Modernizing Transmission Planning

INTEGRATING SILOS TO DELIVER MULTI-DRIVER, MULTI-VALUE OUTCOMES

A Report by the
Energy Systems Integration Group's
Integrating Transmission Silos Task Force

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ESIG
ENERGY SYSTEMS INTEGRATION GROUP

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Modernizing Transmission Planning: Integrating Silos to Deliver Multi-Driver, Multi-Value Outcomes

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Disclaimer

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

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Abbreviations

CAISO	California Independent System Operator
DER	Distributed energy resource
DOE	U.S. Department of Energy
FERC	Federal Energy Regulatory Commission
HVDC	High-voltage DC
IBR	Inverter-based resource
ISO	Independent system operator
ISO-NE	Independent System Operator New England
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
PJM	PJM Interconnection
RTO	Regional transmission organization
SPP	Southwest Power Pool

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Executive Summary

Current Planning Practice–What It Produces and Why It Persists

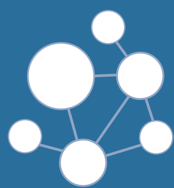
The U.S. grid is changing rapidly. Electrification, new energy-intensive loads, more frequent extreme weather, aging assets, and a shifting resource mix are reshaping when and where electricity is needed. The system will need more—and higher-capacity—transmission to meet a multitude of compounding needs. Yet in most regions, transmission planning still runs in siloed tracks: generator interconnection; reliability and near-term needs; economic and congestion studies; asset management and end-of-life programs; public-policy planning; and new efforts for large loads interconnection. Each track uses its own calendar, inputs, and study methods. Coordination occurs, but mostly as one-off touchpoints rather than a recurring process with shared inputs and firm decision points.

These parallel tracks produce piecemeal upgrades that under-utilize corridors, raise costs, and miss multi-benefit opportunities. What gets built sets the grid's capabilities. As evident in the outcomes of the current planning approach over the past two decades, a pipeline of transmission upgrades that is heavy on lower-voltage, lower-capacity projects addresses local, near-term problems but adds little regional headroom. Regular additions of larger, higher-voltage facilities create durable transfer paths, reduce corridor rework, and make room for new generation and loads without the need for potentially costly workarounds. To identify the most cost-effective regionally focused upgrades requires an integrated approach (Figure ES-1, p. viii).

FIGURE ES-1

A Practical Framework for the Evolution of Transmission Planning

INTEGRATE
planning across silos and timelines



Integrated transmission planning includes coordination across transmission planning silos—including greater interaction between generator interconnection, load interconnection, reliability, economics, asset management, public policy, and operations—to support projects that serve multiple purposes, have multiple benefits, and avoid duplicative investments.

BROADEN
the range of drivers, scenarios, and stakeholders

Integrated transmission planning expands the set of planning scenarios informed by a fuller range of inputs and drivers, providing a spectrum of outcomes and values. In addition to reliability and congestion metrics, it includes emerging factors such as large loads, resilience risks, decarbonization goals, interregional coordination, and system flexibility needs.

DEEPEN
the analysis to support better decisions and outcomes

Integrated transmission planning improves planning analyses to reflect the growing complexity and interdependence of grid needs. This includes using high-resolution modeling tools, examining multiple plausible and diverse future scenarios, assessing impacts of new technologies and their behaviors, and analyzing future system operability.

Source: Energy Systems Integration Group.

What Reform Delivers

The Energy Systems Integration Group convened a task force of utility planners, system operators, developers, and technical experts, and the task force's recommendations center around three actions: integrate planning across silos and timelines; broaden the drivers, scenarios, and stakeholder input; and deepen analysis to support better decisions and outcomes—using tools, processes, and deep experience planners already have. The result is a planning process that can deliver:

- Faster, more predictable interconnection of generators and loads, as shared corridor upgrades address recurring constraints and align with the long-range plan
- A steadier buildout of high-voltage, multi-benefit transmission lines, complemented by targeted lower-voltage work that fits the same scenarios
- Studies that produce coordinated portfolios and documented decisions using shared assumptions, common benefits, and portfolio-level scoring
- Near-term fixes and asset replacements right-sized to address long-term needs, reducing serial mitigations and rework

Why Silos Persist

Planning stays in separate tracks because of who pays, how work is timed, how tools and assumptions differ, and how teams and regions are organized. Some remedies require decisions by utilities, system operators, states, or the Federal Energy Regulatory Commission (FERC), while others fit within existing processes. Common patterns include:

- **Compartmentalized organizations.** Siloed, discipline-based teams are the norm and may limit information flow and cross-functional insights, thereby reinforcing narrow outcomes. Without deliberate coordination among teams, the result is that information, system needs, and solutions stay within a single study track.

- **Fragmented timelines and horizons.** Planning functions run on different clocks. Interconnection cycles are annual or semi-annual and look 2 to 5 years ahead; reliability planning for compliance is annual and looks 5 to 10 years ahead; and regional long-range planning spans even longer horizons. Each process treats uncertainty differently. The misalignment can make coordination difficult and leads to undersized, duplicative, or delayed upgrades.
- **Varied tools, assumptions, and models**. Each planning function uses its own tools and assumptions. For example, reliability studies do power flow analysis focused on select snapshots with generalized dispatch, while economic models simulate hourly dispatch over the entire year. Both are useful, but the inconsistency hampers comparison and weakens feedback across studies.
- **Fragmented mandates and cost recovery.** Because each process has a narrow mandate and costs fall to different payers, planning gravitates to minimum "but-for" fixes, making multi-purpose portfolios harder to approve—even when those projects or portfolios deliver greater value.

If Nothing Changes

Without reform, transmission planning runs the risk of continuing to produce piecemeal fixes that leave assets undersized or stranded. Opportunities to make better use of existing rights-of-way may be missed and planning will stay reactive—returning to the same corridors with serial mitigations. Interconnection queues will continue to churn, and upgrades for generators and loads will remain uncoordinated. Over time, the gap between modeled benefits and operating reality can widen.

Without reform, transmission planning runs the risk of continuing to produce piecemeal fixes that leave assets undersized or stranded. Opportunities to make better use of existing rights-of-way may be missed and planning will stay reactive–returning to the same corridors with serial mitigations.

The result is higher costs, slower delivery, and elevated risk to reliability and resilience.

Integrate, Broaden, Deepen

The integrate–broaden–deepen framework proposed in the report links siloed planning tracks through shared assumptions and clear hand-offs, so transmission projects are designed and selected as a coordinated, multi-driver portfolio. The framework builds on tools that planners already use and makes inputs, limits, and decisions consistent across functions. *Integration* applies one set of assumptions to reveal system-wide needs and supports consistent decisions across planning tracks. *Broadening* brings in the full set of drivers and plausible futures so that studies capture conditions that stress the grid. *Deepening* converts those broader studies into operable, physics-consistent portfolios.

Integration: Core Actions and Near-Term Priorities

Planning functions need to be integrated across silos and timelines so that coordination can take place across planning silos: generation interconnection, load interconnection, reliability, economics, asset management, and public policy. The intent is to scope projects once to serve multiple purposes and avoid duplicate investment. The same assumptions need to be applied, and system needs and limits carried between studies using a shared list of common system needs and constraints. Hand-offs must

be aligned so that solutions are sized for long-term use rather than only meeting the minimum “but-for” fix.

The Integration Continuum

Planning practice falls along a continuum: from separate studies with ad hoc coordination, to shared inputs and documents with occasional joint selection, to recurring planning cycles that design and select portfolios across drivers, and, at the far end, a fully integrated practice where decisions, data, and projects move together. Moving one step along this continuum reduces rework, right-sizes projects, and shortens delivery. Practically, that means working from shared assumptions and inputs, linking the model chain—capacity-expansion to production-cost to AC power flow to stability/electromagnetic transient—with feedback, and selecting portfolios with a common benefits catalog while right-sizing rebuilds by default.

Three Priorities to Integrate First

System operators can start with the following three seams where recurring constraints show up across analyses, where resources and new loads interconnect, where a large share of spend occurs, and where operability limits bind. Connecting these first reduces rework, lowers queue churn, and turns one-off fixes into coordinated corridor upgrades.

Integrate generator and large load interconnection with long-range planning. Planners can synchronize generator and load interconnection assumptions, methods, and study cycles with long-term regional planning. Study teams need to group compatible requests and carry generator-queue signals, large-load indicators, and policy-driven system changes into the same futures used across all planning activities so it is clear where resources and loads are likely to interconnect or drop out. They should apply the same transmission constraints in both interconnection and planning studies and bundle recurring bottlenecks into shared corridor upgrades tied to a long-range plan. Planners can use high-interest queue areas as candidate resource zones and include load-interconnection zones in expansion plans.

System operators can start with the following three seams where recurring constraints show up across analyses: where resources and new loads interconnect, where a large share of spend occurs, and where operability limits bind. Connecting these first reduces rework, lowers queue churn, and turns one-off fixes into coordinated corridor upgrades.

Integrate asset replacement with long-term needs. Planners can tie asset-management programs to long-range transmission planning so that rebuilds meet future needs—which often extend beyond the asset’s initial purpose—rather than defaulting to like-for-like replacements. Study teams should screen end-of-life projects against shared scenarios and a common list of system needs and constraints, and make right-sizing the default. They should bundle overlapping rebuilds and nearby constraints into coordinated corridor upgrades tied to the long-range plan. Mitigation plans need to be scalable or able to accommodate added capability with minimal effort.

Integrate operations with planning. Planners will want to design transmission for how the grid runs, bringing operational considerations, such as ramping, dynamics, and stability, directly into long-range studies and not just as checks after projects are designed and selected. The process for identifying, developing, and testing projects needs to include formal operator input, use production-cost-driven stress periods, and, where needed, electro-magnetic transient (EMT) analysis to ensure that transmission plans reflect expected grid operating conditions.

Broaden–Scope, Futures, and Participation

"Broadening" planning clarifies why we plan and expands what studies see and who participates, so that transmission expansion reflects a more complete set of drivers and priorities.

Why we plan: Planners need to set objectives beyond least-cost reliability or congestion relief to include public policy, resource adequacy, resilience, and flexibility needs.

What is modeled: Studies will need to model high-impact, non-traditional loads (e.g., data centers, electrified oil and gas), distributed energy resources, extreme weather, planned and unplanned outages, and resilience requirements (e.g., emergency import capability).

Who is involved: Planning can coordinate across state agencies, vertically integrated utilities, system operators, municipal systems, impacted tribes, and neighboring regions.

System planners, operators, and stakeholders can define and maintain a shared set of futures that reflects large loads, extreme weather, policy-driven resource shifts, interregional transfers and seams, and flexibility/operability needs. Study teams can apply the same futures across all planning functions so that outcomes are compared on a common basis. Where possible, they should work from the same inputs with state energy offices and neighboring regions to reduce rework and shorten the path from procurement to infrastructure.

Deepen–Analytics, Operability, and Calibration

"Deepening" planning means strengthening its analytical foundation to support decision-making. It refines how value is measured, improves modeling of uncertainty and extreme conditions, addresses emerging operational challenges, and makes methods and results more transparent and connected across study types.

- **Linking the toolchain.** Studies should carry constraints and candidate solutions through capacity-expansion, production-cost (8,760-hour), AC power-flow, and stability/EMT tools with clear hand-offs.
- **Bringing operability in early.** Planners need to incorporate voltage stability, ramping, inertia, weak-grid pockets, and light-load/high-transfer conditions into screening and design, not just after project selection.
- **Using diverse futures and stress tests.** Portfolios can be evaluated across multiple long-term futures and extreme-but-plausible scenarios, with ranges and key sensitivities reported.
- **Building optionality.** Transmission plans can preserve optionality by favoring designs that can scale or be converted, such as expandable bays and convertible AC/DC corridors.
- **Calibration with operations.** Study teams and operators can align planning and operations by comparing modeled flows, congestion patterns, and shadow prices to measured data. Constraints, assumptions, and results can be exchanged in both directions. They will also need to document any resulting adjustments to models and limits, as well as the impacts of proposed transmission.

Multi-Need and Multi-Benefit Analysis

Do multi-need design. Planners will need to scope projects and portfolios to meet multiple system needs from the outset and only then value the benefits.

It is easy to imagine two projects with very different impacts: one designed narrowly to address a specific reliability constraint and another intentionally scoped to also reduce congestion, integrate new resources, and improve resilience. The latter would likely outperform the former in a multi-benefit evaluation, but it may never be proposed unless planning processes are designed to surface multi-need solutions from the outset.

Evaluating benefits after a transmission concept exists is not a substitute for purposefully designing projects that simultaneously address reliability, congestion, policy, resilience, and load growth. To unlock the full potential of a multi-benefit evaluation framework, study teams can prioritize multi-need planning—a process that explicitly identifies, layers, and integrates multiple system needs during project development.

Do multi-benefit analysis (modernize benefit–cost). Planners should use FERC Order 1920's seven benefits as a floor and add region-specific benefits. They can then apply consistent, transparent methods, score at the portfolio level, and align metrics with stakeholder priorities and cost allocation principles.

Why it matters. Projects and portfolios designed for multiple needs yield higher value per dollar and per mile of right-of-way and align better with reliability, economic, and policy goals. It is easy to imagine two projects with very different impacts: one designed narrowly to address a specific reliability constraint and another intentionally scoped to also reduce congestion, integrate new resources, and improve resilience. The latter would likely outperform the former in a multi-benefit evaluation, but it may never be proposed unless planning processes are designed to surface multi-need solutions from the outset.

Closing–Putting It on a Single Recurring Cycle

FERC Order 1920 sets clear expectations for transmission planning: longer-range, multi-driver, scenario-based strategies. The integrate–broaden–deepen approach offers a practical path to meet those expectations using tools planners already have. The task now is to make these practices routine, embedded in how projects are scoped, modeled, reviewed, and approved each cycle, so that portfolios are operable, durable, and ready for changing conditions.

System planners can connect planning functions, work from a shared set of futures, and select least-regret portfolios that keep options open. They should align assumptions across reliability, economics, interconnection, and asset replacement so that results are comparable and traceable.

System operators can align study timelines and standardize methods and assumptions. They should tie interconnection and regional planning together, reflect long-term scenarios and benefits in near-term studies, and use asset-condition data to guide strategic rebuilds.

Utilities can engage in multi-need planning at regional and local levels. They should align internal teams (transmission, resource planning, operations) on shared inputs and timing; bring forward right-sized, flexible solutions; and coordinate early with states.

State and federal regulators need to encourage transparency, scenario diversity, and alignment across agencies. They should provide durable policy signals and enable cross-jurisdiction coordination, and support cost-allocation frameworks that reflect shared, multi-dimensional benefits.

Other stakeholders will want to engage early and consistently to shape inputs, call attention to overlooked needs, and keep decisions transparent. They can propose and support solutions that bridge near-term actions and long-term goals and make local and regional benefits clear.

The opportunity is to make these practices part of every planning cycle—so that solutions are designed for multiple needs before approval, costly redesigns are avoided, and new transmission lines and upgrades deliver lasting value. With Order 1920's implementation window open, these steps can be taken now to move from parallel tracks to coordinated, multi-driver portfolios.

Introduction

The U.S. power system is rapidly changing. Electrification, energy-intensive new loads, and a major shift in the resource mix are reshaping when, where, and how electricity is needed. More frequent extreme weather events, aging assets, and new operational patterns are adding further strain. These pressures create a clear opportunity to modernize the grid, improve efficiency, and meet evolving customer needs. Transmission is central to managing these changes: it unlocks generation, serves emerging load centers, and supports reliability and resilience.

The grid will need far more—and higher-capacity—lines. The U.S. Department of Energy's National Transmission Needs Study finds that many regions will need to at least double their transmission capacity by 2035, even before accounting for the surge of large, energy-intensive loads now seeking service (GDO, 2023). Yet new lines can take a decade to plan, permit, and build. Without closer alignment across planning functions, regions, and disciplines, it will be harder to form a consistent view of system needs, weigh options, and set priorities. The industry will continue

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to encounter the same bottlenecks—analyzing fixes in isolation, building upgrades for just one need, and overlooking chances to design projects that solve multiple problems at once.

Current Planning Frameworks Were Built for a Different Grid

Most regional planning processes were designed for a grid that changed slowly and predictably. They assumed steady load growth, gradual policy shifts, large central generating stations, and incremental reliability fixes. Today, those conditions no longer hold. Yet the planning studies—interconnection, economic planning, reliability, and public policy—still run in separate silos, each with its own calendar, workflows, tools, deliverables, and stakeholder track. The result is fragmented decision-making and missed opportunities to address system needs more efficiently:

- **Congestion costs hit $20 billion in 2022**, reflecting both operational inefficiencies and transmission bottlenecks (Doying, Goggin, and Sherman, 2023).
- **Roughly 2,600 GW** of proposed generation and storage—about twice today's installed U.S. capacity—were in interconnection queues at year-end 2023; historically, only **~14% have reached operations,** with many stalled by a lack of transmission (Rand et al., 2024).
- More than half of North American regions face elevated capacity and/or energy risk through 2028 (NERC, 2024), with transmission limits constraining interregional support and new resources integration.
- **Data center load could reach as high as 130 GW by 2030** (Shehabi et al., 2024), doubling its share of national electricity use and stressing the transmission system.

Siloed Transmission Planning Means Missed Opportunities

Even as transmission investment rises, most projects still move through separate channels—local planning, interconnection upgrades, and asset replacements. This keeps them out of sync and leads to single-purpose fixes, duplication, and missed opportunities to address system needs in a coordinated way.

Each silo focuses on a narrow mandate and rarely looks beyond its primary objective. For example:

- Interconnection planning addresses resource additions but typically focuses only on the minimum upgrades needed, and thus may miss opportunities to address persistent congestion.
- Reliability planning ensures compliance with North American Electric Reliability Corporation (NERC) standards but often omits policy goals or long-term generation and load trends.
- Economic planning reduces production costs but may miss flexibility or resilience needs.
- Asset management replaces equipment without assessing whether upsizing would deliver broader benefits.
- Public policy planning is often treated as an add-on rather than a core driver.

In isolation, these tracks produce piecemeal upgrades that raise costs, underutilize transmission corridors, and miss multi-benefit development opportunities. A line might be upgraded to support a new generator, while ignoring a nearby data center cluster, chronic congestion, or its role in maintaining resilience during extreme weather. Furthermore, planning one project at a time for one single purpose can obscure the broader system value of that upgrade, especially when multiple benefits could be captured through a coordinated portfolio approach.

A better approach links the planning functions—aligning timelines and assumptions, widening the needs and benefits considered, and applying rigorous, forward-looking analysis. This turns isolated fixes into coordinated upgrades that address current priorities and prepare for future demands.

An approach that links planning functions turns isolated fixes into coordinated upgrades that address current priorities and prepare for future demands.

FERC Order 1920–the New Planning Baseline

Federal Energy Regulatory Commission (FERC) Order 1920 set the first nationwide floor for more integrated, multi-benefit, scenario-based planning (FERC, 2024a). Every transmission provider must now prepare a long-range plan at least once every five years, evaluating reliability, economic efficiency, public policy mandates, resilience, and other benefits across a shared set of future scenarios. The rule sets minimum requirements for identifying system needs, assessing benefits, and ensuring that states and stakeholders are meaningfully engaged in the process.

Advancing Integrated Transmission Planning

With the policy baseline set by Order 1920, success depends on implementation. Some regions have made progress—developing multi-benefit portfolios, running joint transmission–generation studies, and expanding multi-state coordination. Even so, implementation of these methods remains uneven and far from standard. The next step is to move beyond compliance and make integrated, scenario-based, multi-driver planning the norm. That means rethinking how transmission is identified and justified before today's fragmented decisions harden into tomorrow's long-term infrastructure. This report offers a practical path to make that shift durable.

The Energy Systems Integration Group (ESIG) convened a task force including utility planners, system operators, developers, and other technical experts to examine how planning processes can evolve. The task force developed this report, which offers a practical framework—integrate, broaden, deepen—that aligns with FERC Order 1920. Drawing from experience in multiple regions, it shows how these principles are being applied and how they can be scaled to meet emerging needs.

Meeting near- and long-term transmission needs will require planning that is better connected, wider in scope, and more analytically rigorous. This report organizes those priorities into three action-oriented strategies of integrate, broaden, and deepen.

Integrate, Broaden, Deepen

Meeting near- and long-term transmission needs will require planning that is better connected, wider in scope, and more analytically rigorous. This report organizes those priorities into three action-oriented strategies:

- **Integrate** planning functions across silos and timelines
- **Broaden** the range of drivers, scenarios, and stakeholder voices considered
- **Deepen** the analysis to support better decisions and outcomes

Modernizing transmission planning does not require starting over. It means strengthening the links among existing processes so they can scale and adapt to new realities. Planners already have powerful tools—rigorous reliability assessments, interconnection studies, production-cost and capacity-expansion modeling, and policy coordination. Yet without tighter alignment, broader inputs, and deeper analysis, those tools can still yield fragmented results, prolong projects, and raise customer costs.

Through real-world examples, this report demonstrates how integrated, expansive, and rigorous planning can deliver more efficient transmission. While no single model fits every region, the following chapters outline how this transition is taking shape, what it enables, and steps the industry can take to move it forward.

Current Planning Practices

Over the past three decades, transmission planning has shifted from a localized engineering exercise into a more regional, stakeholder-driven process. This shift has improved transparency, expanded scope, and brought better coordination. However, many planning processes remain functionally separated.

Historically, utility-led planning focused on local reliability, maintaining asset health, and long-lead generation interconnection—adequate for a more stable, slower-moving grid. The creation of independent system operators (ISOs) and regional transmission organizations (RTOs) enhanced regional coordination, expanded stakeholder engagement, and prompted reforms in governance. But it also preserved—or, in some cases, formalized—separation among planning functions. Interconnection studies remain largely separate from regional planning. Economic studies are often decoupled from policy and reliability planning. Long-term scenarios inform analysis but **do not** consistently drive actionable decisions.

Even as transmission planning has shifted toward improved transparency, expanded scope, and better coordination, many planning processes remain functionally separated.

Rising Investment, Fragmented Planning

Transmission investment has risen steadily, but most spending still flows through fragmented planning channels. It is critical to understand not just how much is being spent, but what kinds of projects are being built. The mix of approvals by voltage and project type provides an indication of whether planning is primarily addressing near-term, local fixes or creating long-term, regional capability.

Why the Mix Matters

What gets built shapes what the grid can do. A pipeline of transmission investments that is heavy on lower-voltage, lower-capacity projects addresses local and near-term problems but adds little regional headroom. Regularly adding larger, higher-voltage facilities creates more durable transfer paths, reduces the need to rebuild the same corridors, and creates room for new generation and large loads to connect without workarounds.

What the Approvals Mix Shows

As FERC Form 1 data show (Figure 1, p. 6), utility-reported spending on transmission has grown significantly in the past decade (FERC, 2022). But most activity flows through siloed, legacy planning processes that tend to

Currently, most spending on transmission flows through siloed, legacy planning processes that tend to focus on local and not regional needs. Multi-driver, long-range upgrades with an eye to regional needs remain the exception.

focus on local and not regional needs. Multi-driver, long-range upgrades with an eye to regional needs remain the exception.

Spending patterns. Figure 1 (p. 6) shows that dollars spent on transmission facilities have risen across all regions, with PJM, MISO, and CAISO accounting for the largest recent shares. Nearly half of the $70 billion in transmission spending from 2013 to 2017 occurred outside of regional planning processes, and much of the recent increase is tied to single-purpose approvals (FERC, 2024a; FERC, 2022).

The key question is what this money is building—and at what scale. Two complementary lenses answer different parts of that question: FERC Form 1 shows reported historical spend (Figure 1, p.6), while ISO/RTO approvals show what is planned by type and kV (a forward view) (Figure 2, p. 7).[1]

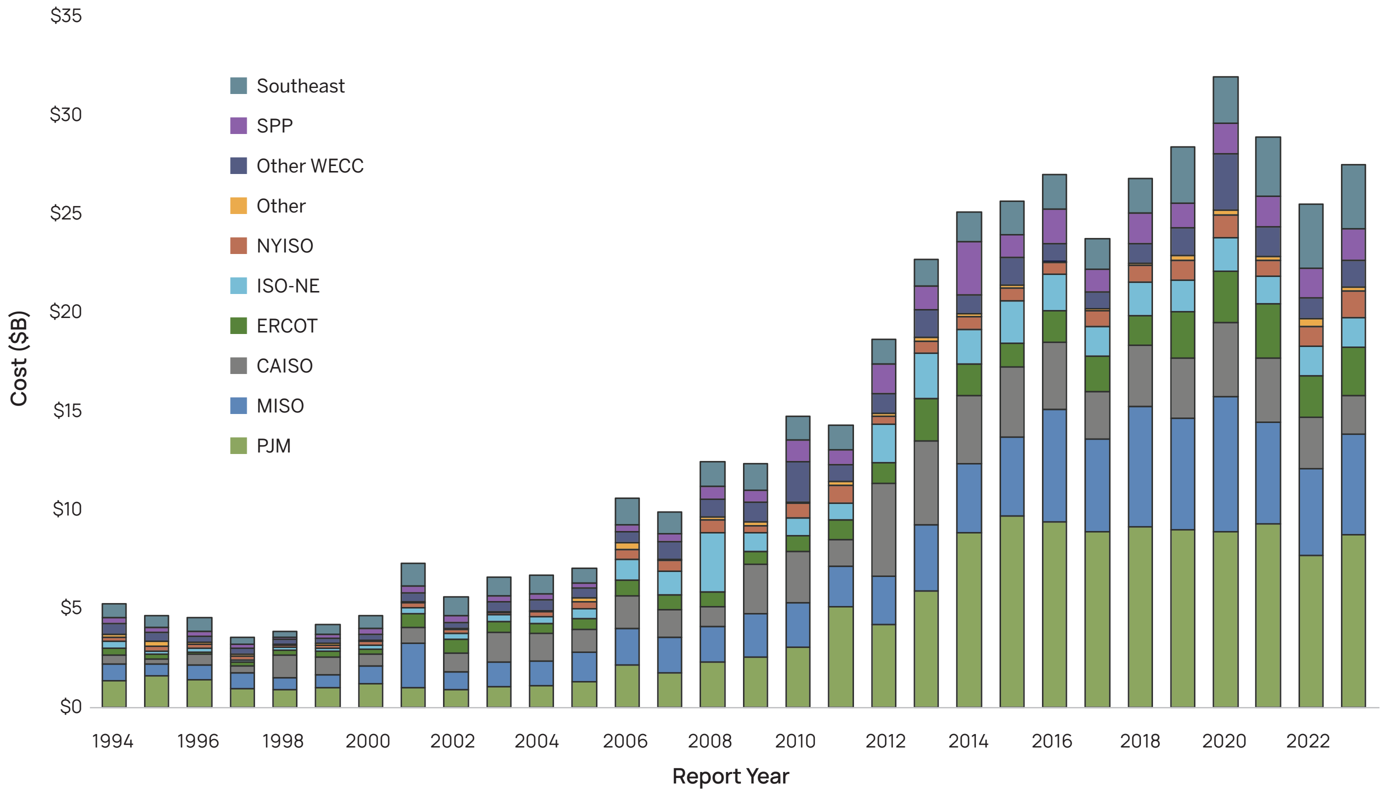
By type and voltage. Looking at MISO, PJM, and Southwest Power Pool (SPP) (together spanning 29 U.S states), most approved projects with expected in-service dates between 2005 and 2035 are below 200 kV, concentrated in the "sponsored upgrades" and "baseline reliability" buckets (Figure 2). Sponsored upgrades are voluntary projects proposed and fully funded by individual transmission customers, typically to address localized needs such as serving a new industrial facility or improving delivery within a limited area; these are overwhelmingly less than 200 kV. Baseline reliability projects are upgrades identified through compliance studies to meet NERC standards and local planning criteria. These categories play an important role in addressing local and near-term needs, but the projects they produce are typically designed as lower-voltage, smaller-capacity, incremental upgrades, and do not incorporate a longer-term or regional perspective.

