seeking service today, but future development interest can change as headroom information changes, planned upgrades move forward, or expected upgrades are delayed. The result is that future large load development patterns can become a function of what the latest transmission plan shows for where and when interconnection capacity will be available. Planners therefore need to treat development patterns as dynamic and feedback-driven, and use scenarios that explicitly test how development migrates as headroom appears, disappears, or slips in schedule.

11 Utilities and regional planning entities are generally best positioned to play an advisory rather than directive role in identifying preferred large load locations, informing siting decisions through analysis of system capability, constraints, and upgrade needs.

Taken together, these practices move the region away from discovering grid capability only through serial interconnection studies. They create a more usable picture of where service is feasible now, where it may become feasible with defined measures or staged upgrades, and where larger transmission development will be needed before additional load can be served.

Use Speed-Aware Planning

Speed-aware planning means identifying fast near-term solutions that are compatible with long-term regional needs. Given the short large load development timelines, planners do not have the luxury of waiting for uncertainty to clear before acting. Near-term decisions must be made while load forecasts continue to change and broader transmission solutions are still years away. Under such conditions, the question is not just what grid solutions can be implemented quickly to address the immediate need, but whether those near-term moves are consistent with the system's longer-term strategy. A fast solution may solve today's problem, but if it makes future expansion harder, more expensive, or less effective, it is not the best move.

A fast solution may solve today's problem, but if it makes future expansion harder, more expensive, or less effective, it is not the best move.

A practical speed-aware approach includes four steps that fit within existing planning cycles, provided that near-term interconnection and reliability studies are informed by an early assessment of longer-term needs in likely large load areas.

1. **Identify candidate large load zones and corridors early.** Queue signals, service requests, and utility information about prospective customer development is used to identify locations where large load clustering is plausible.
2. **Screen for "headroom now" versus "headroom later."** Planners quantify where near-term headroom exists and where it does not, and identify what would be required to create it.

3. **Evaluate near-term fixes for compatibility with a defined long-term plan.** Planners ask whether a near-term action preserves future expansion options or makes future corridors harder to develop. When possible, they will want to select near-term solutions that are components of identified long-term plans.
4. **Right-size transmission expansion and use phased implementation to preserve future options.** When uncertainty is high, staged and expandable solutions can be used, including designs that enable future expansion without full rework. Such solutions may include transmission lines and equipment, grid-enhancing technologies (GETs), and advanced transmission technologies.

Speed-aware studies need to identify what can be served under different combinations of operating conditions and service structures, including with and without remedial action schemes, with firm and non-firm service, and with and without co-located dispatchable resources. These sets of operating conditions and service structures should be consistent with those used for related studies such as long-term regional expansion options and reliability scenarios. This approach requires disciplined comparisons that explicitly account for lead times and the impacts of near-term decisions on long-term upgrade options.

Speed-aware planning cannot make up for the significant timing difference between how quickly large load developers want to interconnect their projects and how long it takes to analyze, plan, and build a larger, reliable, economic transmission and supply system. But it can contribute to a more strategic approach to system expansion and design that will help early large loads interconnect faster and expand a regional system more quickly, durably, and cost-effectively than current incremental, serial planning processes.

Use Available Tools to Expand "Fast Service" Options

Not all near-term interconnection solutions require waiting for major new transmission lines. In some situations, existing grid capacity can be increased or used more efficiently through readily available tools that expand headroom or transfer capability on shorter time frames. Depending on the application, these tools can serve as permanent solutions or as temporary bridges until longer-lead-time grid investments are brought online.

Grid-Enhancing and Other Advanced Transmission Technologies

GETs and other advanced transmission technologies offer valuable upgrade options to serve new large loads and supply resources quickly and cost-effectively.[12] GETs can create incremental amounts of new grid capacity and expand load and generator interconnection headroom in months rather than years, often at much lower cost than new transmission lines. They can also buy time while longer-lead transmission is built and can supplement long-term transmission facilities.[13] Even if they are not ultimately selected, GETs need to be considered as part of all relevant planning and interconnection studies because they expand the solution set under tight timelines and cost constraints.

GETs include topology optimization, advanced power flow controls, dynamic line rating, and the underlying grid-monitoring technologies that enable GETs' use. Related advanced transmission technologies include high-performance conductors and battery storage to supplement transmission at constrained points on the grid. These technologies are attractive as short-term solutions for large load interconnections as they can expand existing grid capacity (including interties with neighboring regions) to address reliability needs, mitigate grid congestion, and avoid uneconomic curtailment of new generation. Many types of GETs equipment (such as battery storage and advanced power flow controls) can be installed and used in one location, then moved to different locations as grid conditions change (such as after a line is rebuilt and upsized).[14] Grid operators can use these technologies to reroute power around congested or overloaded transmission elements to underutilized portions of the grid.[15]

Reconductoring with high-performance conductors is a medium-term option to increase grid capacity. High-performance conductors, such as aluminum conductor composite core technology, can double the thermal capacity of existing lines without requiring new towers (MCETWG, 2023) and can often be installed with limited outages of the existing lines.[16] Google has teamed up with a high-performance conductor manufacturer to "identify high-impact transmission lines through a Request for Information to states, utilities, and transmission developers interested in collaborating on solutions to [potentially] double transmission capacity in months, as opposed to the years typically needed for new transmission builds" (Google and CTC Global, 2025).

12 For overviews of grid-enhancing technologies and advanced transmission technologies, see the ESIG report *Utility Perspectives on Making Grid-Enhancing Technologies Work: Use Cases, Barriers, and Recommendations for Scalable Deployment*, https://www.esig.energy/reports-briefs/utility-perspectives-on-making-grid-enhancing-technologies-work/; MCETWG (2023, sec. 7); U.S. DOE (2022); and U.S. DOE (2020).

13 For example, the German NOVA principle requires that grid optimization have priority over grid enhancement and that grid enhancement have priority over grid expansion (TransnetBW, n.d.). A similar emphasis to "always to look at optimizing and upgrading the existing network [before] new infrastructure will be considered" is used for grid planning in the U.K. (NESO, 2024, 26), including in its new comprehensive planning framework (NESO, n.d.).

14 For example, see Pfeifenberger, et al. (2025).

15 For detailed case studies of topology optimization benefits, see Ruiz (2024), EPRI (2025), and ESIG (2025c).

16 For example, the Edison Electric Institute gave its 2016 Edison Award to American Electric Power's reconductoring project, which was performed without transmission line outage. AEP was able to "replace all 240 miles of line while they were in an energized state utilizing existing structures and right-of-ways" (EEI, 2016).

Because GETs and other advanced transmission technologies have the potential to expand the capacity of the existing grid more quickly and at lower cost than traditional transmission solutions, FERC Orders 2023 and 1920, along with the June 2026 show cause orders on flexible and co-located loads, call for consideration of these technologies in interconnection and transmission planning processes (FERC 2023, 2024a, 2026). Several states have adopted similar requirements.[17] These technology options expand the near-term solution set while keeping long-term options open.

Operational Controls, Including Remedial Action Schemes

Some near-term bridge measures are operational rather than transmission infrastructure options. Under certain conditions, they can increase the effective headroom or usable transfer capability. These operational measures rely on defined control actions, operating procedures, and enforceable response capabilities to maintain reliability while allowing additional near-term access. They can be evaluated alongside transmission technologies even though they do not expand the physical capability of the grid in the same way.

Remedial action schemes (RASs) are a good example.[18] A RAS is not a GET or an advanced transmission technology. Rather, it is an operational control scheme that detects defined system conditions and automatically takes corrective action to keep the system within reliable operating limits. In the context of large loads, that can make additional near-term service possible where conventional planning would otherwise require waiting for a larger transmission upgrade. RASs and similar operational controls can accelerate the interconnection of new loads and generation by controlling how loads, generation, storage, or other grid elements respond to contingencies to avoid overloads. See Example 3.

RASs can be valuable tools when they are well defined, rigorously studied, and supported by credible operational controls. They are not universally embraced, in part because they can be difficult to maintain, easy to overuse as a substitute for more durable upgrades, and risky if they are not modeled, tested, and governed carefully.

EXAMPLE 3

Using a Remedial Action Scheme to Interconnect 1,000 MW of New Load

If a location suitable for new data center load is served by two 500 MW transmission lines, typical transmission planning and load interconnection processes would either: (1) allow for the interconnection of only 500 MW of load, so that load can be served without overloading one of the transmission lines if the other line experiences an outage; or (2) allow for the interconnection of 1,000 MW of load, but only after a third 500 MW transmission line is built to that location, so that the 1,000 MW can be served even if one of the three lines has an outage.

In this case, RASs or similar operational controls would allow the immediate interconnection of 1,000 MW of new load. Contingent on implementing controls to ensure that if one of the two 500 MW transmission lines experienced an outage, the RAS control would immediately reduce net withdrawals at that location to 500 MW. This reduction could be implemented by either automatically curtailing load to 500 MW or dispatching up to 500 MW of back-up generation or battery storage at that location to reduce net withdrawals to 500 MW.

RASs can also enhance interconnection capability for new generation and storage resources. For example, CAISO has identified 21,000 MW of interconnection headroom (16,000 MW of which are for firm deliverable capacity resources) that can be enabled quickly using RASs (CAISO, 2023).

17 For more details, see California Senate Bill 1006 (California Legislature, 2024), WATT Coalition (2024), Montana 68th Legislature House Bill 729 (2024) (https://apps.montanafreepress.org/capitol-tracker-2023/bills/hb-729/), Massachusetts Senate Bill S.2531 (https://www.mass.gov/news/governor-healey-signs-climate-law-to-advance-clean-energy-transition-create-jobs-and-lower-costs), Virginia HB 862 (https://legacylis.virginia.gov/cgi-bin/legp604.exe?241+sum+HB862).

18 Remedial action schemes are also referred to as system protection schemes. See NERC, Reliability Standard PRC-012-2 Remedial Action Schemes Question & Answer Document, February 2026. Remedial action schemes are also referred to as system protection schemes. See also Levitt et al., "Remedial Action Schemes (RAS) to Quickly and Affordably Connect New Generation and Large Loads," The Brattle Group, June 22, 2026.

But the challenges presented by new large loads warrant consideration of RASs, even in regions that currently limit their use.

Capture Large Loads' Flexibility by Making It Visible and Enforceable in Operations

Where existing headroom is limited and conventional transmission upgrades will take longer than large load developers are willing to wait, planners need to consider that not every large load must receive firm service for its full requested demand from the start. Large load flexibility, co-location, and self-supply can help create near-term interconnection options, reduce upgrade requirements, and establish a more manageable operating envelope. However, these arrangements can improve planning outcomes and serve new large loads effectively only if they are clearly defined, visible, and incorporated into all planning studies, and implemented in real-time grid operations.

Use Large Load Flexibility as an Interconnection Accelerator

Historically, transmission planning has generally assumed that customer load is firm, and the system must be planned to serve a customer's full requested demand at all times. But in some cases, a large load may be flexible with regard to when and how much electricity it uses, and that flexibility can materially affect its grid connection needs and how the grid must be built to serve it. Load flexibility, co-location of a load with power supply sources, and self-supply (i.e., resources located behind the customer meter) manageable operating envelope, but only if those facility characteristics are clearly defined and represented consistently in interconnection studies, transmission planning, and grid operations.[19] FERC's six June 2026 show cause orders direct ISOs and RTOs to justify or reform their rules for faster, cost-effective, transparent, and nondiscriminatory integration of flexible loads and co-located load-generation projects (FERC 2026).

19 See extended discussions of large load flexibility in the ESIG Large Loads Task Force reports *Grid Integration of Large Loads: Introduction to the Large Loads Task Force, Data Needs, and Flexibility* (https://www.esig.energy/reports-briefs/large-load-task-force-introduction) and *Resource Adequacy with Large Loads: Planning for Flexibility to Accelerate Integration* (https://www.esig.energy/reports-briefs/large-loads-resource-adequacy).

Large loads can modify their grid-facing demand (net demand) by modifying their energy usage within the facility or by using back-up generation, battery storage, utility-scale generation behind the facility meter, or generation that is electrically proximate and operationally linked to the load.[20] A large load's ability to provide grid-facing demand flexibility significantly impacts transmission needs and the size and cost of system upgrades. If load flexibility can be enabled to address transmission constraints, large loads can be integrated more quickly and at lower cost.

Define Enforceable Flexibility Before Relying on It in Planning

For flexibility to be treated as enforceable, the conditions under which the load will reduce grid-facing demand must be specified in advance; be reflected in applicable operating procedures, interconnection or service agreements, tariff provisions, and market rules; be visible to the system operator; and be capable of being monitored and enforced in real time. In SPP, for example, the proposed CHILLS framework would require load-shedding and curtailment procedures to be established through a CHILLS Operating Agreement before service begins; allow SPP to curtail service during emergency, unforeseen, or transmission-constrained conditions; and impose charges and penalties if the customer fails to reduce service in response to established procedures or SPP directives. If a large load can provide enforceable flexibility, the grid may not need to be expanded to serve the non-firm portion of that customer's load during supply scarcity or grid contingency events (SPP, 2026c).

In some regions, utilities are moving large loads up in the interconnection queue and connecting them to the grid earlier if the load is willing to begin operations at a fraction of its eventual total demand and operate at partial output until the grid can be expanded to serve that full demand. A related strategy is for the utility or grid operator to offer early energization to a large load that agrees to limit its demand or accept electricity service curtailments when those are needed to alleviate grid stress. Several regions with interconnecting large load customers are pursuing rules that would formalize the requirements associated with flexible large loads.

For transmission planning, the key question is whether the assumed flexibility can be relied on under the conditions modeled in the planning study. If not, planners may incorrectly assume demand flexibility that will not actually be available during grid stress, and the resulting planning studies may not ensure actual operational reliability.

Study Both Near-Term Flexible Service and Long-Term Transmission Service Needs

Depending on whether load flexibility requirements are intended to be temporary or permanent, parallel transmission studies may be needed: one set of studies assuming flexible demand levels to ensure near-term reliability and another assuming firm future demand to identify the transmission projects needed to serve it. Transmission planning studies can also estimate the number of hours during which large load customers would be asked to be flexible and curtail their load during real-time operations, which can vary by location and time. These "what if" questions inform the large load integration process by evaluating potential cost increases or savings associated with a load's changing operational procedures. The savings in transmission capital costs resulting from different levels of load flexibility (or co-location arrangements) are an important consideration for the design of large load integration policies.

