# Conceptual Cost Allocation Methods for Interregional Transmission

October 2025

Energy+Environmental Economics

# Authors & Acknowledgements

## Project Team

Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the power sector in North America. For over 30 years, E3's data driven analysis and unbiased recommendations have been utilized across the power industry by the utilities, regulators, government agencies, project developers, investors, and non-profit entities. E3 has offices in San Francisco, Boston, New York, Denver, and Calgary.

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## Acknowledgements

This report was funded by National Grid USA Service Company, Inc. E3 gratefully acknowledges the valuable review and feedback of National Grid contributors; however, the findings and conclusions are solely those of the E3 Study Team.

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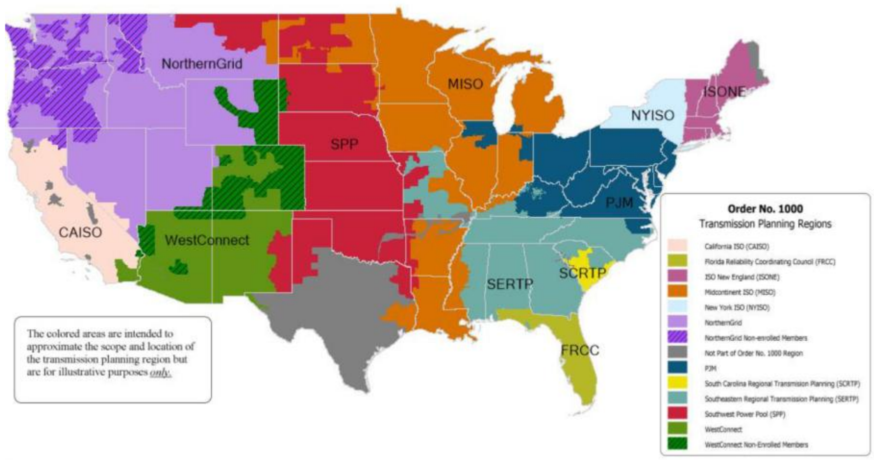
# Introduction

Across the United States, interest in interregional transmission has grown as states, utilities, and system operators respond to a shifting set of drivers for transmission needs: resiliency, access to diverse resources, public policy objectives, and accelerating demand growth. Interregional transmission refers to projects that directly link two or more FERC-defined planning regions shown in Figure 1. The DOE's 2023 National Transmission Needs Study shows that more than doubling interregional transfer capacity by 2035 would produce positive net benefits compared to the cost of upgrades.[1]

***Figure 1. FERC-Defined Transmission Planning Regions***




Since the 2023 DOE study, load growth expectations have increased significantly, further driving transmission needs. Recent forecasts of load growth over the next five years are more than twice as large as projections from just a few years earlier[2], highlighting the urgent need for coordinated action. Growth is being driven by development of domestic industrial processes, rapid proliferation of large data centers, and electrification. Many regions are increasingly recognizing the reliability value that stronger interconnection ties can provide during extreme weather events and other stressed conditions. For example, the New York Independent System Operator's 2023 Comprehensive Reliability Plan identifies the need for greater emergency assistance from neighboring regions during more frequent and intense extreme weather events.[3]

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[1] DOE. National Transmission Needs Study: https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf. Based on DOE scenario with moderate load and high clean-energy growth.

[2] Grid Strategies, Strategic Industries Surging: Driving US Power Demand: https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf

[3] NYISO, 2023-2032 Comprehensive Reliability Plan: https://www.nyiso.com/documents/20142/2248481/2023-2032-Comprehensive-Reliability-Plan.pdf

Despite the growing recognition of the need for expanded interregional transmission, progress has been elusive. No new interregional transmission projects have been built through joint planning and cost allocation processes in recent decades. Part of the challenge lies in how neighboring regions approach planning. Planning cycles are often unsynchronized, modeling tools differ, key assumptions including load growth and resource costs may differ, and methods for defining and calculating transmission benefits vary. These differences make it difficult to merge processes in a collaborative manner. Recent FERC orders and efforts to standardize regional planning practices may make it easier to harmonize approaches across regions.

As planning alignment improves, agreeing on cost allocation methods remains the decisive hurdle to whether interregional projects get built. It is important to distinguish between two related but separate processes: (1) the analytical process used to determine whether a transmission project should move forward, and (2) the framework used to divide its costs. The first process, often referred to as benefits assessment or project justification analysis, answers whether a project's benefits to the system outweigh its costs. In some cases, such as projects that address clear reliability needs, this determination is straightforward. In others, particularly projects justified on economic or policy grounds, it requires complex modeling and assumptions. Once a project clears that hurdle, the focus shifts to cost allocation, where regions face a fundamental choice: they can either rely on historically common practices that use a proxy to approximate how benefits are likely to be distributed, or they can extend the same analytical tools used in the benefits assessment to explicitly measure and allocate benefits as the basis for cost sharing.

This paper does not revisit the question of how to assess if an interregional project should be built. There are many studies that clearly and convincingly outline the need for interregional transmission. Instead, this paper focuses on the second step: *how* the costs of a project are shared between regions. Cost allocation is particularly challenging for interregional projects because they are typically one-off undertakings, rather than part of a larger balanced portfolio. Unlike portfolio approaches, where uneven benefits across individual projects can average out, single interregional projects must stand on their own, resulting in disagreements over who benefits and who should pay.

Among the many factors that complicate cost allocation for interregional projects, three warrant emphasis:

- **Benefits are uneven and scenario-sensitive.** Results hinge on assumptions about load growth, fuel and technology costs, and policy trajectories, all of which are in flux.
- **Operational uncertainty persists**. Historical reliance on market participant scheduled bilateral transfers has at times led to under-utilization of existing ties, undermining confidence that modeled benefits will materialize.[4]
- **Neighboring regions differ across planning cycles, modeling tools, benefit definitions, and policy priorities**, creating both real and perceived cross-subsidy risks.

[4] Simeone, Christina E., and Amy Rose. 2024. *Barriers and Opportunities To Realize the System Value of Interregional Transmission.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-89363.

This paper's goal is not to prescribe a single method, but rather to show how different approaches can be tailored to regions' unique circumstances and objectives. In practice, regions will need to arrive at customized cost-allocation agreements that are acceptable to them, and our intent is to surface and address common barriers to acceptance. Successful frameworks hinge less on perfecting the precision of benefit metrics and more on identifying and addressing conditions that either region would find untenable. For some regions, the greatest risk may be exposure to costs allocated based on long-term benefits that are uncertain to be realized; for others, it may be the prospect of paying for projects that advance policies they do not share. By clarifying which sources of risk or misalignment are most important to address, regions can make more pragmatic choices among the methods outlined here, and thereby advance cost allocation arrangements that are both viable and durable.

This paper begins by providing context on successive FERC orders that shape the foundation for interregional cost allocation, as well as FERC's recent guidance on which types of benefits should be considered to justify projects. We then introduce key criteria that form a framework to evaluate different cost allocation approaches. Building on this foundation, we present a set of potential cost allocation approaches that regions can adapt or combine, illustrating how different allocation design choices address distinct priorities and tradeoffs. The paper concludes with a set of recommendations for regions and states to consider when choosing interregional cost allocation frameworks that work for their context.

# Interregional Cost Allocation Context

Efforts to strengthen transmission planning across larger footprints have been underway for nearly three decades. Most of these improvements, however, have focused on economic utilization, planning, and cost allocation at the regional level. Because comparable regulatory requirements have not been applied interregionally, they have had limited direct effects on advancing projects spanning multiple regions. Nonetheless, examining the core principles embodied in regional planning and cost allocation frameworks can help guide efforts for stronger interregional transmission cost allocation.

## Roles of States, Planning Regions, and FERC in Cost Allocation

Implementing any cost allocation approach depends on the respective responsibilities of states, planning regions, and FERC, and how they interact. Planning regions design and administer transmission planning efforts and cost allocation methods through their tariffs, run technical studies, and manage stakeholder processes. States, meanwhile, play a pivotal role: they generally hold the final say on siting and permitting decisions that determine which projects ultimately get built, and under Order 1920 and 1920-A, discussed further below, they have an enhanced role in shaping cost allocation through structured consultation requirements. FERC, for its part, provides the overarching framework, which requires that cost allocation methods be “roughly commensurate” with benefits and approves any tariff changes filed by planning regions.

While Order 1920 provides a potential regulatory pathway to leverage for interregional planning, the principles and approaches discussed here apply broadly to any interregional coordination effort. For example, if states across two regions coalesce around a preferred approach, they can express that alignment through joint resolutions, memoranda of understanding, or coordination through commissions. Planning regions can then translate those preferences into tariff provisions, which FERC ultimately reviews. This layered governance structure means that effective interregional cost allocation requires coordination at all three levels.

## FERC Regulatory Context

FERC issued Order 888 in 1996 establishing the pro forma Open Access Transmission Tariff which included a requirement for utilities to account for the needs of its network customers in its transmission planning activities with equal weighting in its considerations of its own transmission needs.[5] Order 888-A then encouraged but did not require utilities to jointly plan regional transmission with other utilities. In 2007, FERC Order 890 laid out core principles for transmission planning and required regions to implement more transparent and coordinated approaches.[6] In 2011, Order 1000 expanded these requirements by mandating that regions establish formal planning and cost allocation processes, while also suggesting that neighboring regions should coordinate to evaluate potential interregional projects that might serve needs more efficiently or at lower cost than region-only solutions.[7] Importantly, Order 1000 required that costs be allocated at least “roughly commensurate” with estimated benefits, which requires that costs assigned to a region be in line with the benefits it receives. This principle continues to guide cost allocation decisions today. While the reforms of these FERC Orders improved coordination and information sharing for intraregional planning, they fell short of driving significant interregional development, as most processes remained focused within regional boundaries.