In contrast, "multi-value" projects are significantly fewer but are more often 300 kV and above, consistent with

1 FERC Form 1 shows the scale and timing of past utility-reported spend; ISO/RTO approvals show what's planned and at what kV (a forward pipeline). Totals are not one-to-one: approvals can be re-scoped, delayed, or cancelled, while spend records a historical view. Comparability caveats: plant additions can post over multiple years, and approved voltage/driver may change before energization. Together, the two views provide context (past spend) and composition + outlook (approvals).

FIGURE 1

Total Utility-Reported Transmission Plant Additions Since 1994: Investment Is Rising, but Still Flowing Through Silos



Inflation-adjusted dollars spent on transmission facilities, as reported by utilities, have risen across all regions, with PJM, MISO, and CAISO accounting for the largest recent shares.

Notes: CAISO = California Independent System Operator; ERCOT = Electric Reliability Council of Texas; ISO-NE = Independent System Operator New England; MISO = Midcontinent Independent System Operator; NYISO = New York Independent System Operator; SPP = Southwest Power Pool; WECC = Western Electricity Coordinating Council.

Source: Energy Systems Integration Group; data from FERC Form 1 and public ISO/RTO sources.

regional backbone facilities designed to serve multiple drivers. The data also show that a measurable share of "baseline reliability" dollars is for projects that are greater than 300 kV, indicating that some large, regional facilities are advancing through local compliance processes rather than through coordinated regional processes that would more fully evaluate their broader system benefits.

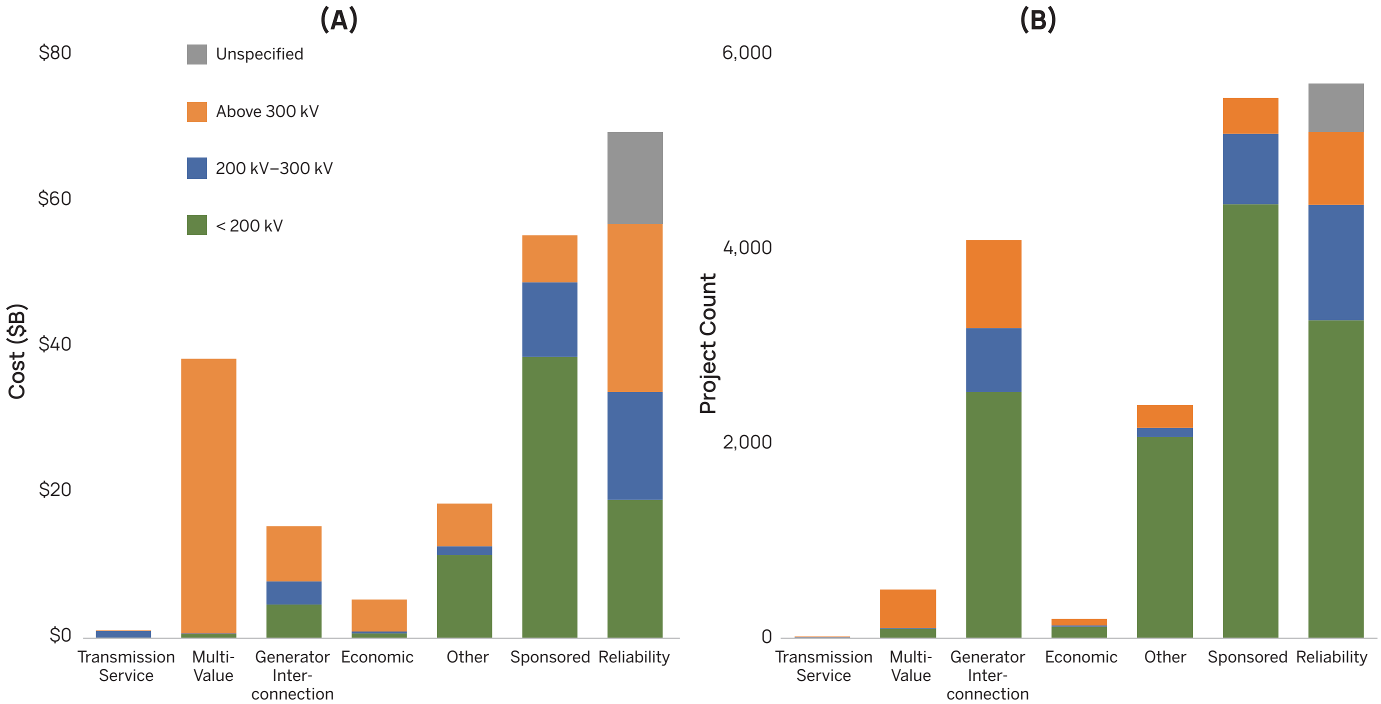
Channel vs. scale. When projects above 300 kV are approved, they are concentrated in multi-benefit portfolios (e.g., multi-value), not routine reliability channels. Regional capability tends to surface when multiple drivers are assessed together (interconnection, congestion relief, resilience), rather than in single-purpose tracks. This pattern suggests that single-driver processes infrequently advance large, high-capacity backbone facilities; these are typically justified when needs are combined.

Timing.[2] As seen in Figures 3 and 4 (pp. 8 and 9), most projects with expected in-service dates in the mid-2020s are under 200 kV. Projects at ≥300 kV are clustered in later expected in-service years, consistent with both larger system needs in the out-years and the longer development timelines for higher-voltage lines. Approvals for the larger lines also arrive in batches rather than at a steady pace. The timing and voltage mix point to the

2 Years shown are expected in-service dates, not approval years.

FIGURE 2

Most Transmission Approved Is Below 200 kV, Concentrated in Reliability and Sponsored Projects (MISO, PJM, SPP)



(A) Cost by Project Type × kV (stacked). Spend concentrates in "sponsored" and "baseline"; ≥300 kV is largely in "multi-value," with a visible ≥300 kV slice inside "baseline reliability." (B) Project Count by Project Type × kV (stacked). Approvals cluster below 200 kV across "sponsored," "reliability," and "generator interconnection"; ≥300 kV projects are fewer by count but larger in scale.

Source: Energy Systems Integration Group. Data from public ISO/RTO sources.

planning approach: near-term reliability and sponsored projects address immediate issues, while higher-kV lines reflect longer-horizon planning that can address multiple needs and make better use of corridors. The lack of consistency in advancing higher-voltage portfolios highlights how siloed processes prioritize near-term fixes, leaving regional solutions to advance inconsistently. Order 1920 establishes recurring long-term planning cycles, which may yield a more consistent cadence for large portfolios.

The Risk of Doing More of the Same

Continuing to rely on decoupled planning processes can leave the system unprepared for the scale and pace of emerging needs, such as when:

- Separate projects tackle a similar problem in the same area, when one coordinated upgrade would solve it more efficiently.

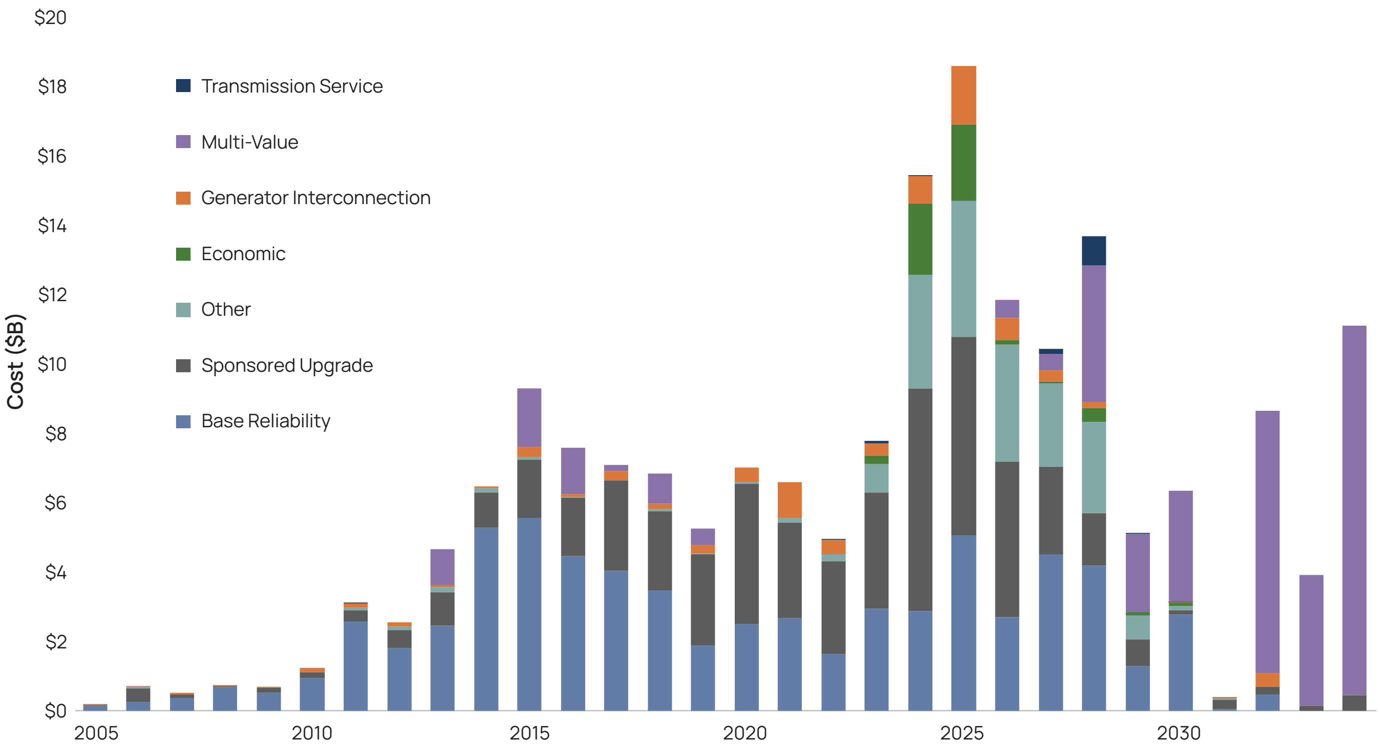
Continuing to rely on decoupled planning processes can leave the system unprepared for the scale and pace of emerging needs.

- Lines and substations are sized for today, then overloaded a few years later by new generation or large loads.
- Planners revisit the same bottlenecks several times, running costly studies and building short-term fixes instead of long-term solutions.

For example: a line built to meet near-term reliability needs may be overwhelmed by new generation within a

FIGURE 3

Transmission Approvals in MISO, PJM, and SPP by Type, 2005 to 2034



Annual cost by project type (stacked). Transmission approvals in MISO, PJM, and SPP have grown but remain skewed toward short-term needs. "Reliability" and "sponsored" lead most years; "multi-value" peaks align with the ≥300 kV waves.

Source: Energy Systems Integration Group; data from public ISO/RTO sources.

few years; a policy-driven spur to a renewable zone may not add backbone capacity, so curtailment persists when the wider corridor is congested; and like-for-like asset replacements miss chances to right-size or repurpose infrastructure.

In today's context of rising costs and growing demand, these fragmented approaches not only increase the risk of inefficient outcomes but also leave significant value on the table—missing opportunities to deliver greater reliability, flexibility, and long-term savings through more coordinated solutions.

Key Attributes of Regional Planning Practices Today

Across U.S. ISOs and RTOs, planning practices are evolving in response to new system needs, policy drivers, and reliability challenges. Several common themes are emerging from recent planning initiatives and reforms.

Progress Toward Integration

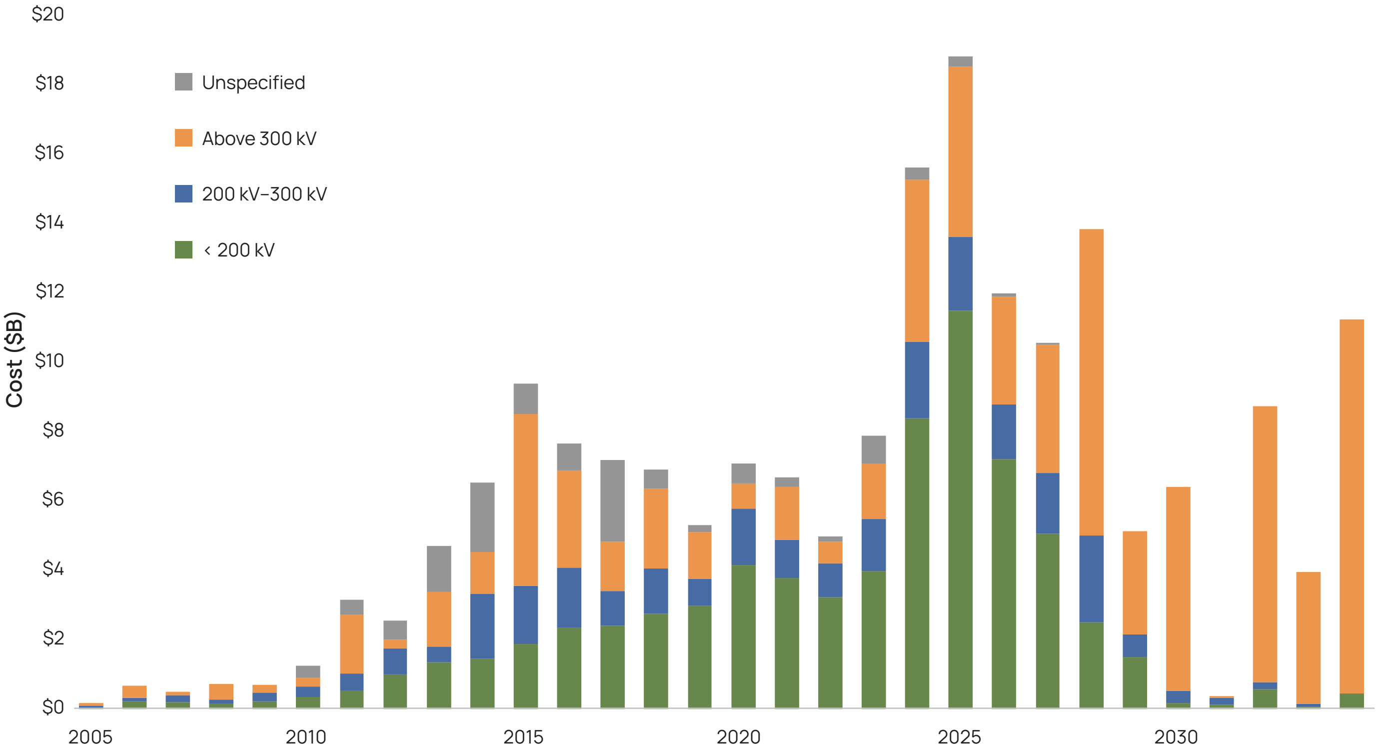
Some regions are increasingly linking reliability, congestion, and policy planning into unified studies, and long-range portfolios and shared modeling frameworks are beginning to take shape.

Scenario-Based Long-Term Planning, but Often Not Actionable

Scenario planning is being used to test how transmission performs under different policy, load, and resource futures, and it helps surface projects that deliver value across multiple needs. However, the use of these scenarios in actionable, recurring planning cycles remains inconsistent.

FIGURE 4

Transmission Approvals in MISO, PJM, and SPP by Voltage Level, 2005 to 2034



Annual cost by kV (stacked). Transmission approvals in MISO, PJM, and SPP are below 200 kV, with larger higher-voltage lines expected in service in later waves. Sub-200 kV dominates the mid-2020s; ≥300 kV appears in waves later.

Source: Energy Systems Integration Group. Data from public ISO/RTO sources.

Generator Interconnection as a Persistent Silo

Generator interconnection is one of the most active areas of planning and has undergone several significant recent reforms. However, it remains largely reactive, driven by developer requests rather than coordinated system goals, and operates separately from broader system planning, limiting alignment with long-term needs.

Limited Operational Integration

While a few regions incorporate grid operability and real-time dynamics into transmission expansion planning, most do not. Operational realities such as ramping, stability, or flexibility are often ignored in transmission expansion efforts.

The Continuing Challenge of Interregional Planning

Aside from notable efforts like the MISO–SPP Joint Targeted Interconnection Queue (JTIQ), cross-boundary coordination is largely ad hoc. Formal interregional processes are rare, especially those that proactively identify needs rather than react to proposals.

Widely Varying Institutionalization of These Practices

Some integrated practices are embedded in routine cycles with clear roles and updates, but others are pilots or informal efforts without sustained support. In many places, promising practices lack formalization.

Current Silos in Transmission Planning

Despite progress, planning remains segmented by driver and scope—reliability, economic, and public policy—consistent with how many regions implement FERC Order 1000 (FERC, 2011).

Reliability Planning

Generator interconnection: Evaluates upgrades for individual generators or clusters, often without considering broader system needs or coordinated transmission zones. These studies are initiated by developer requests and conducted in set queue cycles, and in most regions, they are not well coordinated with long-term planning.

Load interconnection: Assesses upgrades to connect large industrial or commercial customers through localized assessments, often disconnected from long-term reliability or resource plans.

Reliability compliance planning: Focuses on short- to medium-term compliance needs up to a 10-year-out horizon using conservative assumptions designed to meet standards. Procedural rules often limit the inclusion of future generation and load developments.

Asset management: Assesses the need to replace aging infrastructure based on the condition of equipment or risk evaluations, typically resulting in like-for-like swaps that rarely consider broader system needs or opportunities to right-size.

Supplemental planning: Transmission owners may propose projects outside of regional processes and cost allocation, often to address local needs or asset condition. These efforts typically receive limited regional review and may not be aligned with broader system planning.

Operations planning: Focuses on real-time or near-term operability (e.g., system behaviors, ancillary services, system reliability and adequacy), with limited feedback opportunities to transmission planning studies.

Economic Planning

Economic planning uses production-cost modeling to identify congestion-reducing upgrades for near- and long-term system conditions, based on specific market and resource assumptions.

Policy Planning

Public policy planning studies are intended to meet local, state, and federal polices, such as renewable portfolio standards or clean energy mandates, but are often siloed from reliability and economic analyses.

Table 1 (p. 11), while not capturing every nuance of today's planning practices, illustrates the fragmentation still common across transmission planning functions. Most processes operate with different goals, horizons, assumptions, and tools—each shaped by distinct mandates and organizational roles. Some processes target immediate operational or compliance needs, while others focus on

TABLE 1

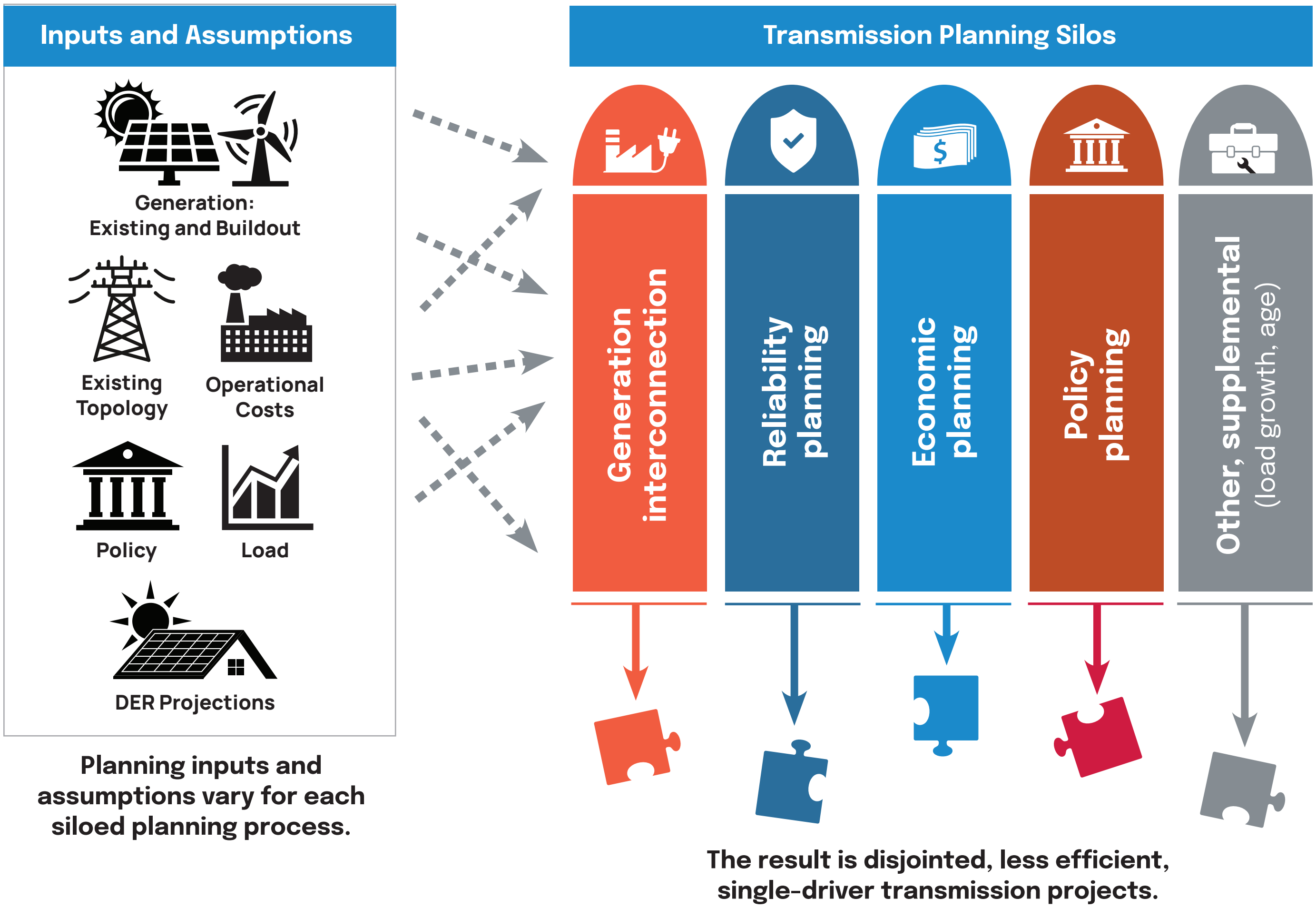
Fragmentation in Current Transmission Planning Processes

Attribute	Purpose	Project Output	Horizon	Assumptions	Study Type	Limitations
Generator interconnection	Processes queued generator requests	Request-focused upgrades	2–5 years	Queue-driven; assumes limited overlap	AC load flow, short-circuit, stability studies	Queue-specific; lacks system-wide coordination
Near-term reliability planning	Maintains NERC reliability compliance	Reliability upgrades (lines, transformers, voltage support)	5–10 years	Static load and supply forecast; conservative assumptions	Contingency analysis, thermal/stability checks	Narrow reliability focus; misses long-term trends
Economic/congestion planning	Alleviates market congestion and increases grid efficiency	Congestion relief upgrades (e.g., reconductoring, new lines)	2-10 years	Average forecasts; assumes current conditions	8,760-hour production-cost modeling, security-constrained unit commitment/security-constrained economic dispatch	Short-term congestion focus; ignores worst hours
Long-term scenario planning	Evaluates long-term futures under varied scenarios	Conceptual backbone projects, scenario-informed corridors	15–20 years or more	Scenario-based forecasts; includes policy sensitivity	Capacity expansion, production cost, and reliability	Often advisory only; has limited influence on near-term projects
Asset management/end-of-life planning	Replaces assets based on condition or risk assessments	Like-for-like replacements, equipment rebuilds	2–5 years	Asset health assessments; prioritizes maintaining current capabilities	Asset risk tools, condition databases	Often incentivizes in-kind replacement, which typically misses opportunity to right-size for future needs
Policy/public policy planning	Supports policy-driven buildouts (e.g., renewable portfolio standards, decarbonization goals)	Policy-driven transmission expansion/upgrades (e.g., renewable integration)	10–20 years	Policy mandates; assumes generation retirements	Scenario studies, policy overlays	Often siloed from economic and reliability processes

Source: Energy Systems Integration Group.

FIGURE 5

Siloed Planning Processes That Lead to Fragmented, Single-Driver Outcomes



Transmission planning functions frequently rely on inconsistent inputs—varying in scope, time frame, and treatment of factors like state policy or long-term load growth. Because these functions are siloed, each applies its own models, assumptions, and timelines, often leading to narrowly scoped projects rather than coordinated, system-wide solutions.

Source: Energy Systems Integration Group.

long-term grid evolution. Because these processes typically run in isolation, their outputs are hard to align or reconcile. The result is inefficiency, uncoordinated solutions, and slower system response as needs are identified late in the cycle.

Figure 5 shows how key system inputs—load forecasts, generation buildouts, and policy mandates—are often funneled into function-specific silos with inconsistent, uncoordinated treatment. Each silo applies its own assumptions, tools, and timelines, yielding fragmented outputs and single-driver projects. The silos depicted are generator interconnection, near-term reliability planning, economic/congestion planning, long-term scenario planning, asset management/end-of-life planning, and public policy planning.

Key system inputs–load forecasts, generation buildouts, and policy mandates–are often funneled into function-specific silos with inconsistent, uncoordinated treatment.

