Modernizing Southeast Grid Investments: How Enhanced Regional Transmission Planning Supports a Growing Economy

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Executive Summary

Southeast Must Invest in Regional Transmission to Cost-Effectively Meet Growing Demand and Maintain Reliability

Facing unprecedented load growth and increasing reliability risks, Southeast utilities need to invest in their regional transmission systems to improve reliability and reduce costs.

- **4x Increase in Transmission Costs over Last 20 years:** Spending on utility-specific upgrades increased during a period of moderate load growth due to aging infrastructure and new generation capacity needs
- **20 GW of Load Growth in Next 10 Years:** Serving the rapid 25% increase in load cost-effectively requires identifying opportunities for regional projects to supplement local upgrades and reduce system costs
- **80 GW of New Generation to Serve Load:** New generation (gas, solar, and storage) faces cost & schedule risks due to limited transmission capacity, which can be mitigated by proactive regional upgrades
- **Increasing Severity & Frequency of Winter Storms:** Winter storms have created new reliability risks over last 5 years that drive a need for both regional and interregional upgrades

Recent national studies find a significant need for new regional transmission across the Southeast.

Yet, all recent Southeast transmission upgrades are based on utility-specific local transmission planning* that has not considered the benefits of supplementing local upgrades with larger, more cost-effective regional and interregional transmission projects.

*In some portions of the Southeast (e.g., GA, NC, and SC), utilities within the same state collaborate on “local” reliability-driven transmission planning for their service territories.

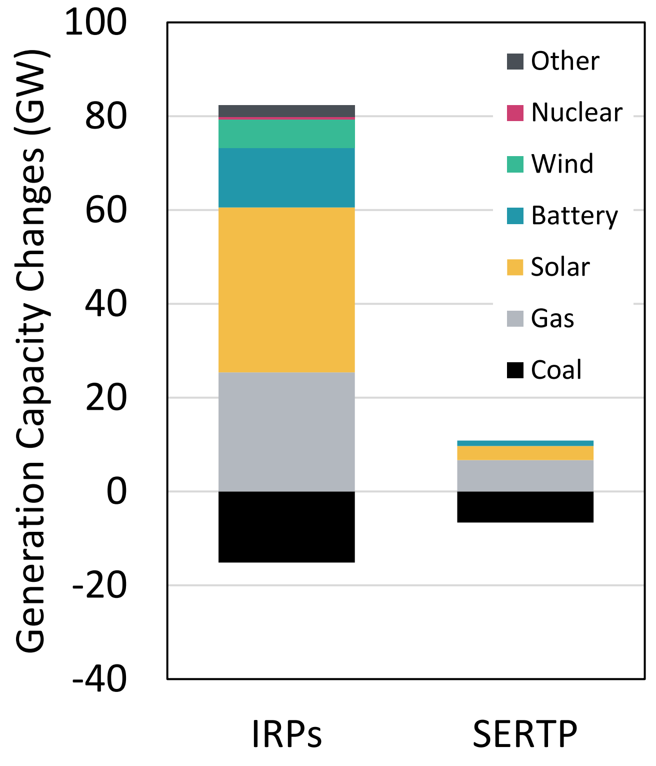
Existing Regional Planning Process Results in Insufficient Investment in the Regional Transmission Network

Southeastern Regional Transmission Planning (SERTP) completes an annual “bottom-up” regional planning process that has several limitations for identifying beneficial regional upgrades.

- **Limited Scope**: SERTP aggregates local planning studies and confirms regional reliability for a single future load scenario, failing to utilize scenarios developed in Sponsors’ resource planning studies
- **Inconsistent with IRPs**: SERTP studies include just 12% of the 80 GW of new generation identified as needed by the most recent IRP studies
- **Lack of Transparency:** SERTP provides limited information on transmission costs, violations, or alternatives studied to meet needs
- **No Regional Projects Approved**: SERTP analyzes regional alternatives based on a limited set of system needs, resulting in <u>no regional upgrades in 11 years of SERTP regional planning studies</u>

Existing SERTP planning process will not identify and approve the most cost-effective transmission infrastructure to reliably serve future load

IRP vs SERTP 2035 Generation Changes
(TVA, Duke, LG&E/KU, GPC)



Recommendations to Enhance SERTP Regional Planning that will Reduce Costs and Increase Reliability of the Southeast Grid

SERTP can leverage industry-wide experience over the past 20 years by implementing proven practices to reduce long-term system costs and risks, including the MISO LRTP and CTPC/Duke MVST planning processes

I. Improve Existing Planning Process

1. **Increase transparency** of study assumptions, approach, and results
2. **Engage state commissions and energy agencies** to participate in process and ensure results reduce costs and address state policies
3. Expand solutions studied to reflect **least-cost transmission "loading order"** that maximizes existing grid, upgrades existing lines, and builds new lines where necessary

II. Expand SERTP Planning Capabilities

4. Develop **multiple scenarios based on recent IRPs** to plan for a range of load and generation portfolios
5. Accurately identify congestion and quantify cost savings of regional upgrades via **region-wide production cost model**
6. Develop guidelines to evaluate a **comprehensive set of cost savings and other benefits** when analyzing regional upgrades

III. Implement Comprehensive & Proactive Planning Process

7. Implement **multi-driver approach to identifying regional & interregional needs** and candidate solutions
8. Estimate cost savings and other benefits of solutions **over the entire useful life of the assets**
9. Establish regional cost allocation that reflects **beneficiaries pays and cost causation principles**

Case Study: SERTP-Identified Upgrades Reduce Costs

To demonstrate the value for regional transmission, we performed a high-level analysis of three 500 kV upgrades SERTP identified in its 2024 process based on historical data.

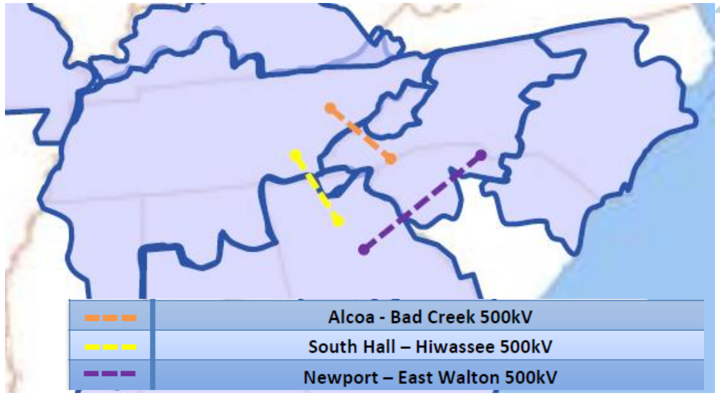
We estimated $8 billion of benefits compared to $5 billion in costs, resulting in at least $3 billion of net benefits

- Production cost savings: $2.9 billion (*range*: $2.0–3.6 billion)
- Load diversity cost savings: $3.3 billion (*range*: $0.9–6.0 billion)
- Resilience benefits: $1.6 billion (*range*: $0.7–2.3 billion)
- Additional potential benefits: avoided reliability and interconnection upgrade costs, greater production cost savings with increased solar/wind additions and reduced generation costs

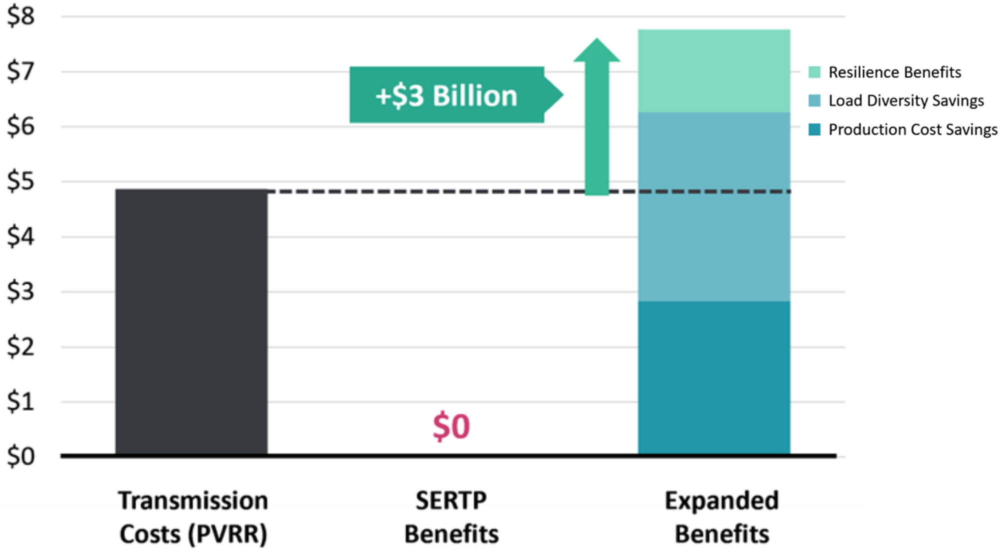
Regional transmission can reduce system costs when a broader scope of cost savings and other benefits are analyzed

By contrast, SERTP's very narrow view of benefits based solely on avoided local transmission costs identified no cost savings

SERTP-Identified Regional Projects



Estimated Net Benefits of Regional Projects



Order 1920 Provides Southeast Opportunity in 2025 to Enhance its Regional Transmission Planning Process

- **Southeast is the only major U.S. region that has not pursued significant regional transmission projects over the past decade**
- **The lack of proactive regional transmission planning process results in higher costs, lower reliability, and delays in serving growing load due to insufficient grid infrastructure**
- **FERC issued Order No. 1920 last year that requires SERTP to implement a proactive, long-term, multi-value regional planning process, presenting a pivotal opportunity for the Southeast to align its regional transmission planning with industry best practices developed over the past 10–20 years**
- **The Southeast should embrace this opportunity in 2025 to modernize SERTP's regional transmission planning to build a stronger, more efficient grid that supports economic growth, energy affordability, and long-term resilience**

Report Contents

I. The Southeast Must Invest in Regional Transmission to Cost-Effectively Meet Growing Demand and Maintain Reliability

Southeast Needs to Invest in its Transmission Infrastructure

Facing unprecedented load growth and increasing reliability risks, Southeast utilities need to invest in their transmission systems to **improve reliability** and **reduce cost**.

Local Reliability Needs Increased Transmission Investment by 4x

- Local reliability projects are increasing due to load growth, new generation, and aging infrastructure
- In-kind replacements will miss opportunities to more cost-effectively expand system capabilities
- No investment in regionally-planned transmission projects

Load Growth Increases Need for Regional Transmission Investment

- Growth being driven by commercial and industrial activity will increase needs for infrastructure
- Proactive transmission upgrades can increase system capacity and allow new loads to interconnect more quickly

Insufficient Regional Capacity Increases Winter Risks and Customer Costs

- Regional transmission capacity increases resilience to extreme weather events and reduces likelihood of outages
- Regional projects can reduce total annual system costs, including production costs, capacity costs, local transmission costs, etc.

Proactive Planning De-Risks Generation Needed to Serve Load

- New load requires additional generation resources to enter the system that are currently limited by lack of capacity
- Proactive regional planning can build out upgrades prior to need and reduce new resource development timelines to efficiently meet IRP needs

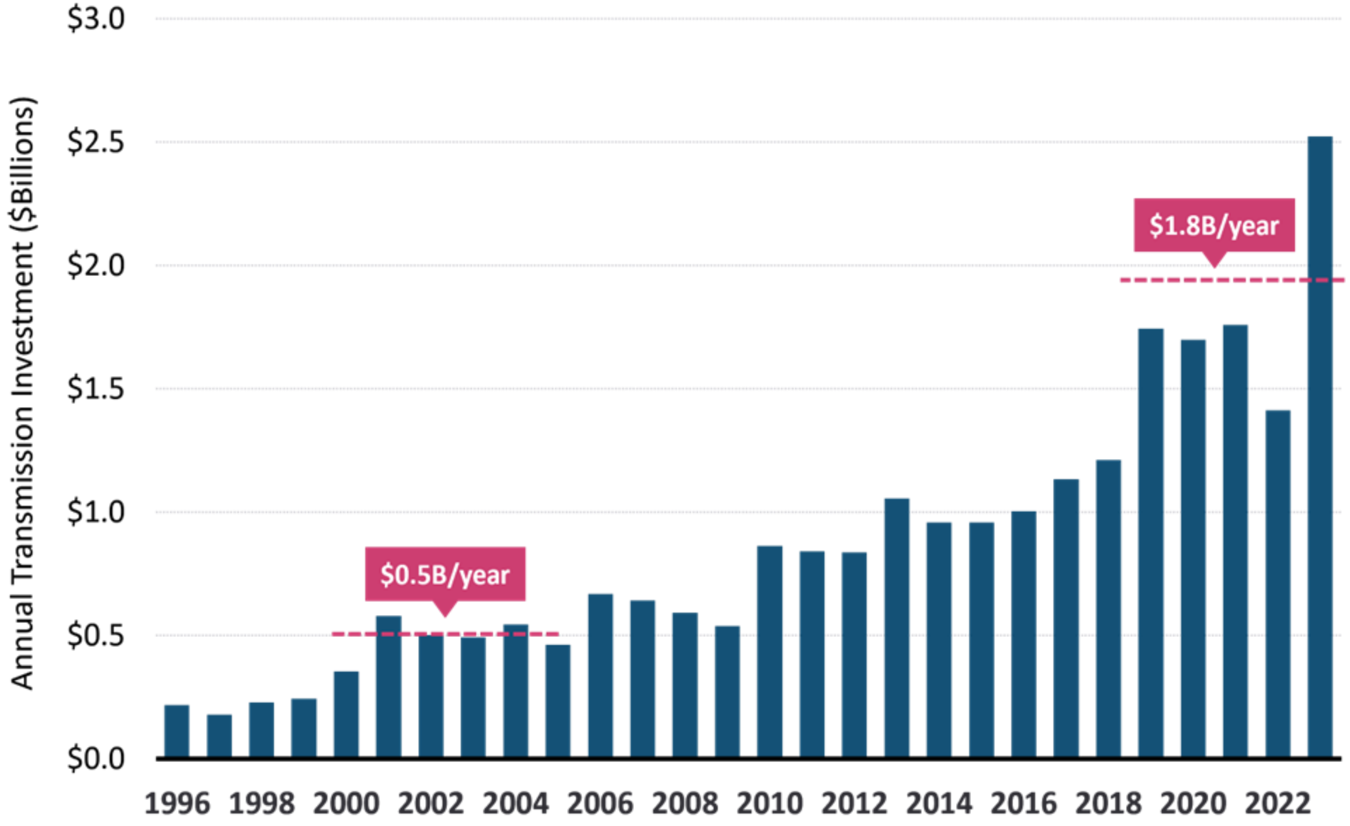
4x Increase in Reliability-Driven Local Transmission Needs

Transmission investment of three major utilities in the Southeast increased from **$0.5 billion per year in the early 2000s to $1.8 billion per year in the past 5 years**.

