Right-Sizing Future Electric Transmission Systems

Strategies for Improving Coordination Between Resource Planning and Transmission Planning

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GridLAB

Table of Contents

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Abbreviations

AC	Alternating Current
BA	Balancing Area
CCA	Community Choice Aggregators
CPCN	Certificate of Public Need and Necessity
CTPC	Carolinas Transmission Planning Collaborative
DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
DER	Distributed Energy Resources
DOE	Department of Energy
DSM	Demand-Side Management
DSP	Default Service Provider or Distribution Service Provider
EER	Evolved Energy Research
EEA	Executive Office of Energy and Environmental Affairs
EIM	Energy Imbalance Market
ERCOT	Electric Reliability Council of Texas
ERIS	Energy Resource Interconnection Service
ESMP	Electric Sector Modernization Plans
ESIG	Energy Systems Integration Group
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
G&T	Generation and Transmission
GHG	Greenhouse Gas
IDP	Integrated Distribution Planning
IOU	Investor-Owned Utilities
IRP	Integrated Resource Plan
ISO	Independent System Operators
ISOP	Integrated System and Operations Planning
LSE	Load Serving Entities
LRTP	Long-Range Transmission Planning
MISO	Midcontinent Independent System Operator
MPUC	Minnesota Public Utilities Commission
MTEP	MISO Transmission Expansion Plan
MTO	Minnesota Transmission Owners

MVST	Multi-Value Strategic Transmission
NCUC	North Carolina Utilities Commission
NESCOE	New England States Committee on Electricity
NREL	National Renewable Energy Laboratory
NSP	Northern States Power Company
NTTG	NorthernGrid (formerly Northern Tier Transmission Group)
NYISO	New York Independent System Operator
OSC	Oversight/Steering Committee
POLR	Providers of Last Resort
PPA	Power Purchase Agreements
PUC	Public Utility Commissions
PUD	Public Utility Districts
PVRR	Present Value of Revenue Requirement
RA	Resource Adequacy
RC	Reliability Coordinator
NM-RETA	New Mexico Renewable Energy Transmission Authority
RFP	Request for Proposal
RPSG	Regional Planning Stakeholder Group
RTO	Regional Transmission Organizations
SCTRP	South Carolina Regional Transmission Planning
SEEM	Southeast Energy Exchange Market
SERTP	Southeast Regional Transmission Planning
SPP	Southwest Power Pool
TAG	Transmission Advisory Group
TO	Transmission Owners
TVA	Tennessee Valley Authority

Executive Summary

The future of the U.S. electric transmission system — how much, where, when, and which kinds of new transmission will be built over the next two decades — is perhaps more uncertain now than it has ever been.[1] On the one hand, load growth, technological innovation, energy and environmental policy, and extreme weather have the potential to drive an unprecedented expansion of the transmission system. On the other hand, many of these transmission drivers are themselves uncertain, and new technologies and planning practices — from advanced transmission technologies[2] to lower-cost battery storage[3] — may significantly reduce new transmission needs.

Right-sizing the transmission system is critical. An overbuilt transmission system may be more reliable and have lower congestion but will have higher transmission costs. An underbuilt transmission system will have lower transmission costs but may be less reliable and have more congestion.[4]

Better coordination between resource planning and transmission planning is an important strategy for right-sizing future transmission. Resource planning, broadly defined, uses optimization models to determine least-cost projections of supply-side and demand-side resources to adequately meet forecasted demand over some time horizon, subject to policy and other constraints. Transmission planning identifies transmission needs over 10- to 20-year time horizons. At a minimum, these two processes should be interactive. For instance, changes in expected generation mix should lead to changes in the amount, location, and timing of new transmission capacity, and vice versa. In practice, however, they are often siloed, for practical, policy, and regulatory reasons.

This report identifies strategies for improving coordination between resource and transmission planning. It draws on four case studies that represent a mix of geographies, whether transmission-owning utilities participate in regional transmission organizations (RTOs) or Independent System Operators (ISOs), different state requirements for integrated resource planning (IRP), and whether

1 The range in estimates of U.S. transmission needs over the next two decades is extremely wide. For instance, in the U.S. Department of Energy's (DOE's) *National Transmission Needs Study* (DOE, 2023), estimates of interregional transmission capacity needs by 2035 differed by an order of magnitude across different scenarios for load and clean energy growth. Jenkins et al. (2022) argue that fully unlocking the emission reduction potential of the Inflation Reduction Act would require a doubling of the pace of transmission expansion over the past decade. By contrast, Zheng et al. (2024) argue that optimal transmission expansion only minimally reduces the costs of meeting a 100% clean electricity system, relative to a scenario that relies solely on the current transmission system.

2 For instance, see Chojkiewicz et al. (2024).

3 For an overview of DOE's strategies to reduce the cost of long duration storage, for instance, see DOE (2024).

4 Overbuild and underbuild are useful ways to think qualitatively about transmission expansion over longer time horizons, but they are not useful metrics for evaluating transmission expansion in the short term. Transmission infrastructure is characterized by economies of scale, which means that, in some cases, oversizing transmission may be more cost-effective in the long run. In addition, transmission systems exhibit strong network effects, which means that the location of transmission may be as important as the total transfer capacity. Transmission also involves difficult-to-quantify benefits, such as market competitiveness or resilience during extreme weather events. All of these dimensions make it difficult to develop ex post metrics to determine whether a transmission system is overbuilt or underbuilt.

there are state-level processes and requirements for transmission planning (Table ES1).

TABLE ES1. Case Studies Representing Varying U.S. Electricity Planning and Operating Contexts

COMPANY	REGION	ISO/RTO	IRP REQUIREMENTS	STATE TRANSMISSION PLANNING
PacifiCorp	West	None	Yes, multistate	None
Northern States Power	Midwest	MISO	Yes, single-state	Yes
Duke Carolinas	Southeast	None	Yes, multistate	Yes
National Grid	Northeast	ISO-NE	None	None

The case studies illustrate the practical barriers to better integration of resource and transmission planning — different processes and organizations, monopoly power and efforts to limit it, challenges with interstate cost allocation, and the often-conflicting intersection between competitive energy markets, regulated transmission, and state-level energy policies.

Greater coordination between resource and transmission planning does not necessarily mean that they are fully integrated, nor that generation and transmission infrastructure are fully co-optimized. Rather, coordination is mostly about ensuring the timely exchange of information between different processes and organizations and the effective use of that information.

For instance, an IRP may include a high-level representation of the regional transmission system, using publicly available information from transmission planners, helping to inform decisions on where to site new generation, storage, and demand-side resources cost-effectively and to assess whether new transmission infrastructure might be economically justified (see PacifiCorp example in Section 5.1.2). Similarly, an RTO might use utility IRPs to develop a vision of future generation and loads that supports longer-term transmission planning, supported by mechanisms for regional transmission cost allocation and risk sharing (see MISO example in Section 5.2.2). These are examples of coordination rather than integration.

The case studies also highlight recent efforts by some state public utility commissions (PUCs) and the Federal Energy Regulatory Commission (FERC) to improve resource and transmission planning coordination. For instance, among the case studies PacifiCorp likely provides the best illustration of coordinated processes, an outcome that required significant investments of time and effort from both PacifiCorp and PUCs in some of the states in which it operates. At the federal level, FERC Orders 1920, 1920-A, and 1920-B require regional transmission providers to undertake long-term, scenario-based transmission planning, with avenues for participation by Relevant State Entities. The transmission planning outlined in these orders requires longer term load and resource forecasts than have been needed historically. As a result, some transmission providers will need to develop new processes for generating these forecasts.

The case studies illustrate how planning coordination might help avoid undesirable outcomes. For instance, for Northern States Power (section 5.2), including transmission constraints and costs in its resource planning models may have provided more visibility on whether, when, and how to address growing levels of congestion and wind curtailment in southern Minnesota. For Duke Carolinas (section 5.3), closer alignment among resource planning, transmission planning, and generator interconnection may have better anticipated transmission needs and reduced delays and costs in interconnection in North Carolina.

Coordination in long-term planning does not necessarily mean that transmission planners would select and transmission developers would build transmission based on longer-term resource forecasts, or that resource planners would necessarily include long-term transmission plans as fixed inputs in their resource plans. For instance, a transmission need identified 15 years into the future, based on long-term forecasts of supply and demand, does not necessarily need to be solved today but could help (1) generate ideas for solutions that could be later evaluated within the "action" window for transmission development (e.g., 10 years) or (2) evaluate and prioritize nearer-term solutions that would also address longer-term needs. In resource planning, longer-term transmission solutions could be evaluated through scenarios and sensitivities, for instance by considering "in and out" cases in production simulation modeling.

There is no simple playbook for improving coordination between resource and transmission planning. What works in one jurisdiction may prove unworkable in another. However, some generalization is possible. Drawing on the case studies, the report outlines "idealized coordination" among resource planning, transmission planning, and two other closely related processes — generator interconnection and resource procurement (Section 2). Figure ES1 shows information flows among these different processes.

FIGURE ES1. Information Flows with Idealized Coordination Among Resource Planning, Transmission Planning, Generator Interconnection, and Resource Procurement

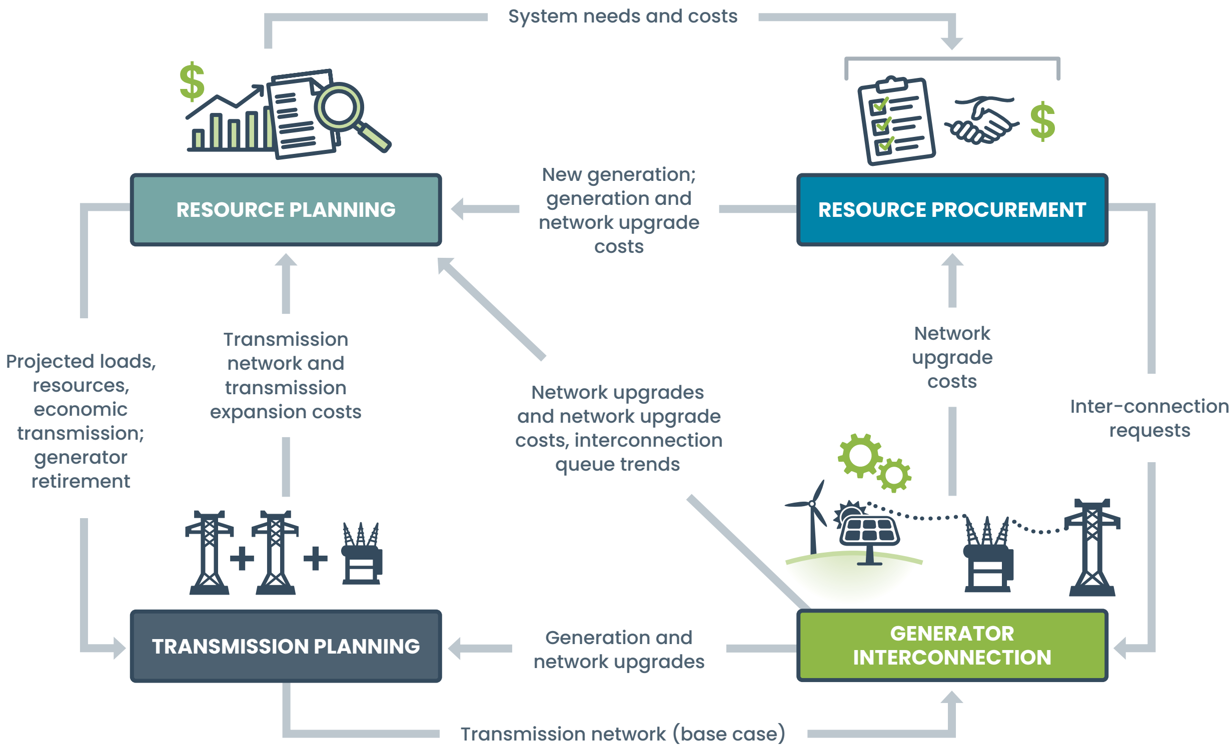


Figure ES1 illustrates how resource planning can use transmission constraints and costs to add spatial detail. In this idealized coordination, resource planning information — forecasted net loads and demand-side resources, planned and expected generator retirements, planned and expected generator and storage additions — is used in long-term transmission planning, either directly or indirectly as a reference. Both resource and transmission planning use information on network upgrades and generator interconnection queues. Information on evolving market conditions from resource procurement is used in resource planning. Although many of the challenges in implementing coordination lie in the "how" details, the ideal process diagrammed here can be a useful high-level reference.

This report develops a priority list of recommendations for improving coordination between resource and transmission planning. These recommendations are intended as considerations rather than best practices, and they do not apply to all contexts. In some cases, resource and transmission planners already have coordinated processes in place. The recommendations are organized into three categories: cross-cutting areas, areas for better incorporation of transmission in resource planning, and areas for better incorporation of resources in transmission planning. The following summary includes the actors that are most directly relevant for each recommendation, in parentheses. The case studies explore additional recommendations.

