# Incorporating transmission into TVA’s IRP for truly “Integrated” Resource Planning

BY MICHAEL GOGGIN

GridStrategies

FOR THE SIERRA CLUB

October 2024

**Introduction**

To inform TVA's planning efforts, this report reviews best practices for integrating transmission and generation planning. For an Integrated Resource Plan (IRP) process to truly be "integrated," it must assess the multiple ways in which transmission affects generation plans, and how generation plans affect the need for transmission, including:

-Transmission has a direct impact on the cost and timeline for accessing resource options evaluated in generation planning;

-The need for transmission is affected by generation retirements and the type and location of planned generation resources; and

-Expanding transmission ties to neighboring grid operators can also offer a lower-cost source of energy and capacity than building in-region resources.

This report explains how TVA can incorporate transmission planning into its resource decision-making, including moving to proactive multi-value transmission planning and assessing opportunities for expanding ties with neighboring grid operators. This report reviews techniques other utilities and grid operators have used to successfully integrate transmission and generation planning, typically by iterating between transmission and generation planning to refine those plans over time.

The first section of the report discusses how other grid operators have settled on proactive multi-value transmission planning as a best practice for maximizing ratepayer benefits. The second section explains the benefits of integrated transmission and generation planning, and provides examples of the methods other utilities have used to successfully integrate their planning processes. The third section discusses opportunities for TVA to benefit its ratepayers by expanding transmission ties with neighboring grid operators.

Proactive multi-value transmission planning that is integrated with generation planning can yield large savings and improved reliability for TVA's ratepayers. Recommended steps and methods for TVA to implement this type of beneficial planning include:

1. Identify portfolios of generation and transmission that minimize cost and risk for ratepayers,

2. Account for the multiple types of benefits provided by transmission, which the Federal Energy Regulatory Commission (FERC) listed in Order 1920,

3. Proactively plan the high-capacity transmission that will be needed to cost-effectively meet needs looking at least 20 years in the future, with that transmission planning preceding interconnection applications for specific generators,

4. Iterate between transmission and generation planning and among different models to develop, test, and refine optimal portfolios as additional information becomes available,

5. Include stakeholders in the transmission planning process to provide overall direction and feedback on how to refine iterative plans,

6. Quantify the net benefits of expanding transmission ties to other grid operators, and weigh those against local generation projects, and

7. Fully integrate transmission planning into future resource decisions and into all future IRPs.

## I. The benefits of proactive multi-value transmission planning

Multiple regions have found that proactive multi-value transmission planning that is integrated with generation planning maximizes net benefits for ratepayers. Grid Strategies and the Brattle Group coauthored a 2021 report detailing those methods and their benefits.[1] Many of those methods are now required of FERC-jurisdictional transmission service providers under FERC Order 1920, as FERC determined that those methods are needed to ensure just and reasonable rates. While TVA is not FERC-jurisdictional, it should use these methods as they offer large economic and reliability benefits to its ratepayers, consistent with TVA's past adoption of FERC transmission planning requirements.

**"Proactive"** encompasses planning transmission that will meet generation, load, and other reliability needs over a long time horizon, in advance of those needs arising. Order 1920 requires planning over at least a 20-year time horizon, accounting for state and federal policy and utility plans and goals.[2] Proactive planning contrasts with the reactive approach of building transmission to accommodate specific generators that have applied to the interconnection queue, as discussed below. Because key variables like electricity demand, generation costs, and fuel costs are uncertain over that time horizon, scenario-based generation and transmission planning is often used to assess how those variables drive changes in the optimal portfolio or the resilience of a portfolio to changes in those variables. This allows identification of least-regrets portfolios of generation and transmission that perform well or will be needed across a range of scenarios. Some modelers have even used probabilistic tools (which are discussed in more detail in Section II.A) to quantify risk, and found that this provides large additional value by hedging against uncertainty.[3]

A primary benefit of proactive transmission planning is that it ensures transmission is complete by the time generators come online. By building transmission into areas where low-cost generation can be built, in advance of specific generation projects being proposed, proactive planning fixes the timing mismatch between long lead transmission investment and generation resources that can be deployed far more quickly. The generation portfolio or portfolios identified in an IRP are the ideal basis for conducting this type of transmission planning, as generation planning in IRPs typically extends over a long time horizon and is not focused on specific proposed generators. As discussed in more detail in Section II.B below, most utilities then refine these initial conceptual generation

---

[1] J. Pfeifenberger et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, (October 2021) https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Planning-for-the-21st-Century-Proven-Practices-that-Increase-Value-and-Reduce-Costs.pdf.

[2] FERC, *Order 1920*, https://www.ferc.gov/media/e1-rm21-17-000, at Paragraph (P) 409.

[3] B. Hobbs et al., *Large-Scale Stochastic Programming to Cooptimize Networks and Generation in the Face of Long-Run Uncertainties: What Lines Should We Build Now?* (June 2015) https://www.ferc.gov/sites/default/files/2020-08/T4-A-2-HOBBS.pdf.

and transmission plans as they receive more information on the need for generation and transmission and the cost of specific generation projects.

Another major benefit of proactive planning is that it taps into transmission's large economies of scale. As shown in the table below, higher voltage and double circuit transmission offers a much greater increase in transfer capacity with a less than proportional increase in cost. As a result, these higher capacity lines on the right and bottom part of the table are much more cost-effective on a $/MW-mile basis, which reflects the cost of transmission capable of delivering one MegaWatt (MW) one mile. By building higher-capacity lines that meet multiple needs over a longer time horizon, proactive planning results in a lower cost for ratepayers versus multiple more incremental transmission additions.

**Table 1: Economies of scale from investment in higher-capacity transmission**[4]

| | Voltage (kV) | 69 | 115 | 138 | 161 | 230 | 345 | 500 | 765 |
|---|---|---|---|---|---|---|---|---|---|
| **Single Circuit** | $M/mile | $1.7 | $1.9 | $2.0 | $2.1 | $2.2 | $3.5 | $4.4 | $5.5 |
| | MW or MVA | 140 | 329 | 394 | 460 | 657 | 1792 | 2598 | 6625 |
| | $/MW-mile | **$12,143** | **$5,775** | **$5,076** | **$4,565** | **$3,349** | **$1,953** | **$1,694** | **$830** |
| **Double Circuit** | $M/mile | 2.5 | 2.8 | 2.9 | 3 | 3.6 | 5.8 | NA | NA |
| | MW or MVA | 280 | 658 | 788 | 920 | 1314 | 3584 | NA | NA |
| | $/MW-mile | **$8,929** | **$4,255** | **$3,680** | **$3,261** | **$2,740** | **$1,618** | **NA** | **NA** |

Grid operator studies confirm that proactive transmission planning yields major savings through economies of scale in transmission investment. The PJM grid operator recently found that proactive transmission planning could integrate 12.4 GW of offshore wind resources along with 14.5 GW of onshore wind, 45.6 GW of solar, and 7.2 GW of storage, for a total cost of $2.2 billion.[5] This equates to a cost of $27/kilowatt for new generation capacity, a fraction of the cost found through interconnection queue studies. For example, Brattle Group analysis of PJM queue study results show $1.3 billion in total identified

---

[4] Calculations based on transmission cost and capacity estimates from Midcontinent Indep. Sys. Operator, *Transmission Cost Estimation Guide for MTEP24* (May 2024), https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf. (Table 1 was prepared using the reported Power rating (MVA) capacity data in Table 3.1-5 on page 43 and the estimated costs for Arkansas reported in Tables 4.1-1 and 4.1-2 on pages 47–49. Costs for Arkansas were used as they are in the middle of the range of MISO's cost estimates by state, and are likely to be most representative of costs in TVA's footprint. The Power rating (MVA) capacity data for the Double Circuit are twice the capacity for the Single Circuit.)

[5] PJM, *Offshore Transmission Study Group Phase 1 Results*, (August 2021) at 16, Scenario 6 (OTSG Phase 1), https://pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx.

transmission upgrades for integrating 5.6 GW of PJM offshore wind resources alone,[6] which equates to a cost of $415/kilowatt, 15 times greater than costs under PJM's proactive plan. Other analyses found that integrating 15.5 GW of offshore wind in PJM using upgrades identified through reactive queue studies would lead to $6.4 billion in upgrades,[7] at a cost of $236/kilowatt.