FERC’s 2024 Order 1920 and its companions, Order 1920-A and Order 1920-B, represent the most recent and ambitious effort to address these gaps.[8] The orders direct transmission providers to adopt longer-term and more forward-looking planning practices, including:

- **Scenario planning** that incorporates multiple policy, economic, and demand futures
- A **20-year planning horizon**, substantially extending beyond historical practices
- **Right-sizing** transmission facilities to better anticipate future needs

[5] FERC, Order 888 and 888-A: https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform/order-no-888

[6] FERC, Order 890: https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/summary-compliance-filing-requirements-order-no-890

[7] FERC, Order 1000: https://www.ferc.gov/electric-transmission/order-no-1000-transmission-planning-and-cost-allocation

[8] FERC, Order 1920 and 1920-A: https://www.ferc.gov/news-events/news/ferc-strengthens-order-no-1920-expanded-state-provisions

- A **greater role for states** in both transmission planning and cost allocation decisions
- Explicit consideration of **seven categories of transmission benefits**, enumerated and defined in Table 1, which FERC suggests should inform both planning and cost allocation methodologies

Together, these requirements aim to push transmission planning beyond incremental reliability fixes and toward a proactive, holistic process that can accommodate policy goals, load growth, and resilience needs.

***Table 1. FERC Order 1920 Defined Transmission Benefits***

| Benefit | Description |
|---|---|
| **Avoided or Deferred Reliability Transmission Facilities and Aging Infrastructure Replacement** | The reduced costs due to avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities. |
| **Reduced Loss of Load Probability OR Reduced Planning Reserve Margin** | Increased transmission can reduce the need to maintain large planning reserves in each connected area. The ability to share capacity lowers loss-of-load probabilities and can reduce reserve margin requirements, delivering direct reliability and cost savings. |
| **Production Cost Savings** | The reduction in total fuel and variable operating costs from a transmission investment, calculated as the change in modeled regional production costs after netting energy purchase costs and energy sale revenues. |
| **Reduced Transmission Energy Losses** | By strengthening the grid, new projects can reduce resistive losses in electricity flows, lowering total energy needs and associated costs. While this is discussed in Order 1920 as a separate benefit, it is typically included in Adjusted Production Cost Savings mentioned above. |
| **Reduced Congestion During Outages** | Transmission provides alternate pathways during planned or unplanned outages, reducing costly congestion and improving system reliability. Like Reduced Transmission Energy Losses, this benefit is typically included in Adjusted Production Cost Savings calculations. |
| **Mitigation of Extreme System Events** | Additional transfer capacity helps regions support one another during extreme events such as storms, heat waves, or cold snaps, reducing reliability and economic risks. |
| **Reduced Capacity Costs from Lower Peak Energy Losses** | Projects that reduce peak-period transmission losses can decrease the amount of generation capacity required to reliably serve load, lowering overall capacity costs. |

Order 1920 and 1920-A significantly expand the role of states in shaping transmission cost allocation and project selection. Transmission providers are now required to engage in a structured consultation process with Relevant State Entities, including a six-month period (extendable to a year) in which states may negotiate preferred cost allocation methods or propose alternative approaches. Providers must publicly report the outcomes of these consultations and, where states reach consensus, include those state-preferred methods in their compliance filings to FERC. In addition, Order 1920 encourages regions to establish a formal state agreement process, modeled on PJM's State Agreement Approach. Such a process allows states to voluntarily agree to shoulder the costs of transmission projects they consider beneficial, even when consensus on cost allocation among all participating states cannot be reached. This mechanism provides flexibility for states to advance projects that align with their goals. These requirements reflect FERC's recognition that state regulators play a central role in determining how costs are recovered within their jurisdictions and ensures that state perspectives are directly embedded in regional transmission planning.

Order 1920 represents a major step forward for long-term regional planning. However, like Order 1000, it only requires interregional coordination to identify and evaluate projects. Regions must now adopt consistent long-term scenario planning frameworks and evaluate a common set of benefits within their own footprints, but the rule stops short of mandating that these processes be coordinated across regional seams. As this paper will discuss in subsequent sections, neighboring regions may have different views on future scenarios that could affect the operational and capacity benefits they expect to receive in the long-term. The hope is that by establishing parallel planning practices within each region, Order 1920 lays the groundwork for more robust interregional planning efforts in the future.

## Relevant Precedents

Cost allocation has long been the barrier for major transmission development. While analytical tools can model benefits, there is no universal framework for equitably sharing costs between regions. To date, the only large-scale examples of shared allocation are intraregional, not interregional. MISO's Multi-Value Project (MVP) Portfolio, approved by FERC in 2011, is a constructive intraregional example. The portfolio consisted of 17 high-voltage lines with an estimated cost of about $5.2 billion. The projects were justified on the basis of reliability, congestion reduction, and enabling state renewable mandates. Costs were allocated 100% region-wide on a load ratio share basis,[9] which FERC approved as 'roughly commensurate' with benefits.[10, 11] The lines were completed during the 2010s, making the MVPs one of the few examples of a major regional portfolio that was both approved and built under broad socialization of costs.

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[9] Under a load ratio share cost allocation method, the costs of a transmission project are distributed among all transmission owners in proportion to their annual load.

[10] Midwest Independent Transmission System Operator, Inc. 2011. 137 FERC ¶ 61,074 (order on rehearing). Washington, DC: Federal Energy Regulatory Commission.

[11] *Midwest Independent Transmission System Operator, Inc.*, 133 FERC ¶ 61,221 (2010); order on reh'g, 137 FERC ¶ 61,074 (2011)

More recently, in December 2024, MISO's Board approved "Tranche 2.1" of its Long Range Transmission Planning (LRTP) portfolio, totaling about $22 billion in new high-voltage lines. The projects were approved under MISO's Multi-Value Project (MVP) tariff, which applies a "postage stamp" allocation. Costs are spread to all load-serving entities in MISO's Midwest subregion on a load ratio share basis. Thus, MVP costs are broadly socialized across a large portion of the MISO footprint, but are not allocated to the MISO South subregion. This hybrid approach combines regional allocation within a defined sub-region with the exclusion of other areas. This approach selectively uses postage stamp allocation for a targeted subset of transmission owners to avoid pushback from specific stakeholders who may not benefit as directly from the portfolio of projects. While the costs of these MISO efforts were not allocated based on calculated benefits, it is recognized that the Tranches were portfolios of many projects with diverse impacts on multiple parties, which would make it difficult to parse out benefits to individual parties.

SPP's Highway/Byway cost allocation approach provides another instructive intraregional case. Projects at 300 kV and above are allocated region-wide on a load ratio share basis, while lower-voltage upgrades are allocated more locally, reflecting differences in benefit footprints.[12] In addition, SPP conducts Regional Cost Allocation Reviews (RCAR) every six years to assess whether actual benefits align with forecasts. If a zone's benefit-to-cost ratio falls below 0.8, SPP may reallocate transmission revenues or adjust future cost responsibilities to restore balance, ensuring that no zone persistently subsidizes others.[13]

The example of the MISO–SPP Joint Targeted Interconnection Queue (JTIQ) illustrates how hard it is to turn coordination frameworks into real interregional projects. By jointly studying interconnection clusters, the RTOs identified seam constraints and built a five-project portfolio enabling nearly 29 GW of new generation.[14] FERC approved the framework in 2024–2025 as generator-interconnection upgrades, with costs (net of outside funding) assigned to interconnection customers and only a limited load backstop.[15] DOE initially awarded a $464.5 million grant to offset about a quarter of the capital cost, but its reported termination now raises pressure to revisit cost allocation: absent federal support, higher network charges may trigger withdrawals, and stakeholders may seek to reclassify projects into regional portfolios or explore subscription models.[16] The lesson is clear—without durable allocation rules, even promising coordination efforts risk stalling.

The "roughly commensurate" standard, affirmed by FERC and the courts, underpins all cost allocation discussions: allocations need not match modeled benefits with precision, only

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[12] SPP. 2016. Regional Cost Allocation Review (RCAR II) Report. Little Rock, AR: Southwest Power Pool.

[13] Ibid.

[14] Southwest Power Pool & Midcontinent ISO, *Joint Targeted Interconnection Queue (JTIQ) Study – Executive Summary* (2022).

[15] (*Mid-Continent Indep. Sys. Operator Inc.*, 189 FERC ¶ 61,108 (2024*), order on rehearing*, 191 FERC ¶ 61,231 (2025)).

