TOGETHER WE CAN BUILD THE FUTURE

January 29, 2025

Bryn Baker, Senior Director

Katie Southworth, Deputy Director

CEBA

Clean Energy Buyers Association

Customer-driven clean energy for all.

The Clean Energy Buyers Association is a business trade association that activates energy buyers and partners to advance **low-cost, reliable, carbon emissions-free** global electricity systems.

. CEBA's more than 400 members

- Include one-fifth of the Fortune 500
- Represent more than $20 trillion in market capital
- Are institutional energy customers of every type and size – corporate and industrial companies, universities, and cities.

FERC Order 1920 on Corporate Commitments

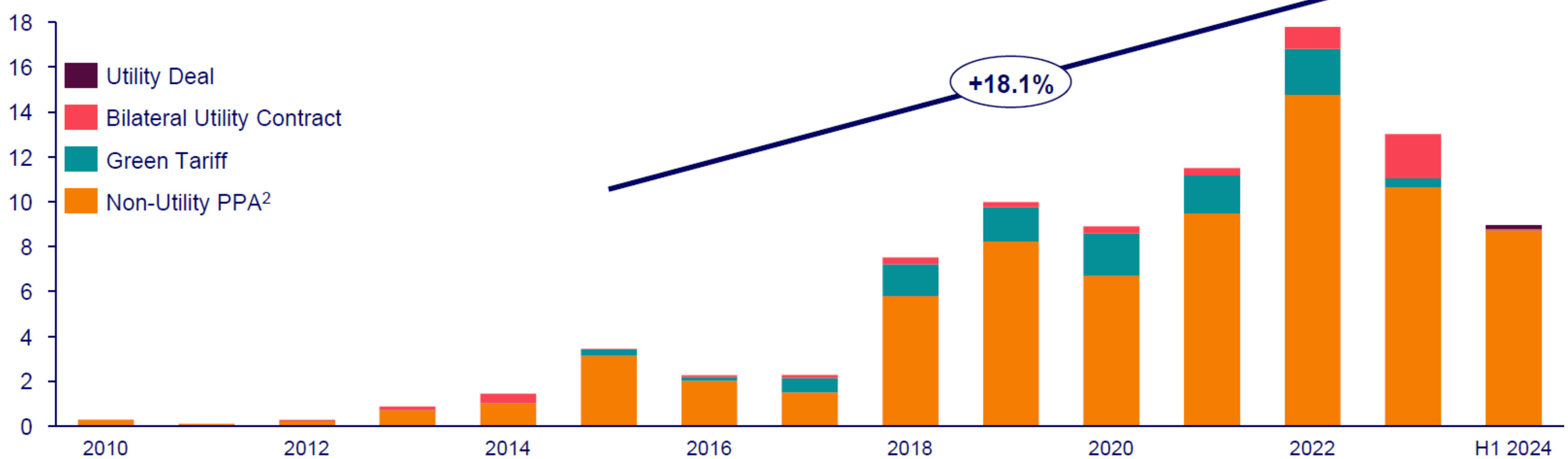
FERC Order 1920A (paragraph 303) states:

"We continue to require transmission providers to consider corporate commitments that are likely to affect Long-Term Transmission Needs as part of Long-Term Regional Transmission Planning to the extent that these commitments affect transmission customers' transmission needs, because transmission providers must plan for the needs of all transmission customers on a comparable basis under Order Nos. 888, 890, and 1000."

Recent Trends: Corporate Carbon Free Energy Procurement has Grown Steadily to ~13+ GW/yr

Corporate procurement in the Southeast: 5.9 GW through utility and bilaterial contracts out of 91 GW nationally (2014-2024)

