Opportunities for Transmission in TVA's 2025 Integrated Resource Plan

Best Practices and Recommendations for Integrated Resource and Transmission Planning

TELOS ENERGY

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Table of Contents

1. Executive Summary

The Tennessee Valley Authority (TVA) faces a critical moment in planning for its future energy needs. As the region experiences substantial economic growth and transitions to a more diverse resource mix, it is essential that TVA's long-term planning fully integrates both generation and transmission to ensure the grid remains reliable, resilient, and cost-effective. While TVA's 2025 Integrated Resource Plan (IRP) conducts detailed analysis around new generating resources, it largely ignores transmission - both internal to TVA and interregional connections to its neighbors - as an asset to improve system economics and reliability.

Proactive transmission planning, fully integrated with resource planning, is foundational in enabling a modernized grid that delivers reliability in a forward looking and optimized fashion. Recognition of the multiple benefits that both internal and external transmission already provide the grid is growing and allowing more robust transmission planning to succeed. Methods like MISO's Multi-Value Planning (MVP) approach used in their Long Range Transmission Planning (LRTP) process are exemplary of this trend. Today, existing interregional transmission ties already provide substantial benefits, including supporting resource adequacy during extreme weather events and allowing TVA to access cost-effective energy from neighboring regions. Reports such as NERC's recently published Interregional Transfer Capability Study and ACORE and Grid Strategies' analysis of Winter Storm Elliott highlight the critical reliability value that these connections offer during times of peak demand or system stress.

TVA has taken important steps by initiating a long-term integrated transmission plan (ITP). However, gaps remain in fully representing various transmission scenarios in its IRP and improving interregional resource and transmission representations. Not only is transmission needed to interconnect and deliver energy from new resource additions, but transmission can also defer new capacity additions entirely.

Furthermore, TVA assumes its footprint is a copper sheet and does not differentiate between locations for siting new generation resources. This prevents opportunities to proactively identify transmission to access new renewable energy zones or facilitate the reliable retirement of aging plants. At a minimum, TVA should adopt an internal zonal representation of transmission constraints in its capacity expansion and resource adequacy modeling, otherwise portfolios developed are suboptimal and do not adequately reflect system constraints nor identify opportunities to enact large-scale multi-benefit projects, nor can it capture opportunities to optimize system costs through interregional coordination.

The purpose of these comments is to provide actionable recommendations that TVA can implement to incorporate transmission considerations in its IRP and adopt proactive, multi-value transmission planning principles. By leveraging best practices adopted by MISO, SPP, and other regions and outlined in FERC Order No. 1920, TVA can develop a least-cost, least-regrets plan that evaluates generation and transmission together. To this end, the checklists below are recommendations TVA can adopt for the final 2025 IRP and for its next IRP cycle. TVA should consider a new integrated resource and transmission plan (IRTP) that combines both the IRP and ITP framework into a cohesive planning process. Faced with increased retirements, substantial population and manufacturing growth, new electrification, and a changing resource mix, these practices are foundational elements for TVA and its 10 million customers.

Based on existing best practices for IRPs, multi-value planning, and interregional transmission planning the following recommendations should be adopted in the Final 2025 IRP:

Table 1. Near-term improvements to TVA's 2025 IRP

Recommendation	Implementation
Adjust transmission costs for external wind resources	Align transmission costs for accessing wind resources in MISO and SPP to reflect recent interregional transmission awards from DOE GRIP funding.
Incorporate scenarios from SERTP economic study to represent new resource candidates	Use planning level transmission upgrade estimates from SERTP economic studies for candidate resources in IRP scenarios. Determine how these transmission projects could reduce reserve margin requirements. High priority should be given to solar resources in MISO South and wind resources in MISO North informed by recent SERTP results.
Conduct a sensitivity in the Planning Reserve Margin Study with increased interregional transfer capability	Use TVA's SERVM model to evaluate how increased interregional transfer capability can reduce reserve margin needs. Ideally, determine at which point interregional benefits are saturated and no longer reduce reserve margin requirements.

Additionally, longer term improvements can be made for the next IRP cycle if the following recommendations are adopted:

Table 2. Proposed actionable long-term studies/improvements to facilitate integrated resource and transmission planning for TVA's long-term analyses.

Recommendation	Implementation/Benefits
Quantify internal zonal transfer capability and adopt it in EnCompass and SERVM	Conduct zonal transfer analysis to identify existing constraints in TVA's system. Incorporate these as separate zones for optimized capacity expansion modeling with different resource types. Model transmission builds to increase zonal limits to identify high-level transmission upgrades.
Identify renewable energy zones (REZs) to expedite interconnecting clean energy and reduce interconnection costs	Shortened timelines for new resources, proactive community engagement, targeted developer activity. Coordinate REZ builds to alleviate transmission bottlenecks due to retiring resources. Include REZ build options in EnCompass.
Enhance TVA's Strategic Coal Plant Retirement Studies	TVA has identified 5.8 gigawatts (GW) of coal plants for retirement by 2035 based on their age. Evaluating transmission and generation needs for all retirements system-wide could improve economies of scale and enable proactive planning. Avoid piecemeal EIS retirement analyses which could cause delays.
Evaluate large load interconnection in coordination with resource additions and retirements	Coordinate large load interconnections with retirement and REZ analyses. Facilitate new loads and support the transmission network under one framework, not using piecemeal approaches for different planning silos. Proactively Signal to large loads where they should develop new projects to streamline interconnection and reduce new fossil builds.
Improve representation of external ties and interregional transfer capabilities	Model full transfer capability between TVA and its neighbors. Quantify the probabilistic availability of external resources to improve external resource representation and allow interregional transmission as a capacity resource in the IRP.

The remainder of this document provides both near- and long-term recommendations for TVA's IRP and transmission planning processes. The focus of these comments is related specifically to transmission given its omission as a dedicated resource in the IRP. The comments are organized as follows:

- Section 1 provides near-term improvements to TVA's 2025 IRP that can be implemented prior to the final IRP filing,
- Section 2 outlines opportunities for adopting a forward looking, scenario-based, multi-value transmission planning approach, and
- Section 3 provides recommendations for five specific compendium studies that would provide foundational information for a future integrated resource and transmission plan.

2. Near-term Improvements to TVA's 2025 IRP

TVA has taken meaningful steps toward integrating transmission considerations into its planning framework and developing a long-term plan. Creating an integrated transmission plan (ITP) provides the opportunity to link generation portfolios in the IRP to the transmission infrastructure necessary to support them. However, resource portfolios are developed with no existing transmission constraints in the EnCompass model. While both processes are described as "Integrated," they are in practice isolated into two planning silos. Two separate planning processes risk missing lower-cost portfolios that balance generation, transmission and storage.

This section of the comments focuses on near-term recommendations that TVA could adopt for its current 2025 IRP before the final publication.

Near-Term Recommendation 1: Adjust Transmission Costs for External Wind Resources

In Appendix E - Utility Scale Resource Methodology, TVA states that wind accessed via high voltage direct current (HVDC) transmission would cost 3,171 $/kW. Another external wind resource is identified as Midcontinent Independent System Operator (MISO) wind which is 1,625 $/kW, or 1,546 $/kW cheaper than the HVDC wind, almost half the cost. The IRP states that HVDC resource costs were based on a vendor offer for wind delivered from the Southwest Power Pool (SPP) into TVA. However, this high cost assumption for SPP wind appears to contrast with the current 800 megawatts (MW) of SPP wind selected in the recent DOE Grid Resilience and Innovation Partnerships (GRIP) program.[1] Funding information for the GRIP award shows that the federal cost share ($250 million) and the recipient funding ($283.2 million) equates to 666 $/kW to access 800 MW of wind. This is less than half of the transmission costs for generic HVDC wind assumed in the IRP. Since transmission is only represented as a $/kW cost assumption in TVA's current IRP, these discrepancies should be addressed since as it is modeled now, accessing SPP wind would cost far more than actual plans indicate based on the GRIP award.

Furthermore, the GRIP funding is an excellent example of how transmission projects provide multiple benefits instead of TVA's current IRP approach which solely considers gen-tie line benefits since transmission is only a $/kW cost adder for building a plant. In fact, the project is delivering multiple benefits such as increasing transmission capacity by 2,400 MW, reducing solar interconnection queues, reducing localized outage time, and as well as providing access to the SPP wind resource. All of these

[1] U.S. Department of Energy, *System Hardening for Coalition of Local Power Companies and Tennessee Valley Authority*, https://www.energy.gov/sites/default/files/2024-10/TVA_GRIP2_Fact_Sheet.pdf

benefits should be reflected in the TVA IRP alongside adjusting the transmission cost adder for accessing SPP wind. Additionally, a non-HVDC SPP wind option should be considered if the HVDC technology cost is substantially higher than the alternating current (AC) option.

Near-Term Recommendation 2: Incorporate scenarios from SERTP economic studies to represent new resource candidates

TVA occupies a critical position at the northern boundary of the Southeastern Regional Transmission Planning (SERTP) region, serving as a key pathway for power transfers accessing SPP, MISO, and much of PJM. This geographic position presents unique opportunities for TVA to play a central role in coordinating interregional planning efforts. Enhanced interregional transmission can facilitate greater access to low-cost generation resources from neighboring regions, such as high capacity factor, low cost wind and solar projects from SPP and MISO, while also improving resilience and operational flexibility during extreme weather events.

TVA participates in the SERTP process, including in the economic transmission studies undertaken by this group. These studies provide a regional view of the costs for transmission system upgrades required for different power transfers between SERTP entities and their neighbors during winter and summer peak load cases. However, these transmission proposals are not evaluated further in the TVA IRP. TVA should leverage the planning estimates for transmission costs to deliver power from external resources to TVA during peak load.

It is recommended that TVA directly incorporate one of the SERTP planning cases as a scenario in the 2025 IRP, including a representation of resource cost for MISO or SPP wind or MISO South solar. The table below summarizes previous SERTP studies where costs to upgrade TVA's transmission system would be incurred to facilitate different transfers during peak load for different seasons.

Table 3. Summary of SERTP economic planning cases where TVA would incur costs for transfers between regions.

SERTP Year	Case Year	Season	Transfer Level (MW)	Source to Sink	TVA Cost ($)	Total Cost ($)	Total Cost ($/kW)
2023	2028	Winter	2,900	MISO South to TVA	$21,500,000	$21,500,000	$7.41
2023	2028	Summer	1,600	TVA to North Georgia	$22,800,000	$56,520,000	$35.33
2024	2029	Summer	4,000	MISO South/FRCC to SOCO	$321,000	$1,921,000	$0.48
2024	2034	Summer	10,000	MISO North to SOCO	$980,817,000	$4,607,934,000	$460.79

While only the first SERTP case shown references TVA as the sink from MISO South, the other three cases impact TVA and result in flow through TVA's system. Several themes stand out when reviewing these cases. First, MISO South could potentially provide substantial transfer capability into TVA during winter peak load conditions at minimal cost. This cost estimate could be used in EnCompass as the adder for unlocking resources in MISO South. Then the Strategic Energy Risk Valuation model (SERVM) can be used to assess probabilistic resource availability to inform how much firm capacity the region could provide TVA, or if the planning reserve margin requirement could be reduced by increasing transfer capabilities. Additionally, if desired, the study could solely look at providing solar resources in MISO South to TVA and inform high level transmission costs.

The second theme is that transfers into Southern Company (SOCO) territory will also impact TVA. While not directly assessed by SERTP, TVA should evaluate how much economic and resource adequacy benefit could be realized through enabling large transfers from MISO North into TVA. This can be reflected in the final IRP by representing possible economic transfer into TVA and giving the connection a firm capacity value for increasing transfer capability. For example, the estimate for the SOCO study would be about 460 $/kW for 10,000 MW transfer during summer peak load conditions. Potentially, this could be lower if TVA were the direct sink, or some of this transfer could be made available to TVA to facilitate the projects being built and shared in costs as well as benefits.

Similar to the MISO South example, planning level costs could be assumed to enable large transfer capability into TVA from MISO North for use in EnCompass that aren't strictly connected to wind resources. In turn, SERVM could be used to assess resource availability to provide firm capacity for TVA, or to reduce the planning reserve margin requirement. Again, the scenario could be tailored to evaluate only as an adder for providing very large amounts of wind energy from MISO North to TVA as a large-scale option relative to the 200 MW candidate resource considered in the current IRP.

Existing regional planning studies show there is potential for large amounts of power to flow across the Southeast and that TVA plays a critical role in facilitating these transfers while also accessing economic and resiliency benefits for itself. These studies show there could be opportunities to reduce costs and boost TVA resilience through evaluating SERTP studies in the TVA IRP and acting on these plans. Furthermore, it highlights the importance of improving interregional planning and coordination and the role that external regions already play in TVA's system today.

Near-Term Recommendation 3: Conduct a sensitivity in the Planning Reserve Margin Study with increased interregional transfer capability

Currently, TVA's IRP is driven by the planning reserve margin requirement determined in the probabilistic resource adequacy analysis conducted by TVA and Astrapé Consulting. In this analysis, external zones are modeled based on transfer capabilities between TVA and its neighboring balancing authorities and utilities. This is a good practice and transfer capability internal to TVA should also be modeled. The analysis includes modeling the probabilistic availability of external resources that TVA may call upon to support its system during peak load or extreme weather events. This type of system-wide support is well documented and plays an important role in maintaining grid reliability during extreme weather events like Winter Storms Uri and Elliott. In fact, the availability of imports was shown to reduce the reserve margin requirement by eight percentage points, avoiding roughly 2,500 MW of reserve capacity needs based on winter peak loads for 2024 to 2030.