Similarly, a proactive planning effort in New Jersey for offshore wind resulted in selections of onshore transmission upgrades that save New Jersey ratepayers approximately $1 billion for 6,400 MW of additional offshore wind, a two-thirds reduction relative to the costs identified though PJM queue studies.[8]

Proactive transmission planning should not only evaluate long-term transmission upgrades but also shorter-term solutions, particularly those that can serve as an interim solution while new transmission is planned, permitted, and built. Technologies that can be deployed quickly and at low cost on existing transmission rights-of-way include reconductoring with high-performance conductors, rebuilding lines with modern tower designs, strategically siting batteries to address local congestion or reliability concerns, adding circuits, or deploying grid-enhancing technologies (GETs).

GETs include dynamic line ratings, power flow control devices, and topology optimization techniques.[9] Dynamic line ratings allow more power to safely flow on transmission lines by accounting for how ambient weather conditions affect the thermal limits of those lines. Power flow control devices, also known as Flexible Alternating Current Transmission Systems devices, reroute power flows around constraints. Topology optimization plays a similar role by taking specific transmission lines out of service to redirect power flow away

---

[6] J. Pfeifenberger, J. M. Hagerty, *et al.*, *New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report,* (October 2022) at Table A-2 (SAA Evaluation Report), https://www.brattle.com/wp-content/uploads/2022/10/New-Jersey-State-Agreement-Approach-for-Offshore-Wind-Transmission-Evaluation-Report.pdf.

[7] Burke and Goggin, *Offshore Wind Transmission Whitepaper*, (October 2020) at 40, https://gridstrategiesllc.com/wp-content/uploads/business-network-osw-transmission-white-paper-final.pdf.

[8] SAA Evaluation Report at Figure 4.

[9] Rob Gramlich, *Bringing the Grid to Life: White Paper on the Benefits to Customers of Transmission Management Technologies* (March 2018), https://watttransmission.files.wordpress.com/2018/03/watt-living-grid-white-paper.pdf.

from congested transmission elements and onto more optimal paths. These solutions can be deployed quickly, typically within a matter of months,[10] and are highly cost-effective.[11]

**"Multi-value,"** the second key element of effective transmission planning, means planning transmission that optimizes net benefits across the multiple benefits of transmission. In Order 1920, FERC requires at least seven distinct benefits of transmission to be accounted for in effective planning:

> *(1) avoided or deferred reliability transmission facilities and aging infrastructure replacement;*
>
> *(2) a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin;*
>
> *(3) production cost savings;*
>
> *(4) reduced transmission energy losses;*
>
> *(5) reduced congestion due to transmission outages;*
>
> *(6) mitigation of extreme weather events and unexpected system conditions; and*
>
> *(7) capacity cost benefits from reduced peak energy losses.*[12]

Multi-value planning is particularly valuable for TVA because many factors are driving a large need for transmission investment. Replacing large retiring generators with the most economic new resources will require reconfiguring the transmission system to accommodate the different locations and characteristics of those replacement resources. Power flows are also shifting as generation economics change, likely resulting in congestion that is increasing production costs. Like many utilities, TVA is also experiencing load growth, including due to large new load interconnections. This will require transmission investment to both interconnect the new loads and the generation that will be needed to serve them. Aging transmission assets also need replacement to maintain reliability.

The following table summarizes why integrated proactive multi-value transmission planning is more effective than TVA's status quo, which relies on the reactive generator

---

[10] *See* Idaho Nat'l Lab., *A Guide to Case Studies of Grid Enhancing Technologies*, 11, 26 (October 2022), https://inl.gov/wp-content/uploads/2023/03/A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf.

[11] Bruce Tsuchida, Stephanie Ross, Adam Bigelow, *Unlocking the Queue with Grid-Enhancing Technologies*, at 8 (February 2021), https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.

[12] Order 1920, at P 720.

interconnection process to drive most new transmission investment. Under the interconnection queue process, specific proposed generators apply to interconnect to TVA's system. TVA then studies those requests and assigns those generators the cost of the network upgrades required to interconnect them. Pursuant to FERC Order 2023, TVA is moving to a cluster study approach. That offers some efficiencies relative to the current approach of studying individual interconnection applications, but does not solve these fundamental problems that result from relying on reactive queue studies instead of proactive planning for building large-scale network upgrades.

**Table 2: Benefits of integrated proactive multi-value planning vs reactive queue-driven transmission investment**

| Problem with TVA's reactive approach driven by interconnection queue studies | How integrated proactive multi-value planning solves problem |
|---|---|
| Transmission solutions tend to be inefficient smaller, short-term fixes | Higher-capacity upgrades to meet longer-term need realize economies of scale in transmission |
| Building major network upgrades takes longer than it takes to build a generator | Transmission is ready when generation comes online |
| Generators have little incentive to pay for upgrades that also benefit other users, so they drop out of queue | Broadly allocate the cost of network upgrades, reflecting that they provide various benefits to many users |
| Generators face uncertain upgrade costs, and when they drop out of the queue costs change for other generators | Network upgrade costs are not assigned to generator |
| Does not plan transmission to new resource areas | Builds transmission in anticipation of generation |
| Interconnection upgrades sub-optimally planned separately from reliability and economic upgrades | Optimizes transmission build to maximize all benefits |

Across the country, interconnection queues have become massively backlogged because inadequate proactive transmission development is forcing interconnecting renewable and storage projects to pay for network upgrades that are needed for many reasons.[13] In a vicious cycle, queue delays and interconnection cost uncertainty cause queue withdrawals, which only further increase delays and uncertainty for projects remaining in the queue. Integrated proactive multi-value planning alleviates the pressure on that broken system by proactively planning and paying for large network upgrades. Under that system, interconnecting generators pay for their direct interconnection facilities, but not large network upgrades that provide multiple benefits to all grid users. This is analogous to the

[13] LBNL, *Queued Up*, April 2024, available at https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf.

generator paying for the driveway that connects them to the grid, but not adding another lane to a major highway as that benefits many others.

The primary problem with assigning large network upgrades to interconnecting generators is that those transmission investments provide many benefits to other grid users.[14] Allocating all of the cost of network upgrades to interconnecting generators results in an underinvestment in transmission. The generators do not receive most of those benefits, so they withdraw from the queue instead of making the needed investments. Moreover, transmission is open access, so once a generator has paid for a network upgrade, a competing generator is free to use it. Because it provides benefits to a range of grid users and is open access, transmission is what economists call a natural monopoly public good. As with highways, sewer systems, emergency responders, and other public good infrastructure, broad cost allocation is more effective than attempting to require private parties to pay for upgrades, which will result in underinvestment. Network upgrade costs that are assigned to generators fully flow through to TVA ratepayers anyway because those costs are incorporated into the total cost of generation owned or purchased by TVA. As a result, TVA should be focused on finding the most efficient way to plan and pay for needed transmission.

Fortunately, other grid operators have found alternatives to the dysfunctional queue-driven reactive approach for building needed network transmission. The Midcontinent Independent System Operator (MISO) pioneered the integrated proactive multi-value transmission planning approach by proposing its Multi-Value Projects (MVPs) in 2011. Subsequent analyses have confirmed that those projects are providing large net benefits.[15] MISO's process was informed by Texas's success in using proactive transmission planning to build the Competitive Renewable Energy Zone projects, a portfolio of upgrades that allowed the state to more than double its use of renewable energy[16] but have also met reliability and load growth needs. The Southwest Power Pool (SPP) also adopted a regional proactive multi-value transmission planning approach, and two subsequent SPP studies have confirmed that those upgrades are providing large net benefits by meeting a range of economic and reliability needs.[17]

---

[14] V. Sankaran et al., *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits,* (September 2021) https://acore.org/wp-content/uploads/2021/10/Just_and_Reasonable.pdf.