Historical Corporate Procurement Capacity by Year Contracted[1], GW



Wood Mackenzie

Source: Wood Mackenzie, CEBA

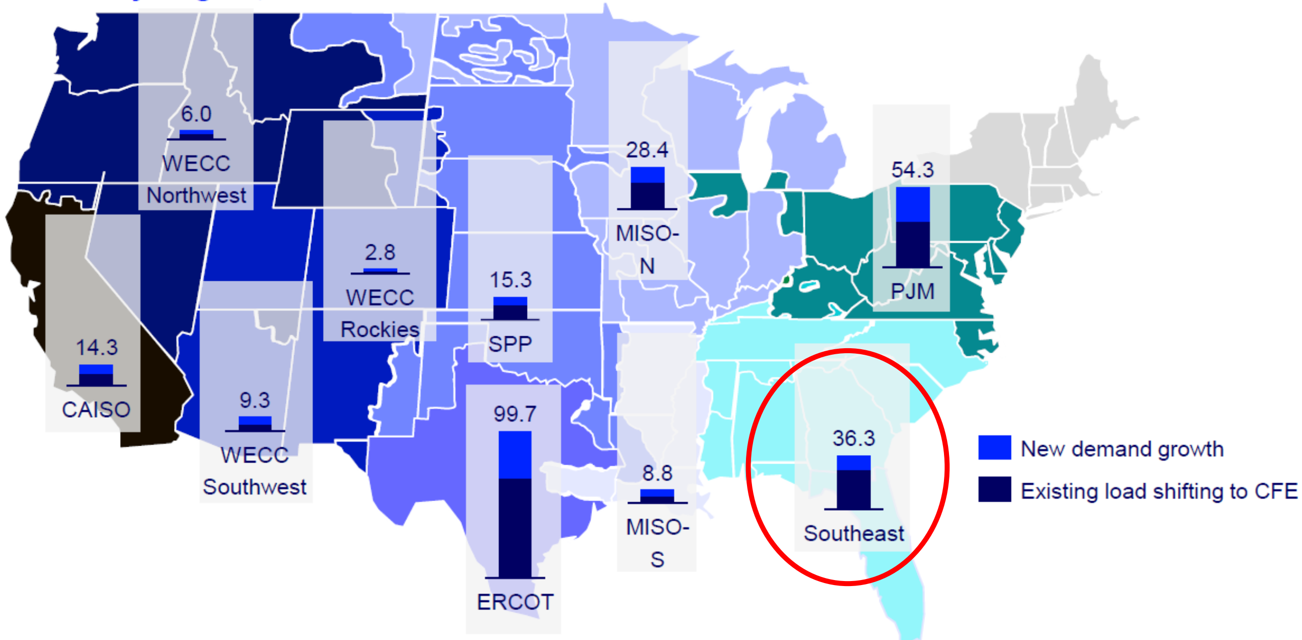
Notes:.[1] This figure does not reflect the starting year of the contract, but rather the year a contract was agreed upon. [2] Non-Utility includes non-corporate buyers that are not utilities or IPPs, such as universities, the military, and state/municipal governments. 'Utility Deals" and 'Bilateral Utility Contracts' are a type of procurement mechanism where an Utility is an offtaker of the output from a generator.

CEBA

Wood Mackenzie: Corporates (Fortune 1000) want **275 GW** of carbon-free energy by 2035

- This is based on a conservative estimate of demand growth (7.7% CAGR to 2035)
- Around 35% of this CFE demand is driven by large load sector growth, and most of the demand comes from a shift of existing demand to CFE sources

2035 Corporate CFE Demand by Region, GW



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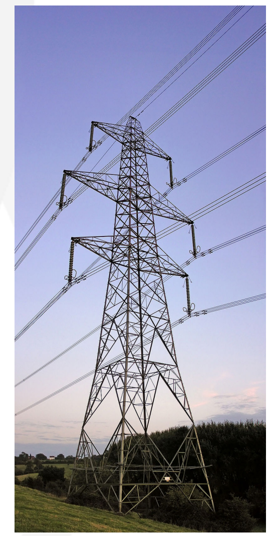
Why Regional Transmission?

Increasing load growth (15-35% by 2035), extreme weather, generation and load shifts

- More **cost-effective** solutions:
  - *Production cost savings;*
  - *Lower energy losses;*
  - *Local transmission and interconnection cost savings;*
  - *Generation capacity cost savings.*
- Enhanced **reliability** during extreme weather events
- Faster **integration** of advanced energy technologies
- Boost regional **economic competitiveness**



Reduced overall costs for ratepayers.

Faster integration of advanced energy technologies

Improved grid reliability and resilience.

Regional economic competitiveness

Key Challenges in SERTP Planning

- Current planning is reactive and **bottom-up.**
- Southeast needs **significant investments** in transmission system.
  - No regional upgrades in 11 years of studies.
- **Limited transparency** and stakeholder engagement in regional process.

Proposed Enhancements

- Develop **multi-driver, scenario-based** planning.
- Incorporate comprehensive **cost-benefit analysis.**
- Align planning models with **future resource and customer needs.**

Recommended Next Steps

SUPPORT CUSTOMERS

Consider large customer energy goals and targets.

MEANINGFUL DIALOGUE

Engage stakeholders to design iterative planning process.

REGIONAL PROJECTS

Implement regional transmission upgrades.

STATE PARTNERSHIP

Collaborate with state agencies for better alignment.

We look forward to continued engagement with SERTP sponsors and state agencies.

Thank you for the work that you do.

CEBA

Ted.Thomas@energizestrategies.com

Energize Strategies

Regulator as Risk Manager.

Key risk factors:

1. Changing prices.
2. Changing policy.
3. Changing technology.

Transmission mitigates risk.

1. Flexibility: The grid serves all of the above.
2. Least regrets planning.
3. Economic benefits reduce the cost of transfer capability that improves resilience.

Benefits of FERC Order No. 1920 and 1920-A.

1. Extended planning horizon.
2. Benefits of scale.
3. A more robust grid paid for by generation savings.

THANK YOU!