Persistent Challenges Associated with Siloed Decision-Making and Organizational Structures

Separate planning teams—often organized by discipline—limit cross-functional insight and reinforce narrow outcomes. Within those teams, work is further split into specialties such as steady-state, short-circuit, transient stability, and electromagnetic transient (EMT) analyses. Specialization provides significant value, but without deliberate coordination, it can reinforce the silos illustrated in Figure 5. The result is that information needed for robust planning often remains trapped within one study track rather than being shared across the processes.

For example, stability studies should test realistic high-stress operating points—low inertia, high-IBR levels, and light-load with high regional power transfers. Yet those scenarios rarely come from markets, operations, or economic-planning teams running 8,760-production-cost modeling. The information gap also runs the other way: economic studies often ignore stability limits, assuming transfer capability the system cannot deliver. In both directions, the feedback loop between economic and stability studies is weak, leaving important constraints and stress conditions unrecognized in planning.

This disjointed, traditional approach can result in persistent challenges, including the following.

Process design often follows cost allocation–who pays shapes how we plan.

Difficult Cost Allocation

Process design often follows cost allocation—who pays shapes how we plan. For example, in generator interconnection, costs fall on developers, so studies often target the least-cost "but-for" fix—the minimum upgrade needed to connect a project while meeting reliability standards. This approach ensures compliance but may not yield the most effective solution for the broader grid. Regional planning, by contrast, looks across the system's footprint and across longer horizons, with costs spread broadly to customers. These different cost-allocation rules can lead to very different kinds of projects. Without a shared

framework among different planning functions for assigning benefits and costs, multi-purpose transmission projects are difficult to justify and often undersized or duplicative.

Fragmented Timelines and Horizons

Different planning functions can operate on distinct timelines. For example, interconnection studies run on more frequent annual or semi-annual cycles, while regional planning unfolds over longer horizons. The misalignment makes it difficult to coordinate upgrades across processes, resulting in projects that are undersized, duplicative, or approved too late.

Varied Tools, Assumptions, and Models

Each planning function uses its own tools and assumptions. For example, reliability studies may rely on peak loads met with generalized generation dispatches, while economic models simulate hourly dispatch based on a system's average demand profiles. Each is useful, but the inconsistency hampers our ability to compare them.

Inefficient and Redundant Project Development

Projects scoped for a single problem can lead to duplicate builds or undersized upgrades. Such an approach increases the risk that expected benefits—such as congestion relief, curtailment reduction, or reliability margins—prove smaller or short-lived once in operation. Like-for-like asset replacements also miss chances to right-size or repurpose existing transmission corridors, for example, by rebuilding lines at a higher voltage, adding an additional circuit, or converting to high-voltage DC. Over time, these choices drive up total system costs.

Limited Flexibility and Responsiveness

Current planning processes are not agile enough to respond quickly to new industrial loads, climate risks, or shifting policy. Greater integration may add coordination steps, but it improves visibility, reduces duplication, and enables more proactive, system-wide responses.

Misaligned Treatment of Uncertainty

All planning studies face uncertainty about future load, generation, policy, and reliability risks. Near-term studies are usually deterministic, grounded in today's conditions, but unable to adapt if conditions change. Long-term studies use scenarios to explore a range of futures, but aren't tied to actionable upgrades, so decisions are often postponed until conditions are clearer. This imbalance—where near-term studies drive outcomes while long-term studies remain advisory—discourages "limited-regrets" projects that could adapt as system needs evolve.

As transmission planning expands to cover longer time frames, broader system benefits, and deeper analyses, applying beneficiary-pays models becomes more challenging. Adding to the difficulty, states, utilities, and regulators often use different cost-justification metrics. These inconsistencies make it hard to reach a common view of who benefits and by how much, which can undermine approval of projects that could serve multiple users or regions.

The Beginnings of Evolution in Planning Practices

While fragmentation persists, several regions are adopting forward-looking, system-wide approaches that coordinate across functions and institutions, though progress remains gradual. Some early efforts show not only the beginnings of integration, but also steps to broaden the scope of drivers considered and deepen the rigor of analysis. First, we list some early examples of linking planning functions, followed in the next section by three examples of systems moving toward more fully integrated planning.

Early Examples

- **Electric Reliability Council of Texas's (ERCOT's) Competitive Renewable Energy Zones (CREZ)** initiative enabled over 18 GW of wind by proactively building more than 3,600 miles of high-voltage transmission to connect designated renewable zones—demonstrating the value of linking transmission and generation planning.
- **SPP's Priority and Balanced Portfolios (2009–2012)** combined reliability and economic needs in coordinated regional plans, reducing duplication and demonstrating how shared solutions could support multiple drivers (SPP, 2025b).

These efforts showed that large-scale, multi-need planning is both achievable and impactful, even if they were not fully sustained.

Institutional Coordination and Multi-Driver Improvements

- **The Independent System Operator New England (ISO-NE),** working with states through its **Long-Term Transmission Planning,** is incorporating state policy goals and multiple benefit streams into its evolving long-term transmission framework, with the aim of improving alignment across planning horizons.
- **PJM** allows reliability, congestion, and public policy drivers to be addressed together through its **Multi-Driver Planning** process, enabling either single projects or coordinated portfolios (PJM, 2021).

Emerging and Cross-Regional Collaborations

- **MISO and SPP's Joint Targeted Interconnection Queue** initiative shows how coordinated interconnection planning across RTO seams can identify mutually beneficial transmission upgrades and improve cost sharing (MISO, 2025a).
- **WestTEC** and updates to **PacifiCorp's Integrated Resource Plan** are testing new approaches to multi-state, scenario-based planning in the Western U.S.,

linking transmission development with long-term regional resource goals (WestTEC, 2024; PacifiCorp, 2025).

These examples differ in scope, maturity, and institutional support. Some are recurring and well-integrated; others are still pilots or planning experiments. But together they show how planning practices are beginning to evolve—linking drivers, broadening perspectives, and laying the groundwork for more strategic, system-wide approaches.

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From Siloed Studies to Integrated, Multi-Driver, and Rigorous Planning

A small number of regions have taken meaningful steps to move beyond fragmented studies and bring together long-range scenarios and diverse planning drivers through recurring, cross-institutional planning processes. These efforts differ in structure, but each represents a deliberate move toward more strategic, multi-driver, and analytically rigorous planning.

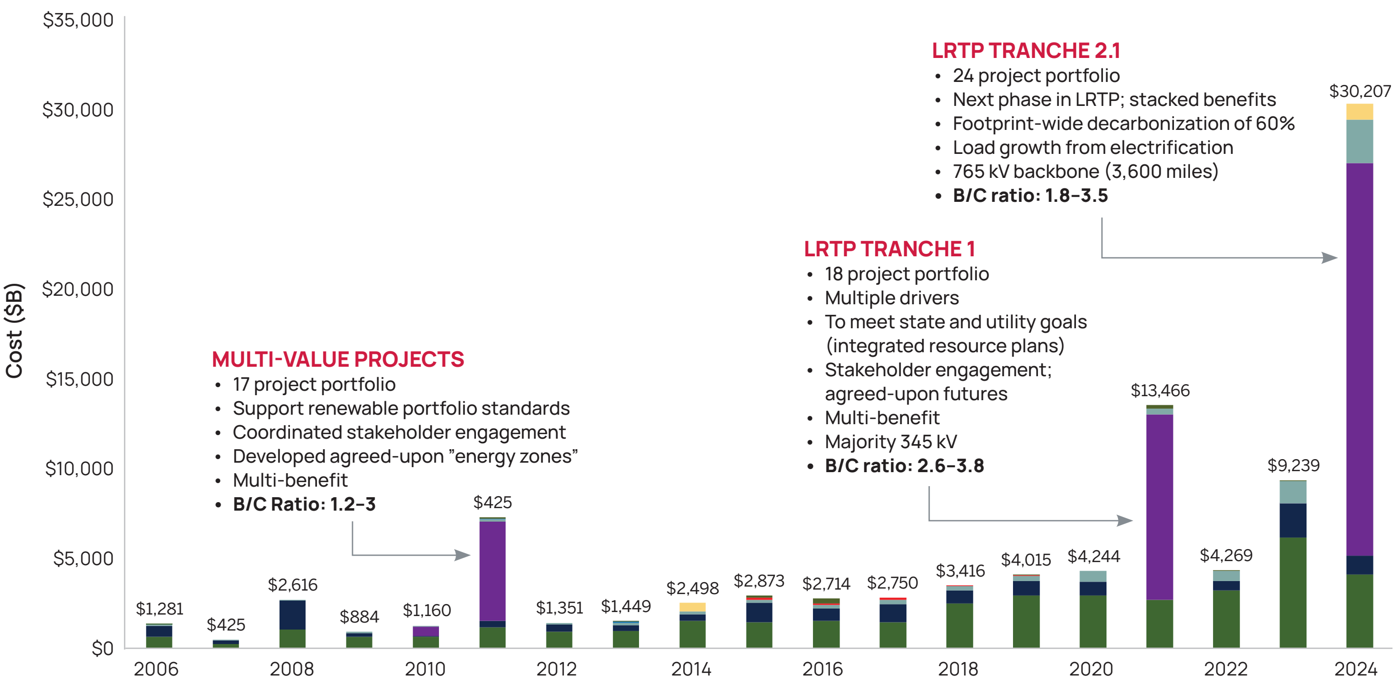
MISO: Long-Range Transmission Planning

MISO offers one of the clearer examples of sustained, multi-cycle integration (MISO, 2025b). Its approach has evolved over more than a decade (see Figure 6):

- **2011—Multi-Value Projects:** A $5.2 billion portfolio of 17 projects designed to meet public policy mandates, improve reliability, and reduce congestion—justified

FIGURE 6

MISO's Flagship Portfolios Demonstrate the Value of Comprehensive Planning



Over the past decade, the Midcontinent Independent System Operator (MISO) has approved three major portfolios that reflect the principles of proactive, multi-driver planning: the 2011 Multi-Value Projects, 2022's Long-Range Transmission Planning (LRTP) Tranche 1, and 2024's Long-Range Transmission Planning Tranche 2. Each portfolio incorporates long-range scenarios, coordinated modeling, and shared benefit-cost frameworks.

Source: Energy Systems Integration Group; data from the Midcontinent Independent System Operator (https://www.misoenergy.org/planning/transmission-planning/mtep/#t=10&p=0&s=&sd=).

through scenario analysis and a unified cost-allocation approach.

- **2021—Long-Range Transmission Planning, Tranche 1:** Approved in 2022, this $10.3 billion portfolio includes 18 projects selected based on long-term scenarios, with modeling assumptions developed collaboratively by states, utilities, and stakeholders through a regionally coordinated process. Projects were distributed across four Midwest subregions to support the integration of clean energy, maintain reliability, and relieve congestion (MISO, 2024a).
- **2024—Long-Range Transmission Planning, Tranche 2 and the Joint Targeted Interconnection Queue:** Approved in 2024, Tranche 2 advances a $21.8 billion portfolio spanning 26 projects, including up to 3,600 miles of new 765 kV backbone lines (MISO, 2024b). These projects are designed to support regional energy transfers, reduce renewable curtailment, and accommodate large-scale changes in generation and load.

These efforts reflect a structurally different approach—applying multi-driver need identification, scenario-based analysis, and cross-functional coordination. Across these three cycles, benefit-cost ratios ranged from 1.2 to 3.8, demonstrating the value of integrated, forward-looking planning.

SPP: Consolidated Planning Process

SPP's proposed **Consolidated Planning Process** represents a major structural reform aimed at replacing siloed transmission planning with a unified, multi-driver framework (SPP, 2025e). The Consolidated Planning Process is designed to merge five previously separate processes—reliability, economic, public policy, persistent operational issues, and generator interconnection—into a single, recurring planning cycle. See Figure 7.

The process introduces several foundational changes:

- A common set of scenarios and modeling assumptions across all drivers
- Integrated needs assessments and portfolio development
- More consistent cost allocation tied to project benefits
- Streamlined stakeholder engagement and regulatory review

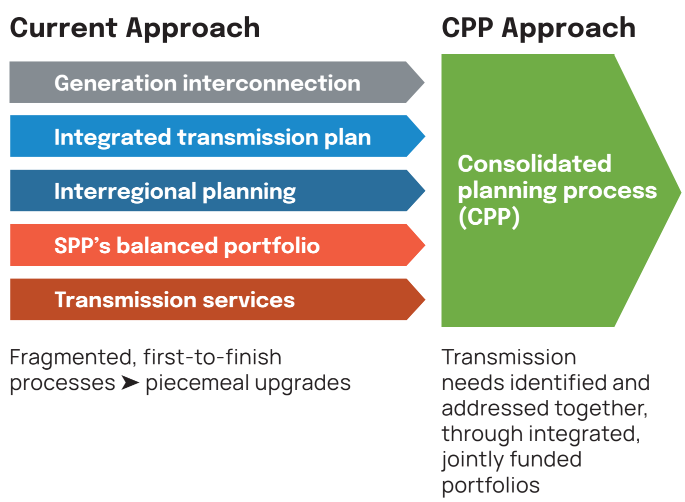
The Consolidated Planning Process is intended to be iterative and recurring, enabling SPP to identify projects that address overlapping needs while reducing duplication and timing mismatches. If implemented as proposed, it would provide one of the clearest examples of an RTO-wide planning framework built for multi-driver, long-range transmission development.

The Consolidated Planning Process reflects SPP's recognition that legacy processes won't keep pace with today's system complexity. Its success will depend on how effectively it integrates diverse drivers, navigates cost allocation, and maintains consistency over time.

CAISO: Coordinated Planning Through Agency Alignment

CAISO's **Transmission Planning Process** demonstrates a different—but equally significant—approach to integration: formal coordination across state agencies. Through a

FIGURE 7
SPP's Consolidated Planning Process



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

memorandum of understanding with the **California Public Utilities Commission** and the **California Energy Commission**, CAISO receives and incorporates 10- and 15-year resource portfolios and demand forecasts into its annual transmission planning cycle (CAISO, 2022). This alignment allows CAISO to:

- Translate policy and procurement decisions directly into grid infrastructure plans
- Sequence planning, procurement, and permitting actions to reduce delays
- Assess reliability, deliverability, and clean energy integration in a single process
- Support offshore wind, long-duration storage, and other emerging technologies with grid-ready planning

The Transmission Planning Process has supported large-scale upgrades such as the Humboldt–Collinsville 500 kV line, designed to enable offshore wind integration in Northern California, and transmission reinforcements for out-of-state solar and geothermal development.

Although generator interconnection remains a separate process, CAISO's model shows how sustained institutional alignment can functionally integrate policy, resource, and transmission planning—even within a multi-agency environment.

Why These Examples Matter

MISO's Long-Range Transmission Planning, SPP's Consolidated Planning Process, and **CAISO's Transmission Planning Process** show what better planning can look like when functions are linked across silos, a wider set of drivers and benefits are considered, and analysis is extended to capture uncertainties and emerging risks. As system change accelerates, exceptional processes need to become standard practice.

Order 1920 responds to this need, requiring every transmission provider under FERC jurisdiction to produce a long-range plan at least once every five years. It establishes a broad requirement for long-range, scenario-based, multi-driver, multi-benefit transmission planning—setting expectations for state engagement, benefit analysis, and recurring planning cycles. The goal is to make processes like those in MISO, SPP, and CAISO not the exception, but the norm.

As system change accelerates, exceptional processes need to become standard practice.

Progress also depends on cost-allocation frameworks that assign costs in proportion to multiple needs and beneficiaries. Although detailed design is beyond the scope of this report, the above examples also illustrate workable approaches that regions can adapt.

A Practical Framework for Evolving Transmission Planning

To meet the moment, planning must evolve—not by discarding current practices, but by improving how they connect, expand, and anticipate future needs. The sections that follow show how more integrated, inclusive, and rigorous planning is already emerging in different forms—and how it can be strengthened and scaled going forward.

This report offers a practical framework for that evolution: integrate, broaden, and deepen (Figure 8, p. 19).

- **Integrate** planning functions to better coordinate timelines, reduce duplication, and support projects that serve multiple needs—linking interconnection, reliability, public policy, and asset management.
- **Broaden** the scope of planning to incorporate a wider range of drivers and benefits, such as load growth, resilience risks, clean energy targets, and system flexibility, not just traditional reliability and congestion metrics.
- **Deepen** the analytical foundation to reflect the growing complexity and interdependence of the grid. This includes the use of high-resolution tools, diverse future scenarios, and explicit assessments of technology behavior and system operability.

These strategies are already being applied in regional planning efforts across the country. What's needed now is consistency, coordination, and commitment to not treat them as exceptions and incorporate them as standard practice.

These strategies are not theoretical. They are already being applied in regional planning efforts across the country. What's needed now is consistency, coordination, and commitment to go beyond thinking of them as exceptions and incorporate them as standard practice.

The next sections explore these strategies, beginning with the foundation: **Integration.**

FIGURE 8

A Practical Framework for the Evolution of Transmission Planning

INTEGRATE
planning across silos and timelines

Integrated transmission planning includes coordination across transmission planning silos—including greater interaction between generator interconnection, load interconnection, reliability, economics, asset management, public policy, and operations—to support projects that serve multiple purposes, have multiple benefits, and avoid duplicative investments.

BROADEN
the range of drivers, scenarios, and stakeholders

Integrated transmission planning expands the set of planning scenarios informed by a fuller range of inputs and drivers, providing a spectrum of outcomes and values. In addition to reliability and congestion metrics, it includes emerging factors such as large loads, resilience risks, decarbonization goals, interregional coordination, and system flexibility needs.

DEEPEN
the analysis to support better decisions and outcomes

Integrated transmission planning improves planning analyses to reflect the growing complexity and interdependence of grid needs. This includes using high-resolution modeling tools, examining multiple plausible and diverse future scenarios, assessing impacts of new technologies and their behaviors, and analyzing future system operability.

Source: Energy Systems Integration Group.

Integrate: From Silos to Integration

Transmission planning has made progress, but it still operates in separate processes that rarely align. This keeps upgrades focused on a single purpose, missing opportunities to solve multiple needs at once. Integration connects these processes, so they share inputs, coordinate schedules, and evaluate projects across functions. That can mean:

- **Aligning study timelines** so outputs from one process feed directly into the next.
- **Sharing data and assumptions** across reliability, economic, policy, and interconnection studies.
- **Coordinating scenario development** so each function evaluates the same futures.
- **Carrying constraints and solutions forward** between study types so they can be refined and re-evaluated.
- **Restructuring institutional roles** so that planning teams are organized to collaborate across functions rather than operate in isolation.

A few regions are showing how to bridge these divides:

- CAISO aligns its transmission plan with the California Public Utilities Commission and California Energy Commission resource portfolios, ensuring generation and transmission decisions are based on the same scenarios and inputs—reducing mismatches and avoiding rework.
- MISO's Long-Range Transmission Planning links reliability, economic, and policy needs in a single portfolio, proving that multi-driver integration can deliver large-scale, widely supported projects.
- NYISO adds economic analysis to public-policy transmission evaluations, uncovering more cost-effective solutions than isolated reviews.

Integration doesn't necessarily require a complete redesign. It is best viewed as a continuum of progress–small steps to align timelines, share assumptions, and coordinate solutions can significantly improve outcomes.

- ISO-NE reconciles near- and long-term studies, avoiding conflicting recommendations and delays.

These cases show that shared scenarios, coordinated study calendars, and a common list of needs can turn isolated fixes into upgrades that serve many purposes. Integration doesn't necessarily require a complete redesign. It is best viewed as a continuum of progress: small steps to align timelines, share assumptions, and coordinate solutions can significantly improve outcomes (Figure 9, p. 21).

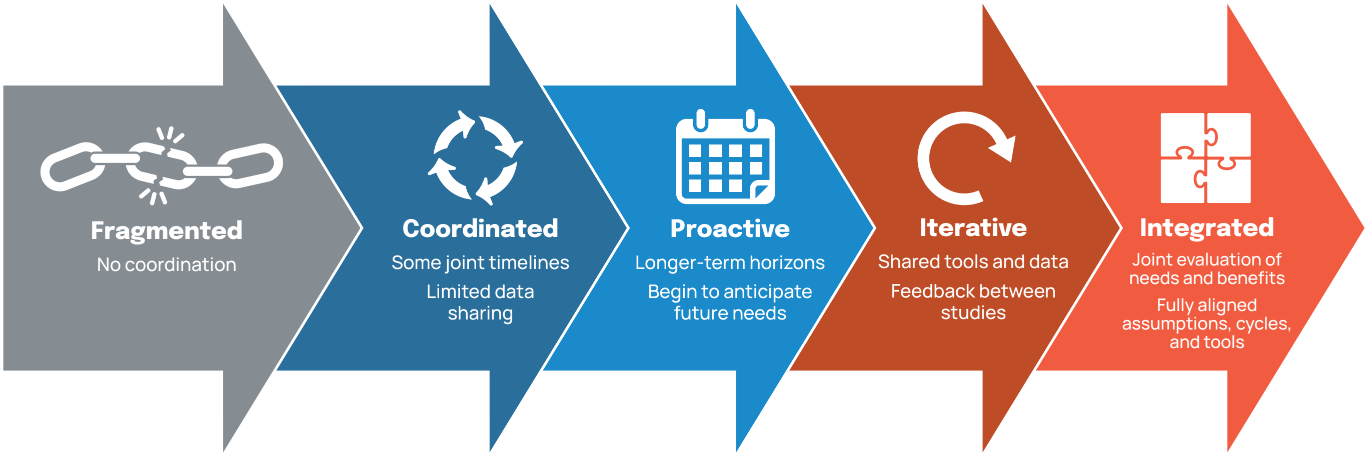
Four Foundational Strategies for Integration

This section outlines four foundational strategies for integration:

- Improve institutional coordination across planning teams and timelines
- Align assumptions and data to support consistent analysis across studies
- Develop coordinated upgrade portfolios that reflect multiple system needs
- Evolve planning processes to support multi-driver evaluation and decision-making

FIGURE 9

A Continuum Toward Fully Integrated Transmission Planning



This continuum illustrates the progression from siloed to fully integrated planning. Each stage reflects deeper coordination across planning functions, more consistent use of inputs and tools, and stronger alignment with long-term system needs.

Source: Energy Systems Integration Group.

Each strategy is illustrated with real-world examples that demonstrate how integration can move planning from fragmentation to coordination—and from single-purpose fixes to long-term, multi-value solutions.

Institutional Alignment—Moving from Fragmented to Coordinated

Challenge

Conflicting inputs and repeated studies result from parallel mandates, calendars, deliverables, and stakeholder processes that keep core planning functions out of sync. Blind spots emerge, overlapping needs are identified too late to address efficiently, and internal misalignment grows. The result: missed opportunities for joint solutions and inconsistent messaging to stakeholders and regulators, undermining trust, obscuring value, and weakening support during approvals.

Solution

The solution is to establish formal, recurring coordination processes among planning functions within and across institutions. Practical tools include an internal planning alignment forum, shared study calendars, joint modeling, and coordinated stakeholder engagement. Aligning processes early helps identify shared needs and enables joint solutions to be scoped, evaluated, and socialized more effectively.

Example: MISO Long-Range Transmission Plan Tranche Staging

MISO used a phased approach to manage complexity across its large, diverse footprint. By staging the plan in tranches, MISO prioritized areas with the most urgent needs, then applied lessons learned and refined assumptions in later phases (Table 2, p. 22). This enabled a more coordinated planning approach without overwhelming any single process or stakeholder group. Institutionalizing this type of coordinated, iterative planning within regular planning frameworks would help ensure that the system remains aligned with evolving needs while continuing to identify cost-effective transmission solutions.

Alignment of Assumptions and Data—Moving from Coordinated to Proactive

Challenge

While alignment across teams sets the foundation, turning coordination into coherent outcomes depends on starting from shared assumptions. When different studies use inconsistent assumptions—such as inconsistent load forecasts, generation retirements, or policy mandates—

it becomes difficult to compare results or develop coherent transmission strategies. These differences also obscure shared needs and make it harder to justify joint solutions.

TABLE 2

MISO's LRTP Tranche 2.1 Journey from Futures and Modeling to Board Approval, 2021–2024

Step	What MISO Did (Dates, Scope, Outputs)
Stakeholder engagement occurred throughout all steps.	Nineteen LRTP workshops were held between 2022 and 2024.
1. Define futures	MISO defined three futures in 2021, refreshed them in July 2022, and published the Futures Report* in October 2023.
2. Identify needs	Using production-cost and reliability models, MISO identified reliability and economic issues: in some areas, 10% to 20% of facilities were overloaded, curtailments were >15%, and there was overall significant congestion (April to December 2023).
3. Develop and fine-tune solutions	MISO progressed from conceptual ideas to a conversation starter and then to an initial draft portfolio, assessed the 345/765/HVDC mix, and screened 97 stakeholder alternatives (January 2023 to August 2024).
4. Test robustness and analyze business case	The benefit-metrics framework was developed between March 2023 and July 2024, and the business-case analysis was conducted from July through September 2024, during which nine benefit metrics were evaluated.
5. Board approval	Supported by more than 40,000 staff hours and around 300 meetings, the MISO Board approved the final portfolio in December 2024.

To manage complexity across its footprint, MISO implemented a phased, cross-functional planning process for Tranche 2.1, including stakeholder workshops, scenario development, reliability and economic analyses, and business case development that were sequenced and aligned over multiple years. This illustrates how formal coordination can enable shared assumptions, joint solutions, and effective stakeholder engagement.

*https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

Source: Energy Systems Integration Group. For more information, see https://cdn.misoenergy.org/20240924%20LRTP%20Workshop%20Item%2001%20Tranche%202.1%20Journey649711.pdf.

For example, a reliability study may use a conservative baseline load forecast, while a long-term scenario study models high electrification and distributed energy resource (DER) adoption, leading to vastly different conclusions about needed upgrades. Some divergence may be warranted, but without a shared baseline and clear rules for when to depart from it, studies produce conflicting upgrade signals, overlook constraints, and suggest redundant fixes. Reconciling those differences late in the process is often more difficult and expensive, with fewer opportunities to align solutions.

Solution

To address these challenges, planners need a shared set of planning assumptions, data sources, and scenarios to be used consistently across all planning studies. At a minimum, key variables can be aligned, such as load growth, resource additions and retirements, and policy targets. When divergence is necessary, the reasons should be explicitly documented and results compared across cases—for example, examining how different load-growth or retirement scenarios change congestion patterns and the set of upgrades identified. This makes it possible to see which projects are robust across multiple futures and which are more scenario-specific. Such an approach ensures that critical needs are not missed and supports clearer communication of trade-offs and benefits.