[15] MISO, *MTEP17 MVP Triennial Review–A 2017 review of the public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio* (September 2017), https://cdn.misoenergy.org/MTEP17%20MVP%20Triennial%20Review%20Report117065.pdf.

[16] *See, e.g.*, Lasher, *The Competitive Renewable Energy Zones Process*, ERCOT (August 2014), https://www.energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf.

[17] *See* SPP Transmission Planning, *The Value of Transmission – A 2021 Study and Report by Southwest Power Pool*, SPP (Mar. 31, 2022), https://www.spp.org/documents/67023/2021%20value%20of%20transmission%20report.pdf; *see also* SPP, *The Value of Transmission*, SPP (January 2016), https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf.

Utilities outside of Regional Transmission Organizations like MISO and SPP are also moving to proactive multi-value planning. Earlier this year, Duke obtained FERC approval to add a Multi-Value Strategic Transmission category to its transmission planning process.[18] The next section provides multiple examples of utilities successfully incorporating transmission planning into IRPs.

MISO's planning is multi-value in that it accounts for and plans a portfolio of transmission investment to maximize net benefits across a range of benefit categories. MISO's net benefit analyses of the MVP projects and recent and ongoing Long-Range Transmission Plan (LRTP) projects[19] account for transmission's broad range of benefits. In addition to production cost savings and a reduced need for generator capacity due to transmission accessing net load diversity and reducing losses, MISO's LRTP analysis also accounts for reduced generator capacity investment from accessing more productive renewable resources, savings from deferring transmission system investment needed to meet reliability criteria, reduced risk of load shedding from extreme events and other threats to resilience, and the value of reduced carbon emissions.

In the 2010 Regional Generator Outlet Study (RGOS)[20] and subsequent MVP report, MISO identified renewable resource zones and proactively planned transmission to minimize total transmission and generation cost by accessing lower-cost wind resources. More productive renewable resources offer a significantly lower cost of electricity because the cost of building and operating those plants can be amortized across a larger amount of generation. As illustrated in the following chart from the RGOS study, integrated planning minimizes the total cost to ratepayers of generation plus transmission by building the optimal amount of transmission. The red area on the left of the chart represents an underinvestment in transmission that results in higher generation costs and therefore total costs to customers. The blue area on the right shows a theoretical overinvestment in transmission, though given TVA's large transmission need, TVA would almost certainly be on the left side of this chart if a comparable chart were made for its service territory. The goal of synchronized planning should be to minimize the total cost of generation plus transmission, as occurs in the white area in the middle of the chart. For IRPs to truly be "integrated," they must account for the transmission needed to realize an optimal generation buildout. Minimizing the total cost of transmission plus generation is the quintessential goal of integrated proactive planning, and TVA should use a similar approach in its IRP.

[18] FERC, *Order Accepting Filing*, (March 2024) https://elibrary.ferc.gov/eLibrary/filedownload?fileid=E477145D-2EEA-C4C3-9692-8E345BD00000.

[19] MISO, *LRTP Tranche 1 Portfolio Detailed Business Case,* (March 2022) https://cdn.misoenergy.org/20220329%20LRTP%20Workshop%20Item%2002%20Detailed%20Business%20Case623671.pdf.

[20] Midcontinent Indep. Sys. Operator, *Regional Generation Outlet Study* (November 2010), https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf, at 2.

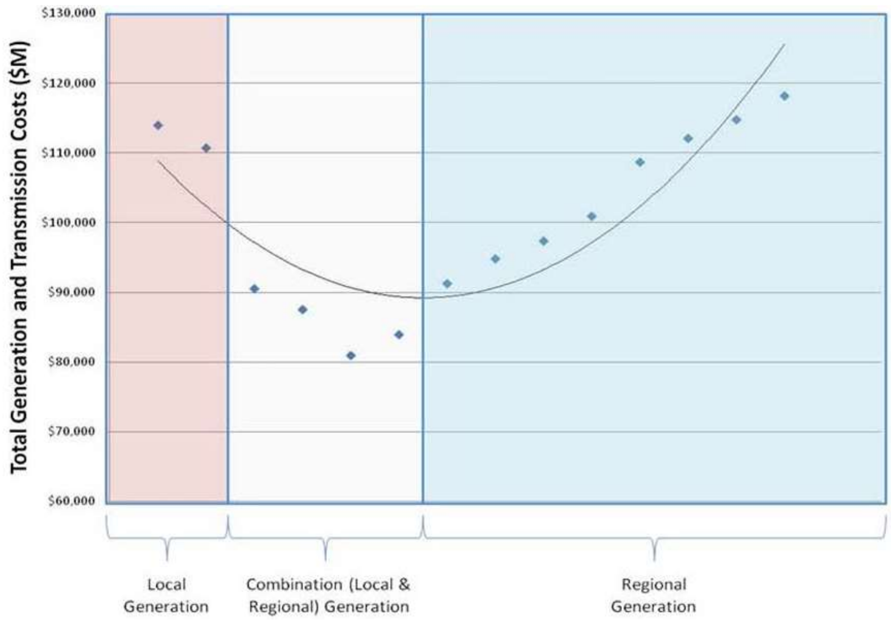


**Figure 1: MISO chart showing how synchronized planning minimizes ratepayer costs**[21]

[21] *Id.*, at 3.

## II. Integrating transmission planning and generation planning

### A. Benefits of integrated generation and transmission planning methods

To be effective, transmission planning must be integrated with generation planning because of the complex interrelationship between generation and transmission needs. Transmission has a direct impact on the cost and timeline for accessing generation planned, the need for transmission is affected by generation retirements and the type and location of generation resources planned, and expanding transmission ties to neighboring grid operators can also offer a lower-cost source of energy and capacity than building in-region resources.

A failure to plan transmission as part of TVA's resource planning and decisions will lead to suboptimal outcomes for TVA ratepayers. Without integrated proactive planning, needed transmission will not be available in time to enable the interconnection of cost-effective resources. TVA's resource planning may also miss opportunities to obtain more cost-effective resources from neighboring areas. Without integrated planning, TVA may also miss opportunities to strategically site resources like battery storage where they can alleviate the need for transmission upgrades.

Integrated planning is essential for maximizing the value of batteries, as they provide a range of services that bridge the gap between generation and transmission.[22] Batteries function somewhat like generators in that they provide energy and capacity, but they also complement transmission in ways that mitigate, defer, or even eliminate the need for grid upgrades. Due to batteries' speed of dispatch, the ability of their power electronics to regulate voltage and reactive power and address local stability concerns, and their ability to be quickly deployed at points on the grid where they are needed, battery storage can be an effective alternative to transmission upgrades, particularly upgrade needs triggered by contingency conditions.[23] Batteries are highly modular with a small footprint, so they can be deployed at almost any point on the grid in the exact quantity needed to meet the local reliability need, including in dense urban areas. Batteries located at or near renewable resources can also facilitate their interconnection by providing those reliability services and storing excess renewable output until transmission capacity is available to deliver it to

---

[22] A. Manocha et al., *Reducing transmission expansion by co-optimizing sizing of wind, solar, storage and grid connection capacity*, (August 2024) https://arxiv.org/abs/2303.11586.

[23] See Brent Oberlin, *Storage as a Transmission Only Asset*, (May 2022), https://www.iso-ne.com/static-assets/documents/2022/05/a7_storage_as_a_transmission_only_asset.pdf, at 11-15; and Quanta Technology, *Storage as Transmission Asset Market Study*, (January 2023), https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf.

load. Similarly, distributed generation and demand-side management can obviate transmission upgrade needs in some cases, and so should be part of the planning process.

Often utilities integrate transmission and generation planning through an iterative process that involves proactively proposing large multi-value transmission projects into regions that are known to offer low-cost generation resources, and then fine tuning those plans over time. Iteration is necessary for a few reasons:

-<u>Given its longer lead time, transmission must be planned before generation</u>. This is particularly true for interconnecting renewable and battery generating resources, which are highly modular and thus can be deployed more quickly than conventional generation. Greenfield and high-capacity transmission expansion also takes longer to permit and build than more incremental upgrades, so initial transmission planning should focus on those large projects. Once the broad outlines of high-capacity transmission expansion are proposed, developers can respond by proposing specific generation additions in that area. As more information about specific generation types, sizes, and points of interconnection is obtained, details of the transmission design can be refined. This is the process multiple utilities have successfully used to integrate transmission and generation planning, as documented below.