Grid Strategies

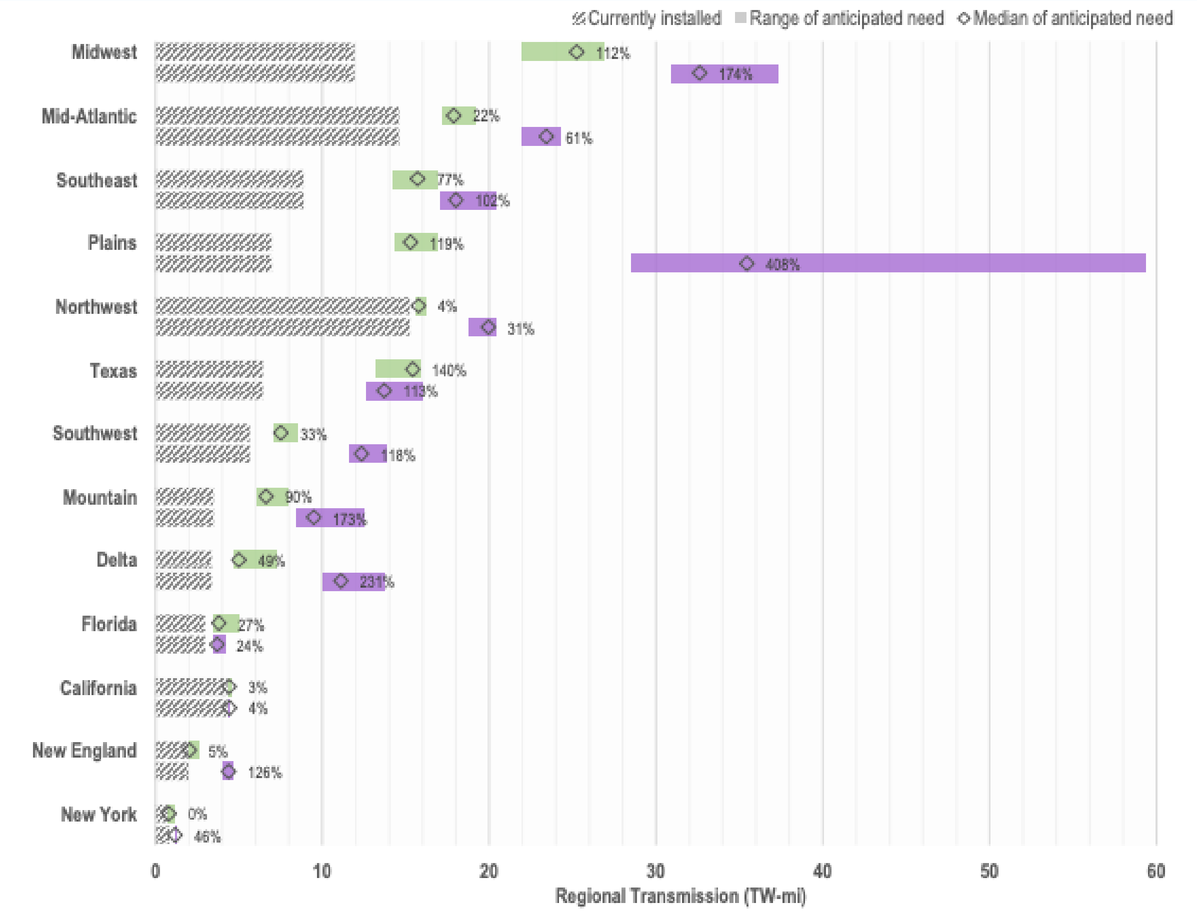
Cost of delaying Order No. 1920 long-term regional transmission planning

Zach Zimmerman, Research and Policy Manager

January 29, 2025

Need for large-scale regional transmission

Anticipated future within-region transmission need in 2035



- Studies estimate the U.S. needs to double or triple transmission capacity to meet load growth and connect new resources to load while maintaining reliability.
- DOE's National Transmission Needs study found the Southeast needs to increase transmission capacity 77% by 2035 compared to the 2020 system, and under a high load growth scenario increase transmission capacity 102%.

GridStrategies

SOURCES | DOE, National Transmission Needs Study (October 2023) at 9.

3 of the 10 areas with the fastest load growth in the country are in the Southeast

17 GW

In cumulative load growth from these three utilities over the next 5 years.

Growth is driven by data center and advanced manufacturing growth.

Additional generation and transmission capacity is needed to affordably and reliably connect the new load growth.