- Increased transmission costs in the Southeast (and across the U.S.) have been driven by utility-specific projects* to support limited load growth, replace aging infrastructure, and interconnect new generation, driving up transmission rates
- Southeast utilities risk inefficiently investing in lower-value projects in the absence of a regional forward-looking strategy to maximize the value of its future grid investments

*In some portions of the Southeast (e.g., GA, NC, and SC), utilities within the same state collaborate on "local" reliability-driven transmission planning for their service territories.

Annual Transmission Investment in SERTP Region
(Southern Company, Duke, LG&E/KU)



Source: Analysis of FERC Form 1 Data

Transmission Needed to Serve 21 GW of Load Growth

Southeast utilities are projecting **21 GW (+25%) of load growth by 2035** in their resource planning studies due to new data centers and manufacturing facilities, equivalent to adding twice New York City's power demand in 10 years.

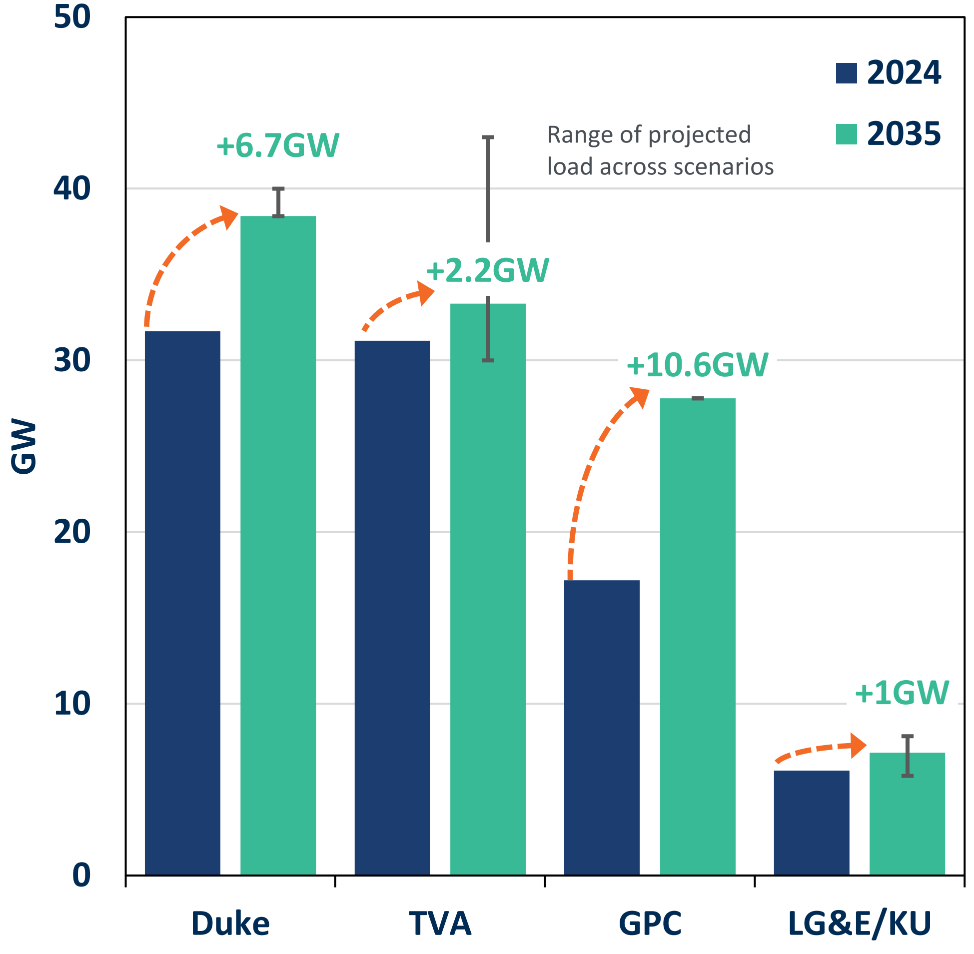
- Duke Energy: +7 GW to +9 GW
- TVA: +1 to +12 GW (base: 2 GW)
- Georgia Power (GPC): +11 GW

Combining utility-specific local planning with improved regional planning will support utilities in meeting the significant increase in load at lower total costs and allow for efficient interconnection of new loads.

Transmission studies recently identified large-scale regional upgrades needed for cost-effectively supporting large load additions in Texas ($32 billion) and Mid-Atlantic ($6 billion).

Sources: ERCOT 2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan Comparison; PJM Board Approves New Transmission Projects To Support Grid Reliability

Projected Load Growth by 2035 in Duke, TVA, GPC, and LG&E/KU



Sources: Duke 2023 2023 Carolinas Resource Plan Supplemental Planning Analysis; TVA 2025 Draft IRP; Georgia Power Company 2025 IRP; LG&E/KU 2024 IRP Volume I

Transmission Upgrades De-Risk New Generation Additions

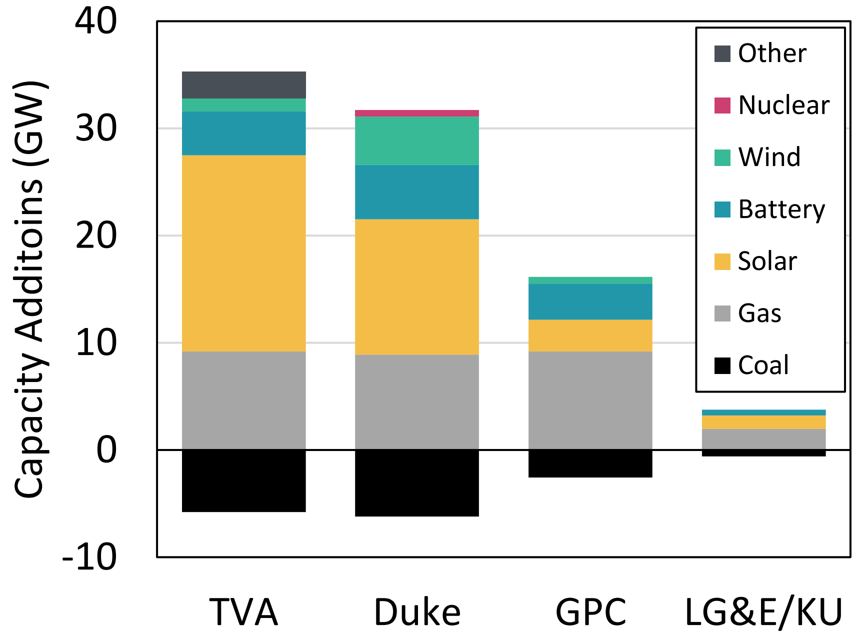
Southeast utilities' resource planning studies demonstrate the need to build and interconnect **more than 80 GW of new generation capacity** by 2035, or 8 GW per year.

- For context, the new Vogtle nuclear units added 3 GW to the grid
- New generation requires significant time to identify and construct network upgrades prior to interconnection
- Changing generation types and locations are shifting flows across the grid and increasing regional transmission needs

Without a stronger regional grid, new generation could face delays that increase energy prices and slow economic growth.

Yet Southeast utilities do not study regional upgrades to support the future generation mix; instead, higher-cost network upgrades will be identified on a just-in-time basis through generator interconnection studies.

New Generation Additions in Recent IRPs



Sources: TVA 2025 Draft IRP; Duke 2023 2023 Carolinas Resource Plan Supplemental Planning Analysis; Georgia Power Company 2025 IRP Technical Appendix Vol II ("Resource Mix Study"), Capacity Expansion Plans; LG&E/KU 2024 IRP Volume I

Regional Transmission Reduces Risks of Extreme Weather

In addition to load growth and new generation, recent extreme weather events have stressed the Southeast grid and lead to reliability events that could have been avoided with increased regional and interregional capacity.

Winter Storm Elliott in December 2022 demonstrated the need for access to additional import capacity to maintain grid reliability in the Southeast, as several utilities were forced to order firm load shedding:

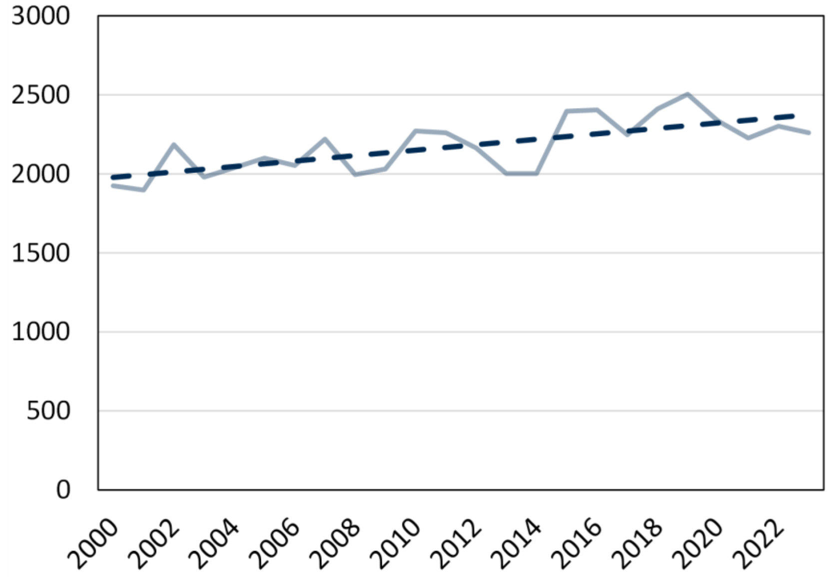
- DEC and DEP: Approximately 5,000 MWh over four hours
- TVA: Approximately 19,000 MWh over seven hours
- LG&E/KU: Approximately 1,200 MWh over four hours

Despite similar outages, Georgia Power avoided firm load shedding through imports from Florida; similarly, PJM avoided outages by relying on regional and interregional capacity with MISO to maintain system reliability.

As summers get warmer and winters storm increase, regional planners need to consider extreme conditions in future planning.

Regional and interregional transmission is an insurance policy against future extreme conditions, such as winter storms, heat waves, and renewable droughts, etc., providing access to a wider set of generation to serve load that increases reliability and reduces cost risks for customers.

Change in Cooling Degree Days for the South Atlantic Division



Sources & Notes: EIA Monthly Energy Review, January 2025. Population-weighted degree days are used by the EIA to model and forecast energy consumption.

Source: FERC, NERC and Regional Entity Staff Report, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott, October 2023.

Investing in Regional Transmission Reduces Total System Costs

Regional transmission can significantly reduce costs across the power system in excess of the incremental costs of the transmission solutions, resulting in lower total costs of serving demand.

The most significant drivers of cost savings from regional transmission projects include:

- **Production cost savings**: Reduce operational costs by increasing access to lower cost, more efficient generation resources, especially during heat waves, major generation and transmission outages, etc.
- **Lower energy losses**: Reduce operational costs by offloading highly utilized lines and reducing energy losses, and reduce capacity costs due to lower on-peak energy losses
- **Local transmission and interconnection cost savings**: Reduce costs of lower voltage local reliability projects needed for serving load, replacing aging infrastructure, or interconnecting new generation when regional plans are effectively developed and implemented
- **Generation capacity cost savings**: Reduce costs of new capacity to meet reserve requirements by taking advantage of load diversity between utilities across the region

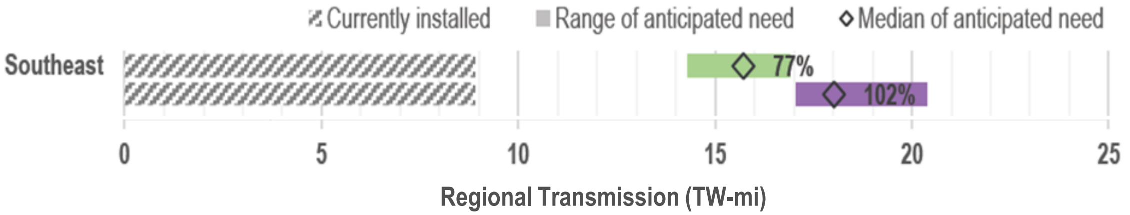
In the past 3 years, MISO approved $33 billion of regional projects that will **reduce net system costs by $50–125 billion** over the life of the assets based on a broad view of transmission cost savings.

Source: MISO, Long Range Transmission Planning, accessed February 2025.

Southeast Transmission Needs Highlighted in National Studies

National Transmission Needs Study (2023)

Summarizes 300 future scenarios and sensitivities from 6 independent studies for 2030, 2035, and 2040. By 2035, Southeast will need **7 TW-miles of new within-region transmission** and significant expansion of interregional transmission, ranging from **5.1 – 39.9 TW-miles with neighboring regions**.

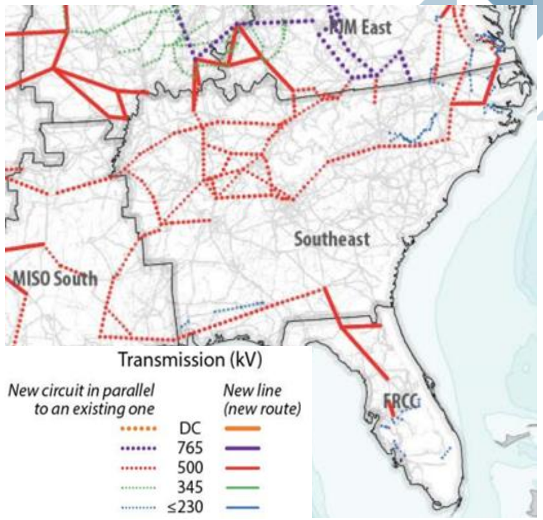


Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.

Source: National Transmission Needs Study

National Transmission Planning Study (2024)

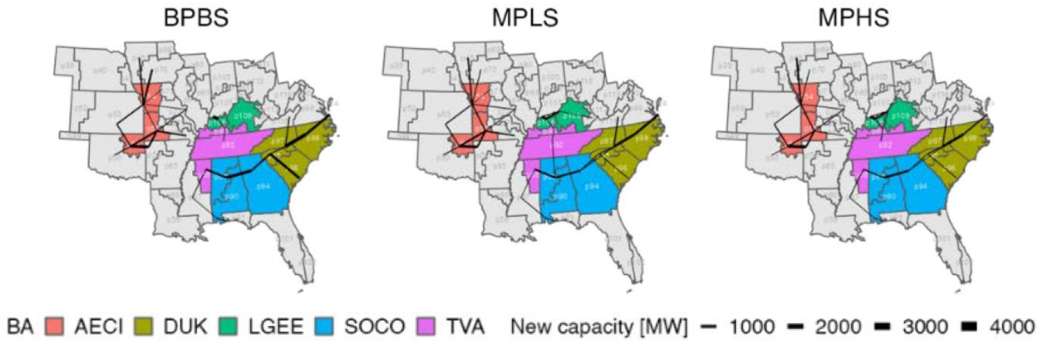
Conducted zonal capacity expansion and RA modeling through 2050 under 96 scenarios. Mid-demand, 90% emissions reduction AC scenario **strengthens existing 500 kV networks and connects SERTP to the Midwest and Plains through 345 kV and 500 kV lines** to enable flows across north-south and west-east interfaces to key load centers.