[16] https://www.rtoinsider.com/116314-doe-terminates-756b-energy-grants-blue-states/ and https://www.latitudemedia.com/news/scoop-these-are-the-321-awards-doe-is-canceling/?utm

approximate them closely enough to avoid clear cross-subsidization.[17] This legal flexibility creates space for pragmatic compromise, especially relevant for interregional projects where exact attribution is elusive. FERC precedent demonstrates acceptance of a wide spectrum of approaches, from postage-stamp to benefit-based to blended portfolios, so long as outcomes remain broadly aligned with benefits.[18] Experience suggests hybrid cost allocation methods, that combine two or more approaches, are often more durable, combining administrative simplicity with benefit attribution to avoid extreme or unfair results. The key lesson is that "roughly commensurate" is as much art as science, giving regions leeway to design fit-for-purpose frameworks that balance fairness, stability, and practicality.

# Challenges and Evaluation Framework for Interregional Cost Allocation

The greatest obstacle to advancing interregional transmission is cost allocation, even when improved venues for collaboration identify significantly positive net benefits to the regions. Allocating costs across regions in a way that is fair, predictable, and operationally feasible is challenging for several reasons. In addition to being fair and predictable, credible cost allocation frameworks must also provide sufficient financial certainty for developers to secure project financing when pursuing interregional projects. To support the discussion of potential cost allocation methodologies, we evaluate each method across the following criteria:

**Beneficiary Alignment:** The fundamental aim of cost allocation is to ensure that each region pays roughly in proportion to the benefits it receives from a project. Differences in modeling approaches, assumptions, and definitions make agreement challenging. This criterion focuses on how clearly a method aligns the allocation of costs with the distribution of project benefits, reinforcing the principle that stakeholders who receive the greatest benefits should bear the corresponding share of costs. All of the methods discussed are intended to satisfy the roughly commensurate standard and are therefore intended to be deemed admissible by FERC. The purpose of this criterion is to assess how closely each method tracks with the actual performance of the transmission line once in operation.

**Robustness to forecast uncertainty:** Transmission benefits are sensitive to evolving policy, technology, fuel costs, and load growth. Longer planning horizons increase the potential for divergence between projected and realized outcomes. Allocation methods are evaluated on their ability to remain resilient across a wide range of plausible future conditions, providing confidence that regions will not overpay if actual benefits differ from projections.

[17] NREL. 2011. Survey of Transmission Cost Allocation Methodologies for RTOs. Golden, CO: National Renewable Energy Laboratory.

[18] Dennis, Jeffery S. 2015. "Transmission Cost Allocation and 'Beneficiary Pays.'" Presentation at IEA ESAP and CEER Expert Workshop IV, Paris, France, January 14. U.S. Federal Energy Regulatory Commission.

**Cost Certainty:** One of the key advantages of well-structured allocation is providing regions and financiers with predictable, stable cost expectations. Methods that frequently adjust allocations based on realized outcomes may improve fairness but reduce certainty, complicating financing, regulatory approvals, and long-term planning. Cost certainty measures the degree to which a method offers reliable, long-term clarity about each region's financial obligations.

**Administrative Efficiency:** Collaborative and analytically rigorous allocation methods require substantial resources to design and maintain. Complex or repeated modeling exercises, extensive data processing, and frequent stakeholder meetings can discourage participation. The administrative efficiency criterion captures the practicality of implementing a method, including the staff time, analytical effort, and procedural complexity required.

**Transparency:** Complex or opaque allocation methods can undermine trust and increase stakeholder opposition, both in allocation decisions and subsequent permitting or regulatory approvals. The transparency criterion evaluates whether a method is understandable and replicable, enabling stakeholders to see clearly how costs are assigned.

These five criteria form the basis for evaluating interregional cost allocation methods throughout this paper. Each method will be assessed qualitatively as very low, low, moderate, high, or very high on each criterion. Table 2 establishes the overall framework for this assessment, which is applied in more granular detail later in the paper. This integrated framework ensures that evaluation is grounded in the real-world challenges that have historically hindered equitable and effective cost allocation, while providing a consistent lens for comparing new and precedent-based approaches.

***Table 2. Cost Allocation Method Criteria Evaluation Matrix***

| Criterion | Low/ Very Low | Moderate | High/Very High |
|---|---|---|---|
| **Beneficiary Alignment** | Costs poorly aligned with benefits; clear cross-subsidies | Partial alignment; some mismatches between costs and benefits | Costs clearly commensurate with benefits across all regions |
| **Robustness to Forecast Uncertainty** | Highly sensitive to future changes; risk of major misallocations | Mixed resilience: some protection, but notable risks remain | Very resilient; allocation method remains appropriate under wide range of scenarios |
| **Cost Certainty** | No predictability; highly variable costs over time | Moderate predictability; some exposure to volatility | Very high certainty; long-term stability in costs across planning horizon |
| **Administrative Efficiency** | Complex; burdensome to calculate and administer | Moderate complexity; manageable but resource-intensive | Very simple; minimal burden to calculate and administer |
| **Transparency** | Opaque; stakeholders cannot see or replicate allocation | Some transparency; understandable to SMEs but not general stakeholders | Very clear; fully replicable and intuitive to all stakeholders |

# Conceptual Cost Allocation Methods

For the purposes of exploring the implications of different proposed methods, this paper uses a hypothetical interregional transmission project connecting two regions: Region A and Region B. In this example, Region A and Region B have studied the project and arrived at a baseline scenario. They quantify the loss of load probability savings (shortened to capacity savings) and production cost savings as described in Table 1. FERC Order 1920 Defined Transmission Benefits

Table 3 below indicates the hypothetical itemized savings, studied at three different time periods using a discount rate of 7%. For the purposes of calculating the present value, it is assumed the final study year (year 20) benefits repeat for the remainder of the 40-year lifespan of the transmission line. Region B consistently accrues a larger share of both operational and capacity benefits, with the present value showing 66% of total benefits accruing to Region B and 34% to Region A.

*Table 3. Benefit Accrual for an Example Interregional Transmission Project*

| Year | Capacity Savings ($MM) | | Production Cost Savings ($MM) | | Total Savings ($MM) | |
|---|---|---|---|---|---|---|
| | Region A | Region B | Region A | Region B | Region A | Region B |
| Year 0 | $8 | $10 | $2 | $5 | $10 | $15 |
| Year 10 | $12 | $21 | $4 | $13 | $16 | $34 |
| Year 20 | $12 | $21 | $4 | $13 | $16 | $34 |
| **Present Value** | **$150** | **$250** | **$50** | **$150** | **$200** | **$400** |
| **Share of Benefits** | **-** | **-** | **-** | **-** | **34%** | **66%** |

The two regions decide to study two additional scenarios that examine the impacts of key assumptions that drive the value of the line. Scenario 1 models higher load growth in Region A driven by new data centers, which increases imports and raises Region A's share of benefits. Scenario 2 models a delay in Region B's achievement of a key policy goal, reducing its benefits at year 10 before returning to baseline levels by year 20. Figure 2 shows these dynamics in annual total benefits accrued to each region while Table 4 illustrates how Region A receives a larger share of total project benefits in the two scenarios as compared to the baseline scenario.

*Figure 2. Total Annual Benefits Projected for Each Region across Modeled Scenarios*

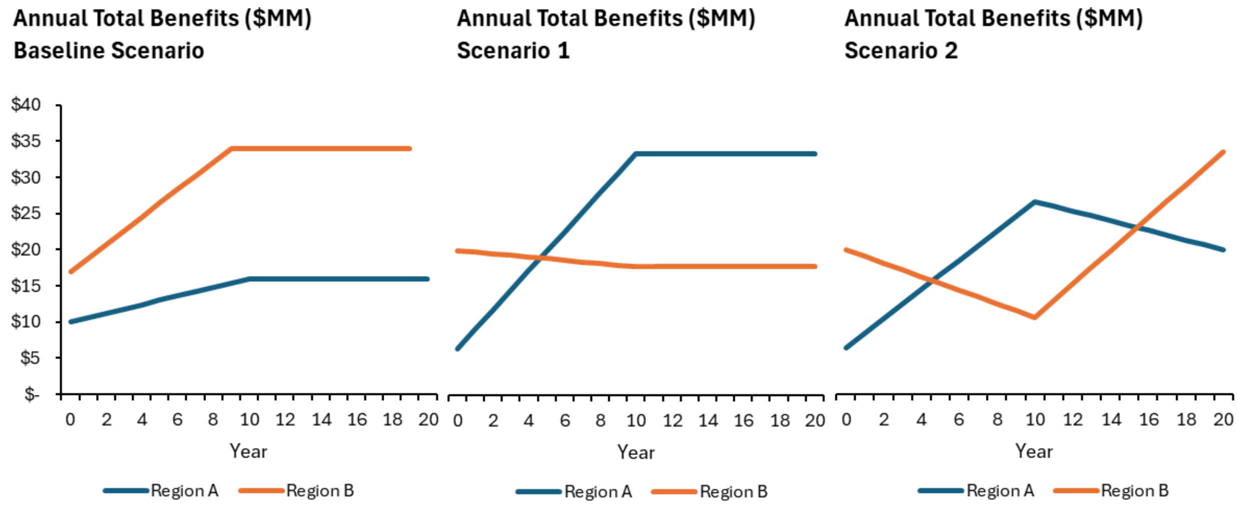



*Table 4. Present Value Shares of Benefits Accrued to Region A and Region B across Scenarios*

| Scenario | Region A Benefit Share | Region B Benefit Share |
|---|---|---|
| Baseline | 34% | 66% |
| Scenario 1 | 55% | 45% |
| Scenario 2 | 50% | 50% |

This illustrative example serves as the common reference point for evaluating each cost allocation method described throughout this section. Region A and Region B must now decide how to divide project costs—whether strictly in proportion to the calculated benefits, according to simplified proxies such as load, or through other mechanisms. Each proposed method applies a different allocation framework to this same set of results, highlighting trade-offs among fairness, certainty, and administrative feasibility.