Areas with Greatest Increase in Summer 2029 Peak Demand

	2029 Peak Demand						
Planning Area	2022 Forecast (GW)	2023 Forecast (GW)	2024 Forecast (GW)	Forecast Updates (GW)	Forecast Increase (GW)	Forecast Increase (Percent)	Total Growth Through 2029 (GW)
ERCOT	84.4	89.6	88.1	+ 36.9	**40.6**	48.1%	**42.8**
PJM	153.3	156.9	165.7	+ 15.2	**27.5**	18.0%	**29.6**
Georgia Power	16.3	17.3	22.4	+ 7.3	**13.5**	83.1%	**13.0**
MISO	132.4	133.0	138.4		**6.1**	4.6%	**9.1**
Pacific Northwest	37.4	38.4	38.5	+ 2.0	**3.1**	8.2%	**7.4**
SPP	56.6	59.5	62.5		**5.9**	10.4%	**6.3**
Duke Energy (North & South Carolina)	33.9	36.2	36.6		**2.7**	7.8%	**2.6**
Arizona Public Service	8.7	9.8	9.9		**1.2**	13.6%	**1.5**
NYISO	31.5	32.3	32.3		**0.9**	2.8%	**4.6**
Tennessee Valley Authority	31.8	32.4	32.5		**0.7**	2.2%	**1.4**
All other planning areas	251.2	250.5	249.5		**-1.7**	-0.7%	**10.0**
Total	**840.5**	**858.9**	**879.8**	**+ 61.4**	**100.7**	**12.0%**	**128.2**

GridStrategies

SOURCES | Grid Strategies, Strategic Industries Surging: Driving US Power Demand (Dec. 2024) at 24.

Transmission improves resilience during extreme weather

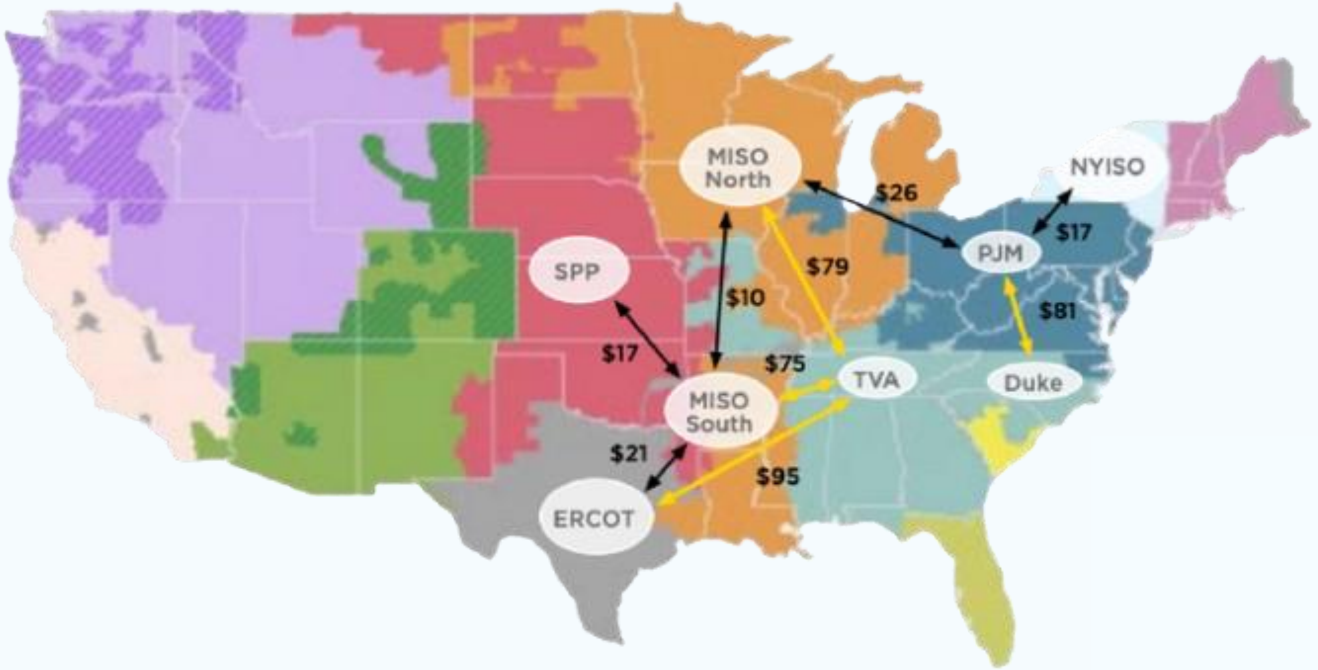
In 2022, Duke, TVA, and LG&E/KU were forced to shed load during Winter Storm Elliot…

…modest investments in interregional transmission capacity would have yielded nearly $100 million in benefits during the 5-day event.

While some regions had limited generation to export during Winter Storm Elliot, it is important to note:

- Winter Storm Elliott's scale was rare; in most storms a neighboring region will have generation available.
- MISO's LRTP Tranche 2.1 is greatly expanding ties to PJM, likely ensuring additional available generation for future extreme weather events.
- Net load diversity benefits are growing with increased natural gas use, renewable energy, and electrification.

Benefit of 1 GW transmission expansion between each pair of regions, in millions of dollars, December 22-26, 2022



Grid Strategies

SOURCES | Grid Strategies and ACORE, The Value of Transmission During Winter Storm Elliott (February 2023) at 1.

Regional transmission planning creates the most cost-effective system

In SPP…

$12 billion

in net benefits for consumers over the next 40 years from transmission upgrades installed by SPP between 2012 and 2014.