-<u>Effective planning requires iteration among highly specialized models, including generator capacity expansion, production cost, power flow, and dynamic stability models</u>. Iteration is necessary because each of those models are specialized to solve specific parts of the problem, and cannot fully model other parts of the problem due to their computational complexity, as shown in the following table. For example, generator capacity expansion models devote their computational power to testing thousands of potential combinations of generation additions, so must simplify other parts of the problem. Production cost models evaluate costs of operating that power system with a granular geographic and chronological resolution, so they cannot test combinations of resources and must simplify Alternating Current (AC) power flow to linear Direct Current (DC) power flow. AC power flow and dynamic stability models are then added to ensure actual power flows can be reliably accommodated at discrete snapshots in time, including under contingencies such as the loss of a large transmission line or generator. Generation and transmission planning modeling usually progresses down the table below, with more complex transmission representation as the details of the generation and transmission expansion are refined. While not included in the table below, probabilistic resource adequacy tools can also be added following the generator capacity expansion step to ensure the generation supply adequately meets load under thousands of iterations of possible weather events; these models have little to no representation of in-region transmission, but can be used to probabilistically assess the availability of imports.

**Table 3: Planning models and their specialties**

| Model type | Specialty | Transmission representation |
|---|---|---|
| Generator capacity expansion | Testing thousands of possible combinations of generator additions | If any, typically highly simplified |
| Production cost | Hourly representation of generator dispatch, typically needs to be nodal not zonal for effective transmission expansion modeling | Moderately complex, Direct Current simplification of actual AC power flow[24] |
| Power flow | AC power flow at a snapshot in time, including contingency events | Highly detailed snapshot |
| Transient and dynamic stability | Ensuring system is stable following a contingency | Highly detailed snapshot |

The first two modeling steps, iteration between generator capacity expansion and production cost modeling, are the primary method used in integrated generation and transmission planning. Production cost modeling is used to identify transmission constraints that prevent those resources from being able to deliver their output to load, and to develop and test transmission solutions to those constraints. Solutions are often proposed by the transmission planners, but third parties should also be allowed to propose solutions. This is the general process MISO is using to plan its LRTP lines.[25]

Capacity expansion plus production cost modeling provide the full economic picture that is required for optimizing generation and transmission expansion. The capacity expansion model minimizes the capital and other fixed costs of building and maintaining generating capacity, while production cost modeling accounts for the fuel and other variable costs of operating that generation over time. These models also work together to ensure generation supply is adequate, with capacity expansion meeting the peak demand hour and production cost models testing to ensure demand will be met in all hours in the year.

Minimizing generation plus transmission costs requires information about the cost and performance of generating resources in certain locations, particularly for wind and to a lesser extent for solar resources. One source of that information is the result of a "Request for Proposals" or other solicitation to get market cost data from proposed generators in different locations. Then, TVA can determine the cost of potential grid upgrade portfolios to accommodate groups of those projects, and choose the grid upgrades that minimize the

[24] Bin Wang and Jin Tan, *DC-AC Tool: Fully Automating the Acquisition of the AC Power Flow Solution*, (February 2022) https://www.nrel.gov/docs/fy22osti/80100.pdf, at 2-3.
[25] MISO, *Long Range Transmission Planning (LRTP) Tranche 2 – Frequently Asked Questions*, (July 2024) https://cdn.misoenergy.org/MISO%20Long-Range%20Transmission%20Planning%20LRTP%20Tranche%202%20FAQs631005.pdf.

total generation plus transmission cost. TVA can also provide generation developers with more transparency regarding transfer capacity, transmission utilization, and congestion on its transmission system. This information would allow developers to submit more efficient proposals for where generators should interconnect.

TVA will also need to develop initial concepts for transmission expansion that can then be refined through iteration with generation plans. The current interconnection queue can be a useful input for transmission planning as it indicates where developers are interested in building low-cost generation projects, but it should not be the only input. The location of proposed projects in the queue is heavily shaped by where there is currently available transmission capacity, and new transmission build will change the topology of the system and create new unconstrained entry points for renewables. As a result, TVA should also proactively plan transmission to new areas that are promising for low-cost renewable development.

Incorporating stakeholder feedback into the transmission planning process is critical for effective iteration between transmission and generation plans. Stakeholders can provide valuable input regarding scenarios, methods, assumptions, potential transmission solutions, and other key planning questions. Stakeholders should be given access to key assumptions and methods in TVA's planning analysis, and their feedback should be incorporated throughout the process in a meaningful way. For example, the Carolinas Transmission Planning Collaborative allows stakeholders to propose scenarios, methods, and assumptions, and has a Transmission Advisory Group that provides meaningful input throughout the process,[26] while MISO's LRTP process includes regular workshops where stakeholders help refine the plans.[27]

For TVA, transmission need is likely to be more driven by retirements and a need to maintain local reliability of the transmission system, rather than a need to expand transmission into new areas to facilitate the interconnection of new resources. For solar, the main constraint on development is cost-effective land that is suitable for construction, and there are likely to be many areas in TVA's footprint that offer cost-effective land relatively near existing transmission. Other utilities have had a greater need to expand transmission into new areas to access wind, as wind resources are more location-constrained than solar because the cost difference between moderate and good resources is more pronounced. TVA will likely find it economically optimal to obtain a large share of its wind from neighboring regions, so it will likely need less of this type of transmission. The location of replacement generation has an important impact on local reliability concerns triggered by generator retirements, so integrated planning will allow TVA to determine

[26] Carolinas Transmission Planning Collaborative, *Transmission Advisory Group Scope* (April 2024) https://carolinastpc.org/static/tag/Scope-Transmission-Advisory-Group.pdf.
[27] MISO, *Long Range Transmission Planning (LRTP)*, https://www.misoenergy.org/engage/committees/long-range-transmission-planning/.

locations for siting solar and storage resources that will minimize transmission investment needs.

Iterating between generation and transmission planning to refine plans over time fits well with TVA's current generation planning processes. TVA's IRP does not select specific resources, but rather evaluates broad courses of action; later, TVA makes specific resource decisions that are consistent with the general direction identified in the IRP. TVA can thus add transmission planning early in that process, particularly for high-capacity transmission that has a much longer lead time than generation, to iterate between generation and transmission planning as plans are refined. As discussed in the next section, many utilities begin with rough conceptual plans for a co-optimized generation and transmission expansion, and then refine them over time based on evolving needs and market bids for specific generation projects.

### B. Case studies of integrating transmission and generation planning

#### Salt River Project

Arizona utility Salt River Project (SRP) has moved to an Integrated System Plan that attempts to minimize the total cost to ratepayers of generation plus transmission and distribution, consistent with the MISO method described above. Because precise generator locations are not known, SRP explores different scenarios for generation additions and their locations, and assesses the impact of adding those resources on transmission constraints.[28] SRP then models the transmission expansion that will be required under each scenario, and identifies the lowest-cost solutions. SRP indicates it intends to "Proactively plan to expand transmission infrastructure to enable generator interconnections and load growth"[29] based on those results, with a particular focus on proactively identifying higher-voltage transmission expansion that takes longer to plan, permit, and build.