Cross-Cutting Issues

- **Functional separation.** Some improvements in coordination between resource and transmission planning may generate open access or other conflict of interest concerns. In such cases, review existing practices and determine whether more transparency is needed in the information that is shared or in the process, and whether additional rules and safeguards are needed to mitigate conflicts of interest. (PUCs, FERC)
- **Integrated versus coordinated planning.** As an alternative to an integrated planning department, consider different approaches to planning coordination by thinking through which departments are best placed to do what kind of planning, which data and expertise need to be shared across departments, how planning processes can be aligned, and what kinds of organizational changes are needed for better coordination. (Utilities)
- **State transmission agencies.** In some states, transmission-related roles and responsibilities are expanding. Before setting up a new state transmission agency, consider developing an inventory of roles and responsibilities, analyzing any organizational changes needed to fulfill responsibilities, and identifying any longer-term needs for staffing and expertise to determine whether a new organization would be justified or whether there might be other alternatives. (PUCs, state energy offices)

Resource Planning

- **Incorporation of transmission in resource planning models.** Explore whether and how to incorporate transmission constraints, costs, and spatial detail for loads and resources in capacity expansion models and production simulation models used in resource planning, even for utilities that are in RTO regions.[5] The aim is to identify opportunities for economic transmission and optimize tradeoffs between transmission and resource investments, in order to complement but not replace transmission planning. The PacifiCorp case study (Section 5.1.1) illustrates how transmission can be incorporated into resource planning in practice. (Utilities, PUCs, stakeholders)
- **Transmission alternatives.** Review whether and how energy storage and demand-side resources can offset new transmission investments in resource planning models. (Utilities, PUCs, stakeholders)
- **Regional and interregional transmission drivers.** Review how imports and exports are treated in IRP models and whether the benefits of utilities taking more open market positions — either as importers or exporters of capacity and energy — outweigh the costs and risks. If utilities plan to build or procure resources to supply all or most of their needs, then the resource adequacy value of regional and interregional transmission may be limited. (Utilities, PUCs, stakeholders)

Transmission Planning

- **Long-term transmission planning.** In FERC-jurisdictional RTO and independent system

5 Biewald et al. (2024) include consideration of transmission alternatives and infrastructure expansion as a best practice in integrated resource planning.

operators (ISO) regions complying with Order 1920 (and subsequent orders 1920-A and 1920-B), consider what the process for developing load and resource scenarios for long-term transmission planning will look like — how much modeling will be involved; who will do the analysis; how states, transmission owners, and market participants will review scenarios and inputs; how differences in resource forecasts will be reconciled, and how any transmission costs will be allocated. (RTOs/ISOs, state agencies, market participants, stakeholders including customers and advocates)

- **Incorporation of transmission in resource forecasts.** Explore the inclusion of transmission constraints and costs and spatial detail for resources in models used for projecting long-term resource expansion. Including spatial detail in modeling and analysis for long-term resource projections may be more accurate than using high-level algorithms to site generation and storage for inputs in long-term transmission plans.
- **Resource adequacy and regional transmission.** Examine and better understand the potential roles of transmission in supporting resource adequacy across multi-state regions. (RTOs/ISOs, non-RTO regional transmission planners, state agencies, market participants)

None of the considerations above lends itself to ready-made answers. Instead, coordination requires thoughtful design, adaptation as designs prove more or less effective, and the time and effort to make it work. This report aims to provide support to these efforts.

The report is broken down into five sections.

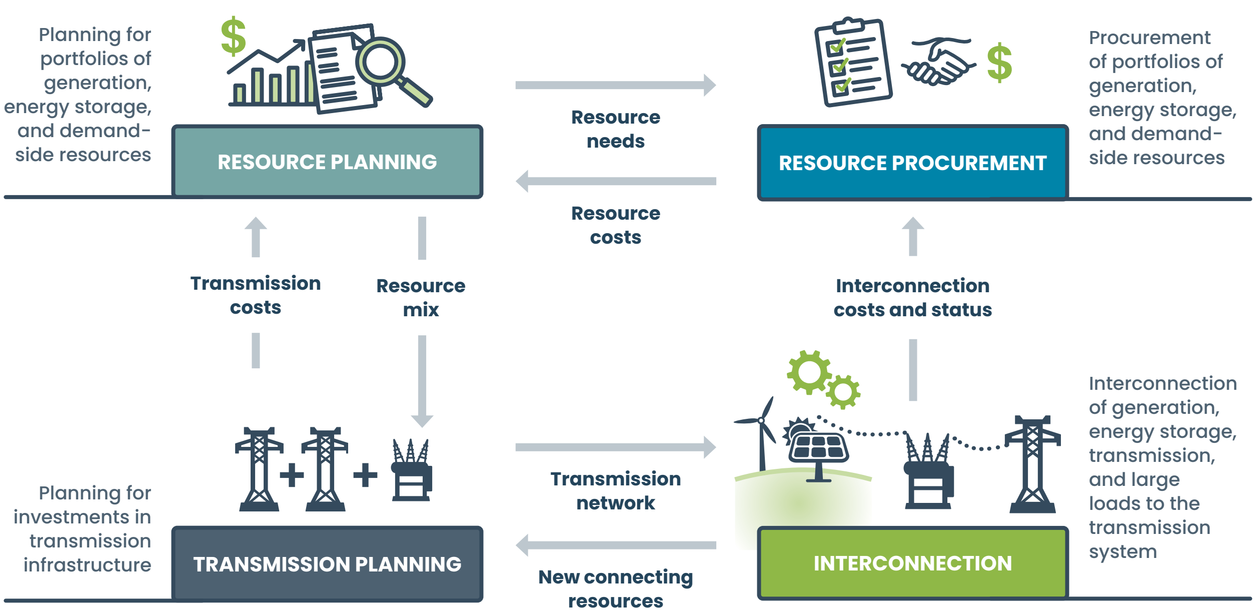
1. **Background –** Provides an overview of interactions between resource planning, transmission planning, interconnection, and resource procurement; how the diversity of load serving entities (LSEs) and transmission providers shapes the planning context; and how changing planning requirements, such as Order 1920, are changing coordination needs.
2. **Idealized coordination** – Sketches out an idealized process of information sharing among resource planning, transmission planning, generator interconnection, and resource procurement.
3. **Key themes and focus areas for improving resource and transmission planning coordination** – Distills key themes and areas of focus for improving coordination, drawing on the case studies.
4. **Recommendations** – Provides recommended steps for different actors to improve coordination.
5. **Appendix: Case studies** – Describes the four case studies.

1 Background

1.1 Resource and Transmission Planning Interactions and Coordination

Resource planning, resource procurement, generator interconnection, and transmission planning are all part of a suite of interrelated processes that bring new generation resources online and ensure their delivery to loads. We use these four terms broadly in this report to encompass any portfolio planning and procurement by developers, load serving entities (LSEs), transmission owners (TOs), and system operators (Figure 1). While the report primarily focuses on resource and transmission planning, it occasionally touches on procurement and interconnection as well.

FIGURE 1. Interrelationships Among Resource Planning, Resource Procurement, Interconnection, and Transmission Planning



Resource planning and transmission planning have distinct objectives and use different methods. A resource plan uses optimization models to project least-cost combinations of supply-side and demand-side resources needed to reliably meet forecasted demand over a specified time horizon, subject to policy and other constraints. In contrast, a transmission plan uses power flow, production cost, and other models to identify solutions for (a) ensuring reliable operation of the transmission system under normal and contingency conditions and (b) cost-effectively reducing congestion. For a variety of reasons — such as institutional barriers, externalities (both positive and negative), economies of scale and scope, and modeling challenges — integrated generation-transmission expansion planning has proven difficult.[6] As a result, resource and transmission planning have traditionally been separate processes, with planners attempting to address interdependence and interactions through coordination rather than integration.

There are two complementary ways in which resource and transmission planning interact: (1) how the transmission network shapes resource plans and (2) how resources shape transmission plans. Including transmission cost estimates in resource plans can help weigh the tradeoffs between building generation close to energy resources and delivering it via long-distance transmission, versus building generation near load centers. It can also weigh the tradeoffs and highlight the complementarities between battery storage and transmission. Transmission plans, in turn, rely on a representation (amount and location) of net loads and bulk generation and storage facilities, along with the ability of these resources to adjust demand or supply in real-time. This helps assess the reliability and economic needs for new transmission infrastructure.

The interactions between resource planning and transmission also affect regional resource development — resources built, at least in part, to export to non-local buyers, including in other states — and the development of interregional transmission. For example, a vertically integrated utility that has planned for adequate supplies to meet all of its own load has little need or incentive to build new transmission to facilitate imports from neighboring areas. Similarly, the utility is unlikely to plan to rely on imports in its resource plan if it lacks sufficient transmission import capability.

Coordination between resource and transmission planning can also enhance the utilization of existing transmission infrastructure and reduce the need for new transmission. For instance, transmission planning can identify areas of the transmission system that are uncongested and support energy-only resources[7] that lower wholesale electricity costs or contribute to emissions reductions and other state goals but are not needed for resource adequacy (RA). Resource plans can evaluate energy-only resources in these areas and determine whether they might be cost-effective, factoring in curtailment when the transmission system is congested. Additionally, resource and transmission plans can also coordinate on alternative transmission technologies, such as dynamic line ratings or reconductoring.[8] In principle, resource plans can evaluate these transmission technologies alongside new transmission investments, for example, by treating them as selectable resources in capacity expansion models.[9] The evaluation of alternative transmission technologies in transmission planning can, in turn, inform resource plans, through the representation of the transmission system used in resource planning models.

6 These challenges predate the emergence of wholesale markets in the U.S. See Baldick and Kahn (1992).

7 Energy-only resources are resources that are not counted toward resource adequacy. In non-ISO/RTO regions, these would have energy resource interconnection service (ERIS) and non-firm transmission service. In ISO/RTO regions, they would have non-deliverability status and not being eligible to be counted toward resource adequacy.

8 Order 1920 requirements for considering alternative transmission technologies include four technologies: dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching (FERC, 2024, pp. 877-885).

9 Biewald et al. (2024).

1.2 Resource and Transmission Planning in Practice

How resource and transmission plans interact in practice depends on industry structure, which is region-specific and difficult to generalize due to the diversity of transmission and resource planners in the U.S. Transmission planners include multi-state regional transmission organizations (RTOs); single-state independent system operators (ISOs); transmission-owning utilities in RTOs or ISOs (local planning); utility balancing area authorities (BAAs); federal, state, and non-profit cooperative generation and transmission (G&T) providers; a small number of larger municipal utilities (munis); and regional transmission planning associations. Resource planners include vertically integrated investor-owned utilities (IOUs), restructured IOUs that act as default service providers or providers of last resort, munis, rural cooperatives (co-ops), community choice aggregators (CCAs), public utility districts, G&T providers, and competitive retail providers. Munis, co-ops, and competitive retail providers account for a large share (36% in 2023) of U.S. electricity sales.[10]

Resource planning objectives, processes, and methods vary across the different kinds of utilities. Most — but not all — vertically integrated IOUs are required to file formal, public-facing IRPs with state public utility commissions (PUCs).[11] Resource planning by public and non-profit entities is more diverse,[12] but some form of "IRP-like" resource planning is common among G&T providers, munis, and co-ops.[13] In restructured states, resource planning is generally focused on short-term portfolio management, due to concerns around load migration and utility monopsony power. In some restructured regions — the Northeast, New York, and California — state agencies are involved in long-term resource planning, either directly or indirectly by supporting long-term decarbonization studies.[14]

Transmission planning varies by scale and context. Local transmission planning typically refers to planning by utilities and other transmission owners to meet local needs. Regional transmission planning generally refers to planning for transmission that connects individual transmission owners and addresses the needs of multiple transmission owners. Interregional transmission planning refers to transmission that connects different regions and meets the needs of multiple regions. For transmission owners that are part of an RTO or ISO, local transmission planning is integrated into the RTO/ISO transmission planning process. For those that are not, local planning occurs through a separate process.

FERC Order 1000 (2011) requires all FERC-jurisdictional transmission providers to participate in a regional transmission planning process. In RTO/ISO regions, this regional transmission planner is the RTO itself. In non-RTO/ISO regions, a separate regional entity coordinates planning among transmission providers. These regional entities include NorthernGrid (NTTG) and WestConnect in the

10 Munis accounted for 8%, co-ops 11%, and competitive retail providers 18% of sales in 2023 (differences are due to rounding). IOUs accounted for 55% of sales. The remainder includes CCAs, PUDs, and state and federal authorities. Data are from the Energy Information Administration's (EIA's) Form EIA-861, available at https://www.eia.gov/electricity/data/eia861/.

11 For an overview of state-level requirements for IRP, see Biewald et al. (2024).

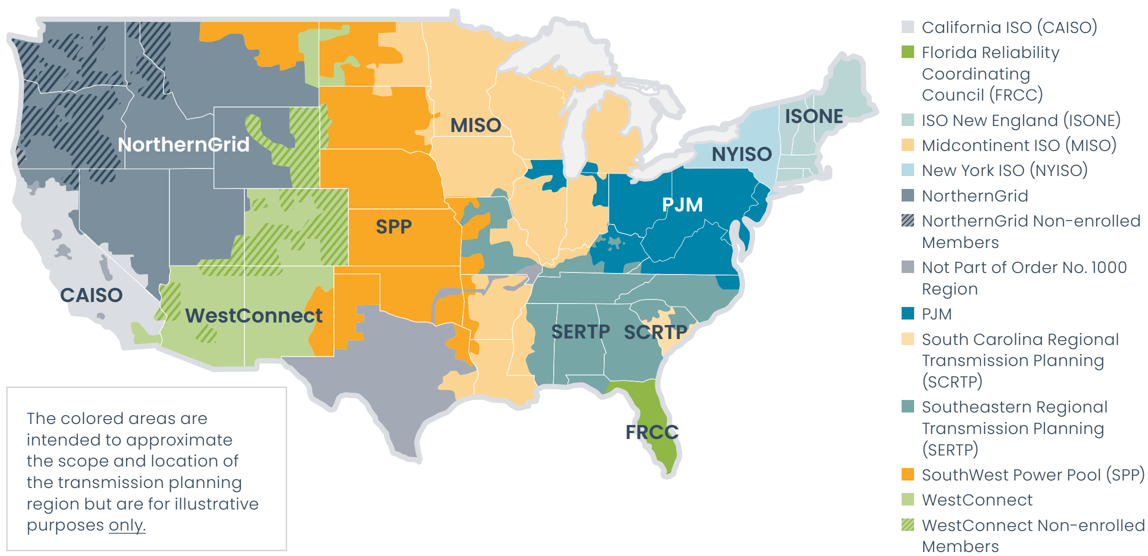
12 For a history of resource planning in the public sector, see Garrick et al. (1993).

13 The two largest of the four federal power marketing administrations (Bonneville Power Administration [BPA] and the Western Area Power Administration [WAPA]) and the Tennessee Valley Authority (TVA) undertake some form of IRP. Some cooperative G&T providers (e.g., Tri-State) publish resource expansion plans but others (e.g., Oglethorpe Power) do not. Most of the larger munis and co-ops appear to do IRP or IRP-like planning. In some cases, the muni or co-op does not do its own resource planning but buys its power from a G&T provider that does IRP.