This is equivalent to $800 for each person currently served by SPP, or $2,400 per each metered customer.

$16.6 billion

in gross savings is higher than SPP's transmission planning models had initially estimated, and 3.5 times greater than the cost of the transmission upgrades

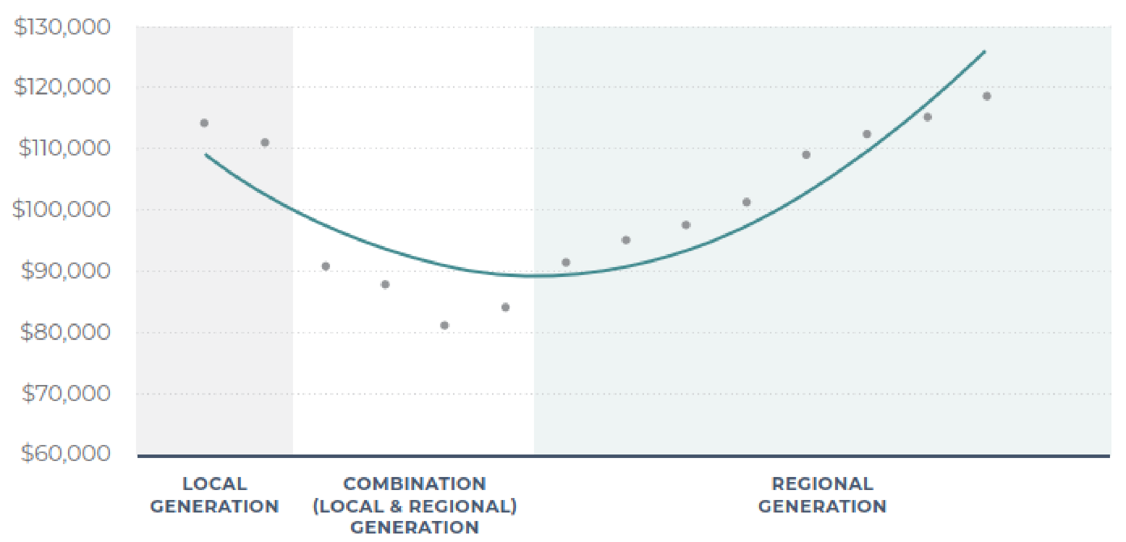
In MISO…

$12-53 billion

in net benefits over the next 20 to 40 years from new transmission, based on analysis of cost and benefits of grid upgrades that are nearing completion.

This is between $250 and $1,000 for each person served by MISO.