Two sensitivity analyses were also performed where market imports were reduced by 50% and 100% (island case with no imports). These analyses showed that the winter reserve margin would be +3% and +8% higher with less imports. But sensitivities were only evaluated by *reducing* market purchases. No sensitivities quantified reducing reserve margin requirements by increasing interregional transfer capability. It is recommended that TVA conduct an additional sensitivity that identifies how the planning reserve margin could be reduced if interregional transfer capability were increased.

Ideally, a saturation point for transfers between TVA and its neighbors could be determined and new interregional transmission could be prioritized based on which neighbor has the most uncorrelated resource risk. This can be used to characterize how interregional transmission could be expanded to reduce capacity reserve requirements and is a natural starting point for evaluating expanded transmission with TVA's neighbors.

Furthermore, the study can also determine the availability of importing resources using probabilistic analysis to create confidence intervals for different import levels and cost of imports from external regions. This type of information can feed into the IRP capacity expansion modeling to reflect external market purchases in a robust fashion without requiring modeling external regions directly in EnCompass.

3. Adopting a Forward Looking, Scenario-Based, Multi-Value Transmission Planning Approach

The previous section outlined three actionable steps that TVA can implement to enhance the current 2025 IRP through improved transmission assumptions. These incremental improvements, such as refining external resource transmission cost assumptions, evaluating SERTP economic planning cases in the IRP, and leveraging resource adequacy modeling for additional interregional transmission benefits, represent low-hanging fruit that can immediately strengthen the plan's ability to align generation and transmission resources.

However, while the 2025 IRP can be incrementally improved, there are broader opportunities available in future planning cycles. TVA has not yet embraced a fully integrated approach that combines generation and transmission planning with forward-looking and scenario-based economic planning. This includes leveraging multi-benefit analyses to assess intraregional and interregional transmission projects and creating an **Integrated Resource and Transmission Plan (IRTP).** The remainder of this document explores how TVA can implement a more integrated planning process.

To align transmission planning with the IRP's 20+ year horizon, a forward-looking approach must anticipate system changes, such as generation retirements, new resource additions, and load growth driven by electrification and economic development. This process would include three core tenets included in FERC Order No. 1920 on Long-Term Regional Transmission Planning.[2]

1. **Forward Looking:** The IRTP should be forward looking, similar to the current IRP and plan for potential changes for 20 or more years. This is important given the required lead times for new transmission and to coordinate future resource builds.
2. **Scenario-based:** Methodologies should be employed to evaluate diverse futures, capturing uncertainties in fuel prices, state and federal energy policies and regulations, and technological advancements. By identifying least-regrets pathways, this framework can guide resource and transmission investments that remain resilient under various conditions.
3. **Multi-Benefit:** Adopting a multi-value perspective ensures that the full spectrum of transmission benefits is assessed, including production cost savings, deferred capital investments in aging infrastructure, capacity benefits from reduced loss of load probability (LOLP) or lower planning reserve margins (PRM), and enhanced system resilience against extreme weather events.

Together, these considerations form the foundation of a truly integrated resource and transmission planning process, offering a pathway to a more efficient, reliable, and cost-effective grid.

3.1. The Need for an Integrated Resource and Transmission Plan (IRTP)

A siloed approach to planning, where generation resources are developed independently of transmission infrastructure, is suboptimal. An IRTP addresses these challenges by coordinating generation, load, and transmission planning, leading to a more reliable, cost-effective, and resilient energy system. The following five topics show why an IRTP is a critical need for TVA's long-term planning.

Addressing intraregional transmission constraints: Intraregional constraints can prevent surplus capacity in one area from supporting demand elsewhere, especially during resource adequacy shortfalls. Transmission enhancements can enable capacity transfers, reducing overall capacity needs, deferring new capacity investments, and enhancing system resilience. This capacity value is explored in Section 4.1.

Proactively plan for new resource additions and transmission upgrades: Identifying the lowest-cost generation resources, particularly wind and solar, often requires building new or expanded capacity to deliver power efficiently. Coordinated planning identifies optimal locations for resource development, minimizing transmission upgrade costs and accelerating project timelines. In turn, this information guides the development of transmission infrastructure in areas best suited for renewable resource integration. TVA already has experience identifying constrained paths due to renewables, this process can be developed further not just to identify where renewables can't be built, but to guide where they can be most beneficial and provide economies of scale. This topic is explored further in Section 4.2.

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[2] FERC Order No. 1920, https://www.ferc.gov/explainer-transmission-planning-and-cost-allocation-final-rule#:~:text=1920%20states%20that%20transmission%20providers,facilities%20to%20meet%20those%20needs.

Identify transmission reliability needs triggered by coal retirements: Large coal plant retirements, such as Cumberland, Kingston, Gallatin, and Shawnee may trigger significant transmission reliability upgrades. Proactively addressing these needs ensures that reliability is maintained without relying on reliability must runs or in-kind thermal replacements. Additionally, considering the effects of all pending retirements will help right-size system upgrades and expedite replacement resources. Further details are discussed in Section 4.3.

Streamline interconnection of new large loads: Emerging large loads, like data centers, fleet electrification, and new industrial facilities, create additional transmission demands. If planned correctly, these loads can expand TVA's customer base, improve load diversity, and spread fixed costs over more users. Poor planning, however, could result in long interconnection delays or unfair cost burdens on existing customers. This is detailed in Section 4.4.

Mitigate extreme weather impacts with interregional transmission: Events like Winter Storms Uri, Elliott, and others disproportionately impact reliability, costs, and public safety. While generation plays a role in mitigating such events, it is also vulnerable to fuel supply disruptions and weather-related outages. Expanding interregional transmission enables the transfer of surplus power from unaffected areas, mitigating localized impacts and ensuring greater system stability. This concept is elaborated in Section 4.5.

3.2. Overview of Integrated Resource and Transmission Planning

To maximize the value of its transmission and generation resource investments, TVA should adopt a multi-benefit transmission planning framework that evaluates a broader range of benefits than currently considered. Although FERC Order No. 1920-A set aside the requirement to use a defined set of benefits in the determination of transmission needs, the Order is still requiring that multi-benefit analysis in the evaluation and selection of transmission. ,[3] Implementing such an approach that evaluates and selects transmission based on a full range of benefits is crucial to ensure TVA's ratepayers derive maximum value from coordinated planning efforts and prepare TVA for future challenges in a changing energy landscape.

According to the Energy Systems Integration Group (ESIG), "Currently, transmission planning processes are built around achieving a reliable system at the local level, not necessarily improving economic efficiency or bulk system reliability. Moreover, while the current planning framework may be efficient under average circumstances, it fails to protect consumers from tail-end risks—low-probability but high-impact events—and potential exposure to extreme costs."[4] This is true for most utilities and RTOs, including TVA. As noted by Brattle, "More than 90 percent of these transmission upgrades have been based solely on local reliability needs, with the majority of this investment going toward operations and

[3] FERC Order No. 1920-A, P 380, finding that "it is necessary to require transmission providers to measure and use in Long-Term Regional Transmission Planning a set of particular benefits so that they may identify, evaluate, and select regional transmission facilities that are more efficient or cost-effective transmission solutions to Long-Term Transmission Needs."

[4] Energy Systems Integration Group. 2022. Multi-Value Transmission, *Planning for a Clean Energy Future*. A Report of the Transmission Benefits Valuation Task Force. Reston, VA. https://www.esig.energy/multi-value-transmission-planning-report.

maintenance of existing infrastructure, replacement of aging infrastructure, and new substations for plant interconnection."[5] This overlooks the additional benefits, including economic ones, achievable through better integration with the IRP process.

Production cost savings, which are typically used as the primary metric for justifying transmission investments, represent only one component of the potential benefits. As ESIG notes, "A wide range of benefits should be considered when evaluating transmission, including reduced operating costs, environmental benefits, access to low-cost renewable energy, and generation capital cost benefits, risk mitigation, and improvements in reliability and resilience."[6]

The multi-benefit planning need was recently recognized by FERC in the landmark transmission planning reform issued in FERC Order No. 1920. According to FERC, transmission planners must:

> *"[E]stablish a long-term, forward-looking, and more comprehensive approach to regional transmission planning, which will ensure that transmission providers identify, evaluate, and select more efficient or cost-effective transmission solutions to address Long-Term Transmission Needs. Long-Term Regional Transmission Planning, as set forth in this final rule, requires regional transmission planning based on a multitude of drivers of Long-Term Transmission Needs and provides the opportunity for transmission providers to meet those needs by selecting more efficient or cost-effective Long-Term Regional Transmission Facilities. […] transmission providers relying on relatively inefficient and less cost-effective piecemeal transmission solutions to address these needs shortly before they manifest, to the detriment of customers. […] To adequately prepare for the future, transmission providers need to make decisions in the present that are grounded in a thorough, informed analysis of the factors that drive Long-Term Transmission Needs."*[7]

Furthermore, there is growing recognition in the southeast that multi-value studies should be implemented with guidance from FERC Order No. 1920. For example, the Carolinas Transmission Planning Collaborative (CTPC) has initiated a Multi-Value Strategic Transmission (MVST) study to assess the region's future transmission needs focused on the following transmission portfolio benefits.

1. Avoided capacity costs
2. Capacity savings from reduced losses
3. Congestion and fuel savings
4. Energy savings from reduced losses
5. Avoided customer outages
6. Avoided transmission investment

[5] 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/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf
[6] ESIG *Multi-Value Transmission Planning for a Clean Energy Future*
[7] Federal energy Regulatory Commission, *Order No. 1920: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 18 C.F.R. Part 35, Docket No. RM21-17-000, issued May 13, 2024

The study focuses on a 10-year outlook (2034 Summer and 2034/2035 Winter period), aiming to identify transmission projects provide multiple benefits. It recommended that TVA adopt a multi-value benefit framework for transmission portfolios as well as integrate resource and transmission planning. More details on how several regions have implemented multi-value planning and improved integration of resource and transmission planning are detailed in the next section.

3.3. Case Studies of Integrated Resource and Transmission Planning

Recent case studies in multi-benefit transmission planning highlight the potential for utilities like TVA to adopt best practices in integrating transmission and resource planning. Highlighted in this document are three examples that showcase how multi-benefit, integrated transmission planning frameworks have been successfully implemented, providing critical insights for TVA's future planning. These case studies include the ESIG "Multi-Value Transmission Planning for a Clean Energy Future" report,[8] the MISO "Long Range Transmission Plan (LRTP)"[9,10] and the SPP Integrated Transmission Plan.[11]

Energy Systems Integration Group (ESIG) Multi-Benefit Framework

The ESIG report provides a foundational framework for multi-benefit transmission planning, serving as a practical guide for utilities and planners. This framework was applied to two project types. The first evaluated intraregional transmission linking resource-rich regions in West Texas to major load centers like Dallas and Houston. The second considered interregional transmission to improve resource adequacy and resilience to winter storms through enhanced interregional connections.

The results, shown in Figure 1, highlight two important findings. The first is that few transmission projects are economic when only considering one benefit in isolation, showing that the multi-benefit "waterfall" approach to stacking benefits beyond adjusted production cost is important to recognizing appropriate benefit-cost ratios. The second finding is that different transmission projects will have different relative benefits depending on the use case. So while transmission benefits in one use case may be relatively small, they may be larger in others. These case studies underscore the importance of a flexible framework that can evaluate diverse transmission projects based on their specific value propositions.

[8] ESIG *Multi-Value Transmission Planning for a Clean Energy Future*
[9] MISO, *LRTP Tranche 2.1 Benefits Analysis Results Review*, September 25, 2024, https://cdn.misoenergy.org/20240925%20LRTP%20Workshop%20Item%2001%20Tranche%202.1%20Business%20Case%20Overview649810.pdf
[10] MISO, *Economic Planning Whitepaper*, October 2024, https://cdn.misoenergy.org/MISO%20Economic%20Planning%20Whitepaper651689.pdf
[11] SPP 2024 Integrated Transmission Plan, https://spp.org/documents/72605/2024%20itp%20report%20draft%20v0.6.pdf

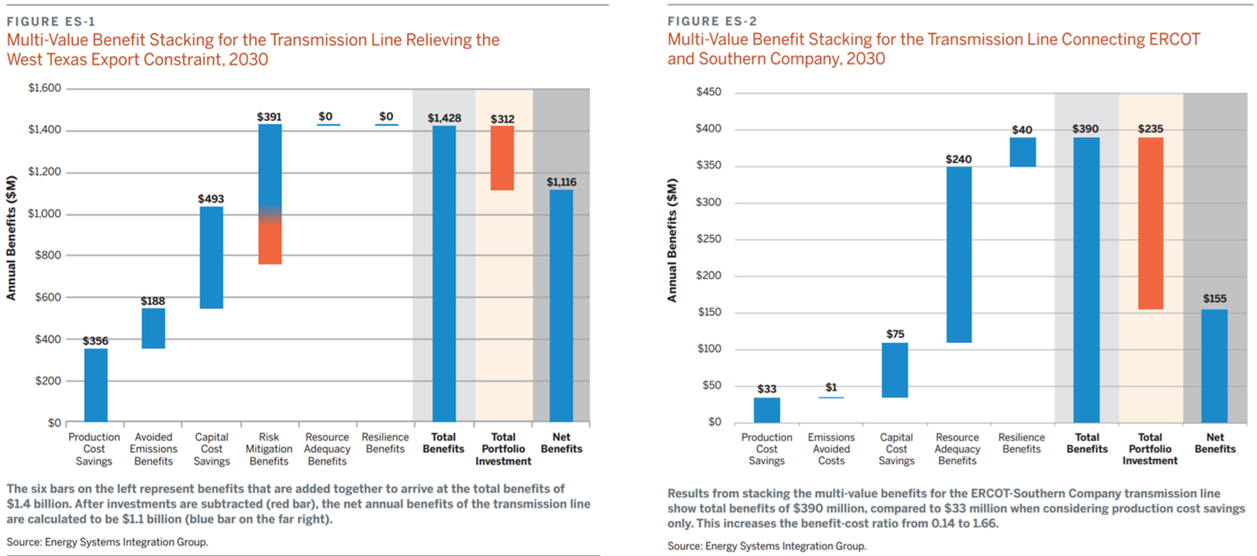

Figure 1. Multi-benefit transmission planning in a Texas case study

MISO Long Range Transmission Planning (LRTP) Process

MISO's LRTP exemplifies a structured, multi-benefit planning approach, which evaluates new transmission investments across a range of metrics. The projects are collectively analyzed in tranches, considering both reliability and economic benefits. Results from LRTP (Figure 2) highlight that while individual benefit streams, such as production cost savings, may not outweigh the costs of transmission, a combined multi-benefit approach yields substantial net benefits, with benefit-cost ratios ranging from 1.8 to 3.5.