14 State roles in resource planning range from California's state-wide IRP, which is run by the CPUC, to legislatively mandated state decarbonization planning in Massachusetts.

West, and Southeast Regional Transmission Planning (SERTP), South Carolina Regional Transmission Planning (SCTRP), and the Florida Reliability Coordinating Council (FRCC) in the Southeast.[15] Order 1000 also requires regional transmission providers to coordinate their planning and develop cost allocation methods for interregional transmission. Figure 2 shows regional transmission planning organizations as defined by Order 1000. Interregional transmission refers to transmission between these planning regions.

FIGURE 2. Order 1000 Planning Regions



Notes and source: ERCOT, which covers most of Texas and is in gray here, is not FERC-jurisdictional. Figure modified from https://www.ferc.gov/sites/default/files/industries/electric/indus-act/trans-plan/trans-plan-map.pdf.

At a high level, transmission and resource planning practices can be categorized by region (Table 1). The Northeast and New York have an RTO (ISO-NE) and a single-state ISO (NYISO), respectively. Both regions have retail competition, but state agencies and utilities are active in resource planning. The Mid-Atlantic states[16] have an RTO (PJM), and resource planning practices are a hybrid of utility IRP and state and utility planning. The Southeast and West are characterized primarily by utility transmission and resource planning. The Midwest has RTOs (MISO, SPP) and utility IRP. Texas has a single-state ISO and a competitive retail market, although some larger munis and co-ops conduct IRP-like planning. California also has a single-state ISO, along with a statewide IRP process intended to coordinate resource planning by CCAs and utilities. Within this high-level categorization, many exceptions exist.

15 As of the time of writing, SCTRP was planning to join SERTP. See https://www.scrtp.com/.
16 We include the Midwest states that are part of PJM (Ohio and parts of Illinois, Indiana, and Kentucky) in this region.

TABLE 1. High-Level Categorization of Transmission and Resource Planning in the U.S. by Region

REGION	TRANSMISSION PLANNING	RESOURCE PLANNING
Northeast	Multi-state RTO (ISO-NE)	State and utility planning, retail competition
Mid-Atlantic	Multi-state RTO (PJM)	IRP, state and utility planning, retail competition
New York	Single-state ISO (NYISO)	State and utility planning, retail competition
Southeast	Utility BAAs and TVA, with munis and co-ops	Mostly IRP
Midwest	Multi-state RTOs (MISO, SPP)	Mostly IRP
Texas	Single-state ISO (ERCOT)	Competitive retail and muni/co-op IRP
West	Mostly utility BAAs and G&T providers	Mostly IRP
California	Single-state ISO (CAISO)	Statewide IRP with CCA and utility planning

The four case studies examined in this report capture geographic diversity (West, Midwest, Southeast, Northeast), as well as variation in state IRP requirements, ISO/RTO participation, and state requirements for transmission planning and reporting. Even so, they represent only a subset of the diverse planning arrangements described above. The case studies illustrate how unique geographic, institutional, and regulatory contexts shape interactions between resource and transmission planning, but also how despite that uniqueness some considerations and practices are generally applicable across different contexts.

For most transmission providers, interactions between resource and transmission planning are governed by federal standards of conduct that require separation between wholesale generation and network functions (transmission and distribution) within utilities.[17] These standards were established to prevent transmission-owning utilities from using their knowledge of the transmission system to favor their own generation — for instance, by building transmission that reduces congestion for utility-owned generators while worsening it for non-utility-owned generators. This functional separation has, to some extent, limited coordination between resource and transmission planning.[18] The case studies in this report show how these concerns have been addressed in practice.

1.3 An Evolving Context for Planning

Discussions on the need for coordination between resource and transmission planning have evolved over time: first, as the industry implemented IRPs in the 1980s and 1990s; then through industry restructuring and the transition to wholesale markets in the late 1990s and early 2000s;

17 Since 1996 (Orders 888 and 889), FERC has required jurisdictional public utilities to "implement standards of conduct to functionally separate transmission and wholesale power merchant functions." FERC (1996), p. 1. These rules technically do not apply to transmission providers outside of FERC's jurisdiction (e.g., those in Texas or federal power market authorities).

18 Anecdotally, utilities often erred on the side of being conservative in how they implemented functional separation, leading to significant changes in internal planning coordination. For instance, Entergy's 2002 resource plan notes that "[functional separation] means that resource (generation) planning has become much more complicated, because of the limitations on the information that can be shared between the separated generation and transmission functions" (Entergy, 2002, p. 6).

and more recently, with the declining cost of developing location-constrained, variable wind and solar resources in the 2010s.[19] Challenges to coordination have included a lack of perceived need, analytical complexity, software limitations, market efficiency concerns, utility incentives, and issues related to transmission cost allocation. Several of these challenges persist.

However, the context for these discussions is shifting, and there may now be greater momentum for improving coordination than in the past. Recent changes influencing resource-transmission planning coordination include:

- **Wind and solar economics** – A major shift in resource plans toward expanding location-constrained wind and solar resources, where incremental, location-specific transmission costs play an important role in determining overall project value.
- **Generator retirements** – Growing resource adequacy concerns driven by retirement of older generation — issues that could be addressed through either new local generation or additional transmission.
- **Lower cost battery storage** – The emerging potential for storage to serve as a cost-effective alternative to new transmission investments in some cases.
- **Load growth** – Rapid and geographically concentrated increases in electricity demand across many U.S. regions.
- **Federal requirements** – FERC Order 1920 requires transmission providers to conduct scenario-based transmission planning over a 20-year horizon.
- **State participation in transmission planning** – Increasing interest from states in taking a more active role in transmission planning processes, enabled by a regulatory framework established in FERC Order 1920 and its follow-on orders (1920A and 1920B).
- **Extreme weather** – More frequent severe heat waves, wildfires, cold snaps, and storms, resulting in lost load or emergency operating conditions that might have been alleviated through additional local resources or interregional transmission.
- **Concern over rising transmission costs** – Growing concern among state agencies and other stakeholders over the cost of transmission investments.

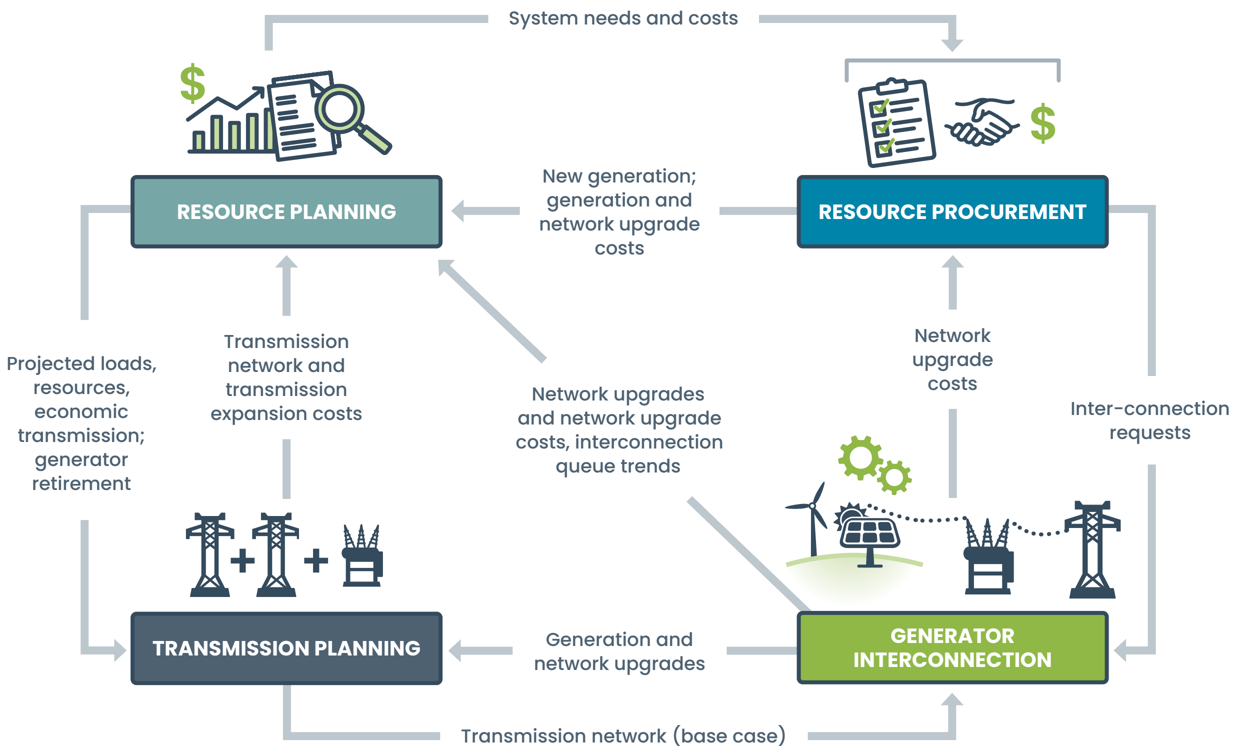
Despite growing interest in improving coordination between resource and transmission planning, identifying where to focus those efforts remains challenging. The remainder of this report aims to offer guidance on strategies for enhancing coordination. Section 2 outlines an idealized framework for coordination. Section 3 highlights key focus areas for improvement. Section 4 provides recommended steps for different actors. Section 5 presents case studies that illustrate coordination efforts across a range of transmission operator backdrops.

19 For overviews, see Baldick and Kahn (1992), Hobbs (1995), Baughman et al. (1995), Sauma and Oren (2006), Stoft (2006), Chao and Wilson (2013), and Liu et al. (2013).

2
Idealized Coordination

Figure 3 illustrates idealized information flows among resource planning, transmission planning, generator interconnection, and resource procurement in a generic context.

FIGURE 3. Information Flows Among Resource Planning, Transmission Planning, Resource Procurement, and Generator Interconnection



In this idealized process, resource planning provides transmission planning with information on projected loads, resources, new economic transmission, and generator retirements. It also supplies system needs and cost data to inform resource procurement. Transmission planning, in turn, supplies resource planning with network topology and cost estimates for new transmission, and provides a base case for interconnection studies. Generator interconnection contributes data on siting trends for interconnection requests, pending network upgrades, and associated cost estimates to resource planning; information on generator interconnection agreement and network upgrades to transmission planning; and information on network upgrade costs to resource procurement. Resource procurement provides information on new generation and network upgrade costs to resource planning and prompts new interconnection requests.

What these relationships look like in practice varies substantially across jurisdictions, as illustrated by the case studies in Section 5. These interactions depend on factors such as whether the state has IRP and transmission planning requirements, whether TOs participate in an ISO/RTO, and other location-specific considerations. Despite this variation, the idealized information flows in Figure 3 offer a useful reference point for gauging whether coordination is working effectively in practice.

3
Key Themes and Focus Areas for Improving Resource and Transmission Planning Coordination

This section identifies key themes and focus areas for improving resource and transmission planning coordination, drawing on insights from the case studies. The themes and focus areas are organized under three headings:

- **Cross-cutting issues** – Themes that are common to both resource and transmission planning.
- **Resource planning** – Areas where coordination can be strengthened within resource planning models and processes.
- **Transmission planning** – Areas where coordination can be improved within transmission planning models and processes.

3.1 Cross-Cutting Issues

The case studies highlight four cross-cutting themes that influence the effectiveness of coordination efforts:

- **Iterative, adaptive planning** – Do planning processes allow resource and transmission planning to co-evolve as new information about the future becomes available?
- **Open access rules** – How can information be shared across resource and transmission planning processes without violating FERC's codes of conduct for open access transmission?
- **Integrated system planning** – What organizational structures or changes can help align resource, distribution, and transmission planning more effectively?
- **States' roles and responsibilities** – What kinds of institutional arrangements can best position state PUCs and energy offices to fulfill their roles and responsibilities in coordinating between resource and transmission planning?

Iterative, adaptive planning. Neither resource nor transmission planning is meant to deliver a rigid blueprint for future investments. Rather, the goal of long-term planning is to provide longer-term visibility — based on current understanding of future technologies and costs — that can inform near-term decision-making. Through iterative and recurring resource planning, near-term investment decision-making can adapt — with projects going ahead or being postponed or cancelled — as future conditions become clearer. Transmission development lead times are generally much longer than those for generation and storage, but even in a 10-year transmission plan not all projects that are identified or approved will need to begin within the next year. Projects that do not address urgent needs can remain in a portfolio of potential solutions and be reassessed as conditions evolve.

Many planners already incorporate aspects of this iterative, adaptive approach. However, as transmission planning horizons extend to 20 years — and as more utilities align their planning with long-term decarbonization goals — it will become more important to be clear about the difference between needs that are part of a near-term action plan and those that can continue to be monitored and assessed in the next or a later planning cycle. Having resource and transmission plans that both extend 20 years or more also underscores the need for improved coordination — resource and transmission plans should co-evolve over time.

Open access rules. The need for strict codes of conduct limiting transmission providers' strategic use of generation information has not diminished since these rules were established in the late 1990s. The case studies in this report illustrate how potential conflicts of interest can be addressed in practice through transparency and rules-based processes. In a non-ISO context (PacifiCorp [Section 5.1], Duke [Section 5.3] case studies), transmission-owning utilities can use information from utility IRP in transmission planning, but this information must be available to all transmission customers, and the transmission planning process must be sufficiently open and transparent that other transmission customers can meaningfully weigh in on resource scenarios and cost allocation mechanisms in transmission planning. In Duke's case, conflict of interest concerns were addressed by creating a third party — the Carolinas Transmission Planning Collaborative (CTPC) — to administer the transmission planning process. Visualization tools such as the congestion heat maps required by Order 2023 can also support transparency by aggregating data and ensuring that all transmission customers have access to the same information.