Examples

Several regions offer working examples of aligning assumptions and data:

- The state of New York, the New York Independent System Operator (NYISO), and the New York Department of Public Service collaborate to ensure that policy-driven assumptions used in the state's Climate Action Council's plans are reflected in transmission needs assessments, such as the System and Resource Outlook study (NYISO, 2024a).
- California uses a sequenced approach (Figure 10, p. 23): the California Public Utilities Commission provides integrated resource plan portfolios, and the California Energy Commission provides demand forecasts—both of which are passed to the California Independent System Operator (CAISO) for use in annual transmission planning (CAISO, 2025). This alignment ensures

that infrastructure decisions are grounded in consistent load and policy expectations.

- MISO's Futures Framework defines three long-term scenarios that vary in policy ambition, load trajectory, and technology adoption. These futures shape assumptions across all of MISO's planning efforts (MISO, 2025c).

Starting from common assumptions—and coordinating any necessary deviations—helps shift coordination from reactive to proactive, enabling more coherent, system-wide alignment. A shared baseline creates a unified understanding of system needs, but realizing its full value requires workflows that translate insights into actionable, cross-functional solutions.

Coordinated Upgrade Portfolios– Moving from Proactive to Harmonized

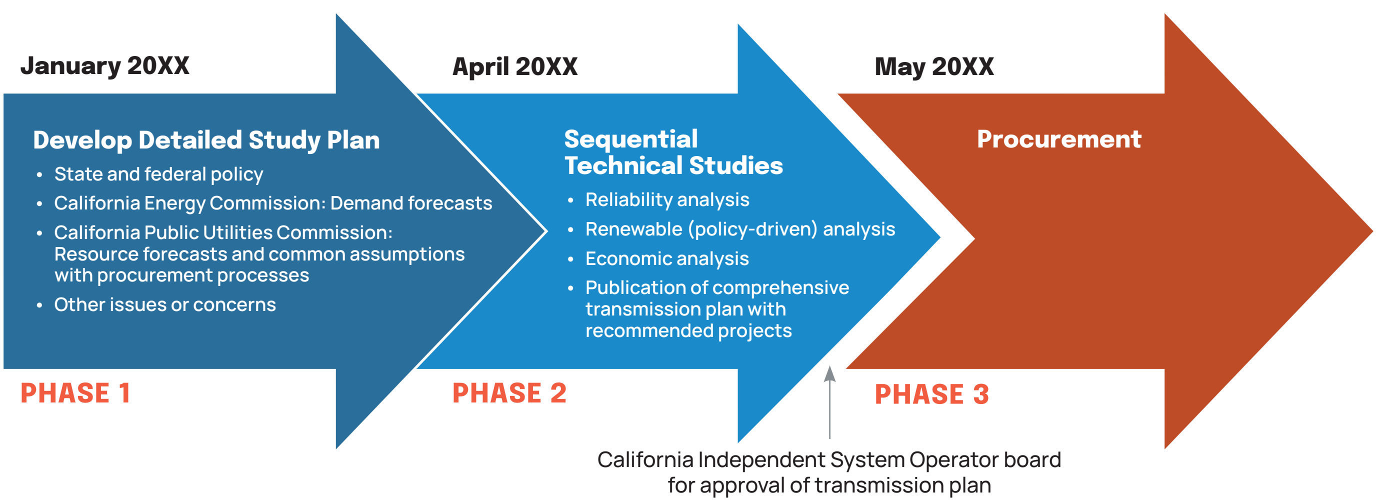
Challenge

Even with common inputs, planning functions often identify upgrades independently. The same transmission corridor or interface may show up as a constraint in multiple studies, yet each silo advances its own fixes on the same path—duplicating effort and missing the chance to design a shared solution.

For example, economic planning may point to a backbone reinforcement to relieve chronic intra-regional congestion, but if that transmission candidate is not sized or studied for interregional transfer capability, it yields only limited resilience during wide-area emergencies. Conversely, the same interface may be flagged in a resilience/transfer study, but if planners do not evaluate its effects on

FIGURE 10

CAISO's Structured, Sequential Transmission Planning Process



CAISO's structured, three-phase planning process demonstrates how shared inputs—like demand forecasts and integrated resource plan portfolios—can drive consistent, policy-aligned transmission studies. By starting from a common foundation and sequencing technical analyses, planners can reduce duplication, clarify trade-offs, and enable more actionable solutions across planning functions.

Source: Adapted from California Independent System Operator.

chronic congestion and deliverability, the solution can shrink to a small, non-backbone device (such as a phase-shifting transformer, remedial-action scheme, or limited reconductoring) that marginally helps emergency imports yet leaves day-to-day congestion and future headroom unchanged.

The use of uncoordinated modeling tools compounds this disconnect. Capacity-expansion, production-cost simulation, power-flow, and stability studies are typically run on separate platforms, with different formats and limited handoffs. Each serves a distinct purpose and generates valuable insights, but without structured workflows to connect them, information often stalls at the boundaries between tools. Key findings can be lost in translation, making it harder to identify upgrades that address multiple system needs.

For example, a capacity-expansion model might identify zones that are well suited for renewable development. But if that insight does not carry into congestion or reliability studies, the associated transmission needs may be overlooked. Without integrated workflows, upgrades are scoped separately rather than developed as part of a coordinated, system-wide portfolio.

Solution

Integrated workflows can be developed that translate study outputs into shared upgrade assessments. Rather than each study being treated as a standalone effort, structured connections can be built between them—so that findings from one (e.g., new generation zones from a capacity-expansion model) automatically inform others (e.g., congestion or stability analysis). This can be enabled by standardizing data formats, aligning scenarios, and establishing mapping protocols between models. Tools can support this integration when used with consistent inputs and designed to pass results across planning functions. Upgrades can be co-developed across teams to ensure that solutions reflect multiple system needs.

Several regions are beginning to demonstrate this approach:

- **California:** The California Public Utilities Commission's Integrated Resource Planning process uses a busbar mapping process and tools to locate policy-aligned generation portfolios at specific substations. These mapped resources then become inputs into CAISO's transmission planning process.
- **NYISO:** Assumptions and findings from economic, reliability, and interconnection analyses are used to inform the analysis of public policy–driven projects.
- **MISO:** The Renewable Integration Impact Assessment linked production-cost modeling with AC power-flow and stability analysis, enabling iterative refinement of upgrade portfolios. Constraints identified in

production-cost models (e.g., congested flowgates) were passed to power-flow models, while monitored element-contingency pairs from power flow were fed back into production-cost models—revealing vulnerabilities missed by traditional snapshots and supporting more coherent, cross-functional planning.

When studies are linked through shared data and iterative workflows, planning teams can identify upgrade portfolios that address multiple system needs—thus reducing duplication, enhancing value, and enabling more effective cost allocation. Integrated portfolios can deliver greater system value, but weak alignment across processes can delay projects and leave significant benefits unrealized.

Integrated Planning Processes–Moving from Harmonized to Integrated

Challenge

While models and assumptions may become more coordinated, the processes through which planning studies are scoped, reviewed, and approved often remain disjointed. Each planning process typically has its own regulatory drivers, stakeholder groups, approval bodies, and benefits criteria.

This separation can limit the ability to design or approve projects that serve multiple needs. For instance, a project identified in a long-term study may be dismissed if it does not meet reliability or economic justification criteria, even if it provides significant policy or resilience benefits. Fragmented cost allocation processes further discourage cross-silo coordination. Without process integration intended to identify multi-driver needs from which multi-benefit solutions can be developed, even well-aligned technical analysis can stall due to procedural misalignment.

Solution

A solution is to move from single-driver planning to integrated cycles that explicitly combine the goals of generator interconnection, reliability, public policy, and economic efficiency. Using multi-value benefit criteria helps identify solutions that address multiple needs within a single portfolio—improving justification, coordination, and long-term system impact.

While some changes may require regulatory or governance reform, such as joint planning agreements, many regions are already taking steps in this direction:

- SPP's proposed **Consolidated Planning Process** would address economic, reliability, and policy needs in a single cycle, increasing the potential for multi-need transmission solutions (SPP, 2025c).
- MISO–SPP **Joint Targeted Interconnection Queue** was a coordinated effort across two RTOs to resolve queue backlogs and deliver shared interconnection capacity through a jointly planned $1.8 billion portfolio intended to meet the needs of multiple cycles of generator interconnection studies (MISO, 2025a).
- CAISO's **Transmission Planning Process** involves coordinating reliability, policy, and economic studies, in addition to considering interregional projects as potential solutions to meet regional needs (CAISO, 2025).
- New York's **Public Policy Transmission Planning Process** incorporates state policy and reliability needs into a single approval track, more closely aligning the two drivers (NYISO, 2024a).

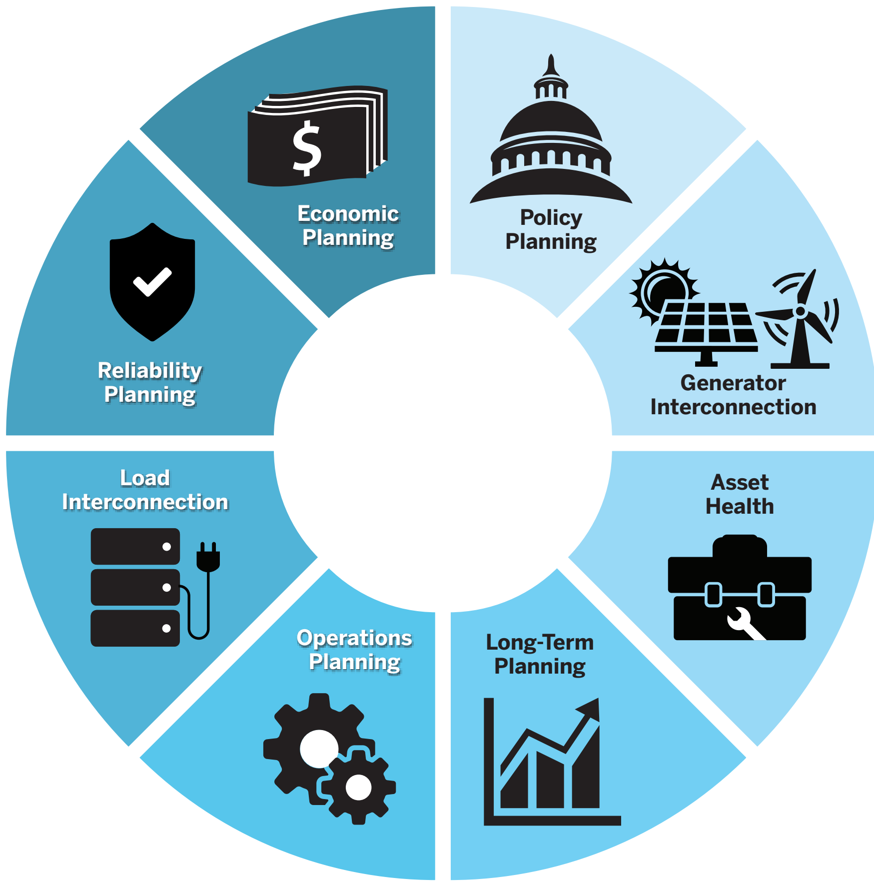
Regions adopting broader benefit metrics and shared governance are setting the stage for more integrated approaches. Embedding multi-driver analysis in study cycles and aligning approvals and cost allocation will help planning keep pace with emerging system needs.

Siloed Planning Areas That Can Be Integrated

To move from concept to implementation, planners need clarity on where integration can capture the greatest value. The previous sections outlined how to align processes, and this section discusses which specific interfaces should be connected to reduce duplication, improve timing, and deliver multi-need solutions. Figure 11 (p. 26) illustrates the major transmission planning silos—ranging from reliability, economic, and policy planning to interconnection, operations, and asset health—all of which shape the same grid.

FIGURE 11

Transmission Planning Functions That Need to Be Integrated



Integrated planning requires coordination across multiple traditionally siloed functions—including interconnection, reliability, asset management, operations, economic analysis, long-term scenario planning, and policy. Aligning these functions enables planners to develop solutions that are more holistic, multi-benefit, and system-oriented.

Source: Energy Systems Integration Group.

Once processes are aligned, specific interfaces need to be connected to reduce duplication, improve timing, and deliver multi-need solutions.

At its core, transmission planning exists to ensure that the right infrastructure is in place when and where it is needed for efficient, reliable, resilient system operations. Treating planning functions in isolation leads to missed opportunities and slower, more expensive outcomes. By contrast, integration across the following key planning tracks can streamline development and deliver more scalable, cost-effective results.

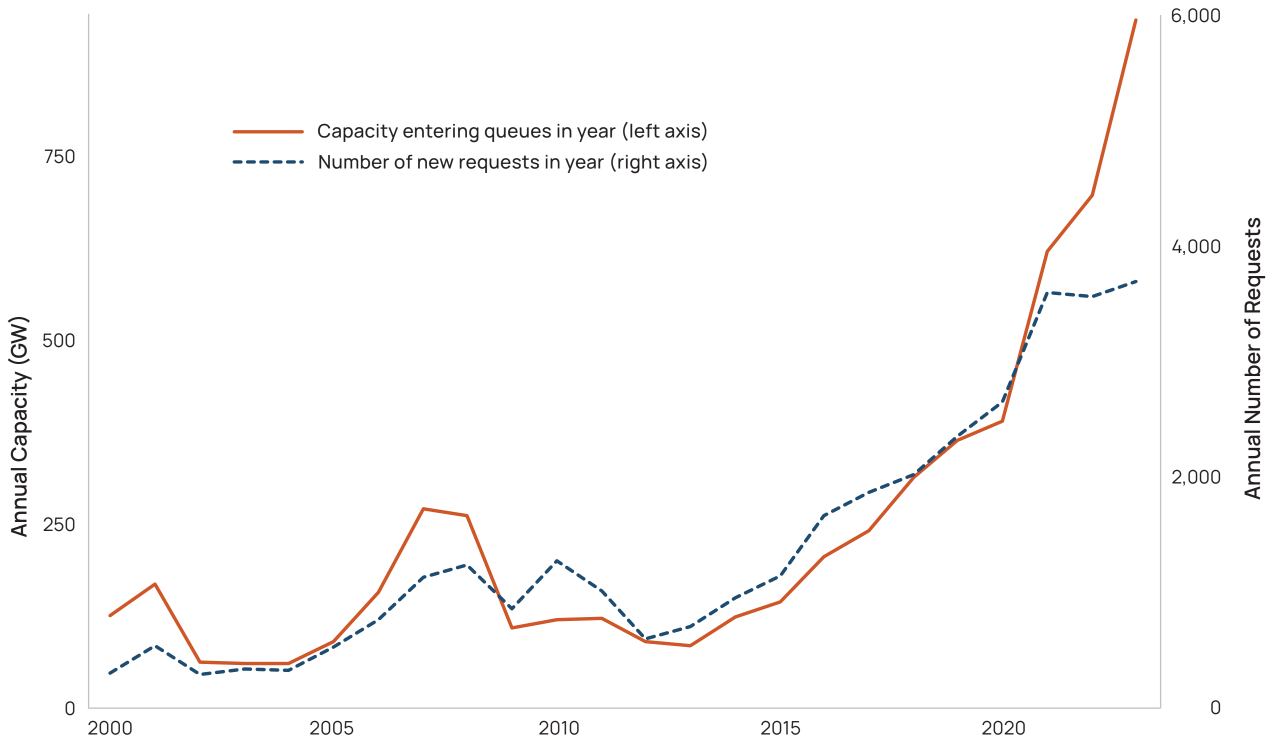
Integrate Generator Interconnection and Long-Term Transmission Planning

Why Prioritize

Generator interconnection has seen meaningful reforms, including cluster processing and stronger readiness requirements, which are helping surface recurring system constraints. As the gateway for new generation in a very active development landscape (Figure 12, p.27), it has become a de facto—if still imperfect—mechanism for identifying system needs. While the process provides valuable information on siting and constraints, its queue-driven, project-specific design often yields upgrade lists that remain unbuilt or are misaligned with long-term regional planning. Generator interconnection remains

FIGURE 12

Interconnection Requests Have Grown Sixfold Since 2015, Surpassing 900 GW in 2023



This figure shows the sharp rise in both the number of generator interconnection requests and the annual capacity entering U.S. queues. From 2015 to 2023, annual requested capacity grew more than six-fold to over 900 GW, while the number of new project requests climbed to nearly 3,700. This surge, now totaling nearly 2,600 GW of generation and storage seeking connection, reinforces the need to better integrate generator interconnection with long-term transmission planning.

Note: Annual totals include projects with status “active,” “suspended,” “withdrawn,” or “operational.” Earlier years may be incomplete and should be interpreted as approximate.

Source: Adapted from Lawrence Berkeley National Laboratory’s *Queued Up 2024* (Rand et al., 2024).

initiated by developer requests and conducted in set queue cycles.

For example, recent cluster studies have identified candidate upgrades totaling billions (e.g., ~$2.5 billion for the interconnection of 9.2 GW in MISO South (MISO, 2019) and $7.7 billion, including 765 kV in SPP (SPP, 2017). Because these upgrades are developed in narrow, queue-driven processes, they are often advanced outside of coordinated long-range portfolios, increasing the risk of rework and repeated construction in the same corridor.

Most generator interconnection studies focus on short-term, project-specific analysis (2 to 5 years), using static, single-snapshot assumptions and steady-state models.

Without integration, near-term upgrades may be misaligned with long-term system direction, and cost allocation may not reflect the full set of beneficiaries.

They rarely reflect the longer-term needs of the system or public policy drivers. As a result, transmission upgrades are frequently identified too late to be in service when new generation needs it—leaving generation projects constrained or delayed by insufficient transmission capacity. In contrast, long-term transmission planning spans 10 to 20 years and uses multi-year, multi-hour chronological modeling, including capacity-expansion and production-cost tools, to address future needs driven by policy mandates, economic efficiency, and reliability. Without integration, near-term upgrades may be misaligned with long-term system direction, and cost allocation may not reflect the full set of beneficiaries. Order 1920 takes initial steps to bridge this gap by linking persistent issues in generator interconnection with analyses of long-term needs and by expanding how transmission benefits are evaluated.

Benefits of This Integration

- Reduces the risk of restudy for generator interconnection and lowers generators' per-MW upgrade costs
  - Generators have a reduced risk of being allocated the full cost of large-scale transmission expansion costs.
  - Lower congestion and curtailment risks increase revenue certainty for generators.
- Enables proactive transmission development in areas where there is high interest in developing new generation
  - Generator interconnection has fewer delays.
- Aligns generation siting with long-term transmission plans
  - Generator interconnection siting is aligned with long-term plans. Regions can identify their ideal zones for generation development, balancing both cost and community impacts while still leveraging the benefits of competitive solicitation processes.
- Ensures that upgrades support multiple planning drivers
  - Projects are not built solely to respond to the minimum need of a single generation interconnection study cycle, reducing the time and expense of repeatedly resizing or rebuilding transmission in the same corridor as queue conditions change, instead of building once at the scale needed for long-term use.
- Increases stakeholder confidence in both transmission and generation plans
  - Stakeholder-vetted assumptions, for example, about load growth, generation additions and retirements, and policy targets, are used to develop the most efficient plans to meet forecasted system change.
- Distributes transmission upgrade costs among a large set of beneficiaries
  - Upgrade costs are better aligned with "beneficiaries-pay", as determined under the region's approved cost-allocation method.
  - There is a lower risk of project cancellation due to withdrawals based on factors outside of a region's control, such as loss of financing or supply chain issues.

How to Integrate These Planning Areas

- Use zonal or busbar mapping for queue-informed siting (as done in CAISO and MISO) in regular and ad-hoc transmission planning study efforts
- Bundle multiple generator interconnection cycles for joint analysis (such as implemented in the MISO-SPP Joint Targeted Interconnection Queue)
- Include early indicators from interconnection trends in long-range scenario modeling, enabling proactive development of infrastructure before bottlenecks emerge

Integrate Generator Interconnection and Near-Term Reliability and Long-Term Scenario Planning

Why Prioritize

Generator interconnection and reliability planning both look only a few years out and rely on similar technical foundations—steady-state and dynamic system models—to evaluate the same infrastructure in specific local areas. Yet even between these two closely related processes, differences in assumptions, study timelines, responsible teams, and approval tracks can lead to conflicting or duplicative upgrades.

Long-term scenario planning looks 10 to 20 years ahead, uses capacity-expansion and production-cost tools, along with steady-state models, and spans broader regions.

Because this broader view necessarily encompasses the same local areas evaluated in interconnection and reliability studies, misalignment across all three processes can compound conflicts, leading to repeated construction in the same corridors, cost misallocations, and delays in delivering needed capacity.

Generator interconnection is highly active and produces valuable information on siting and system constraints, but those insights often remain confined to cycle-specific reports. Reliability studies, meanwhile, are scoped to meet compliance standards and may not reflect forward-looking drivers such as electrification or resilience. Without stronger coordination among these tracks, valuable insights are left unused, and upgrades remain narrowly scoped to meet immediate needs rather than designed for longer-term, regional, multi-driver benefits.

Benefits of This Integration

- Prevents duplicative or conflicting upgrades for the same transmission constraint
- Enables cost-sharing for upgrades serving both reliability and interconnection needs
- Reduces restudies and queue churn by aligning assumptions and timelines
- Increases stakeholder confidence—including regulators, utilities, and developers—in grid adequacy and investment timing

How to Integrate These Planning Areas

- Use areas where there is high interest in developing generation resources, taken from interconnection queues, for future resource siting locations when developing long-term transmission plans
- Incorporate the same transmission constraints in both analyzing interconnections and developing transmission plans
- Use hosting capacity with forward-looking capability to add certainty in generation development
- Have the generator interconnection process input information about queued projects, expected locations, and associated network upgrade needs into the transmission planning process, as is done in CAISO (CAISO, 2025)

Application Areas for Integration

Coordination needs to be improved both within the interconnection process and between generator interconnection and broader planning functions.

- **Internally**, multiple queue cycles can be analyzed together to identify persistent constraints and identify transmission upgrades that efficiently address multiple needs. This improves the efficiency of system upgrades, allows the greatest number of new resources to interconnect, and offers greater predictability of upgrade costs for developers.
- **Externally**, generator interconnection data—such as volume, geography, and technology trends—can be used as a leading indicator of where transmission will be needed. Feeding these insights into long-range planning helps identify priority corridors, inform generation development zones, and better align infrastructure with evolving system needs.

Better coordination would enable better use of interconnection data to support proactive planning, improve upgrade efficiency, reduce restudy risk, and provide clearer signals to developers about where capacity is most needed and most likely to be deliverable.

Examples

- ERCOT: The “Connect and Manage” approach allows new resources to interconnect more quickly by managing transmission constraints via operational and market tools, while new transmission is being built. However, its success depends on timely follow-on transmission upgrades to prevent persistent congestion (ERCOT, 2024).
- NYISO *System and Resource Outlook* study: Uses queue and congestion data to inform siting considerations and identify congestion pockets (NYISO, 2024a).
- MISO-SPP: The $1.8 billion transmission portfolio identified by the Joint Targeted Interconnection Queue alleviated generator interconnection constraints across interconnection cycles and regions (MISO, 2025a).
- CAISO: Busbar mapping aligns integrated resource plan portfolios with generator points-of-interconnection for consistent planning inputs. Network upgrades from the Phase II Generator Interconnection and Deliverability Allocation Process are considered (depicted in the transmission planning process in Figure 13, p. 31) (CAISO, 2025).
- MISO: The Long-Range Transmission Planning process incorporates interconnection queue data and siting potential into long-range grid design.
- SPP: The Consolidated Planning Process and Integrated Transmission Planning use generator interconnection patterns to guide the selection of regional lines supporting interconnection, reliability, and economic goals.

Integrate Near-Term Reliability Planning and Long-Term Scenario Planning

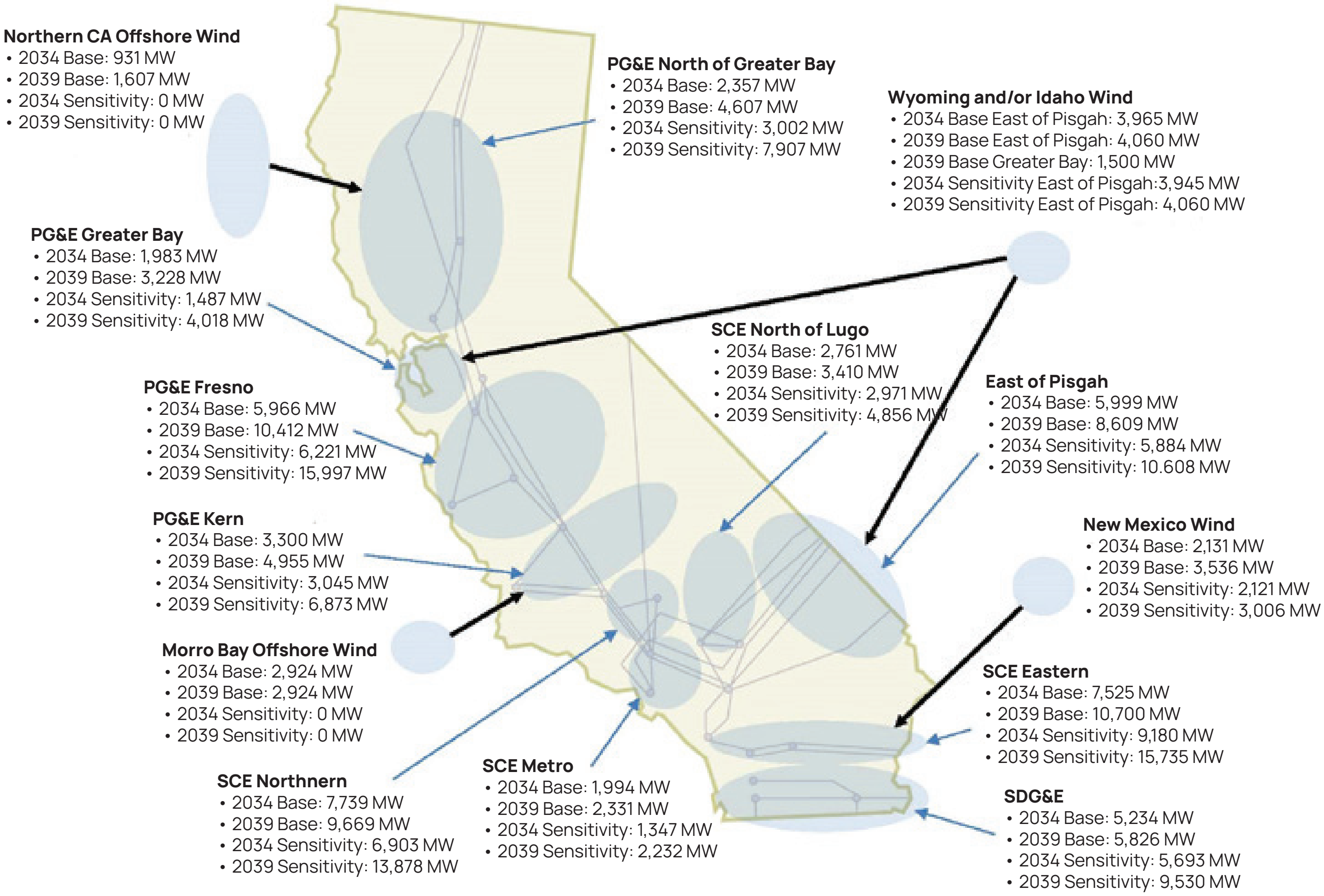
Why Prioritize

Since near-term planning—such as generator interconnection and near-term reliability—is often conducted independently from long-term, scenario-based studies, upgrades approved today may not align with future needs, leading to stranded assets or costly retrofits. Meanwhile, long-term plans frequently remain aspirational, with limited mechanisms to translate forecasts into near-term investment decisions.