MISO's process also integrates a seven-step iterative methodology, aligning transmission planning with long-term resource planning. By extending the planning horizon to 20 years and incorporating scenario-based planning, MISO ensures that transmission investments are least-regrets solutions, addressing uncertainties in generation, load, and policy changes.

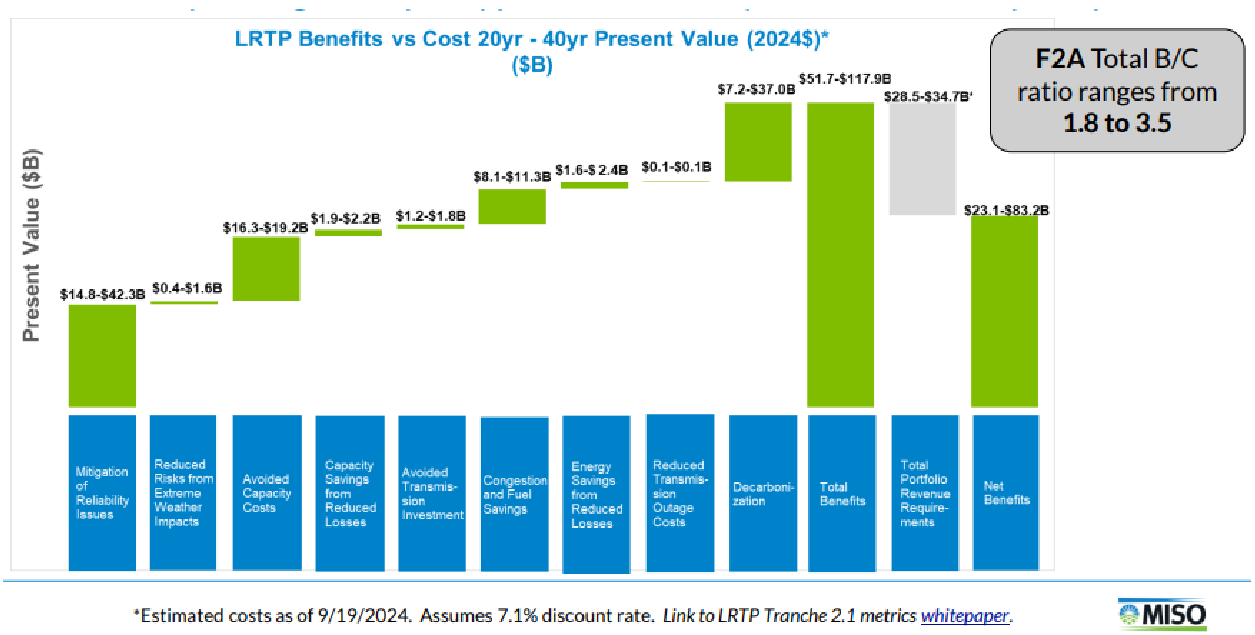

Figure 2. MISO LRTP Multi-Benefit Transmission Value for the Tranche 2.1 Portfolio. [12]

SPP Integrated Transmission Planning (ITP) Framework

The SPP ITP evaluates multiple benefits for new transmission projects, including adjusted production costs (APC), reliability, resiliency during winter storms, optimizing seams, and energy equity. Each of these benefits identified targeted areas for new transmission across the footprint. "SPP crafted the 2024 ITP portfolio to capitalize on the economic benefits of improved system flows caused by projects identified in the reliability portfolio. SPP is optimizing seams by extending [extra-high-voltage 765kV] transmission into southern central Missouri where the SPP region shares customers with neighboring utilities. This transmission will enable lower cost energy from the central part of SPP to reach an area where real-time pricing data shows consistently higher prices compared to the rest of SPP. Additionally, SPP expects the 2024 ITP portfolio projects to increase energy equity by expanding SPP's EHV footprint to areas designated by the U.S. Department of Energy (DOE) as National Interest Electric Transmission Corridors (NIETC). SPP's analysis of resiliency against winter storms identified projects that improve system voltages throughout the approved target areas."[13]

[12] MISO, *LRTP Tranche 2.1 Benefits Analysis Results Review*

[13] Southwest Power Pool (SPP), 2024 Integrated Transmission Planning (ITP) Report, Draft v0.6, pg 5,, https://spp.org/documents/72605/2024%20itp%20report%20draft%20v0.6.pdf

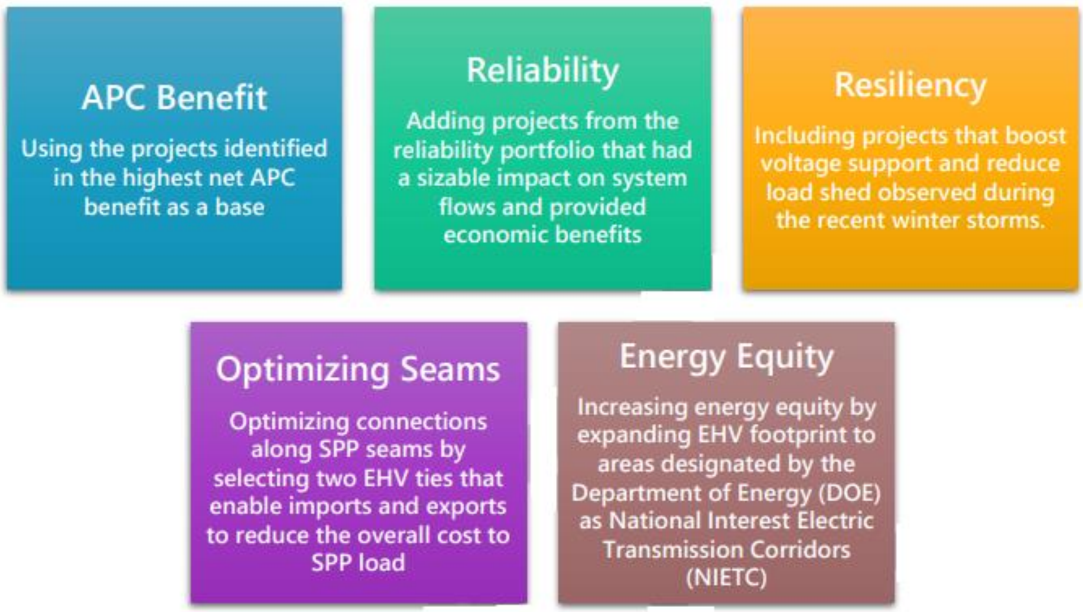

Figure 3. Multi-benefit structure of proposed transmission projects in SPP. [14]

A unique consideration of the SPP ITP was the treatment of extreme weather events, which were evaluated in response to Winter Storm Uri and Winter Storm Elliott to make the system more reliable from extreme winter weather. A similar approach would yield benefits for TVA.

> *"After Winter Storm Elliott, SPP and its members began discussions on incorporating extreme winter weather planning into the SPP planning processes. [...]*
>
> *After significant staff and stakeholder collaboration, SPP brought the revised 2024 ITP scope to [...] identified a Target Area consisting of south and south-central Missouri, northwest Arkansas, and southeast Kansas. This target area includes facilities where the TO-directed load shed occurred in December 2022. Another determining factor for the identification of this target area was the significant congestion identified in the 2024 ITP constraint assessment.*
>
> *"SPP built two distinct sets of powerflow models to mimic the effects of extreme winter weather on the SPP system. The first winter weather model set is based upon winter storm Elliott, while the second model set is based upon a combination of real-time data from Winter Storm Uri and expected future load on the system. describes at a high level the recommended model development for the evaluation of extreme winter weather. The following sections provide more details on the development of each model set."*[15]

[14] Ibid. pg. 92
[15] Ibid. pg. 51

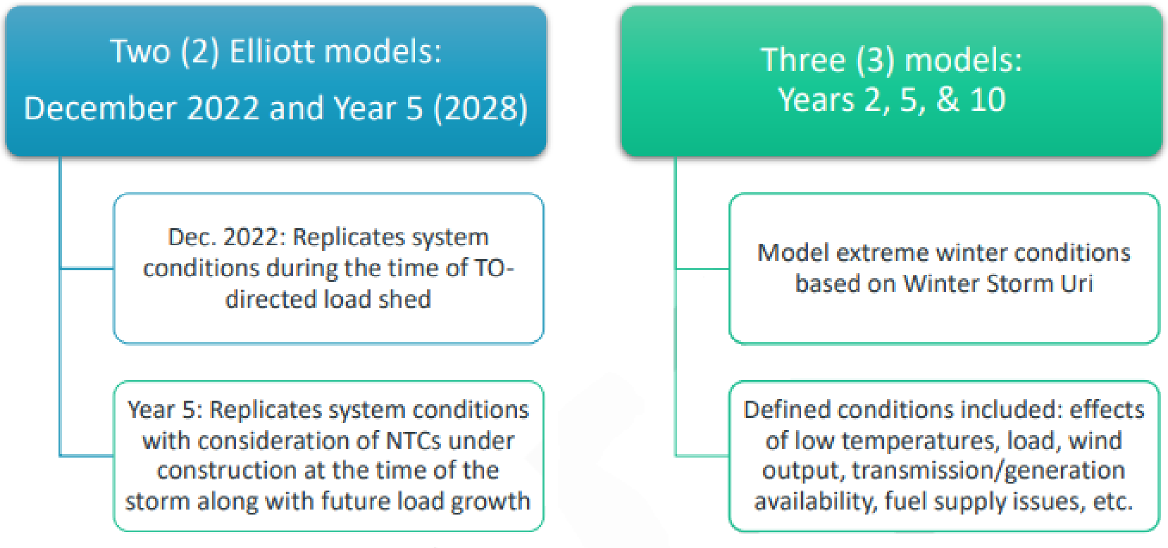

Figure 4. Extreme weather transmission models developed by SPP for the 2024 ITP.

3.4. Implementation Steps for TVA

To implement the Forward-looking, Scenario-based, Multi-Benefit Transmission Planning by TVA, the following three step implementation process is recommended.

Step 1: Develop Scenario-Based Planning

TVA should adopt a systematic approach to benefit-cost analysis for transmission projects, integrating it with the IRP to evaluate system needs under a range of potential future conditions. This scenario-based planning framework should account for uncertainties such as demand growth driven by electrification, fluctuations in fuel prices, state and federal energy policies, decarbonization targets, and extreme weather events. By capturing these variables, TVA can identify least-regrets solutions that align with long-term goals.

- **Establish a Formal Transmission Planning Framework Aligned with FERC Order No. 1920:** FERC Order 1920 emphasizes the importance of forward-looking, comprehensive regional transmission planning to address long-term needs. TVA should mirror this approach by developing a structured planning framework that identifies and evaluates transmission solutions proactively, ensuring they are efficient and cost-effective. TVA should similarly adopt FERC's requirement that planners evaluate advanced transmission technologies (ATTs) such as dynamic line rating, advanced conductors, and transmission switching. This alignment would enable TVA to address emerging system needs, such as resource retirements and load growth, before they manifest as reliability risks.
- **Build Iterative Feedback Loops Between IRP and Regional Transmission Planning:** To ensure cohesive strategies, TVA must create iterative feedback loops between its IRTP and regional transmission planning processes with SERTP. These loops would refine transmission and resource planning by incorporating updated data, stakeholder input, and evolving market dynamics.

A practical model for TVA's scenario-based planning is MISO's seven-step process, which integrates long-term planning for both transmission and generation.[16] While TVA's IRP already covers the first two steps (developing futures and modeling generation), steps 3 through 6 could extend this approach to transmission planning. These steps involve analyzing the transmission system's ability to deliver resources reliably and economically under different scenarios, considering a minimum 20-year planning horizon.