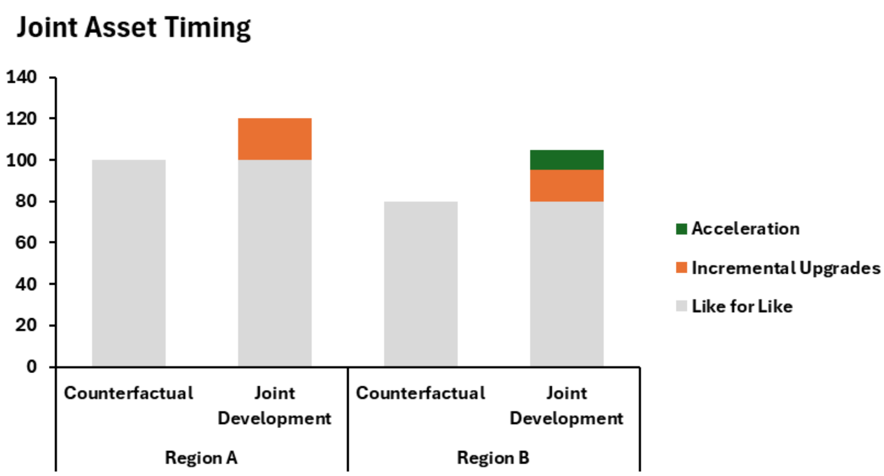
## Defining Costs to be Allocated

Before allocating costs, regions must first define which costs are subject to interregional cost allocation. This is simple for greenfield projects, where the full project cost is subject to interregional cost allocation. For projects involving facilities that would in any case need replacement or local upgrades, however, the distinction is more nuanced: only the portion of costs that arise because of interregional coordination should be placed into the interregional cost allocation pool.

In practice, a region may already be planning to replace or upgrade a facility for local or regional needs. If an interregional project builds on that baseline, the relevant cost to allocate is not the total cost of the joint project, but rather the incremental costs compared with what would have been done locally. These incremental costs can include, for example, higher-capacity equipment, additional substation work, or other modifications needed to increase transfer capability beyond the baseline plan. They may also include costs that arise from adjusting project timing so that both regions can move forward on a coordinated schedule, as seen in Figure 3. Defining Joint Asset Timing Costs for Allocation

This distinction is important because it ensures that interregional cost allocation focuses on how to share the incremental costs of coordination, rather than on costs each region would have needed to incur even without the interregional project. Benefits of coordination are calculated separately for each region and can then be used to guide how those incremental costs should be shared.

***Figure 3. Defining Joint Asset Timing Costs for Allocation***




## Avoided Regional Cost Method

This approach, modeled after established FERC Order 1000-compliant interregional cost allocation methodologies, allocates interregional project costs based on the incremental costs of regional projects that the interregional project displaces.[19] Each participating region identifies the set of regional projects it would need to build absent the interregional project using its established regional transmission planning processes, and the costs of those projects are quantified using standard planning cost estimates. The interregional project's total cost is then divided proportionally according to each region's share of the avoided regional project costs. This method links cost allocation directly to tangible planning impacts rather than relying solely on modeled benefits or system load.

[19] NYISO, ISO-NE and PJM filed this approach in their tariffs for projects across their seams, as did MISO and SERTP.

For example, consider an interregional transmission project that offsets regional projects in two regions. Region A would have otherwise spent $200 million on reliability upgrades, while Region B would have spent $400 million. If the interregional project costs $300 million, the allocation would be calculated as:

$$Region\ A\ Share = \frac{200}{200 + 400} \times 300 = 100\ million\ (33\%)$$

$$Region\ B\ Share = \frac{400}{200 + 400} \times 300 = 200\ million\ (67\%)$$

This method will often score low on **beneficiary alignment**. It can be well aligned in specific situations when the only major benefit of the interregional project is the savings (avoided cost) from each region's displaced regional project. For many interregional projects that also produce production cost savings, emissions reductions, or other types of benefits for the regions, however, this approach can end up far out of alignment with overall distribution of total benefits.[20] One favorable feature of this method is that cost allocation is fixed for a predetermined period of time, which gives it high **cost certainty**. Because the allocation is fixed, its **robustness to forecast uncertainty** is low—if conditions diverge from planning assumptions, the predetermined shares may no longer reflect actual outcomes. Fixed allocation requires moderate/low **administrative efficiency**, since the analysis is driven from identification of displaced intraregional projects within existing processes. Because avoided cost estimates are derived from regional planning processes, differences between assumptions or planning practice methodologies of each region can introduce inconsistencies and disputes. **Transparency** is strong, as the method is intuitive and easily replicable: stakeholders can clearly see how each region's share relates to the cost of regional projects displaced.

## Load Ratio Share

Under this historically common approach for intraregional projects, costs are allocated proportionally to each region's share of coincident peak demand. The method does not rely directly on a benefits analysis, but instead assumes that benefits naturally scale with system size. While FERC Orders 1920 and 1920-A encourage allocation based on forecasted benefits, load ratio share remains a common precedent in practice. Notably, MISO's Multi-Value Project portfolio, New York's Climate Leadership and Community Protection Act Transmission projects and New England's regional Pool Transmission Facilities all use a load ratio share cost allocation method.

If applying this method to the previous illustrative example, Regions A and B do not need to directly forecast benefits. Instead, costs can be allocated based on each region's load – either on a dynamic or static basis. Under the dynamic approach, the participating regions identify the hour when single joint system coincident peak load occurs, and they record each region's load during that hour. Over 12 months, those values are averaged to determine each region's annual network load share. Table

[20] As an alternative, carefully defining which incremental interregional costs should be allocated (as described in the section above) can be a better way to reflect avoided cost as one, but not the only, component of total benefits.

5 illustrates how load ratio shares might be calculated for Region A and Region B. At year's end, the average of these monthly shares is applied to cost allocation. If Region A's average share over the year is 37%, then it pays 37% of total project costs for that billing year. This process is then repeated annually for the full financial life of the project, resulting in a dynamic allocation.

***Table 5. Load Ratio Share Example***

| Month | Combined System Peak Hour Load | Region A Coincident Peak Load (GW) | Region B Coincident Peak Load (GW) | Region A Share | Region B Share |
|---|---|---|---|---|---|
| Jan | 23 | 8 | 15 | 35% | 65% |
| Feb | 27 | 9 | 18 | 33% | 67% |
| Mar | 27 | 10 | 17 | 37% | 63% |
| Apr | 24 | 9 | 15 | 38% | 63% |
| May | 27 | 10 | 17 | 37% | 63% |
| Jun | 29 | 11 | 18 | 38% | 62% |
| Jul | 30 | 11 | 19 | 37% | 63% |
| Aug | 31 | 12 | 19 | 39% | 61% |
| Sep | 27 | 10 | 17 | 37% | 63% |
| Oct | 24 | 8 | 16 | 33% | 67% |
| Nov | 25 | 9 | 16 | 36% | 64% |
| Dec | 25 | 10 | 15 | 40% | 60% |
| **Avg** | — | — | — | **37%** | **63%** |

Alternatively, under the static approach if each region's share of coincident peak load is expected to be relatively stable, a single forecast of load ratio share (or a historical average calculation) can be used.

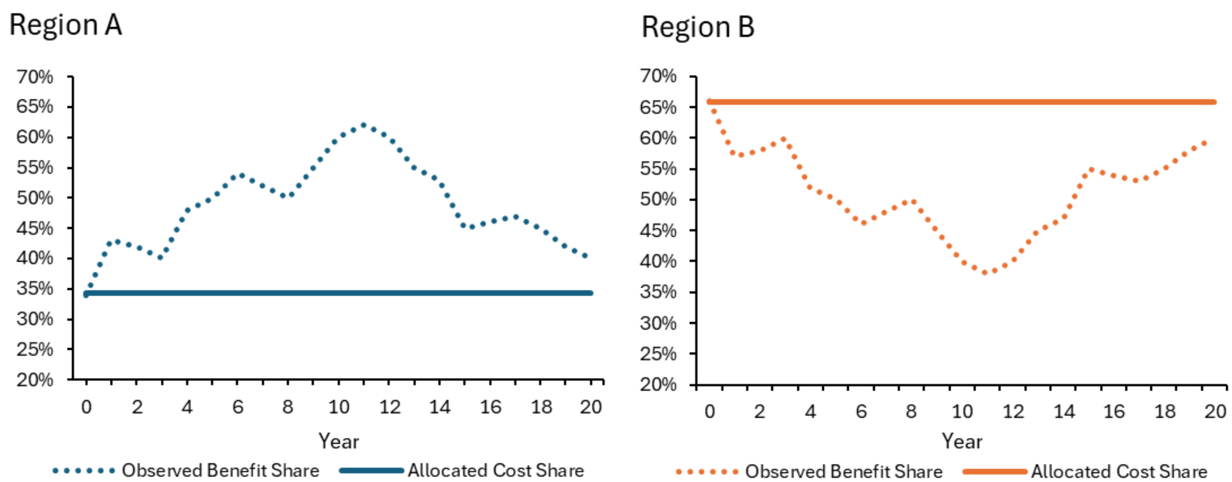
If load shares continue to be a reasonable proxy for benefit shares, then the dynamic approach to load ratio share should do moderately well at keeping up with the **beneficiary alignment** and **robustness to uncertainty**. However, this is an assumption, and aligning cost allocation more directly with modeled or otherwise dynamically verified benefits is likely to provide a more accurate match between who pays and who benefits. Because costs are recalculated annually and can thus fluctuate, **cost certainty** is relatively low. **Administrative efficiency** scores highly, as the allocation methodology is simple and replicable, using publicly available load data. Similarly, **transparency** is very high: stakeholders can easily understand and audit the methodology, minimizing disputes about the allocation process.