Match Flexibility Assumptions to the Capabilities of Different Large Loads

Planning studies must recognize the different types and levels of flexibility available from differently situated large

20 Many data centers are beginning to secure dedicated electricity supplies by signing contracts with nearby generators or building multiple back-up or utility-scale generators in energy parks next to the data center. While these supply assets may reduce the customer's need for future grid supply capability, if those supply assets are on the grid side of the customer's meter, they do not count as load flexibility because they may still require use of the transmission system for delivery to the customer. The latest variant on this approach is for large load customers to "bring [their] own generation" (BYOG), installing their own utility-scale generation (often batteries or natural gas turbines) on site behind the utility meter for stand-alone operation, asserting that they will not need the grid to provide future transmission or power and will not need to impose those future costs on other customers. Alternatively, many data centers are pursuing BYOG now in order to become operational quickly but seek future grid interconnection to ensure a continuing reliable back-up power supply. BYOG arrangements will require well-defined operational and contractual limitations before they can be appropriately included in transmission planning studies. The BYOG approach, covering the entirety of a new data center's load, is part of a recent ratepayer protection pledge initiated by the Trump Administration and large data center developers (U.S. EOP, 2026).

load customers. A customer using back-up generators with limited annual operating hours or a duration-constrained set of dispatchable batteries will have different flexibility capabilities and timing than a customer that can shift computing to a different data center. Some loads may be able to reduce consumption only during resource adequacy events, while other loads can reduce consumption for local transmission reliability reasons. Some customers may only be able to deliver load flexibility for a limited number of hours per year, while others can respond flexibly both to market prices and grid events.[21] Some large load customers may even elect to be subject to economic dispatch in the regional wholesale markets. And as noted above, some may be willing to limit energy demand over the near term and transition to firm load as grid infrastructure gets developed.

Recognize Practical Limits on the Use of Large Load Flexibility

While load flexibility has the potential to offer substantial time and cost savings, several factors can limit its use. First, many large load customers prefer firm transmission service and may accept flexible arrangements only when those arrangements materially accelerate interconnection and energization (NERC, 2026). In addition, many site developers proceed through the grid interconnection queue before they have contracted with a tenant and do not know how flexible their ultimate electricity customer can be. Although flexibility can be built into a facility design, doing so requires the site developer to weigh the trade-offs between impact on the customer, the cost of resources to enable flexibility, and the incentives (most importantly, the speed to connection) provided by flexibility commitments. Co-located resources can support some forms of large load flexibility by allowing a facility to reduce its net withdrawals from the grid. However, as of May 2026, only 13% of projects in the ERCOT large load interconnection queue were registered as having co-located resources (ERCOT, 2026e).

In many regions, flexibility arrangements are still being developed, and the benefits to a large load customer for providing flexibility are not yet well defined (Horger, 2026).[22] Some transmission entities may not offer load flexibility options at all. While incorporating flexibility into large load facilities is often possible, enabling flexibility may not be within the customers' core expertise and business model, and it may create compliance requirements that the customer cannot fulfill. As interconnection timelines and costs have increased, however, large load customers have become more willing to bring the necessary capabilities in-house or subcontract the expertise necessary to create that flexibility.[23]

The main planning value of flexibility is not that it makes transmission needs disappear. It is that, when flexibility commitments are clearly defined and enforceable, they can reduce the amount of firm service the transmission system must be able to support, either as a temporary bridge or as an ongoing service arrangement. This can speed up and widen the set of feasible interconnection and transmission options.

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Take Advantage of Co-located Loads and Generating Resources

One way to enable large load customer net-demand flexibility is through co-located load and supply configurations. When a new load brings its own resources that can reliably reduce its net demand, these configurations can reduce transmission upgrade requirements, accelerate service, and create clearer operational envelopes. They can convert a broad and uncertain load forecast

21 Cryptocurrency miners are typically quite price-sensitive and will quickly reduce demand when the price of electricity (or value of compensation for curtailment) exceeds the value of the cryptocurrency being produced. In contrast, data center energy use is typically not price-sensitive, and data centers currently prioritize "speed to power" (i.e., interconnection and start of operations) over energy savings.

22 MISO (n.d.-b) discusses zero-injection generator interconnection agreements, firm service step-up, and non-firm service step-up pathways for large load integration.

23 For example, see Clavenna (2025).

into a more bounded net-withdrawal or net-injection profile if the configuration and operating limits are clear enough to be modeled and enforced.

For large load planning, the value of co-location is that it can decrease grid infrastructure costs. It reduces forecast uncertainty by turning an ambiguous "how much load will show up and when?" question into a more structured "what is the maximum net withdrawal, when would it occur, and how would it be controlled?" specification. Co-location can be used as either a bridging strategy, while grid upgrades are developed, or as a long-term solution that limits net demand and avoids major transmission reinforcements.

Recent reports indicate that large load developers are increasingly pursuing co-location as a means to accelerate grid interconnection. One recent market report estimates that while less than 2 GW of data center capacity was planned in a co-located, behind-the-meter configuration in December 2024, by the end of 2025 roughly 40 such projects, totaling 50 GW, had been announced (Thomas, 2026). At the same time, several market regions are developing new programs to allow large loads with co-located resources to interconnect to the grid more quickly (SPP, 2026b).[24] Some new data centers are even being planned as stand-alone or islanded facilities to reduce dependence on the timing of full grid build-out.[25]

Different types of co-location options have different operational characteristics. Co-located configurations can range from loads and resources that are co-located behind the customer's meter, to loads and resources that are physically co-located at the same grid location but with their own meters (resources are in front of a customer's meter), to loads and resources that are located near each other in electrically close locations and with separate meters.[26] The specific configuration of these co-location options will affect their operational requirements for the coordination of load and resource to ensure that the net injection and withdrawals from the grid can effectively be controlled in real-time operations, whether by the grid operator or the customer. These jointly controlled, co-located loads and resources have been referred to as energy parks or hybrid loads, including in FERC's recent Advance Notice of Proposed Rulemaking (ANOPR) for large load interconnection (FERC, n.d.). For transmission planning purposes, however, accurately reflecting these characteristics requires facility-specific information to determine how the load is co-located with supply resources, the magnitude of and limits to its firm (and non-firm) net injections and withdrawals, and how and when the supply resources will be controlled or dispatchable.[27] Once the parameters for real-time operations of these hybrid loads or energy parks are defined, they can be incorporated into load and generator interconnection studies and transmission planning studies.

A co-location configuration may be implemented as a "bridging" solution until the necessary grid upgrades can be completed or as a permanent solution to avoid otherwise necessary grid upgrades. Even if loads and associated generation resources are not interconnected at the same grid location, significant time and cost savings may be possible if they are located electrically near each other and controlled as a single resource to limit net grid injections and withdrawals to the broader grid (Levitt et al., 2025a; Levitt et al., 2025b; Levitt, Pfeifenberger, and Mohan, 2025). SPP has established High-Impact Large Load (HILL) and High-Impact Large Load Generator Assessment (HILLGA) frameworks to analyze and handle loads and resources that are no more than two substations apart.[28]

24 See PJM (2026c). For ERCOT see ERCOT bring-your-own-generation (BYOG) proposals in the discussion starting on slide 5 of ERCOT (2026b). See also ERCOT (n.d.), including forms and guidance for large loads co-located with generation or energy storage and net-metering arrangements.

25 As an example, see Microsoft's planned off-grid facility in West Virginia in Boudreau (2026). Also see Clavenna (2025).

26 As discussed in Levitt et al. (2025a), a generator and load are located "electrically close" to one another when power flows from the former to the latter are confined within the immediate/local area of the grid.

27 MISO (2026) describes how MISO is exploring a large load interconnection framework in which operationally linked generation and loads would achieve "speed to reliable power" through zero-injection generator interconnection agreements (ZGIAs). Under the ZGIA process, the generator(s) would be studied through a 90-day interconnection study process while the associated load would be evaluated through the MISO Transmission Expansion Plan (MTEP). Because the MTEP study would account for the accompanying generator, the required network upgrades could be reduced relative to studying the load without that associated generation (slide 28). Implementing the ZGIA process will require coordination across MISO's planning, markets, and operations functions.

28 See SPP (2025b) and SPP (2025c) at SPP (2026b).

While the growing interest in co-located facilities is partly driven by large load developers seeking faster and more certain access to the grid than the standard interconnection queue can currently provide, there may still be project delays caused by a lack of available gas turbines rather than delays in the large load interconnection process itself (Chang, 2025; Noble, 2026).[29] Even so, co-location will likely become a valuable tool for large load developers who, working within new grid operational constructs, can use it to manage their development timelines and minimize costly grid upgrades.

Batch Interconnection Studies

Facing increasing numbers of large load projects in interconnection queues, several regions are modifying their interconnection study processes to use a cluster or batch study approach.[30] Traditional interconnection studies evaluate the grid impacts of one project at a time, but that approach fails when there are multiple load projects with close geographical proximity and development timelines. The overlapping cumulative impacts of these nearby projects can lead to multiple rounds of restudies as new projects move through the interconnection queue.

As a result, planners are turning to batch studies that combine multiple interconnection requests. Batch studies of all projects in a specific study area that meet objective project milestones can eliminate the need for restudies and can give planners and large load developers an accurate assessment of available and needed transmission capacity in the relevant interconnection area. Batch studies can also inform other parallel planning studies and provide a better basis for coordinating interconnection analysis with broader transmission planning.

However, batch studies are not a quick fix for siloed planning processes, nor are they a substitute for comprehensive regional transmission planning. Moving from individual to batch review does not by itself resolve the disconnect between interconnection studies and broader planning processes. In some cases, it may reinforce the load-interconnection silo by making transmission recommendations developed through batch studies appear more credible and actionable, simply because they reflect multiple large load requests rather than one. Batch studies can suffer from the same near-term reliability bias discussed above: just because a batch study includes multiple projects in one area, that does not mean that the study incorporates all of the developer interest in that area.

In developing batch study processes, planners need to require that (1) batch study assumptions align with other planning studies, (2) batch study results be compared with those studies' recommendations, and (3) projects advanced through batch studies be consistent with long-range and multi-value planning studies. As an example, in ERCOT the implementation of a batch process has prompted a rethinking of how all planning studies fit into a comprehensive process (Hobbs, 2026).

Use One Set of Shared Assumptions, Data, and Scenarios

Transmission planning with large loads can become inefficient and unreliable when different study processes incorporate different sets of data and assumptions on which projects to include, when those projects arrive, how quickly they ramp up electricity demand, whether and how they offer flexibility, or whether they are paired with co-located resources. Once planning assumptions

29 Wood Mackenzie reports that global gas turbine orders exceeded manufacturing capacity at the end of 2025, that order books were sold through 2027, and that supply constraints and six-year lead times are affecting gas-fired power project viability (Wood Mackenzie, 2026).

30 See, for example, the batch study process being proposed in ERCOT (2026a).

diverge between studies, those studies are no longer answering the same question, and their results stop lining up cleanly. More consolidated planning processes can help, but the immediate need is more basic: interconnection studies, reliability assessments, operations, and longer-term planning need to start from consistent, compatible assumptions so their results can be compared and used together effectively.

Use a Common Set of Shared Assumptions and Data

Siloed planning fragments decision-making and limits the development of shared assumptions and analytical workflows needed to understand large load impacts across system needs, geographies, and time horizons. Even when planning teams are aligned on intent, the results can still conflict when studies rely on inconsistent assumptions or disconnected tools. Geographical and planning entity silos make it harder to access all the needed grid and customer data and to build it into comprehensive planning cases.

When the same prospective load is represented differently across analyses, the problem is not that one view or model is “wrong”; rather, the studies are solving different versions of the planning question, so the upgrade signals will not align. Differences in overall demand forecasts, development timelines for specific new large loads, assumptions regarding development of new resources including co-located resources and completion of planned transmission upgrades can change which constraints bind and which upgrades appear necessary, as well as when they are needed. Differences in study assumptions also limit the ability to compare study results or even understand inconsistent findings.

Planning for large loads must not rely on separate teams making separate assumptions and hoping the results can be reconciled later. Planning teams must address the inconsistency of planning assumptions as an immediate action to ensure that all planning studies remain comparable.

Build and Maintain One Common Large Load Dataset

Achieving this consistency requires, among other things, developing and using a common forecast dataset that tracks every large customer’s size, geographical and electrical location, demand, demand ramp timing, demand flexibility capability, expected operations pattern, and milestone status to determine its credibility and likelihood of progress toward completion. That dataset needs to be updated on a regular, agreed-upon schedule and imported consistently into interconnection, reliability, and long-range planning studies.

Use Common Scenario Definitions Across Studies

Coordination requires more than a common project list. It also requires common scenario definitions. In this context, a scenario is a fully defined, internally consistent, plausible view of the future, built around a coherent set of assumptions about key uncertainties and major system drivers (AEMO, 2023a).[31] Where regions develop scenario sets for large load planning, those same scenario definitions need to be used consistently across interconnection studies, reliability planning, economic studies, and longer-horizon transmission planning in the same planning cycle.

Using common scenario definitions helps prevent silo-specific assumptions from creating conflicting study results. It also makes it easier to compare solutions developed in different planning channels on a more consistent basis. This does not mean every study must use the same model or answer exactly the same question, rather all of the studies need to use a common set of underlying facts and futures, including common assumptions and scenarios for load growth, resource development, and relevant policies. If a study needs to depart from that common set of facts and scenarios, that analytical deviation should be made explicit, documented, and applied consistently. This practice will reduce avoidable differences across studies before those differences create conflicting results (ESIG, 2025b).

31 The Australian Energy Market Operator report describes scenarios as internally consistent, plausible, distinctive, broad, and useful, and explains that they are designed to capture key uncertainties and material drivers shaping possible futures.