#### Xcel Colorado

Xcel's utility subsidiary Public Service Company of Colorado uses similar methods to conduct integrated transmission and generation planning in its IRP, which is called an Electric Resource Plan (ERP). Xcel notes that "following the Company's 2016 ERP, Public Service's Transmission Planning and Resource Planning groups have been actively collaborating on how to better align their respective processes for future ERPs. One of the outcomes of those efforts has been attempting earlier identification of the anticipated size and location of potential generation resources needed to meet public policy initiatives, so

---

[28] Salt River Project, *2023 Integrated System Plan*, https://www.srpnet.com/assets/srpnet/pdf/grid-water-management/grid-management/isp/SRP-2023-Integrated-System-Plan-Report.pdf, at 12-14, 84-92, 115-118.
[29] *Id.*, at 14.

that Public Service's transmission planners can help identify the transmission necessary to reliably accommodate new resources."[30]

This process resulted in Xcel's ERP successfully proposing a looped double-circuit 345-kV transmission expansion from the Denver area into eastern Colorado, called the Pathway Project. In the ERP, Xcel describes the iterative process through which the proactive transmission plan precedes the selection of specific interconnecting generators through an economic bidding process: "Generation facilities that will ultimately interconnect to the Pathway Project will largely be driven by the competitive Phase II resource solicitation that will occur in this Proceeding. However, the proposed location and route of the line is strongly influenced by the location of developer bids received in previous ERPs."[31] Xcel also explains that it accounts for direct interconnection costs in reviewing bids, but not network upgrades as those are shared among many generators and provide multiple benefits: "Transmission network upgrade costs are not factored into bid comparisons as these costs address the cumulative system impact of the aggregate bids comprising the Preferred Plan and do not affect individual bid pricing."[32]

The initial transmission expansion was proposed with the expectation that those plans would be refined in response to generation bids received in Phase II. As Xcel explains, "Determining transmission system reliability is an iterative process that consists of performing increasingly rigorous system performance assessment studies to determine and/or validate system reliability needs. This iterative process will result in better defined scope and specifications for the suite of transmission facilities needed to reliably operate the system. As the uncertainties affecting transmission planning study assumptions narrow with the availability of additional information, such as the known resource portfolio, the Company can correspondingly better identify its system reliability needs."[33] Low-cost generation bids in certain areas also resulted in additional transmission expansion into those areas becoming cost-effective: "those needs have greatly expanded and this Phase II analysis identified a substantial magnitude of network upgrade projects

[30] Hari Singh, *Direct Testimony and Attachments of Hari Singh,* (March 2021) https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/Clean%20Energy%20Plan/HE_107_-Direct_Testimony-Hari_Singh.pdf, at 19.

[31] *Id.*,at 27.

[32] Xcel Energy, *2021 ERP, Appendix Q: Phase II Transmission Report*, (September 2023) https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/PUBLIC%20Appendix%20Q%20-%20Transmission%20Report.pdf, at 23.

[33] Hari Singh, *Direct Testimony and Attachments of Hari Singh,* (March 2021), https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/Clean%20Energy%20Plan/HE_107_-Direct_Testimony-Hari_Singh.pdf, at 49.

within the San Luis Valley as well, given the competitiveness of bids and the size of the portfolios."[34]

Xcel explains how this proactive transmission plan is more cost-effective than a reactive queue-driven approach: "Absent a new major, strategic transmission resource in eastern Colorado, generators would be left to develop, on an ad-hoc and uncoordinated basis, long radial lines or generation tie lines (referred to as "gen-ties") to interconnect dispersed clean energy resources to the Company's existing transmission network. This approach has numerous drawbacks from a transmission planning and operations perspective and should be avoided. Moreover, requiring individual bidders/generators to construct radial lines or gen-ties on an uncoordinated basis to interconnect to the Company's system would add potentially significant costs to projects."[35]

To confirm the cost-effectiveness of transmission expansion, in Phase 2 Xcel allowed generators to bid in their costs with or without the proposed May Valley – Longhorn Extension (MVLE) line, and then compared the total cost of generation plus transmission under the two scenarios. This analysis found that adding this segment to the Pathway Project was cost-effective: "the Company's analysis shows that the Preferred Plan, including the costs of the MVLE, is a lower-cost plan than if the Company were to not construct the MVLE."[36]

Xcel further documents its focus on proactive planning of long-term transmission solutions to realize economies of scale: "the Company avoids the development of minimum viable transmission projects that are unable to accommodate expected future growth and instead prioritizes projects that strike a reasonable balance between short- and long-term system needs. This is done by evaluating the transmission project concepts on a long-term horizon using forecasted load growth assumptions. Seeking out projects that solve near-term transmission constraints, while also providing a reasonable level of increased capacity, allowing for future load growth, operational flexibility, and in turn provides better value to customers."[37]

---

[34] Xcel Energy, *2021 ERP, Appendix Q: Phase II Transmission Report*, (September 2023) https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/PUBLIC%20Appendix%20Q%20-%20Transmission%20Report.pdf, at 8.
[35] Hari Singh, *Direct Testimony and Attachments of Hari Singh,* (March 2021), https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/Clean%20Energy%20Plan/HE_107_-Direct_Testimony-Hari_Singh.pdf, at 22-23.
[36] Xcel Energy, *2021 ERP, Appendix Q: Phase II Transmission Report*, (September 2023) https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/PUBLIC%20Appendix%20Q%20-%20Transmission%20Report.pdf, at 25.
[37] *Id.*, at 6-7.

## PacifiCorp

PacifiCorp has successfully integrated generation and transmission planning in its IRP. This resulted in the Energy Gateway project, including Gateway South and Gateway West, which are now nearing completion. PacifiCorp explains why it transitioned to this proactive approach: "Until PacifiCorp's announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered on new resource additions identified in the IRP. With timelines of seven to ten years or more required to site, permit, and build transmission, this traditional planning approach was proving to be problematic, leading to a perpetual state of transmission planning and new transmission capacity not being available in time to be viable for meeting customer needs. The existing transmission system has been at capacity for several years, and new capability is necessary to enable new resource development."[38]

That initial plan has been iteratively refined over time in response to changes in interest from generation developers and others. For example, "PacifiCorp included in its original plan the potential for doubling the project's capacity to accommodate third-party and equity partnership interests. During late 2007 and early 2008, PacifiCorp received in excess of 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint, which supported the upsized configuration. PacifiCorp identified the costs required for this upsized system and offered transmission service contracts to queue customers. These queue customers, however, were unable to commit due to the upfront costs and lack of firm contracts with end-use customers to take delivery of future generation and withdrew their requests. In parallel, PacifiCorp pursued several potential partnerships with other transmission developers and entities with transmission proposals in the Intermountain Region. Due to the significant upfront costs inherent in transmission investments, firm partnership commitments also failed to materialize, leading PacifiCorp to pursue the current configuration with the intent of only developing system capacity sufficient to meet the long-term needs of its customers."[39]

PacifiCorp has reduced the voltage and thus capacity of some proposed transmission elements in response to updated information about developer interest in those locations. "In 2012, PacifiCorp determined that one new 230-kV line between the Windstar and Aeolus substations and a rebuild of the existing 230-kV line were feasible, and that the second new proposed 230-kV line and proposed 500-kV line planned between Windstar and Aeolus would be eliminated. This decision resulted from PacifiCorp's ongoing focus on meeting customer needs, taking stakeholder feedback and land-use limitations into consideration, and finding the best balance between cost and risk for customers."[40]

---

[38] Pacificorp, *2023 Integrated Resource Plan: Volume I*, (March 2023) https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_I.pdf, at 100.
[39] *Id.*, at 103.
[40] *Id.*, at 104.

**Idaho Power**

Idaho Power has also incorporated transmission into its IRPs.[41] This has resulted in proactive development of transmission tie projects that provide it with the ability to import resources from and access net load diversity with other regions. This includes the Boardman-to-Hemingway line it is co-developing with PacifiCorp as part of Gateway West, and the SouthWest Intertie Project North (SWIP-North). Idaho Power also accounts for the cost of interconnecting generation as part of its IRP economic modeling.

**Portland General Electric**

In its most recent IRP, Portland General Electric (PGE) included transmission capacity and the associated enabled generation as a selectable resource, based on estimated costs for the transmission capacity.[42] PGE allowed the model to economically select transmission upgrades that would allow it to access in-region resources. The IRP also modeled options for transmission to access Wyoming wind and Desert Southwest solar, either through transmission upgrades or purchases of rights on existing transmission capacity. As discussed more in the following section, PGE also accounted for the capacity value benefit of these interregional ties due to net load diversity with those different regions. PGE's economic optimization found that all of these options were net beneficial, and they were selected for the preferred portfolio.