## Single-Scenario Fixed Cost Allocation

This approach uses modeling to estimate benefits—such as adjusted production cost savings and capacity savings—under a single baseline planning scenario. The present value of those benefits determines each region's proportionate share of costs. Once established, the allocation is fixed for the lifetime of the project.

In our example baseline case, Region A receives 34% of total project benefits while Region B receives 66%. Under the single-scenario fixed allocation, costs are assigned in direct proportion to these shares. Region A would be responsible for 34% of project costs and Region B for 66%. This will hold even if conditions change such that the observable share of benefits varies widely from the modeled baseline and the share of allocated costs as shown in Figure 4.

***Figure 4. Single-Scenario Fixed Cost Allocation***




The method takes important steps toward improving **beneficiary alignment**, since it incorporates explicit modeling of transmission benefits, however some regions may be reluctant to accept allocations that rest entirely on a single scenario, particularly if they perceive the assumptions as unfavorable. Since it relies on only one scenario, it lacks **robustness to forecast uncertainty** as the allocation may not hold if future conditions diverge from the baseline. The approach does provide strong **cost certainty**, as cost shares are fixed once determined. On **administrative efficiency**, it is more demanding than load ratio share since regions must agree on benefit metrics and modeling assumptions. Still, it is relatively manageable because the analysis is conducted only once at the outset, and the fact that it tests just a single scenario makes it simpler than more complex multi-scenario approaches. **Transparency** is moderate: the results of the benefit study can be published and explained, but the complexity of the modeling may limit replicability for non-experts.

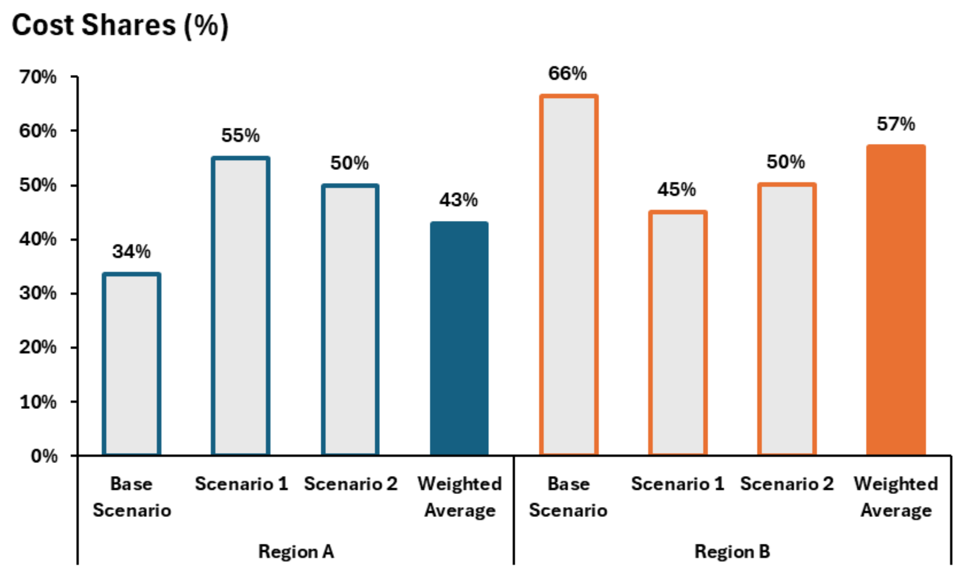
## Multi-Scenario Fixed Cost Allocation

This method builds on the single-scenario fixed approach by incorporating multiple scenarios into the benefit analysis. While the same benefit quantification methodologies are used (such as adjusted production cost and capacity benefits) key assumptions are varied across scenarios to capture realistic sources of uncertainty. Targeted assumptions may include rates of policy achievement, load growth, extreme weather, and other economic and environmental conditions.

In our baseline scenario approach, the single-scenario allocation produced lopsided results, which can create skepticism or pushback from regions that are assigned disproportionately higher costs. By examining multiple plausible futures, the method better captures variations in benefits across regions and improves the defensibility of the resulting allocations. Each scenario is weighted, often giving greater emphasis to the baseline scenario. Once allocations are determined, costs remain fixed for the lifetime of the project.

Building on the baseline, the regions also consider sensitivity scenarios. In this example, they consider two scenarios. In Scenario 1, Region A captures 55% of benefits; in Scenario 2, the shares are evenly split at 50%/50%. Applying a weighted average across scenarios—for instance, 50% weight to the baseline, 25% to each sensitivity—produces a composite allocation shown in Figure 5 of roughly 42% to Region A and 58% to Region B. Costs are then fixed at these blended shares.

***Figure 5. Blended Scenario Cost Shares for the Scenario-Based Fixed Cost Allocation Method***




In terms of **beneficiary alignment**, this method is similar to the single-scenario approach because it still relies on the same baseline benefit quantification. The inclusion of multiple scenarios clearly strengthens **robustness to forecast uncertainty**, as the allocation accounts for a broader range of potential futures, reducing the risk that allocations will be misaligned if actual conditions diverge from the baseline. **Cost certainty** remains high, since allocations are fixed once the scenario analysis is complete, providing financial stability to participating regions. On **administrative efficiency**, the method is more complex than single-scenario fixed allocation because multiple scenarios must be modeled and agreed upon by the regions, but it remains simpler than fully dynamic methods because allocations are determined only once at the outset. **Transparency** is moderate: while assumptions and scenario weights can be documented, the additional complexity may make replication more challenging for non-experts.

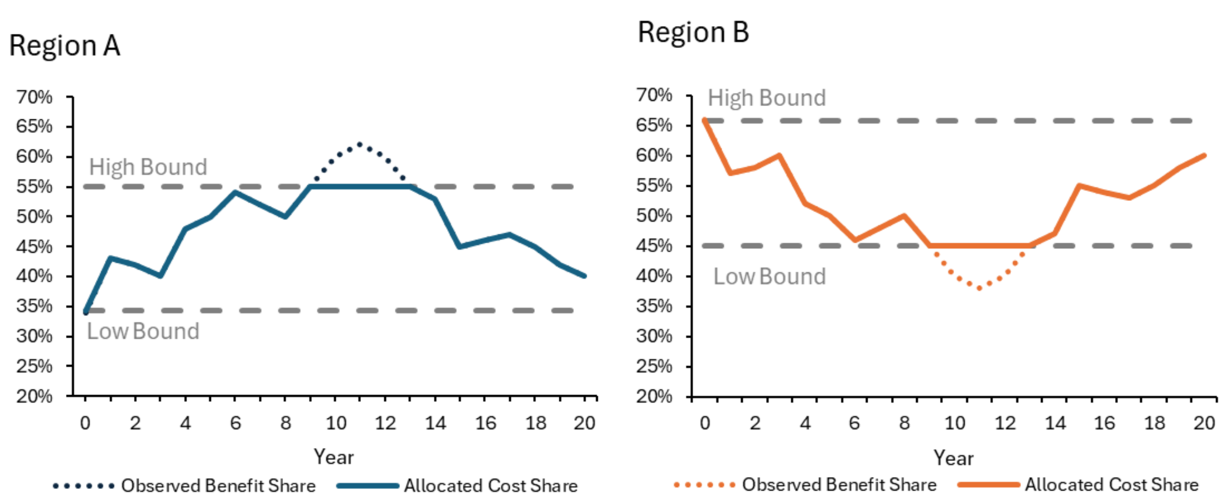
## Bounded Dynamic Cost Allocation

This method introduces the dynamic approach of cost allocation found in the load ratio share method, in which cost shares are recalculated at regular intervals (typically at the end of each year) based on retrospective performance of the system. Unlike fixed approaches, this ex-post methodology adjusts allocations to reflect actual benefits observed by each region, rather than relying solely on forecasted or scenario-weighted estimates. Because the method depends on observed outcomes, it is critical that regions pre-determine a method for measuring performance and establishing how reallocations will be calculated. This dynamic approach makes allocation more robust to uncertainty and better aligned with the distribution of project benefits. Yet the approach carries tradeoffs: because conditions are continually changing, it is difficult to define a stable counterfactual for comparison, and the method can impose significant administrative demands by requiring repeated recalculation.

True dynamic cost allocation can introduce too much uncertainty for participants, since cost shares may fluctuate widely from year to year. To address this, the "bounded" aspect of the approach uses the range of outcomes from the scenario-based fixed allocation to establish limits on how much cost shares can vary. These bounds act as a floor and ceiling on allocations, preventing extreme swings while still allowing the method to better align costs with actual realized benefits. By combining dynamic recalculation with scenario-informed bounds, this approach aims to balance robustness to forecast uncertainty with cost predictability and political acceptability.