Near-Term Fixes

The actions discussed here address uncertainty and path-dependence in near-term planning for transmission needs over the next three to seven years. Their purpose is to test candidate transmission upgrades and other solutions across plausible futures, identify scalable options, and improve transmission planning approaches to meet near-term needs while preserving longer-term flexibility.

Planning for Uncertain Large Load Futures

Uncertainty around large load development directly affects the sizing, sequencing, and location of transmission upgrades. The traditional single base case is no longer enough. Planners need methods that can test multiple plausible futures, identify scalable options, and compare how different transmission strategies perform when conditions turn out differently than expected.

Recognizing Increased Uncertainty in Transmission Planning

Large load uncertainty has several implications for transmission, including whether a project materializes at all (realization risk), when it energizes (schedule risk), how quickly it ramps and utilizes capacity once energized (usage risk), and how co-located generation or storage changes net injections and withdrawals.[32] These dimensions often diverge materially. A project can be "real" but delayed, energized but lightly loaded, or fully contracted but clustered with other projects that alter regional flows. Each dimension affects transmission sizing and sequencing differently. These uncertainties are further complicated by uncertainty in the generation and storage that will be developed to serve new and existing load.

Better information and better forecasting would help, but they will not eliminate the problem. The scale and volume of large load requests require planners to move beyond a single reliability-centered base case and instead use multiple load growth and transmission expansion scenarios.

The scale and volume of large load requests require planners to move beyond a single reliability-centered base case and instead use multiple load growth and transmission expansion scenarios.

Some utilities and system planners have begun differentiating large load forecasts based on defined commercial and interconnection milestones, increasing forecast weight as projects move from preliminary inquiries to executed agreements, equipment orders, and site control. This does not eliminate uncertainty, but it introduces structure into what would otherwise be a binary choice between "include everything" and "include only the most certain." Milestone-based weighting cannot fully resolve clustering risk, ramp uncertainty, or supply-side churn, particularly when multiple large load requests advance simultaneously within the same electrical area, but it does help planners to develop appropriate load growth scenarios and better identify durable, least-regrets transmission expansion options that can serve a substantial set of future new large loads even if the specific large load customers in that set are as-yet uncertain.

32 See the ESIG Large Loads Task Force report *Forecasting for Large Loads: Current Practices and Recommendations*, https://www.esig.energy/reports-briefs/forecasting-for-large-loads.

Reliability-driven planning processes within a 10-year horizon rarely use scenarios explicitly. Until recently, the future was deemed sufficiently predictable over a 10-year time frame that planning for a single base case was considered sufficient.[33] However, the complexity of large load conditions necessitates that even near-term reliability-driven planning be supplemented with scenario-based analysis to assess the robustness and cost-effectiveness of alternative transmission upgrades and flexibility options. While NERC, regional, and local planning standards still require system planning to meet reliability criteria for a single planning base case, scenario analysis is needed to understand how transmission upgrades and flexibility options perform when outcomes diverge materially from the planning assumptions. Just as FERC Order 1920 now requires scenario-based long-term planning, these same tools can offer insight for system planning in the era of rapid grid expansion for large loads. See Example 4.

The base case in transmission planning can no longer be treated as a single "best estimate," but rather be a set of near-term study cases that bracket plausible clustering, project development timelines, and supply-side churn. Transmission solutions can be designed to be flexible as needs become clearer, reducing the risk of both over-building and undersizing. Near-term upgrades would be selected not only to fix the most likely constraint but also to fit cleanly into a larger, expandable configuration if additional load ultimately materializes. Later sections of this report discuss how transmission solutions can be made more flexible and how larger, expandable configurations can be designed and evaluated under uncertainty.

Near-term upgrades would be selected not only to fix the most likely constraint but also to fit cleanly into a larger, expandable configuration if additional load ultimately materializes.

Uncertainty also requires the use of decision heuristics that select the most robust, least-regrets solutions that perform well across the plausible range of future uncertainties rather than focusing on the lowest-cost solutions to address base case needs. The need for timely increases in transmission capacity also requires planners to make decisions based on limited information available today. Delaying a decision may reduce uncertainty but would also lead to significant delays that make it harder to provide timely increases in transmission capacity.

EXAMPLE 4

Uncertain Multiple Load Requests

A planning region sees multiple 200 to 500 MW load requests seeking interconnection in the same area, electrically close and with similar in-service dates, but they are at different stages of commercial maturity. One has a real site, executed agreements, and a defined staging plan for ramp and growth, while the others are still contingent on financing or a tenant.

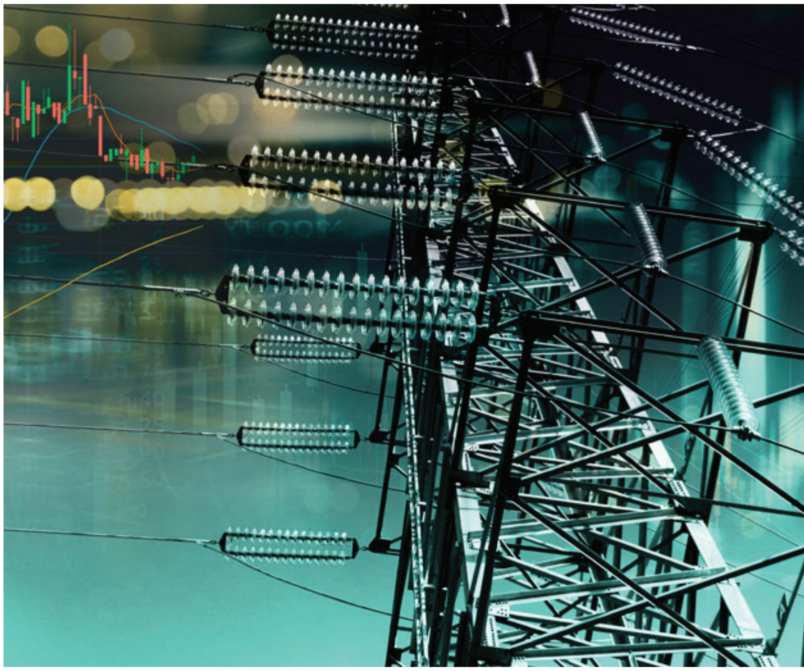
If the transmission planning base case treats all of the load requests as equally certain, the transmission study will point toward a heavier build than would be justified if only the first project materializes. On the other hand, if the base case includes only the "most certain" project, the analysis would plan for a smaller load, which could lead to transmission constraints if later projects continue to advance. This uncertainty is amplified by the changing resource mix, including generator retirements, new generation and storage additions, and any co-located or associated supply tied to the large load requests themselves. Different assumptions about both load and supply can change which transmission constraints appear and which upgrades look necessary.

Futures-Based Scenario Analysis

Scenario-based analysis allows planners to move from asking "what clears the base case" to "what performs acceptably across plausible near-term outcomes"? That shift matters when the risk of being wrong has

33 In fact, current NERC planning requirements call for analysis of one peak load forecast (NERC, 2023, sec. 2.1).

substantive operational and financial consequences. In regions with a significant large load interconnection queue, scenario analysis is not an optional robustness check. It is the primary way to test whether a near-term solution is a durable first step or a short-lived fix that the next wave of requests will supersede.



Futures-based scenario planning is designed to handle this kind of uncertainty. Rather than try to predict the future accurately, this approach examines several plausible futures designed to help planners break away from the implicit assumption that the future will be consistent with current trends, and tests how plans perform against those alternate futures (Ramírez et al., 2017).

Unlike approaches that vary one or two planning parameters at a time, futures-based planning is a multi-step process that uses internally consistent scenarios defined by specific combinations of important assumptions and uncertainties. First, planners define a set of plausible futures based on current conditions, trends, forecasts, uncertainties, and other internal and external drivers (see Example 6, p. 34). Second, they test plans, projects, or policies across those futures and identify options that perform reasonably well under a range of conditions. Third, they identify a plan, along with predefined indicators that signal when conditions are shifting, and additional actions may be needed (Pfeifenberger and Heller, 2025). This preferred plan may be designed to maximize its average value across all plausible futures while simultaneously mitigating the risk of poor performance given the large range of uncertainties.

Today, the use of scenarios or sensitivities is largely relegated to long-term advisory studies. It is not often used for near-term planning studies that lead to actionable project endorsements (Burmester et al., 2007). The Australian Energy Market Operator (AEMO) develops its Integrated System Planning framework using a holistic, scenario-based, multi-value planning process; identifies the plans that offer the highest value (net benefits) across the specified scenarios; and identifies more flexible transmission solutions through a risk-minimizing least-regrets planning framework (AEMO, 2023b). The Alberta Electric System Operator (AESO) is developing a similar process (AESO, 2026). ERCOT has used planning scenarios for its Long Term System Assessment since 2008, with scenarios developed around planning parameters including load growth, environmental regulations, generation technology options/costs, oil and gas prices, transmission regulations and policies, resource adequacy, end-use markets, and weather and water conditions.[34]

Futures-based scenarios for near-term transmission planning to accommodate large load development will need to cover a plausible range of load forecasts along with other key planning assumptions on how load and generation could develop over the longer term. Those assumptions include load growth ranges, the availability and cost of generation and storage technologies, fuel costs, the likely locations and timing of new loads and supply resources, the cost and availability of transmission equipment and development, the extent to which loads are flexible or co-located with new resources behind the meter or nearby on the grid, and public policy goals and mandates. To the extent these factors are correlated (such as public policies and macroeconomic conditions), those relationships can be incorporated as well.

Recent policy direction reinforces this shift. FERC Order 1920 requires transmission providers to conduct long-term, scenario-based regional transmission planning that considers a broader set of drivers and benefits when

34 For more details specifically on the 2014 LTSA, see (Hagerty et al., 2015).

identifying more efficient or cost-effective transmission solutions for long-term needs (FERC, 2025b). It requires transmission planners to develop at least three distinct long-term scenarios, including sensitivities that can stress-test each scenario. Under the order, planners must also specify transparent evaluation processes based on a benefit-cost framework with clear selection criteria to identify preferred transmission solutions (FERC, 2025b). Beyond these general directions, however, FERC does not specify how scenario analysis should be used to select specific projects. In particular, it does not prescribe the use of "least-regrets" frameworks.

Least-Regrets Planning and the Value of Flexibility

Scenario analysis can show how candidate transmission solutions perform across different futures, but planners still need a practical approach for deciding which solutions to select and how to sequence them. That decision process is especially important when results differ materially across scenarios and the costs of being wrong are asymmetric and high. Over-building can strand capital, complicate cost allocation among customers, and provoke stakeholder resistance, while under-building can delay service, force reliance on emergency or corrective actions, and lock planners into repeated rounds of incremental upgrades.

Least-regrets planning provides the decision logic that connects scenario analysis to action under these conditions. Rather than treating uncertainty as something to be averaged away, least-regrets approaches actively manage it by selecting solutions that perform well across several plausible futures while limiting the magnitude of downside outcomes when reality diverges from expectations.

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The goal of least-regrets planning is to mitigate the risks of high-cost outcomes associated with transmission solutions that turn out to be too big or too small, too late, in the wrong place, or ineffective. The terms "no regrets" or "least regrets" are widely used in transmission planning, but they are not used consistently. To some, "least regrets" simply means finding the least-cost solution for the specific transmission need at hand. To others, it may refer to the minimal level of investment necessary to deal with the least-challenging future scenario (to avoid any risk of building more than necessary) or the investment necessary to address the most challenging future scenario (to handle multiple outcomes effectively by avoiding reliability problems and high costs from getting "caught short"). But when properly implemented, least-regrets planning informs the decision making process and leads to selection of transmission projects that maximize the upside and minimize the downside across all scenarios.

Least-regrets planning is likely to highlight the benefits of flexible and scalable transmission solutions, i.e., transmission improvements that can work for multiple future large-load scenarios by allowing expansion capability over time as long-term uncertainties resolve themselves, mitigating risk by widening rather than tightening future transmission options. For example, spending slightly more to construct a new single-circuit transmission line on double-circuit towers creates a low-cost expansion opportunity that has great value in the face of unpredictable large load build-outs. Unless uncertainty and optionality are recognized, valued, and prioritized from the start, spending more to build double-circuit towers or an HVDC-ready transmission design with added right-of-way would not appear valuable or justified. One good example of least-regrets transmission design is found in California, where CAISO created transmission for 1,600 MW of offshore wind generation that can be cost-effectively expanded to serve 3,300 MW or 8,000 MW if needed in the future. It designed a new 500 kV line to be "HVDC-ready" and acquired rights of way sufficient to add a second HVDC line in the future (Pfeifenberger and Sheilendranath, 2025, slide 10).

Australian integrated system planning uses scenario-based planning and least-regrets planning to value flexible transmission solutions under uncertainty (AEMO, 2023b). AEMO starts with a 30-year outlook to identify long-term needs and candidate transmission solutions, and links long-term planning to near-term decisions by explicitly valuing optionality, including projects that can be built or expanded in stages. The integrated system plan distinguishes between "actionable projects," where the need is sufficiently certain to proceed, and future projects that may be needed later. AEMO applies an "expected net benefits" approach to identify the most valuable solutions from a total system cost perspective.[35] It then applies the least-regrets framework to select solutions that also limit downside risk across multiple futures.[36] Some future projects can be advanced as "early works" to create fully permitted, shovel-ready projects that can be built quickly when needed.[37]

Least-regrets analysis treats flexibility as a measurable source of system value rather than a hedge against indecision. More flexible designs may have higher initial costs, but they can lower the cost of adaptation when future conditions diverge from expectations. That option value is often invisible in deterministic studies, but becomes visible once outcomes are evaluated across multiple plausible futures. Least-regrets planning does not eliminate risk, but it reduces the cost of being wrong by embedding adaptability into multiple assets and the system as a whole.

Identifying Inflection Points and Designing for Scalability

Once uncertainty is built into alternative future load and supply scenarios, scenario-based analysis can be used to shape transmission design choices. By evaluating a range of plausible load and generation trajectories, planners can identify the amount and locations of new demand and supply that make different types and combinations of

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solutions preferable—for example, when higher-voltage facilities, load flexibility options, additional circuits, or new corridors begin to outperform incremental reinforcements. These are infrastructure inflection points, which can be used to distinguish between solutions that merely satisfy near-term needs and those that preserve flexibility and long-term options. Rather than committing immediately to the largest possible build, planners can use scenario analysis to identify the thresholds (inflection points) at which more substantial investments or alternative technologies become the preferred solution. These types of flexibility or scalability analyses are at the core of developing more robust grid solutions through planning processes that rely on futures-based, least-regrets planning.