**Xcel Minnesota**

Xcel Minnesota's need to plan transmission is more limited than the other utility examples discussed above because it is part of MISO, a Regional Transmission Organization that has primary responsibility for transmission planning in the region. However, Xcel's 2020-2034 IRP, approved in 2022,[43] did include the addition of two 345-kV transmission tie lines from retiring coal plants to access a diverse mix of replacement resources, with the exact resources to be chosen using subsequent RFPs. This integrated generation and transmission planning meets both economic and reliability needs by accessing the lowest-cost mix of replacement resources and ensuring local reliability is maintained with the system reconfiguration required due to the retirements.

---

[41] Idaho Power, *Integrated Resource Plan*, (September 2023) https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2023/2023-irp-final.pdf, at 83-98.
[42] Portland General Electric, *Clean Energy Plan and Integrated Resource Plan 2023*, https://assets.ctfassets.net/416ywc1laqmd/7gZv7ENSucpUszs63bDQG6/aaae6d2a430e97189edcc836cd2a604e/2023_CEP-IRP_Ch_09.pdf, at 227-228.
[43] Minnesota Public Utilities Commission, *Order Approving Plan with Modifications and Establishing Requirements for Future Filings*, https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={202C2F80-0000-C11A-BA52-EC8AB5636CD4}&documentTitle=20224-184828-01, at 31.

**Other examples**

Several years ago, NV Energy obtained state regulatory approval for its Greenlink Nevada proactive transmission expansion.[44] This expansion was proactively designed to access known renewable resource areas, including a diverse mix of solar, wind, and geothermal resources that best meet its generation needs. The project was also multi-value in that it was designed to address local reliability and load growth needs. NV Energy also focused on how the expansion would interface with existing and planned regional transmission projects to increase import and export capacity.

As mentioned above, Duke recently obtained FERC approval to create a new category of Multi-Value Strategic Transmission in its local planning process. Duke also used its 2022 and 2023 Carbon Plan and Integrated Resource Plan to develop Red Zone Expansion Projects that facilitate the interconnection of proposed solar and battery resources in the queue. Duke's 2022 plan also included a conceptual high-voltage transmission expansion needed to meet carbon reduction requirements.[45]

---

[44] NV Energy, *PUCN Approves NV Energy's Greenlink Nevada Transmission and Renewable Energy Initiative*, (March 2021) https://www.nvenergy.com/about-nvenergy/news/news-releases/pucn-approves-nv-energys-greenlink-nevada-transmission-and-renewable-energy-initiative.

[45] Duke Energy, *2022 Carolinas Carbon Plan: Appendix P*, (May 2022) https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-carbon-plan/supplemental/appendix-p.pdf?rev=f9cda767bc2d4c55a100771b314689f2, at 13-21.

## III. Opportunities for and benefits of TVA expanding transmission ties to neighboring grid operators

### A. Value of expanding ties

Expanding transmission ties to neighboring grid operators can significantly improve reliability and reduce cost. Expanded ties could not only deliver lower-cost resources, including wind and solar energy, but also offer TVA dependable capacity because of diversity in the timing of peak demand, renewable output, and conventional generator outages between TVA and neighboring regions.[46] These opportunities should be evaluated to inform TVA's resource decision-making because they can offer energy and capacity at lower cost than building generating resources in TVA's footprint.

Utilities experience peak demand and generator outages at different times, and tapping into this diversity significantly reduces the planning reserve margin that is needed to maintain the same level of reliability.[47] That diversity also increases resilience during extreme weather events, as extreme weather systems move over time and tend to be at their most severe in relatively small geographic areas.[48] With expanded ties to neighbors, TVA could have reduced or eliminated the need to resort to rolling blackouts following correlated generator outages during Winter Stom Elliott. For example, MISO South was not

---

[46] M. Goggin *et al.*, *Quantifying a Minimum Interregional Transfer Capability Requirement*, (May 2023) https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf, at 4.

[47] For example, MISO finds around $3.2 billion in annual benefits because "MISO's large geographic footprint allows members to lower planning reserve margins (PRM), ultimately reducing the amount of required installed capacity. Much of the value MISO creates comes from the value of sharing capacity across MISO's large geographic footprint—by setting requirements for a system peak instead of each balancing authority keeping reserves for their own region. Savings are generated because MISO members do not need as much capacity for the same level of reliability." MISO, *MISO Value Proposition Annual View, 2023 Overview* (March 2024), at 6, available at https://cdn.misoenergy.org/2023%20Value%20Proposition%20Annual%20View%20-%20Detailed%20Report%20Final632082.pdf?v=20240306103856. Similarly, PJM finds $1.2-1.8 billion in annual savings because "There is considerable diversity in electrical use patterns in the large PJM footprint; not all areas peak at the same time of the year. As a result, resources in one area of the system are available to help serve other areas at peak times, and a smaller reserve is required. In addition, the large and varied resource fleet across the entire PJM region spreads the generator outage risk across a larger collection of generators, improving reliability." PJM, *PJM Value Proposition*, at 2, available at: https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ashx.

[48] M. Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, (July 2021) https://www.cleanenergygrid.org/wp-content/uploads/2021/09/GS_Resilient-Transmission_proof.pdf; M. Goggin and Z. Zimmerman, *The Value of Transmission During Winter Storm Elliott*, (February 2023) https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf.

experiencing major generation shortfalls during TVA's time of peak need on Christmas Eve 2022, while ERCOT had an abundance of surplus generation.[49]

Given TVA borders grid operators whose footprints stretch from Texas to Florida to New Jersey to the Dakotas, at least one of TVA's neighboring power systems is likely to have available capacity during TVA's time of peak need. A stronger regional grid allows all utilities to share in those resilience benefits and maintain the same level of reliability with a lower reserve margin. This is confirmed by preliminary modeling from NERC's Interregional Transfer Capability Study, which identifies large transmission capacity increases between TVA and its neighbors as prudent additions due to significant diversity benefits with neighbors like SPP and Duke.[50] Because these neighbors would benefit from these lines, they and their regulators should have an interest in partnering on the planning and cost allocation for these lines. While the study does not identify a resource shortfall for TVA when extrapolating from historical weather patterns to model future years, if TVA were to experience generation shortfalls like it did during Winter Storm Elliott expanded transmission ties would mitigate or prevent rolling blackouts. Ties also significantly reduce production costs by allowing TVA to import lower-cost power from neighbors when it is available and profitably export power when its supply is greater than its demand.

TVA's planned solar additions further increase the value of expanding these ties. Given TVA's relatively inflexible conventional generation fleet, expanding ties will allow TVA to export solar during the day and summer and import other energy resources, including wind, at night and during the winter. Capturing diversity in renewable output across large geographic areas is essential for cost-effectively achieving higher renewable penetrations. Geographically diverse renewables, as well as a more diverse portfolio of solar and wind, provide more dependable capacity and less variable output because their output profiles are weakly or negatively correlated. Multiple studies have confirmed that expanding transmission ties within and among grid operators to access that diversity is essential for cost-effective decarbonization.[51] For example, stronger ties to neighboring grid operators

[49] M. Goggin et al., *Quantifying a Minimum Interregional Transfer Capability Requirement*, (May 2023) https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf, at 4.
[50] NERC, *Interregional Transfer Capability Study Advisory Group Meeting (Updated slide deck 8/29)*, (August 2024) https://www.nerc.com/pa/RAPA/ITCS/ITCS_AG_Presentation_20240827.pdf, at 27-29.
[51] *See, e.g.*, Patrick Brown and Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, Joule 5(1), (January 2021) https://www.sciencedirect.com/science/article/pii/S2542435120305572; NREL, *The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study* (September 2021) https://ieeexplore.ieee.org/document/9548789; MacDonald et al., *Future Cost-Competitive Electricity Systems and Their Impact on US CO2 Emissions*, Nature Climate Change, 526–531 (2016) https://www.nature.com/articles/nclimate2921, at 6.

will allow TVA and other utilities in the Southeast to export solar during the day and in the summer and import wind from other areas at night and during the winter.[52]

Expanded transmission capacity is particularly important because it provides TVA with access to wind resources in neighboring regions that are higher quality and have a different output profile than wind resources that can be developed within its footprint. These more productive wind resources offer energy at a significantly lower cost than lower output resources in the Southeast. Modeling using the EnCompass capacity expansion tool by Synapse Energy Economics found that importing wind resources from neighboring regions was economically optimal, even after accounting for the cost of transmission: "The TVA Baseline scenario models 45 TWh of wind power purchase agreements (PPA) with neighboring regions by 2050; the 100% Clean Energy scenario has 130 TWh of non-TVA wind PPAs (about one-third of TVA's total generation)."[53] "our 100% Clean Energy scenario would require $45 billion of new capital investment on new inter-regional transmission lines in order to facilitate 39 GW of low-cost, high-capacity factor wind in TVA's neighboring territories."[54] That analysis assumed all transmission tie lines are built at 500 kV Alternating Current, so costs could be lower if higher-voltage solutions including Direct Current lines were used.