To compute "observed" benefits, each update period would require a shadow dispatch: re-running the system with the realized loads, outages, fuel prices, and renewable profiles, but with a no-project counterfactual (the new tie removed or constrained to its pre-project rating), and then comparing those counterfactual costs and reliability metrics to actuals. Since that counterfactual is model-based, choices about inputs and rules will be sensitive to assumptions. To manage this, the methods used to verify performance and determine re-allocation quantities should be established ex-ante through a transparent, consensus-based process. Defining the data sources, metrics, and analytical procedures clearly before project construction begins is essential to ensure that future re-allocations will be accepted by all parties and that results remain credible. A documented measurement-and-verification protocol and stakeholder governance established before the project reaches commercial delivery would be essential, yet disagreements over the "right" baseline are still possible.

*Figure 6. Bounded Dynamic Cost Allocation*




In our example scenario, the baseline and sensitivity scenarios are first used to establish a range of plausible cost shares: Region A at a minimum of 34% and a maximum of 55%, and Region B at 45%

to 66%. Actual cost allocation is then updated periodically (e.g., annually) based on observed benefits, but the results are bounded within this range. For example, if Region A's realized benefits one year suggest a 62% share, its allocation would be capped at 55%. This dynamic is shown in Figure 6. Bounded Dynamic Cost Allocation as costs are allocated annually according to observed benefits but bounded based on the scenario results.

This approach represents a significant step toward **beneficiary alignment** because allocations are based on observed outcomes rather than purely modeled projections. It also enhances **robustness to forecast uncertainty**, as the dynamic nature of the method allows cost shares to adjust in response to unforeseen changes in system conditions. **Cost certainty** is significantly reduced compared with fixed approaches, but the scenario-informed bounds help maintain predictability and limit extreme fluctuations. **Administrative efficiency** is much higher than fixed methods due to the need for ongoing measurement, calculation, and adjustment of allocations, as well as regular stakeholder engagement. **Transparency** is moderate to low: the methodology can be fully documented, but the recurring calculations and reliance on system performance data may be challenging for some stakeholders to fully replicate.

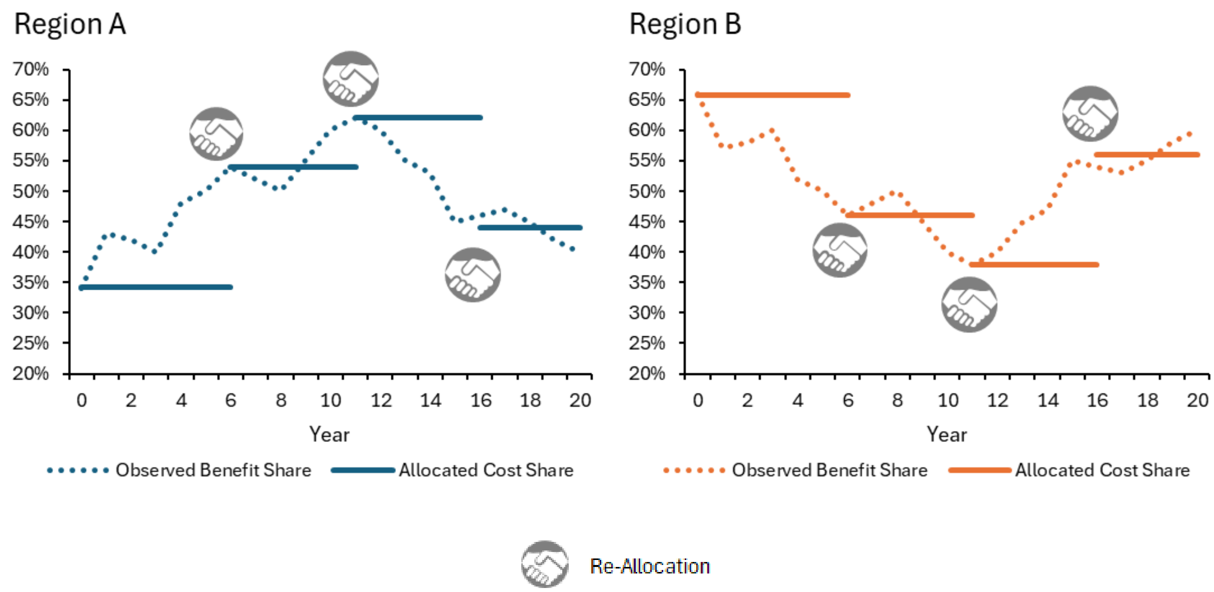
## Fixed Re-Allocation

This method attempts to combine the best qualities of fixed allocation methods' cost certainty and relatively low administrative burden with dynamic allocation's stronger beneficiary alignment and improved robustness to forecast uncertainty. Under this approach, costs are initially allocated using a fixed methodology; however, rather than locking in these cost allocations for the full life of the project, the regions agree in advance to reconvene after a predetermined timeframe (for example, 5 or 10 years) to reassess and reallocate costs based on new forward-looking benefit analysis. This periodic reset allows the method to adjust to changed conditions without requiring annual recalculation. The Fixed Re-Allocation method can be viewed as an adaptation of the Bounded Dynamic approach that relies on forward-looking adjustments rather than retrospective ones. As with the bounded dynamic method, a methodology that includes fixed re-allocation would require a pre-determined, ex-ante approach for conducting the updated analysis and applying new cost shares, as well as an established timeframe for reallocation, agreed upon by all parties. This approach would ensure that results are transparent, replicable, and remain broadly acceptable to all participants.

In our example project, the two regions start with the baseline allocation of 34% for Region A and 66% for Region B, as shown in Table 2. Then, every five years the cost shares are reset based on re-run benefit analysis forecasts. For example, if benefit analysis at year 5 shows Region A receiving 54% and Region B 46%, costs for the following five-year period are allocated on that fixed basis. At year 10, updated modeling might show Region A with 62% of benefits and Region B with 38%, while by year 15 the shares could shift again to 44% and 56%, respectively.

Figure 7 illustrates this approach: annual observed benefits fluctuate each year, but the cost allocation is held constant in five-year blocks until the next scheduled reallocation. This creates a stepwise pattern, with horizontal lines representing fixed allocations for each interval.

***Figure 7. Fixed Re-Allocation of Costs***




In terms of **beneficiary alignment**, this method improves on single-scenario and scenario-based fixed approaches because it allows allocations to adjust over time, though less frequently than dynamic methods. **Robustness to forecast uncertainty** is stronger than fixed approaches, since periodic reallocation provides a mechanism for adapting to new policy, load, or economic conditions. **Cost certainty** remains relatively strong, as allocations are fixed for multi-year intervals, but participants must accept that shares may change at each reallocation point; this change can be mitigated in part through pre-defining the details and timing for how a reallocation would be applied. **Administrative efficiency** is moderate: higher than one-time fixed methods, but lower than fully dynamic approaches, since updates are required only at long, predefined intervals based on predetermined benefit analysis processes. **Transparency** is similar to the scenario-based fixed approach, as the assumptions and methodology can be documented, though the periodic recalculations may create additional complexity.

# Guide to Cost Allocation Method Selection

## Comparative Analysis

Table 6, below, summarizes how each method scores on a scale from very low to very high according to the five criteria outlined. No method is perfect, and each has strengths and weaknesses. Some of the below methods may not score highly, but they may still provide value by bringing parties to the table to negotiate.

Several patterns stand out:

+ **From left to right across the table, methods move from simple proxies to more precise beneficiary-pays approaches.** Load ratio share and Avoided Cost both build on established allocation practices that use stand-ins for benefits – system size in the case of LSR, displaced regional projects in the case of Avoided Cost. These approaches may not offer fine-grained precision, but they are administratively efficient, transparent, and already accepted under FERC rules. Further to the right side of the table, methods target sharper alignment between costs and benefits, which may be critical for individual interregional projects where bespoke allocation may be required.
+ **Forward-looking versus backward-looking designs also shape the trade-offs between cost certainty and forecast certainty.** Forward-looking methods – Avoided Cost, Single-Scenario Fixed, Multi-Scenario Fixed, and Fixed Reallocation – tie allocations to forecasts and modeled assumptions. They deliver stable obligations but are vulnerable if planning assumptions diverge from reality. Backward-looking methods – (dynamic) Load ratio share and Bounded Dynamic – link allocations to observed outcomes, either through changes in load or measured benefits. These approaches are more resilient to forecast error but reduce cost certainty, since obligations shift with realized conditions.
+ **Administrative feasibility versus technical precision.** The more technically precise methods – multi-scenario fixed, bounded dynamic, and fixed re-allocation – demand repeated modeling, stakeholder agreement on assumptions, and complex measurement protocols. While this precision may improve fairness, it can reduce transparency and stakeholder acceptance.

The patterns confirm that interregional cost allocation is about the balance between setting priorities and avoiding risks. Stakeholders must weigh which qualities they value most: robustness to future uncertainties, stable and predictable costs, or transparent and understandable rules. Each choice carries both risks and potential rewards. For example, prioritizing stability may reduce responsiveness to changing conditions, while emphasizing flexibility may introduce greater uncertainty in outcomes. In this sense, cost allocation is less about minimizing downside and more about balancing risk and reward in line with regional preferences.