[16] MISO, *Economic Planning Whitepaper*

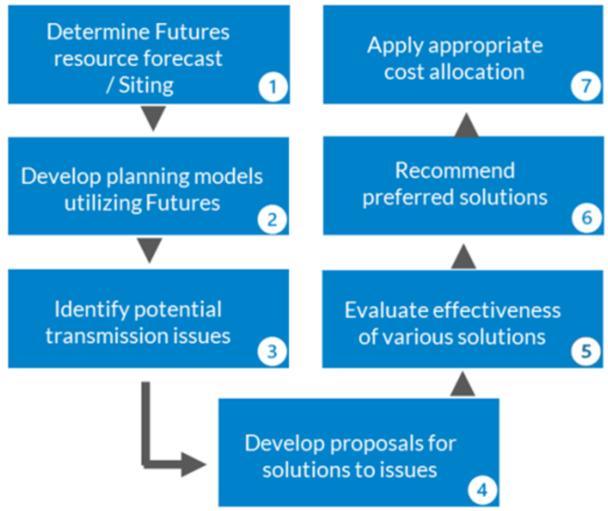

Figure 5. MISO 7-Step Economic Transmission Planning Process

As MISO describes, "Through a seven-step iterative process, MISO plans, assesses, evaluates and repeats steps as necessary to ensure a least-regrets plan. It begins with development of the Futures with stakeholders based on a minimum 20-year horizon because transmission can take 8 to 12 years to identify, site and develop. MISO forecasts and sites generation resources, as well as load and energy growth. MISO then analyzes the ability of the transmission system to perform reliably and safely in delivering resources economically to load, recognizing member and state goals across the entire footprint."

This process highlights the importance of aligning transmission planning with long-term resource needs and stakeholder priorities. TVA should adopt similar practices, incorporating scenario-based planning into its transmission framework.

Step 2: Integrate transmission considerations in generation planning models, database, and software

For TVA to achieve fully coordinated resource and transmission planning, it is essential to enhance the representation of transmission within generation planning tools like EnCompass and SERVM, and simultaneously improve the modeling of generation resources within transmission planning tools like TARA and PSS/E. This bidirectional integration ensures that both systems reflect the complexities and interdependencies of a modern grid, enabling TVA to identify optimized solutions for resource deployment and grid reliability.

Enhancing Transmission Representation in Resource Planning Models

Current resource planning models often use simplified representations of transmission systems, which can overlook key constraints and opportunities. TVA should incorporate detailed transmission topology and capabilities into EnCompass and SERVM to capture how transmission limitations and upgrades impact generation dispatch and resource adequacy. By doing so, TVA can evaluate the economic and operational feasibility of resource plans with greater accuracy and ensure alignment with transmission system realities (See Section 4.1).

MISO's iterative planning approach provides an illustrative example of how transmission representation can be updated in economic planning tools. In MISO's case, the PROMOD tool iteratively integrates detailed transmission modeling, and in TVA's case, this functionality can be extended to EnCompass and/or SERVM. This allows for continuous refinement of both generation and transmission planning, improving the ability to identify least-regrets solutions.

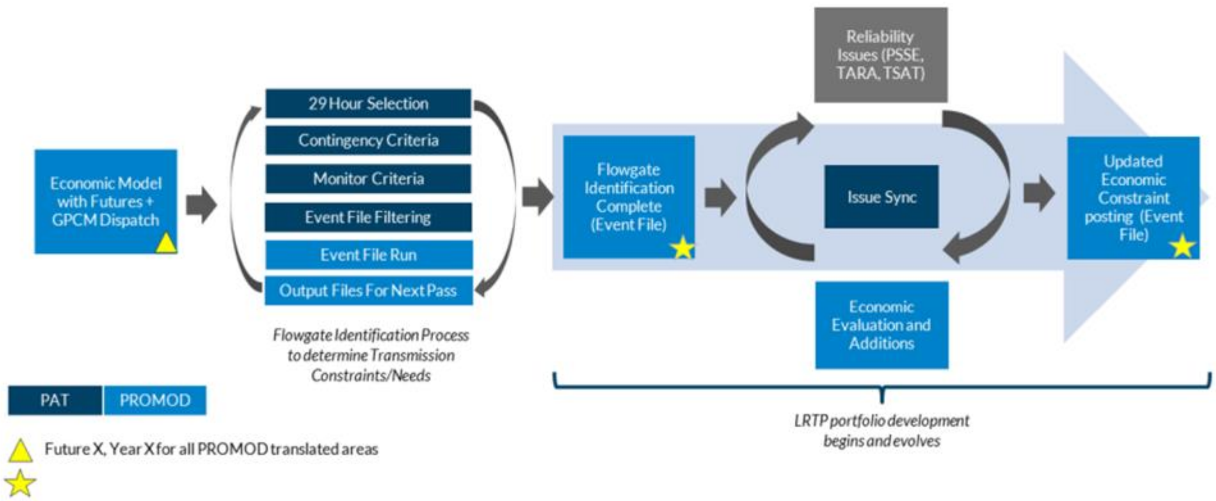

Figure 6. Multi-tool iterative process for generation and transmission modeling (MISO). [17]

Expanding Resource Representation in Transmission Models

In addition to enhancing transmission modeling in resource planning, TVA should improve the representation of generation resources in its transmission planning tools, like PSS/E. An iterative process is critical to integrating generation and transmission planning effectively. TVA should evaluate a broad range of dispatch conditions representing diverse scenarios of load and generator output. Historically, transmission planning has focused on conventional snapshots like summer peak, winter peak, and spring light load. However, these conditions may no longer capture the full spectrum of grid dynamics in an era of increased availability of cost-effective variable generation and increasing electrification.

Instead, TVA can adopt a screening method to identify similar groupings of conditions for further evaluation. For instance, MISO's approach groups dispatch scenarios based on season, load, and renewable output, allowing planners to prioritize conditions most likely to affect grid performance. This reduces computational complexity while ensuring that critical conditions are adequately represented.

[17]MISO, *LRTP Tranche 2.1 Benefits Analysis Results Review*, September 25, 2024, https://cdn.misoenergy.org/20240925%20LRTP%20Workshop%20Item%2001%20Tranche%202.1%20Business%20Case%20Overview649810.pdf

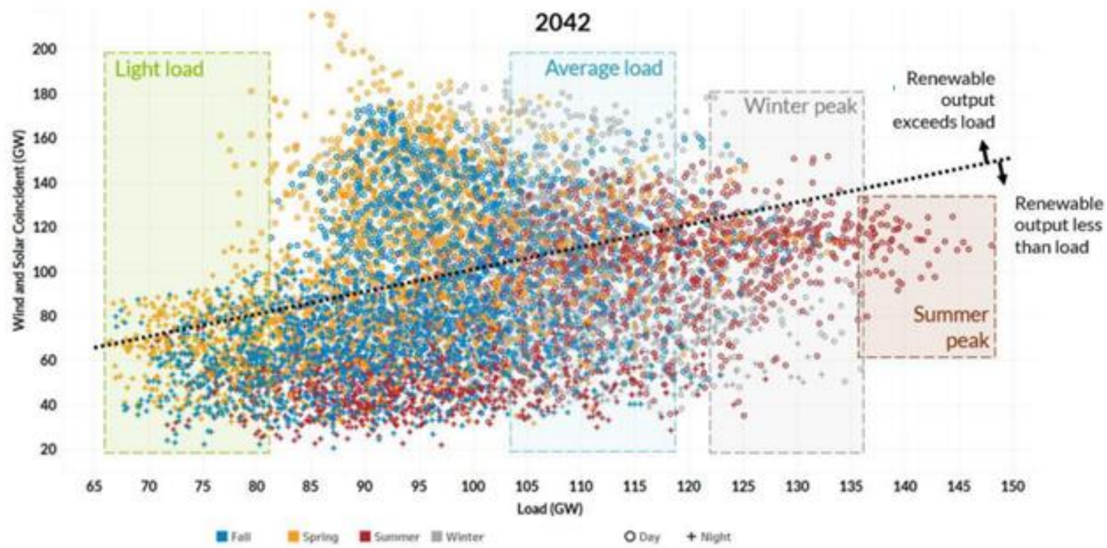

Figure 7. Selected dispatch conditions based on load, renewable output, and season (MISO LRTP Tranche 2.1).

Integrating transmission considerations into resource planning models and vice versa ensures that TVA's planning framework is comprehensive and responsive to the evolving grid landscape. This iterative, data-driven approach supports the development of reliable, cost-effective, and resilient resource portfolios, laying the groundwork for future multi-benefit transmission projects.

Step 3: Develop a portfolio of generation and transmission projects that meet TVA's cost, reliability, and clean energy requirements over the 20+ year horizon.

To meet TVA's cost, reliability, and clean energy goals over a 20+ year horizon, a fully integrated portfolio of generation and transmission projects must be developed. Ideally this would be done for each scenario identified in the IRP, but at a minimum should be developed for the preferred plan. This includes specific resource additions, such as renewable energy projects and storage, as well as the transmission upgrades required to support these resources. For the preferred plan, this alignment is especially critical to ensure a cohesive strategy that addresses TVA's long-term system needs. An example of this resulting transmission plan is provided in Figure 8, based on the results of MISO's Long Range Transmission Planning (LRTP) Tranche 2.1 portfolio. This portfolio of projects has a benefit to cost ratio of at least 1.8 and up to 3.5 depending on the future grid conditions. This type of planning provides least-regret investments where benefits are greater than costs across a range of futures.

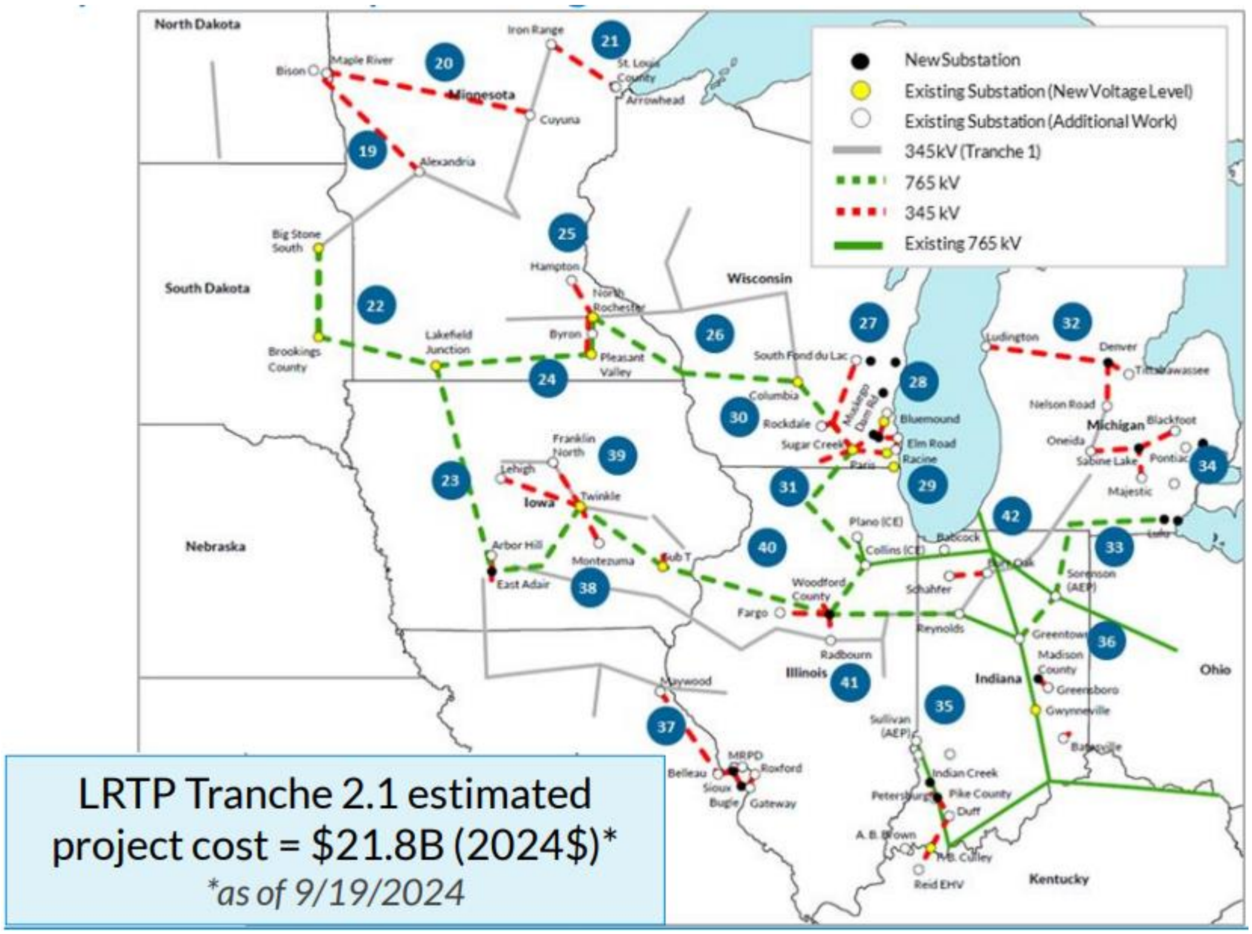

Figure 8. MISO LRTP Tranche 2.1 Multi-Value Benefit Projects.