Source: National Transmission Planning Study

NREL/LBNL Solar and Storage Integration Study (2024)

Investigates higher levels of solar and storage on transmission needs by 2035 and benefits of increased operational coordination among utilities. In lower-solar scenarios, **transmission additions added east-west regional capacity.**



Source: Solar and Storage Integration in the Southeastern United States

NERC Interregional Transfer Capability Study (2024)

Analyzed transfer capability between neighboring regions and recommended "prudent" interregional additions to maintain reliability. Identifies 4.1 GW of transmission into SERC-E (NC/SC) from other Southeast regions and PJM by 2033 **justifiable based on reliability alone** to alleviate resource deficiencies.

Table ES.1: Recommended Prudent Additions Detail

Transmission Planning Region	Weather Years (WY) / Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
SERC-E	Winter Storm Elliott (WY2022)	9	5,849	4,100	SERC-C (300) SERC-SE (2,200) PJM-W (1,600)
SERC-Florida	Summer WY2009 and Winter WY2010	6	1,152	1,200	SERC-SE (1,200)
MISO-S	WY2009 and WY2011 summer events	4	629	600	ERCOT (300) SERC-SE (300)

Source: Interregional Transfer Capability Study (ITCS)

Southeast Can Build on Order 1920 to Improve Regional Planning

In 2024, the Federal Energy Regulatory Commission (FERC) issued Order No. 1920 to improve long-term regional transmission planning and cost allocation by proactively planning for regional grid needs based on industry-wide best practices implemented across the country.

Southeast utilities will need to update their regional planning process to meet Order 1920 requirements:

- Complete a comprehensive long-term (20+ year) planning process every 5 years that considers at least 7 drivers of transmission needs plus asset refurbishment and generator interconnection needs
- Develop at least 3 plausible and diverse scenarios, including at least 1 “stress test” sensitivity
- Quantify at least 7 benefits metrics for upgrades that meet long-term regional needs
- Consider a broader set of solutions including grid-enhancing technologies (GETs), upsizing existing lines
- Develop default or state-sponsored cost allocation mechanisms
- Engage regional state entities through the transmission planning process

Order No. 1920 provides the Southeast an opportunity in 2025 to implement a new regional transmission planning process that will modernize its transmission network.

II. SERTP Regional Transmission Planning Process Is Insufficient to Meet Future System Needs

Who Is SERTP?

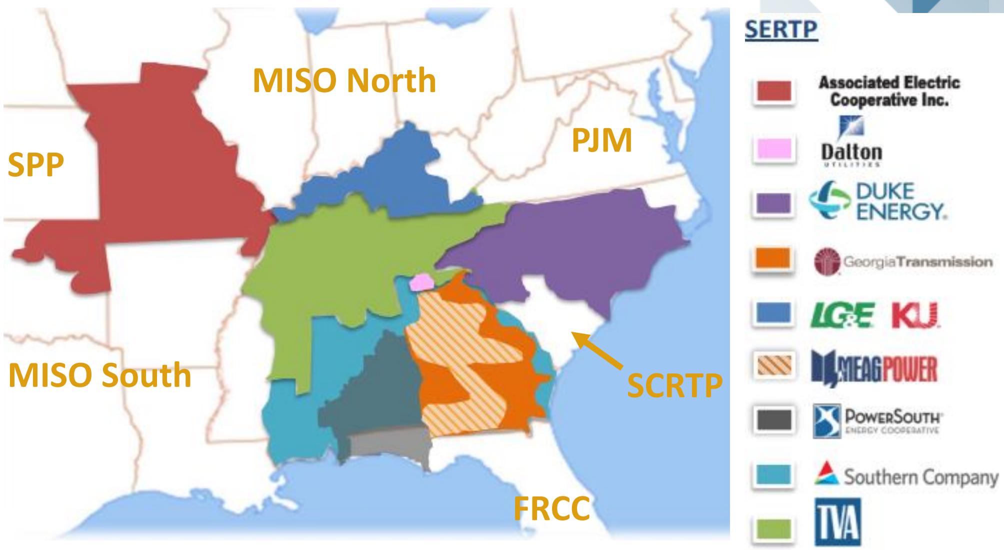
The Southeast Regional Transmission Planning (SERTP) was formed in 2007 to comply with FERC Order No. 890 by Southeast transmission providers (or "Sponsors").

- There are currently 10 Sponsors spanning 12 states
- South Carolina Regional Transmission Planning (SCRTP) members expected to join SERTP in 2025
- SERTP process was updated in 2015 to meet Order 1000 regional/interregional planning requirements

SERTP is a forum for Sponsors to collaborate on regional planning and cost allocation and has no independent SERTP staff beyond the utility Sponsors.

SERTP produces a Regional Transmission Plan each year that primarily reflects the aggregated 10-year local transmission plans provided by each Sponsor.

SERTP Regional Footprint



SERTP Sponsors' Peak Demand

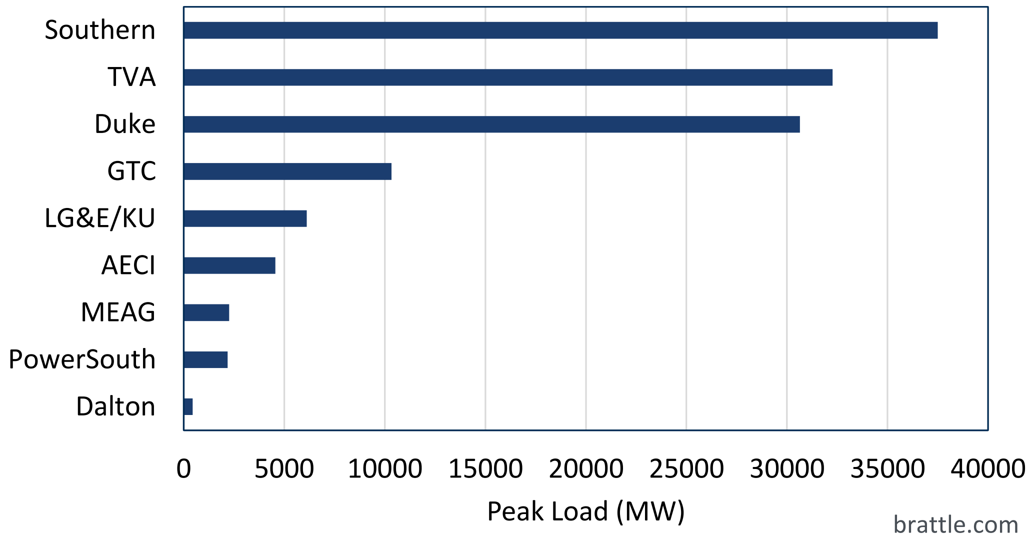


Image Source: SERTP - 1st Quarter Meeting (southeasternrtp.com). March 19th, 2024.

SERTP Produces an Annual 10-Year Regional Transmission Plan

In the annual regional planning process, SERTP Sponsors aggregate local plans into a preliminary expansion plan and assess whether regional projects meet reliability criteria at lower cost than local projects.

- SERTP hosts 4 meetings in each annual planning cycle to present their progress and allow for stakeholder input
- Stakeholders can request SERTP to study regional “economic” and “policy” needs and identify required upgrades

(1) Sponsors’ Local Transmission Plans (Feb.–Jun.)

- Developed by each Sponsor or load serving entities (LSEs) in the 7 BAAs

(2) SERTP Preliminary Expansion Plan (Apr.–Jun.)

- “Bottom-Up Reliability Study Process” based on local transmission plans to identify any regional reliability constraints
- Evaluation of stakeholder-submitted public policy requirements

(3) SERTP Regional Planning Analyses (Sep.–Nov.)

- Evaluation stakeholder-requested economic planning studies
- Analysis of regional projects identified to be potentially more efficient or cost effective

(4) SERTP 10-Yr Regional Transmission Plan (Oct.–Dec.)

- “Snapshot” of transmission plan presented at the Annual Transmission Planning Summit

Source: 2024 2nd Quarter SERTP Meeting Presentation (southeasternrtp.com)

Regional Transmission Planning vs. Local Planning and IRPs

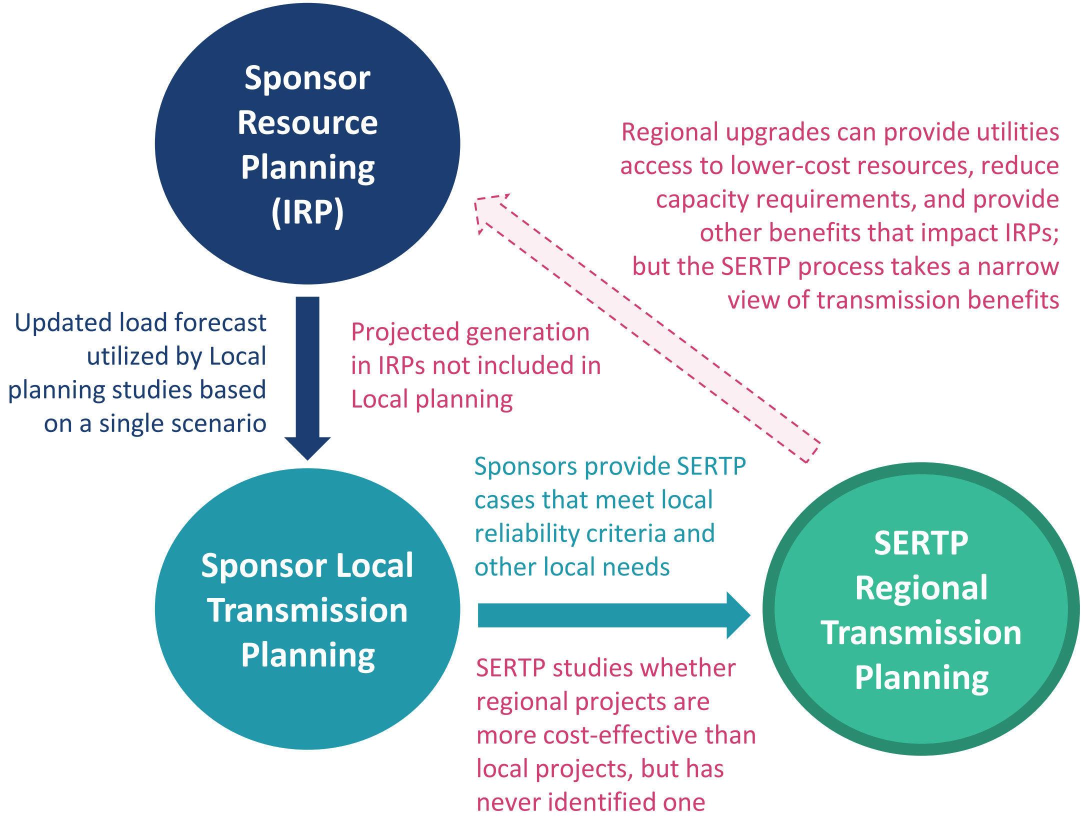
SERTP's planning models reflect system conditions studied in each Sponsor's local transmission planning study, not a consistent regional view of future system conditions.

- Each Sponsor completes local transmission planning studies that incorporate the latest load forecast but only a limited set of new generation resources and retirements
- Sponsors identify local upgrades to resolve reliability violations based on NERC criteria* and provide those cases to SERTP

SERTP planning does not account for the full set of new generation identified in recent IRPs, limiting SERTP from identifying least-cost upgrades to support new resources.

Regional planning can identify upgrades that provide utilities access to a broader set of resources in their IRPs and for dispatching generation more efficiently (see figure).

Coordination across Resource Planning and Transmission Planning Studies



* Duke recently began studying several future scenarios and multi-value upgrades via the CTPC MVST local planning process (as summarized later in the slides), but has not yet completed it first MVST study.

SERTP Assumptions Not Aligned with Local Resource Planning

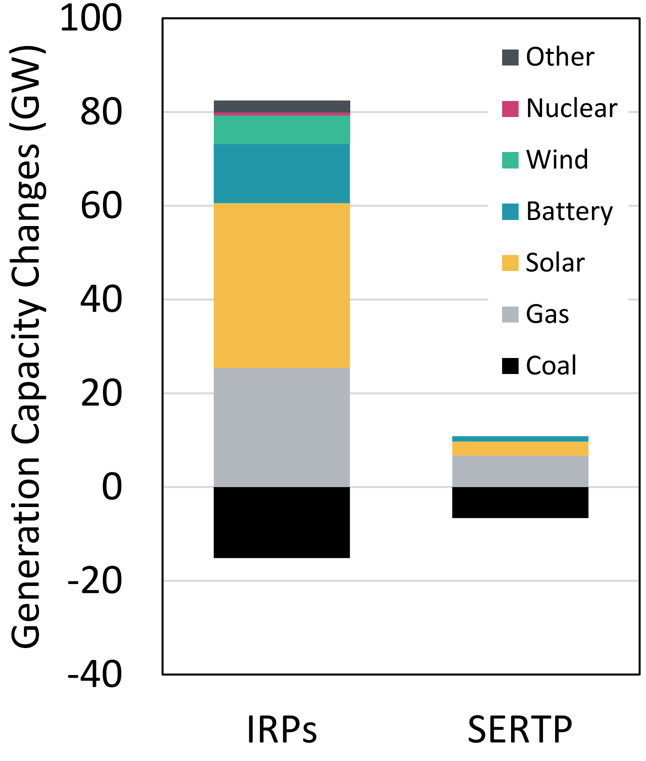
SERTP models regional system conditions for a single future scenario based on Sponsor-specific assumptions that are not aligned with the Sponsors' own resource planning studies.

Significant discrepancies exist between the projected generation resources in Sponsor IRPs and the SERTP planning models.

- SERTP model only includes 10 GW of the 80 GW of new generation resources identified in the latest IRPs by 2035 (12%), including just 8% of solar additions, 27% of gas additions, and 41% of coal retirements
- In some cases, utilities are not including resources that they already requested approval from its state commissions for construction
- In some regions, SERTP includes hypothetical "proxy units" to ensure there are sufficient resources to meet load, instead of utilizing IRP portfolios

SERTP's single future scenario does not utilize the future scenarios developed in each Sponsor's resource planning studies to assess how the regional system could adapt to uncertainties in future changes (e.g., high growth scenarios or alternative generation resource mixes).