### *Table 6. Summary Cost Allocation Evaluation Matrix*

| | Avoided Cost | Load Ratio Share | Single-Scenario Fixed | Multi-Scenario Fixed | Bounded Dynamic | Fixed Re-Allocation |
|---|---|---|---|---|---|---|
| ***Method Summary*** | *Costs allocated based on displaced intraregional projects* | *Allocates costs based on each regions share of annual load, without benefit analysis* | *Allocation based on benefits calculated from a single collaborative planning scenario* | *Allocates costs using multiple scenarios with agreed weighting to capture sensitivity.* | *Reallocates costs dynamically within scenario-based bounds based on observed outcomes* | *Uses fixed allocation but resets cost shares at predetermined intervals* |
| **Beneficiary Alignment** | Only measures displaced project benefits, not other benefits | Not benefits -based; costs follow load, regardless of cross-border benefits | Single-scenario modeling ties costs to modeled benefits at time of approval | Blends multiple scenarios; better alignment with expected benefits | Tracks realized benefits over time; closest to beneficiary alignment | Periodic step-changes align shares with updated benefit evidence |
| **Robustness to forecast uncertainty** | Insensitive to fuel/policy assumptions (no modeling) | Costs adapt to changes in load, assumed correlated to benefits | Sensitive to input assumptions; locked to a single case | Less sensitive than single case, but still model dependent | Adapts to realized outcomes; caps/floors reduce volatility risk | Adaptive at set intervals; lower model risk than fixed methods |
| **Cost Certainty** | High certainty; fixed share for asset life | Costs assigned proportional to load, which could vary over time | High certainty; fixed share for asset life | High certainty; fixed share for asset life | Lower certainty; year to year adjustments within bounds | Medium; certainty within each interval, then step changes when renegotiated |
| **Administrative Efficiency** | Uses existing processes; sensitivity to displaced project assumption may be challenging | Simple load-ratio math | Only one benefit study at approval | Requires multiple scenarios, weighting, documentation | Recurring benefit measurement, settlement changes | Requires periodic studies and negotiations |
| **Transparency** | Leverages existing analytical process | Easy to understand and audit | Model-based with clear static assumptions | Requires clarity on scenario weights and drivers | Requires annual reports and measurement rules | Step changes must be well documented |

**LEGEND** Very High | High | Medium | Low | Very Low

## Decision Tree Framework for Cost Allocation

Given no single cost allocation method fits every circumstance, the decision tree belowFigure 8 is meant to serve as a structured guide to navigate cost allocation discussions. It lays out the common forks in the road that regions face and connects those choices to potential allocation approaches. The framework is not prescriptive, but helps stakeholders identify which methods align with their priorities around benefits alignment, simplicity, and adaptability. It is intended as an organizing tool to help stakeholders reason through trade-offs.

The framework can be broken down into three sequential categories of considerations, as labeled in Figure 8:

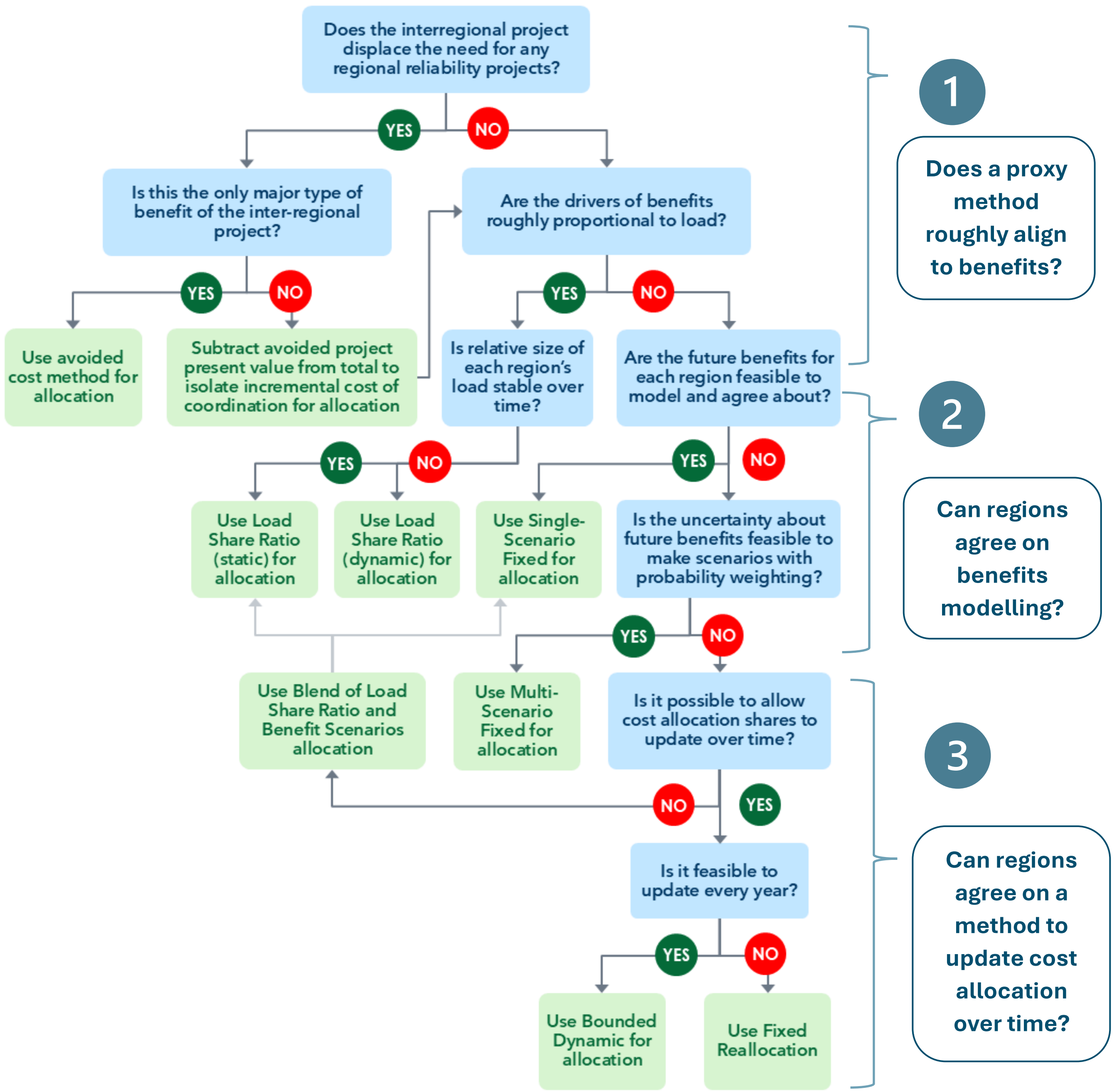
1. **Does a proxy method roughly align to benefits?** The first section begins by asking if a proxy method correlates to anticipated benefits. The first option proposed is **Avoided Cost**. This method may be an appealing starting point, since it ties directly to existing regional planning assumptions. Still, this approach may be too narrow if the project delivers broader benefits, in which case regions might pair avoided-cost with benefits-based methods. If no avoided projects exist, regions might consider whether benefits tend to scale with load. **Load Ratio Share** is simple and transparent, which may be attractive where predictability or administrative efficiency matter most. Yet it can also be contentious, for example if a small region and a much larger one are linked, the cost allocation can appear unbalanced, prompting some stakeholders to prefer other approaches despite its simplicity.

2. **Can regions agree on benefits modelling?** If regions can reach agreement on future forecast assumptions, a **Single-Scenario Fixed** approach may provide a reasonable balance of fairness and stability. But where modeling assumptions are deeply contested and agreement can be reached by blending a mix of forecast sensitivities, the **Multi-Scenario Fixed** approach may be best. If probability weighting does not resolve disagreement, and there is little appetite for dynamic or re-allocative methods, regions may blunt the effects of a single-scenario analysis by blending it with a load ratio share allocation, producing a hybrid allocation that balances simplicity with a partial link to modeled benefits.

3. **Can regions agree on a method to update cost allocation over time?** Fixed allocations offer long-term stability, while **Fixed Reallocation** or **Bounded Dynamic** methods can better reflect realized benefits but add uncertainty. Here, choice depends on tolerance for cost certainty versus robustness to changing conditions, as well as practical considerations for forward- versus backward-looking adjustments. Implementing such an approach would require regions to agree ex ante (before project construction) on the parameters for how costs are updated, whether annually or at fixed intervals, and to establish tariff provisions that specify what triggers a reallocation and how those adjustments would be calculated. Determining the parameters ahead of project development is critical for developers to finance projects.

In this way, the decision tree complements the comparative analysis: it highlights common decision points and trade-offs without prescribing a single path. Regions can use it as a guide to clarify their options, or bypass it if they already know which balance of criteria feels most acceptable.