In RTO/ISO contexts, conflict of interest concerns are also addressed by having a third party — the RTO or ISO — run the transmission planning process. However, transmission-owning utilities can still exert undue influence if they possess more detailed information on local resources and transmission than the RTO/ISO and use that advantage strategically. For example, a vertically integrated utility might propose new transmission projects through the RTO/ISO planning process that disproportionately benefit the utility, based on its own load and generation forecasts. To limit this influence, as in MISO (NSP case study, Section 5.2.2), it is important that the RTO/ISO plays an active gatekeeper role in evaluating transmission owner-proposed transmission projects and assessing alternatives from a regional system perspective.

Integrated system planning. Both Duke (Section 5.3) and NSP (Section 5.2) created new departments to encourage more integrated planning across distribution, transmission, and resources. In principle, integrated system planning departments may help overcome utility departmental "silos." However, it is worth considering what the goals and functions of integrated planning departments will be. For instance, should integrated planning departments do their own planning or should they be primarily tasked with improving coordination among other planning departments? Creating a separate integrated planning department will not, in and of itself, lead to more integrated or even coordinated planning.

Based on the case studies, the most important components of planning integration — in this report, "coordination" — are likely to include information sharing among planning departments, alignment of planning processes, and sharing expertise across departments. *Information sharing* includes diverse data from a range of different processes, such as load and DER forecasts, resource portfolios, and scenarios from resource plans; data on costs, locations, and parameters from interconnection requests and studies; data on transmission system topology and capacity limits from transmission planning; and historical and forecasted load, wind, and solar data and weather information from across different planning domains. *Process alignment* means that when data is updated in one planning process it can be updated in another process in a meaningful way. *Sharing expertise* means that resource planning staff have some transmission planning knowledge and transmission planning staff have some resource planning background. For utilities, sharing expertise does not require shared staff, which is not permitted under FERC codes of conduct. Instead, it could mean that transmission staff provide regular trainings to all transmission customers, including utility generation business units. Ultimately, effective information sharing, process alignment, and shared expertise all require thoughtful, intentional design.

States' roles and responsibilities. States will likely play a larger role in transmission development over the next decade, both through local transmission planning to address local resource needs and through regional and interregional long-term scenario planning that complies with FERC Orders 1920, 1920-A, and 1920-B. State participation in RTO regional and interregional planning may be direct or through regional organizations — the Organization of MISO States, the New England States Committee on Electricity, the New England Conference of Public Utility Commissions, the Organization of PJM States, Inc., and the Southwest Power Pool's Regional State Committee. Because states have jurisdiction over resource planning for their energy providers, state agencies have an important role in thinking through, evaluating, and overseeing coordination between resource and transmission planning.

Several states have established new organizations dedicated to transmission — such as Colorado's Electric Transmission Authority and New Mexico's Renewable Energy Transmission Authority (RETA)[20] — with varying objectives and functions. These dedicated organizations may help consolidate state transmission responsibilities and develop the state-level expertise necessary for effective and efficient transmission development. However, before creating a separate transmission organization it will be useful to assess current and anticipated future state transmission-related responsibilities, how these intersect with or overlap with those of FERC, RTO/ISO, and transmission owner responsibilities, and whether a new organization is warranted. This mapping of responsibilities can also help states identify where relevant expertise exists or is lacking — for instance, in areas such as transmission-related policy, planning, ratemaking, permitting and siting, and engineering.

20 CETA was created "to plan and develop electric transmission corridors and power lines in the state for the purpose of increasing grid reliability, helping Colorado meet its clean energy goals, and aiding in economic and community development," https://www.cotransmissionauthority.com/. RETA "facilitates planning, financing, developing and acquiring high-voltage transmission lines and utility-scale storage projects to promote the expansion of carbon-free renewable energy use in local and regional markets and enhance economic development in New Mexico," https://nmreta.com/.

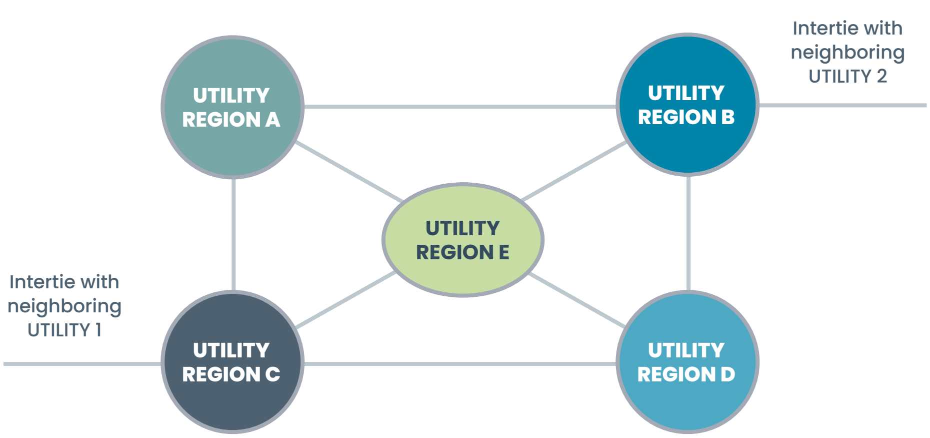
3.2 Resource Planning

The case studies highlight four focus areas for resource planning:

- **Transmission in resource planning models** – How are transmission costs and constraints incorporated into resource planning models?
- **Imports and exports** – How are imports from and exports to neighboring LSEs or balancing areas (BAs) represented in resource planning models?
- **Storage, demand-side management (DSM), and transmission** – How do energy storage, DSM, and new transmission interact in resource planning analyses?
- **Energy-only resources** – How are resources that have no RA credit and do not require transmission deliverability (energy-only resources) treated in capacity expansion models?

Transmission in resource planning models. Including transmission constraints and costs in resource planning models can improve the optimization of resource portfolios and provide insight into where new transmission may be cost effective over both nearer (less than 10 years) and longer-term (more than 10 years) planning horizons. Transmission can be included in different stages of resource modeling. In the capacity expansion stage, planners can include a simplified representation of the transmission system ("bubbles and pipes," see Figure 4) and allow models to build new transmission where it is cost-effective (see PacifiCorp case study, Section 5.1.1).[21] In the production simulation stage, planners can incorporate a more detailed representation of the transmission system and run sensitivities with and without new transmission to evaluate impacts on production costs, reliability, and emissions (see Section 5.1.1). Incorporating transmission constraints into planning analyses requires the added step of assigning different locations and location-specific profiles to loads and resources. In capacity expansion models, including more detail on the transmission system may require reducing detail in other areas, such as the number of time periods being modeled.

FIGURE 4. Simple Illustration of Bubbles and Pipes Representation of Transmission



21 More detailed spatial and physical representations of the transmission are possible, for instance, by including some DC power flow logic to capture the physics of power flow. However, more detail must be weighed against increased computational time. Mai et al. (2015), for example, found that adding DC power flow greatly increased run time but did not lead to significant differences in results.

Historically, many utilities have not included the transmission system or spatial detail in their resource planning models.[22] An alternative to including transmission directly in capacity expansion models, illustrated in two of the three utility case studies (Northern States Power, or NSP, in Section 5.2.1, Duke in Section 5.3.1), is to apply transmission cost adders to different kinds of resources. So long as the transmission costs are accurate, this approach can help make appropriate tradeoffs between resources with lower and higher expected transmission costs. However, if transmission cost adders are inaccurate or overly aggregated, this approach can lead to resource portfolios that do not reflect realistic transmission constraints and costs. It also does not directly help identify where new transmission may be cost-effective.

Whether the benefits of including transmission constraints and allowing transmission to be built in models outweigh the costs will be case-specific. It will depend on the size of the transmission system being modeled and the spatial variability in loads, generation resources, and resource costs. As a reference point, however, previous studies have shown that spatial detail can have a larger impact on the results of capacity expansion models than temporal detail.[23] This suggests that larger utilities that conduct resource planning should at least rigorously explore whether the added value of including transmission justifies the additional modeling effort. Some of the issues highlighted in the case studies — such as congestion-driven wind curtailment in NSP (Section 5.2) and solar interconnection bottlenecks in Duke (Section 5.3) — might have been anticipated by including transmission in IRP models. Many resource planning models now offer transmission functionality.[24]

Including transmission in capacity expansion and production simulation models used in resource planning is a complement, not a substitute, for the modeling conducted by transmission planners. In capacity expansion, new transmission is built for what are ultimately economic reasons — reducing costs for energy, emission reductions, or RA — rather than to address transmission system reliability violations per se.[25] Conventional production simulation models will not be able identify all potential reliability violations because, for instance, they do not include alternating current (AC) power flow.

Imports and exports. Electricity imports from neighboring regions can provide lower-cost RA, reduce energy and reserve costs, and change the economics of local resources. Exports can provide additional revenues that offset LSE costs and improve the economics of local resources by spreading capital costs across a broader customer base. Both imports and exports are enabled by regional or interregional transmission and markets or bilateral agreements that facilitate trade.

The case studies illustrate the different approaches that utilities take to modeling and evaluating imports, exports, and regional transmission in IRP. PacifiCorp (Section 5.1.1) and NSP (Section 5.2.1) used forecasted market prices as a proxy for resource dispatch in neighboring regions in IRP

22 Reviews done in the early 2010s found that few utilities included transmission in resource planning models (Mills and Wiser, 2012; Sterling et al., 2013).

23 See, for instance, Mai et al. (2015).

24 For a review of different models and whether and how they incorporate transmission, see Appendix B of ESIG (2024).

25 In principle, under FERC's categorization of projects established in Order 1000, transmission built in a capacity expansion model with the objective of reducing costs would be for economic rather than reliability reasons. In practice, however, the line between economic and reliability transmission can be blurry; some reliability concerns — such as contingencies, voltage issues, and system protection needs — examined in a transmission plan would not be considered in resource plans.

modeling.[26] Duke (Section 5.3.1) included external transactions with firm transmission reservations but not short-term economic transactions. PacifiCorp's capacity expansion analysis allowed new transmission to be built between its system and other regions, but NSP's and Duke's analyses did not. Both Duke and NSP expressed concerns about relying on imports but did not conduct more rigorous assessments of the potential benefits and risks.

Resource planning approaches may create barriers to regional transmission development. If utilities develop resource plans in which their own resources are sufficient to cover their forecasted loads in all or most hours, the perceived value of regional transmission may be relatively low.[27] Different jurisdictions will differ in the level of market exposure they are comfortable with, but those decisions should be informed by a transparent analysis and weighing of benefits and risks. PUCs that want utilities to consider regional transmission opportunities, such as the North Carolina Utilities Commission (NCUC) in the Duke case study, may also need to request that utilities evaluate more open import and export positions in their capacity expansion and production simulation modeling.

Resilience is another important consideration for imports. During extreme weather events, for instance, imports can reduce the need for local load shedding. However, resilience can also be provided by local resources. Resource planning tools can assess tradeoffs between investing in local, low-capacity-factor resources to manage infrequent, high impact events versus more transmission capacity to increase imports during these events. None of the LSEs in the case studies have yet included resilience analysis in their IRP modeling, but this is an important area for future coordination between resource and transmission planning.

Storage, DSM, and new transmission. In principle, transmission should be highly interactive with bulk power system energy storage and demand-side management. Siting storage or DSM on the high-cost side of a transmission constraint may reduce the need for new transmission, while new transmission will generally reduce the value of storage and DSM. Whether storage can economically substitute for new transmission depends on the frequency and magnitude of congestion — factors that can be evaluated by including transmission constraints in both capacity expansion and production simulation models, and by allowing new transmission to be built in capacity expansion models. Without including transmission in models, however, it is difficult to capture the locational value of storage.

There are multiple ways to capture interactions between DSM and transmission. Some utilities — such as NSP (Section 5.2.1) — allow incremental DSM to be selected as a resource in capacity expansion models. Holding all else equal, including transmission costs in these models — either as an adder to resource costs or by including transmission in the model — will tend to increase the amount of DSM procured in transmission-constrained areas. Including DSM and transmission in the capacity expansion model can provide spatial information to help target DSM programs. If the

26 Alternative approaches to using market prices would be to either model a larger region in a capacity expansion model or include regional resource plans developed, for instance, through regional transmission planning processes using production simulation modeling.

27 Serving load with local resources and limiting market exposure reduces both the high-priced hours (capacity constraints) and the low-priced hours (curtailment) that might otherwise make regional transmission cost-effective. However, the basic economics of trade and comparative advantage suggest that serving all or most of an LSE's local load with local resources is unlikely to be least-cost.

model includes transmission but not DSM — as in the PacifiCorp case (Section 5.1.1) — shadow prices from the model can still help with targeting. Alternatively, deferred or avoided transmission costs can be separately included in DSM program evaluation, rather than including DSM as a resource in capacity expansion models.

Energy-only resources. Not all resources need to be fully deliverable for RA purposes. For example, a wind project might be part of a utility's cost-minimizing resource portfolio even if it is not counted toward the utility's RA requirement. Resources that are not fully deliverable (energy-only resources) will tend to have lower incremental transmission costs associated with them because they can be curtailed if the transmission system is constrained. Historically, most utilities have required that all new owned or procured resources be fully deliverable, and none of the utilities in the case studies evaluated energy-only resources in their IRP. Some PUCs — such as the North Carolina Utilities Commission (NCUC), discussed in the Duke case study (Section 5.3.1) — are beginning to require that utilities explore the inclusion of energy-only resources in IRP and procurement processes.

In principle, energy-only resources can be evaluated in capacity expansion models as resources that have no capacity credit, no assigned transmission costs, and full curtailability. In interconnection, these resources would have energy-only (or energy resource interconnection service [ERIS]) status. In transmission planning, they would be treated as resources that are fully curtailable and are not studied for deliverability.

3.3 Transmission Planning

The case studies highlight two focus areas for transmission planning:

- **Loads and resources in long-term transmission planning** – How are location-specific load and resource inputs developed for use in transmission planning models?
- **Transmission-resource planning linkages** – Can transmission projects identified in LSE resource planning be developed through regional transmission planning?