Near-term reliability planning (2 to 10 years) uses deterministic tools such as AC contingency and TPL-001 compliance studies focused on system reliability during peak-load and high transfer snapshots. These analyses focus on known peak demand profiles met by generic generation dispatch scenarios and often result in planning solutions that are sized to address only near-term system needs. Meanwhile, long-term scenario planning extends 15 to 20 years out and addresses uncertainty in load growth, policy, DER adoption, and climate stress. These longer studies use capacity-expansion and stochastic models to evaluate structural shifts as well as hourly (or even sub-hourly) production-cost models to determine impacts on the transmission system. But without integration of the near-term and long-term planning studies, reliability fixes may be undersized or quickly outdated.

FIGURE 13

Targeted Resource Zones in CAISO Support More Proactive Transmission Planning



Agreed-upon resource expansion zones in the California Independent System Operator territory facilitate increased certainty in transmission planning and represent a step toward integration between generation and transmission planning. Aligning these zones with system upgrades helps coordinate generator interconnection with long-term transmission planning, enabling more efficient infrastructure buildout and reducing uncertainty for developers.

Source: California Independent System Operator. Licensed with permission from the California ISO. Any statements, conclusions, summaries or other commentaries expressed herein do not reflect the opinions or endorsement of the California ISO.

Benefits of This Integration

- Aligns short-term fixes with long-term grid needs
- Avoids building infrastructure that cannot scale
- Improves overall grid resilience by providing a longer-term platform to analyze and address potential risks

How to Integrate These Planning Areas

- Re-evaluate previously approved transmission solutions, taking into account evolving system needs such as a subsequent increase in load forecast, and modify appropriately (e.g., CAISO's Transmission Planning Process) (CAISO, 2024a)
- Harmonize load, resource, and policy assumptions across study horizons
- Link scenario-based capacity expansion with reliability requirements
- Increase the continuity of assumptions between near-term static and long-term scenario-based assessments

- As required in FERC Order 1920, develop a transparent process to include projects selected through long-term regional transmission planning studies in regional transmission plans

Application Areas for Integration

FERC Order 1920 requires all transmission providers to conduct 20-year, scenario-based planning at least once every five years and explicitly calls for improved coordination across planning horizons. It emphasizes that short-term fixes must not undermine long-term objectives and that near-term studies should be informed by long-range needs. CAISO has institutionalized these principles through its dual-track structure: a 10-year actionable planning horizon (Transmission Planning Process) and a 20-year Transmission Outlook that informs geographical and policy priorities (CAISO, 2025). This approach enables upgrades that serve current reliability needs while anticipating long-term growth, policy mandates, and resource shifts.

Structured connections need to be built between near- and long-term studies that:

- Use shared data and assumptions across both horizons (e.g., load forecasts, policy portfolios, resource buildouts)
- Incorporate modular and scalable project design, such as reserving right-of-way for additional/higher-voltage circuits or future high-voltage DC (HVDC) expansion
- Create feedback loops, where long-term scenarios shape short-term screening criteria and development priorities
- Provide transparent documentation to show how near-term decisions support long-range outcomes

Examples

- CAISO Humboldt 500-kV line: This line was designed for offshore wind with built-in HVDC conversion optionality to accommodate future expansion requirements (CAISO, 2024b).
- SPP 2024 Integrated Transmission Plan: This process selected 765 kV lines that address both immediate reliability needs and future transfer capacity (SPP, 2025a).

- ERCOT Permian Basin Expansion: Transmission upgrades were routed to anticipate load growth in oil and gas regions (ERCOT, 2025a).
- CapX2020 Transmission Expansion in Minnesota: 345 kV lines were built to accommodate additional circuits in anticipation of increasing renewable energy development (Monti et al., 2016).

Integrate Long-Term Scenario Planning, Generator Interconnection, and Load Interconnection

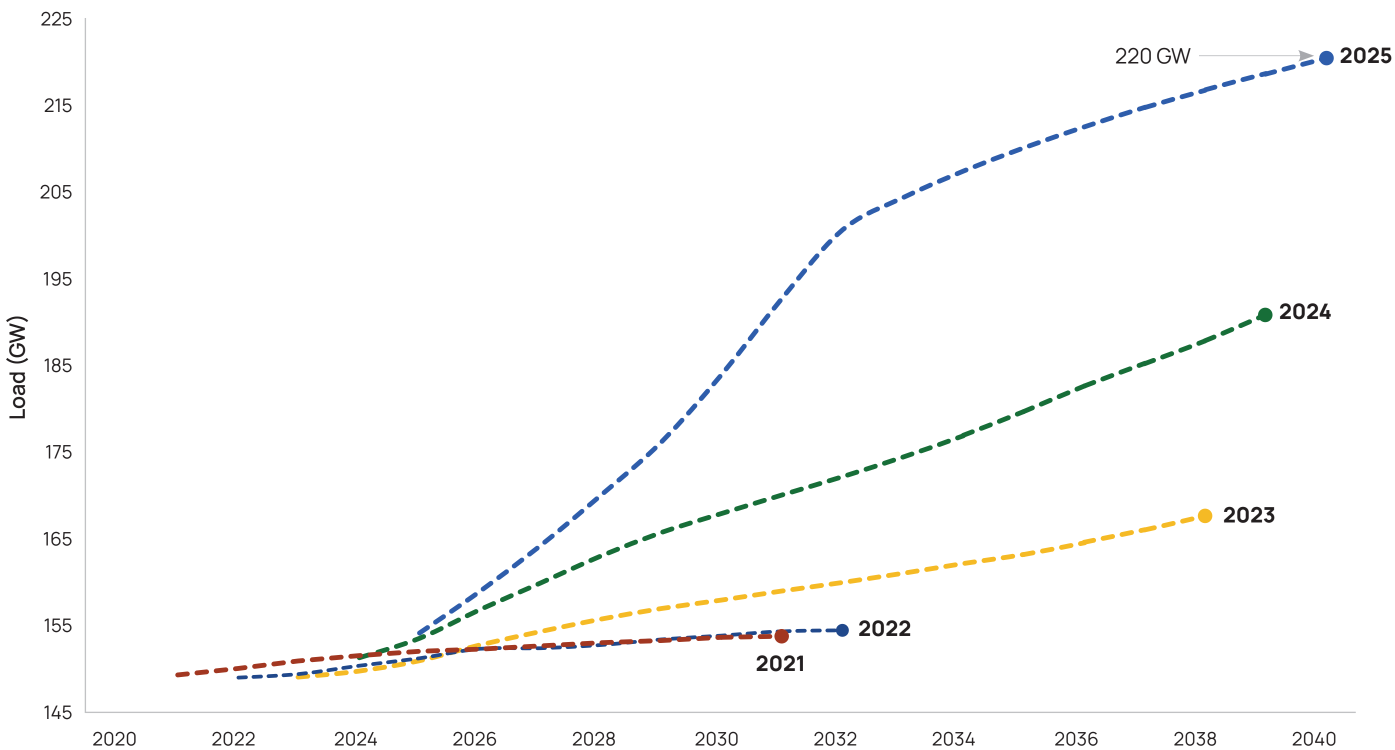
Why Prioritize

Large load interconnections—such as data centers, hydrogen electrolyzers, electric vehicle charging stations—require transmission and resource buildout beyond the typical 1- to 3-year study window. These needs align more closely with 5- to 15-year transmission and capacity planning horizons. Load studies often miss system-wide drivers like policy mandates or resilience and use simplified assumptions that understate long-term impacts. Current transmission planning processes offer only limited opportunities for iterative processes to consolidate upgrades across multiple drivers or benefit streams. Planning streams remain segmented, and coordination often stops once upgrades are identified within individual studies.

Recent PJM forecasts illustrate how rapidly expectations can shift: the 2025 outlook is 27 GW higher than the 2024 forecast, and overall demand growth is now projected at approximately 70 GW over 15 years (Figure 14, p. 33).

FIGURE 14

PJM Summer Peak Demand Forecasts, Showing Sharp Increases in Recent Years



PJM's most recent load forecasts project roughly 70 GW of additional demand growth over 15 years. The 2025 forecast is 27 GW higher than the 2024 outlook, underscoring how quickly expectations are shifting.

Source: Energy Systems Integration Group; data from PJM (PJM, 2025a).

Benefits of This Integration

- Matches new load with buildable, scalable infrastructure
- Reduces the need for emergency solutions to meet short implementation timelines identified in generation and load interconnection analyses
- Supports resource adequacy by ensuring that generation and transmission expansion are planned together in support of new customer interconnections
- Aligns new load development with areas of available or developing generation capacity

How to Integrate These Planning Areas

- Incorporate load interconnection zones into transmission expansion plans (SPP CPP, ERCOT Permian, CAISO/California Energy Commission (CEC, 2025)
- Use joint studies to evaluate generation siting, interconnection, and transmission delivery together
- Incorporate demand-side flexibility and non-wires transmission options into planning timelines

Application Areas for Integration

To meet rapidly evolving demand, planning must focus on identifying system needs based on future limitations and opportunities, rather than relying only on fixes to current or past problems. FERC Order 1920 highlights this shift, emphasizing the importance of forward-looking analysis. A more integrated and proactive approach can improve coordination across processes, ensure that needs are fully addressed, and support cost allocation. Using a common set of inputs and assumptions across studies creates a foundation for identifying multi-driver projects and avoiding under- or over-building.

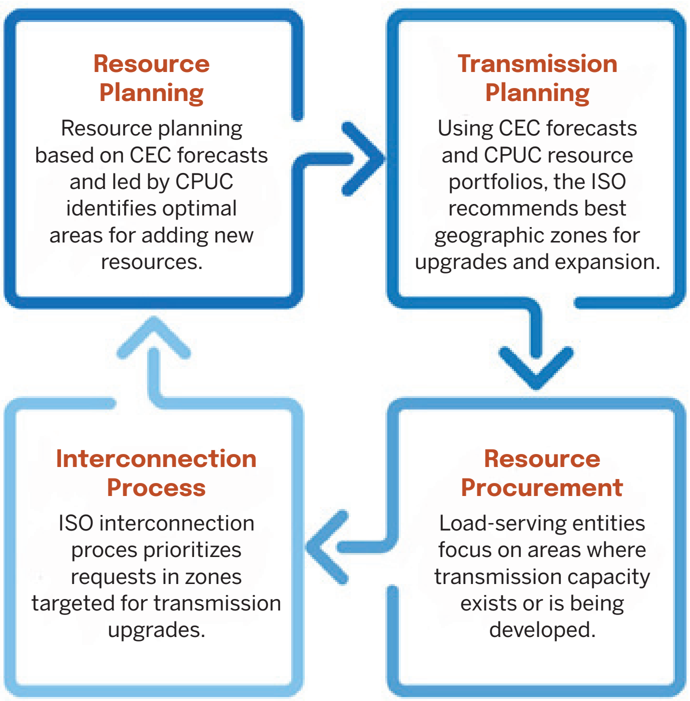
California offers a model for this type of alignment. Figure 15 shows how CAISO, the California Public Utilities Commission, and California Energy Commission have created tighter feedback loops between resource planning, transmission planning, generator interconnection, and resource procurement. Through shared data and cross-process coordination, they align resource planning, interconnection, and procurement with infrastructure development.

Planners can also:

- Add a "need consolidation and upgrade optimization" step into transmission planning, using shared scenarios, assumptions, and system models

FIGURE 15

Integrated Cycle of Resource and Transmission Planning in California



CAISO, the California Public Utilities Commission, and the California Energy Commission coordinate planning cycles by linking resource planning, transmission studies, interconnection prioritization, and procurement decisions. This feedback loop ensures that infrastructure development aligns with policy goals and resource needs, offering a replicable model for multi-agency integration.

Source: Adapted from California Independent System Operator.

- Identify and bundle upgrades that serve multiple needs
- Use tracking tools to monitor overlaps across processes, and incorporate forward-looking information (e.g., resource buildout or policy targets) to maximize the long-term value of investments
- Prioritize flexible design strategies—such as upsized lines or expandable rights-of-way
- Align cost allocation methodologies to support shared funding

Planning cycles should explicitly include screening for overlap, and composite scoring tools can help identify projects that deliver the most value across planning goals.

Examples

- MISO's Multi-Value Projects and Long-Range Transmission Planning bundled reliability, economic, and policy-driven needs into coordinated corridors, with cost allocation based on multi-value criteria (MISO, 2025b).
- NYISO's Public Policy Process combined asset upgrade and offshore wind delivery in a single project (NYISO, 2020).
- SPP's Consolidated Planning Process evaluates generator interconnection and economic, reliability, persistent operations, and policy needs in a unified cycle, supporting consolidation and reducing planning redundancy (SPP, 2025c).
- Open need solicitations, such as what is performed in PJM and NYISO, allow for increased breadth of analysis on the front end, creating a more effective path to more efficient and cost-effective solution development (PJM, 2024; Herman, 2025).
- Organizational structures that connect study teams—for example, ISO-NE's reliability and economic planning teams—improve coordination and enable organic consolidation, yielding transmission portfolios that capture more benefits. ISO-NE's technical guide requires coordination among study teams to identify shared solutions (ISO-NE, 2025).
- CAISO's Transmission Planning Process is a coordinated effort with the California Energy Commission and the

California Public Utilities Commission. The Transmission Planning Process coordinates reliability, policy, and economic studies in addition to the consideration of interregional projects as potential solutions to meeting regional needs (CAISO, 2025).

Integrate Asset Replacement/Management and Long-Term Transmission Planning

Why Prioritize

Transmission asset replacements are typically scoped over 5- to 10-year horizons using asset condition scores and risk assessments. These studies usually assume like-for-like rebuilds without modeling broader system drivers. In contrast, long-term scenario-based planning (10 to 20 years) evaluates system performance under evolving resource mixes, policy shifts, and economic constraints. While the investments in existing infrastructure were primarily driven by the limited change in generation and demand in the past, a growing volume of transmission investment is being spent on aging assets initially designed to serve different purposes and load profiles than the system demands today.

Integration of asset replacement and long-term planning ensures that asset rebuilds can meet future needs and reduce duplication of efforts and costs to mitigate issues identified on common facilities. One approach is to use mitigation plans that are scalable or able to accommodate additional capability with minimal effort. This could manifest as a double circuit–capable structure design with a single circuit initially constructed or as a project that can easily be converted between AC and DC operation.

Benefits of This Integration

- Coordinates rebuild studies with assessments of system-wide needs
- Avoids duplicative costs stemming from (1) the need to mitigate the same issues multiple times, and (2) unscalable upgrades that require significant effort to expand capabilities to meet future needs
- Reduces siting, permitting, and landowner impacts through efficient use of existing rights-of-way
- Assesses opportunities to right-size asset condition replacements so they can also serve future system needs

How to Integrate These Planning Areas

- Include end-of-life asset schedules in long-range model inputs so that long-range plans can make use of existing routes and facilities that require upgrades, regardless of the future scenario that materializes (MISO, PJM)
- Screen asset replacements for additional generator interconnection, policy, or economic benefits
- Use shared benefit-cost tools across the industry

Application Areas for Integration

A significant share of today's transmission investment is directed toward replacing aging infrastructure—yet most end-of-life projects are scoped and approved as like-for-like rebuilds. These projects are often initiated without evaluating how the asset could be right-sized or repurposed to meet future needs, such as for reliability, policy alignment, or system expansion. In fact, regional planning procedures often incentivize utilities to *ignore* potential grid upgrades in favor of in-kind replacement. Many legacy assets were built 50 to 100 years ago for different system purposes, yet current practices default to rebuilding them to the same specifications, missing opportunities for more strategic, cost-effective solutions.

Many legacy assets were built 50 to 100 years ago for different system purposes, yet current practices default to rebuilding them to the same specifications, missing opportunities for more strategic, cost-effective solutions.

End-of-life investments need to be reframed as opportunities for multi-need, forward-looking planning. Rather than treating these projects as isolated maintenance items, regions can assess whether end-of-life assets can be upgraded to support additional system benefits. When asset condition data and replacement schedules are incorporated into regional studies, this enables a more strategic, system-wide view. End-of-life-driven projects can then be bundled with upgrades that increase transfer capacity, reduce congestion, improve reliability, integrate renewables, and/or enable policy delivery.

Recent reforms support this shift. FERC Order 1920 reinstated a federal right of first refusal for utilities pursuing right-sized replacements, reducing the disincentive to expand or enhance assets beyond like-for-like rebuilds. This change helps remove a regulatory barrier that previously discouraged utilities from pursuing strategic upgrades for fear of triggering competitive solicitations. Framing asset replacement within a broader system context can help reduce duplication, accelerate modernization, and contribute to a grid that is more resilient and adaptable.

Integrate System Operations and Transmission Planning

Why Prioritize

Transmission planning has been primarily focused on static performance and N-1 and N-1-1 reliability, variability, predictability, and visibility and does not factor in transitions between different operating states. In contrast, operational planning (real-time to one year) has a greater emphasis on system behaviors and modeling of ramping, voltage, frequency response, and inertia—areas not typically captured in long-range planning. These operational considerations are becoming increasingly important with the growing integration of inverter-based resources (IBRs), DERs, and large loads. Bridging these functional areas will lead to increased operational grid stability at lower cost.

Benefits of This Integration

- Improves system operability by ensuring that the right capabilities (inertia, voltage support, infrastructure, operational tools, etc.) are available at the right times
- Reduces reliance on redispatch, special protection schemes, and extraordinary grid operations
- Accelerates the integration of grid-forming technologies

How to Integrate These Planning Areas

- Incorporate operational considerations—such as ramping needs, inertia, and voltage support—into long-term transmission planning (MISO, 2021; CAISO, 2025).
- Evaluate production cost–driven stress periods for voltage stability. In MISO's Renewable Integration Impact Assessment, this revealed grid vulnerabilities that deterministic N-1 thermal analysis would have missed, highlighting the value of early dynamic analysis in scenario-based planning.
- Apply transient and electromagnetic transient analysis to validate project designs and ensure operational reliability under high-penetration resource scenarios.
- Formalize operator input during scenario screening and transmission needs identification to better align planning with operational realities.

Bringing planning functions together is a critical first step—but integration alone does not ensure the right projects are selected. If the inputs to an integrated process are still narrow—focused on only a handful of drivers, scenarios, or stakeholders—the solutions will be, too. The next step is to widen the lens: incorporating a broader set of needs, futures, and perspectives so that integrated planning can identify projects that deliver value across multiple dimensions.

Broaden: Expanding the Scope of Planning Inputs and Outcomes

Many planning processes focus on a narrow set of drivers, scenarios, or stakeholders. Whether shaped by compliance rules, market efficiency metrics, or single-policy mandates, their scope and outcomes are often limited by the assumptions they start with. Broadening the lens means stepping beyond traditional constraints to capture the full range of needs, scenarios, and perspectives. That can mean:

- **Expanding why we plan:** Setting objectives that go beyond least-cost reliability or congestion relief to include public policy, resilience, economic development, and flexibility needs
- **Broadening what is modeled:** Capturing high-impact, non-traditional loads (e.g., data centers, electrified oil and gas infrastructure), DERs, extreme weather, planned and unplanned transmission and generation outages, and resilience requirements (e.g., emergency import capability)
- **Widening who is involved:** Coordinating across state agencies, vertically integrated utilities, RTOs/ISOs, municipal systems, impacted tribes, and neighboring regions

Examples from current practice:

- **MISO's Long-Range Transmission Planning** integrates state policies and utility resource plans into regional portfolios with multi-driver value.
- **Strategic extra-high-voltage backbones (ERCOT, PJM, SPP, MISO)** are being advanced to align industrial development, load growth, and resource adequacy—broadening the focus to economic-development corridors.
- **ISO-NE's Future Grid Reliability Study** evaluates pathways to meet climate mandates while integrating DERs and demand-side flexibility, recognizing the need for bulk transmission that adapts to a more distributed, uncertain future.
- **DOE's National Transmission Planning Study** tested 96 futures, varying policy, load growth, resource mix, and technology, to identify high-opportunity transmission corridors where value recurred—highlighting least-regrets options for long-lead buildout.

While these examples demonstrate progress, they remain isolated cases or are closely tied to specific policy mandates. In many instances, broader scenario modeling and policy coordination help shape the discussion but do not ultimately determine which projects move forward. A more systematic, binding use of these approaches is needed to fully realize their value for transmission planning and investment.

Application Areas for Broadening Transmission Planning

The following application areas show where broadening scope is delivering value, and where more is needed.

Integrate Large, Non-traditional Loads

Challenge

Transmission planning has long relied on steady, incremental load growth. Today, however, a growing share of new demand is being driven by large, high-intensity users—such as data centers, crypto-mining operations, hydrogen production, electrified manufacturing, and transportation electrification. These loads are emerging rapidly, often cluster in specific areas, and may require levels of energy and reliability that, in some cases, far exceed past planning assumptions. They introduce new challenges in terms of scale, timing, voltage sensitivity, and operational flexibility that current forecasting and planning approaches do not capture well.

Demand projections for these new grid consumers are depicted in the light blue portion of the last column in Figure 16 (p. 39).

As a result, the transmission providers and system operators are confronting a fundamental shift in load dynamics. The core purpose of transmission planning—to ensure the system can reliably serve future demand—has made the integration of these emerging loads a top priority. Industry experts, regulators, and utilities have highlighted a range of technical and operational challenges, including:

- Loads' uncertain operating behaviors and ramp profiles
- Loads' sensitivity to voltage and frequency fluctuations
- The potential for low-frequency oscillations
- The need for enhanced reactive power support and compensation
- The lack of defined voltage and frequency ride-through performance standards
- Gaps in study methods for evaluating interconnection impacts

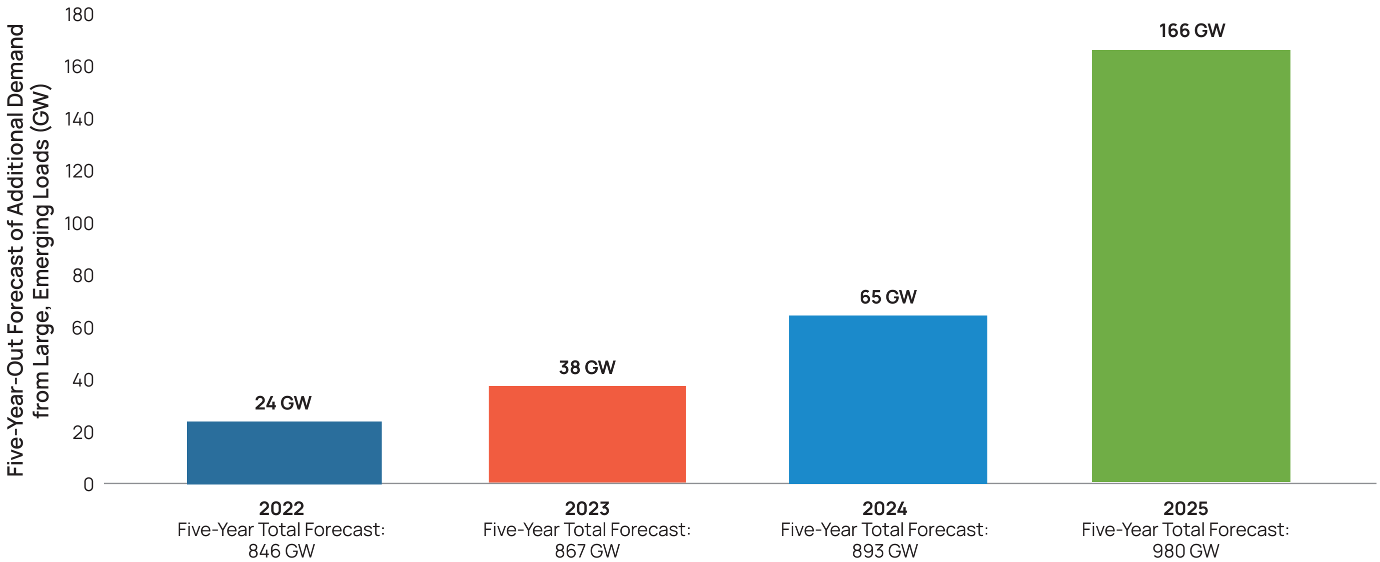
Why Prioritize

To date, loads have largely been passive participants in power systems, and as such, there are currently no performance requirements or best practices established for large load interconnections. Continuing to interconnect large loads without addressing the technical and planning gaps described above will introduce significant uncertainty into grid operations and may lower overall system reliability.

As highlighted by NERC, ERCOT, and others, this issue is not theoretical. Figure 17 (p. 39) from ERCOT shows rapid and accelerating large load growth—driven by siting of energy-intensive industries and data-driven applications (ERCOT, 2025b).