Although identifying inflection points clarifies when and why different transmission options become attractive, it does not by itself determine which scalable option should be advanced first. In practice, planners still must choose among multiple designs that perform differently across futures and carry different costs if conditions diverge

35 "Transmission benefits" are cost savings or better reliability offered by transmission investments. For example, a more expensive transmission solution may be more attractive than a less expensive solution if, in addition to addressing a particular transmission reliability need, the more expensive solution also offers reduced congestion costs, avoids other future transmission upgrades, or creates lower-cost additional interconnection capacity—all of which lower total electricity system–wide costs. Studies like MISO's Long-Range Transmission Planning analyses show that every $1 billion spent on well-planned transmission upgrades may reduce other electricity system costs by $2 to $3 billion. The transmission solutions that offer the highest net benefits will consequently tend to yield the lowest overall electricity system–wide costs. See slide 6 of Pfeifenberger and Heller (2025).

36 The AEMO Integrated System Planning Methodology (AEMO, 2023b) uses both a "least worst regrets" and a "least worst weighted regrets" approach to assess the extent to which different transmission solutions (referred to as candidate development paths) mitigate the risk of over-building or under-sizing.

37 Great Britain's National Energy System Operator (NESO) has used AEMO's "least worst regrets" approach in transmission planning (NESO, 2022; Mancarella et al., 2020). NESO recently evaluated "least worst regrets" in comparison with other planning frameworks that allow for the consideration of risk mitigation in transmission planning under uncertainty, such as robust decision-making, decision tree analyses, info-gap decision theory, robust Bayesian analyses, and stochastic optimization (NESO, 2025; Palmer et al., 2025). Taken together, these frameworks illustrate that least-regrets planning is not about delaying decisions, but about making earlier decisions that preserve flexibility and reduce exposure to costly misalignment with future system needs.

from expectations. That remaining decision requires a framework that explicitly weighs the cost of being wrong across scenarios as well as the benefits of being flexible and scalable.

Scenario-Based Comparison of Planning Pathways

In the context of large loads, traditional planning methods expand transmission incrementally in response to individual (or sometimes batched) interconnection requests and narrowly scoped reliability needs. Each incremental decision may appear reasonable and optimal on its own but can embed significant risk when viewed across multiple futures. As large loads arrive in discrete increments and on compressed timelines, this sequencing can lead to repeated rounds of upgrades, creating higher total system costs and growing constraints on future options.

Scenario-based analysis makes these trade-offs visible. By evaluating candidate solutions across multiple futures, planners can directly compare how proactive, portfolio-based planning performs relative to more incremental, interconnection-driven expansion. This perspective reveals expected costs and the distribution of outcomes when growth turns out to be faster, slower, larger, or more clustered than assumed. In many cases, solutions that appear more expensive in a base-case analysis outperform incremental alternatives once the cost of being wrong is explicitly considered.

Scenario-based transmission planning evaluations reframe the planning question from “how do we serve the next request?” to “which planning pathway performs best across multiple plausible futures?” Scenario-based pathway comparison exposes the hidden costs of reactive sequencing, and highlights the value of coordinated solutions that anticipate a range of development trajectories rather than optimizing narrowly around a single expected case, as shown in Example 5 (p. 31).

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EXAMPLE 5

The Math of Designing and Selecting Least-Regrets Solutions

Assume that future load and generator interconnection needs might range from 800 MW in Future 1, to 1,600 MW in Future 2, to 2,400 MW in Future 3, shown in Table 1. Transmission planners have determined that the optimal solution for Future 1 is a single-circuit 500 kV line at a cost of $500 million. For Future 2, the optimal solution is a double-circuit 500 kV line at a cost of $600 million; and for Future 3, a 765 kV line for $800 million.

A least-regrets analysis would ask how each solution performs if a different future materializes. In a future different from the one planned, there will be regret of having either over-built or under-built relative to the actual transmission need.

Table 2 (p. 32) shows how each of the three solutions performs across all three futures. If Solution A is selected (the smallest transmission option), another 500 kV line would need to be built if Future 2 occurs, and a double-circuit 500 kV line would need to be added if Future 3 occurs. The initial choice of the smallest transmission option could lead to an eventual cost of $1.1 billion if Future 3 brings 2,400 MW of new large load to be interconnected.

Similarly, if Solution B is selected (a $600 million double-circuit 500 kV line optimized for Future 2), the line could be scaled back to a single-circuit placed on double-circuit towers, which would reduce total cost to $550 million if Future 1 occurs. But if Future 3 occurs, another single-circuit 500 kV line would need to be added, for a total cost of $1.1 billion.

If Solution C is selected (the 765 kV line), total costs would be $800 million in either Future 2 or Future 3,

TABLE 1

Planning for Interconnection Needs in Three Scenarios

	Future 1	Future 2	Future 3	
Need	800 MW	1,600 MW	2,400 MW	
Optimized Transmission Solutions				
Solution A	1 x 500 kV			A single-circuit 500 kV line is optimal for Future 1.
Solution B		2 x 500 kV		A double-circuit 500 kV line is optimal for Future 2. (It can initially be operated as single circuit.)
Solution C			765 kV	A 765 kV line is optimal for Future 3. (It can initially be operated at 500 kV.)
Cost of Optimized Solutions				
Cost A	$500 million			
Cost B		$600 million		The cost would be $550 million if it's initially built as single-circuit line on double-circuit towers.
Cost C			$800 million	The cost would be $650 million if operated at 500kV initially; plus $150 million for transformation.

Source: Energy Systems Integration Group

EXAMPLE 5

The Math of Designing and Selecting Least-Regrets Solutions CONTINUED

TABLE 2

Evaluation of How Each Solution Performs in All Three Futures: Outcomes and Costs

	Future 1	Future 2	Future 3		
Outcome if Actual Future is Different from Optimized					
Solution A+	1 x 500 kV	+1 x 500 kV	+2 x 500 kV	The system would need to add another 500 kV line (or 2 x 500 kV line) if Future 2 (or Future 3) is realized.	
Solution B+	Op as 1 x 500 kV	2 x 500 kV	+1 x 500 kV	The system would need to add another 500 kV line if Future 3 is realized; the solution is oversized for Future 1.	
Solution C+	Op at 500 kV	765 kV	765 kV	The solution is oversized in Futures 1 and 2. The line is operated at 500 kV in Future 1 (which saves $150 million in transformation costs).	
Ultimate Cost				**Weighted Average Cost**	**Other Considerations**
Cost A+	$500 million	$1,000 million	$1,100 million	$866 million	Right-of-way for up to 1 x 500 kV and 2 x 500 kV is needed.
Cost B+	$550 million	$600 million	$1,100 million	$750 million	Right-of-way for up to 2 x 500 kV plus 1 x 500 kV is needed.
Cost C+	$650 million	$800 million	$800 million	$750 million	Right-of-way is needed for single 765 kV only.

Note: Blue shading indicates the optimal solution per future.

Source: Energy Systems Integration Group.

but the ability to initially operate the line at 500 kV (without the added transformation) reduces the total cost in Future 1 to $650 million. If we assume that each of the three futures has the same probability of occurring, the probability-weighted average cost of selecting Solution A would be $866 million, while the probability-weighted average cost of Solutions B and C would only be $750 million. Solutions B and C thus perform equally well on a weighted average cost basis.

A least-regrets analysis compares the realized cost of each solution with the cost of the optimal solution in the future that actually occurs (Table 2). For example, the "regret" associated with Solution C if Future 2 occurs is that the solution ended up $200 million more costly (i.e., over-built) relative to Solution B.

Similarly, if we had selected Solution B but Future 3 occurs, the regret of having under-sized the solution would be $300 million in additional costs incurred (i.e., having to spend $1.1 billion when the optimal solution would have cost only $800 million). Solution C also reduces right-of-way needs by avoiding the second line required under Solution A in Futures 2 and 3 and Solution B in Future 3 (per Table 2).

These economic "costs of being wrong" are calculated for each of the three solutions in Table 3. For each solution, the "largest regret" is shown in red. As the table shows, Solution C (the 765 kV line) has a maximum regret of $200 million (having over-built transmission if Future 2 occurs), while Solution B has a larger, $300 million regret if we find ourselves with an under-sized solution in Future 3. Solution C (the largest

EXAMPLE 5

The Math of Designing and Selecting Least-Regrets Solutions CONTINUED

TABLE 3

Evaluation of How Each Solution Performs in All Three Futures: Maximum Regrets

	Future 1	Future 2	Future 3	
Maximum Regret (the Added Cost of Being Wrong)				
Regret A	$0	+$400 million	+$300 million	Regret: Up to $400 million extra cost due to underbuilt solution
Regret B	+$50 million	$0	+$300 million	Regret: $300 million extra cost due to underbuilt solution for Future 3; $50 million extra cost for overbuilding in Future 1
Regret C	+$150 million	+$200 million	$0	Regret: Up to $200 million due to overbuilt system

Note: Blue shading indicates the optimal solution per future. Red text indicates the greatest regrets.

Source: Energy Systems Integration Group.

expansion sequence) has the least (smallest) regret across all three futures, while Solution A (the smallest expansion sequence) has the largest regrets, under the two higher demand scenarios. This example shows how sometimes it can be more costly to underbuild in the face of uncertainty than to commit to a highly flexible transmission solution.

The least-regrets analysis shown in Table 3 provides important additional information beyond the probability-weighted expected costs (calculated in Table 2, p. 32) by highlighting the solutions that can better mitigate the risk of over-building or under-sizing if the future realized differs from the future planned for. It illustrates the difference between proactive transmission planning and reactively expanding transmission in response to individual interconnection requests.

Assume, for instance, that Future 1 reflects a current interconnection request for delivering 800 MW of generation to new load. If transmission is built for that future, the selected solution would be the single-circuit 500 kV line for $500 million. If a second interconnection request for 800 MW follows, a second single-circuit 500 kV line would be built. If there were a third interconnection request, building a third line would yield a total investment cost of $1.5 billion. If equal probabilities are attached to the individual interconnection requests, the probability-weighted average cost of this interconnection-driven planning approach would be $1 billion, or about $250 million higher than the probability-weighted $750 million average of the proactively planned Solutions B and C. The maximum regret of pursuing these transmission investments incrementally would be $700 million, relative to Solution C.

In summary, designing a transmission solution either for a single base-case scenario or incrementally in response to individual interconnection requests is unlikely to yield solutions that are cost-effective in futures that differ from the base-case planning assumptions. In contrast, when planners evaluate multiple futures and identify flexibilities that allow these solutions to be scaled up or scaled down, this can produce more robust solutions with lower expected total costs and lower regrets. See Example 6.

EXAMPLE 6

ATC's Scenario-Based Benefit-Cost Analysis of a Transmission Project

American Transmission Company (ATC), serving several states in the Upper Midwest, produced its *Planning Analysis of the Paddock-Rockdale Project* in 2007, which presented one of the first U.S. examples of a futures-based transmission planning study that analyzed costs and benefits and applied a least-regrets planning framework to show that a proposed transmission solution performed well across a range of scenarios (Burmester et al., 2007). The transmission project was proposed as an optional economic project (not a reliability-driven project), which means it was worth pursuing only if expected but uncertain cost savings exceeded projected project costs across a range of future outcomes.

ATC developed plausible future outlooks for multiple drivers, including load growth inside and outside the ATC footprint, availability of low-cost generation in Wisconsin, amounts and sources of renewable energy, nearby extra-high-voltage transmission projects, fuel prices and availability, environmental regulations, and availability of low-cost-generation nearby. These drivers were combined into six plausible futures: (1) robust (national) economy, (2) high generation retirements, (3) increased environmental regulations, (4) slow demand growth, (5) fuel (natural gas) supply disruption, and (6) high demand growth (in Wisconsin).

ATC estimated the economic transmission benefits (cost savings) that the project would provide to its customers for each selected future relative to the project's $136 million 40-year net present value of revenue requirements. Benefits included production cost savings, improved wholesale market competitiveness, reliability and insurance benefits, reduced generation investment costs, and resource capacity savings from reduced power losses. Benefits fell $56 million short of the $136 million net present value revenue requirement in the "slow growth" future but exceeded costs in the other five future scenarios. Estimated net benefits ranged from approximately $100 million under the "high environmental regulations" future, to approximately $400 million under the "robust (national) economy" and "high growth Wisconsin" futures, and approximately $700 million for the "fuel supply disruption" and "high generation retirements" futures.

The results varied widely across scenarios. If ATC had built the transmission line but ended up in the "slow growth" future, its "regret" would be $56 million in added costs. But not investing in the project would leave customers $700 million worse off in two of the most challenging futures.

This example shows the value of assessing the potential impact of more robust, more flexible transmission projects across plausible futures for transmission planning under uncertainty. The example also shows that the "regret" of landing in an over-built future is limited to a portion of the project costs ($56 million in regret out of $136 million in project costs), while the regret of ending up in a future where the project was not built but was needed can be several times greater than the project's costs (in this example a $400 to $700 million regret).

Importantly, least-regrets planning does not mean "build for the biggest analyzed future scenario." In practice, a careful analysis of how project alternatives perform in equally plausible futures, assessing the expected benefits and regrets from each alternative in each scenario, will provide the results needed to appropriately select the option that maximizes upside across all scenarios and minimizes any downsides. The specific selection criteria are not as important as having the information available to make an informed decision.

Design for Scalability and Future Fit

Near-term upgrades do more than solve immediate constraints. They can preserve or foreclose later expansion options (such as by using existing rights-of-way or substation space, or by changing cost-benefit assessments of alternative projects), affect how quickly additional capacity can be created, and shape whether the system can respond efficiently if load develops sooner, larger, or in different locations than expected. Under large load conditions, proposed solutions need to be tested not only for whether they solve the first identified constraint but also for how well they preserve practical expansion paths if load growth continues or clusters more tightly.