IRP vs SERTP 2035 Generation Changes
(TVA, Duke, LG&E/KU, GPC)



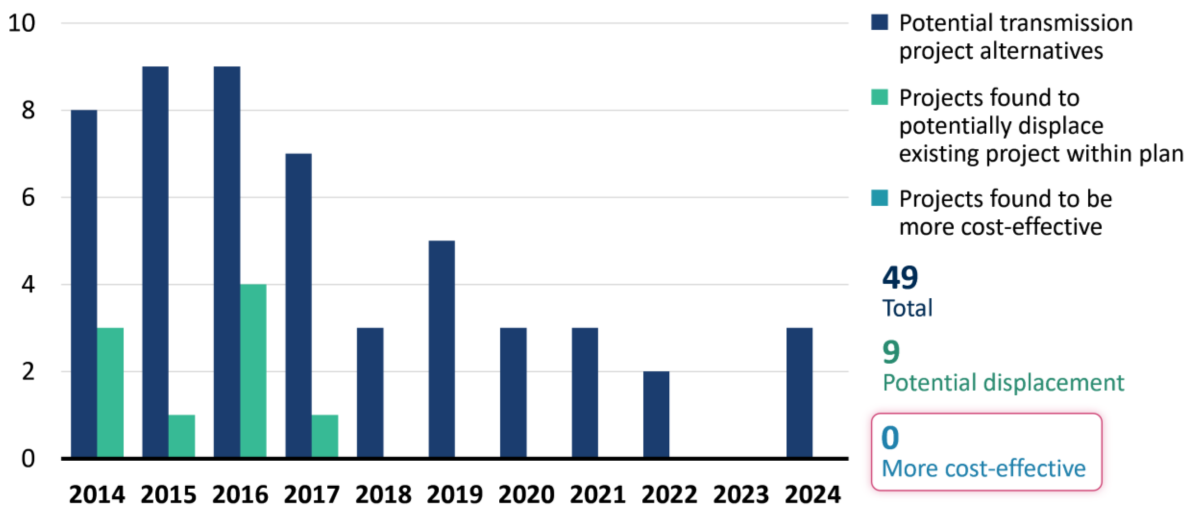
SERTP Has Not Identified Cost-Effective Regional Projects

Based on Sponsor-provided plans, SERTP conducts a reliability study to determine if regional projects could provide a more cost-effective solution than proposed local upgrades based on the following criteria:

- Ability to resolve reliability violations based on NERC criteria
- Project feasibility (i.e., viability of constructing and tying in the proposed project by the in-service date)
- Avoided local transmission costs
- Ability to reduce real power losses

SERTP **has never identified a more efficient or cost-effective regional project** to include in its annual regional plan, despite studying 49 alternative projects due to the limited scope of benefits analyzed.

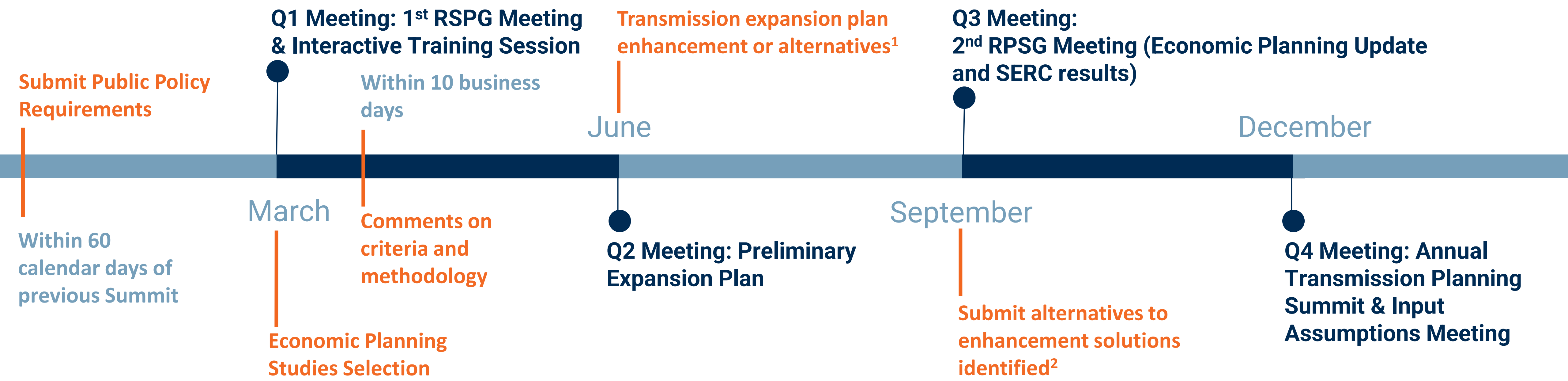
Potential Transmission Project Alternatives Evaluated by SERTP



SERTP Stakeholders Can Request Economic & Policy Studies

SERTP completes economic planning studies and an assessment of public policy requirements (PPRs) submitted by stakeholders in the Regional Planning Stakeholder Group (RPSG)

- SERTP may review up to 5 economic studies each year; stakeholders responsible for costs of additional studies
- Stakeholders can provide additional comments to SERTP at several points of the process, as noted below



[1] Preliminary transmission expansion plan will be posted on the **secure/CEII area** of the Regional Planning Website at least 10 calendar days prior to the Preliminary Expansion Plan meeting. Gaining access to the secure/CEII information is a process requiring background checks, $280 in fees, and executing a restrictive NDA.

[2] Preliminary economic planning study results posted 10 calendar days prior to the 2nd RPSG meeting. Stakeholders have 30 calendar days after the meeting to submit alternatives.

Source: Duke Joint OATT, Attachment N-1. Joint_OATT.pdf (duke-energy.com)

Economic Requests for <4 GW Identify Limited Regional Needs

SERTP economic studies analyze stakeholder requests for regional bulk power transfers and identify the least-cost upgrades required to enable those transfers while maintaining reliability.

- SERTP economic studies do not represent a commitment to proceeding with recommended enhancements
- Studies provide costs to entities seeking service across SERTP, which informs their decisions to pursue regional transfers, but does not consider a broader set of cost savings to SERTP customers

Amongst requests for 500 MW - 4,000 MW of transfers, SERTP identified limited upgrades (<$100 million), demonstrating that there is available capacity to accommodate incremental regional flows in this range.

2023 and 2024 SERTP Economic Study Results

Project No.	Year & Load Level	Source	Sink	Transfer Amount	Costs	
				MW	*$ Million*	*$/kW*
1	2028 - Winter Peak	MISO	TVA	2900	$21.5	$7.4
2	2028 - Summer Peak	South Georgia	North Georgia	1600	$95.9	$59.9
3	2028 - Summer Peak	TVA	North Georgia	1600	$56.5	$35.3
4	2028 - Summer Peak	MISO	LG&E/KU	1242	$83.5	$67.3
5	2033 - Summer Peak	SOCO	DEC	500	$0.0	$0.0
6	2029 - Summer Peak	MISO South/FRCC	SOCO	4000	$1.9	$0.5
7	2026 - Summer Peak	PJM	DEC/DEP	2000	$7.0	$3.5
8	2034 - Summer Peak	MISO North	SOCO	10000	$4,607.9	$460.8
9	2029 - Summer Peak	SPP/MISO North	AECI	2500	$0.0	$0.0
10	2034 - Winter Peak	DEC/SOCO	Santee Cooper	2400	$24.3	$10.1

Sources: SERTP 2024 Economic Planning Study Final Results
SERTP 2023 Economic Planning Study Final Results

2023 and 2024 SERTP Economic Study Requests

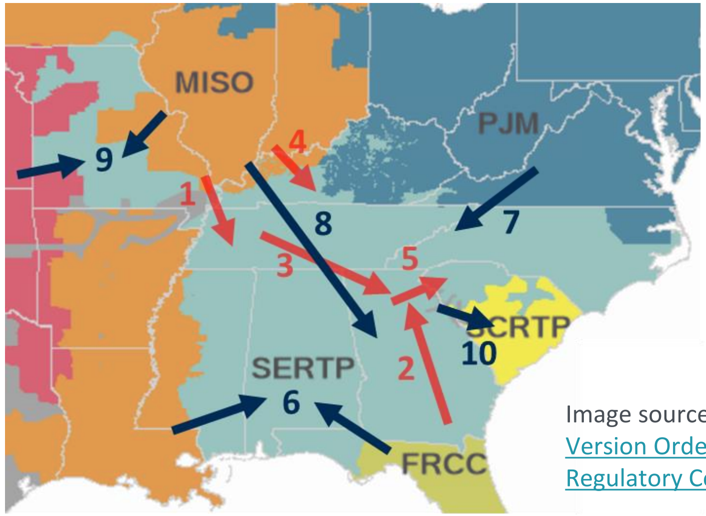


Image source: Regions Map Printable Version Order No. 1000 | Federal Energy Regulatory Commission (ferc.gov)

Major Regional Upgrades Identified for 10 GW Request

Stakeholders in 2024 requested SERTP to study a 10 GW transfer from MISO North to SOCO that resulted in SERTP identifying $4.6 billion of regional upgrades between TVA, Duke, and SOCO.

- Request triggered 139 violations and identified the need for seven new 500 kV lines and 40 other upgrades

SERTP selected three 500 kV lines for their analysis of more efficient and more cost-effective regional upgrades but identified no avoided local upgrade costs and considered no other cost savings or benefits.

10 GW Economic Request Reliability Violations

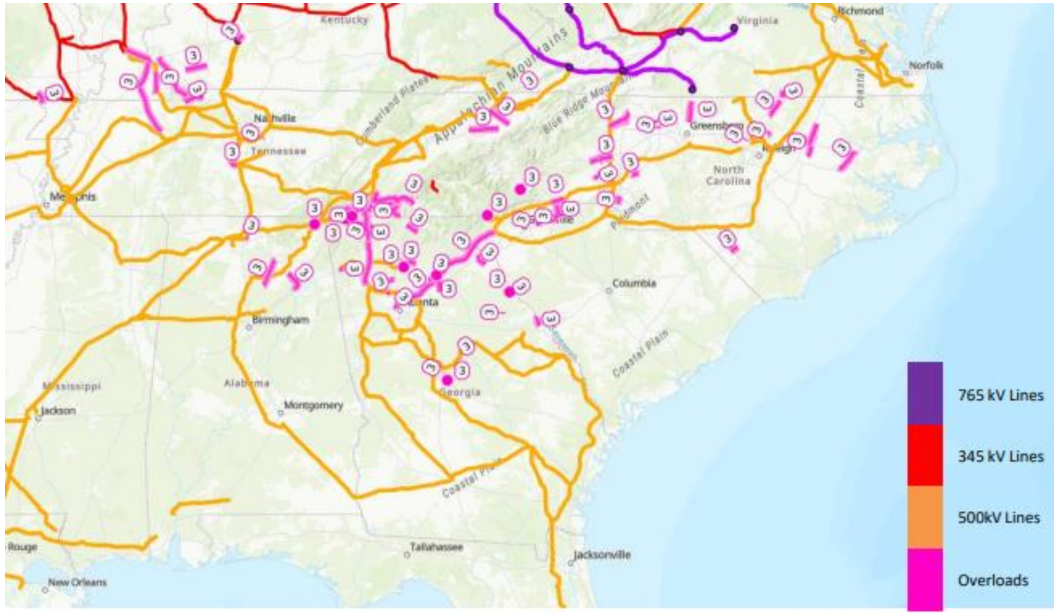


Image Source: SERTP 2024 SERTP 3rd Quarter Meeting Presentation, slide 25.

Regional Projects for Additional Analysis

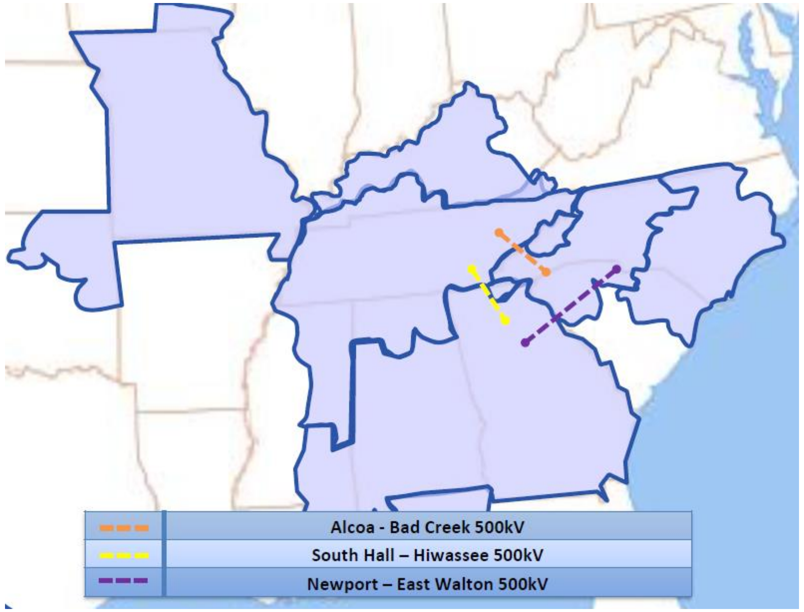


Image Source: SERTP 2024 SERTP 3rd Quarter Meeting Presentation, slide 49.

SERTP Has Not Studied Regional Public Policy Needs

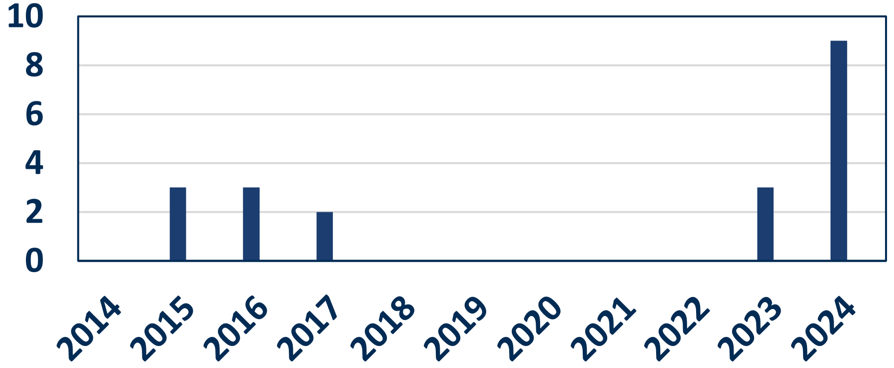
Stakeholders may propose transmission needs driven by Public Policy Requirements (PPRs) for SERTP to assess if the requests meet the following criteria:

1. Is the PPR an enacted local, state, or federal law(s) and/or regulation(s)?
2. Does the PPR drive a transmission need(s)?
3. Is the transmission need already addressed or otherwise being evaluated in the then-current planning cycle?