Loads and resources in long-term transmission planning. The case studies illustrate the range of approaches to including loads and resources in transmission planning, from long-term load and resource forecasts (MISO Long-Range Transmission Planning, or LRTP, and ISO-NE Longer-Term Transmission Planning, or LTTP), to shorter-term to medium-term load and resource forecasts (PacifiCorp), to short-term load forecasts using existing or near-existing resources (CTPC). FERC Order 1920 requires all transmission operators to undertake scenario-based planning over a 20-year horizon, which will involve developing some form of long-term resource forecast. This may take the form of transmission providers aggregating the load forecasts of their member LSEs, or creating their own forecasts based on thematic scenarios.

Different regions face different obstacles to developing load and resource forecasts for long-term transmission planning. ISO-NE's *2050 Study* and LTTP process (National Grid case study, Section 5.4) illustrate some of the challenges that ISOs/RTOs in restructured states will face in developing longer-term resource plans. Most of the New England states are restructured and, though few utilities in the region conduct long-term resource planning, a growing number of distribution utilities — such as

National Grid — conduct distribution-focused planning that includes long-term forecasts for load and distributed generation.[28] ISO-NE has begun building bottom-up load forecasts that incorporate electrification as part of its 10-year transmission plan. The LTTP process will require long-term forecasts of both loads and resources.

For the *2050 Study*, ISO-NE used regional inputs developed for Massachusetts' *Deep Decarbonization Roadmap*. However, for future iterations of the LTTP process, ISO-NE will need to develop its own regular, scenario-based long-term load forecasts and resource projections that have buy-in from its member states. This could be achieved through a single process in which ISO-NE and state agencies (via NESCOE) jointly develop scenarios and review model inputs, or through parallel processes in which ISO-NE develops its own capacity expansion model, NESCOE member states support their own models, and all stakeholders converge on consistent inputs and scenarios.

The inputs used in ISO-NE's scenarios do not need to be identical to state-level forecasts, but it should be clear why they differ. For instance, ISO-NE may have a different forecast of EV adoption and load in Massachusetts than what the Massachusetts distribution utilities use in their Electric Sector Modernization Plans, but Massachusetts state agencies should be able to understand the reasons for these differences and, ideally, how differences might affect the results. This underscores the importance of transparency in data assumptions, inputs, and analysis.

The challenges of long-term load and resource scenario development may be less pronounced for RTOs that can rely on utility IRPs as inputs to long-term scenario planning, as illustrated by MISO's LTPP process (NSP case study, Section 5.2.2). However, even in MISO's case, there is the added difficulty of siting resources with the spatial granularity needed for transmission planning models. Including at least a high-level representation of the transmission system in capacity expansion models used to develop resource inputs for transmission planning could help to more realistically site resources. Currently, most transmission planners (CTPC, ISO-NE, MISO in the case studies in this report) appear to be using algorithms to site resources for their models.

28 See https://emp.lbl.gov/state-distribution-planning-requirements for a database of state-level distribution planning requirements.

Transmission-resource planning linkages. To enable transmission opportunities identified in resource planning to be built, there must be a pathway between resource planning and the transmission planning process. In all of the case studies, some form of this pathway already exists, though it is different in each case study. PacifiCorp (Section 5.1) runs both an IRP and a multi-state transmission planning process, which means that the pathway from transmission identified in a resource plan and transmission development is more seamless. For NSP (Section 5.2), that pathway is more complicated. MISO manages the transmission planning process, but NSP and other transmission-owning utilities can propose new transmission, which MISO evaluates, and pay for it themselves if they choose.

In parts of the Carolinas (Duke case study, Section 5.3), the non-profit CTPC provides a forum for transmission planning. Its public policy request mechanism and forthcoming multi-value strategic transmission process allow stakeholders to examine transmission needs related to longer-term resource forecasts. In Massachusetts and other New England states (National Grid case study, Section 5.4), state-supported, long-term resource and decarbonization plans can help shape ISO-NE's transmission plans through the LTTP process. While there can be friction in these pathways between resource planning and transmission planning, the fact that some regions are able to overcome such challenges suggests that these linkages need not be a barrier to greater consideration of transmission in resource planning.

4
Recommendations

Improved coordination may require changes in both resource and transmission planning practices, many of which will be jurisdiction-specific and developed through stakeholder processes. The recommendations in this section are therefore framed as broadly relevant areas to explore, rather than as prescriptive guidance. For each recommendation, the relevant actors are listed in parentheses.

Cross-Cutting Issues

- **Functional separation.** Some improvements in coordination between resource and transmission planning may generate open access or other conflict of interest concerns. In such cases, review existing practices and determine whether more transparency is needed in the information that is shared or in the process, and whether additional rules and safeguards are needed to mitigate conflicts of interest. (PUCs, FERC)
- **Integrated versus coordinated planning.** As an alternative to an integrated planning department, consider different approaches to planning coordination by thinking through which departments are best placed to do what kind of planning, which data and expertise need to be shared across departments, how planning processes can be aligned, and what kinds of organizational changes are needed for better coordination. (Utilities)
- **State transmission agencies.** In some states, transmission-related roles and responsibilities are expanding. Before setting up a new state transmission agency, consider developing an inventory of roles and responsibilities, analyzing any organizational changes needed to fulfill responsibilities, and identifying any longer-term needs for staffing and expertise to determine whether a new organization would be justified or whether there might be other alternatives. (PUCs, state energy offices)

Resource Planning

- **Incorporation of transmission in resource planning models.** Explore whether and how to incorporate transmission constraints, costs, and spatial detail for loads and resources in capacity expansion models and production simulation models used in resource planning, even for utilities that are in RTO regions.[29] The aim is to identify opportunities for economic transmission and optimize tradeoffs between transmission and resource investments, in order to complement but not replace transmission planning. The PacifiCorp case study (Section 5.1.1)

29 Biewald et al. (2024) include consideration of transmission alternatives and infrastructure expansion as a best practice in integrated resource planning.

illustrates how transmission can be incorporated into resource planning in practice. (Utilities, PUCs, stakeholders)

- **Transmission alternatives.** Review whether and how energy storage and demand-side resources can offset new transmission investments in resource planning models. (Utilities, PUCs, stakeholders)
- **Regional and interregional transmission drivers.** Review how imports and exports are treated in IRP models and whether the benefits of utilities taking more open market positions — either as importers or exporters of capacity and energy — outweigh the costs and risks. If utilities plan to build or procure resources to supply all or most of their needs, then the resource adequacy value of regional and interregional transmission may be limited. (Utilities, PUCs, stakeholders)

Transmission Planning

- **Long-term transmission planning.** In FERC-jurisdictional RTO and independent system operators (ISO) regions complying with Order 1920 (and subsequent orders 1920-A and 1920-B), consider what the process for developing load and resource scenarios for long-term transmission planning will look like — how much modeling will be involved; who will do the analysis; how states, transmission owners, and market participants will review scenarios and inputs; how differences in resource forecasts will be reconciled, and how any transmission costs will be allocated. (RTOs/ISOs, state agencies, market participants, stakeholders including customers and advocates)
- **Incorporation of transmission in resource forecasts.** Explore the inclusion of transmission constraints and costs and spatial detail for resources in models used for projecting long-term resource expansion. Including spatial detail in modeling and analysis for long-term resource projections may be more accurate than using high-level algorithms to site generation and storage for inputs in long-term transmission plans.
- **Resource adequacy and regional transmission.** Examine and better understand the potential roles of transmission in supporting resource adequacy across multi-state regions. (RTOs/ISOs, non-RTO regional transmission planners, state agencies, market participants)

5
Appendix
Case Studies

This section describes the four case studies: PacifiCorp, Duke Carolinas, Northern States Power, and National Grid Massachusetts. Each case study is organized into two sections: (1) transmission in resource planning — how transmission is represented in resource plans; and (2) resources in transmission planning — how resource planning is coordinated with transmission planning. Each section is guided by a set of framing questions.

For **transmission in resource planning**, framing questions include:

- How are transmission costs and constraints incorporated into resource planning models?
- How are imports from and exports to neighboring LSEs or balancing areas (BAs) represented in resource planning models?
- How do energy storage, DSM, and new transmission interact in resource planning analyses?
- How are resources that have no RA credit and do not require transmission deliverability (energy-only resources) treated in capacity expansion models?
- To what extent does interconnection data inform resource planning?

For **resources in transmission planning**, framing questions include:

- How are load and resource forecasts (including additions and retirements) incorporated into local and regional transmission planning studies?
- To what extent and how do transmission providers and TOs plan for new transmission to relieve congestion caused by new generation?

Framing questions that cut across both areas ("cross-cutting areas") include:

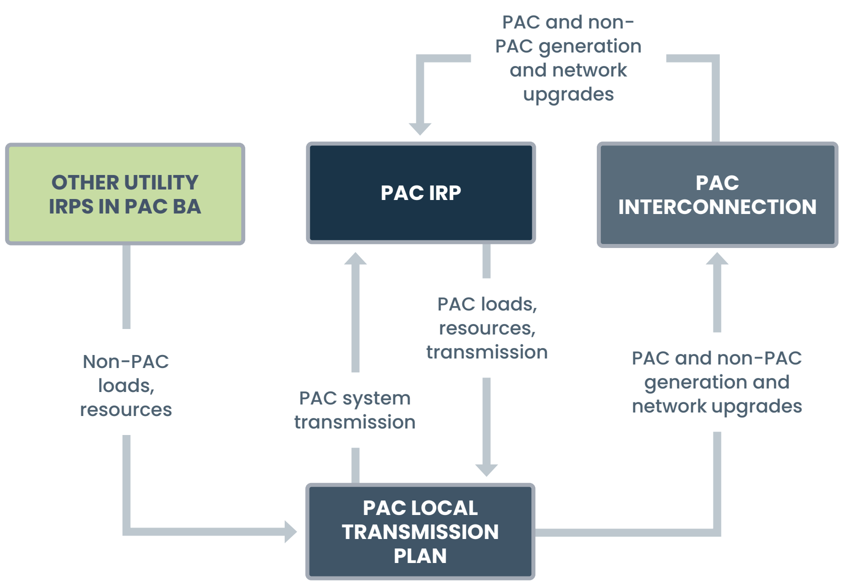
- Do planning processes allow resource and transmission planning to co-evolve as new information becomes available?
- How do local resource and transmission planning intersect with regional resource and transmission planning?
- How can information be shared across planning processes without violating FERC codes of conduct for open access transmission?
- What organizational changes can better align resource, distribution, and transmission planning?
- What kinds of institutional arrangements can best position state PUCs and energy offices to fulfill their roles and responsibilities in coordinating between resource and transmission planning?

5.1 PacifiCorp (Non-ISO, IRP, no state transmission)

PacifiCorp is a multi-state utility in the Western U.S., covering parts of California, Oregon, and Washington (Pacific Power) and Idaho, Utah, and Wyoming (Rocky Mountain Power). It is a vertically integrated, investor-owned utility but also acts as a transmission provider for other utilities within its BA.[30] PacifiCorp is not part of an RTO but participates in the Western Energy Imbalance Market (EIM) and has committed to participate in the CAISO's extended day-ahead market when it becomes operational in 2026.[31]

PacifiCorp's biennial IRP covers its entire six-state service territory. It also has a local transmission planning process and administers a generator interconnection process, both of which are FERC-jurisdictional and must accommodate the needs of other LSEs within the PacifiCorp footprint. Recent changes in planning methods and processes, driven both by regulatory guidance and corporate strategy, have sought to better coordinate among these three processes. (Figure 5 shows the flows of information that aim to coordinate among processes.) PacifiCorp also runs a competitive all-source solicitation process (not shown in Figure 5) that provides input into its IRP.

FIGURE 5. Illustration of Information Flows Between PacifiCorp IRP, Local Transmission Planning, Regional Transmission Planning, and Interconnection Processes



Notes: PAC is PacifiCorp. G&T is generation and transmission. BA is balancing area.

PacifiCorp's historical approach to planning used resource portfolios developed in its IRP as inputs into its transmission planning processes. However, given the long lead times for transmission development and the variability in resource portfolios, this approach resulted in a disconnect between new resources and new transmission, in which new transmission was never completed

30 A balancing area is a part of the electricity system for which a system operator is responsible for maintaining frequency balance.
31 See "PacifiCorp formally commits to California ISO's EDAM" (April 26, 2024), https://www.pacificorp.com/about/newsroom/news-releases/california-iso-edam.html.

in time as new resources came online and short-term fluctuations in resource portfolios did not provide the stability needed for long-term transmission investments. Changes to the IRP and transmission planning processes sought to provide greater complementarity between the two.[32]

5.1.1 Transmission in Resource Planning

PacifiCorp's IRP is a 20-year scenario-based plan that culminates in a preferred portfolio of resources and new transmission investments. In PacifiCorp's 2023 IRP, these transmission investments included some transmission facilities that are already under construction, network upgrades that were identified through interconnection studies, and new transmission expansion that is determined to be cost-effective in the IRP modeling.

PacifiCorp uses a combination of analysis tools in its IRP.[33] It uses a long-term (LT, capacity expansion) model to develop resource portfolios, uses a medium-term (MT) model to calculate risk metrics for portfolios identified in the LT model using day sampling, and uses a short-term (ST, production simulation) model to evaluate the cost, emissions, and reliability (unserved energy) of those portfolios on an hourly basis over the entire 20-year planning horizon.