FIGURE 16

Peak Demand Growth Forecasts Have Risen Six-fold Since 2022, Driven Largely by Data Centers

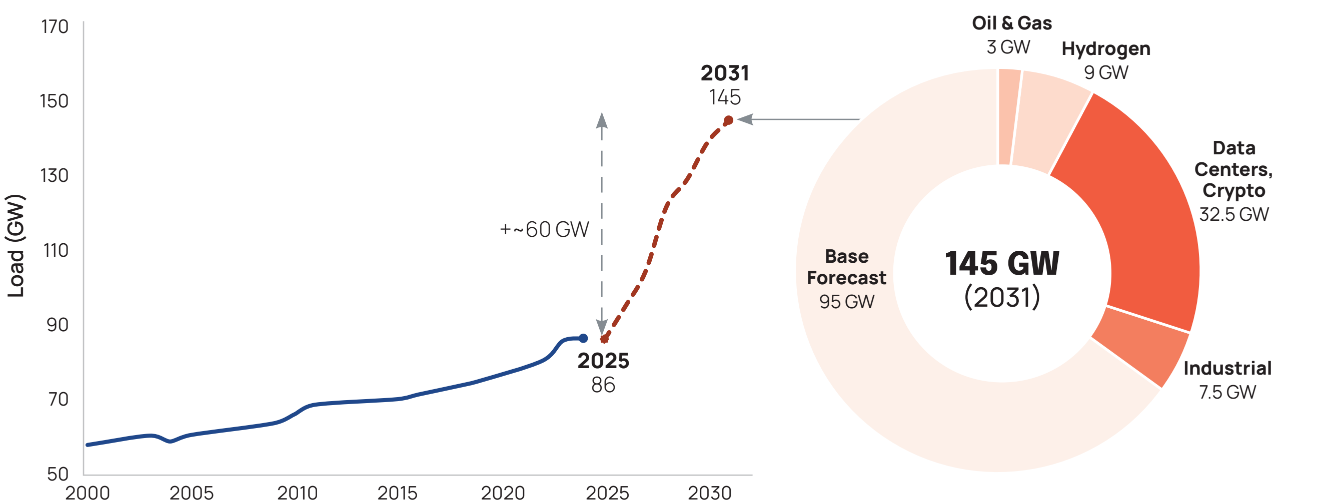


This figure shows five-year U.S. summer peak demand growth forecasts from 2022 to 2025, based on FERC Form 714 filings. The y-axis reflects additional peak demand expected over the five years following each forecast year—rising from 24 GW in 2022 to 166 GW in 2025. Most of this growth is attributed to data centers, which make up over half of the forecasted increase, though some forecasts likely overstate timing or scale due to uncertainty in project completion and infrastructure constraints.

Source: Grid Strategies analysis of FERC Form 714 forecasts (2022–2025). Adapted from Wilson et al. (2025); https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf.

FIGURE 17

ERCOT's Historical and Projected Load Growth, 2022–2031



ERCOT's adjusted forecast, based on historical trends applied to transmission service provider (TSP) load projections, shows summer peak demand growing from approximately 86 GW in 2025 to nearly 145 GW by 2031, an increase of about 60 GW. Most of this growth comes from large, high-intensity loads, with data centers and crypto alone contributing 32.5 GW. ERCOT's non-adjusted forecast reaches 218 GW by 2031, reflecting uncertain load potential. These new demands significantly alter the system load profile and raise critical implications for system planning.

Source: Energy Systems Integration Group. Data from the Electric Reliability Council of Texas (https://www.ercot.com/files/docs/2025/04/07/8.1-Long-Term-Load-Forecast-Update-2025-2031-and-Methodology-Changes.pdf).

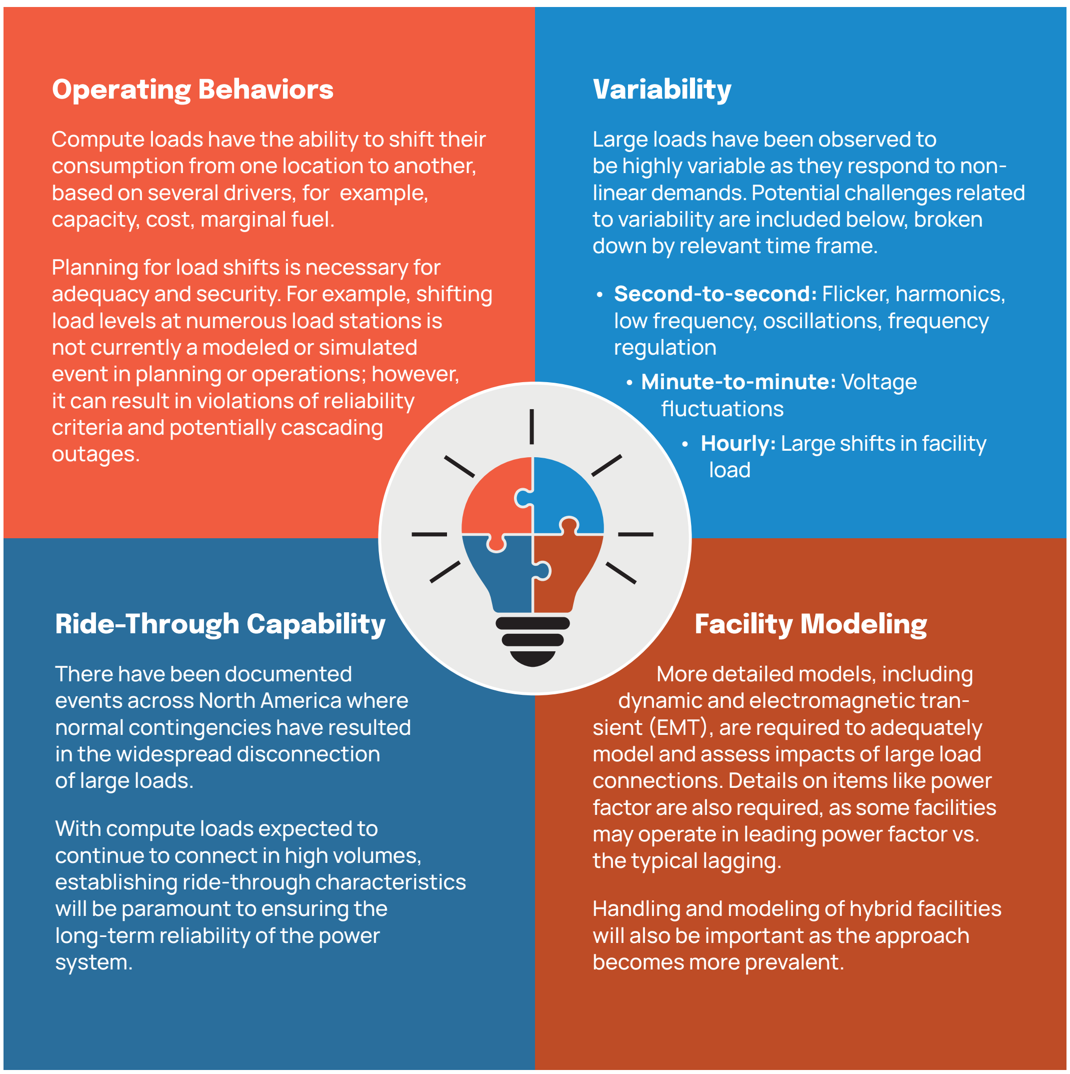
Figure 18 summarizes the salient points concerning large load integration. To maintain system reliability, planners (and operators) must understand how these new customers operate, the variability of this new demand, the ability for these new customers to withstand system fluctuations, and how they should be modeled.

Solution

Planning models need to be broadened to include emerging load categories by building new scenarios, using third-party economic development forecasts, and proactively coordinating with local and state development authorities. These efforts should emphasize spatial resolution, industry-specific demand profiles, and operational characteristics that impact transmission and substation design. Alongside improved modeling, integrated study processes that allow time for iteration and refinement can help large loads interconnect more efficiently and reduce cost impacts on other customers.

FIGURE 18

Main Aspects of Large Load Integration



Historical transmission planning processes benefited from minimal variability in resources and demand. With significant increases in demand projections and the generation additions needed to meet that new demand, additional considerations in planning processes are needed to ensure a reliable future.

Source: Energy Systems Integration Group.

Some regions are exploring co-location of generation and load, which can accelerate generation interconnection and reduce transmission impacts—but requires coordination around injection limits, internal contingency modeling, joint interconnection approvals, and outage management. These operational considerations must be integrated into planning models from the outset.

Going forward, these practices can be institutionalized by:

- Collaborating with state and local agencies to track and forecast economic development, increasing the breadth of the effort
- Working with industrial developers and large-load customers to understand siting preferences and operational requirements to gain a deeper understanding of impacts
- Developing scenario libraries that reflect the diversity of possible demand outcomes—including timing, geography, and load shape—so that infrastructure can be sized and routed accordingly
- Plan with operations in mind, specifically, designing, sizing, and siting upgrades using operational data and constraints

Examples

- SPP's 2024 Integrated Transmission Planning process included high-growth futures focused on hydrogen hubs and data centers. These scenarios were shaped by industrial interconnection requests and stakeholder engagement, aiding in the identification of potential high-load growth corridors (SPP, 2025a).
- ERCOT's Strategic 765 kV Plan maps transmission expansion into the Permian Basin to proactively accommodate expected oilfield electrification and large-scale industrial activity—based not on legacy forecasts but on observed and anticipated siting patterns (ERCOT, 2025a).
- CAISO provides system capability data that the California Public Utilities Commission incorporates into its integrated resource planning process, helping steer new development toward locations that maximize existing transmission use (CAISO, 2022).

Include Resource Adequacy as a Transmission Planning Driver

Challenge

Resource adequacy has traditionally centered on generation, with transmission playing an implicit role. In practice, transmission constraints determine how much capacity is recognized for adequacy and how large local requirements must be (Brooks, Silverstein, and Gramlich, 2025). However, these determinations are usually handled within adequacy studies or tariff rules and are rarely coordinated with transmission planning. In most regions, new transmission is not considered a tool for meeting capacity requirements.

Why Prioritize

This separation overlooks the role of transmission in reducing reserve needs, improving deliverability, and enabling the sharing of resources across zones and regions (ESIG, 2025). FERC Order 1920 requires planners to measure adequacy benefits—whether through reduced loss-of-load risk or lower reserve margins and generation needs. But most adequacy requirements fail to incorporate these benefits when determining total capacity need, leaving value on the table.

Results from DOE's National Transmission Planning Study, regional adequacy assessments, and independent evaluations show that added transfer capability, upgrades that improve the deliverability of resources, and interregional ties can reduce adequacy risk and defer the need for new capacity. This is particularly important as adding new resources is becoming more challenging: the capacity value of wind and solar is already saturated in many regions, battery storage is showing similar saturation, and gas supply chains face both physical constraints and environmental restrictions. Transmission provides another option in the adequacy toolbox, allowing existing and new resources to be used more effectively.

Treating adequacy as a driver for transmission planning puts it on equal footing with economics, policy, and reliability in shaping transmission plans.

Solution

Making resource adequacy a planning driver means planning transmission with adequacy in mind, rather than only reporting those benefits once studies are complete. Three shifts in transmission planning follow:

- **Transmission can be used to support reductions to reserve margins and local resource adequacy requirements.** Expanding energy imports and improving deliverability directly reduce the capacity needed to satisfy reliability criteria. Transmission can also, therefore, be treated as a supply-side resource in capacity markets or IRP procurements.
- **Futures can be stress-tested for adequacy.** Scenarios can be built with correlated weather, large load additions, and regional disruptions, and portfolios can be evaluated with probabilistic adequacy metrics.
- **The adequacy value of transmission can be quantified at multiple scales.** Both portfolios and single lines can be evaluated for how they reduce adequacy risk and defer new generation capacity, for example, by developing capacity accreditation for individual transmission projects or portfolios of projects.

Examples

- **National:** DOE's National Transmission Planning Study shows that interregional transmission supports adequacy by enabling capacity-sharing across weather systems. When resource adequacy coordination was excluded, optimal transmission builds fell by 40% to 60%, and system costs rose by $200 to 350 billion (GDO, 2024).
- **Regional:** MISO's Long-Range Transmission Plan quantified resource adequacy benefits from new transmission, showing lower reserve needs and improved deliverability. NYISO's 2024 assessment credited more than 6 GW of added transfer capability into Long Island by 2030, positively impacting local requirements (NYISO, 2025; NYISO, 2024b).In the Northwest, adequacy studies show that imports offset seasonal hydro shortfalls (Gai, 2025; Gai, 2024). In New England, the benefits of interregional ties likewise reduce adequacy risk by allowing regions to lean on neighboring systems (ISO-NE, 2024a).
- **Project-level analysis**. Astrapé's *North Plains Connector Evaluation* and ESIG's report *Multi-Value Transmission Planning* show how a single line can reduce adequacy risk (in terms of loss-of-load expectation, loss-of-load hours, and expected unserved energy) and provide measurable capacity value (effective load-carrying capability, deferred capacity) (Astrapé, 2024; ESIG, 2022). Both demonstrate the role of probabilistic methods in capturing transmission's adequacy contribution.

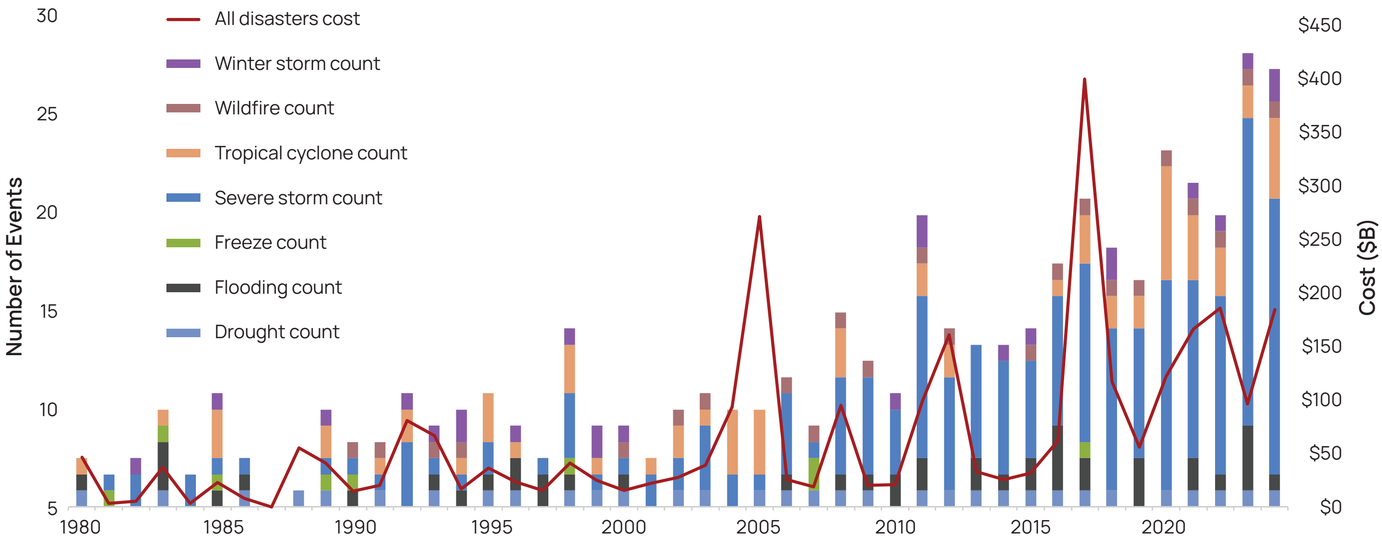
Include/Prioritize Resilience as a Planning Driver

Challenge

Traditional transmission planning is grounded in reliability metrics that prioritize performance under normal conditions or single-contingency events (N-1). But the power system is now facing an escalating frequency and severity of weather-related disruptions. These disruptive events include wildfires, hurricanes, deep freezes, heat waves, and localized storms that have caused massive and prolonged outages. As shown in Figure 19 (p. 43), both the number and cost of extreme events have increased dramatically, threatening not only grid reliability but the broader well-being of our economy and society (NCEI, 2025).

FIGURE 19

United States Billion-Dollar Disaster Events, 1980 to 2024



Extreme weather events are increasing in frequency and cost. There has been a dramatic rise in the frequency and cost of billion-dollar weather-related disasters in the United States since 1980. With the power grid increasingly exposed to severe weather events like hurricanes, wildfires, and extreme temperatures, the need to incorporate resilience into transmission planning has become critical.

Source: National Oceanic and Atmospheric Administration, https://www.ncei.noaa.gov/access/billions/time-series.

Incorporating operational challenges in transmission planning requires modeling and consideration of uncertainties experienced in operations and understanding the reliability impacts of transitioning from one operating state to another. The power system's vulnerability is not just about generation availability—it's about the grid's ability to anticipate, prepare for, withstand, and recover from disturbances across all elements of production and delivery, from generation, transmission, and distribution infrastructure to customer connections. Current transmission planning practices do not sufficiently evaluate the coincidental loss of critical corridors, major substations, or multiple generators from extreme events, nor do they incorporate the cascading risks or correlated failures across regions.

Better transmission planning can help contain and minimize the impacts of these events, helping make the power system more resilient by increasing the ability of distant generation to deliver energy from outside the affected areas during such events.

As noted above, resilience is founded on the grid's ability to anticipate, prepare for, withstand, and recover from disturbances on the system to maintain service or ensure timely restoration. To enable a resilient system, comprehensive planning must account for disturbances in any segment of power delivery (generation, transmission, or distribution). Long-term analysis provides increased value when it informs resource plans as well as incorporates a holistic view of reliability, economics, policy, and system operations during extreme events.

Solution

Resilience should be treated as a core planning objective, with broader contingency definitions, integration of extreme event analysis, and explicit evaluation of grid performance under high-impact disruptions. This involves the following three key stages.

Anticipate

A regional and interregional catalog of past weather-driven disruptions is needed, documenting asset outages, load loss, event timelines, and recovery processes. This database can be used to define a set of extreme weather scenarios—including loss of corridors (storms), substations (flooding, icing), wide-area generation (wildfires, heat domes, droughts), and prolonged fuel constraints. These scenarios will support system-wide analysis that goes beyond traditional N-1 events, offering a clearer view of how the grid performs under more complex, still realistic conditions.

ESIG's report *Stress Testing Methods for Evaluating Resilience to Extreme Events: Valuing Interregional Transmission* offers a practical framework for modeling system performance under high-impact, low-probability scenarios, with a focus on representing interregional transfer capability and wide-area weather impacts to better inform transmission planning (ESIG, 2025).

Prepare and Withstand

Once scenarios are established, transmission planners can evaluate how existing and proposed infrastructure portfolios perform under extreme conditions. This includes:

- Designing for path diversity to reduce the risk of single-corridor failure
- Considering undergrounding transmission lines, especially in areas prone to wildfire or hurricanes
- Strategically siting substations to mitigate regional risk and provide alternative flows
- Specifying equipment hardened for extreme conditions (e.g., cold-weather packages)
- Installing circuit switchers to allow sectional energization of long transmission lines
- Exploring interregional interconnections that can supply dense load pockets during crises

For example, SPP's 2024 Integrated Transmission Plan introduced a "resilience future" scenario that stress-tested projects under stakeholder-defined high-impact events and factored those results into project scoring (SPP, 2025a). ISO-NE's *Future Grid Reliability Study* assessed the system's ability to operate under extreme weather paired with high electrification, identifying where added transmission and flexibility could improve system stability (ISO-NE, 2022).

Recover

Restoration following major outages is often ad hoc, relying on manual sequencing and limited resources. Planning processes should include system restoration coordination—modeling energization paths, expected timelines, and the role of blackstart capabilities. This can include:

- Expanding blackstart resources in locations with robust transmission access
- Using grid-forming inverters and long-duration storage as restoration assets
- Deploying interregional support paths through HVDC or dispatchable transfers
- Installing switchgear that enables partial system reenergization prior to full line repairs

FERC Order 1920 explicitly supports incorporating resilience benefits into project selection and cost allocation—helping to elevate these capabilities from optional enhancements to system-wide priorities. As climate-related risks intensify, resilience is gaining traction as a key consideration in transmission development. Yet in many regions, it is still approached as an operational issue rather than something built into how transmission is planned and prioritized.

Integrating resilience into scenario analysis, infrastructure screening, and system restoration planning can help ensure that the grid not only withstands extreme conditions, but recovers quickly when disruptions occur. Several regions are beginning to adopt this thinking: SPP includes resilience scoring in its Integrated Transmission Planning process, ISO-NE has introduced climate stress modeling, and FERC Order 1920 highlights resilience in its benefit-cost framework.

Integrating resilience into scenario analysis, infrastructure screening, and system restoration planning can help ensure that the grid not only withstands extreme conditions, but recovers quickly when disruptions occur.

Improve Interregional and Multi-Jurisdictional Coordination

Challenge

The electricity grid is physically interconnected across vast regions, yet transmission planning remains institutionally fragmented. RTOs and ISOs generally plan within their own boundaries, while vertically integrated utilities—especially in the West and Southeast—conduct planning independently. These jurisdictional seams often mark the end of coordination, even when the physical system, resource potential, and reliability risks span across them.

This fragmentation results in redundant or misaligned infrastructure, underutilized transmission capacity, and a missed opportunity to tap the geographical diversity of renewable resources and load patterns. Opportunities to share infrastructure costs or coordinate projects across borders are often left unexplored, stymied by differing regulatory authorities, modeling frameworks, and benefit-cost methodologies. Interregional projects face especially steep challenges, with no consistent process for joint evaluation, cost allocation, or stakeholder engagement.

Jurisdictional fragmentation results in redundant or misaligned infrastructure, underutilized transmission capacity, and a missed opportunity to tap the geographical diversity of renewable resources and load patterns.

Why Prioritize

Interregional transmission can deliver substantial system-wide benefits. By linking diverse resource zones and demand centers, these lines reduce the cost of meeting reserve requirements, improve reliability during extreme weather, and expand access to lower-cost, clean generation. They also unlock geographical and temporal diversity, which increases the utilization of existing and planned generation while reducing the amount of redundant capacity needed to ensure adequacy.

Yet these benefits are hard to capture without coordinated analysis, both across planning disciplines and regional planning boundaries. Today, long-term transmission expansion, reserve-margin requirements, and capacity planning run in separate processes under different regulatory authorities. Even when a project could deliver shared benefits, it is evaluated through local or regional lenses with different value criteria—fracturing the assessment and slowing action.

Notable interregional lines like the Champlain Hudson Power Express, SunZia, TransWest Express, Heartland Spirit Connector, and others shown in Figure 20 (p. 46) illustrate both the promise and the challenge. These projects deliver broad benefits across state and regional lines—such as access to low-cost generation, congestion relief, and improved resource adequacy—but were primarily developed as merchant or sponsored projects, outside of coordinated regional or interregional planning.

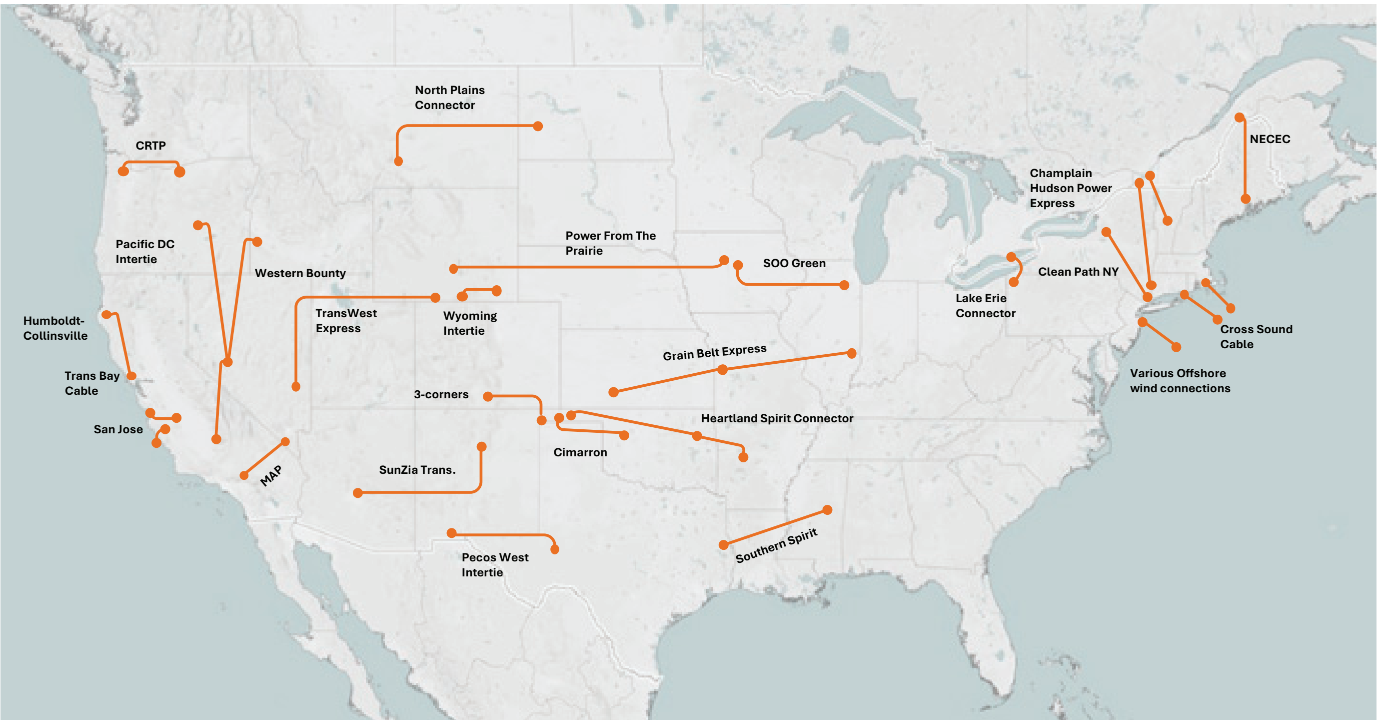
Solution

Formal interregional planning structures can be built that move beyond ad hoc coordination and into institutionalized, recurring collaboration. These planning structures can include:

Formal interregional planning structures can be built that move beyond ad hoc coordination and into institutionalized, recurring collaboration.

FIGURE 20

Notable Interregional Transmission Lines



Transmission projects underway across the U.S.—primarily developed as merchant or sponsored projects—demonstrate strong demand for added transfer capability. More coordinated planning and cost allocation processes could help align these individual initiatives with broader regional and national system needs.

Source: Adapted from James McCalley, Iowa State University.

- Shared scenario development, reserve margin analysis, and capacity-expansion modeling across jurisdictions
- Joint study processes with aligned modeling inputs, synchronized timelines, and standardized benefit metrics
- Established cost-allocation frameworks that recognize regional diversity while enabling cross-border investment
- Clear regulatory pathways and inter-agency coordination to review interregional value on consistent terms

FERC Order 1920 takes an important step by requiring transmission providers to evaluate a broader, standardized set of benefits—including the monetized value of avoided generation capacity—as part of seven required metrics. To fully capture the potential of interregional transmission, however, this type of analysis will need to extend beyond long-term scenario planning and inform near-term, multi-jurisdictional, and interregional processes. Applying these benefit frameworks consistently across states and regulatory boundaries can help align decision-making and better support shared infrastructure solutions.