Use Flexible Transmission Solutions to Preserve Future Options

Flexible transmission solutions translate least-regrets planning from an analytical concept into physical design and sequencing choices that evolve, rather than committing all capital up front to a single, fully built configuration. In the context of large loads, this flexibility functions as a form of risk management, reducing both the cost of under-building if demand materializes faster than expected and the cost of over-building if growth slows or shifts location. In traditional deterministic planning, flexible designs can be hard to justify because their value often does not appear in the base case. But under large load uncertainty, flexible solutions often outperform rigid alternatives by limiting worst-case costs and reducing reliance on emergency measures, corrective actions, or repeated rounds of incremental upgrades.

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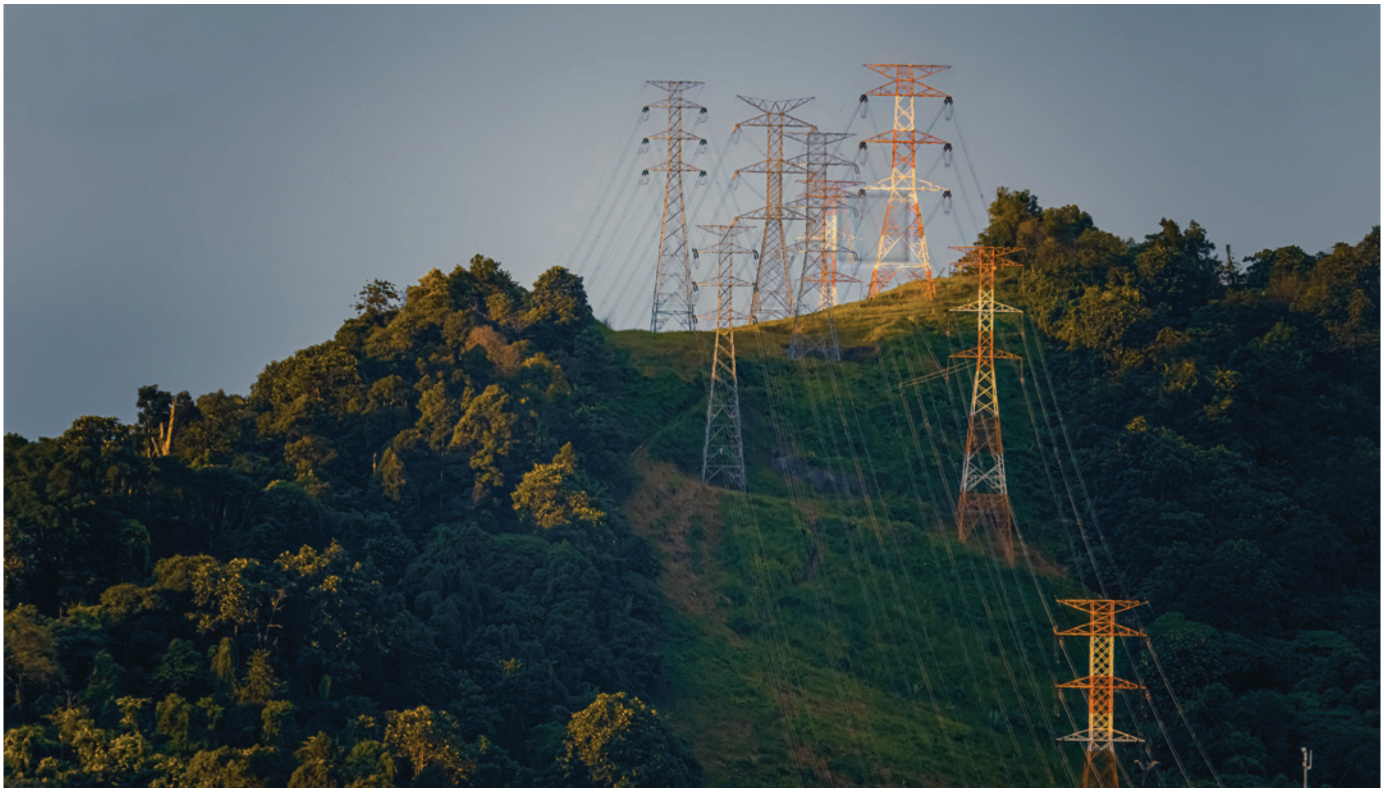
Flexibility can be embedded in transmission plans through:

- Staged construction by using double-circuit structures
- Operating lines initially at lower voltages with the ability to uprate later
- Designing corridors and substations to accommodate future expansion
- Selecting technologies that can be repurposed or augmented over time (as by building AC transmission circuits that could be converted to HVDC in the future)

These design choices materially lower the cost of responding to uncertain large load build-outs by shortening timelines and avoiding the need for entirely new rights-of-way or greenfield projects. While such projects are rarely the lowest-cost solution for the reliability planning base case, they can enable higher-growth futures to be served faster and at lower cost.

Flexible transmission solutions are especially valuable when large loads arrive in discrete increments and on compressed timelines. Designs that can be expanded or repurposed quickly allow planners to respond to verified development signals without restarting multi-year planning, permitting, and siting processes. This capability is critical for maintaining reliability and affordability while avoiding reactive, piecemeal investment patterns that lock in inefficiencies over time.

In practice, flexible transmission can be understood as a portfolio of design and sequencing choices rather than a single technology or project type.



Keep Near- and Intermediate-Term Solutions Aligned with Long-Term System Needs

Some near-term measures are intended to buy time until larger, more comprehensive transmission solutions can be implemented. With large loads, however, those interim measures can become permanent features of the system if the initial upgrade (such as a line reconductoring) ends up standing in for the longer-term plan. Once a load is energized, the initial upgrades may partially relieve symptoms and thus reduce the apparent need for or overall benefits from larger projects in subsequent studies. At the same time, capital invested in the initial solutions may make it harder to approve larger, higher-value reinforcements in later studies. Over time, the system may accumulate a patchwork of individual, incremental fixes that were never designed to scale together or support continued growth, leading to higher long-term system costs and possible delays.

The practical issue is not whether an initial measure solves the immediate need. It is whether that measure leaves room for an efficient next step if more load or supply shows up, if nearby interconnection requests advance, or if the area ultimately needs a broader transmission solution. A near-term fix is only a cost-effective and robust investment if it preserves the path to effective long-term solutions. Near-term investment that pre-empts more effective long-term solutions can increase long-term costs.

Transmission project designs that preserve future options and create a pathway to more comprehensive solutions include higher-voltage-ready structures, wider rights-of-way, substation layouts that allow expansion, and corridor configurations that can accommodate additional circuits. These design choices tend to create headroom, address multiple system needs, and retain value as conditions evolve. They often require more upfront analysis and coordination, making them harder to advance under immediate pressure, even when they are ultimately more cost-effective. They may also require broader geographic evaluation or cross-process coordination, which further slows approval.

Plan for Continued Growth

In regions with sizable large load interconnection queues, it is not feasible to delay interconnections until long-lead transmission solutions can be designed and built, or to deploy only near-term fixes that may become redundant or require future revisions because they do not serve long-term system needs. An increasingly relevant alternative is to serve large loads in a scalable fashion: develop projects that are sized for future rather than current needs and fit into a long-term plan that supports multiple future outcomes. A good way to do this is to shift from request-by-request transmission upgrades to shared corridor or portfolio-based solutions. When multiple large loads target the same area, planning region-level transmission upgrades to serve multiple customer facilities at different stages of the interconnection process can limit serial construction and provide more predictable access to capacity.

Even in regions that analyze groups of interconnection requests at the same stages of the interconnection process in batch studies, there can be serial interconnection requests in the same area or along the same transmission corridor across consecutive batch studies over several years. If upgrades are bundled across multiple interconnection cycles and aligned with longer-term scenarios, this can reduce restudies and queue churn while creating scalable headroom. Rather than sizing to "the next request," the corridor plan is sized to a bracketed range of plausible near-term outcomes, with staged options if the higher end materializes. See Example 7.

Use Staged Implementation to Preserve Cost-Effective Expansion Paths

Staged implementation of transmission projects complements flexible transmission design by aligning near-term projects with long-term needs. Long-term plans can be designed to be built in stages, similar to the phased transmission plan developed for Texas in the Competitive Renewable Energy Zone (CREZ)

EXAMPLE 7

Creating More Flexible Transmission Solutions

The following hypothetical example of an aging 230 kV single-circuit line illustrates how proactive, least-regrets planning can be used to address near-term needs and produce better long-term decisions under uncertainty.

- **Traditional approach:** Rebuild the 230 kV line at an estimated cost of $800 million.
- **Proactive approach:** Identify both the immediate need to refurbish the aging line and the possible (but uncertain) longer-term need to interconnect an additional 1 to 2 GW of large loads and generation along the transmission corridor.
- **Under this proactive approach, a least-regrets solution** might be to rebuild the 230 kV line to be "345 kV ready" with a single-circuit line on double-circuit towers. This may add $100 million to initial project costs but creates valuable options to address additional future needs, such as interconnecting new load and generation. Once additional capacity is needed, the rebuilt, "345-kV-ready" 230 kV line could be converted to operate at 345 kV by adding transformation for another $100 million, creating 1 GW of additional transfer capability and interconnection headroom. If even more capacity is needed, a second 345 kV circuit could be added to the double-circuit towers, at a cost of $150 million, to create 2 GW of total grid expansion at a total cost of $1.15 billion ($800 + $100 + $100 + $150 million).

More traditional planning processes might have refurbished the 230 kV line to the existing specifications only to later find that additional large load growth required an additional greenfield transmission line, costing $1 to $2 billion to create 1 to 2 GW of additional interconnection headroom. The total cost of that traditional pathway would therefore be $1.8 billion to $2.8 billion, significantly above the costs under the proactively planned approach.

This example shows that in a least-regrets planning framework, an upfront investment in more flexible transmission solutions can address near-term needs while preserving a lower-cost pathway to add up to 2 GW later (Pfeifenberger and Heller, 2025, 10, 13).

Transmission Optimization Study, in which the transmission plans designed to accommodate various levels of new wind generation were subsets of larger plans (ERCOT, 2008). Planners working to resolve near-term issues can review the components of long-range plans to see whether these can be implemented to meet immediate needs. Even if none of the components of the long-range plan meet the near-term need, this review can ensure there is no conflict between a near-term project and expected future needs. As shown in the CREZ transmission study (which included a staged implementation pathway and alternative lowest-cost designs), the staged implementation may not be the least-expensive option for the smaller stages of the overall build-out but will likely minimize regrets and lead to less expensive transmission upgrades in the long term.

Ways to stage transmission implementation to sequence right-sized transmission measures include:

- Designing and using structures, corridors, or rights-of-way that can support future expansion
- Exploring permitting and routing early, and, where justified, securing long-lead equipment such as transformers or breakers or reserving manufacturing slots for likely future corridor upgrades
- Designing near-term upgrades so they do not pre-empt or block later backbone development

These measures are particularly valuable to handle projects in large load interconnection queues that are credible but not yet fully confirmed. They allow planners to shorten the implementation timeline for scalable near-term solutions without prematurely committing to expensive upgrades. Such early, strategic measures preserve later development options, create a relatively stable foundation for long-term transmission planning, and reduce the cost and time penalties of coming back later to develop additional transmission solutions under even tighter conditions. Staged implementation can help produce early infrastructure decisions that keep better expansion paths open if they are needed sooner.

Longer-Term Solutions

Longer-term solutions to the planning challenges presented by new large loads focus on planning reforms that consolidate siloed processes and establish how to handle ongoing large load growth in concentrated areas. Their purpose is to move planning beyond project-by-project reinforcement toward stronger coordination across planning processes, more comprehensive evaluation of system needs, and broader comparison of alternative transmission solutions.

Shift from Project-by-Project Upgrades to Proactive and Coordinated Long-Term Planning

Collectively, large loads are often so large, fast, and uncertain that serial project-by-project responses do not constitute, and may even prevent, a competent, effective planning framework. Making better near-term choices, such as incorporating flexibility into project decisions, can improve planning outcomes, but a comprehensive planning process is needed that can identify longer-term transmission needs before repeated project-level responses begin to lock in inefficient outcomes. This proactive, comprehensive planning looks beyond the next interconnection request, uses long-range and multi-value planning earlier, and integrates local, regional, and interregional alternatives before a narrow local fix becomes the default path.

Coordinate and Integrate Transmission Planning and Interconnection Processes

Siloed planning limits regions' ability to proactively and efficiently integrate large loads. Fragmented planning reduces visibility into system-wide impacts, inconsistent screening criteria obscure trade-offs, and sequencing challenges amplify the consequences of early decisions. While each planning channel may function as intended, their combined operation under large load conditions often produces reactive and sub-optimal outcomes. But it is still uncommon to see full consolidation of load interconnection, supply interconnection, reliability planning, and longer-horizon economic and public policy planning. Most regions still run these planning processes separately, with limited mechanisms to harmonize assumptions or evaluate solutions across needs.[38] FERC Order 1920 establishes a new long-term planning requirement, but it does not require consolidation with existing interconnection and reliability-driven planning processes.