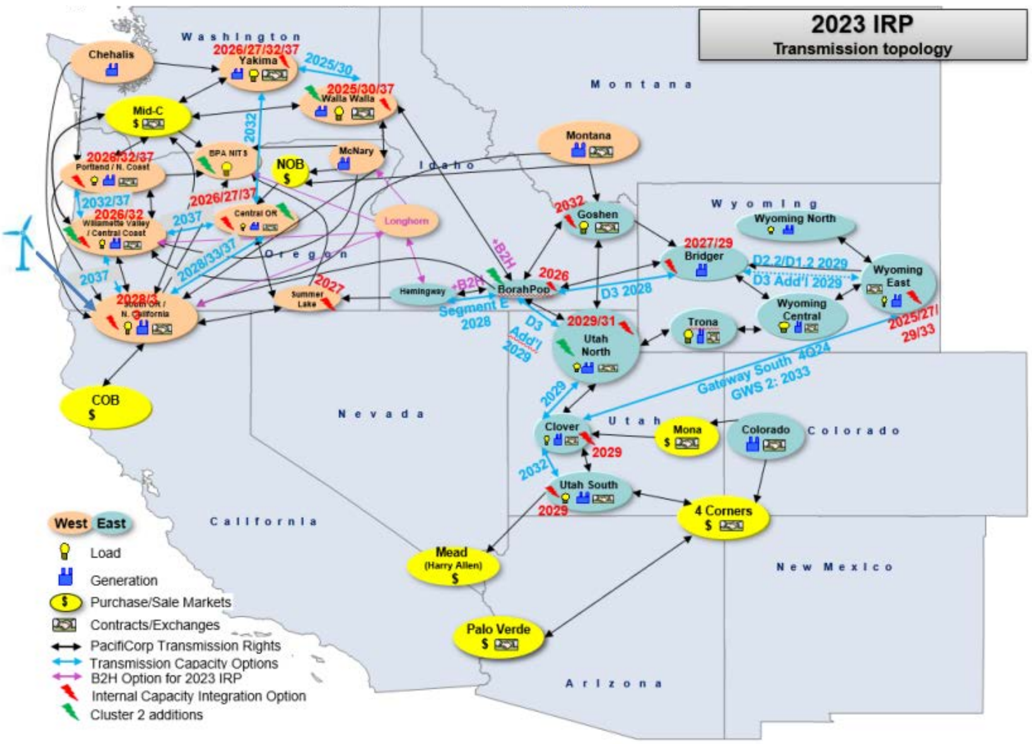
In its 2023 IRP, the LT model included a high-level representation of PacifiCorp's transmission system (Figure 6), with load and resource zones connected by transmission paths that have capacity (MW) limits. Transmission capacity in the LT model included existing firm transmission rights, surplus interconnection capacity, transmission capacity freed up by retiring resources, and network upgrades identified in interconnection studies.[34]

32 PacifiCorp (2023a), pp. 100-105.

33 All of the information in this section is based on the 2023 IRP (PacifiCorp [2023a]).

34 In this context, surplus interconnection capacity refers to transmission capacity that is not fully utilized by a resource. PacifiCorp's LT model allows for endogenous retirement of existing units. For a historical overview of transmission modeling in PacifiCorp's IRP, see PacifiCorp (2021).

FIGURE 6. Illustration of Transmission Topology in PacifiCorp's 2023 IRP[35]



The LT model also allowed new transmission capacity to be added to a portfolio when doing so reduced the portfolio's costs (present value of revenue requirement, or PVRR) over the planning horizon. The 2023 IRP did not describe in detail how new transmission costs were estimated or the increments of and limits on additions of new transmission capacity, other than noting that both resource locations and transmission costs and locations were informed by interconnection studies.[36] The 2023 IRP allowed battery storage to be sited in any location without restriction, enabling batteries to substitute for new transmission investments in the LT model. It also incorporated the transmission deferral value of energy efficiency through a fixed transmission deferral value.[37]

In addition to endogenous modeling of new transmission, PacifiCorp's 2023 IRP also examined the effects of delays in transmission construction, exclusion of some transmission options, and inclusion of additional transmission as sensitivities ("variants") on its preferred plan. These evaluations used the ST (production simulation) model and focused on resource and cost impacts.

35 Figure is from PacifiCorp (2023a).

36 In the note to Table 1.2 (PacifiCorp [2023a], p. 13), PacifiCorp specifies that, "transmission upgrades are generally modeled as all or nothing options," but that "… partial transmission builds … were allowed in the second half of the 2023 IRP planning horizon…" which suggests that the LT model can initially only add transmission capacity in discrete MW amounts but has more flexibility in later years. However, an earlier PacifiCorp presentation (PacifiCorp, 2021) suggests that transmission is modeled as a continuous quantity with a min, max, and lead time. In its 2023 IRP, PacifiCorp noted that "… the endogenous modeling of transmission was enhanced to leverage cluster study data to inform the amounts, types and locations of proxy resources so as to align better with probable near-term projects and their transmission dependencies" (p. 23). Cluster study data appears to be mainly used for shorter-term resource locations and upgrades: "… many of the transmission upgrades and resource additions in the first five years of the IRP preferred portfolio reflect cluster study requests submitted in the past two years" (p. 12).

37 This fixed value ($5.09/kW-yr) likely reflects an average rather than a marginal transmission cost.

PacifiCorp's modeling approach also enabled limited analysis of interregional transmission investments. PacifiCorp relies on market purchases (imports) to meet some of its RA requirements and reduce short-run operating costs. Imports are modeled as market prices and quantities rather than specific resource types. If imports are lower cost than local supply and transmission is capacity constrained, the model will build new transmission between PacifiCorp and neighboring areas. The 2023 IRP did not describe assumed limits on imports, if any.[38]

5.1.2 Resources in Transmission Planning

Separately from its resource plan, PacifiCorp undertakes biennial Local Transmission System Plans (LTSPs) for its combined system and participates in a regional transmission planning process administered by NorthernGrid. LTSPs, which have a 10-year planning horizon, evaluate the ability of the transmission system to meet reliability criteria set by PacifiCorp's regional reliability coordinator (RC West). PacifiCorp's planning documents have not yet incorporated changes that will bring it into compliance with FERC Order 1920.

PacifiCorp's transmission planning study begins with models of the existing transmission system, including transmission infrastructure that has already begun construction. Load forecasts are ostensibly consistent with those used in IRP, though this is not stated explicitly in PacifiCorp's *Transmission Planning Practices Document*.[39] New resource additions are consistent with the preferred portfolio in PacifiCorp's IRP, based on the assumption that future interconnection requests from developers will be consistent with the preferred portfolio. (For PacifiCorp, but not necessarily for other transmission customers, resources requesting interconnection will participate in competitive solicitations.)

LTSP modeling focuses on high-stress periods rather than all hours of the year, based on a dispatch of resources using a production simulation model. The model is then tested using a series of simulated outages (or "contingencies") to evaluate the system's ability to meet transmission reliability criteria. If there is a violation of the reliability criteria, PacifiCorp mitigates it by adding new transmission or non-transmission resources and re-running models with the new additions. PacifiCorp reportedly uses decision rules to evaluate new local transmission investments, though these rules are not described in detail in PacifiCorp's Open Access Transmission Tariff (Appendix K), its *Transmission Planning Practices Document*, or its transmission plans. It is unclear to what extent the combination of dispatch assumptions and mitigation rules aligns with the transmission loading relief — for instance, through re-dispatch — that would be possible via the CAISO's security-constrained economic dispatch.[40] PacifiCorp's request for proposal (RFP) rules require new resources to be able to be designated as network resources, limiting the potential for energy-only (non-firm) resources

38 While PacifiCorp expects to continue to use its transmission access to access markets whenever it is economic to do so, planning to rely exclusively on markets and imports at the same levels is becoming riskier as western resource mix evolves and there is greater reliance on variable and short-duration resources.

39 Based on a review of PacifiCorp (2024a), PacifiCorp (2023b), and PacifiCorp (2024b).

40 In its IRP, PacifiCorp notes that "PacifiCorp has instituted more than 130 grid operating procedures and 19 remedial action schemes to maximize the existing system capability while managing system risk" and that participation in the Western EIM has enabled "more efficient use of the available transmission system" (PacifiCorp, 2023a, pp. 107-108). However, the extent to which these improvements in operational flexibility are reflected in planning is unclear.

to utilize available transmission capacity.[41]

LTSP focuses on solutions to reliability issues. In addition, PacifiCorp's transmission customers (including PacifiCorp) can submit requests to study transmission that will alleviate economic congestion ("Economy Congestion Study"). Since this process was introduced in the 2016-2017 planning cycle, PacifiCorp has received two such study requests.[42]

In addition to LTSP, PacifiCorp also participates in NorthernGrid's regional transmission planning process. In this process, NorthernGrid solicits load and resource inputs from participants and project proposals from TOs and non-incumbent transmission developers. NorthernGrid then conducts power flow studies to identify reliability violations and the extent to which project proposals could address them.[43] In principle, this process can select new interregional transmission projects that are eligible for regional cost sharing, though in practice it appears that PacifiCorp explores the potential for joint ownership and cost sharing bilaterally with other TOs rather than proposing projects through NorthernGrid.[44]

41 PacifiCorp (2022), p. 31.

42 These included requests by the Oregon PUC to study offshore wind and a request by a pumped storage developer to study congestion relief.

43 NorthernGrid (2023).

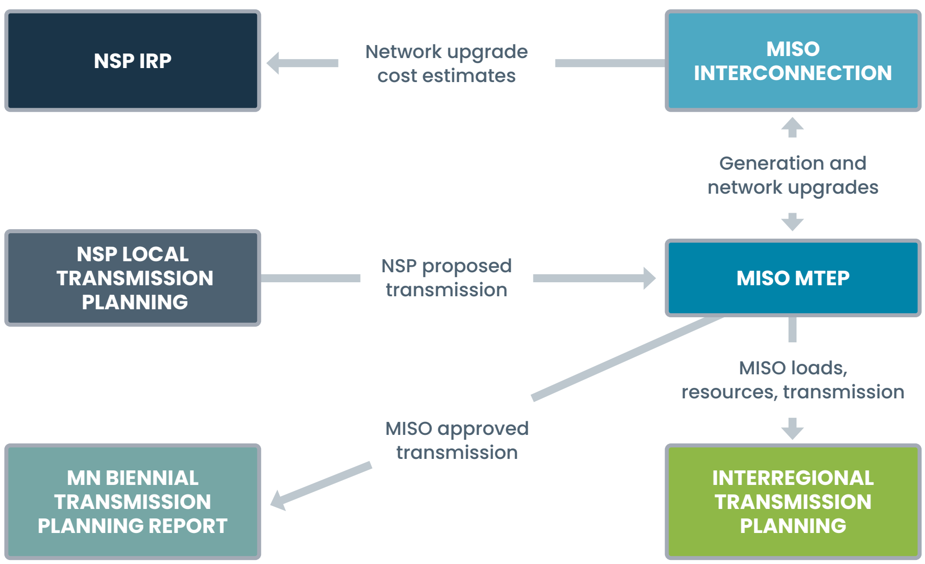
44 For instance, see the description of discussions with Idaho Power and Portland General Electric (PGE) to develop segments of Energy Gateway in PacifiCorp (2024a), pp. 100-105.

5.2 Northern States Power (RTO, IRP, state transmission)

Northern States Power Company (NSP), a subsidiary of Xcel Energy, is a multi-state, vertically integrated utility operating in parts of Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. NSP is a participating TO in MISO.

NSP's biennial IRP covers its entire six-state system. As part of MISO, both regional transmission planning and interconnection in NSP's service territory are administered by MISO. MISO also conducts joint transmission planning with neighboring RTOs. NSP is responsible for local transmission planning. The state of Minnesota requires TOs within the state to participate in a biennial transmission planning process. These various elements form a complex web of interrelated planning processes, illustrated in Figure 7. In addition (not shown in Figure 7), NSP conducts joint transmission planning with other utilities in the Upper Midwest (Minnesota, Wisconsin, North Dakota, and South Dakota).

FIGURE 7. **Information Flows Between NSP's IRP, NSP's Local Transmission Planning, MISO's Regional Transmission Planning, and MISO's Interconnection Processes**



Notes: NSP is Northern States Power. MTEP is the MISO Transmission Expansion Plan. MN is Minnesota.

NSP is one of several operating companies within Xcel Energy's footprint, which stretches from the northern U.S. to Texas.[45] Xcel Energy's Transmission Business Unit centrally manages the company's transmission system across these different regions.[46] In 2022, Xcel brought transmission planning into its Integrated System Planning department, which aims to align its IRP, integrated distribution planning (IDP), and transmission planning.

Minnesota and the broader Upper Midwest region have significant wind resources, though these resources are concentrated in southwestern Minnesota and the Dakotas and are transmission

45 Other operating companies include Public Service Company of Colorado and Southwestern Public Service Company. NSP includes NSP-Minnesota and NSP-Wisconsin.
46 See Appendix L (p. 10) of NSP (2024a).

constrained. Wind curtailment in the region has recently been high. NSP reported that 23% of its company-owned and PPA wind generation was curtailed in 2023.[47] Per the terms of its PPAs, NSP pays wind owners for curtailment.[48]

5.2.1 Transmission in Resource Planning

NSP's IRP is a 15-year scenario analysis that culminates in a preferred plan, chosen from one of three modeled scenarios. The IRP does not include an assessment of transmission needs or a synopsis of transmission investment plans, though in its 2024 IRP NSP conducted side analyses of transmission congestion costs in MISO and the impact of coal generator retirements on system inertia.

NSP uses a combination of capacity expansion and production cost models in its IRP analysis. The capacity expansion model develops least-cost portfolios, optimized for different scenario assumptions, that are analyzed in greater detail using an hourly production cost model. Neither the capacity expansion nor the production cost model appears to include transmission constraints.[49]

NSP applies a transmission cost adder in its capacity expansion modeling to approximate the incremental transmission costs of interconnecting new resources. In MISO, interconnecting generators are assigned the full cost of any network upgrades required for reliability,[50] which means that these costs serve as a proxy for interconnection costs that would be incorporated into an offer in a competitive solicitation for new resources. NSP notes that these cost estimates are based on MISO interconnection ("Definitive Planning Phase") data but does not specify how they were arrived at. In its 2024 IRP, NSP applied a uniform $250/kW interconnection cost adder to all new resources, including storage, except at sites with retiring coal generators.[51] Under MISO's generator replacement program, these new resources are not required to undergo a full interconnection study and would most likely not incur additional network upgrade costs.