Examples

- **MISO-SPP Joint Targeted Interconnection Queue**: This study produced a $1.8 billion jointly planned portfolio addressing congestion and queue backlogs along the RTO seam using shared data, joint analysis, and coordinated cost allocation.
- **Western States Transmission Initiative**: This initiative is a DOE-supported effort aligning assumptions and models across states, utilities, and planning bodies in the West.

- **Memorandum of Understanding Between CAISO, the California Public Utilities Commission, and the California Energy Commission**: This formal agreement links state policy, generation planning, and transmission analysis within a unified governance framework. California Public Utilities Commission resource portfolios include out-of-state resources requiring interregional planning and coordination.
- **Champlain Hudson, SunZia, TransWest, Heartland Spirit Connector lines**: This merchant transmission shows interregional value, but also highlights the need for more structured and coordinated planning with regional and interregional cost-allocation mechanisms to align costs with beneficiaries.

Improve Policy Alignment and Scenario Diversity

Challenge

A growing number of federal, state, and utility mandates—covering decarbonization, electrification, clean energy procurement, and retirements—are rapidly reshaping the power system (see Figure 21, p. 48). Yet many planning processes still treat these policies as external considerations rather than foundational drivers. The result is infrastructure that lags behind resource development, contributing to renewable curtailment, congestion, and missed targets.

FERC Order No. 1920-A directly addresses this gap by requiring transmission providers to incorporate utility commitments and federal, tribal, state, and local policy goals into their long-term planning frameworks. It elevates public policy from a discretionary factor to a foundational input in identifying transmission needs.

The order also mandates the use of at least three long-term planning scenarios—which include considerations of extreme weather impacts—that reflect changes in resource mix, load shape, DER growth, and climate impacts. These scenarios must be developed with transparent stakeholder input and evaluated using benefit metrics, including the monetized value of avoided generation capacity.

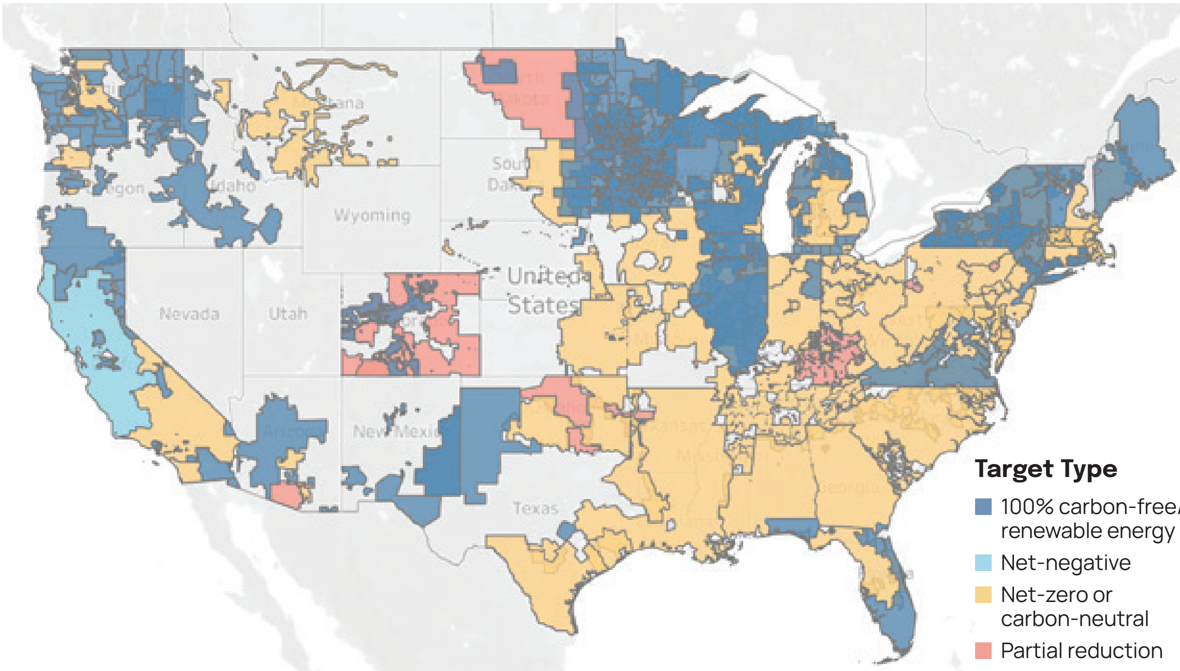
Solution

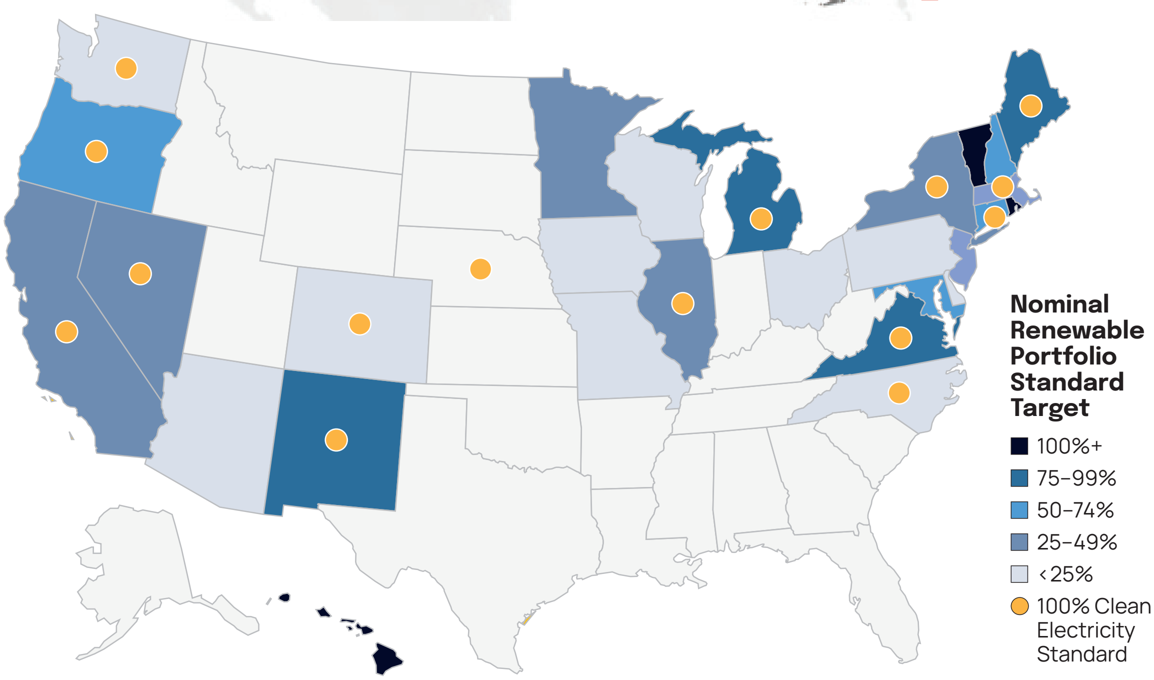
To deliver transmission that is timely, cost-effective, and policy-aligned, planning teams can:

- **Translate policy targets into core planning assumptions** in coordination with state agencies and regulators. These revised planning assumptions should be translated into the entire range of relevant planning studies, representing a broadened transmission plan.
- **Broaden scenario frameworks** to reflect high-renewables, electrification, DER growth, and extreme weather futures, so transmission plans better capture a wider range of system needs.

FIGURE 21

U.S. Utilities Carbon Reduction Targets and State Renewable/ Clean Electricity Standards





(Top) Utility-level targets, including voluntary utility commitments, parent-company pledges, and targets that apply to individual utilities under state 100% clean-energy or net-zero laws. Approximately 80% of U.S. customers are served by a utility with a 100% target (SEPA). (Bottom) State standards: 29 states plus D.C. have an RPS (16 at ≥50%), and 17 states have a 100% clean electricity standard. On a cumulative basis through 2024, RPS and CES policies have supported roughly 151 GW of new capacity additions and call for about 300 TWh more by 2030 and about 1,300 TWh by 2050; transmission must enable these needs (LBNL). Policies continue to evolve.

Sources: (Top) Smart Electric Power Alliance (2025), SEPA Utility Carbon-Reduction Tracker™. Retrieved December 3, 2025, from https://sepapower.org/utility-transformation-challenge/utility-carbon-reduction-tracker; (Bottom) LBNL (2025), © The Regents of the University of California, Lawrence Berkeley National Laboratory.

- **Refine benefit-cost analysis** to capture public value using metrics like avoided generation capacity and enhanced system flexibility to allow for greater depth in value projections.
- **Institutionalize coordination**, including through structures like FERC's Voluntary Agreement Framework (FERC, 2021) and PJM's State Agreement Process (PJM, 2025b), to align multi-jurisdictional priorities and cost recovery.

Examples

- **NYISO** operates a **Public Policy Transmission Planning Process** through which the state identifies transmission needs arising from clean energy mandates like the Climate Leadership and Community Protection Act. This mechanism has enabled transmission upgrades to deliver offshore wind and connect upstate renewables to downstate load, all through competitive project selection directly aligned with state goals (NYISO, 2020).
- **ISO-NE** is conducting its **2050 Transmission Study** and **Future Grid Reliability Study** in close collaboration with the New England states. These studies model decarbonization, electrification, and clean energy procurement, helping shift the planning foundation toward policy-aligned scenario analysis (ISO-NE, 2024b).
- **MISO** modeled state and utility clean energy mandates into its **Long-Range Transmission Planning Futures**, which informed both Tranche 1 and Tranche 2.1 of its regional portfolio. These futures reflect policy targets, electrification levels, and planned fossil plant retirements, resulting in a more forward-looking, multi-value planning approach (MISO, 2025c).
- **PJM** is leveraging its **State Agreement Approach** to facilitate transmission development aligned with state-level policy priorities—most notably in support of offshore wind in New Jersey. The State Agreement Approach provides a flexible structure for states to direct planning while coordinating cost allocation (PJM, 2025b).
- **CAISO** incorporates the California Public Utilities Commission's Integrated Resource Planning portfolios as study inputs to its transmission planning process. The commission submits both base and sensitivity resource portfolios, with sensitivities designed to test different futures—for example, accelerated gas retirements or reduced offshore wind development—alongside other variations (CAISO, 2025).
- **SPP's 2024 Integrated Transmission Plan** includes high-renewables and policy-aligned scenarios that test the system under different decarbonization trajectories—offering broader visibility into future infrastructure needs (SPP, 2025a).

A wider lens reveals more potential solutions—but without rigor, it is easy to spread effort across projects that will not hold up in real conditions. Once the broader set of needs, scenarios, and perspectives is clear, the next step is to dig in: stress-test portfolios, connect tools so that results build on each other, and refine designs to handle uncertainty. When planning anticipates where the system is going—not just where it has been or is today—transmission becomes a proactive enabler of policy success and system resilience. Deepening the analysis turns a broad plan into one that is robust, resilient, believable, and ready for investment.

When planning anticipates where the system is going–not just where it's been or is today–transmission becomes a proactive enabler of policy success and system resilience.

Deepen: Strengthening Analytical Rigor and Alignment in Transmission Planning

Many transmission studies still stop once the immediate objective—often clearing the compliance bar—is met, so grid performance under more varied and challenging conditions goes untested. Deepening planning means strengthening its analytical foundation for decisions: refining how value is measured, improving modeling of uncertainty and extreme conditions, and making methods and results more transparent and connected across study types.

That can mean:

- Designing for multiple needs—ensuring that projects serve reliability, congestion, policy, and resilience objectives from the start.
- Using diverse scenarios and stress tests—evaluating portfolios under multiple long-term futures and extreme but plausible events.
- Linking the toolchain—carrying constraints and solutions forward through capacity-expansion, production-cost, power-flow, and stability/electromagnetic transient studies.
- Bringing operability in early—incorporating inertia, voltage stability, ramping, and weak-grid conditions in screening and design.
- Building optionality—favoring designs that can scale or convert, such as expandable bays, towers with room for a second circuit, and convertible AC/DC corridors.

Some regions are already applying this approach:

- **MISO RIIA linked** 8,760 production-cost runs with AC power-flow and stability/electromagnetic transient studies, passing constraints forward and feeding limits back—surfacing issues that isolated studies miss and highlighting rising dynamic-stability needs as IBR levels grow.
- **PJM Market Efficiency** analysis incorporates reliability constraints into economic planning and credits projects with combined benefits when they resolve both congestion and NERC Transmission Planning Standards violations.

Deepening planning means strengthening its analytical foundation: refining how value is measured, how uncertainty is modeled, and how insights are shared across stakeholders.

- **SPP's 2024 Integrated Transmission Plan** stress-tested candidate portfolios under high-load futures (e.g., hydrogen hubs, data center clusters) to select solutions that remain robust across divergent conditions.
- **DOE's National Transmission Planning Study (2024)** used a linked production-cost and AC power-flow approach to validate candidate corridors under both representative and high-stress hours.

Deepening is not more studies for their own sake. It's about asking the right questions, studying the right scenarios, uncovering emerging risks, exploring options, and sequencing the right tools so that each informs the next. It also means closing the loop between studies and operations and using those findings to drive project selection, sizing, and staging. Better analysis supports smarter investment, greater stakeholder confidence, and stronger alignment between planning and implementation.

Better analysis supports smarter investment, greater stakeholder confidence, and stronger alignment between planning and implementation.

Application Areas for Deepening

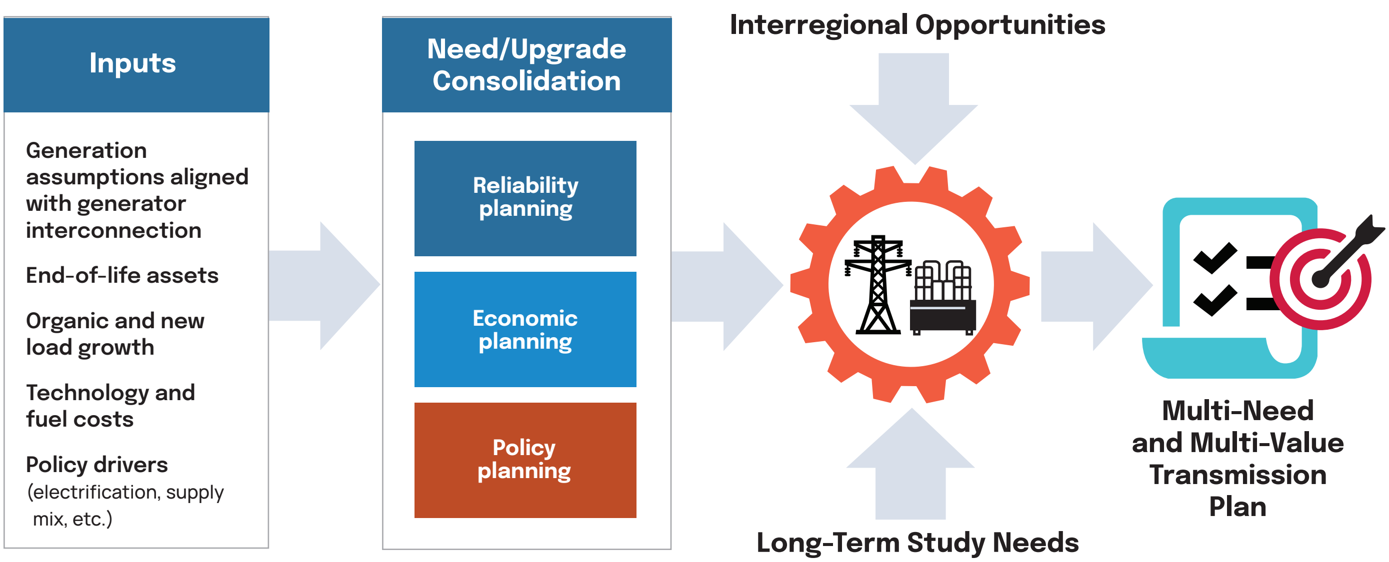
The following application areas show where deepening the analytical base of planning can lead to smarter, more credible, and better-aligned outcomes.

Expand and Modernize Benefit-Cost Frameworks

Challenge

Traditional transmission planning, as shown in Figure 22, has often relied on narrow benefit tests—such as production-cost savings or mitigating reliability violations—that do not capture the full value of transmission infrastructure. This limited lens, which is unable to look beyond silos, can underestimate the benefits of multi-purpose projects, overlook critical system needs such as resilience and policy enablement, and ultimately limit the scope and quality of investment decisions.

FIGURE 22
Example of a Fragmented Transmission Planning Process



Historical transmission planning processes may be coordinated at the beginning and end of development, but heavily siloed during individual analyses.

Source: Energy Systems Integration Group.

FERC Order 1920 addresses this by requiring all transmission providers to evaluate projects using a standardized set of seven benefits:

- Avoided or deferred reliability upgrades and aging infrastructure replacement
- Reduced loss-of-load probability or reduced planning reserve margins
- Production-cost savings
- Reduced transmission energy losses
- Reduced congestion from transmission outages
- Mitigation of extreme weather and unexpected system conditions
- Capacity cost benefits from reduced peak energy losses

This broader set of benefits strengthens the case for forward-looking, multi-driver transmission projects by recognizing the full spectrum of grid services they provide—improving cost justification, increasing transparency, and enabling more equitable cost allocation across beneficiaries.

The broader set of benefits set forth in FERC Order 1920 strengthens the case for forward-looking, multi-driver transmission projects by recognizing the full spectrum of grid services they provide.

The FERC order also allows regions to propose additional benefits—such as resilience, public policy enablement, or market access—where appropriate.

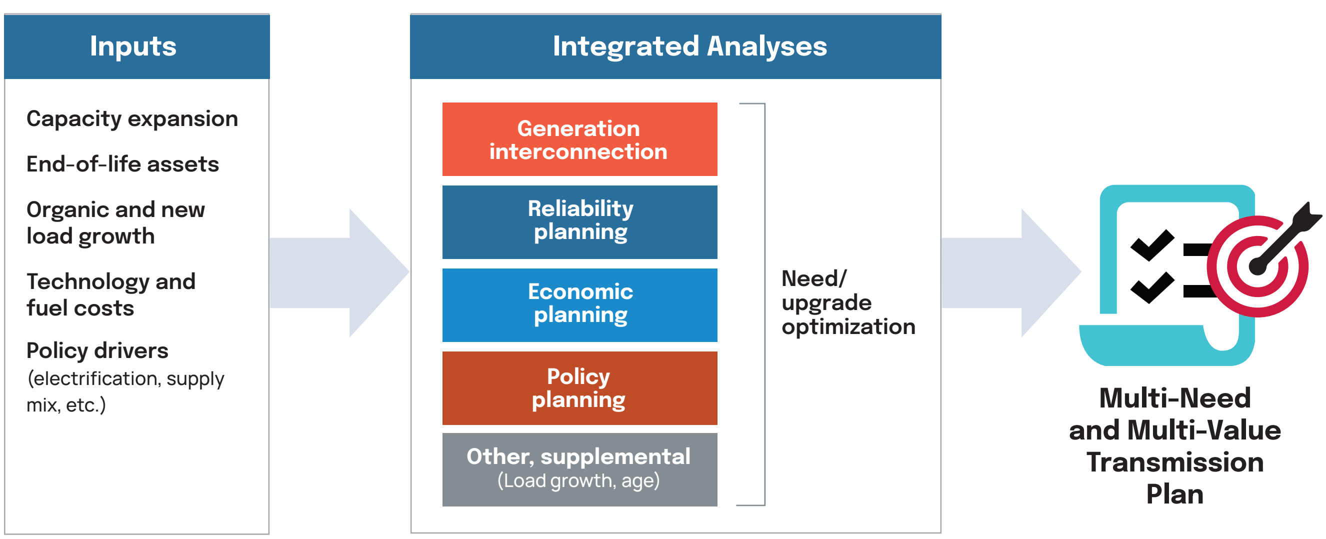
Solution

Planning processes should internalize these benefit categories, not just list them in filings. This is represented visually in Figure 23 and means:

- Using consistent, transparent methods to quantify and compare benefits
- Applying multi-value scoring frameworks to evaluate project portfolios
- Aligning benefit analysis with stakeholder priorities and cost allocation principles

FIGURE 23

Example of an Integrated Process for Transmission Planning



The value of integration is realized to a greater extent when coordination is present through each phase of the planning process.

Source: Energy Systems Integration Group.

Examples

- **MISO Long-Range Transmission Planning and Multi-Value Projects** portfolios were early adopters of multi-benefit analysis, quantifying policy enablement, reliability deferral, and congestion relief to support large-scale investment (MISO, 2025b).
- **CAISO's Transmission Planning Process** provides for a sequential approach to reliability, policy, and economic studies to enable multi-value analysis as well as the consideration of interregional transmission projects in its regional planning process (CAISO, 2025).
- **SPP's Integrated Transmission Planning** process uses stakeholder-defined futures and metrics to evaluate benefits across reliability, policy, and economics (SPP, 2025a).
- **FERC Order 1920** now standardizes this approach to all jurisdictional regions, requiring transparent, quantifiable evaluation of diverse benefits and linking them directly to project selection and cost allocation.

Applying this broader approach helps stakeholders weigh alternatives, focus on the most valuable projects, and ensure that transmission provides durable benefits.

Do Multi-Need Planning: Design Projects with Purpose, Not Just Value

Challenge

FERC Order 1920 requires long-term transmission proposals to be evaluated using a standardized set of seven benefits—a major step toward more comprehensive assessment. But evaluating benefits after a solution is already on the table is not the same as designing projects to deliver those benefits in the first place: this is the key distinction between multi-benefit and multi-need planning. Good planning needs both.

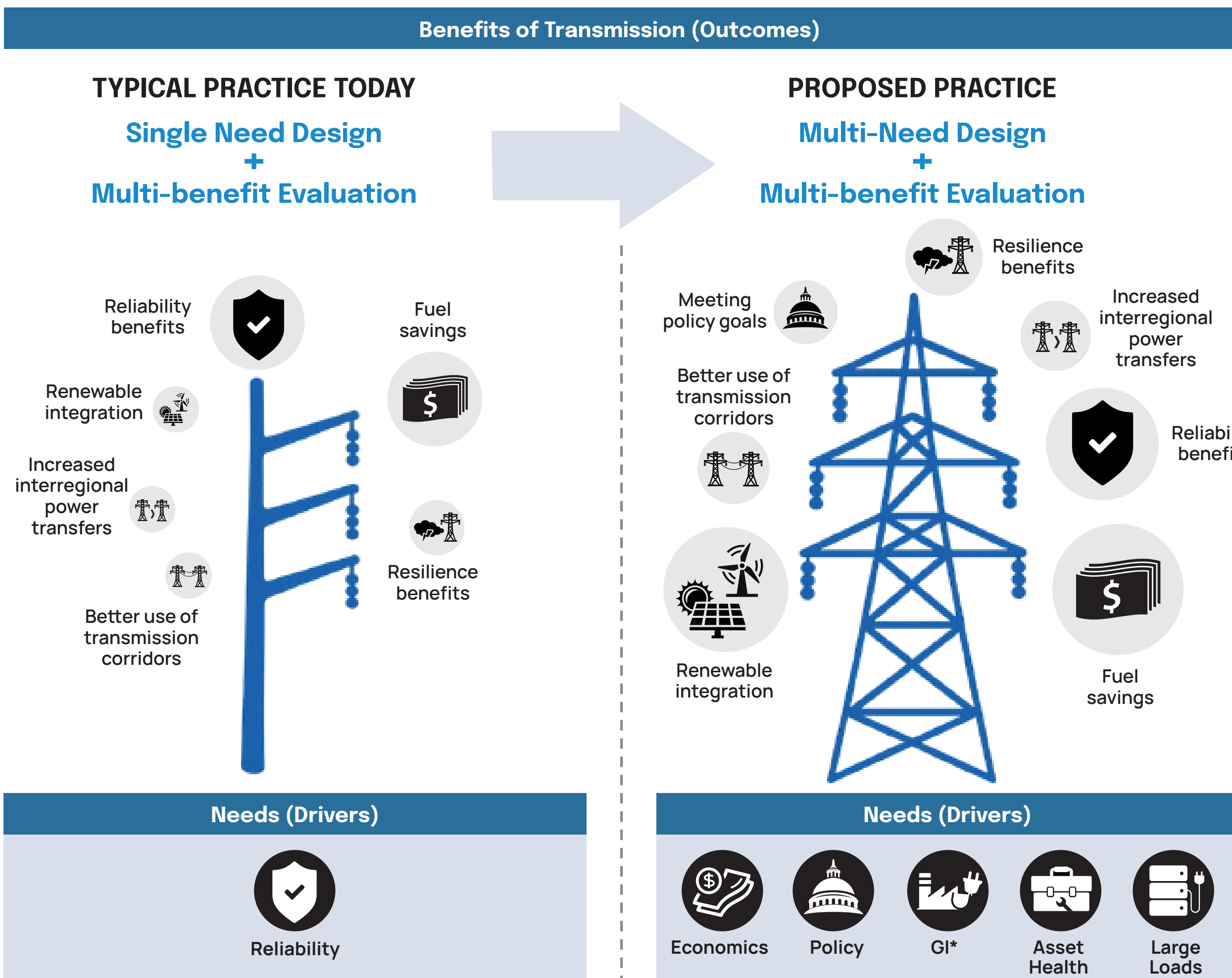
Order 1920-A clarifies that transmission providers must evaluate the listed benefits but are not required to use them as primary drivers for project identification. While this avoids imposing a burdensome, rigid, and prescriptive

Without multi-need planning that is coordinated early, the industry risks defaulting to narrowly scoped solutions that only incidentally address other needs, rather than identifying projects designed from the outset to meet multiple system requirements. This limits opportunities to capture joint benefits and leaves value on the table.

framework, it also leaves a critical gap: multiple system needs are already considered in many regions, but too often through disconnected studies, timelines, and tools that make coordinated solutions harder to identify. Without multi-need planning that is coordinated early, the industry risks defaulting to narrowly scoped solutions that only incidentally address other needs, rather than identifying projects designed from the outset to meet multiple system requirements. This limits opportunities to capture joint benefits and leaves value on the table (Figure 24).

FIGURE 24

Designing for Multi-Need vs. Single-Need Projects



Designing for one need vs. many: Projects built to solve a single identified driver (left) may deliver multiple benefits—but those benefits are often incidental. In contrast, projects designed from the start to address multiple needs (right) can be more strategically targeted and deliver greater overall value. Project drivers (multi-need) and benefits (multi-benefit) are distinct. Evaluating benefits without layered drivers risks undersizing and undervaluing projects. (* Generation Interconnection)

Source: Energy Systems Integration Group.