Total MISO Project Generation and Transmission Costs, $M

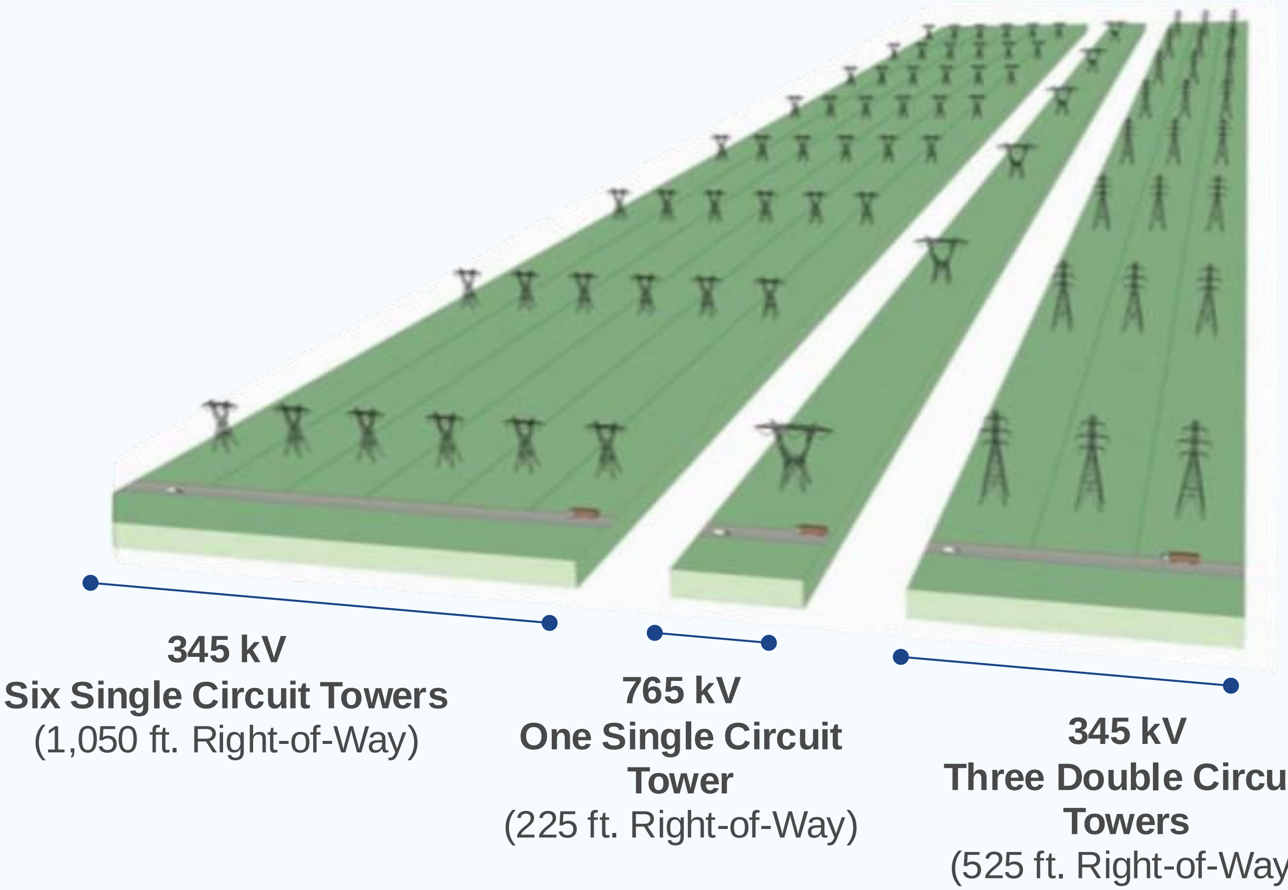


GridStrategies

SOURCES | MISO, *Long Range Transmission Planning - Preparing for the Evolving Future Grid*, (August 2020) at 7.

Large-scale regional transmission provide significant economies of scale

Transmission Voltage (kV)	Cost per Mile ($ Million /Mile)	Capacity (MW)	Cost per Unit of Capacity ($/MW-Mile)
230	$2.253	657	$3,430
345	$3.613	1792	$2,016
500	$4.507	2598	$1,735
765	$5.667	6625	$855



GridStrategies

SOURCES | MISO, Transmission Cost Estimation Guide (May 2024) at 31, 33, and 38.

Very little long-distance transmission has been built recently

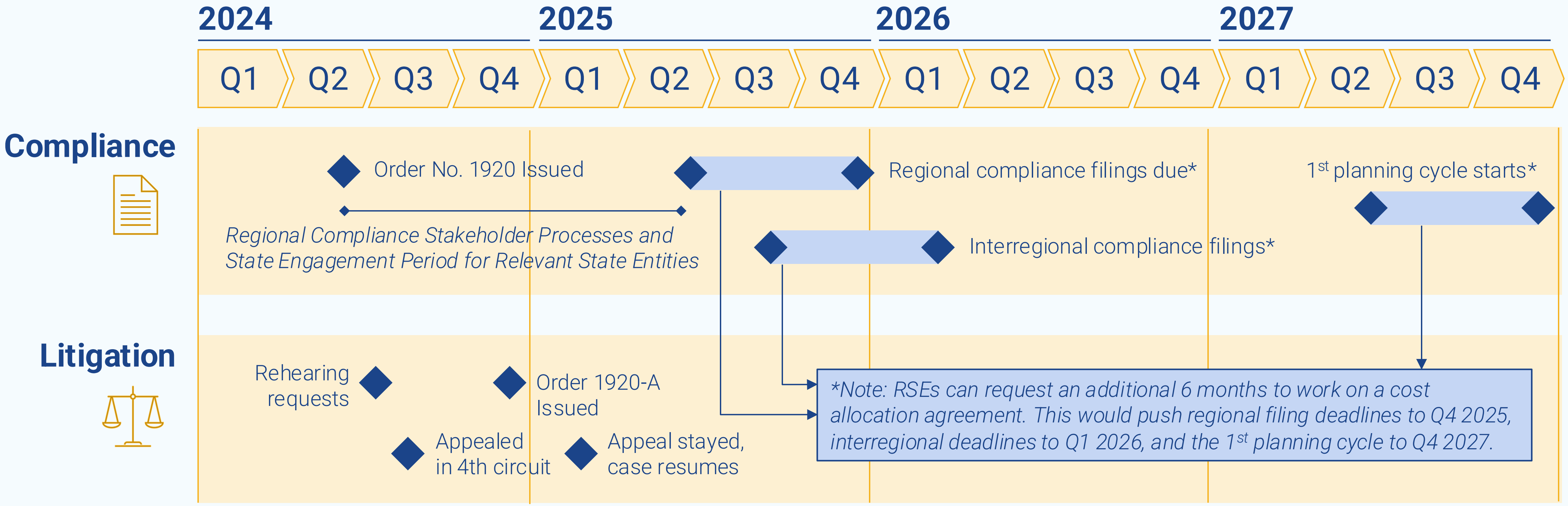
According to FERC data on national transmission build…

- Only 55 new miles of high-voltage transmission were constructed in 2023
- The average of 1,700 miles of new high-voltage transmission built per year from 2010 to 2014 dropped to only 925 miles from 2015 to 2019 and has fallen further to an average of 350 miles per year from 2020 to 2023.