NSP's capacity expansion modeling assumes that NSP will build or procure resources to meet the company's share of MISO's coincident peak demand, which implies that it will rely on imports to meet its own (non-coincident) peak demand. Both the capacity expansion and production cost models represent the broader MISO market using forecasted market prices at trading hubs, rather than modeling the full MISO footprint. In its 2024 IRP, NSP expressed concern about relying more heavily on the MISO market but did not conduct a more comprehensive quantitative analysis of

47 NSP (2024b).

48 NSP (2024b) describes its PPA curtailment terms as "take or pay," though it is not clear whether NSP absorbs all of the risk of wind curtailment.

49 NSP chose to use more temporal detail in capacity expansion following MISO's introduction of a seasonal RA construct and concerns about the shifting nature of loss-of-load probabilities with higher levels of renewable generation.

50 For network upgrades that are 345 kV and above, 90% of costs are allocated to interconnecting generators, with the remaining 10% assigned to all loads.

51 For resources replacing the Sherco and AS King coal units, NSP did not apply a cost adder but limited replacement units to specific resources (solar and Sherco 2; solar, wind and 400 MW of CTs at Sherco 1; solar + wind at Sherco 3; and solar at AS King) with a maximum capacity constraint.

benefits and risks.[52]

NSP's capacity expansion model includes energy efficiency and demand response as a supply-side resource option. Because transmission costs are included as an adder on all (non-replacement) resource costs, in principle this approach allows for investments in demand-side resources to offset the need for additional transmission. The transmission cost adder on storage costs, alternatively, does not allow storage to substitute for transmission.

In a separate analysis (Appendix T: MISO Grid Congestion), NSP's IRP reviewed the potential causes of congestion, and avenues for reducing it, within the northern MISO system and efforts to address them. These efforts are discussed in more detail in the next section.

5.2.2 Resources in Transmission Planning

NSP participates in MISO's regional Transmission Expansion Planning (MTEP) process and is also responsible for local transmission planning within the states where it operates. Outside of the MTEP process, it has also partnered with other utilities in the Upper Midwest to study regional transmission needs.

MISO's MTEP is an ongoing annual process that consists of three components: shorter-term local reliability planning, long-term regional planning, and long-term interregional planning. Local reliability planning consists of projects proposed by TOs through their local planning processes, which are included at the beginning of each annual planning cycle, and MISO's own independent assessment of reliability needs.[53] MISO reviews projects TO-proposed and evaluates alternatives.[54] State agencies participate in this process through subregional planning meetings.[55]

Projects proposed by TOs through local planning ("Other" in MISO parlance) typically fall into three categories: (1) projects needed to address local reliability issues (local reliability), (2) projects replacing aging transmission infrastructure (age and condition), and (3) projects needed to meet growth in demand (load growth). These three types of categories are defined as reliability projects, meaning that they are needed to meet NERC transmission planning (TPL) standards. However, as discussed below, TO-proposed projects can also include economic projects that are designed solely to relieve congestion. The costs of TO-proposed projects are allocated to the TO, unless MISO determines that the project is eligible for cost sharing.

MISO's long-term regional planning differs from local reliability planning in several respects. It is

52 In its 2019 IRP, NSP used a cap on hourly market transfers (25% of retail sales) to limit exposure to the MISO market. Using this approach in the 2024 IRP led to a large increase in near-term wind expansion and imports, as the model built wind to meet the RA constraint but assumed that a significant amount of the wind energy would be exported and that NSP would rely on imports to make up any energy shortfalls. NSP chose to abandon the previous approach and instead "optimized our portfolio without access to the market" on the basis that "historically, we have planned to have enough resources to meet our load serving needs" (NSP, 2024a, pp. 125-126). The argument in this section of NSP's 2024 IRP ("Market Access and Reliability," pp. 122-126) conflates economic exposure and reliability risks. The statement that NSP is optimizing its expansion plan without access to the market is likely misleading, because building to the MISO coincident peak will still require imports during NSP's own (non-coincident) peak.

53 MISO (2024), p. 8.

54 Alternatives may be proposed by TOs, MISO, or other stakeholders. MISO evaluates alternatives on the basis of cost, feasibility, and effectiveness. Alternatives could be complementary with the proposed project and can include like-for-like replacements, regional projects, and multiple local projects. See MISO (2024), p. 189.

55 Minnesota is part of the West Subregional group. Subregional group meetings review transmission needs and proposed solutions. Based on attendance records from these meetings (from https://www.misoenergy.org/engage/committees/subregional-planning-meeting/), staff from several state PUCs regularly participate in these meetings.

periodic rather than annual, has a planning horizon of 20 years or more rather than 10 or fewer, relies on long-term forecasts rather than in-service or soon to be in-service generation and transmission facilities, and focuses on backbone transmission infrastructure. Since 2021, the load and resource forecasts for long-term planning have been developed in the collaborative MISO Futures process. Resource scenarios in the MISO Futures include resources from utility IRPs and are supplemented with capacity expansion modeling to fill any shortfalls. This modeling does not include a spatial representation of loads and resources. Instead, MISO sites new resources using rules from a siting algorithm.[56] Transmission system modeling for this long-term regional plan requires assumptions about the location of future load, generation, and storage.[57]

In addition to MTEP, NSP also participates in a state-level transmission planning process. Since 2001 (pre-dating MISO's first MTEP), Minnesota law has required Minnesota Transmission Owners (MTO), including NSP, to identify transmission system inadequacies and propose alternative ways to remedy them in a *Biennial Transmission Projects Report*.[58] The Minnesota PUC (MPUC) also includes other reporting requirements, such as renewable portfolio standards gap analysis and outage and congestion analysis, as part of the report. Beginning in 2011, MTO was allowed to refer to MTEP in its assessment of inadequacies and alternatives, to avoid duplication with MISO. NSP and other Minnesota TOs are required to obtain a certificate of need (CN) from the MPUC in order to build or upgrade transmission infrastructure in Minnesota.[59]

Since 2004, NPS has also been part of a consortium of IOUs, munis, and co-ops (CapX2020) that has jointly studied transmission expansion in the Upper Midwest region.[60] The first CapX2020 study, begun in 2005, focused on transmission investments needed to meet demand growth and RPS by 2020. This was the first instance of bottom-up regional transmission planning in the U.S. and was later documented in a University of Minnesota report.[61] Several of the transmission investments identified in that study were later included in MISO's multi-value project (MVP) portfolio as part of MISO's first long-term regional transmission plan. CapX2020 became Grid North Partners in 2021.

NSP has also conducted targeted studies on potential solutions for relieving transmission congestion, both independently and through Grid North Partners. In the early 2020s, NSP studied the congestion impact of completing a second circuit on a pre-existing 345 kV line in its service territory (Brookings Second-Circuit Project). NSP initially conducted a high-level screen of production cost savings from the project and submitted it to MISO for potential approval. After MISO approved the project (MTEP22), NSP conducted a more detailed analysis of the project for its CN application. The more

56 This algorithm uses a combination of N-1 capacity limits, reference to the location projects within the generator interconnection queue (wind, solar, gas), and load ratio share (storage). See MISO (2021), pp. 42-43.

57 Once scenarios with sited resources are developed, MISO uses power flow modeling to identify any violations and develop and evaluate solutions.

58 MTO has defined 'inadequacy' as "a situation where the present transmission infrastructure is unable or likely to be unable in the foreseeable future to perform in a consistently reliable fashion and in compliance with regulatory standards" (MTO, 2023, p. 1).

59 Per the Minnesota Energy Infrastructure Permitting Act, transmission lines can be exempted from CN requirements if only a small portion of the line is in Minnesota.

60 The CapX (now Grid North Partners) consortium included Central Municipal Power Agency/Services, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy (CapX2020, 2020).

61 Multi-party ownership of transmission lines rather than bilateral. Monti (2016).

detailed analysis used a combination of MISO scenarios and the results of NSP's IRP.[62] NSP proposed to build and own the new line with or without joint ownership or cost sharing, though the line would provide significant benefits to other MISO market participants.[63] A 2023 Grid North Partners study also identified a significant number of upgrades to existing transmission infrastructure that would alleviate congestion.[64]

5.3 Duke Carolinas (Non-RTO, IRP, state transmission)

Duke Energy Corporation is a multi-state, vertically integrated utility that covers parts of North Carolina, South Carolina, Florida, Indiana, Kentucky, and Ohio. In the Carolinas, Duke Energy (here "Duke") owns Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) and acts as the BAA for co-ops and munis within its transmission service area. DEC and DEP are separate utilities but are planning to merge in 2027.[65] DEC and DEP are not part of an RTO. They participate in the Southeast Energy Exchange Market (SEEM), a voluntary, bid-based, 15-minute wholesale market.[66] The North and South Carolina legislatures have introduced bills that would require large utilities to join an RTO or study whether they should be required to do so.[67]

In the Carolinas, Duke's biennial IRP (*Carolinas Resource Plan*) covers both DEC and DEP. The two utilities administer separate FERC-jurisdictional interconnection processes. They also participate in the Carolinas Transmission Planning Collaborative (CTPC), a state-level transmission planning process that covers North and South Carolina,[68] and in SERTP, which covers most areas of the Southeastern U.S. excluding Florida.[69] Figure 8 shows information flows between these different processes. Duke also conducts single-source competitive procurements (not shown in Figure 8) to acquire resources that fill needs identified in its IRP.

62 NSP adjusted resource portfolios from the MISO MTEP21 Future 1 scenario because it felt that the new gas generation identified in this scenario was inconsistent with its IRP. It also changed the timing of solar resource additions to better match its procurement schedule over the 2020s. See NSP (2023), pp. 55-60.

63 The 20-year benefit-cost ratio was 1.36 for NSP and 2.94 for MISO, suggesting that the line would be cost-effective for NSP but that it would also create significant benefits for other MISO market participants. NSP (2023), p. 58.

64 Grid North Partners (2024).

65 Duke (2024a).

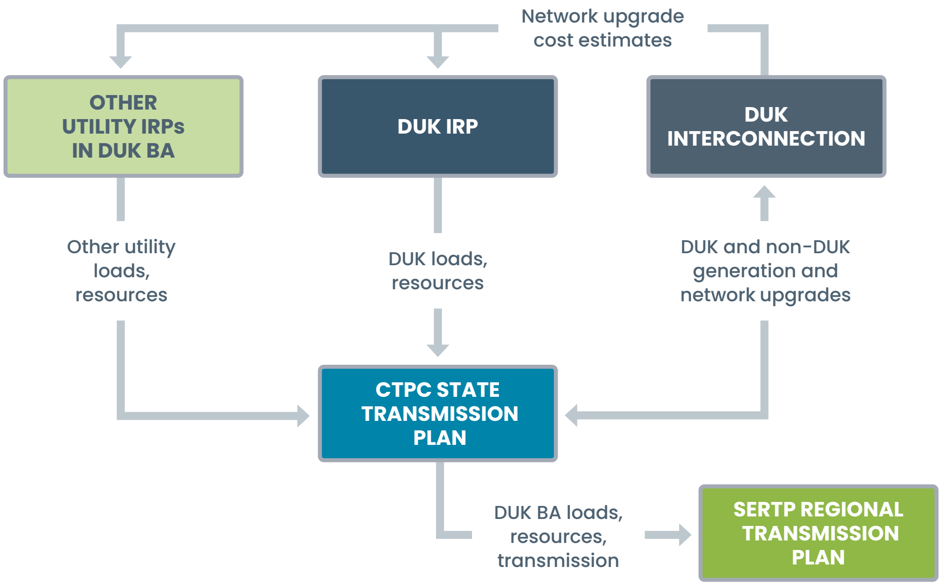
66 For more on SEEM, see https://southeastenergymarket.com/.

67 In North Carolina, House Bill 958 proposed to require larger utilities to join an RTO. In South Carolina, House Bill 4940 (H4940) and Senate Bill 998 established a committee to study whether utilities should be required to join an RTO.

68 CTPC was formerly known as the North Carolina Transmission Planning Collaborative (NCTPC).

69 See https://www.southeasternrtp.com/ for a list of SERTP participants.

FIGURE 8. Illustration of Information Flows Between DEC/DEP IRP, Local Transmission Planning, Regional Transmission Planning, and Interconnection Processes



Notes: DUK is Duke (DEC/DEP). BA is balancing area. CTPC is the Carolinas Transmission Planning Collaborative. SERTP is the Southeast Regional Transmission Planning organization.

In 2019, Duke began developing an integrated system and operations planning (ISOP) framework and stakeholder process to better integrate its resource planning, distribution planning, and transmission planning. This effort has focused on developing non-traditional solutions to distribution and transmission needs, while also addressing data management and sharing, changes in transmission planning, and climate risk and resilience.[70] The ISOP framework is still evolving.[71]

5.3.1 Transmission in Resource Planning

Duke's IRP is both a traditional IRP with a 15-year planning horizon and a long-term plan for meeting 2050 carbon neutrality goals. It culminates in an execution plan that identifies near-term investments in supply-side resources, demand-side and distribution resources, and transmission.

Duke uses a capacity expansion model to develop least-cost portfolios and a production simulation model to examine the cost and reliability of each portfolio in more detail. Duke's capacity expansion model does not explicitly include transmission or the location of resources. Instead, Duke includes transmission costs as dollar per Watt ($/W) resource cost adders for different generation technologies, using facilities and network upgrade cost estimates from interconnection studies (Table 2).[72] The rationale for using $0 transmission costs for battery storage was that it was assumed to be installed at sites where coal generators are scheduled to retire "or at other locations on the

70 Duke (2024a), Appendix L.

71 Beyond a core of non-traditional solutions, the ISOP framework appears to be a catch-all for cross-cutting topics that require stakeholder interface rather than having a clear functional mandate.