It is easy to imagine two projects with very different impacts: one designed narrowly to address a specific reliability constraint, and another intentionally scoped to also reduce congestion, integrate new resources, and improve resilience. The latter would likely outperform the former in a multi-benefit evaluation, but it may never be proposed unless planning processes are designed to surface multi-need solutions from the outset.

Solution

To unlock the full potential of a multi-benefit evaluation framework, one must pair it with multi-need planning—a process that explicitly identifies, layers, and integrates multiple system needs during project development. There are two primary approaches.

Simultaneous Multi-Need Identification

In one approach a consolidated needs assessment is created that incorporates all relevant drivers—reliability, policy, economics, resilience, aging infrastructure, resource deliverability, and long-term load growth. Planners can then design or solicit project concepts that address multiple needs simultaneously, favoring solutions that deliver across categories.

Iterative Need Integration

The other process begins with a project designed to address a primary need (such as reliability) and then systematically evaluates its potential to meet other needs (such as congestion relief or resource access). This may involve modifying, expanding, or reconfiguring the initial concept to improve alignment with additional drivers.

Both of these approaches strengthen planning by moving beyond isolated fixes toward comprehensive grid upgrades that reflect the complexity of modern system challenges. As stated in FERC Order 1920, a need can be identified without a solution being required. This redefinition of "need" and realignment of expectations from transmission studies that do not require investment is a necessary evolution to better understand the value provided by transmission.

Benefits of Multi-Need Planning

- **Better project concepts:** Solutions are designed with a broader purpose, not retrofitted after the fact.
- **Greater cost-effectiveness:** Multi-need projects deliver higher value per dollar and justify more ambitious development.
- **Improved permitting and public confidence:** Projects serving multiple purposes are more straightforward to defend, fund, and permit.
- **Stronger alignment with policy and resilience goals:** As extreme weather and decarbonization continue to challenge the grid, planning must consider multiple overlapping system needs.

Multi-benefit evaluation is essential—but insufficient—without multi-need planning to guide project identification. Shifting from siloed studies to an integrated strategy makes it easier to identify projects that address multiple needs more efficiently and effectively. This approach aligns with the intent of FERC Order 1920 and strengthens its potential to deliver more effective, future-ready transmission outcomes.

Improve Transparency and Traceability

Challenge

Planning studies often rely on complex models, inconsistent assumptions, and limited public access to data—making it difficult for stakeholders to trace how inputs lead to project outcomes. Critical variables like generator availability, load forecasts, or asset condition data are frequently unavailable or are applied differently across studies. This opacity undermines trust and limits the ability of states, developers, and the public to engage meaningfully in transmission planning.

Solution

Transparency can be increased by clearly documenting planning assumptions, making data and models publicly available when feasible, and improving traceability between study inputs, modeling choices, and project outcomes. Planners should also ensure consistency across processes and provide the rationale when assumptions or results differ. Transparency and initiatives to both educate and inform will improve stakeholder trust, reduce the risk of contention or delay, and foster more constructive engagement.

Examples

- **CAISO** aligns its transmission planning with the California Public Utilities Commission's Integrated Resource Plan and the California Energy Commission's Integrated Energy Policy Report through an open and transparent process that involves multiple stakeholder engagements and proceedings (CAISO, 2022).
- **MISO and SPP** have increasingly opened their futures development, scenario inputs, and modeling logic to stakeholder feedback, including hosting technical workshops and publishing modeling documentation alongside study results (MISO, 2025c).
- **FERC Order 1920** encourages greater transparency in planning assumptions and methodologies, particularly for how public policy drivers are incorporated into project selection.

Improve Modeling of Uncertainty and System Risk

Challenge

Transmission planning still relies largely on deterministic models and fixed assumptions, even though the future power system will be shaped by evolving and uncertain conditions. Key variables—such as load growth, fuel prices, policy implementation, technology adoption, and extreme

weather—are unpredictable and interdependent. Traditional methods often evaluate a narrow set of scenarios and operating snapshots to meet compliance requirements or procedural timelines and do not consistently account for probabilistic risk, tail events, or structural shifts. This can lead to underbuilding the transmission system, stranded assets, or project portfolios that perform poorly when the future deviates from expectations.

Solution

Planners should expand how planning treats uncertainty—across functions and scenarios—to identify more robust, resilient solutions. They can apply scenario-based modeling, probabilistic forecasts, and portfolio stress tests to see how projects perform across a wide range of futures and to quantify the risks and costs of inaction.

FERC Order 1920 calls for a more robust treatment of uncertainty. It directs transmission providers to develop multiple long-term scenarios that reflect a range of plausible system futures, including high-impact, low-frequency events, and to assess the likelihood of each scenario manifesting. The rule encourages (but does not mandate) the use of probabilistic and stochastic techniques to evaluate system resilience under extreme conditions and identify projects that deliver value across a broader range of outcomes.

Importantly, these methods can be applied differently across planning functions:

- In **generator interconnection studies**: While governed by strict regulatory mandates and procedural timelines, the supplemental use of probabilistic build-out scenarios or queue-informed resource-siting zone development can help identify where recurring constraints are likely to arise. These insights can guide more durable local upgrades and improve long-term alignment between generator interconnection and regional needs.
- In **reliability planning:** While deterministic N-1 analysis remains the foundation of reliability studies, scenario-informed inputs—such as load variability, resource dispatch, and fuel constraints—can be used to evaluate how existing criteria perform under more extreme or evolving system conditions.
- In **economic and policy planning:** These studies often rely on production-cost and capacity-expansion models that already reflect system-wide uncertainty to a certain extent. When outputs from these models are corrected to include impacts from extreme weather and more realistic outage scenarios—such as new peak stress periods, interregional flow patterns, or generation dispatch profiles—they can be shared with generator interconnection and reliability teams to improve assumptions and refine study conditions.

To improve long-term planning under uncertainty:

- Use *least-regrets* and *probability-weighted* approaches to evaluate project portfolios
- Base scenario development on a core of common concepts, like public policies and demand growth, then expand associated assumptions to create a broad but overlapping set of scenarios
- Expand scenario libraries to include extreme weather, rapid electrification, technology cost swings, or delayed policy timelines
- Stress-test project benefits under diverse futures, ensuring that portfolios are not overly dependent on any single outcome

Examples

- **ISO-NE's Future Grid Reliability Study** models grid needs under multiple high-electrification and decarbonization futures, highlighting potential resource shortfalls and infrastructure gaps under uncertain trajectories (ISO-NE, 2022).
- **SPP's 2024 Integrated Transmission Plan** includes futures with divergent resource mixes, high load growth, and resilience contingencies, enabling identification of projects that perform well across many conditions (SPP, 2025a).
- **CAISO's Transmission Planning Process** coordinates reliability, policy, and economic studies in the transmission planning process. Inputs to this process include generator interconnection studies and local capacity requirements, and interregional transmission projects are also considered (CAISO, 2025).
- **The Australian Energy Market Operator's Integrated System Plan** develops multiple long-term scenarios—such as slow, central, and rapid transition—through extensive stakeholder engagement, including policymakers, utilities, developers, and consumer groups. These shared assumptions build credibility and buy-in across sectors. Projects are tested across all scenarios, and those that perform well under diverse futures are advanced as "least-regrets" investments, strengthening system adaptability and resilience (AEMO, 2024).
- **DOE's National Transmission Planning Study** used **C-PAGE** (Chronological AC Power Flow Automated Generation) to round-trip between production-cost modeling and AC power-flow studies—translating chronological dispatch into time-sequenced reliability cases. This allowed automated screening of high-stress hours and validation of candidate corridors under realistic operating conditions, with results feeding back to planning models (GDO, 2024).
- **MISO's Renewable Integration Impact Assessment** used full-year production-cost modeling to identify critical operational hours, which were then tested using AC power flow to evaluate system stress conditions that are not captured by conventional snapshot-based approaches (MISO, 2021).

- **FERC Order 1920** recommends scenario diversity and requires that planners consider a range of plausible system futures, including extreme weather and load growth variance, to inform project justification.

Better modeling of uncertainty supports the design of portfolios that are not only robust under expected conditions but also resilient to disruption and adaptable as the system changes. It also strengthens coordination across planning tracks by promoting more consistent, data-driven assumptions.

Increase Optionality: Building Flexibility into Transmission Investments

Challenge

Transmission infrastructure often takes 5 to 10 years to plan and build, but it will remain useful for decades, serving a power system that is changing rapidly. Yet many projects are scoped narrowly around current needs or known constraints, without utilizing insights from longer-term planning to add flexibility for evolving demands. This short-term focus increases the risk of stranded assets, repetitive upgrades, and long permitting delays. Without options for future expansion or reconfiguration, today's decisions may lock in inflexible transmission solutions and miss opportunities to expand capacity or shorten development timelines in the future.

Solution

Optionality refers to designing transmission projects with built-in flexibility to accommodate a range of future system conditions. Instead of over- or under-building, this approach supports right-sized projects that meet near-term priorities while keeping open the ability to scale as needs evolve. Examples include:

- Building to higher voltage or tower class (e.g., 500 kV design operated initially at 230 kV).
- Structuring rights-of-way use and agreements to support the addition of future circuits.
- Designing modular substations or expandable interconnection points.
- Staging project components to align with resource development or load growth.
- Specifying HVDC designs to include grid-forming, blackstart, STATCOM, and other beneficial capabilities.

Incorporating these features early in project design can reduce lifecycle costs, improve standardization, speed future deployment, and reduce environmental and permitting impacts from rebuilding or duplicating infrastructure.

Examples from Minnesota, New York, and California

Minnesota's CapX2020 transmission expansion initiative provides a clear example of optionality in action. Several 345 kV lines were built to allow future double-circuit expansion or to be operated initially at 161 kV, depending on near-term needs. Within a decade, the longer-term drivers identified during planning—such as wind development and load growth—materialized, and the pre-built flexibility enabled rapid, cost-effective upgrades. This avoided the need for new permitting, environmental review, or corridor acquisition in environmentally sensitive areas and delivered system benefits sooner and at lower total cost.

Similarly, a transmission project in **New York** was constructed to meet public policy needs at a significantly lower cost, as a previous project had been operated at a lower voltage but built to 765 kV standards. This additional right-of-way and clearance allowed for fast and efficient conversion rather than the much longer and more expensive path of rebuilding.

CAISO approved the **Humboldt 500 kV project** in its 2023-2024 Transmission Planning Process to enable the integration of offshore wind resources as required by the California Public Utilities Commission resource portfolios. The project involves a new Humboldt 500 kV substation; a 260 mile transmission corridor designed with provisions for future HVDC conversion, initially operated as 500 kV AC line to interconnect Humboldt 500 kV to the Collinsville substation; a 140 mile, 500 kV AC line to interconnect Humboldt 500 kV to the Fern Road substation; and a 115 kV phase shifting transformer and a 115 kV line from the Humboldt 500 kV to the existing Humboldt 115 kV substation. This project provides more flexibility as offshore wind development progresses and ensures that transmission will not be stranded in the event that offshore wind does not get developed as quickly as anticipated or if it shifts to a different U.S. Bureau of Ocean Energy Management call area.

> **Operability studies integrate the analysis of real-time system variability, the impact of new technologies, and the resilience of key transmission infrastructure, thus ensuring that transmission planning decisions are more robust and better aligned with future operational conditions.**

Incorporate Operability into Transmission Planning

Challenge

Traditional transmission planning is based on deterministic models and fixed assumptions that do not always account for the dynamic nature of real-time system operations. With the growing integration of inverter-based wind and solar resources and large flexible loads, real-time grid behavior becomes less predictable. These challenges—ranging from variability in generation and load to technology integration issues—require new methods of planning to ensure that transmission networks remain resilient and adaptable to change.

Operability studies are essential in this context, focusing on how new and emerging technologies behave under real-world operational conditions. While traditional transmission planning analyzes steady-state and grid-level stability performance, operability studies address transient behaviors, operational flexibility, and system response to unexpected conditions.

Solution

Transmission planning needs to incorporate operability studies to evaluate the full range of operational risks and opportunities. By integrating the analysis of real-time system variability, the impact of new technologies, and the resilience of key transmission infrastructure, operability studies can ensure that transmission planning decisions are more robust and better aligned with future operational conditions. Key aspects include:

- **Forecast impacts:** The growing integration of IBRs and large loads introduces significant uncertainty into real-time system operations. These resources, often forecasted rather than dispatched, create potential errors in unit commitment decisions and can result in unexpected grid dispatches that may not have been assessed through traditional planning processes. A flexible and adaptable resource fleet—such as demand response or storage—can help balance out these uncertainties, and operability studies should model how forecast errors will impact transmission operations.

- **Variability in generation and load:** IBRs and large loads tend to be highly variable, which can cause significant challenges for balancing authorities, especially during periods of high renewable energy penetration. Operability studies can identify how much and what type of regulation is needed to manage these fluctuations, ensuring that the transmission system remains stable under high variability.
- **Transmission outages:** Power systems rarely operate in a true N-0 condition due to planned and unplanned equipment outages. Evaluating various possible outage scenarios enables more reliable operation and lower maintenance costs for transmission facilities.
- **Voltage control:** Traditional transmission studies typically yield static voltage control solutions based on snapshot assessments. However, with the growing variability in IBRs and flexible loads, a more dynamic voltage-control system is required. Operability studies help assess how voltage swings affect grid performance—especially in areas with high levels of renewables. By incorporating real-time variability and developing appropriate voltage control strategies, planners can ensure that transmission infrastructure remains resilient to sudden shifts in grid status.
- **New technology integration:** As new technologies such as energy storage, electric vehicles, and flexible industrial loads are integrated into the system, operability studies help planners better understand their operational characteristics and limitations. For example, IBRs have specific behavior patterns related to voltage control and frequency response, and operability studies can identify how these resources affect grid stability in practice.

Deepening the analysis ensures that plans are not only broad but also rigorous. When integration, a wider set of planning drivers, and comprehensive testing are combined, transmission planning produces outcomes that are reliable, operable, efficient, and robust.

Moving from Intent to Implementation

FERC Order 1920 sets clear expectations for transmission planning: longer-range, multi-driver, scenario-based strategies. The framework in this report—**integrate, broaden, and deepen**—offers a practical path for planners, utilities, regulators, and stakeholders to meet those expectations.

The challenge now is to make these approaches routine. That means looking for ways to embed these approaches into how transmission is scoped, modeled, reviewed, and approved—not just once, but continually over time. It means designing systems that are flexible and open to change, grounded in shared understanding, and able to deliver value. While regulatory, technical, and organizational barriers remain, ISO/RTOs and utilities alike have demonstrated the ability to make the changes necessary to enable more comprehensive planning.

The path forward requires action across all corners of the industry.

- **System planners can:**
  - Strengthen coordination across planning functions—interconnection, reliability, public policy, and economic planning—to identify solutions that serve multiple needs. Use scenario-based analysis to anticipate uncertainty and pursue "limited-regrets" investments that maintain optionality.
  - Expand inputs to reflect emerging drivers such as large-load growth, resilience, and decarbonization.
  - Improve modeling consistency and align assumptions and scenarios across planning processes to ensure that results support a coordinated, future-ready transmission system.
- **ISOs and RTOs can:**
  - Institutionalize integrated planning practices. This includes aligning study timelines, ensuring consistency in modeling tools and assumptions, and coordinating across jurisdictions and stakeholder processes.
  - Strengthen interfaces across functions—for example, aligning interconnection and regional planning models and timelines, ensuring near-term studies reflect long-term scenarios and benefit frameworks, and coordinating with utilities to use asset condition data to guide strategic rebuilds.
  - Drive the identification and evaluation of scalable, forward-looking solutions.
- **Utilities can:**
  - Actively engage in multi-need planning efforts at the regional and local levels.
  - Align internal teams—transmission, resource planning, operations—around shared inputs and timelines.
  - Bring forward solutions that support long-term system flexibility, and evaluate alternatives based on multiple value streams.
  - Coordinate early with states and regional entities to ensure that upgrades support broader system goals.
- **State and federal regulators can:**
  - Facilitate integrated planning by encouraging transparency, scenario diversity, and alignment across agencies.
  - Support cost allocation frameworks that reflect the shared, multi-dimensional benefits of transmission.

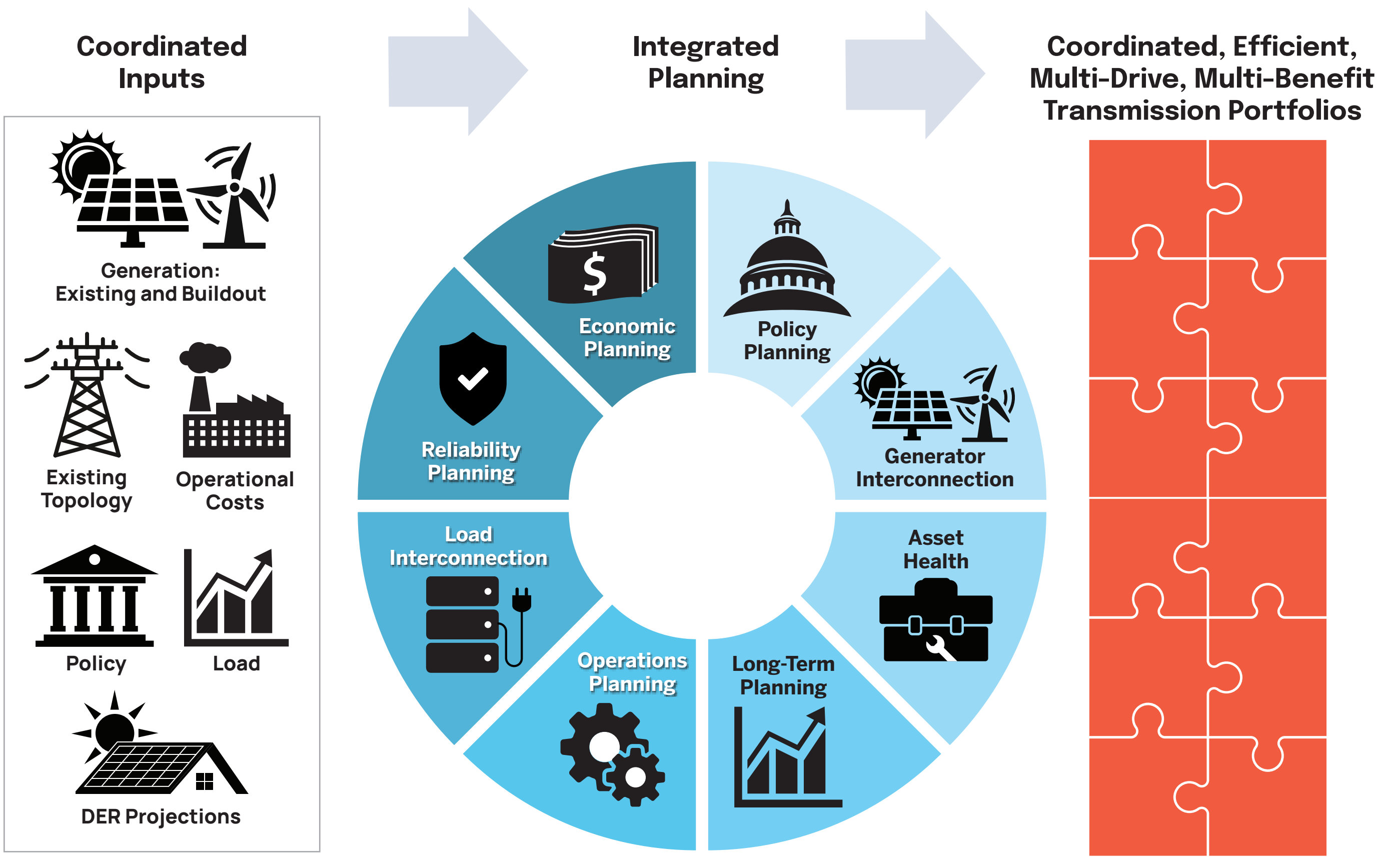
- Provide consistent signals about long-term policy direction to reduce uncertainty and enable proactive investment.
- Create space for cross-jurisdictional coordination and stakeholder-driven solutions.

- **Other stakeholders (such as independent power producers and developers, customers, consumer advocates, and community and environmental groups) can:**
  - Engage early and consistently in planning processes to help shape inputs, identify overlooked needs, and ensure transparent decision-making.
  - Contribute perspectives that reflect system-wide values—reliability, affordability, and decarbonization.
  - Promote solutions that bridge near-term actions and long-term goals and ensure that local and regional benefits are clearly articulated.

The opportunity now is to make these practices part of every planning cycle—so that solutions are tested for multiple needs before approval, costly redesigns are avoided, and new lines and upgrades deliver lasting value. With Order 1920's implementation window open, the steps outlined above can be taken now to weave these approaches into practice. See Figure 25 and Table A-1 (p. 63).

FIGURE 25

From Siloed Inputs and Processes to Integrated, Multi-Benefit Transmission Planning



This figure illustrates how fragmented inputs—such as load forecasts, generation buildout, DER projections, operational costs, and policy targets—can be brought together through an integrated planning process. By aligning across drivers like reliability, public policy, and resource adequacy—and applying the integrate-broaden-deepen (IBD) framework proposed—planners can deliver coordinated, multi-driver, multi-benefit transmission portfolios that more efficiently address long-term system needs and fulfill the scenario-based requirements of FERC Order 1920.

Source: Energy Systems Integration Group.

Appendix

TABLE A-1

FERC Order 1920: Actions Aligned to Integrate, Broaden, and Deepen

FERC Order 1920 Element	Integrate-Broaden-Deepen Response	Primary Actor(s)	Publishable Artifacts	When
Integrating planning functions and governance	**Integrate:** Run one planning cycle under a Governance Charter aligning planning functions (shared calendar, inputs/outputs, roles). **Broaden:** Apply common scenarios and a single benefits catalog across all functions; maintain one Needs and Constraints Registry. **Deepen:** Use a model chain and appropriate loop backs involving capacity-expansion → production-cost → power-flow → stability/electromagnetic transient models with defined hand-offs and decision checkpoints.	RTO/ISO planning with transmission owners, state public utility commission staff	Governance Charter, process map, study calendar, Assumptions Register and Departure Log, Needs and Constraints Registry	Kick-off, annual review
Long-range, scenario-based plan (≥5 yrs)	**Integrate:** Carry out one cycle with a shared study calendar. **Broaden:** Publish a Scenario Book (common drivers/futures). **Deepen:** Set decision checkpoints in the cycle.	RTO/ISO planning, transmission owners, state public utility commission staff	Scenario Book, cycle calendar, models	Kick-off, annual update
Models, data, and transparency (merged)	**Integrate:** Use a single model/data repository with version control; maintain Assumptions Register and a Departure Log (what differs, why). **Broaden:** Publish inputs for external replication. **Deepen:** Calibrate to operations (measured flows/limits) and release model notes and a Limits Table each cycle.	RTO/ISO modeling, transmission owners	Repository link: Assump-tions Register, Departure Log, calibration memo, Limits Table, release notes	Each release
Study sequencing and hand-offs	**Deepen:** Use a model chain and appropriate loop backs involving capacity-expansion › production-cost › power-flow › stability/electromagnetic transient models with explicit hand-offs; build an Operability Test Set (peak, light-load/high-transfer, high-IBR/low-inertia, weak-grid, repre-sentative outages); feed a Limits Table (thermal/voltage/stability/protection) back into the production-cost model.	Planning, operations, and protec-tion/controls staff at ISOs/RTOs and utilities	Sequence guide, Operability Test Set, Limits Table, model notes	Mid-cycle, each release
Multi-driver benefits and selection	**Broaden:** Adopt a benefits catalog and pair multi-benefit analysis with multi-driver planning so that projects are designed and scored across drivers and futures. **Integrate:** Use one portfolio scoring rubric to avoid double-counting.	RTO/ISO planning, stakeholder task force, states	Benefits catalog, scoring rubric, benefit driver mapping, examples	Pre-screening

CONTINUED

TABLE A-1 (CONTINUED)

FERC Order 1920: Actions Aligned to Integrate, Broaden, and Deepen

FERC Order 1920 Element	Integrate-Broaden-Deepen Response	Primary Actor(s)	Publishable Artifacts	When
Coordinated upgrade portfolios	**Integrate:** Maintain a Needs and Constraints Registry (interfaces/corridors/nodes) aggregating generator interconnection, reliability, economics, policy outputs; select shared solutions instead of overlapping single-purpose fixes.	RTO/ISO planning, transmission owners	Registry, candidate list, portfolio benefit-cost analysis and narrative	Post-studies, pre-selection
Asset replace-ments (right-sizing)	**Integrate/broaden:** Screen all rebuilds above a threshold against the Registry and Scenario Book; make right-sizing the default (high temperature low sag (HTLS)/reconductor, larger banks, rating/clearance, protection); require a short variance memo for like-for-like.	Transmission owner asset management and planning	Rebuild screen results, variance log, outage plan	Quarterly, rolling
Interconnection and large-load alignment	**Integrate:** Cluster generator interconnection or large-load requests by zone; identify proactive/zonal upgrades that solve recurring constraints; tie generator interconnection and load milestones to the planning cycle so that upgrades flow into the portfolio, not in parallel.	RTO/ISO generator interconnec-tion and planning, transmission owners, large-load customers	Zone maps, shared upgrades list, timing note	Each cluster window
Interregional seams	**Integrate/broaden:** Exchange scenarios/assumptions; keep a Seams Interface List and run joint studies to size interregional transfer capability; align candidate backbones with DOE High Opportunity Transmission corridors where scenarios converge.	Adjacent RTOs/ transmission owners and states	Joint scope, interface list, seam portfolio and transfer targets	Annual/ biannual
Uncertainty and adaptive portfolios (optionality)	**Broaden:** Design limited-regrets options that deliver across scenarios. **Deepen:** Specify modular, scalable designs (HTLS-ready, spare bays, convertible AC/DC) and record limits in the Limits Table.	RTO/ISO planning, transmission owner engineering and siting, states	Option set and trigger table, corridor/ ROW bank, modular notes, conversion-readiness, contingent list	Portfolio formation, check-points

Source: Energy Systems Integration Group.

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Modernizing Transmission Planning: Integrating Silos to Deliver Multi-Driver, Multi-Value Outcomes

A Report by the Energy Systems Integration Group's Integrating Transmission Silos Task Force

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This report is available at https://www.esig.energy/integrating-transmission-silos.

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

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

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