ACEG data shows very few miles of high-capacity transmission built in the Southeast over the past decade.

Miles of High-Capacity Transmission Lines Added Annually

FERC Order 1920: Compliance timeline



***NOTE**: Planning cycles take 5 years, but project selection happens 3 years into the cycle, so **projects do not have to be selected until the end of 2030**. States then have an additional 6 months to use a State Agreement Approach before the transmission provider's cost allocation approach is used (1920A P 15). Five-year planning cycles mean the second long-term regional planning cycle is not required to start until the end of 2032.*

Grid Strategies

Studies have identified potential opportunities to develop multi-value transmission

- Several studies in recent years have shown very similar transmission lines could provide both reliability and economic benefits to consumers
- SERTP evaluated the transfer of 10 GW of generation from MISO to Southern Company. This transfer resulted in a substantial number of violations requiring significant upgrades between the Carolinas and Southern Company to address the violations.
- A similar area was also identified in the preliminary results of the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITSC) as a region with potentially a need for up to 4000 MW in prudent interregional transmission additions.

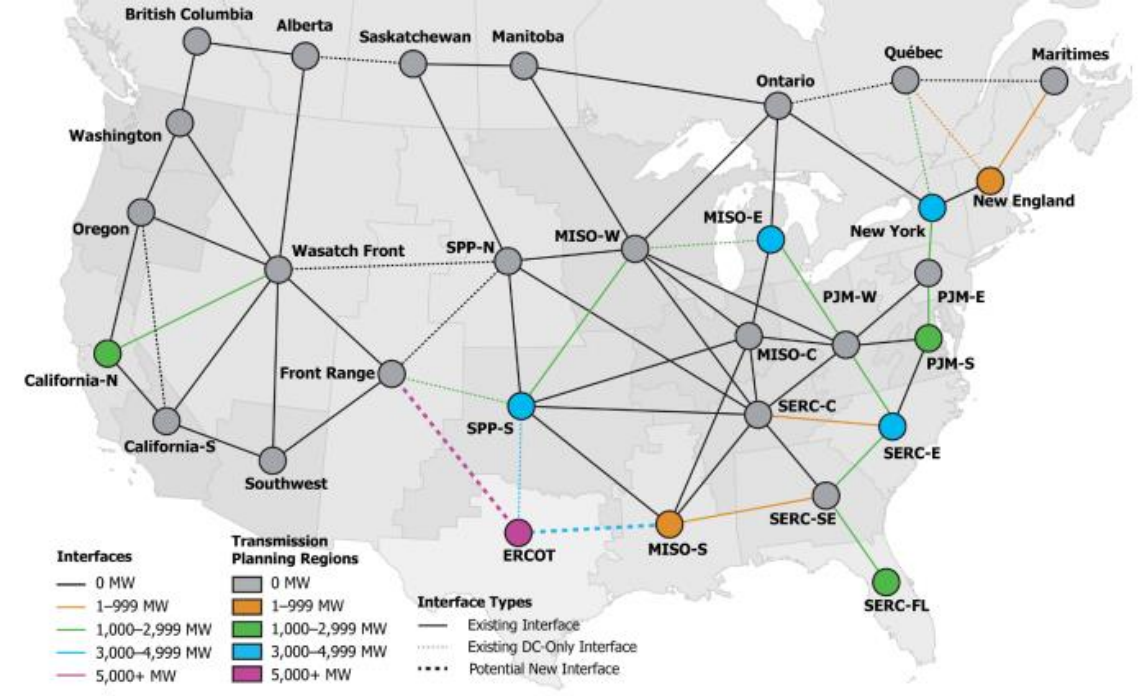
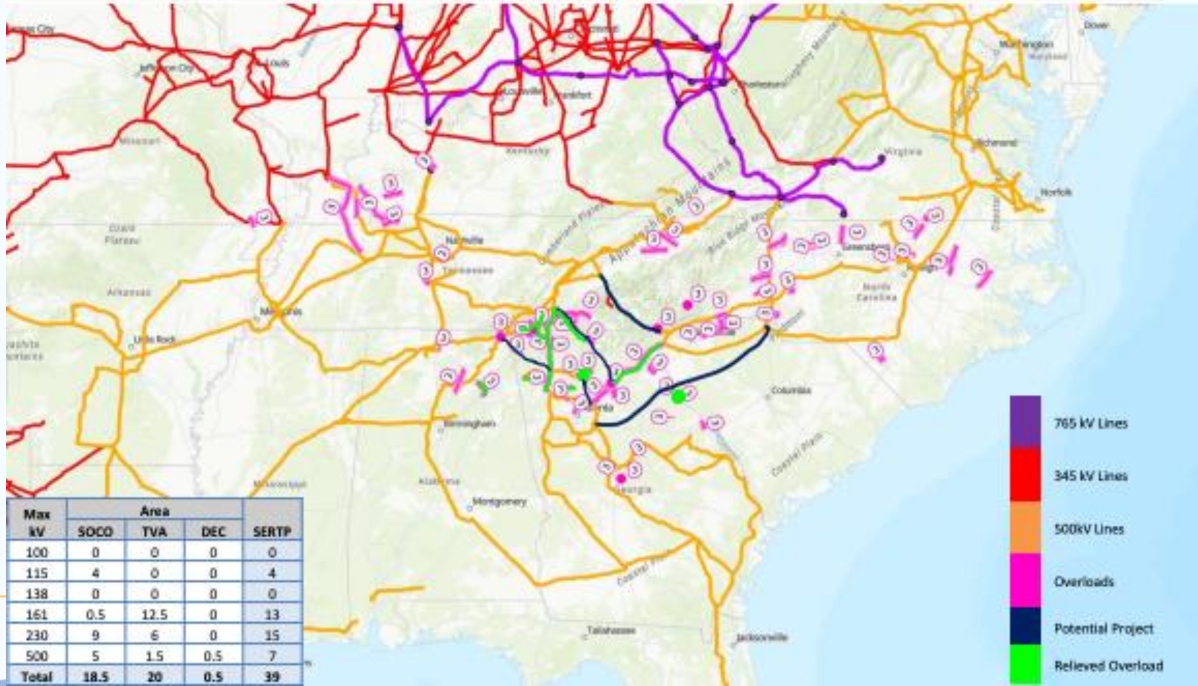