SERTP has never evaluated a regional transmission needs for a PPR

- The narrow scope of a PPR excludes Sponsors' Board commitments and SERTP's reliance on local transmission plans means that state laws can be considered as addressed in Sponsors' local plans
- For example, SERTP responded to a 2024 PPR request to study the North Carolina Carbon Plan by noting that the needs are already being considered in the CTPC local planning process, and so "no additional transmission needs for the proposed PPR have been identified"
- In doing so, SERTP fails to consider the potential for regional capacity to reduce the costs of satisfying policy requirements across the Southeast

SERTP Public Policy Requirements Proposals for Transmission Needs since 2014



Sources: SERTP Archive Documents, Transmission Needs Driven by Public Policy Requirements (2014–2024).

Key Shortcomings in the SERTP Regional Planning Process

Local Transmission Plans

- Sponsors' local transmission plans are developed with little transparency and do not account for multiple drivers of transmission needs
- Local transmission planning studies are not closely integrated with future planned generation additions based on Sponsors' IRPs, limiting scope of system needs identified in SERTP studies

Preliminary Expansion Plan

- Preliminary SERTP expansion plan is an aggregation of local plans to confirm simultaneous feasibility under all applicable reliability standards
- Only one future scenario is modeled based on local plan assumptions, failing to account for the role of regional projects to more efficiently address future outcomes given high levels of uncertainty

Regional Planning Analyses

- Limited scope of scenarios and regional cost savings of transmission quantified in SERTP planning studies
- Economic and policy studies do not provide reasonable opportunity to identify the most beneficial projects
- Study design results in SERTP never identifying a need for any regional projects in its 10-year Plan

Regional Transmission Plan

- SERTP regional transmission plan mimics the local planning results, failing to identify sufficient cost savings and other benefits to identify a regional transmission need and provide low-cost options for accessing a wider range of resources in IRPs and generation dispatch
- Stakeholder engagement does not incorporate meaningful recommendations and does not include active state participation.

SERTP Transmission Planning Results in Higher Total Costs

Current SERTP regional planning does not yield the most valuable and cost-effective transmission infrastructure for the following reasons:

- Reactive, reliability-driven planning results in piecemeal, higher-cost transmission solutions
- Failure to evaluate full range of plausible futures that explicitly account for long-term uncertainties results in higher-cost outcomes when the future deviates from base case planning assumptions
- Lack of consideration of multiple benefits of transmission does not result in the selection of the highest-value projects that reduce system-wide costs; currently only reliability and losses considered

Maximizing the value of regional upgrades may require SERTP Sponsors to modify their approaches to resource planning and market transactions to efficiently utilize the existing and planned regional transmission capacity.

FERC Order No. 1920 presents a critical opportunity for SERTP to enhance coordination, optimize investments, and ensure cost-effective solutions that benefit both utilities and customers.

III. Recommendations to Enhance SERTP Regional Planning

Framework for Improved SERTP Regional Planning Process

Experience across the electric power industry over the past 10–20 years provides proven planning practices that can reduce total system costs and risks:

- Proactively and holistically plan for future generation and load by incorporating realistic projections of all needs: anticipated generation mix and load levels over the lifespan of the transmission investments; critical to avoid siloed, incremental planning processes
- Account for the full range of transmission needs and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits
- Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that accounts for all transmission needs for a broad range of plausible long-term futures as well as real-world system conditions, including challenging weather events
- Use comprehensive transmission network portfolios to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach
- Jointly plan interregional projects across neighboring systems to recognize regional interdependence, increase system resilience, and take full advantage of scale economics and geographic diversification

Source: Brattle & Grid Strategies Report: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

Recommendations to Enhance SERTP Regional Planning

SERTP can leverage industry-wide experience over the past 20 years by implementing proven practices to reduce long-term system costs and risks, including the MISO LRTP and CTPC/Duke MVST planning processes.

I. Improve Existing Planning Process

1. **Increase transparency** of study assumptions, approach, and results
2. **Engage state commissions and energy agencies** to participate in process and ensure results reduce costs and address state policies
3. Expand solutions studied to reflect **least-cost transmission "loading order"** that maximizes existing grid, upgrades existing lines, and builds new lines where necessary

II. Expand SERTP Planning Capabilities

4. Develop **multiple scenarios based on recent IRPs** to plan for a range of load and generation portfolios
5. Accurately identify congestion and quantify cost savings of regional upgrades via **region-wide production cost model**
6. Develop guidelines to account for **comprehensive set of cost savings and other benefits** when analyzing regional upgrades

III. Implement Comprehensive & Proactive Planning Process

7. Implement **multi-driver approach to identifying regional & interregional needs** and candidate solutions
8. Estimate cost savings and other benefits of solutions **over the entire useful life of the assets**
9. Establish regional cost allocation that reflects **beneficiaries pays and cost causation principles**

1. Increase SERTP Planning Transparency

SERTP process lacks transparency, restricting the ability of stakeholders and state utility commission to review study assumptions, approach, and results and provide feedback to SERTP on ways to improve regional planning.

- Modeling approaches and costs of Sponsors' local upgrade projects, the only regional benefit considered by SERTP, are opaque with CEII clearance required to access information that is not restricted in other planning regions
- Even with CEII access, stakeholders lack cost information and only receive raw power flow cases, not study details and results

Greater Access to Input Assumptions

- In 2024, SERTP identified changes in the resource mix by type and utility
- Provide more clarity and consistency in resource updates across utilities
- More granular information on load forecasts between BAAs, including coincident peak analysis

More Information on Study Results

- Provide more detailed results, including:
  1. Limiting element that triggers violation
  2. Alternative solutions studied
  3. Basis for selecting solution
- Include individual solution estimated costs in the preliminary and final regional transmission plan

Expand Results of Regional Project Analyses

- Detail the selection process of each regional project that is selected for analysis: what motivated the selection of the line(s), how many years of the 10-year study are their benefits analyzed for, etc.

Longer Time Windows for Stakeholder Interaction

- Lengthen window that stakeholders have to submit comments on criteria and method used in planning process beyond only 10 business days
- Ensure documents are posted more than 10 days prior to meetings to give ample time to review

2. Engage State Commissions and Energy Agencies

State agencies and commissions should be actively engaged in the SERTP process to incorporate the perspectives and priorities of regulators and energy agencies into regional transmission planning.

By having insight into regional planning, regulators can ensure that customers are paying for an efficient power system that meets state policy goals and provides reliable electric service.

SPP Regional State Committee (RSC)

- Comprised of state commissioners from 12 states within SPP
- **RSC maintains Federal Power Act 205 rights** to file proposals with FERC to modify rules and tariffs
- Decision making is shared between SPP Board and RSC; RSC has primary responsibility for resource adequacy and cost allocation

Organization of PJM State Inc. (OPSI)

- Collaborative body representing 14 regulatory agencies within PJM
- Facilitates communication and coordination among members, **allowing states to collectively address** PJM operations and market rules
- Ensures that **state interests and policies are considered** in regional decision-making processes

NorthernGrid Enrolled Parties and States Committee (EPSC)

- Participate in development of regional study scope and provide comments on draft regional plans
- Enables **state agencies to participate actively in transmission planning** and **ensures that state-specific concerns and objectives are addressed** within the regional planning framework

Other state organizations participating in regional planning include Organization of MISO States (OMS) and New England States Committee (NESCOE). The California Public Utilities Commission and New York Public Service Commission play an active role in regional planning within their respective single-state RTOs.

3. Expand Solutions to Reflect a Least-Cost Loading Order

SERTP should expand the solutions considered in its studies to include grid-enhancing technologies (GETs), advanced transmission technologies (ATTs), and remedial action schemes (RAS) that maximize the utilization of the existing grid to accommodate new load and generation in the near-term.

By studying potential solution alternatives, SERTP can "stack" solutions by estimated cost and schedule to identify the most beneficial solutions to providing a reliable and efficient grid.

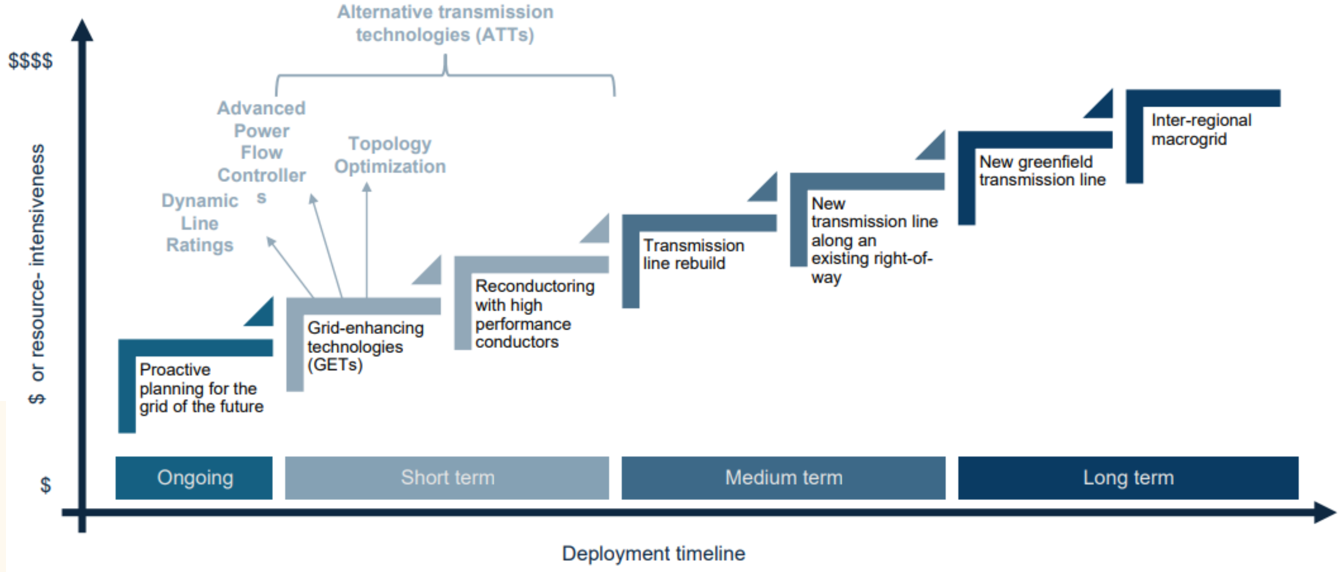
Southeast examples:

- Georgia Power relied on operating guidelines and ATTs in its most recent IRP to resolve reliability-driven system needs
- Duke's MVST will consider GETs, advanced conductors, RAS, and battery storage as well as greenfield transmission and ROW optimization

Further Examples:

- CAISO use of RAS to create 15 GW of headroom
- Priority order required by the German "NOVA Principle"
- MA CETWG Report: "Loading Order" recommendations

Proposed Transmission Solution Loading Order



Source: Sarah Toth (RMI), Alternative Transmission Technologies in Order 1920 and PJM, September 6, 2024.

4. Develop Multiple Future Scenarios Based on IRPs

Scenario-based planning is a process first developed in the 1940s and 1950s as a tool for **integrating uncertainties into long-term strategic planning**.

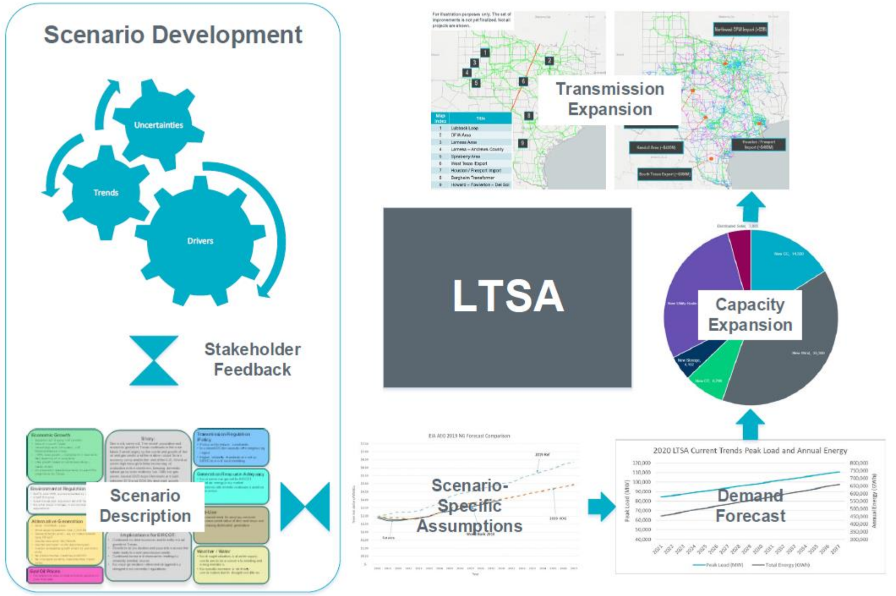
- Used by Shell since the 1970s for long-term planning under large uncertainties
- Assists planners to think in advance about the many ways the future may unfold and how to respond effectively and flexibly as the future becomes reality
- Scenario = one fully-defined, plausible view of what the future may look like

Examples of scenario-based planning approaches used in regional transmission planning include:

- ERCOT's Long-Term System Assessment Process (LTSA)
- MISO's Long Range Transmission Planning (LTRP)
- SPP's recent Integrated Transmission Plan (ITP)

SERTP should leverage the range of future outlooks for demand and generation resources already completed by Sponsor utilities in their IRP studies, similar to Duke's use of the Carolinas Resource Plan to study three scenarios in the MVST process.

ERCOT LTSA Process



5 & 6. Study Comprehensive Set of Cost Savings and Benefits

SERTP can take advantage of the best practices developed across the industry over the past 20 years to estimate transmission benefits.

- Analytical approaches for quantifying transmission benefits have been documented in a report submitted to FERC cited in Order 1920
- Planners have implemented these analyses to justify major investments in regional transmission

Critical for SERTP to develop a detailed nodal production cost model of its region to accurately capture congestion to identify needs and estimate cost savings of transmission solutions.