Transmission often represents the "long pole" in project timelines, requiring extensive lead times for planning, permitting, and construction. Proactively identifying transmission needs is essential to enabling generator retirements, accommodating large-scale renewable energy integration, and facilitating new load interconnections, such as those associated with data centers or industrial facilities. Without this foresight, resource deployment can face delays and inefficiencies, ultimately increasing costs and compromising reliability. By coordinating the development of generation resources and their associated transmission infrastructure, TVA can minimize total portfolio costs and streamline implementation.

This process also ensures that transmission and generation investments are evaluated holistically, capturing synergies that optimize cost and performance. For example, strategic transmission upgrades can unlock high-value renewable energy zones, reduce congestion, and provide interregional access to low-cost resources and geographic diversity.

4. Proposed Actionable Next Steps on Integrated Resource and Transmission Planning

The successful implementation of an integrated resource and transmission plan (IRTP) for TVA will require the robust and coordinated planning framework outlined in the preceding sections. However, to effectively support this transition, five key compendium studies should be undertaken to provide foundational insights and guide the IRTP process. These studies are critical for identifying system needs and opportunities and can be conducted in parallel with, or adjacent to, the IRTP to serve as valuable inputs.

- Quantify internal zonal transfer capability and adopt it in EnCompass and SERVM
- Identify renewable energy zones to expedite interconnecting clean energy and reduce interconnection costs
- Enhance TVA's strategic coal plant retirement studies
- Evaluate large load Interconnection in coordination with resource additions and retirements
- Improve representation of external ties and interregional transfer capabilities

Each of these studies will be explored in the next section, providing detailed recommendations and strategies to ensure TVA's planning framework is comprehensive, forward-looking, and aligned with its cost, reliability, and clean energy objectives. Several of these recommendations were already identified in TVA's *Utility of the Future Information Exchange Report* based on meetings from October 2022 - July 2023 where stakeholders identified that TVA should "[expand] beyond integrated resource planning (IRP) to integrated environmental, resource, and transmission planning".[18]

4.1. Quantify internal zonal transfer capability and adopt it in EnCompass and SERVM

Modeling internal zonal transmission constraints within TVA's capacity expansion, resource adequacy, and production simulations is essential for accurately reflecting the operational realities of the power grid and ensuring that resource investments are both cost-effective and reliable. Transmission plays a pivotal role in shaping resource availability, operational flexibility, and system costs, yet traditional resource planning models often oversimplify or omit these constraints. This leads to suboptimal resource portfolios that fail to account for localized congestion, inter-zonal energy flows, or critical bottlenecks.

It should be noted that TVA stakeholders identified for this current IRP cycle that "[TVA should break] up the modeling by different zones/subregions within the overall TVA region… creating a more place-based model… different load shapes by subregion/zone show what profile of resource would be more appropriate in that zone."[19] Unfortunately, no progress was made on implementing a zonal model for the IRP even though it was delayed. This should be addressed as a top priority for the next IRP cycle.

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[18] Tennessee Department of Environment and Conservation, "Utility of the Future Information Exchange (UF-IX): Final Report," accessed November 25, 2024, https://www.tn.gov/content/dam/tn/environment/energy/documents/Final%20TVA2023-503__UF-IX_IRP_Spreads_Final_i.pdf.

[19] Ibid. pg. 23

Zonal Topology for Capacity Expansion and Production Cost Modeling

Incorporating zonal transmission constraints enables TVA to develop resource portfolios that align better with the physical capabilities of its grid and provide valuable information to developers on best locations to site projects. Omitting zonal constraints, means the interplay between transmission and generation is gone and portfolios may appear feasible on paper but encounter significant hurdles when evaluating them in transmission planning or resource adequacy studies. For example, high-capacity generation concentrated in areas with limited transmission capacity may exacerbate congestion, leading to curtailment, increased operating costs, and delayed project timelines but these would not be identified.

Furthermore, cost-effective transmission to unlock high-value areas for the grid will be missing. Modeling these constraints ensures that resource plans are realistic, executable, and aligned with grid capabilities. TVA faces significant changes on its grid due to generation retirements, renewable energy additions, electrification-driven demand growth, and grid modernization initiatives. Internal zonal transmission modeling allows TVA to update its resource plans in response to these changes, ensuring the grid evolves in a coordinated and efficient manner. It also enables proactive identification of transmission upgrades needed to accommodate new generation or reduce congestion in critical areas.

Production cost simulations also play a key role in assessing the economic performance of resource portfolios determined after capacity expansion modeling. However, their accuracy depends on how well they capture the realities of energy flows across the grid. Ideally, nodal production cost modeling would be done to fully represent transmission constraints. At a minimum, zonal modeling would inform dispatch, so it is more realistic to actual grid conditions experienced by TVA, especially as it relates to congestion between generation pockets and load pockets and congestion seen on interregional transmission interfaces.

Zonal Topology for Resource Adequacy Modeling

Resource adequacy studies aim to ensure there is enough capacity to meet demand under all conditions, including extreme weather or high demand periods. However, resource adequacy models that omit internal transmission constraints fail to capture how localized bottlenecks or inter-zonal transfer limits may impact system reliability. By modeling these constraints, TVA can better identify and mitigate localized reliability risks, ensure adequate reserves are available in constrained zones, and account for how inter-zonal energy transfers contribute to overall system resilience.

Incorporating internal zonal transmission constraints into resource adequacy assessments is crucial for accurately evaluating system reliability. The Electric Reliability Council of Texas (ERCOT) provides a pertinent example through its 2022 Zonal Reliability Study, which offers several key insights:

1. **Zonal Modeling Enhances Reliability Metrics:** ERCOT's study utilized a multi-zonal model to assess reliability across different regions within its grid. This approach gave a more detailed analysis of how interzonal constraints impact overall system reliability.

2. **Identification of Localized Reliability Risks:** Certain zones in ERCOT faced higher reliability risks due to transmission limitations and where generation was located. Identifying these limitations informs where proactive transmission planning would be beneficial to alleviate constraints, reducing reliability risks.
3. **Improved Resource Allocation:** The zonal modeling allowed ERCOT to evaluate how effective planned resources were at reducing loss of load risks by accounting for transmission interfaces. This aids in optimizing where least-cost generation portfolios can provide the most benefit.

Scope for TVA to Develop a Zonal Transmission Topology

This scope outlines a process for TVA to create a zonal topology and establish transfer limits, to integrate transmission capabilities into resource planning while reflecting real-world grid constraints. The zonal topology will enable more accurate resource portfolio allocations, improve loss of load risk analysis, and enable high-level transmission expansion options for a more seamless generation and transmission planning process. This scope is based on the Southwest Power Pool (SPP) zonal topology developed for their 2019 Loss of Load Expectation study and is adapted to TVA.[20]

The goal of developing zonal topology is to represent TVA's internal transmission constraints and external transmission interfaces within system models accurately. These zones enable TVA to:

- Account for localized congestion and energy transfer limitations.
- Improve resource adequacy assessments by reflecting realistic operational constraints.
- Optimize generation and transmission investments for long-term reliability and cost efficiency.

Dividing TVA's territory into distinct zones based on electrical characteristics, transmission constraints, weather variability, and renewable resource quality would enhance several of TVA's existing planning practices. These zones would be used to represent areas where generation can more easily serve load within that zone due to existing transmission topology. Interfaces between zones represent the ability for generation to serve load outside their distinct zone. The topology also limits how much external transfers can be wheeled through the TVA system to reach load, a dynamic that is important for resource adequacy planning.

Task 1: Initial Zone Delineation

Initially, generation and load will need to be grouped based on their impacts to the grid using a 5% transfer distribution factor (TDF) impacts analysis. This will identify how power flows from specific generation sources impact the transmission system.

Once groupings are made, zonal boundaries will be developed based on transmission elements that are known constraints to energy transfers into and out of the groups. In SPP's case, the First Contingency Incremental Transfer Capability (FCITC) analysis was done to identify additional constraints for creating

[20] SPP, *2019 SPP Loss of Load Expectation Study Report*, June 29, 2020, https://www.spp.org/documents/62810/2019%20lole%20study%20report.pdf

zones. Consideration should also be made for geographical and weather variability that may reflect operational realities.

In TVA’s case, there might be a preference for setting zones to reflect Customer Delivery Districts based on how Local Power Companies are grouped. Fundamentally, zonal boundaries should be based on power flow analysis, but the delivery districts shown in Figure 9 are used to illustrate a potential zonal system for TVA.

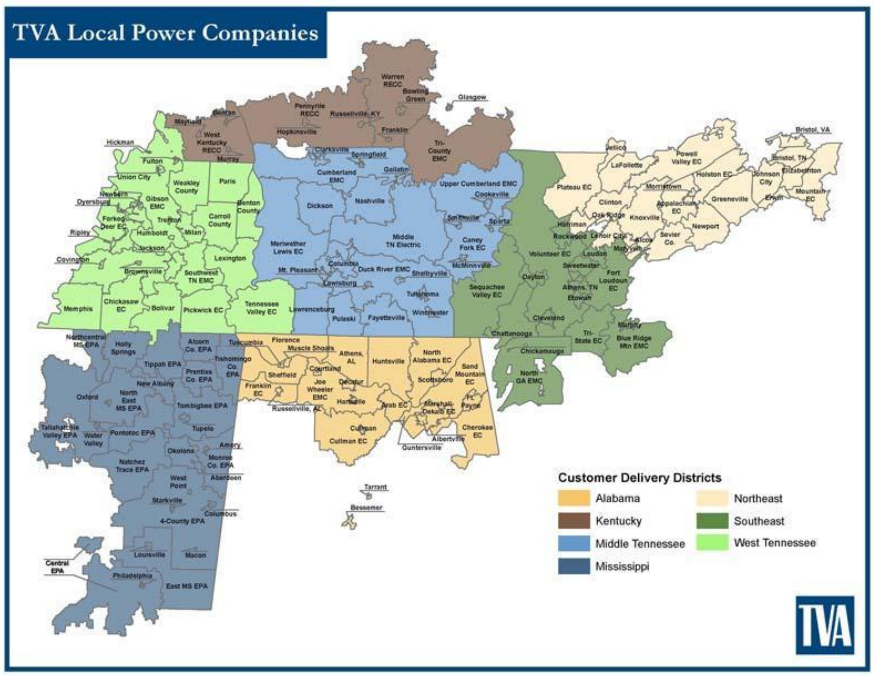

Figure 9. Customer delivery districts as an example of territory divisions in the Tennessee Valley Authority region.

Task 2: Establishing Zonal Transfer Capability Limits
After delineating zones, transfer analysis should be performed with all 100 kV and above lines and transformers as monitored elements. Contingencies can be analyzed for all facilities 230kV and above. Depending on TVA’s preference, the monitored elements and elements analyzed for contingency can be modified.

Transfer capability can then be determined by increasing the generation within a zone for export to importing zones using the maximum transfer function from PowerGem’s TARA software. Determining the maximum transfer capability between zones will involve generator re-dispatch to increase capability without violating constraints until no increases in transfer capability can be achieved.

Task 3: Incorporating Zones into Planning Models
The insights from these analyses should then be integrated into TVA’s resource planning models to enhance their accuracy and relevance. Zonal transfer limits derived from the TDF and FCITC analyses will

enable these models to account for congestion risks, enable more realistic dispatch patterns, and optimize resource deployment. This approach will also allow TVA to identify cost-effective transmission upgrades and optimize the siting of new resources for long-term. Additionally, more seamless integration of locational resources builds, or large-scale transmission needs can be passed between existing generation and transmission planning groups.

Existing generators and load centers can be grouped into zones in TVA's capacity expansion model EnCompass and in their SERVM model for resource adequacy. Candidate resource additions can then be created that better reflect existing zonal hosting capacity, new renewable gen-tie cost estimates, distributed resource locations, and enabling optimization between battery storage siting or increasing transfer capabilities to ensure low-cost portfolios.

4.2. Identify renewable energy zones to expedite clean energy and reduce transmission costs

A key component of a proactive and integrated resource and transmission plan (IRTP) is the development of Renewable Energy Zones (REZs). TVA should select zones on the grid where targeted transmission investments can unlock significant potential for low-cost, high-yield renewable energy development. This type of REZ assessment has been successful in many regions, including ERCOT with the Competitive Renewable Energy Zones (CREZ) lines. Historically, developable land for wind and solar projects has been located far from load centers and is often inadequately served by large-scale transmission infrastructure. As TVA transitions to cleaner energy sources, the lack of transmission access is likely to become the most significant bottleneck to achieving the ambitious wind and solar additions outlined in its resource plans. This is especially important since existing ordinances may make in-region wind development a non-starter, relying on external wind and proactive transmission planning. Additionally, solar deployment so far has already revealed challenges, such as the TVA identified constrained paths due to renewable deployment in the existing system. Identifying existing constraints is valuable, but to achieve long-term planning goals proactive identification of limitations, and where constraints could be alleviated should be pursued.[21]

By identifying and developing REZs, TVA can address this challenge in a systematic and forward-looking manner. These zones would serve multiple goals, ensuring a more efficient and transparent planning process while laying the groundwork for integrating substantial renewable capacity. Specific objectives include:

- **Proactively Identifying Transmission Needs:** REZs enable TVA to determine where transmission upgrades or new lines are necessary to support planned wind and solar projects, reducing delays and ensuring grid readiness as projects come online.
- **Improving Cost Estimates:** Accurate transmission cost estimates for interconnection are critical for resource planning and decision-making. Developing REZs provides better data for TVA's IRP and ensures more realistic and reliable cost assumptions.