Proactively planned ties to neighboring grid operators can also be a more efficient way of addressing needed upgrades on those neighboring systems that can be triggered by interconnecting resources on TVA's system. Currently, whether proposed generation projects in the queue trigger a need for upgrades on neighboring systems is evaluated in "affected system" studies, which are typically conducted at the final stages of the interconnection study process. These studies can result in large upgrade costs being allocated to those generators, which can cause them to drop out, which in turn can shift upgrade costs to other generators through the restudy processes, causing cascading uncertainty and costs to projects throughout the queue. Using proactive transmission planning and shared cost allocation to build needed transmission near the seam can benefit both neighboring grid operators by alleviating the reliance on affected system studies to plan and pay for those upgrades. This was the primary impetus for the Joint Targeted Interconnection Queue projects that MISO and SPP are developing, as discussed

[52] Americans for a Clean Energy Grid, *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.* (October 2020), https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf, at 21-22.
[53] P. Knight et al., *TVA's Clean Energy Future*, (March 2023) https://www.biologicaldiversity.org/programs/energy-justice/pdfs/TVAs-Clean-Energy-Future.pdf, at 4.
[54] *Id.*, at 19, 39.

in more detail below.[55] This would benefit TVA by reducing the interconnection costs and uncertainty associated with generators in its queue.

Because ties can access low-cost generation and provide capacity value, they should be economically compared against other potential sources of energy and capacity in integrated planning. Given the long lead time required to develop new transmission ties, particularly with neighboring grid operators, a long-term planning process like an Integrated Resource Plan is the appropriate forum to assess their value. Probabilistic resource adequacy modeling could be used in the planning process to more comprehensively assess the capacity value benefits of ties with different neighboring grid operators relative to in-region capacity resources.

Other utilities have economically evaluated tie expansions as part of an IRP. As noted above Portland General Electric's most recent IRP selected transmission to access Wyoming wind and Desert Southwest solar as part of the economically optimal portfolio. PGE also included the capacity value benefit this transmission expansion provides due to net load diversity with those other regions, though PGE noted that additional analysis would be needed to more precisely quantify that benefit as more specific plans evolve.[56] This would likely include probabilistic resource adequacy modeling, and is consistent with the general process of iterative modeling that refines options over time.

Xcel Colorado modeled the economic value of a tie with PacifiCorp in its ERP. As discussed above, Idaho Power has successfully planned multiple large transmission tie lines with neighbors. PacifiCorp's IRP includes impacts of planned transmission on its import and export transfer capacity. As noted above, NV Energy including the benefit of expanded ties in evaluating Greenlink Nevada.

### B. Potential options for TVA to expand transmission ties

Given constraints on existing transmission ties, upgrades or new transmission lines are likely to play an important role in expanding TVA's ability to import and export power. In some cases TVA may be able to expand ties by increasing capacity on its own lines to alleviate constraints on its system near interfaces with neighbors that limit import and export capacity. Lines or upgrades that directly interconnect with neighbors may require coordinated planning and cost allocation with those neighbors. Many neighbors should be amenable to this coordination because of their own increasing need for ties due to load growth, the transition of the generation fleet, and recent resilience events.

[55] SPP and MISO, *SPP-MISO Joint Targeted Interconnection Queue Cost Allocation and Affected System Study Process Changes* (December, 2022), available at: https://www.spp.org/documents/68518/spp-miso%20jtiq%20study%20updated%20white%20paper%2020221220.pdf.

[56] Portland General Electric, *Clean Energy Plan and Integrated Resource Plan 2023*, https://assets.ctfassets.net/416ywc1laqmd/7gZv7ENSucpUszs63bDQG6/aaae6d2a430e97189edcc836cd2a604e/2023_CEP-IRP_Ch_09.pdf, at 227-229.

TVA should be able to more easily obtain low-cost wind as MISO's LRTP Tranche 1 and 2 lines are completed, allowing the interconnection of dozens of GW of new wind and the delivery of those resources to eastern MISO. MISO's current Tranche 2 plans include transmission expansion into Kentucky near TVA's interface with MISO.[57] MISO would likely find expanded ties with TVA to be mutually beneficial, given net load diversity between the regions. TVA could use those same ties to export solar given that MISO currently has a limited solar penetration.

Example of potential new transmission projects that would expand TVA's ties with MISO include extending TVA's 500 kV network northward from its current terminus at Paradise in Kentucky to the Wilson 345 kV substation,[58] which could at least partially include expansion of an existing 161 kV corridor. MISO's current plan for LRTP Tranche 2 includes building a new 345 kV line down to the Green substation, which is connected to Wilson with 345 kV.[59] As MISO begins to explore options for expanding transmission ties between MISO North and South in LRTP Tranche 4, TVA could play an important role in those discussions. Because many transfers between MISO South and North flow across TVA's transmission system today, TVA could potentially expand transfer capacity with both parts of MISO through Tranche 4 expansions.

To expand ties with PJM, TVA could extend its 500 kV network from Paradise northward across the Ohio River to the Rockport substation, which is part of PJM's 765 kV network. TVA could also expand or increase the voltage on its 500 kV transmission tie from the Sullivan substation in Tennessee to Broadford in Virginia to access PJM's 765 kV network there.

In addition to building new lines, TVA could also sign contracts for capacity on proposed Direct Current merchant transmission lines. The Southern Spirit transmission line is proposed to provide 3,000 MW of transfer capacity between ERCOT and a point in Mississippi where it could deliver power to TVA's system. The proposed project continues to move forward despite a setback due to legislation in Louisiana that limits its ability to use eminent domain to secure right-of-way for the line. Ties between ERCOT and the Southeast are particularly valuable for providing dependable capacity to both regions.[60]

---

[57] MISO, *Tranche 2.1 Near-Final Portfolio: LRTP Workshop*, (June 2024) https://cdn.misoenergy.org/20240610%20LRTP%20Workshop%20Item%2002%20Near-Final%20Portfolio633836.pdf, at 9.
[58] MISO, *MTEP18*, https://cdn.misoenergy.org/MTEP18%20Full%20Report264900.pdf, at 106.
[59] MISO, *Tranche 2.1 Near-Final Portfolio: LRTP Workshop*, (June 2024) https://cdn.misoenergy.org/20240610%20LRTP%20Workshop%20Item%2002%20Near-Final%20Portfolio633836.pdf at 9.
[60] D. Stenclik and R. Defoe, *Multi-Value Transmission Planning for a Clean Energy Future*, (June 2022) https://www.esig.energy/wp-content/uploads/2022/06/ESIG-Multi-Value-Transmission-Planning-report-2022.pdf, at 47.

Grain Belt Express proposes to deliver up to 5,000 MW of low-cost wind and solar from western SPP, half to MISO in Missouri and half to PJM near the Illinois-Indiana border. Both interconnection points are somewhat electrically near interfaces with TVA, so TVA could contract for capacity on the line and deliver its output by wheeling the power through MISO or PJM.