New approaches continue to be developed to accurately account for the benefits of transmission:

- Use weather-reflective (rather than weather-normalized) production cost and long-term expansion planning simulations (e.g., for 20–30 weather years)
- Production cost simulations with both day-ahead and real-time cycles to capture unpredictable real-time challenges and associated value

Transmission Cost Savings and Benefits Quantified by Planners

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Adjusted Production Cost (APC) savings as currently estimated in most planning processes
2. Additional Production Cost Savings	i. Impact of generation outages and A/S unit designations
	ii. Reduced transmission energy losses
	iii. Reduced congestion due to transmission outages
	iv. Reduced production cost during extreme events and system contingencies
	v. Mitigation of typical weather and load uncertainty, including the geographic diversification of uncertain renewable generation variability
	vi. Reduced cost due to imperfect foresight of real-time system conditions, including renewable forecasting errors and intra-hour variability
	vii. Reduced cost of cycling power plants
	viii. Reduced amounts and costs of operating reserves and other ancillary services
	ix. Mitigation of reliability-must-run (RMR) conditions
	x. More realistic "Day 1" market representation
3. Reliability and Resource Adequacy Benefits	i. Avoided/deferred cost of reliability projects (including aging infrastructure replacements) otherwise necessary
	ii. (a) Reduced loss of load probability or (b) reduced planning reserve margin
4. Generation Capacity Cost Savings	i. Capacity cost benefits from reduced peak energy losses
	ii. Deferred generation capacity investments
	iii. Access to lower-cost generation resources
5. Market Facilitation Benefits	i. Increased competition
	ii. Increased market liquidity
6. Environmental Benefits	i. Reduced expected cost of potential future emissions regulations
	ii. Improved utilization of transmission corridors
7. Public Policy Benefits	Reduced cost of meeting public policy goals
8. Other Project-Specific Benefits	Examples: increased storm hardening and wild-fire resilience, increased fuel diversity and system flexibility, reduced cost of future transmission needs, increased wheeling revenues, HVDC operational benefits

Source: Brattle & Grid Strategies Report: Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

5 & 6. Planners Approved Upgrades based on Cost Savings

SERTP should review industry experience analyzing a comprehensive set of cost savings and other benefits and develop planning guidelines for estimating transmission benefits in future regional studies

SPP 2016 RCAR, 2013 MTF

Quantified

1. **Production cost savings***
   - Value of reduced emissions
   - Reduced ancillary service costs
2. Avoided transmission project costs
3. Reduced transmission losses provide capacity and energy benefit*
4. Lower transmission outage costs
5. Value of reliability projects
6. Value of mtg public policy goals
7. Increased wheeling revenues

Not quantified

8. Reduced cost of extreme events
9. Reduced reserve margin
10. Reduced loss of load probability
11. Increased competition/liquidity
12. Improved congestion hedging
13. Mitigation of uncertainty
14. Reduced plant cycling costs
15. Societal economic benefits

(SPP Regional Cost Allocation Review Report for RCAR II, July 11, 2016. SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012.)

MISO MVP Analysis

Quantified

1. **Production cost savings** *
2. Reduced operating reserves
3. Reduced planning reserves
4. Reduced transmission losses*
5. Reduced renewable generation investment costs
6. Reduced future transmission investment costs

Not quantified

7. Enhanced generation policy flexibility
8. Increased system robustness
9. Decreased natural gas price risk
10. Decreased CO_2 emissions output
11. Decreased wind generation volatility
12. Increased local investment and job creation

(Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011)

CAISO TEAM DPV2 Analysis

Quantified

1. **Production cost savings*** and reduced energy prices from societal and customer perspective
2. Mitigation of market power
3. Insurance value for high-impact low-probability events
4. Capacity benefits due to reduced gen investment costs
5. Operational benefits (RMR)
6. Reduced transmission losses*
7. Emissions benefit

Not quantified

8. Facilitation of the retirement of aging power plants
9. Encouraging fuel diversity
10. Improved reserve sharing
11. Increased voltage support

(CPUC Decision 07-01-040, January 25, 2007, Opinion Granting a Certificate of Public Convenience and Necessity)

NYISO AC Upgrades Analysis

Quantified

1. **Production cost savings*** (includes savings not captured by normalized simulations)
2. Capacity resource cost savings
3. Reduced refurbishment costs for aging transmission
4. Reduced costs of achieving renewable and climate policy goals

Not quantified

5. Protection against extreme market conditions
6. Increased competition and liquidity
7. Storm hardening and resilience
8. Expandability benefits

(Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015)

* Fairly consistent across RTOs

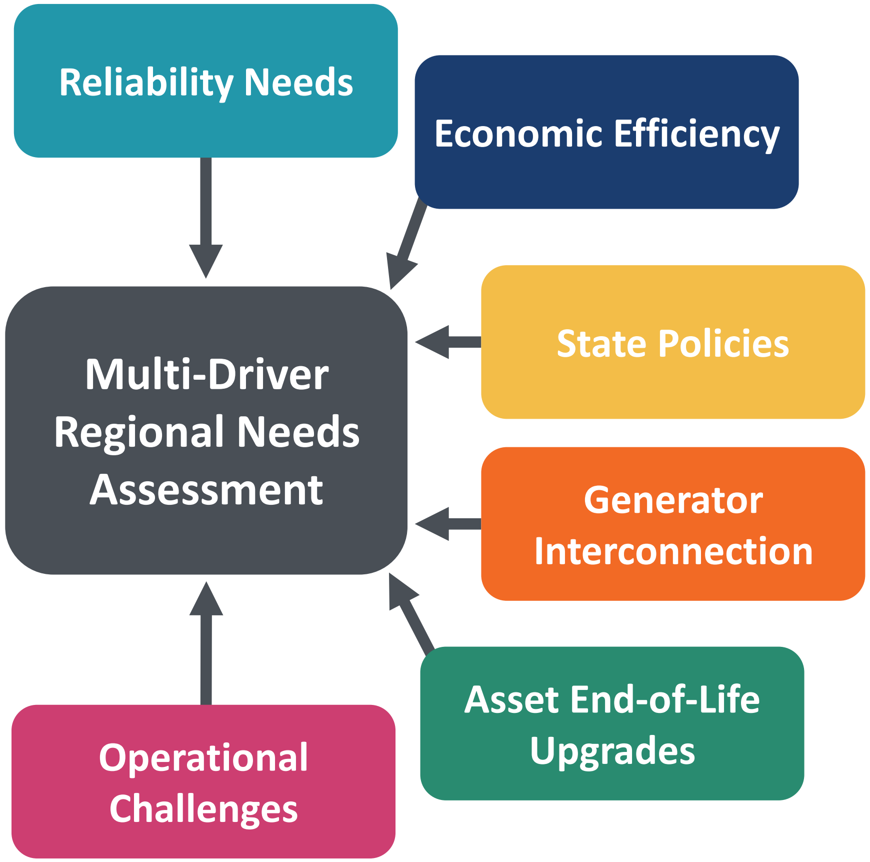
7. Multi-Driver Needs Assessment to Identify Solutions

Implementing a multi-driver approach to identifying regional transmission needs will allow regional transmission planners to identify overlapping concerns and develop cost-effective, right-sized solutions that can provide a broad range of benefits.

- Regional transmission can provide multiple benefits, but regional planners often focus solely on identifying the least-cost solutions for single drivers, e.g., reliability, economic efficiency, generator interconnection, or public policy needs, through a siloed process
- Siloed regional planning misses the broader benefits of regional projects that address multiple needs simultaneously, leading to higher overall electricity costs

MISO's LTRP process includes identifying reliability, economic, and policy needs based on several long-term future scenarios.

SPP completes a five-part needs assessment that reviews (1) economic, (2) reliability, (3) public policy, (4) persistent operational, and (5) winter weather needs.



8. Estimate Benefits & Costs over Entire Asset Life

SERTP should evaluate candidate solutions for an expanded set of cost savings and other benefits based on the guidelines it develops with stakeholders over **the full useful life of the solutions**.

For example, **we estimate the potential cost savings of 1 GW of regional transmission** between BAAs within the SERTP region over a 50-year life of a new transmission asset for three benefit metrics.

Production Cost Savings

Regional transmission could provide **$2.8 billion in fuel and congestion cost savings** by increasing transfer capability between major utilities by 1 GW over 50 years.

Transmission BAA Pair	50-year NPV	
	$0/MWh Hurdle	**$8/MWh Hurdle**
	$ Millions	*$ Millions*
TVA and DUKE	$1,261	$994
SOCO and TVA	$1,244	$963
SOCO and DUKE	$1,138	$871

Load Diversity Savings

By increasing transfer capability for sharing resources between BAAs that take advantage of temporal differences of peak load, SERTP Sponsors could save on avoided generation capacity costs.

Using historical differences in independent system peaks, regional transmission could **reduce costs of achieving resource adequacy requirements by $1.26 billion** by increasing transmission between each of the neighboring SERTP BAAs by 1 GW.

Resiliency Benefits

With additional interregional capability to access generation during Winter Storm Elliot, 1 GW of regional transmission capacity to support customers across the Southeast could have avoided 10 GWh of total load shed.

At a VOLL of $10,000/MWh, **1 GW of regional transmission would avoid $668 million of customer costs due to unserved load,** assuming a similar event occurred every 5 years.

9. Develop Cost Allocation for Approved Portfolios

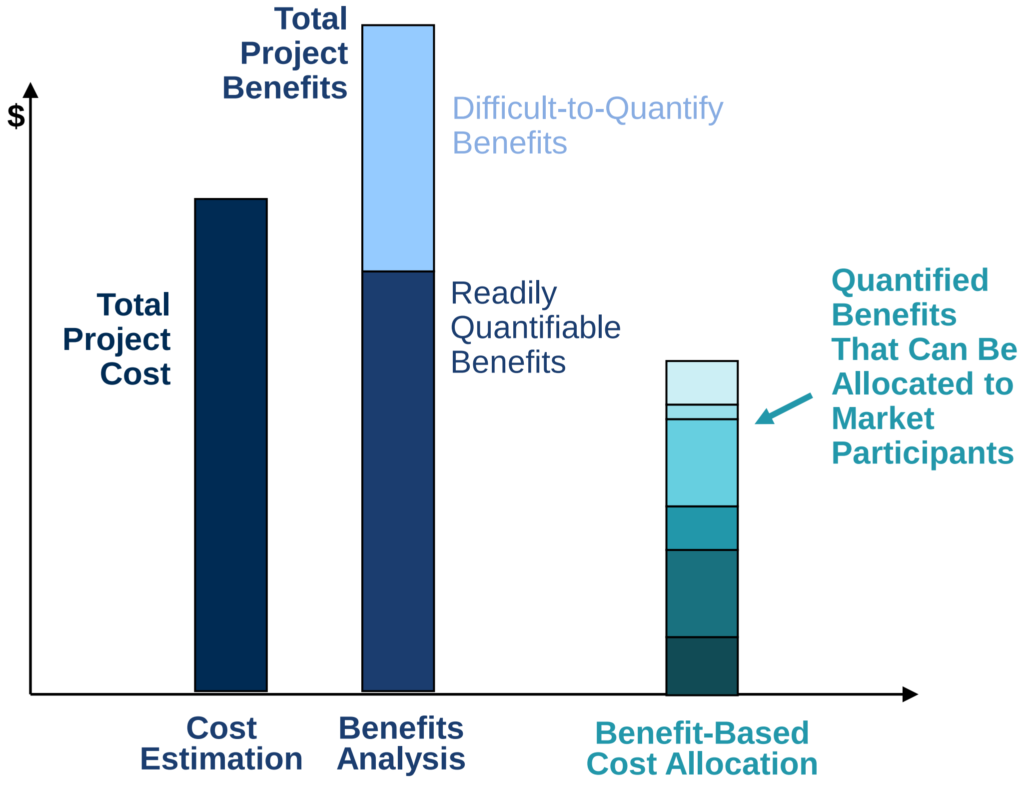
Important for SERTP to develop a regional cost allocation approach that ensures regional customer transmission costs are roughly commensurate with their benefits

To ensure beneficial projects are approved and costs are fairly allocated, recommend a 2-step approach:

1. SERTP determines whether projects are beneficial overall based on a broad set of benefits over the life of the asset
2. Evaluate how to allocate the costs of a portfolio of projects based on their joint distribution of benefits

This approach will tend to reduce issues related to cost allocation, as a broad set of benefits quantified for a portfolio of projects tends to be more stable over time and be distributed more uniformly.

SERTP should weigh the tradeoffs of an overly formulaic approach to cost allocation versus a simpler load-ratio-share approach for Sponsors with demonstrated benefits.



IV. Why the Southeast Needs to Modernize Its Regional Planning Process Now to Reduce Costs and Increase Reliability

Regional Upgrades Are Providing Benefits Across U.S.

Every region across the U.S. other than the Southeast has taken proactive steps to build out its regional grid in order to lower electricity costs, improve reliability, and support economic growth.

The following regional projects pursued in the past few years represents $117 billion of investments:

- MISO LRTP Tranche 1 and Tranche 2.1 Portfolios: $33 billion (see following slides)
- ERCOT 2025 Upgrades to Serve Load Growth: $32 billion
- Southwest Power Pool 2024 Integrated Transmission Planning (ITP) Portfolio: $11 billion
- California ISO 2022/23 and 2023/24 Policy Projects: $10 billion
- PacifiCorp Energy Gateway and Boardman-to-Hemingway Projects: $8 billion
- Champlain Hudson Power Express and NECEC to Access Canadian Hydro: $8 billion
- PJM 2024 RTEP Data Center-Driven Regional Upgrades: $6 billion

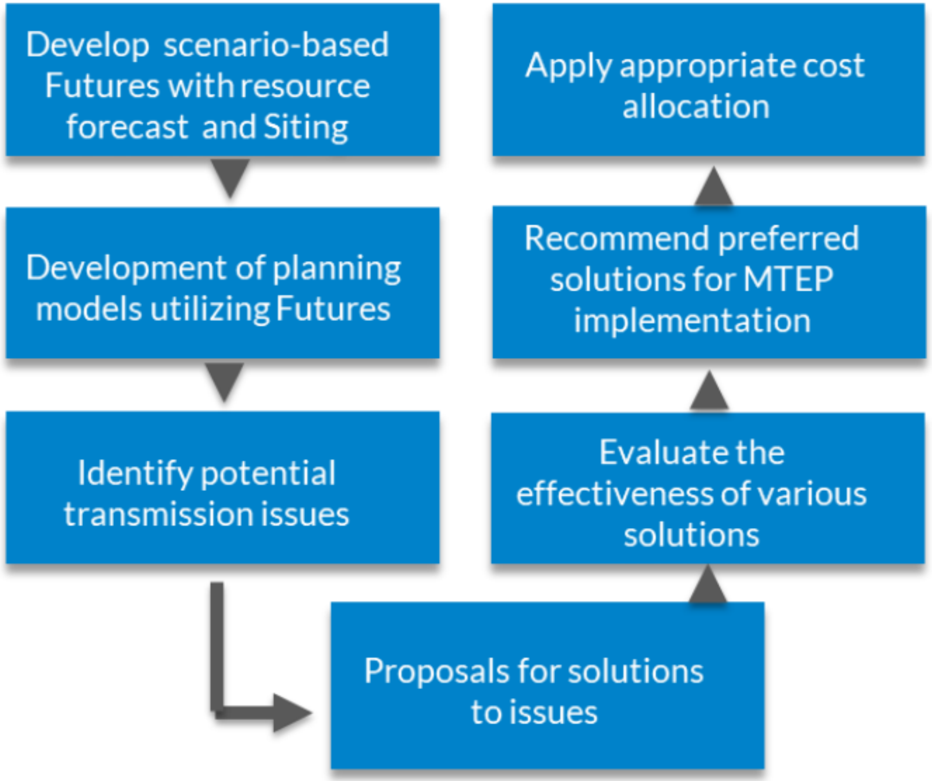
Similar system needs that led transmission planners across the country to embrace proactive regional transmission planning also apply to the Southeast and SERTP as demonstrated by national studies.