[21] TVA, Constrained Transmission Corridors, 2023, http://www.oasis.oati.com/woa/docs/TVA/TVAdocs/Constrained_Transmission_Corridors_2023.pdf

- **Facilitating Stakeholder Engagement:** Early identification of REZs allows TVA to engage with impacted communities at the beginning of the planning process, fostering collaboration and addressing concerns proactively.
- **Signaling to Developers:** By increasing transparency, REZs guide developers toward regions with expedited and lower-cost interconnection options, accelerating renewable energy deployment and lowering overall project costs.
- **Coordinating with Large Load Interconnections:** REZs can also identify opportunities for synergy with new large load interconnections, such as data centers or industrial facilities, enabling efficient and cost-effective resource allocation (see Section 4.4).

By addressing these goals, the creation of REZs not only supports TVA's clean energy targets but also ensures that the transmission system evolves in alignment with resource needs. This proactive approach reduces risks, streamlines project timelines, and maximizes the value of TVA's infrastructure investments.

Three case studies highlight the process for REZs in integrated resource and transmission planning: 1) Australian Energy Market Operator (AEMO) Integrated System Planning (ISP); 2) Xcel Colorado Energy Resource Plan (ERP); and (3) Hawaiian Electric Company (HECO) Integrated Grid Plan (IGP). Each of these utilities or ISOs intentionally calls their planning process something other than IRP, in part to specifically differentiate that they also include transmission planning in the process.

AEMO Integrated System Planning Renewable Energy Zones

AEMO's Integrated System Plan has an extensive process to identify renewable energy zones. These zones are selected for "the quality of their renewable resource, and their proximity to consumers, existing transmission and available skilled workforces. The REZs are a place-based way to build and coordinate electricity assets, with a more holistic approach to the needs of the energy transition and the aspirations of regional communities."[22]

According to AEMO, the development of REZs have the following benefits:

- Reduce the overall cost and disruption of the energy transition, and deliver significant regional benefits,
- Meet the needs of the power system, with better grid reliability and security, and the option to scale up to address the future needs of the power system,
- Allow for more coordinated and effective community consultation,
- Share the costs of transmission, connection and support infrastructure (such as weather observation stations) across multiple projects,
- Promote regional expertise and employment over long periods to build and maintain generation and storage assets and the equipment needed to ensure power system security, and

[22] AEMO, *2024 Integrated System Plan For the National Electricity Market: A roadmap for the energy transition*, 6/26/2024, pg. 52, https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?la=en

- Reduce the community, environmental and aesthetic impacts of state-wide development.

The outcome is available in Figure 10,

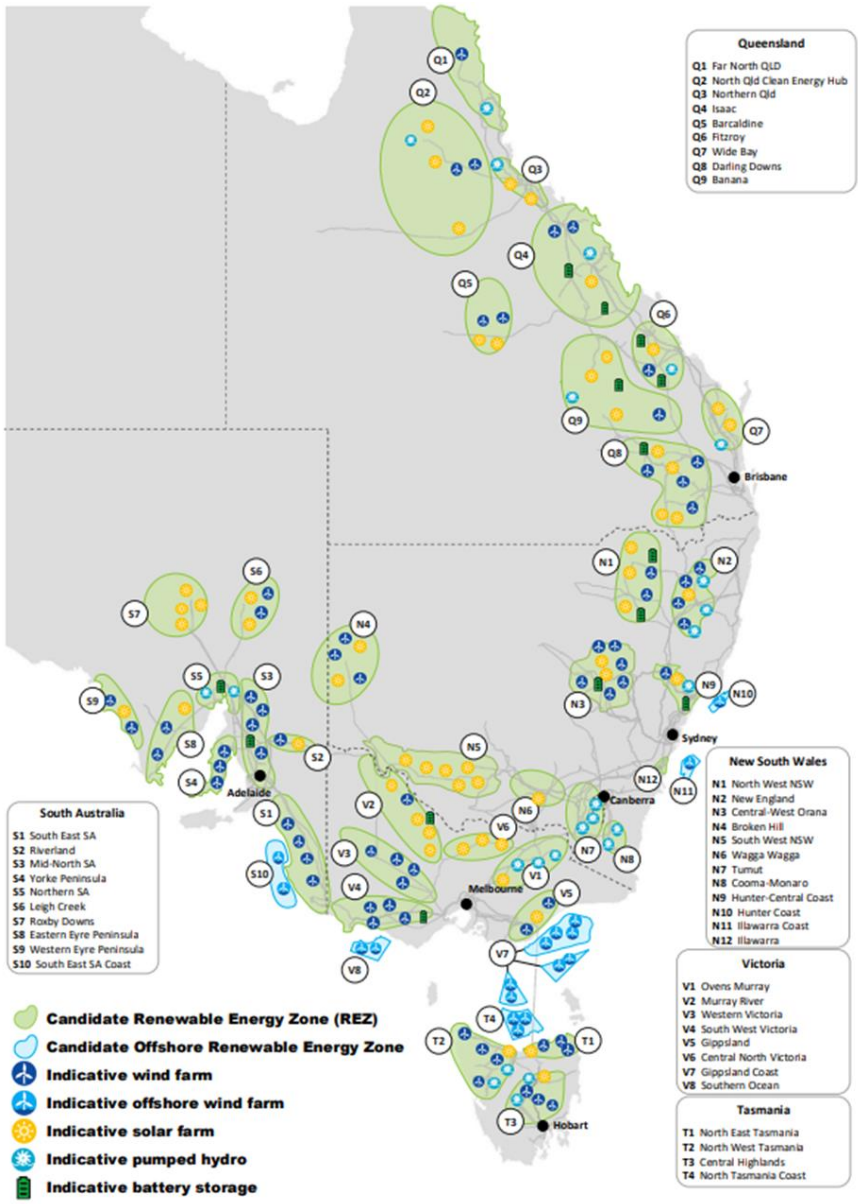

Figure 10. Australia renewable energy zone candidates (Source: AEMO ISP). [23]

[23] AEMO, *Appendix 3. Renewable Energy Zones: Appendix to the 2024 Integrated System Plan for the National Electricity Market*, June 2024, https://aemo.com.au/-/media/files/major-publications/isp/2024/appendices/a3-renewable-energy-zones.pdf?la=en

Xcel Colorado, Colorado's Power Pathway

Xcel Energy's Colorado Power Pathway exemplifies a forward-looking transmission planning initiative designed to support renewable energy integration, enhance grid resilience, and meet future electricity demands. This $1.7 billion grid investment establishes a robust transmission backbone across Colorado, specifically designed to enable the state to access its nation-leading renewable energy potential.[24]

The Colorado Power Pathway includes approximately 550 miles of new double-circuit transmission lines, the construction of four new substations, and the expansion or enhancement of four existing substations. The project is expected to be operational between 2025 and 2027. This infrastructure will connect the resource-rich Eastern Plains—a region recognized as one of the nation's best for wind and solar energy production—to the Front Range, Colorado's primary population and load center. The proposed 345-kilovolt transmission system will serve as the backbone to deliver approximately 5,500 megawatts of new renewable resources to Xcel Energy's customers.[25]

The Colorado Power Pathway was identified as a critical component of Xcel Energy's forward-looking ERP, a planning framework that integrates both generation and transmission needs. Unlike traditional IRPs, Xcel's ERP explicitly incorporates the transmission infrastructure required to unlock renewable energy potential and support future load growth.

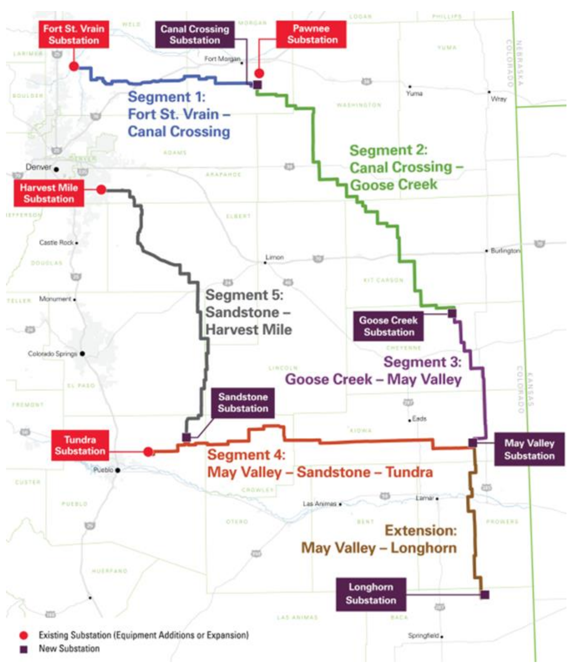

Figure 11. Colorado Power Pathway transmission to access renewable energy zones.

[24] Xcel Energy, *Colorado's Power Pathway*, https://xcelenergytransmission.com/projects/colorados-power-pathway/

[25] Xcel Energy, *Colorado's Power Pathway: Winter 2023 update*, https://www.coloradospowerpathway.com/wp-content/uploads/2024/02/24-02-409_CO_PowerPathway_IS_P02.pdf

HECO Renewable Energy Zone

Another example of proactive planning for renewable energy zones is from the HECO IGP. HECO's IGP – again a renaming of the IRP to incorporate transmission and distribution planning into a single planning structure – included the development of REZ for each of the utility's island grid. According to HECO,

> "Prime locations for grid-scale development, flat land with rich solar and wind resources adjacent to existing transmission, have been developed through [recent] procurements. In addition to location, transmission capacity is becoming a limiting factor. The current transmission system was not designed for large generator interconnections at various locations, but rather one that supports bulk generation resources supplying power to load centers. […]
>
> Creating REZs will enable efficient interconnections to the transmission system to new areas that are prime for development but either is far from existing transmission infrastructure or requires robust transmission upgrades to accommodate the interconnection of generating resources, composed of two types:
>
> 1. Transmission network expansion costs, which are the transmission upgrades not associated with a particular REZ but are required to support the flow of energy within the transmission system, and
> 2. REZ enablement costs, which are the costs of new or upgraded transmission lines and new or expanded substations required to connect the transmission hub of each REZ group to the nearest transmission substation."[26]

The goal of REZ development is also to coordinate with impacted communities early in the process to have a more stakeholder driven planning process recognizing that the state's renewable energy goals, land use, and transmission needs must be planned in a coordinated manner. The outcome of the REZ process is illustrated in Figure 12 for the Oahu system, Hawaii's primary load center.[27]

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[26] HECO, *Integrated Grid Plan: A pathway to a clean energy future*, May 2023, pg. 93, https://hawaiipowered.com/igpreport/03_IGP-Report.pdf

[27] HECO, *Renewable Energy Zones*, https://www.hawaiianelectric.com/a/10175

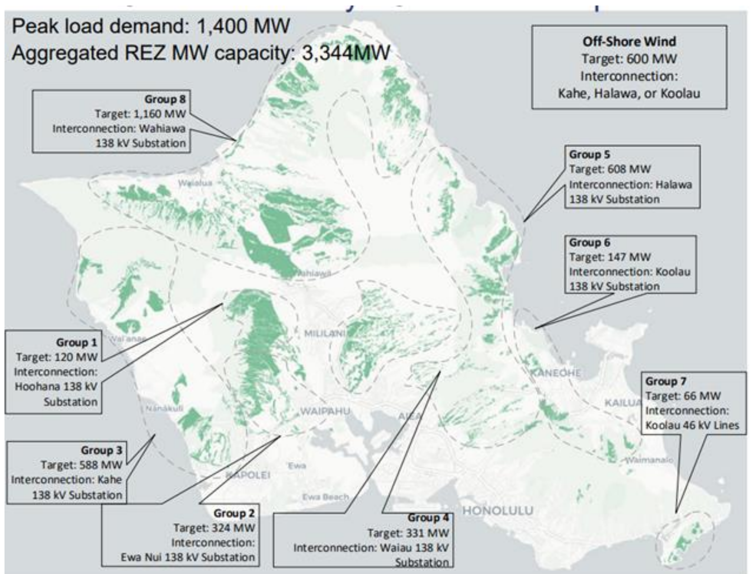

Figure 12. Oahu renewable energy zones from the Hawaiian Electric (HECO) Integrated Grid Plan (IGP).

Next Steps for TVA

TVA should start a stakeholder driven process that includes TVA's resource planning team, transmission planning team, renewable energy developers, and targeted communities to identify proposed renewable energy zones, the current capacity of integrating renewables onto the grid, and proposed transmission upgrades necessary to unlock renewable potential. TVA should target completion of the renewable energy zone analysis prior to the next IRP cycle.

4.3. Enhance TVA's strategic coal plant retirement studies

TVA's recent decisions regarding the retirements of the Cumberland and Kingston Fossil Plants highlight a siloed approach to coal plant retirement planning, which separates these critical decisions from the broader framework of its IRP. While these evaluations have involved detailed Environmental Impact Statements (EIS), they lack the system-wide perspective and integration necessary to align with TVA's long-term strategic goals.

For both Cumberland and Kingston, replacement portfolios were pre-selected and focused on large-scale gas-fired generation to replace retiring coal capacity. However, these decisions were made without considering the full spectrum of replacement options in the context of the IRP. The IRP, which should serve as a roadmap for least-cost and least-regret planning, was not leveraged to evaluate how wind and solar energy, energy storage, transmission upgrades, and gas generation could be optimally combined to meet system needs and support decarbonization goals.