Some regions are testing more integrated approaches. While it does not fully integrate planning functions, MISO's long-range transmission planning process provides a channel for evaluating larger, regional multi-value transmission solutions over longer distances, which is expected to reduce reliance on serial, locally scoped fixes

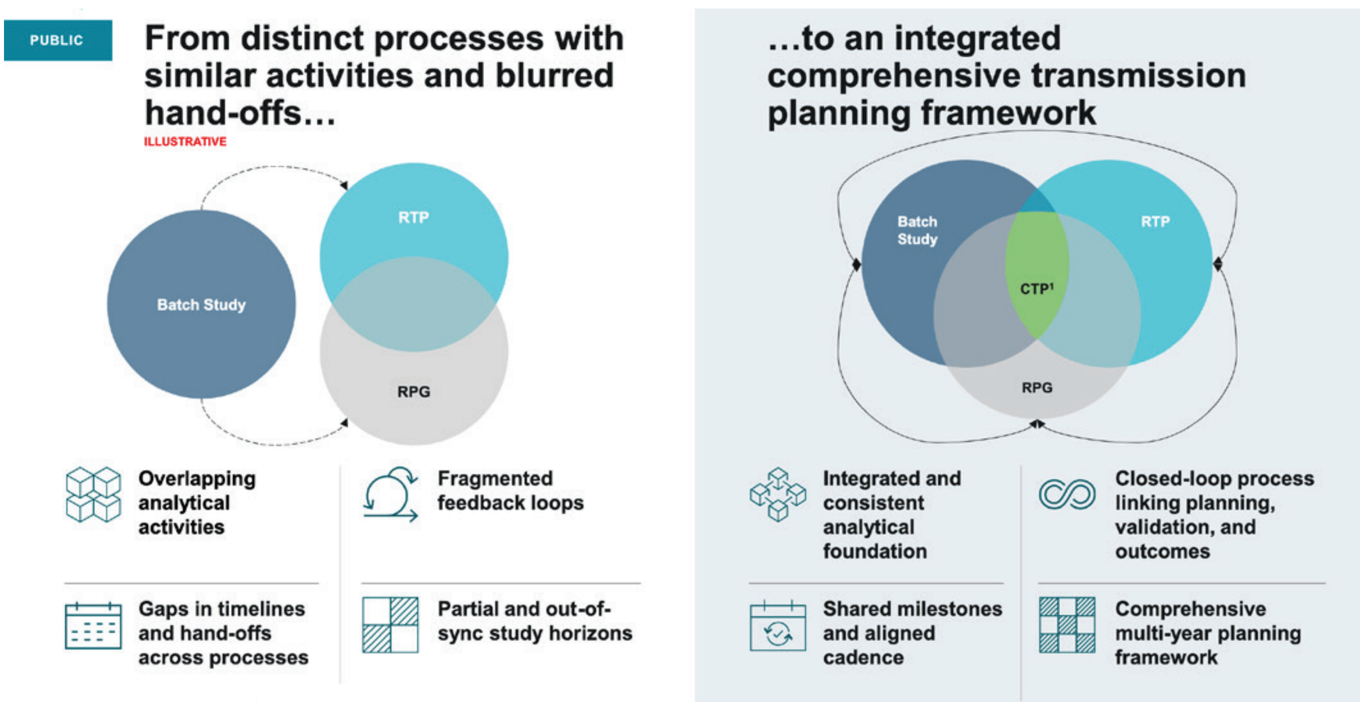
38 See, for example, ESIG (2025b) and Pfeifenberger (2025b).

(MISO, 2024a). ERCOT is evaluating how to combine its large load interconnection process with other aspects of its planning studies into a Comprehensive Transmission Planning process now that an increased amount of its planning efforts will be focused on its annual batch large load interconnection studies (Figure 6) (Hobbs, 2026).

SPP has also proposed a Consolidated Planning Process intended to improve coordination across Open Access Transmission Tariff (OATT)-required interconnection, reliability, and transmission planning studies (depicted in Figure 7, p. 41) (SPP, 2026a).[39] If implemented, the Consolidated Planning Process would replace the current approach of advancing upgrades through separate, reliability-focused, and interconnection-driven workflows and could enable more proactive planning for near- and long-term needs, including the creation of interconnection headroom.

SPP and MISO's Joint Targeted Interconnection Queue (JTIQ) Study demonstrates the value of process consolidation. In this study, planners consolidated generator interconnection requests for 5 and 10 years from both regions near the SPP-MISO seam to identify more comprehensive and cost-effective transmission and interconnection solutions than could be identified through each RTO's individual interconnection processes (MISO and SPP, 2022). The JTIQ process successfully identified transmission solutions to support 9 GW of existing generator interconnection requests and enable an additional 20 GW of projects near the SPP-MISO seam at a cost of $58/kW, along with additional avoided-cost benefits from congestion relief. The per-kilowatt cost of the identified upgrades is less than half the typical $100 to $130/kW cost of SPP's and MISO's individual (incremental) generator interconnection queue processes (Tsuchida, 2022).

FIGURE 6
ERCOT Proposed Comprehensive Transmission Planning Process



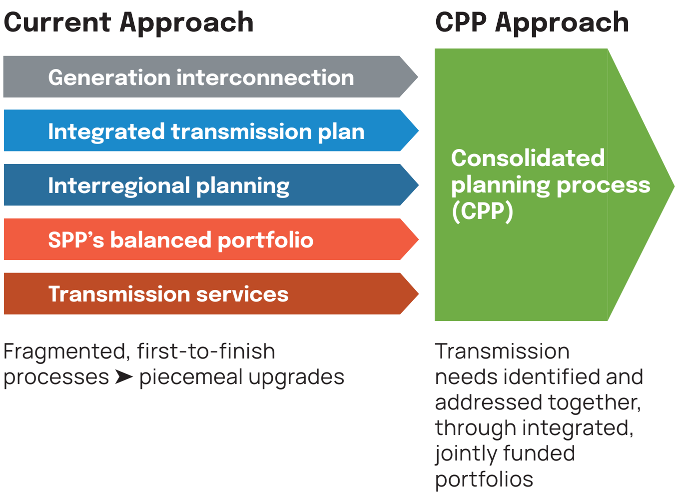
Notes: CTP = Comprehensive Transmission Plan; RPG = Regional Planning Group; RTP = Regional Transmission Plan.

Source: K. Hobbs, "Update on Comprehensive Transmission Planning," presentation at the ERCOT Board of Directors Meeting, June 1-2, 2026 (Electric Reliability Council of Texas), https://www.ercot.com/files/docs/2026/05/24/6.1-Update-on-Comprehensive-Transmission-Planning.pdf.

39 Implementation of the Consolidated Planning Process remains subject to SPP's Open Access Transmission Tariff (OATT) and NERC reliability requirements. It was approved by FERC in March 2026.

FIGURE 7

SPP Current and Proposed Consolidated Planning Processes



Southwest Power Pool's (SPP's) Consolidated Planning Process is intended to replace the current siloed generation, transmission service, and regional planning tracks with a single integrated framework that produces coordinated transmission solutions.

Source: Southwest Power Pool. For more information, see https://www.spp.org/Documents/73788/CPP%20Education%20Session%201%20-%20Meeting%20Materials%2020250507.zip

Reducing the separation and enhancing coordination between planning silos does not require abandoning existing planning procedures. Rather, we can integrate the various processes through shared assumptions, coordinated workflows and tools, consolidated studies where feasible, and explicit attention to how near-term actions shape long-term outcomes. Developing a more efficient, coordinated and consolidated transmission process can preserve system planners' ability to evaluate scalable, multi-driver solutions before incremental fixes to individual, early interconnection requests narrow the field of future system solutions.

Link Analytical Workflows Across Study Types

To plan effectively for large loads and other system changes, coordination across transmission study processes and planning entities requires both information-sharing and structured analytical workflows that promote consistency of insights across models. Production cost modeling, power flow analysis, voltage and stability studies, and deliverability assessments should not be stand-alone exercises. Rather, the congestion patterns identified in production cost modeling should inform the

selection of stressed system conditions and monitored elements in power flow studies. Voltage and stability limitations need to feed back into assessments of feasible load growth, transfers, and transmission expansion. And assumptions about large load demand flexibility and resource co-location need to be reflected consistently across all planning domains. See Example 8.

EXAMPLE 8

MISO's Scenario Discipline and Linked Planning Workflows

MISO's Futures Framework defines a small set of long-term scenarios that shape assumptions across planning efforts (MISO, n.d.-a). If this process were to be adapted for large loads, it could be used to define a small set of long-term futures that vary key drivers such as the magnitude, timing, geographical clustering, and credibility of large load development, as well as assumptions about flexibility and co-located generation. If used consistently across interconnection studies, reliability assessments, and long-range planning, these future scenarios would give planners a clear view of which transmission solutions are robust across multiple outcomes rather than optimized for a single load forecast.

In its Renewable Integration Impact Assessment, MISO linked production cost modeling with AC power flow and stability analysis, passing congested interfaces to power flow studies and monitored contingencies back to production cost models (MISO, 2021). Applied to large load–driven constraints, a similar approach can help ensure that solutions addressing near-term violations are also evaluated for their longer-term performance as load grows and system conditions evolve.

Modernize Planning Workflows to Keep Pace with Fast-Moving Load

Given how quickly load forecasts and interconnection queues evolve, planning workflows need tighter data integration, better modeling tools, and more automated studies. Better alignment between scenario-based transmission planning efforts and interconnection studies can leverage tools that automate study set-up and enable systematic data transfer across processes.[40]

In many regions, automation is already reducing cycle time for interconnection studies by compressing historically time-intensive tasks.[41] Some interconnection modeling efforts that previously required months can now be completed in hours through automation, even though overall timelines are still stretched by coordination, review, and required milestones. Automation is also useful for building queue scenario models, reducing multi-week tasks and processes to minutes.

Automation does not remove governance or approval constraints, but it enables planners to refresh assumptions more frequently, test a wider range of large load scenarios, and maintain consistency across studies as conditions change. Automation does not replace planners' judgment, but it removes some of the manual bottlenecks that slow down planning relative to real-world advances.

A shared study foundation is therefore not only a matter of process design but depends on the practical ability to keep assumptions current, rebuild cases quickly, and compare options using the same underlying facts across planning functions.

Use More Comprehensive Planning for Large Loads

As large load project requests increase, planners need to evaluate the full range of system needs and solution types on a comparable basis. That requires more

40 For example, National Grid and GridCARE announced a 2026 partnership to use artificial intelligence–enabled modeling, grid simulations, and real-time system intelligence to identify available grid capacity and reduce time to power for large loads in New York (GridCARE and National Grid, 2026; Martucci, 2026).

41 ESIG 2025 Fall Technical Workshop, Session 3B, "Modernizing the Interconnection Queue: AI, Automation, and Process Reform," which included presentations from SPP, MISO, PJM, Lawrence Berkeley National Laboratory, and NextEra Energy Resources on artificial intelligence, automation, queue reform, Energy Resource Interconnection Service, and automated interconnection studies (https://www.esig.energy/event/2025-fall-technical-workshop/).

coordinated planning across interconnection, reliability, long-range, and other study processes, with a broader evaluation of the benefits and trade-offs associated with different transmission options.

Evaluate a Broader Set of System Benefits

The scenario examples in the section "Scenario-Based Comparison of Planning Pathways" on addressing future uncertainty intentionally simplify the cost-benefit analysis of project to integrate large loads to highlight the issues of regret and scalability. In practice, most real-world transmission decisions should not be reduced to "large load interconnection capacity and grid expansion at lowest cost." Regional transmission solutions address multiple system needs and deliver a range of system-wide benefits and cost savings that need to be quantified as part of any least-regrets analysis.

Comprehensive planning is the proactive development of transmission solutions that address near-term needs, including large load interconnection, while remaining aligned with long-term system needs. It needs to address a range of additional reliability, economic, and public policy needs including by:

- Creating additional headroom for load interconnections beyond the active requests
- Creating headroom for additional supply interconnections in feasible or attractive grid locations, including resource types associated with public policy goals
- Relieving existing or projected transmission constraints or resource curtailments
- Reducing transmission line losses (yielding both energy and capacity-related savings)
- Improving grid resilience, for example, during extreme weather and other adverse events
- Reducing resource adequacy requirements, for example, by adding inter- and intra-regional transfer capabilities

If these broader impacts are not taken into account, a set of transmission solutions may appear optimal in a narrow framing but inferior on a total system cost basis. In a large load environment, the most valuable solutions need to create headroom while also delivering broader reliability, economic, and resilience value. These additional benefits can materially shift which set of transmission, load, and supply solutions produces least-regrets across multiple futures, which is why FERC Order 1920's planning and multi-benefits framework is appropriate for transmission planning in the face of large load uncertainty.[42]

Several proactive multi-driver transmission planning efforts focused on developing solutions that offer benefits beyond individual reliability needs have identified $2 of savings (or more) for every $1 spent (Pfeifenberger and Heller, 2025; Pfeifenberger et al., 2021b). For example, MISO's most recently approved, approximately $22 billion portfolio of multi-value transmission projects is estimated to offer $52 to $101 billion in benefits (i.e., system-wide cost savings) (Figure 8, p. 44).

Include Interregional Solutions

Interregional transmission delivers significant value across a broad set of system needs, including resource adequacy, resilience, and sharing of energy and capacity between regions. The projected growth in large load demand and the size of new large loads strengthens the case for examining transmission projects and options that span multiple planning regions for cost-effective grid interconnection and resource adequacy solutions.

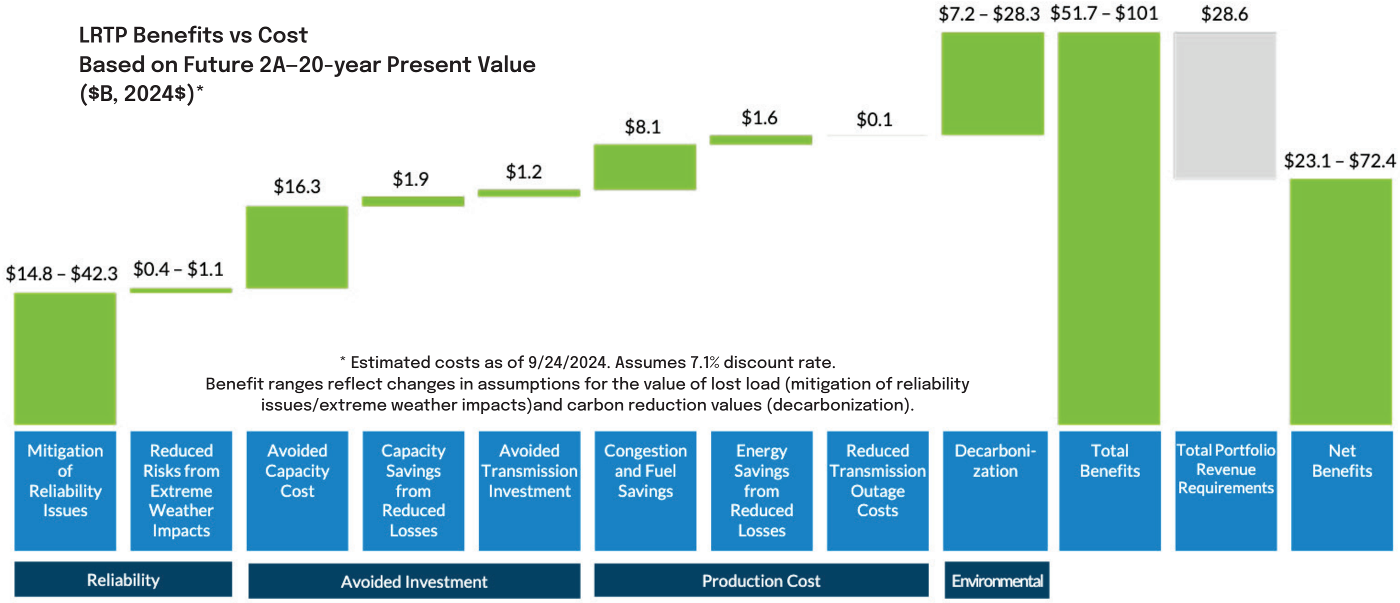
As large loads grow, interregional transmission can create interconnection headroom and support energy transfers, resource-sharing, congestion management, reliability, and resilience across diverse operating conditions. But the development of interregional transmission is challenged by the complexity of multi-regional planning, cost allocation, and multi-jurisdictional regulatory approvals, which can materially affect project feasibility and timelines.[43]

42 For a summary discussion of proactive, multi-value transmission planning, see Pfeifenberger and Heller (2025); for a detailed discussion, see Pfeifenberger et al. (2021b), which Order 1920 frequently cited in its discussion of transmission-related benefits.