72 Duke (2024a), Appendix C, pp. 40-41.

grid as to not negatively impact the transmission system."[73]

TABLE 2. Transmission Cost Adders in Duke's 2023 IRP[74]

	DEC	DEP
Advanced nuclear reactors	$0.45/W	$0.22/W
Battery storage	$0/W	$0/W
Natural gas CC and CT	$0.45/W	$0.22/W
Offshore wind	N/A	800 MW - $0.48/W 1,600 MW - $0.84/W 2,400 MW - $0.65/W
Onshore wind	$0.27/W	$0.16/W
Pumped hydro storage	$0.37/W	N/A
Solar PV	$0.35/W	$0.21/W

Duke includes DSM measures and distributed generation as load adjustments in its capacity expansion model, based on forecasted program outcomes.[75] The transmission cost adders thus do not affect the size or location of DSM and distributed generation programs. For RA, Duke appears to plan for DEC and DEP as separate systems.[76] It allows for emergency reliance on neighboring systems in its RA study but does not include imports from neighboring BAs in its capacity expansion analysis.[77] Duke's IRP includes a cursory analysis of import capacity with neighboring systems, but Duke expressed concern about the risks of relying on external ("off-system") capacity purchases though did not provide any analysis of tradeoffs.[78]

Duke effectively requires that new resources are deliverable for RA, though this requirement is not explicitly stated in its procurement rules.[79] In Duke's current IRP modeling framework, allowing more flexibility in deliverability requirements could be done by including resources that have no associated transmission costs but have a capacity credit of zero and are allowed to be curtailed if transmission constraints bind.

73 Duke (2024a), p. 35.

74 *Ibid.*

75 Duke (2024a), Appendix C, pp. 12-14, 24-25.

76 Astrape's (2023) RA study for DEC and DEP developed reserve margins for the two companies based on their combined coincident peak, rather than the sum of their coincident peaks. In the IRP, however, Duke develops separate load forecasts (Duke 2024, Appendix D) and load-resource balance tables (Appendix C) for the two companies. Even if the reserve margin is based on coincident peak for the two systems, if it is applied to their non-coincident peaks this implies planning for two systems.

77 Astrape's reserve margin study (Astrape, 2023) is based on the coincident peak of the combined system. Imports are not included in the load-resource balance tables in Duke's IRP (Duke, 2024a, Appendix C, pp. 108-111).

78 Duke (2024a), Appendix L, pp. 33-37.

79 Duke's 2024 RFP for its Solar and Solar Paired with Storage Procurement Program (Duke, 2024b) does not specify any requirements for interconnection or transmission service. However, in its response to the Carolinas Clean Energy Business Association (CCEBA) Duke (Duke, 2024c, p. 1) explained that, "… any off-taker of the energy from the Generating Facility interconnecting to the Transmission Provider's Transmission System through ERIS would need to request transmission service on the Transmission Provider's system to deliver energy from the ERIS Generating Facility to the off-taker's load or neighboring system," implying that resources need either firm point-to-point or network transmission service. NRIS or firm transmission service for deliverability is consistent with the use of transmission cost adders in IRP. Norris and Watts (2024) found that allowing solar to interconnect with ERIS rather than NRIS — with some level of non-firm transmission service (implied) — would significantly reduce interconnection costs and timelines in Duke's service territory.

5.3.2 Resources in Transmission Planning

DEC and DEP participate in local transmission planning through CTPC and regional transmission planning through SERTP. CTPC is an annual, multi-stakeholder transmission planning process for the DEC and DEP transmission systems. Participants include DEC, DEP, and co-ops and munis that use the DEC and DEP transmission systems. The process includes a base reliability study and optional (requested) public policy and local economic studies.

The base reliability study has a 10-year planning horizon. It uses a 10-year load forecast, limits generation and storage to resources that are already in-service or have interconnection agreements, and limits transmission to facilities that are in service or expected to be in service soon. The public policy study is more forward-looking. In its 2023 planning cycle, CTPC received three public policy study requests: (1) a request from Duke to study transmission needed to support interconnection of larger amounts of solar and storage, and (2 and 3) two separate requests from a consortium of non-profit groups and staff from the North Carolina Utilities Commission (NCUC) to study the transmission impacts of scenarios linked to the 2022 Duke Carbon Plan. The latter two requests were ultimately merged and addressed through a single study.

The first public policy request stemmed from a combination of Duke's 2022 Carolinas Carbon Plan, which identified the need to interconnect up to 5,400 MW of solar by 2030, and from interconnection studies, which indicated the need for network upgrades to interconnect solar generation at roughly 80 sites that had historically been proposed for solar generation.[80] The proposed transmission projects have generated controversy over their need and the allocation of their costs.[81]

For the second public policy request, the groups requested CTPC to study the transmission impacts of a portfolio of resources with higher levels of solar and storage than what was in the 2022 Carbon Plan. New resources in the portfolio did not have a location associated with them, which meant that CTPC had to assume sites for all new resources — solar PV, solar plus storage, standalone storage, gas plants, onshore and offshore wind, and small modular reactors.[82] To site these resources, CTPC drew on historical data from interconnection requests, analysis of wind resources, and existing sites for thermal power plants.

In CTPC studies, LSEs provide CTPC with the dispatch for their designated resources. Storage dispatch has been an area of concern in CTPC studies, specifically the question of whether storage should trigger network upgrades or whether storage will always be dispatched to avoid the constraints that trigger network upgrades.[83] Ideally, detailed production simulation from resource planning or conducted in transmission planning can address questions around resource dispatch, and storage dispatch in particular.

In collaboration with CTPC, Duke has also developed a multi-value strategic transmission (MVST) process that will commence in 2025. The MVST process will comply with Order 1920 requirements: it will be forward-looking, scenario-based, analyze multiple benefits, and shift to portfolio evaluation

80 NCTPC (2022).
81 NCUC (2024).
82 NCTPC (2024).
83 Duke (2024c).

rather than line-specific evaluation.[84] CTPC's Oversight/Steering Committee (OSC) will develop scenarios with input from the Transmission Advisory Group (TAG). If MSVT scenarios have regional implications, CTPC will refer them to SERTP for analysis in SERTP's regional planning process.

SERTP conducts annual transmission studies for the Southeast region, though SERTP is primarily a forum rather than a planning organization.[85] SERTP analyzes up to five scenarios that are developed by a Regional Planning Stakeholder Group (RPSG), whose members include utilities, RTOs, and market participants.[86] SERTP conducts power flow studies to identify thermal and voltage violations on the regional transmission system. Transmission owners, with input from SERTP stakeholders, develop and test solutions to any violations and provide cost estimates for any potential solutions. SERTP's study reports do not provide detail on how scenarios are developed or assumptions used in planning studies.[87]

5.4 National Grid (RTO, no IRP, no state transmission)

National Grid is a distribution service provider (DSP), TO, and distribution utility that provides service in several Northeast states. This report focuses on National Grid in Massachusetts. National Grid is a participating TO in ISO-NE.

LSEs in Massachusetts, including National Grid, do not engage in formal resource planning (Figure 9). In 2020, Massachusetts state agencies commissioned a roadmap for meeting the state's goal of net zero greenhouse gas (GHG) emissions by 2050. This roadmap has served as a resource plan for multiple applications. National Grid and other distribution utilities are required to file Electric Sector Modernization Plans (ESMPs) that describe how the utilities will meet Massachusetts' GHG emission reduction goals on 5-year, 10-year, and longer-term (2050) planning horizons. These ESMPs focus on distribution systems. ISO-NE is responsible for planning the New England regional transmission system (> 69 kV) and coordinates transmission planning with NYISO, Hydro Quebec, and New Brunswick Power.

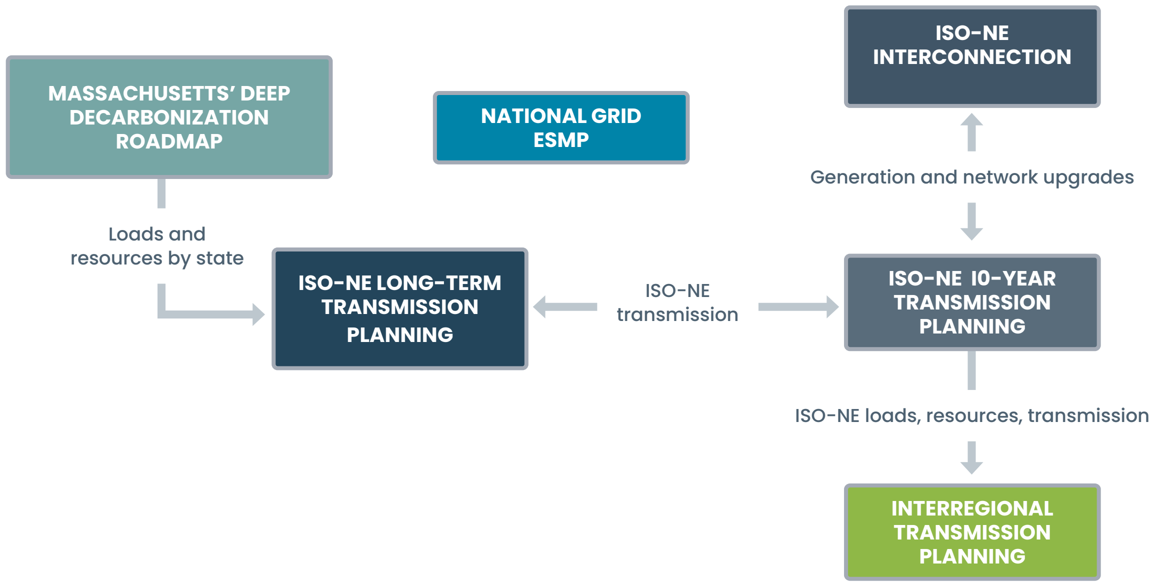
84 CTPC (2023).

85 SERTP refers to these as "economic planning studies," but the term 'economic' does not refer to transmission that only relieves congestion, as per the FERC Order 1000 usage.

86 Sixteen RPSG members are elected and can come from eight sectors, with a maximum of two per sector: transmission owners and operators, transmission service customers, cooperative utilities, municipal utilities, power marketers, generation owner or developer, ISO or RTO, and demand-side management providers. SERTP (2024a).

87 The information in this paragraph is based on SERTP (2024b)

FIGURE 9. Illustration of Information Flows Between State and Distribution Utility Resource Shorter-Term and Longer-Term ISO-NE Transmission Planning, and ISO-NE's Interconnection Process



5.4.1 Transmission in Resource Planning

Resource planning in Massachusetts consists of state-level deep decarbonization planning and distribution-level load and resource forecasts. In *Massachusetts' 2050 Deep Decarbonization Roadmap,* the state's Executive Office of Energy and Environmental Affairs (EEA) developed a scenario-based resource plan for 2020 to 2050 (5-year intervals).[88] National Grid's ESMP includes 2024-2034 and 2050 forecasts of distributed solar PV and loads, including electric vehicle and electric heating loads.[89] Like most of the six Northeast states, Massachusetts faces land, environmental, and political constraints that limit energy development. The *Roadmap* found that the state's three main electricity resources of the future are solar PV, energy imports, and offshore wind.[90]

Distributed-focused ESMP loads and resources were developed to be consistent with outputs from the *Deep Decarbonization Roadmap* and state goals. For instance, the amount of rooftop solar PV (7 GW by 2050) in the *Roadmap* is based on Massachusetts' state goals.[91] National Grid's ESMP allocates National Grid's share of this 7 GW to different regions in its service territory, rather than conducting a separate PV adoption forecast.[92]

ISO-NE is the main RA planner for the New England region, because most of the states in the region have competitive retail sectors. ISO-NE does not do optimal resource expansion planning. Instead, it operates a forward capacity market to procure capacity resources. ISO-NE's interconnection process supports the transmission network upgrades needed to ensure that resources participating

88 EEA (2020).
89 National Grid (2024).
90 EER (2020), p. 3.
91 *Ibid.*, p. 23.
92 National Grid (2024), p. 211.

in its forward capacity market are deliverable.[93] However, it is not clear whether the transmission planning process allows for imports or interstate transmission as an economic substitute for new generation.[94]

5.4.2 Resources in Transmission Planning

National Grid participates in ISO-NE's regional transmission planning process and is responsible for local transmission system planning. ISO-NE's regional system planning process is a biennial planning process with four sub-processes: (1) reliability planning, (2) market efficiency planning, (3) public policy planning, and (4) long-term transmission planning. The reliability, market efficiency, and public policy planning processes use a 10-year forecast of loads and existing resources or resources that could be in service in the near term.

The long-term transmission planning (LTTP) process originated in the New England States Committee on Electricity's (NESCOE's) *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid*, which recommended that ISO-NE work with stakeholders to develop a comprehensive, long-term transmission plan.[95] This recommendation led to ISO-NE's *2050 Transmission Study* (LTTP Phase I) and, subsequently, a process (LTTP Phase 2) that allows NESCOE to identify new transmission needs and cost allocation mechanisms. The LTTP studies (Phase I) will occur on a regular basis.

The 2050 study required location-specific load and resource inputs for 2035, 2040, and 2050. ISO-NE used state-specific hourly load and resource capacity projections from the Massachusetts' *Deep Decarbonization Roadmap* report, along with solar and wind profile data developed by a consultant.[96] The capacity expansion model used for the *Deep Decarbonization Roadmap* included transmission limits and allowed optimal transmission expansion.[97] To site resources at transmission nodes, ISO-NE used rules for different resources and made iterative adjustments to site resources in ways that relieved transmission constraints or reduced costs, while preserving the resource capacity totals for each state in the *Deep Decarbonization Roadmap*.[98]

93 At the time of writing, ISO-NE was in the process of filing a new interconnection process with FERC. Both its existing and its new interconnection processes would support network upgrades for RA deliverability.

94 Based on a review of Appendix K of ISO-NE's transmission tariff, Transmission Planning Technical Guide, and 2023 *Regional System Plan*.

95 NESCOE (2020).

96 The Massachusetts *Roadmap* had load and resource projections for each New England state. ISO-NE (2024).

97 EER (2020).

98 For offshore wind, ISO-NE sited it to minimize cable length between points of interconnection and wind facilities, relocating some interconnection points over the course of the study. For storage, ISO-NE assumed it would be located at major 345 kV stations but relocated some of it to relieve transmission constraints. For solar, ISO-NE assumed at it was distributed evenly at 115 kV substations in each state, making adjustments in land-constrained areas. ISO-NE (2024), p. 12.

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gridlab.org
admin@gridlab.org