By isolating coal plant retirements from the IRP, TVA's retirement replacements are not reflective of a system-wide strategy that accounts for the cumulative impacts of retiring all coal plants by 2035. Furthermore, this fragmented approach limits the ability to evaluate economies of scale in replacement infrastructure and to plan proactively for necessary transmission upgrades to support resource integration. Establishing a more integrated planning process is essential for achieving cost-effective, reliable, and sustainable solutions as TVA transitions away from coal.

Currently, TVA still has an important window to adopt a forward-looking approach to the retirement of its remaining coal plants, ensuring the transition is cost-effective, reliable, and aligned with clean energy goals. By evaluating the transmission system needs in 2035, when all coal plants are scheduled to be retired, TVA can take a system-wide perspective that considers the full scope of changes required to replace these aging assets. This process can be integrated into a zonal capacity expansion plan that optimizes the siting of battery storage, renewable energy, and potential new gas generation to maintain system reliability and minimize costs.

TVA should stop evaluating site-specific replacement portfolios with a pre-selected set of replacement resources and instead use the zonal capacity expansion plan to aid in resource siting and portfolio development. After this process, an iterative approach between transmission modeling and generation modeling can be used to plan for system-wide changes to address all coal plant retirements at once and use the current 10-year runway to 2035 to implement this plan and enable the coal retirement goal while minimizing additional environmental impacts.

Evaluating the 2035 Transmission System

The cornerstone of this strategic approach is a comprehensive evaluation of TVA's transmission system requirements under a scenario where all coal plants are retired by 2035. This analysis should aim to identify critical areas of the grid that will require reinforcement or expansion to address the loss of coal capacity while accommodating increased levels of wind and solar energy and battery storage and minimizing reliance on new fossil fuel resources. By proactively assessing these needs, TVA can ensure that the grid evolves in a way that supports both reliability and goals to reduce carbon emissions 70% by 2030 and achieve net-zero by 2050.[28]

Power flow modeling and zonal transfer capability analysis should be central to this effort. These tools can identify existing bottlenecks, opportunities to reuse infrastructure, and regions where transmission upgrades will deliver the greatest value. This forward-looking analysis will also provide the data necessary to strategically site battery storage resources. Properly located storage can help mitigate transmission congestion, balance variable renewables, and reduce the reliance on costly fossil resources for peaking capacity.

This evaluation should not only focus on internal system improvements but also consider TVA's interregional transmission ties. By assessing opportunities to strengthen connections to regions like MISO and SPP, TVA can expand access to low-cost renewable resources, diversify its portfolio, and enhance system resilience during extreme weather events. Addressing these needs comprehensively now will allow TVA to align its replacement timeline with the development of critical infrastructure, avoiding delays and costly reactive measures.

Planning for 2035 with Zonal Capacity Expansion

Once TVA has identified the 2035 transmission system needs, the next step should be to develop a coordinated zonal capacity expansion plan that aligns coal plant retirements with strategic investments in new resources and infrastructure. This approach divides TVA's grid into zones based on transmission constraints and operational characteristics as discussed in section 4.1. By addressing these needs at a zonal level, TVA can ensure that its replacement portfolio optimally balances reliability, cost, and emissions reductions across its service territory.

This zonal plan would evaluate the optimal mix of resources for each zone, including solar, wind, battery storage, and, where necessary, gas generation. For example, zones with strong solar potential and adequate transmission capacity could prioritize renewables, while zones with limited flexibility might focus on battery storage or limited gas peaker plants to support system stability. Incorporating this granularity enables TVA to align resource additions with both local and system-wide requirements, minimizing costs and ensuring reliability.

Taking a system-wide approach to planning all coal plant retirements simultaneously allows TVA to unlock significant economies of scale. By avoiding repetitive studies and staggered decision-making, TVA can streamline resource integration and focus on large-scale solutions that reduce costs and enhance resilience. Furthermore, this approach positions TVA to take advantage of interregional transmission opportunities, such as accessing high-quality wind resources from SPP or MISO. These connections can further reduce reliance on fossil fuels while enhancing the diversity and flexibility of TVA's energy

[28] TVA, *2022 TVA Federal Sustainability Plan*, https://www.sustainability.gov/pdfs/tva-2022-sustainability-plan.pdf

portfolio. Through a coordinated plan, TVA can ensure its grid is ready for the clean energy transition while maintaining a least-cost, least-regret strategy for resource deployment.

Proactive Planning for Coal Plant Retirements

As TVA approaches the 2035 target for retiring its coal fleet, a system-wide, long-term planning approach is essential to ensure a reliable and cost-effective system. Planning at the system level provides TVA with the opportunity to address the cumulative impacts of all coal plant retirements simultaneously, rather than tackling each retirement individually. By taking this approach, TVA can align its coal retirement strategy with broader system needs, reduce redundancy in replacement studies and replacement resources, and design a least-cost, least-regret portfolio that meets energy, capacity, and reliability requirements.

A 2035-focused evaluation should begin with a comprehensive assessment of the transmission system under a no-coal scenario. This analysis can identify critical grid constraints, opportunities for infrastructure reuse, and areas where new transmission upgrades are required to support future resource portfolios. Coupling this assessment with a zonal capacity expansion plan allows TVA to determine the optimal mix of solar, storage, wind, and gas resources to maintain system reliability across its service territory. For example, strategic placement of battery storage can alleviate transmission congestion, balance renewable variability, and reduce the need for local fossil peakers, while solar and wind resources can provide cost-effective energy supply in areas with high resource potential.

Interregional transmission should also play a pivotal role in this system-wide planning framework. By expanding interregional ties with neighboring systems like MISO and SPP, TVA can gain access to high-quality wind resources that complement solar generation and reduce reliance on storage to balance renewable variability. Moreover, interregional connections enable TVA to leverage the entire resource fleets of neighboring regions, including thermal capacity, during periods of high demand or system stress. This regional diversity improves reliability, reduces the need for overbuilding local capacity, and optimizes costs through shared resources.

In summary, TVA should enhance its retirement planning for the remaining coal plants using the following recommendations to build on TVA's current foundations of the retirement EIS and 2025 IRP.

1. Develop a 2035 Transmission Roadmap: Assess and address grid constraints that will arise when all coal plants are retired, prioritizing upgrades that facilitate renewable integration and accessing more interregional wind and thermal resources to support reliability. Working backwards from the known future coal-free system should be the starting point.
2. Leverage zonal planning for resource optimization: As discussed in the previous section, zonal models will aid in identifying the best mix of generation, storage, and transmission resources to realize low-cost portfolios across TVA's future scenarios.

4.4. Coordinate large load interconnection alongside new resources and retirements

The industry is experiencing a significant shift in load interconnection requests. Data centers, fleet electrification, and new industrial facilities are seeking connections to the transmission system, often requiring loads of several hundred megawatts. These large loads have substantial impacts on the transmission system, varying based on factors like the condition of existing infrastructure and proximity to generation resources. As a result, such requests must be factored into transmission expansion plans and generation resource adjustments.

Unlike peers in Duke Energy Carolinas and Southern Company, who give significant attention to large load and data center interconnection in the IRP, TVA does not discuss the topic explicitly. The objective of this screening analysis is to identify regions where multiple large loads can be interconnected in relatively close proximity to one another while minimizing the total transmission upgrades required. This is analogous to the renewable energy zone analysis, but for large loads like data centers or other large industrial infrastructure that may have some flexibility on location of interconnection. If done properly, the large load and renewable energy zones could be coordinated, siting the load and renewable resources together and minimizing total infrastructure requirements. Large load interconnection study can follow a clear, step-by-step process:

1. **Assess Existing Infrastructure:** Determine the load that can be served at the requested point of interconnection (or within a selected area) using current infrastructure and planned upgrades.
2. **Identify Necessary Upgrades:** Evaluate additional upgrades required to serve load beyond the initial capacity. Examples of necessary upgrades may include transmission line upgrades, transmission line additions, or adding dynamic reactive devices. This can be done in conjunction with generation interconnection needs and future transmission expansion plans to maximize the value of the necessary upgrades.
3. **Determine Costs and Schedules:** Calculate the cost and timeline for the required upgrades beyond interconnection costs. If applicable, provide a phased load ramp schedule tied to upgrade completion. Early communication of costs and timelines helps manage customer expectations.
4. **Cluster studies:** Identify zones where multiple large loads could interconnect, sharing transmission interconnection costs and siting in closer proximity to renewable resources.

However, doing this for a single large load request, as they approach the utility for interconnection is short-sighted and reactionary. An alternative approach is to develop proactive plans in strategic regions most capable of serving large loads, streamlining the interconnection process and providing potential new industrial customers with location screening and development guidance. Again, this would be analogous to cluster studies that are performed for multiple renewable resource interconnection requests.

A proactive, transparent approach is critical for handling large load interconnection requests. This approach includes identifying load amounts that can be served with the existing system, recognizing thresholds that require additional upgrades, and providing high-level cost and timeline expectations for upgrades. By addressing these factors and coordinating them with other transmission and generation resource planning, the system can better accommodate large load requests while ensuring efficient system planning.

4.5. Improve representation of external ties and interregional transfer capabilities

Existing interregional transmission plays a critical role in improving system reliability, resilience, and cost-effectiveness by enabling power transfers between regions with diverse load profiles, generation resources, and weather conditions. Previous studies like the ESIG "Multi-Value Transmission Planning for a Clean Energy Future" highlighted that:

> *"Transmission can do more than reduce costs between regions by transferring low-cost generation in one region to higher-priced load centers or enabling additional renewables development. Large-scale transmission projects can improve resource adequacy by improving capacity interchange between regions, which can replace or defer the need for development of generation capacity in both regions. These projects can also make the system more robust and resilient against extreme events by connecting regions to faraway locales that are likely not to be subject to the same weather patterns or fuel supply constraints."*[29]

Results of this study reinforced that resource adequacy, reliability, and resilience benefits were realized by increasing interregional transfer capabilities. These benefits are likely to be a priority for TVA alongside reduced generation costs for accessing high quality renewable energy locations. A well-planned approach to identifying and prioritizing these opportunities is essential for maximizing the value of interregional transmission investments.

The importance of interregional transmission in supporting a reliable grid has also been explored in greater detail in the recent NERC Interregional Transfer Capability Study). The study provides a starting point, but did not consider economics such as reducing costs, nor how regions could share generating capacity to reduce reserve margin costs. However, the study did consider how increasing interregional transfer capabilities can be explored to mitigate extreme weather conditions and other high stress grid conditions and recognizes that:

> *"The North American system is vulnerable to extreme weather. Transmission limitations, and potential for energy inadequacy, were identified in all 12 weather years studied. Enhancing specific transmission interfaces could reduce the likelihood of energy deficits during extreme conditions."*[30]

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[29] Energy Systems Integration Group. 2022. Multi-Value Transmission Planning for a Clean Energy Future. A Report of the Transmission Benefits Valuation Task Force. Reston, VA. https://www.esig.energy/ multi-value-transmission-planning-report.

[30] North American Electric Reliability Corporation (NERC), *Interregional Transfer Capability Study: Part II and Part III*, December 2022. Available at: https://www.nerc.com/pa/RAPA/Documents/ITCS_Part2_Part3.pdf.

In addition, the study recognizes the importance of evaluating both generation resources and transmission planning in a holistic manner.

> *"With sufficient available generation from neighboring systems, interregional transmission could mitigate certain extreme conditions by distributing resources more effectively, underscoring the value of transmission as an important risk mitigation tool. However, there are numerous barriers to realizing these benefits in a timely fashion."*[31]

The report recognizes that the interconnectedness of the system must be considered to provide effective plans for ensuring a reliable system in the face of extreme weather and a changing grid. This is further compounded by the expected increase in load growth due to data centers, artificial intelligence, and electrification and the relatively long lead times for transmission development.

We recommend that TVA pursue evaluating regions that may mitigate extreme weather risks while providing access to low cost resources. The following section details existing studies that identify where high value opportunities exist for TVA to enable greater interregional transmission. TVA should provide a concerted effort to evaluate the benefits of these connections and the potential to increase transfer capability with these regions and incorporate their effects into scenarios for their resource and transmission planning efforts. Fortunately, the use of probabilistic modeling tools like SERVM for the planning reserve margin requirement study can expedite this assessment.

Recent Studies Characterizing High-Value Opportunities for TVA/SERTP

Several studies have shown that existing transfer capabilities provide substantial reliability and resilience benefits for the whole system, including for TVA and the SERTP region.

Following Winter Storm Elliott, ACORE and Grid Strategies produced a report on the value of additional interregional transmission during extreme weather events. The study found that an additional 1 GW of transfer capability between ERCOT North, MISO North, and MISO South to TVA would have provided $249 million in benefits for that extreme event alone.[32] The variations in prices between MISO, ERCOT, and TVA were due to how the winter storm moved across the grid, providing opportunities for each region to support the other and mitigate fuel price volatility and risks posed due to increased generator outages.