MISO and the Carolinas Transmission Planning Collaborative (CTPC) provide clear examples of proactive transmission planning approaches that SERTP should consider for enhancing its regional planning process.

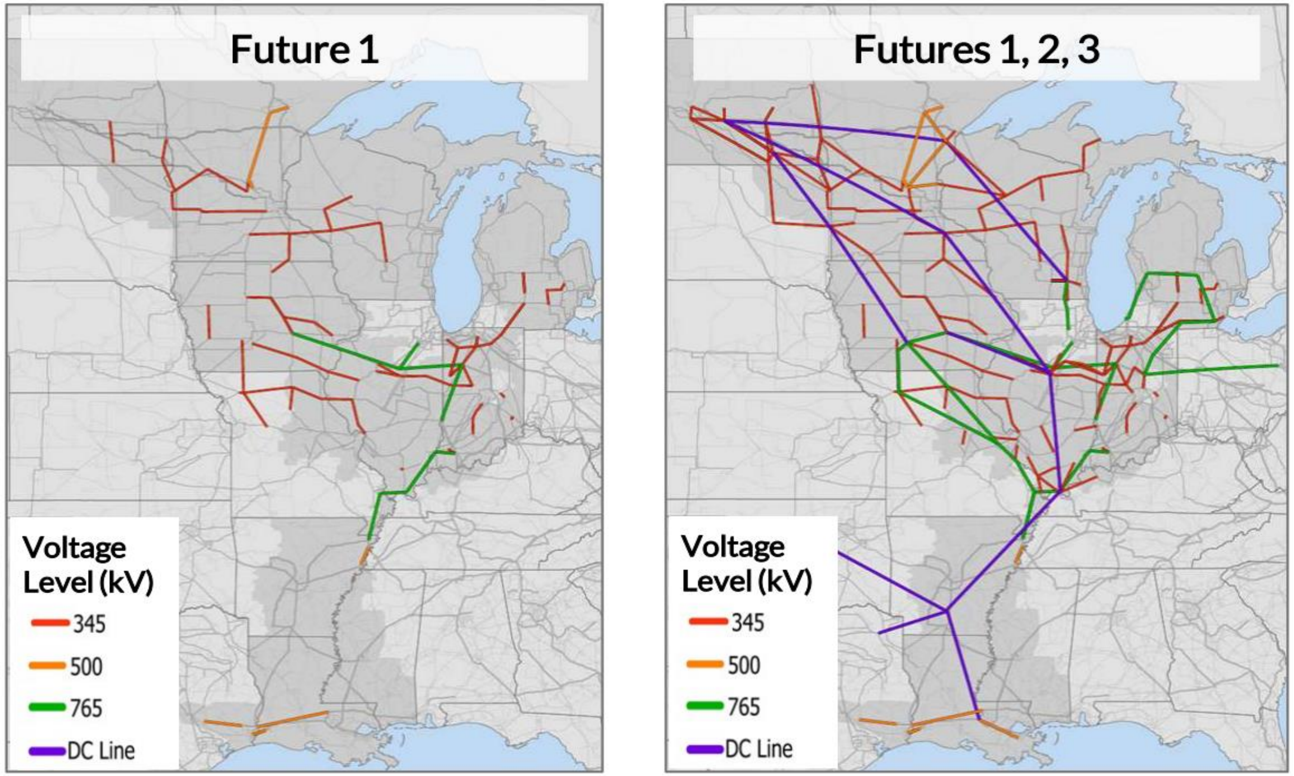
MISO Long Range Transmission Planning Process

MISO's LRTP Tranche 1 and Tranche 2.1 evaluated 20-year reliability, economic, and policy needs for three plausible "Futures" scenarios that accounted for uncertainty in load growth and generation.

MISO' LRTP Process



MISO's Identified Long-Term Transmission Needs



Source: [MISO LRTP Roadmap March 2021](#)

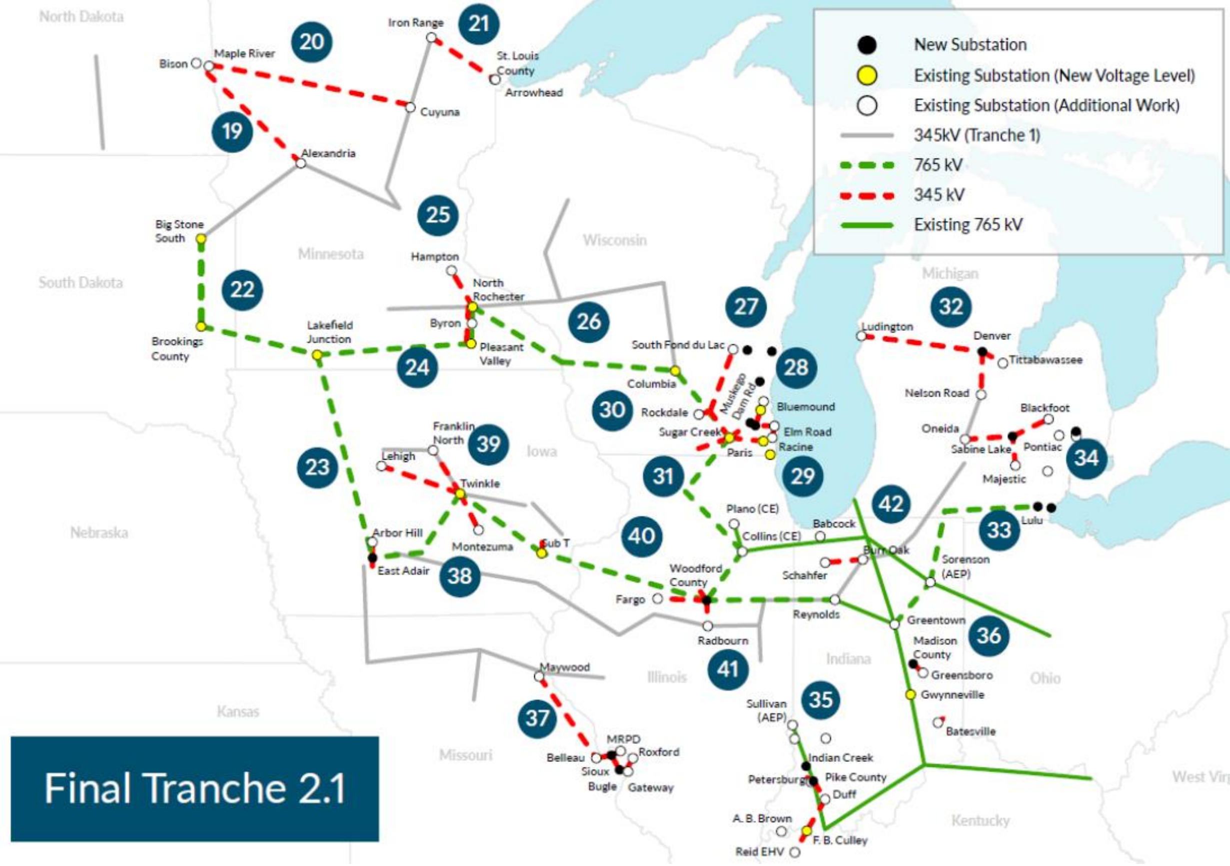
MISO Long-Range Transmission Planning Results

MISO completed the first two tranches of its LRTP multi-value planning process, which resulted in $33 billion of regional transmission investment to modernize its grid.

MISO LRTP RESULTS

- Tranche 1 results:
  - $10 billion portfolio of new 345 kV projects
  - Supports interconnection of 53 GW of renewable resources
  - Reduces system costs by $37–70 billion
- Tranche 2.1 results:
  - $22 billion portfolio of new 345 kV and 765 kV projects and substations
  - Reduces system costs by $34–62 billion
- Portfolios of LRTP projects designed to benefit each zone within MISO's Midwest Subregion with costs allocated on a postage-stamp (per-MWh) basis to customers in MISO Midwest

MISO LRTP Tranche 1 and Tranche 2.1 Projects



Source: https://www.misoenergy.org/planning/long-range-transmission-planning/

CTPC/Duke Multi-Value Strategic Transmission (MVST) Study

Carolinas Transmission Planning Collaborative (CTPC) completes local transmission planning for utilities in North and South Carolina, including Duke Energy (DEC/DEP), ElectriCities, and NCEMC

CTPC identified **$503 million of Public Policy upgrades** in its 2023 Annual Plan to support solar additions based on upgrades identified in multiple interconnection cluster studies.

CTPC added to its local planning process a **proactive, scenario-based, multi-driver process to identify Multi-Value Strategic Transmission (MVST) projects;** implementing its first MVST study in 2024–2025.

Key Aspects of CTPC Multi-Value Strategic Transmission Process

IRP-based Scenarios	Alternative Solutions	Portfolio Evaluation	Benefits Analysis
Identify reliability and economic needs for future scenarios based on Duke's projected load and IRP-developed generation portfolios	Consider GETs, advanced conductors, Remedial Action Schemes (RAS), and storage as potential solutions as well as existing lines upgrades and greenfield transmission	Evaluate a portfolio of transmission solutions over the life of the assets to resolve identified needs	Quantify (1) avoided capacity costs, (2&3) capacity cost and energy cost savings from reduced losses, (4) congestion and fuel cost savings, (5) avoided customer outages, and (6) avoided transmission costs

Case Study: Assessing Benefits of SERTP Regional Projects

To demonstrate the value of Southeast regional transmission, we performed a high-level analysis of three 500 kV upgrades SERTP identified in its 2024 regional planning process (see map).

The analysis evaluated the potential cost savings and other benefits of the regional projects based on an expanded set of benefits utilizing recent historical market data:

- **Production cost savings** based on historical 2015–2023 system lambdas reported by SERTP Sponsors as a proxy
- **Load diversity benefits** based on historical 2011–2023 load shapes, accounting for capacity cost savings from imports
- **Resilience benefits** during extreme weather conditions, such as Winter Storm Elliott

Regional Projects Evaluated in 2024 SERTP Regional Plan

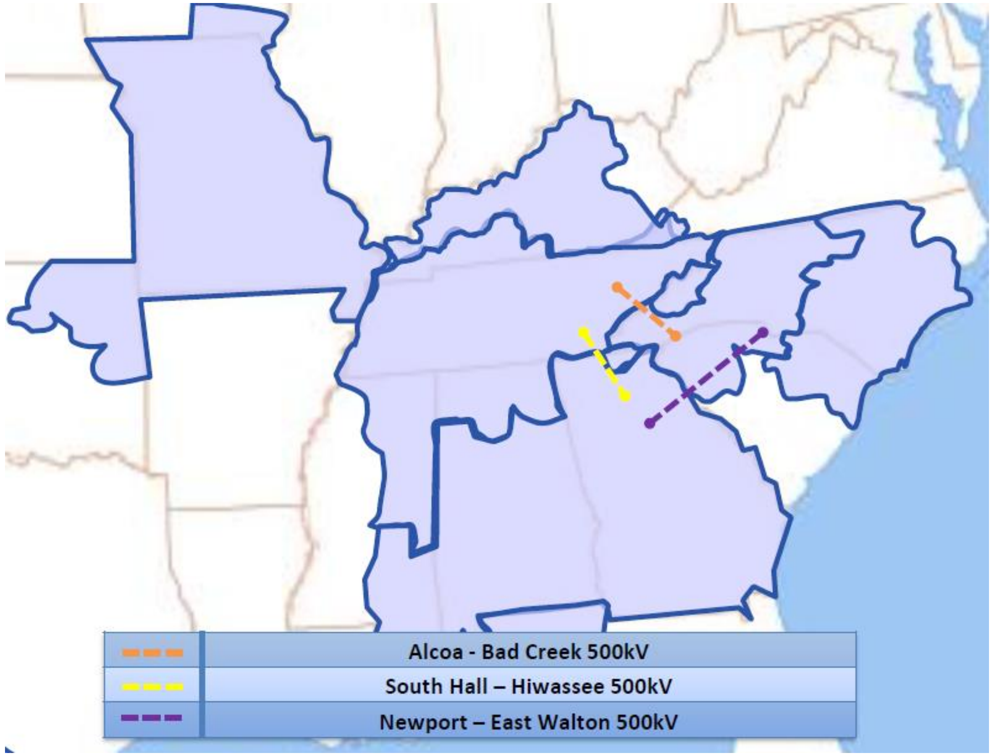


Image Source: SERTP 2024 SERTP 3rd Quarter Meeting Presentation, slide 49.

Expanded Scope of Cost Savings Identifies Cost-Effective Upgrades

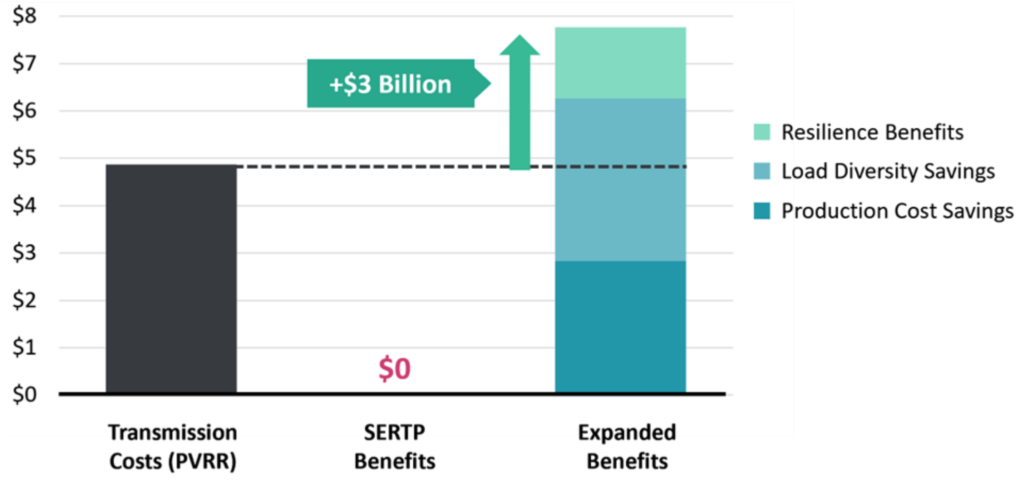
Using an expanding set of benefits, we estimated $8 billion of cost savings and other benefits for these proposed regional lines, resulting in $3 billion of net benefits for customers in the Southeast over the life of the assets.