43 For a discussion and industry survey of barriers and possible roadmaps to planning interregional transmission, see Pfeifenberger et al. (2021a).

FIGURE 8

Example: Multi-Value Benefit-Cost Analysis of MISO's Tranche 2.1 Transmission Portfolio



Waterfall chart of the components of the multi-value benefits calculation from MISO's Tranche 2.1 Transmission Portfolio.

Source: Midcontinent Independent System Operator, "MTEP24 Executive Summary" (p. 13, Tranche 2.1 LRTP Benefits vs. Cost),https://cdn.misoenergy.org/20241212%20Board%20of%20Directors%20Item%2009a%20MTEP%20Executive%20Summary%20Appdendix%20A%20Appendix%20F665158.pdf.

Because large loads often arrive in discrete increments and on compressed timelines, initial transmission planning solutions typically focus on local and, in some cases, regional reinforcements. Evaluating interregional transmission alongside local and regional solutions expands the feasible set of transmission solutions and resource options (see Example 9, p. 45). It allows planners to draw on a wider mix of resources, transmission solutions, and operating options, reducing reliance on single corridors or siting new rights-of-way in heavily constrained areas. Interregional solutions can include new extra-high-voltage AC or HVDC "backbone" or "overlay" facilities, which can provide large transfer capabilities over long distances, and smaller seams-related upgrades.

The recent approvals of regional 765 kV overlays in MISO, PJM, SPP, and ERCOT reflect a recognition of the value of extra-high-voltage backbone investments, including to serve load-growth needs (Figure 9, p. 45). While these plans were developed through individual regional planning efforts, the high-voltage facilities can be used for increased power transfers across multiple planning regions. Potential future connections between the

EXAMPLE 9

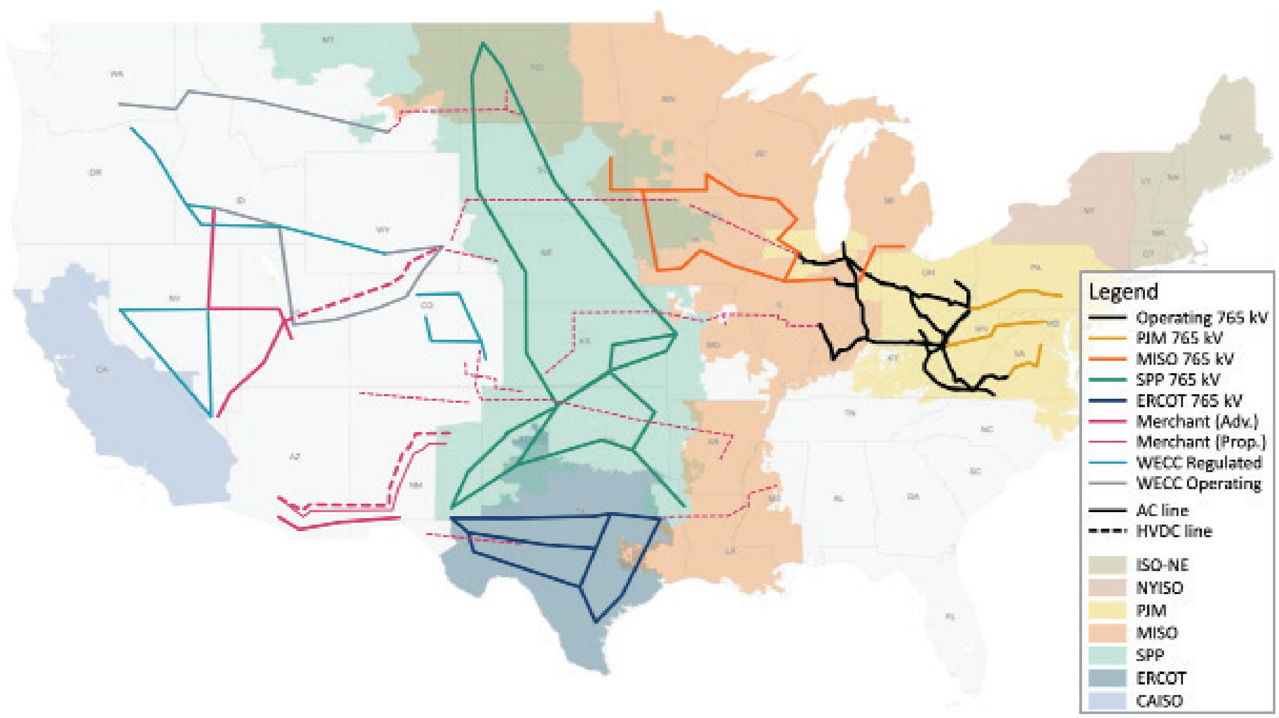
Comparing Local and Interregional Solutions

A region sees a concentrated wave of new load in a part of the footprint that is already transmission-constrained. Incremental local upgrades could work, but they quickly run into right-of-way and siting limits. At the same time, an adjacent region has different load shapes, resource mixes, and weather-correlated outage risk. If there are plausible options for interregional transmission projects, either targeted seams upgrades or larger backbone projects, these need to be evaluated, as they can expand the feasible set of solutions and provide benefits that local upgrades cannot.

If planners only look locally or even just regionally, they can end up forcing the problem into a small pocket of the grid and layering incremental fixes on top of one another. But if they also evaluate interregional solutions, they can reduce the number of new local and regional projects, improve performance during extreme events by tapping into diversity across regions, and create additional interconnection head-room that offers value across multiple futures.

FIGURE 9

Planned and Proposed High-Voltage Transmission Overlays and High-Voltage DC Lines



The recent approvals of regional 765 kV overlays in MISO, PJM, SPP, and ERCOT reflect a recognition of the value of extra-high-voltage backbone investments, including to serve load-growth needs. While these plans were developed through individual regional planning efforts, the high-voltage facilities can be used for increased power transfers across multiple planning regions. Potential future connections between the overlay projects shown in the figure will be able to strengthen regional and cross-regional transmission, among other things, to serve future load growth across larger regions.

Note: The northern portions of SPP's proposed 765 kV overlay have been proposed for SPP's 2026 planning cycle but are not yet approved. The shown "operating" and proposed "regulated" transmission projects in WECC are operated at 500 kV.

Source: J. Pfeifenberger and P. Heller, "Interregional Transmission and Benefits from Improved Planning," Presentation at MGA MID-GRID Webinar, December 15, 2025, The Brattle Group, https://www.brattle.com/insights-events/publications/interregional-transmission-and-benefits-from-improved-planning/.

overlay projects shown in the figure would be able to strengthen regional and cross-regional transmission, among other things, to serve future load growth across larger regions.

Once built, these major new transmission investments will operate for decades; therefore, they need to be planned using a least-regrets framework that recognizes the range of multiple future benefits beyond serving projected large loads. Interregional transmission options require collaborative planning and evaluation alongside local and regional solutions to identify the most effective and robust solutions for expanding the grid to every region's benefit.

Compare Local, Regional, and Interregional Options on the Same Basis

Where interconnection needs are large enough or grid impacts broad enough, planners can compare local fixes, regional reinforcement, and interregional solutions under a common set of multi-value planning assumptions and within the same planning cycle. This is the only way to judge whether the lowest-cost near-term solution is actually part of the most effective or highest-value path looking forward.

Used well, this broader comparison of regional and interregional options does not replace local planning. It puts local projects in a larger context and helps identify when a broader regional and interregional solution would create superior planning outcomes with more headroom created more quickly, lower total system costs, and better performance across multiple futures.

Use Development Zones to Support Long-Term Planning

Planners and state agencies can reduce uncertainty and support more proactive planning by identifying and creating likely development zones for large loads and generation rather than solely responding to the locations selected in new interconnection requests. Such development zones can be defined or proposed based on a review of locations in interconnection queues along with an

analysis of land availability, permitting feasibility, access to other necessary resources (such as natural gas or fiber-optic networks), and proximity to major transmission corridors. By anticipating or explicitly guiding where large loads and new generation are likely to locate, planners can develop corridor-level solutions that are better aligned with plausible future development patterns.

Developing these zones and transmission corridors requires close coordination between industry groups and state economic development agencies to identify economic development zones for large loads and generation development. Because grid planners generally do not designate land for economic development, their role would likely be advisory, providing information on grid capability, expansion options, and transmission implications. Such a process could be similar to the designation of Texas Competitive Renewable Energy Zones two decades ago or Illinois's Renewable Energy Access Plan (Cohn and Jankovska, 2020; ICC and The Brattle Group, 2024). The identification of load and resource development zones would then support more proactive grid planning and more timely, cost-effective system expansion.

Recommended Practices for Proactive, Comprehensive Grid Planning

The integration of large loads requires a shift from deterministic, base-case forecast-driven planning toward adaptive, scenario-informed decision-making. Planning processes need to explicitly recognize uncertainty, evaluate solutions across futures, and preserve options so that early transmission upgrades do not lock in inefficient outcomes. Input assumptions also need to be aligned across planning study horizons so that near-term solutions can be compared directly to transmission upgrades identified through longer-term planning studies.

These changes do not require abandoning existing planning frameworks. But they do require using them differently, by coordinating processes, connecting silos, broadening the set of futures considered, valuing option-rich designs, and treating uncertainty as a core analytical input rather than a residual risk. Rather than redesigning the entire planning system at once, regions can identify what can be done now, what process changes should follow, and what longer-term structural changes are needed if large load growth continues.

While significant changes in transmission planning processes are long overdue, the integration of new large load customers raises multiple challenges addressed in this report. By facing them head-on, system planners can:

- Better align grid interconnections, planning, and operations
- Explicitly address uncertainty, including in the near term
- Better identify location-specific transmission needs for load and generation
- Create and take advantage of load flexibility

- Take advantage of the efficiencies associated with co-location of new loads and generation
- Adopt automation tools that can streamline time-consuming study processes
- Consolidate siloed planning processes

Here we summarize the recommendations offered by the ESIG Large Loads Task Force. The phases describe how long different actions may take to mature and deliver results. These are not the order in which planners should begin working on them; rather, the three groups are meant to proceed in parallel. Group 1 actions are both short-term and urgent because they can create headroom quickly and reduce near-term reliability risk. Group 2 and Group 3 actions often require longer lead times, so work on them should begin early, even though their full benefits will be realized over a longer horizon. Near-term Group 2 tools, such as advanced transmission technologies and conditional service, need to be guided by the same long-term vision that informs development zones, scenario-based planning, least-regrets project selection, scalable design, and broader regional or interregional solutions.

Group 1: Urgent Actions (Up to 12 Months to Complete)

Goal: To maximize existing transmission assets and halt the lock-in of inefficient decisions

1. **Measure and publish near-term headroom and locational signals**

   - **Action:** Conduct and publish a standardized headroom study showing where and how much load interconnection capacity exists today and under all relevant system operating conditions.
   - **Reasons:** Without a shared understanding of headroom, interconnection requests will be studied one by one, constraints will be discovered late, and planners will have limited ability to guide projects toward locations that can be served reliably in the near term.
   - **Impact:** Better siting decisions, fewer re-studies, faster service in viable areas.
   - **Description:** Transmission planning analyses can be used to identify grid locations with existing headroom that can accommodate large load interconnection requests quickly. These analyses can evaluate headroom with and without RASs; with firm or non-firm load assumptions, including load flexibility or dispatch of back-up generators; and with and without co-locating loads with fully dispatchable new supply resources. Studies need to adequately represent a variety of normal and stressed operational conditions, including summer peak, winter peak, net peak, off-peak (shoulder) cases, light load, and high-transfer conditions. Results need to then be published in a consistent, public, stakeholder-oriented format rather than being limited to confidential project studies.
   - **Responsible parties:** Transmission planning, system operations, interconnection study teams
   - **Deliverables:** A public headroom map and short technical note documenting assumptions, study conditions, and limitations

2. **Use GETs, advanced transmission technologies, and operating measures as clearly defined short-term bridge solutions**

   - **Action:** Evaluate short-lead-time options, including GETs, advanced transmission technologies, reconductoring, RASs, and other operating measures to help resolve load-driven constraints.
   - **Reasons:** For many large load projects, the development timeline is often the binding constraint. Short-lead-time options enable a faster interconnection timeline.
   - **Impact:** Faster service, fewer premature high-cost upgrades, and a wider near-term solution set
   - **Description:** Planners need to conduct studies to explore the feasibility and impact of short-lead-time bridge tools on large load integration options. In addition, short-lead-time bridge tools need to always be explored as part of interconnection and planning studies. Regional planners can work with utilities to develop datasets of potential short-lead-time projects, such as mapping all rights-of-way that were built to support double circuits but only have one circuit installed, or identifying circuits that would experience a significant improvement in ampacity through reconductoring. Short-lead-time, low-cost solutions can also be implemented along with larger improvements to provide a viable on-ramp for large loads seeking interconnection.
   - **Responsible parties:** System operations, transmission owners, and transmission planning teams
   - **Deliverables:** A summary of short-term bridge solutions, including where they may be applicable, what constraints they address, and how they can be combined to buy time and increase headroom before new transmission investments are completed