***Figure 8. Decision Tree Framework for Interregional Cost Allocation***



# Recommendations and Path Forward

As FERC precedent makes clear, cost allocation is an art, not a science.[21] The goal is not to produce mathematically perfect alignment with modeled benefits, but to craft solutions that are 'roughly commensurate' with the distribution of benefits, politically durable, and administratively workable. The risk is not imperfect allocation, but rather failing to reach agreement on a project that would produce positive net benefits compared to its cost**.** This white paper broadens the conversation on cost allocation for interregional transmission projects by laying out a diverse toolkit of cost allocation approaches, including both (existing interregional planning processes regulated by FERC, as well as bilateral or voluntary processes such as the Northeast States Collaborative effort. These approaches build on key precedents, particularly from cost allocation for intraregional projects, and draw lessons from what has and has not worked to inform the design of cost allocation approaches for interregional lines.

In this concluding section, we offer recommendations for states and planning regions seeking to advance interregional transmission projects. These recommendations focus on how to (1) match cost allocation approaches to regional priorities while balancing fairness, stability, and flexibility, (2) explore both portfolio and stand-alone solutions to make cost allocation more workable across regions, and (3) strengthen coordination between states and planning regions so that policy preferences can be translated into technically feasible frameworks for FERC approval.

**Recommendation:** The best cost allocation method is the one aligned with addressing regions' core priorities – whether that is certainty, acceptability, simplicity, or accuracy. Achieving that may include blending or combining the approaches described here.

Recognizing and surfacing these underlying priorities explicitly may help reduce stakeholder deadlock. Rather than debating cost allocation in the abstract, parties can frame the discussion around what risks they most want to protect against, whether overpaying under uncertain conditions, facing unpredictable cost swings, or having opaque rules. The method should be guided by regions' underlying priorities:

+ If robustness to forecast uncertainty is the paramount issue, regions may gravitate toward Load Ratio Share, Fixed Reallocation or Bounded Dynamic allocation methods that allow for recalibration as conditions evolve.
+ If cost certainty and broad acceptability are more important, avoided costs or fixed approaches (single- or multiple-scenario fixed) are likely to be preferable.

[21] FERC and the courts have recognized that transmission cost allocation involves judgment, not precision; methodologies need only be 'roughly commensurate' with benefits. See: Order No. 1000, 136 FERC ¶ 61,051 (2011), at P 624, and *Illinois Commerce Comm'n v. FERC*, 721 F.3d 764, 774–75 (7th Cir. 2013)

- If simplicity and transparency dominate, Load Ratio Share and Avoided Cost methods may be the easiest to implement, even if they score lower on accuracy.
- If maximized beneficiary alignment is the goal, the preferred method may be any of the four methods that aim to quantify benefit shares, whether forecasted or observed.

***Figure 9. Cost Allocation Method Tradeoff Matrix***

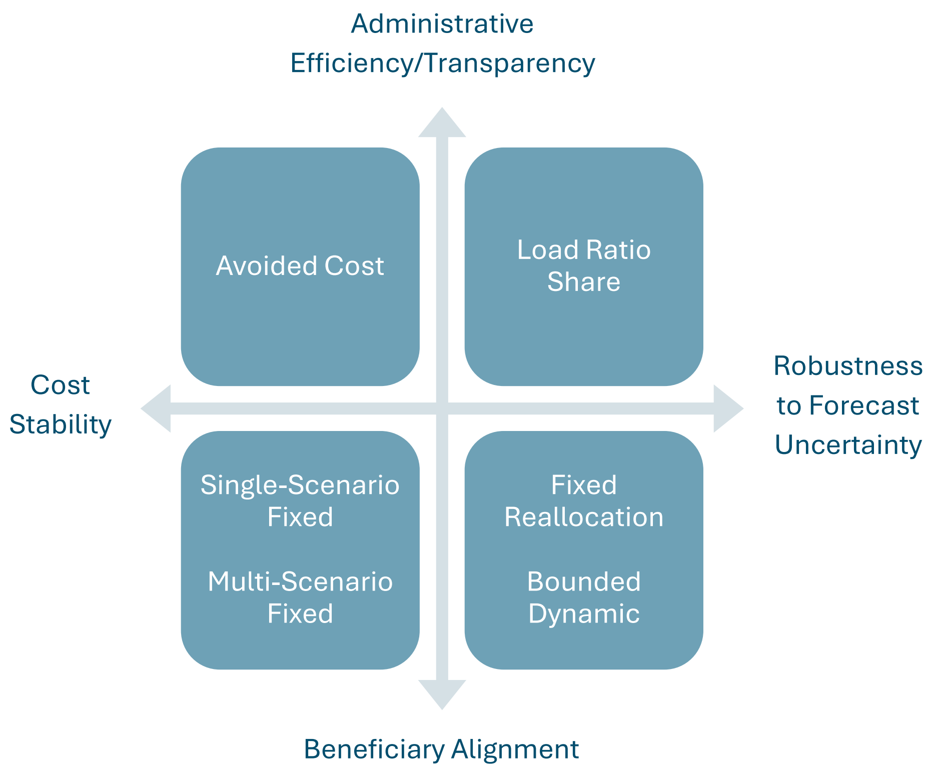



Figure 9 demonstrates that each approach embodies trade-offs. While the matrix, Table 6, captures how methods perform across key evaluation criteria, applying those tradeoffs in practice also requires grounding decisions in the kinds of practical considerations highlighted in the decision tree framework in Figure 8. Together, these tools provide both an analytical lens and a step-by-step guide for regions to translate principles into workable choices.

Another key decision-making tool that can help find contextually appropriate allocation methodologies is to leverage both the conceptual and practical strengths of methods proposed in this paper by creating hybrid methodologies. These could be solutions that deliberately combine carefully selected components of proposed methods. One such example would pair scenario blending with fixed renegotiation. Scenario blending produces an allocation based on multiple plausible futures, improving the robustness of the initial cost split and reducing the risk of one region feeling unfairly treated under a single baseline scenario. Yet, like all fixed approaches, it locks those shares in for the life of the project, even as policies, load growth, and fuel prices evolve. By layering in fixed renegotiation and committing the regions to revisit the allocation at predetermined intervals, the framework gains flexibility to adapt as conditions unfold. This hybrid combines the precision of benefit-based modeling with a built-in mechanism for recalibration, reducing the likelihood of long-term misalignment while maintaining multi-year periods of cost certainty that are valuable for financing and regulatory approval.

Another hybrid approach could start with avoided regional project costs as a proxy, providing a straightforward and historically accepted way to ground the allocation. This proxy alone may not capture the full range of benefits provided by the interregional solution. To address this gap, regions could agree to a two-part framework: first, allocate a share of costs in proportion to avoided regional projects, and second, jointly measure additional interregional benefits using a single-scenario benefits analysis. The combined outcome would be a fixed allocation that preserves the stability of proxy methods while also recognizing broader system benefits that would otherwise be overlooked.

**Recommendation:** Bundling interregional projects into portfolios can make cost allocation easier by spreading benefits more evenly to regions, but because portfolios are hard to coordinate, practical stand-alone cost allocation solutions are also needed.

While interregional projects are relatively rare in recent history, it may be easier to secure agreement if they are evaluated on a portfolio basis rather than project by project. A single line can appear unbalanced in terms of who benefits, but across a portfolio the benefits are more likely to even out. Expanding the tent to include multiple lines, or aligning interregional builds with broader regional portfolios, may reassure stakeholders that their share of costs will align more proportionally with long-term benefits. Building such a portfolio, however, requires regions to make forward-looking commitments to develop multiple projects together or to evaluate future interregional lines under the same framework.

Where portfolios are not feasible, interregional projects will continue to be advanced on a bespoke, one-off basis. In these cases, cost allocation methods cannot rely on benefits averaging out across multiple lines and instead must stand on their own. This reality makes it all the more important to ground the choice of method in the practical concerns of the participating regions. If stakeholders are explicit about what they most need to avoid, they are more likely to converge on an allocation framework that is workable in practice. By focusing on addressing concrete concerns rather than striving for theoretical perfection, regions can increase the chances of reaching agreement and moving interregional projects forward.

**Recommendation:** States should identify which cost allocation tradeoffs are most acceptable, while planning regions can work to translate those preferences into frameworks that are technically feasible and ready for FERC approval.

Putting these conceptual approaches into practice will depend on the respective roles of states and planning regions, and how they interact within the broader framework FERC oversees. If states across two regions identify an approach they prefer, they have several avenues to express that preference. They may signal alignment through joint resolutions or memoranda of understanding, ask their regulated utilities to advance proposals through stakeholder processes, or coordinate across commissions to present a unified position at FERC. Alternatively, states may also choose to use the emerging State Agreement Process set forth in Order 1920 in their respective regions, which allows them to voluntarily assume project costs even across regional boundaries, though this option may be less attractive if the project delivers benefits beyond those participating states.

In this way, states provide direction on what is acceptable from a policy and cost recovery perspective, while planning regions develop and implement the mechanics needed to administer the method. When both levels of governance move in concert, it increases the likelihood that FERC will find a proposed approach reasonable and durable. This interplay highlights how conceptual frameworks can evolve into practical cost allocation arrangements that enable interregional transmission development.

Next steps should focus on states assessing their own transmission interests, convening to study areas of alignment, and evaluate the viability of candidate interregional solutions. In doing so, they can also begin to consider which cost allocation mechanisms are most workable and exercise their influence within regional planning processes. By coordinating early, states can test multiple allocation methods side by side, illustrate how costs and benefits would be distributed, and surface where compromises may be possible. This process not only clarifies tradeoffs but also builds trust among participants and strengthens the likelihood that projects ultimately selected will be both durable in design and broadly acceptable.