[31] Ibid. 30

[32] American Council on Renewable Energy (ACORE), *The Value of Transmission During Winter Storm Elliott*, February 2023. Available at: https://acore.org/wp-content/uploads/2023/02/ACORE-The-Value-of-Transmission-During-Winter-Storm-Elliott.pdf

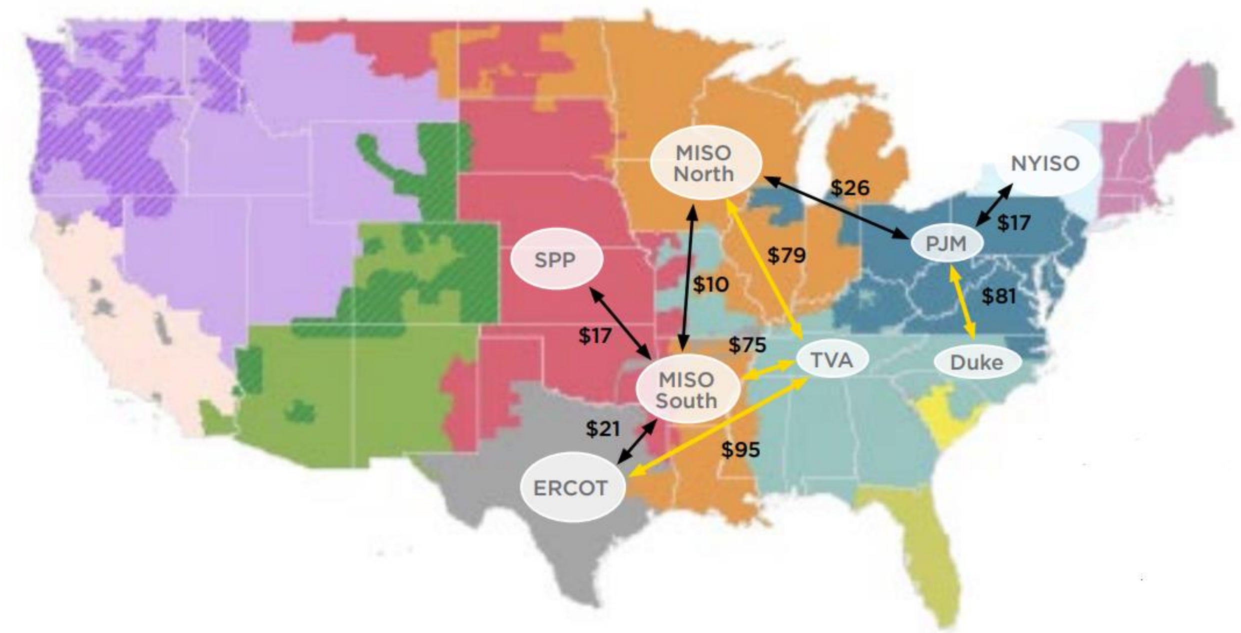

Figure 13. Benefit of 1 GW transmission expansion between each pair of regions, in millions of dollars, December 22-25, 2022 (Grid Strategies & ACORE, February 2023).

Another study conducted by ESIG *"Interregional Transmission for Resilience: Using Regional Diversity to Prioritize Additional Interregional Transmission"* evaluated the FERC Order 1000 planning regions across multiple years of weather for future load and resource mixes. In this analysis, TVA was included in the SERTP region. Results for where SERTP should prioritize expanding interregional transfer capability to reach different levels of import capability are shown in the table below from the report.

Table 4. SERTP priority regions to expand interregional transmission based on load, resource, and weather diversity for different levels of import capability as a percentage of region peak load (Source: ESIG).

Importing Region	Export -> Import Path	Base Transmission Capability (MW)	Incremental Transmission to Reach 10% Import Capability (MW)	Incremental Transmission to Reach 20% Import Capability (MW)	Incremental Transmission to Reach 30% Import Capability (MW)
SERTP	FRCC -> SERTP	2,862	0	453	791
	MISO -> SERTP	5,326	0	1,848	3,286
	PJM -> SERTP	4,310	0	3,153	7,297
	SPP -> SERTP	1,484	0	7,121	14,480

Based on the evaluation of multiple years of weather and resource diversity, SERTP would prioritize SPP, PJM, MISO, and FRCC, in that order due to geographic diversity in load, renewable resource availability, and correlated generator outages. While this study did not evaluate transfers between secondary neighbors, the ACORE report and ESIG Multi Benefits report both indicate that ERCOT would also be a beneficial region to prioritize due to load, resource, and weather diversity and there are current HVDC transmission projects proposed between ERCOT and the Southeast.

Additional analysis based on the ESIG report is provided below which breaks down the FERC Order 1000 regions into NERC's Transmission Planning Regions used in the recent ITCS report. This provides a more granular view of all regions, including SERC Central where TVA is the largest part of the region. Results shown in the table represent the correlation between SERC Central and all other regions in the United States across different subsets of risk hours and all hours analyzed in the ESIG work.

Table 5. Correlation (R-value) in hourly energy margin for SERC Central across multiple subset of risk hours. Data reflects hourly weather conditions from 2007 – 2013 and divides FERC Order 1000 regions into the NERC Interregional Transfer Capability Study regions for increased granularity (Source: Telos Energy).

Order 100 Region	NERC ITCS Region	SERC-C High Risk Hours n = 1,840 hours	SERC-C Margin <3% n = 3,445	SERC-C Margin <10% n = 7,559	SERC-C All Hours n = 61,365
NorthernGrid	Washington Region	0.17	0.14	0.13	0.47
	Oregon Region	0.05	0.04	0.09	0.37
	Wasatch Front	-0.02	0.01	0.06	0.18
CAISO	Northern California	0.01	0.00	0.03	0.31
	Southern California	0.07	0.07	0.05	-0.02
WestConnect	Southwest Region	-0.19	-0.16	-0.07	0.08
	Front Range	-0.12	-0.08	0.03	0.39
SPP	SPP North	-0.03	-0.02	0.08	0.41
	SPP South	0.05	0.05	0.10	0.36
ERCOT	ERCOT	-0.02	0.02	0.05	0.35
MISO	MISO West	-0.01	0.02	0.15	0.49
	MISO South	0.04	0.08	0.17	0.62
	MISO Central	0.07	0.13	0.27	0.77
	MISO East	0.06	0.08	0.18	0.53
PJM	PJM West	0.24	0.25	0.37	0.74
	PJM East	0.00	0.02	0.11	0.55
	PJM South	0.06	0.11	0.17	0.33
SERTP	SERC Southeast	0.21	0.27	0.37	0.80
	SERC FL Peninsula	-0.04	0.00	0.05	0.29
SERTP/SCRTP	SERC East	0.19	0.24	0.34	0.72
NYISO	NPCC New York	-0.09	-0.05	0.03	0.48
ISONE	NPCC New England	-0.02	0.01	0.06	0.55

Using more granular transmission regions shows that SERC Central, and thus TVA, has high reliability and resilience potential between SERC Florida Peninsula, ERCOT, SPP North and South, and all of MISO. Increased resilience benefits (due to lower correlations in risk) can be achieved by going further west or further north, but distance will likely lead to increased costs.

In general, nearby neighbors like SERC Southeast, SERC East, and PJM are likely to provide less benefits due to the correlated nature and closer proximity to SERC Central. These results align with the previous examples shown so far. TVA should look to regions with lower correlations in risk. This analysis can be enhanced by using probabilistic assessments to evaluate the effectiveness and reliability benefits of interregional transmission to each of these regions.

TVA and the National Transmission Planning Study Results

Another recent national study that evaluated opportunities for interregional transmission is the Department of Energy's National Transmission Planning Study in partnership with the National Renewable Energy Laboratory (NREL) and the Pacific Northwest National Laboratory (PNNL).[33]

It was a novel study that evaluated the U.S. power system with coordinated generation and transmission planning across all regions and incorporated resource adequacy analysis, nodal production cost simulations, and AC power flow analysis. It considered four transmission frameworks, including a Limited reference case (Lim), along with AC transmission expansion (AC), a point-to-point (P2P), and multiterminal (MT) accelerated transmission frameworks.[34] The results of this process are provided in Figure 14.

Regardless of the framework, the findings for TVA are similar, new interregional transmission is most beneficial for TVA to expand westward to MISO and SPP to access lower cost renewable energy and geographic diversity in resource availability and load. In the multiterminal framework, there are also additional opportunities to export or wheel power to the Southeast.

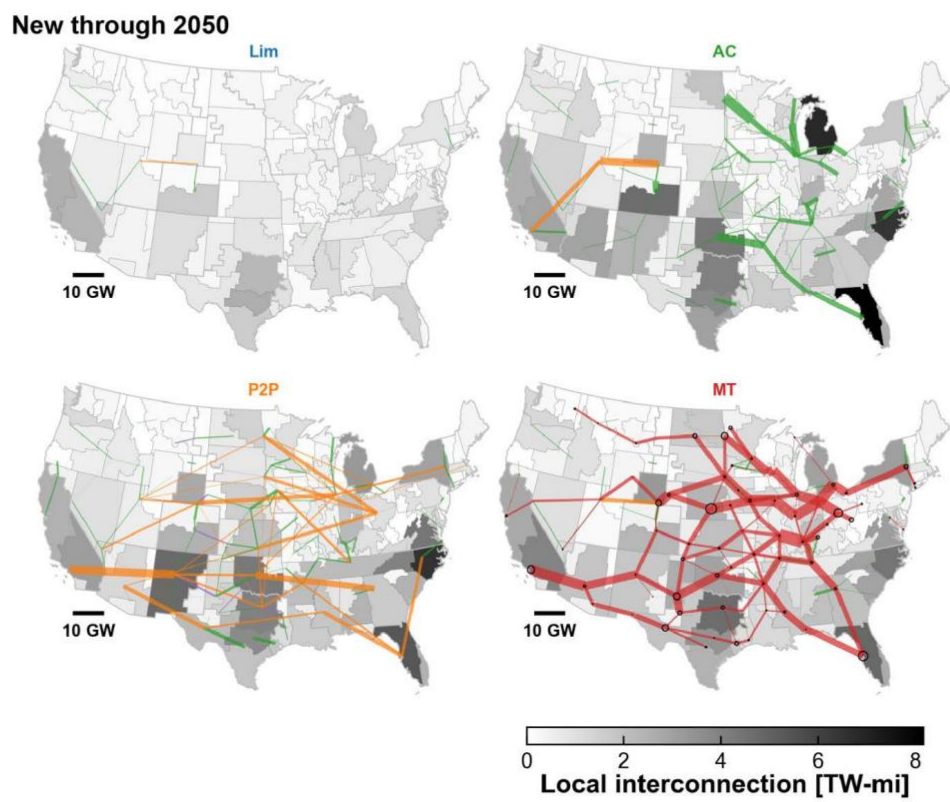

Figure 14. Transmission expansion by National Transmission Planning Study (NTPS) scenario (Source: US DOE).

[33] U.S. DOE, Grid Deployment Office. 2024. *The National Transmission Planning Study*. Washington, D.C.: U.S. Department of Energy. https://www.energy.gov/gdo/national-transmission-planning-study
[34] U.S. DOE, Grid Deployment Office. 2024. *Chapter 2: Long-Term U.S. Transmission Planning Scenarios*. Washington, D.C.: U.S. Department of Energy. https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-Chapter2.pdf

5. Conclusions and Recommendations

TVA has a unique opportunity to modernize its planning processes to meet the challenges of a transitioning energy landscape. By addressing the gaps in its 2025 IRP and adopting a forward-looking, scenario-based, multi-benefit transmission planning framework, TVA can ensure a more reliable and cost-effective energy future for its customers. This document lays out several actionable recommendations for both the current IRP cycle and future planning processes.

Near-Term Improvements to the IRP

Enhancing the 2025 IRP with better transmission assumptions and a stronger integration of resource and transmission planning will ensure that TVA's resource portfolios are more realistic and aligned with system needs. Near-term actions, such as refining cost assumptions for external wind resources, incorporating SERTP scenarios, and assessing the impacts of interregional transmission on reserve margin requirements, can provide immediate value and strengthen the IRP's alignment with long-term goals.

Transition to a Multi-Benefit Transmission Planning Approach

Proactively transitioning to a multi-benefit transmission planning framework will allow TVA to maximize the value of its investments across economic, reliability, and resilience metrics. A scenario-based, iterative planning process that aligns with FERC Order 1920 principles and best practices of multi-benefit analysis will ensure TVA can address future uncertainties, optimize resource integration, and enhance grid performance.

Proposed Next Steps

To support the development of an Integrated Resource and Transmission Plan, we recommend the following five actionable steps:

1. **Quantify Internal Zonal Transfer Capability**: Adopt zonal transmission constraints in planning tools like EnCompass and SERVM to reflect realistic grid conditions and support localized resource optimization.
2. **Identify Renewable Energy Zones):** Expedite renewable energy development by proactively identifying zones where targeted transmission investments can unlock low-cost, high-potential renewable resources.
3. **Enhance Coal Plant Retirement Studies:** Evaluate the system-wide transmission impacts of coal plant retirements and develop a coordinated strategy for integrating replacement resources and infrastructure.
4. **Screen Opportunities for Large Load Interconnection:** Coordinate large load interconnections with resource additions and transmission planning to minimize costs and streamline development.
5. **Improve Representation of Interregional Transfer Capabilities:** Expand studies on interregional transmission opportunities to reduce costs, improve resilience, and access diverse renewable resources.

By adopting these recommendations, TVA can create a cohesive planning framework that integrates generation and transmission to address both immediate needs and long-term opportunities. This comprehensive approach will ensure TVA remains a leader in delivering reliable, affordable, and sustainable energy to its customers.