3. **Use flexible-load and co-location arrangements to expand feasible interconnection options when their operating assumptions, limits, and obligations are defined, visible, and enforceable**

   - **Action:** Account for rule-based flexible load, back-up generation, batteries, and co-located resources in planning studies to reduce the need for transmission system upgrades, accelerate service, and widen the set of feasible interconnection and transmission options

- **Reasons:** Flexible-load and co-location arrangements can reduce near-term firm service needs and make more interconnection pathways workable. However, these arrangements should be relied on in planning only when planners and operators can verify how they will perform under the conditions modeled in the study.
- **Impact:** More credible non-firm service options, fewer unnecessary upgrades, faster load integration, and better alignment between planning and operations
- **Description:** Transmission planners will need to work with system operations, interconnection study teams, market and tariff staff, regulators, and customers to obtain detailed, regularly updated information on large load customers' projects and their operational flexibility and bring-your-own-generation plans. Working with grid operations, planners can develop frameworks for analyzing flexible and co-located new loads and generation that can manage and control their net grid withdrawals or injections (including large loads' back-up supplies, bring-your-own-generation, energy parks, and hybrid loads) for use in interconnection studies and transmission planning. Flexibility and co-located operating limits should be counted in planning only when they are clearly defined, visible to operators, and supported by telemetry, control, testing, well-defined response expectations, and penalties for noncompliance. Where the flexible load or co-located resource arrangement is temporary, both the near-term temporary off-grid and flexible load cases and the future firm load case should be studied to ensure near-term reliability and develop a flexible, scalable, and cost-effective long-term transmission build-out plan.
- **Responsible parties:** Transmission planning, system operations, interconnection study teams, and market/tariff staff
- **Deliverable:** Standard conditional service option, study framework, and verification process for flexible and co-located large load arrangements

4. **Use one shared large load assumptions dataset across all studies**
    - **Action:** Planning teams need to adopt a consensus, version-controlled dataset that includes every large load project location, desired operations start date, ramp rate to full load, maturity likelihood, use of co-located resources, expected operational characteristics, and committed flexibility. A consistent dataset and assumptions needs to be used across interconnection, reliability, economic, and longer-horizon planning studies in the same planning cycle. The dataset should feed into local and regional load forecasting, with utility and load-serving entities' forecasts harmonized so that large load projects are represented consistently across entities.
    - **Reasons:** When different planning processes use different assumptions, the resulting studies can identify different transmission constraints, system needs, and solutions. Shared data and assumptions reduce inconsistent or inaccurate results across the different transmission planning functions.
    - **Impact:** More consistent assumptions across study processes, fewer study reruns, and greater ability to identify transmission solutions that work across multiple planning needs
    - **Description:** A shared, version-controlled large load dataset will provide consistent information to all planners at the utility and the regional levels that can be used to assess transmission needs and compare solutions developed through various study processes. The dataset should include all necessary data regarding all projects in the interconnection queue. This dataset will serve as the common basis for consistent scenario definitions across all relevant planning processes.
    - **Owners:** Planning teams, load forecasting teams, interconnection study teams, transmission owners
    - **Deliverables:** A shared large load dataset for use across planning functions

Group 2: Near-Term Process Fixes (1 to 3 Years to Complete)

Goal: To change the study process and early project choices before continuing growth locks in higher-cost, less-durable outcomes

5. **Use standard sets of near-term and long-term scenarios in every planning cycle and update them as conditions change between planning cycles**

   - **Action:** The shared dataset from Recommendation 4 is used to develop and adopt a standard set of near- and long-term scenarios, which are applied consistently across all planning processes. Adjustments to these scenarios between planning cycles should be limited to material changes in future expectations and be well documented.
   - **Reasons:** A single base-case forecast in near-term planning is no longer sufficient to capture the impact of uncertainty regarding load development, timing, clustering, operating characteristics, and co-located resources. Standard scenarios allow planners to identify transmission needs and test solutions across plausible futures.
   - **Impact:** Fewer serial transmission upgrades, fewer load interconnection re-studies, better alignment between near-term projects and longer-term needs, and a more realistic picture of risk

   - **Description:** Planners should use the shared dataset to develop near-term and long-term scenarios that span the likely range of large load and associated supply resource development. Planners can proactively plan for both near-term and long-term local and regional transmission needs based on these consistent planning assumptions and uncertainty ranges (i.e., the set of scenarios describing the range of plausible futures). Scenarios will need to encompass potential variation in aggregate large load demand, locations, development ramps, clustering, flexibility provided by new customer facilities, co-located resources, and other operating characteristics. These scenarios need to be used in every planning study cycle and would replace current base case forecasts.
   - **Responsible parties:** Transmission planning, load forecasting, and system operations teams
   - **Deliverable:** A single set of planning futures for each planning cycle, with near-term study years embedded within the same long-term trajectories, including documentation of assumptions, scenario drivers, modeled sensitivities, and updates made between planning cycles

6. **Develop a least-regrets evaluation framework, including metrics and criteria, to compare transmission alternatives across future scenarios**

   - **Action:** A process can be developed to analyze total net benefits and potential regrets and costs from proposed transmission projects across a set of standard planning futures. The results will be used to support project selection, prioritizing projects with the greatest combination of total net benefits and least regrets across a range of scenarios. Planners would work with regulators and stakeholders to build agreement around the modified planning methodology and evaluation and selection process.
   - **Reasons:** Given the amount of uncertainty in near-term future demand resulting from large load development, it is important to consider both the net benefits and the potential regrets provided by a suite of transmission projects.

- **Impact:** By accepting uncertainty as a design constraint, it is easier to identify and justify the selection of transmission projects that best suit the range of potential future outcomes.

- **Description:** The scenario set developed in Recommendation 5 is used to identify system needs and evaluate alternative transmission plans across different large load and broader system futures. Planners can then apply a least-regrets methodology to compare transmission alternatives using a broad, well-defined set of transmission and system benefits. The evaluation also needs to account for long-term cost and time savings as well as short-term project costs. The methodology, assumptions, and results should be presented in a transparent format so that regulators and stakeholders can understand how alternatives were compared and why the preferred projects were selected.

- **Responsible Parties:** Transmission planning teams, regulators, and stakeholders

- **Deliverable:** A standard least-regrets and broader-benefits evaluation framework, including metrics, scenario-comparison methods, and transmission project-selection criteria

7. **Link interconnection, reliability, and longer-horizon planning on a common process cadence**

   - **Action:** Interconnection studies, near-term reliability planning, and longer-horizon planning need to be brought into a more coordinated planning rhythm with common assumptions, scenarios, and handoffs.
   - **Reasons:** When these study processes operate in silos and on different timelines, narrow local fixes can advance before broader regional or long-term transmission options receive a fair look.
   - **Impact:** More complete need identification and consolidation, better project comparability, fewer conflicting recommendations, and reduced risk that early decisions prematurely lock in narrow fixes
   - **Description:** Consistent, comprehensive, proactive planning frameworks can be implemented to plan for both near-term and long-term transmission needs, including load interconnection needs, generator interconnection needs, and broader network needs driven by reliability standards, economic benefits, and public policy objectives. Common assumptions, common scenario versions, and coordinated timing need to be used across interconnection, reliability, and longer-horizon studies. Near-term studies should be used to determine when project components from long-term plans need to be advanced, while longer-horizon studies can provide the context for evaluating near-term solutions. Planners need to ensure that all project recommendations from different study tracks are compared and are consistent with long-term plans.
   - **Responsible parties:** Transmission planning and interconnection study teams
   - **Deliverables:** A coordinated study calendar, common data and assumptions package, defined points for transferring assumptions and results between study processes, and criteria for advancing near-term project components from long-term plans

8. **Use scalable design and check "future fit" before approving major upgrade**

   - **Actions:** Planners will document whether each proposed upgrade preserves flexible expansion options and how all proposed transmission projects and solutions interrelate. If a proposed upgrade would limit future transmission expansion, planners would either redesign the project or clearly justify the design choice.
   - **Reasons:** Near-term fixes can solve the first problem while making later expansion harder and more expensive.
   - **Impact:** More flexible transmission options, better alignment between near-term upgrades and long-term plans, and greater ability to add capacity when future load materializes
   - **Description:** Planners need to prioritize scalable/flexible grid solutions that are consistent with plausible future scenarios and do not foreclose future development options. Near-term solutions can be designed with consideration of, and optimized to work efficiently with, longer-term solutions. The

default should be expandable structure and substation standards (e.g., double-circuit-capable towers even if stringing one circuit) in areas of large load development instead of sizing strictly for the first interconnection request or project cluster. Planners should document whether a proposed upgrade preserves future expansion options, including whether the selected project design includes expandable structures, foundations, substation layouts, and terminal equipment. In areas with continued growth of large loads, expandable design standards need to be used unless there is a clear reason why this is not feasible.

- **Responsible parties:** Transmission planning and transmission owner engineering teams, in coordination with interconnection study teams
- **Deliverable:** One-page "future-fit" review attached to approvals

Group 3: Long-Term Structural Solutions (More than 3 Years to Complete)

Goal: To build the larger, more durable grid solutions that individual large load interconnection requests cannot support on their own

9. **Establish state-designated or state-supported development zones**

- **Action:** States, with input from RTOs/ISOs and utilities, can establish or support the development of zones where large load development, supply, and transmission can be planned and advanced together.
- **Reasons:** Scattered interconnection requests drive inefficient one-off builds. Transmission planners cannot "zone" land; states can.
- **Impact:** More coordinated clustering, fewer bespoke upgrades, more efficient and economical transmission builds, and faster interconnection service
- **Description:** States, economic development agencies, utilities, RTOs/ISOs, and large load industry experts can work together to identify locations suitable to host large load customer facilities so that grid infrastructure development can be planned proactively to support these locations. This process should consider locations with the necessary fuel supply to allow development of new large load facilities with co-located generation resources and other generation. Planners should provide a hosting capacity map that states can use to develop energy parks or large load development zones, directing developers to areas where the grid can provide service or can be expanded easily.
- **Responsible parties:** State agencies' leads, with support from RTO/ISOs, utilities, and transmission owners
- **Deliverable:** State-issued "development zone" map with incentive package

10. **Connect and coordinate planning functions and studies through shared workflows and common assumptions**

- **Action:** More connected study workflows can be built across planning functions (supply interconnection, load interconnection, reliability planning, long-term regional and interregional planning). Shared assumptions, defined data and model exchanges, and automated analytical tools can be used to reduce manual bottlenecks and improve repeatability.

- **Reasons:** When planning functions use different assumptions, disconnected workflows, and uncoordinated study timelines, it has the disadvantage of being easier for narrow fixes to move ahead by default and harder to identify a comprehensive set of system needs and to compare solutions directly.
- **Impact:** Better alignment and coordination across planning functions, fewer conflicting study results, fewer piecemeal upgrades, and more consolidated identification of needs and transmission solutions
- **Description:** Planning functions need to coordinate on common and consistent study assumptions, model inputs, and analytical procedures. Planners will want to establish and document specific procedures for exchanging data, model inputs, model updates, and study results between departments and organizations. Where possible, planners should automate study workflows to facilitate scenario case-building, batch analyses, screening studies, and the creation of standardized data input and output packages. Automation can shorten study cycles, allow more scenarios and sensitivities to be evaluated, and replace bespoke manual modeling with repeatable batch runs and standardized output packages in each planning cycle. Regions can start with a repeatable handoff across planning functions, with shared assumptions, then move toward consolidated workflows and calendars.
- **Responsible parties:** Planning teams at RTOs/ISOs and utilities
- **Deliverables:** Connected workflows and data flows, consolidated system needs and solutions, automated study pipeline

11. **Use comprehensive and coordinated planning processes to inform all planning decisions**
    - **Action:** Move beyond serial evaluations of single customer needs by conducting proactive studies that evaluate the full range of system needs and solution types (local fixes, regional reinforcement, and interregional options).
    - **Reasons:** Defaulting to the near-term reliability fix based on one or a limited number of interconnection requests will often lead to higher total costs over time and repeated delays in providing adequate customer service.
    - **Impact:** Better long-term project choices, fewer serial upgrades, and a broader set of viable regional and interregional solutions
    - **Description:** Regions can develop long-term transmission plans that create system headroom and proactively address large load growth and other system needs. These plans need to identify and stage scalable backbone projects, including high-voltage corridors and major substations, that perform well across multiple future scenarios. Planners need to compare local fixes, regional reinforcement, and interregional options using the same assumptions, and evaluate project alternatives using a multi-value, least-regrets planning framework. The evaluation will address large load and generation interconnection needs while also considering other regional needs and accounting for interregional load and resource diversity. This more comprehensive analysis of local, regional, and interregional needs will identify near- and long-term development options that meet interconnection requests and make the entire transmission system more reliable, resilient, and affordable.
    - **Responsible parties:** Regional planning, interregional planning, and seams coordination teams
    - **Deliverables:** Broader alternatives summary and a long-term project shortlist

These recommendations will address current deficiencies in transmission planning processes highlighted by the growing interest in large load development. By following these recommendations, planners can stop relying on near-term fixes that limit future options for more comprehensive transmission upgrades and expansion and lock in inefficient planning outcomes, and move to a least-regrets planning framework that compares local, regional, and interregional solutions across plausible future scenarios. The goal is to identify transmission investments that can serve large loads on practical timelines while also addressing broader grid needs, including reliability, resource deliverability, economic efficiency,resilience, and future system expansion.

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Transmission Planning with Large Loads: Current Practices and Recommendations

A Report by the Energy Systems Integration Group's Large Loads Task Force

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This report is available at https://www.esig.energy/reports-briefs/transmission-planning-large-loads.

To learn more about the ESIG Large Loads Task Force and the recommendations in this report, 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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