TVA's proposal to the Department of Energy to fund transmission upgrades on TVA's system to interconnect solar and build a connection to SPP to access wind energy confirms the value of transmission expansion. TVA explains that its proposal "will enable the construction of an inter-regional 800-megawatt transmission line to bring wind power to the region, will increase grid capacity by about 5,500 megawatts, and will unlock more than 6 gigawatts of solar in TVA's interconnection queue."[61]

The Department of Energy's National Transmission Planning Study identified upgrades similar to those discussed above in its economically optimal transmission expansion, as shown in the maps below.[62] In the Alternating Current ("AC") framework, the study found several new 500-kV ties to each of MISO and PJM were optimal, along with a major expansion of TVA's internal 500-kV network. The study's Multi-Terminal High-Voltage Direct Current ("MT-HVDC") framework built two Direct Current ties into the Southeast from SPP and one each from MISO and PJM, in addition to significant 500-kV AC expansion within TVA and with MISO and PJM.

---

[61] TVA, *TVA, Partners Seek $350 Million in DOE Grant Funding to Lower Energy Costs, Strengthen Grid and Increase Clean Energy*, (June 2024) https://www.tva.com/newsroom/press-releases/tva--partners-seek--350-million-in-doe-funding-to-lower-energy-costs--strengthen-grid-and-increase-clean-energy.

[62] DOE, *National Transmission Planning Study: Executive Summary*, (October 2024) https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-ExecutiveSummary.pdf, at 23.

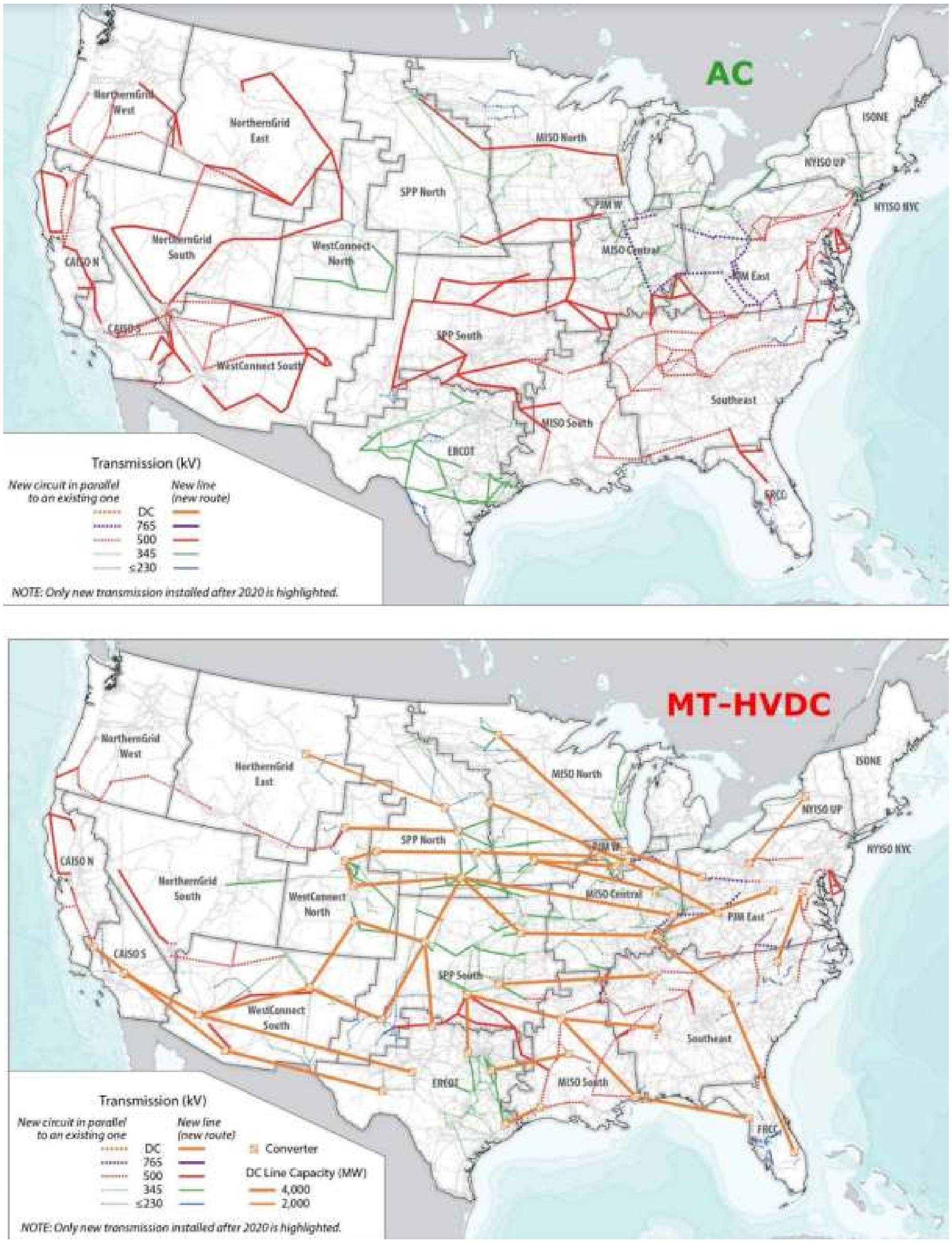


**Figure 2: National Transmission Planning Study map showing transmission expansion by 2035 in Alternating Current and Multi-Terminal High Voltage Direct Current cases**

Where available, TVA can also secure expanded transmission rights to access renewable resources or increase its ability to import or export power. FERC gives the purchaser of transmission rights with a term of at least five years the right to extend those rights indefinitely, which would allow TVA to ensure deliverability for the life of a generation project.

### C. Policy drivers for expanding transmission ties

FERC and the U.S. Congress have explored options for requiring regions to increase their transfer capacity with other regions. By direction of Congress, NERC is currently completing a study on prudent additions to interregional transmission capacity. NERC will deliver that report to FERC in December 2024, and FERC is then required to develop a report. FERC or Congress could also take action on interregional transfer capacity requirements in the interim.

In Order 896, FERC directed NERC to develop a reliability standard that accounts for risks and requires the region to implement solutions to address any reliability concerns, and those solutions can include transmission expansion. NERC is currently drafting a new standard, TPL-008, that implements that requirement.[63]

TVA can also take action on its own to partner with neighboring utilities to proactively plan net beneficial upgrades to their ties with a negotiated cost allocation, like what MISO and SPP have recently adopted through the Joint Targeted Interconnection Queue projects.[64]

FERC Order1920 and TVA's engagement with SERTP

FERC Order 1920 is likely to be the most important policy driver for new transmission between TVA and other utilities in the Southeast. As it has done with past FERC transmission planning orders, TVA can voluntarily work with other utilities in Southeastern Regional Transmission Planning (SERTP) processes to develop a workable mechanism for planning and paying for net beneficial regional transmission, per the requirements of FERC Order 1920. As explained above, this would be in the interests of TVA ratepayers due to the economic and reliability benefits of expanding transmission ties.

[63] NERC, *Project 2023-07 Transmission System Planning Performance Requirements for Extreme Weather*, https://www.nerc.com/pa/Stand/Pages/Project-2023-07-Mod-to-TPL00151.aspx.
[64] SPP and MISO, *SPP-MISO Joint Targeted Interconnection Queue Cost Allocation and Affected System Study Process Changes* (Dec. 20, 2022), available at: https://www.spp.org/documents/68518/spp-miso%20jtiq%20study%20updated%20white%20paper%2020221220.pdf.

## Conclusion

Proactive multi-value transmission planning that is iteratively integrated with generation planning can yield large savings and improved reliability for TVA's ratepayers. To realize those benefits, TVA should:

1. Identify portfolios of generation and transmission that minimize cost and risk for ratepayers,

2. Account for the multiple types of benefits provided by transmission,

3. Proactively plan the high-capacity transmission that will be needed to cost-effectively meet needs looking at least 20 years in the future, with that transmission planning preceding interconnection applications for specific generators,

4. Iterate between transmission and generation planning and among different models to develop, test, and refine optimal portfolios as additional information becomes available,

5. Include stakeholders in the transmission planning process to provide overall direction and feedback on how to refine iterative plans,

6. Quantify the net benefits of expanding transmission ties to other grid operators, and weigh those against local generation projects, and

7. Fully integrate transmission planning into future resource decisions and into all future IRPs.