- Production cost savings: $2.8 billion (range: $2.0–3.6 billion)
- Load diversity cost savings: $3.3 billion (range: $0.9–6.0 billion)
- Resilience benefits: $1.6 billion (range: $0.7–2.3 billion)
- *Note: A more detailed study is likely to identify additional benefits not quantified in this high-level analysis, including avoided reliability and interconnection upgrades, greater production cost savings with increased solar/wind, and reduced generation costs*

Regional transmission can reduce system costs when a broader scope of cost savings and other benefits are analyzed

By contrast, SERTP's very narrow view of benefits based solely on avoided local transmission costs identified no cost savings.

Estimated Net Benefits of Regional Projects



Note: Detailed results included in the appendix slides. Load diversity savings were capped at 1 GW of potential value, as we assumed the new lines would be limited to about 1 GW of capacity.

Order 1920 Provides Southeast Opportunity in 2025 to Enhance Its Regional Transmission Planning Process

- **Southeast is the only major U.S. region that has not pursued significant regional transmission projects over the past decade**
- **Every year without a proactive regional transmission planning process in the Southeast results in higher electricity bills, increased blackout risks, and lost business investment over the long term due to insufficient grid infrastructure**
- **FERC issued Order No. 1920 last year that requires SERTP to implement a proactive, long-term, multi-value regional planning process, presenting a pivotal opportunity for the Southeast to align its regional transmission planning with industry best practices developed over the past 10–20 years**
- **The Southeast should embrace this opportunity in 2025 to modernize SERTP's regional transmission planning to build a stronger, more efficient grid that supports economic growth, energy affordability, and long-term resilience**

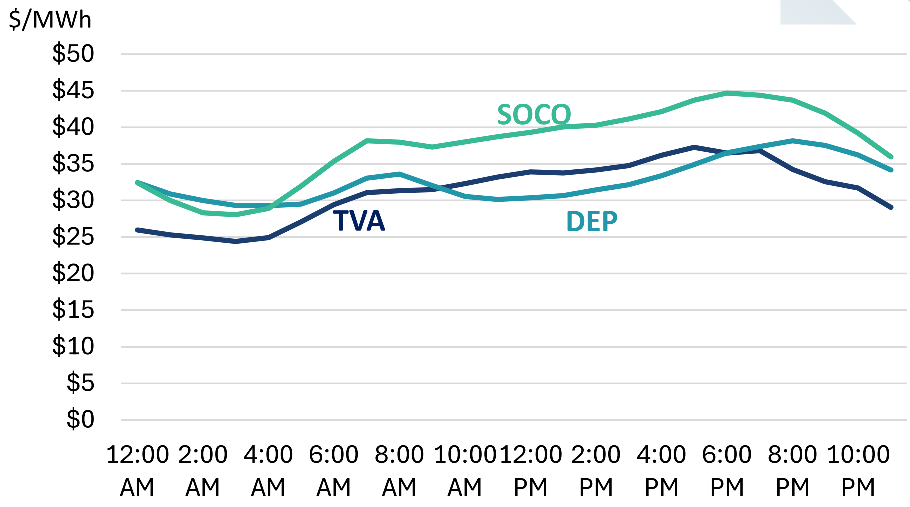
Appendix: Case Study Detailed Analysis

Estimated Production Cost Savings

Using historical system lambdas, we estimate the potential value of 1 GW of transfer capability for pairs of our case study balancing authorities

- Methodology for Estimating Production Cost Savings:
  - System lambdas represent an approximation of marginal unit cost in an hour and are directly reported by each utility to FERC
  - We assume the new transmission will optimize flows by sending power from the BA with a lower price to the BA with a higher price every hour when the price separation exceeds a specific "hurdle" (representing trading costs like wheeling charges and other frictions)[1]
  - Resulting flow and price separation estimate value of new transmission upgrades
- Production Cost Savings Results:
  - With a trading hurdle of $8/MWh, the regional upgrades provide $2.8 billion in production cost savings
  - Average price separation between BAs is $8 - $10/MWh, but there is significant value in periods of high price separation

2019-2023 Average Marginal Cost of Energy



Estimated 2019 – 2023 Value of 1 GW of New Transmission

Transmission BAA Pair	Average Annual 2019-2023 Value			50 Year NPV of 1,000 MW (at 7% Discount Rate)		
	$0/MWh Hurdle	$8/MWh Hurdle	$15/MWh Hurdle	$0/MWh Hurdle	$8/MWh Hurdle	$15/MWh Hurdle
	$ Millions	*$ Millions*	*$ Millions*	*$ Millions*	*$ Millions*	*$ Millions*
TVA and DUKE	$91	$72	$55	$1,261	$994	$758
SOCO and TVA	$90	$70	$49	$1,244	$963	$671
SOCO and DUKE	$82	$63	$43	$1,138	$871	$596
			Total Savings	$3,643	$2,828	$2,025

[1] The selection of $8/MWh and $15/MWh hurdle rates mimics the low-coordination and high-coordination scenarios in the Southeast from Kahrl, Fredrich, et al., *Solar and Storage Integration in the Southeastern United States: Economics, Reliability, and Operations.* Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, 2024.

Load Diversity Savings Value

Interregional transmission unlocks a planning benefit to utilities that we call 'load diversity savings' which is: The value of capacity avoided by one region by relying on capacity in another region that is enabled by transmission

- Utilities plan their generation fleet to meet their own annual peak load, not considering that a balancing authority near them may have spare capacity at the same time due to regional diversity in load shapes
  - *Duke for example may experience peak load at 6pm EST while TVA may peak at 7pm EST, or in different months entirely*
- **This savings value is calculated by determining how much lower the combined coincident peak of two balancing authorities is compared to their own independent annual peak loads**
  - By planning for one combined coincident peak, you can avoid capacity costs in one or both balancing authorities
  - This benefit **is only reliable if you have expanded interregional transmission** that allows you to rely on capacity from another balancing authority during peak load periods
- **The next three slides walk through how we estimate this metric historically**

APPENDIX

Load Diversity Benefits of Regional Upgrades

Potential capacity savings exist from the diversity of peak load in the Southeast

- **Potential capacity savings**: Comparison of two BAAs **independent peaks** and their BAA peak under the pair’s **joint coincident peak**
- **Existing transmission capacity:** EIA historic 95th percentile and maximum transmission flows between the BAAs
- Potential savings vs. EIA 95th percentile historic (2015-2023) transfer limits

At an avoided capital cost of $833/kW, the potential capital cost savings using the sum of the average potential savings **would be $1,256 million**

- *Based on 2025 AEO Tennessee Gas-CT capital cost*
- *Cost savings are higher once you include operating cost of the gas plant and cost of capital*
- *Would be even higher for avoided storage*

Potential Load Diversity Benefits of Transmission Expansion (MW)

BAA Pair		Potential Peak Savings from TX		EIA Historic Transfer Limits	Potential Savings - EIA Limits	
BAA Pair	BAA	2011-2023 Average Potential Savings	2011-2023 Maximum Potential Savings	EIA Implied Transfer Limit	Average Potential Savings - EIA Transfer Limit	Maximum Potential Savings - EIA Transfer Limit
TVA <> AECI	TVA	28	205	325		
	AECI	461	1,459	38	**423**	**1,421**
TVA <> SOCO	TVA	446	2,170	1,546		**624**
	SOCO	127	670	1,802		
TVA <> DEC	TVA	221	1,133	154	**67**	**979**
	DEC	658	1,597	323	**335**	**1,274**
TVA <> DEP	TVA	118	906	68	**50**	**838**
	DEP	737	2,380	104	**633**	**2,276**
DEP <> SOCO	DEP	604	1,932	1,501		**431**
	SOCO	106	934	1,692		
DEC <> SOCO	DEC	287	885	502		**383**
	SOCO	199	1,515	1,163		**352**

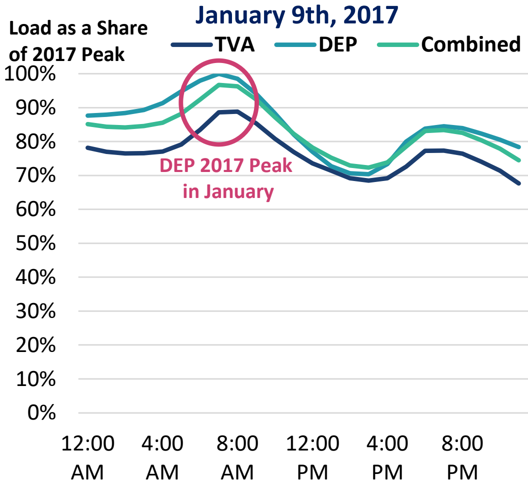
APPENDIX

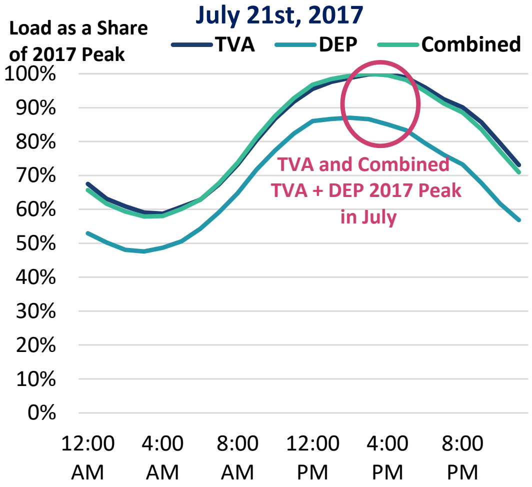
Load Diversity Savings Value

As an example, DEP peaks independently in January 2017 while TVA is 3.4 GW below its own 2017 peak that it planned its system to meet

TVA and DEP's load diversity savings calculation is shown on the right

- The independent gross peak is each BAs annual peak on their own
- The coincident peak is each BAs load during the joint TVA + DEP peak during the year
- The potential load diversity savings is the difference between a BA's gross peak and load during the coincident peak
- **This is then compared in our summary table in the previous slide to the existing transfer capacity** to see if this diversity value can be captured via existing transmission already





Load Diversity Savings Calculation Example for TVA and DEP

	Tennessee Valley Authority			Duke Energy Progress LLC		
Year	Independent Gross Peak	Peak During TVA + DEP Coincident Peak	Potential Load Diversity Savings from TX	Independent Gross Peak	Peak During TVA + DEP Coincident Peak	Potential Load Diversity Savings from TX
	MW	*MW*	*MW*	*MW*	*MW*	*MW*
2011	36,765	36,627	138	16,244	15,861	383
2012	36,696	36,696	0	16,095	15,989	106
2013	33,897	33,897	0	15,278	14,649	630
2014	39,355	39,355	0	17,342	17,170	172
2015	38,646	38,646	0	18,994	17,713	1,281
2016	35,192	35,192	0	16,224	16,224	0
2017	35,281	35,235	46	17,731	15,351	2,380
2018	38,361	37,454	906	18,933	17,969	964
2019	34,891	34,891	0	16,676	15,533	1,143
2020	34,139	34,111	27	16,144	16,144	0
2021	35,883	35,553	329	15,916	15,666	250
2022	39,442	39,355	86	17,181	15,538	1,643
2023	37,578	37,578	0	15,825	15,202	622
Average Peak Saving			118			737
Maximum Peak Saving			906			2,380

Load Diversity Savings Value

Potential load diversity savings between our four case-study examples from 2011 – 2023 average over $900 million, mostly between TVA and Duke

- Average avoided capacity cost denotes the 2011 – 2023 average annual load diversity savings vs. the maximum which denotes the highest year of possible savings
- Maximum avoided capacity savings are nearly $6 billion across the four BAAs for up to 2.3 GW of transmission
- These savings are likely to increase in the future as it does not include projected load growth

BAA Combinations for 2011 – 2023 Potential Load Diversity Savings

Metric			TVA - DEP		TVA - DEC		TVA - SOCO		SOCO - DEP		SOCO - DEC	
Metric	Unit	Col.	TVA	DEP	TVA	DEC	TVA	SOCO	SOCO	DEP	SOCO	DEP
Average Load Diversity Savings	MW	[1]	118	737	221	658	446	127	106	604	199	287
Maximum Load Diversity Savings	MW	[2]	906	2,380	1,133	1,597	2,170	670	934	1,932	1,515	885
EIA Implied Import Capacity	MW	[3]	68	104	154	323	1,546	1,802	1,692	1,501	1,163	502
Avg. Savings - Import Capacity	MW	[4]	50	633	67	335	-	-	-	-	-	-
Max. Savings - Import Capacity	MW	[5]	838	2,276	979	1,274	624	-	-	431	352	383
Avg. Avoided Capacity Cost	$ Millions	[6]	$42	$527	$56	$279	-	-	-	-	-	-
Max. Avoided Capacity Cost	$ Millions	[7]	$698	$1,896	$816	$1,061	$520	-	-	$359	$293	$319

$904 million savings

$5,962 million savings

Notes: [1] & [2] include 2011 – 2023 hourly load data from EIA calculated for each BAA pair. [3] is the 95th percentile of historic 2015 – 2023 EIA transfers between BAAs. [4] is [1] – [3] when [1] > [3]. [5] is [2] – [3] when [2] > [3]. [6] and [7] multiply [4] and [5] by $833/kW, our assumed cost of peaking capacity from the EIA's 2025 AEO Gas-CT cost for Tennessee.

Resilience Benefits from Transmission

Additional customer savings are unlocked from transmission in the form of resilience to extreme weather events like Winter Storm Elliott by allowing BAs to import power in periods of system stress

TVA, Duke, and LG&E/KU were all forced to order firm load shedding during Winter Storm Elliott

- TVA shed 19,000 MWh; Duke shed a combined 4,936 MWh; and LG&E/KU shed 1,265 MWh

Utilizing regional and interregional transmission to unlock greater access to imports during emergency events can avoid load shed and create significant cost savings resulting from lost load

- Lost load is valued somewhere between $10,000/MWh (in MISO) and $35,000/MWh (in ERCOT)
- Based on outage data from Winter Storm Elliott, 1 GW of additional transmission available to import generation across the region could have avoided between $95 million to $333 million in lost load during the event

If we assume these events happen roughly every five years, regional transmission could provide nearly $668 million to $2.3 billion in resiliency benefits of avoided lost load.

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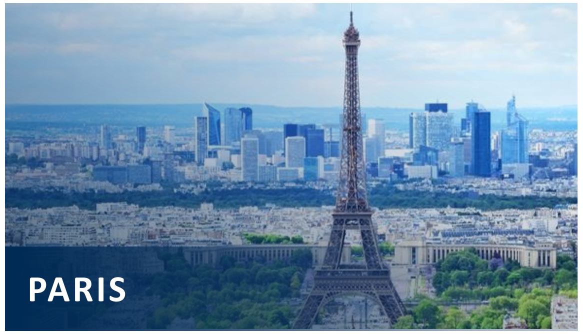

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