Figure ES.5: Prudent Additions to Transfer Capability



Max kV	Area			SERTP
	SOCO	TVA	DEC	
100	0	0	0	0
115	4	0	0	4
138	0	0	0	0
161	0.5	12.5	0	13
230	9	6	0	15
500	5	1.5	0.5	7
Total	18.5	20	0.5	39

GridStrategies

SOURCES | NERC, Interregional Transfer Capability Study (November 2024) at xvi; SERTP, 4th Quarter Meeting Presentation (December 2024) at 175-191.

Impact of delay in implementation of Order No. 1920 long-term regional transmission planning

- Delaying transmission planning and development may delay load growth potentially costing states economic development and job growth
  - Some regions have already indicated their grid has reached capacity and new large loads may have to wait years to connect
  - Timing mismatch between load development, generation development, and grid development
    - It may take only one or two years to connect new load to the grid, while it may take over four years to bring new generation online and even longer to build new transmission
    - In addition, in some cases current load growth has caused utilities to rush into service high-cost solutions, such as new gas plants
    - Proactively planned transmission would have allowed for the development of new transmission to access low-cost renewables
- Delays in transmission planning can also cost consumers billions in benefits
  - Delay has a real cost in the form of foregone benefits to consumers over the period of time of the delay.
  - MISO estimated the net benefits of their LRTP Tranche 1 projects to be between$23 billion to $41 billion. A two-year delay would reduce discounted future net benefits by roughly $3 billion to $6 billion, made up of the production cost, generation capacity, and other savings included in MISO's benefit-cost analysis.
- At a minimum SERTP should stick to the FERC mandated timeline to begin Order No. 1920 planning in 2027, but SERTP has the ability to start its first Order No. 1920 long-term transmission planning cycle earlier than the 2-year maximum laid out in 1920-A.

SOURCES | Grid Strategies, Fostering Collaboration Would Help Build Needed Transmission (February 2024) at 39.

Order 1920 Scenarios Stakeholder Engagement

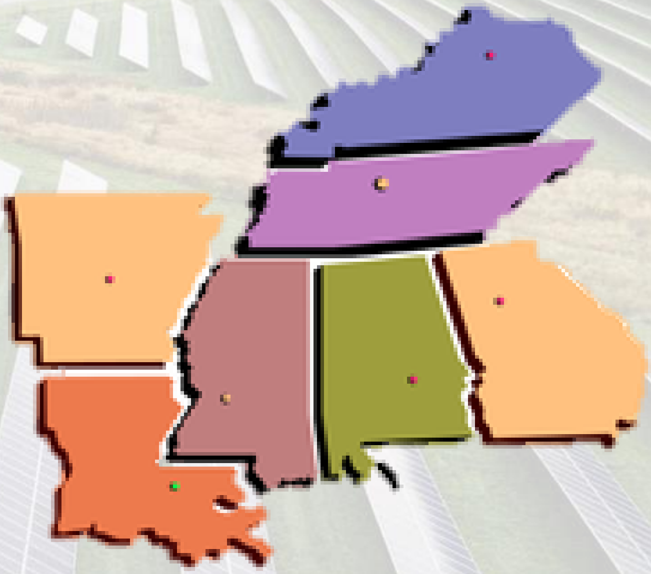
Andy Kowalczyk
Transmission Director
Southern Renewable Energy Association

January 29, 2025

About

The **Southern Renewable Energy Association** (SREA) is an industry-led initiative that promotes responsible use and development of wind energy, solar energy, energy storage and transmission in the South.

SREA's geographic region covers seven Southeastern states, but we frequently coordinate with orgs in the Carolinas



Contents

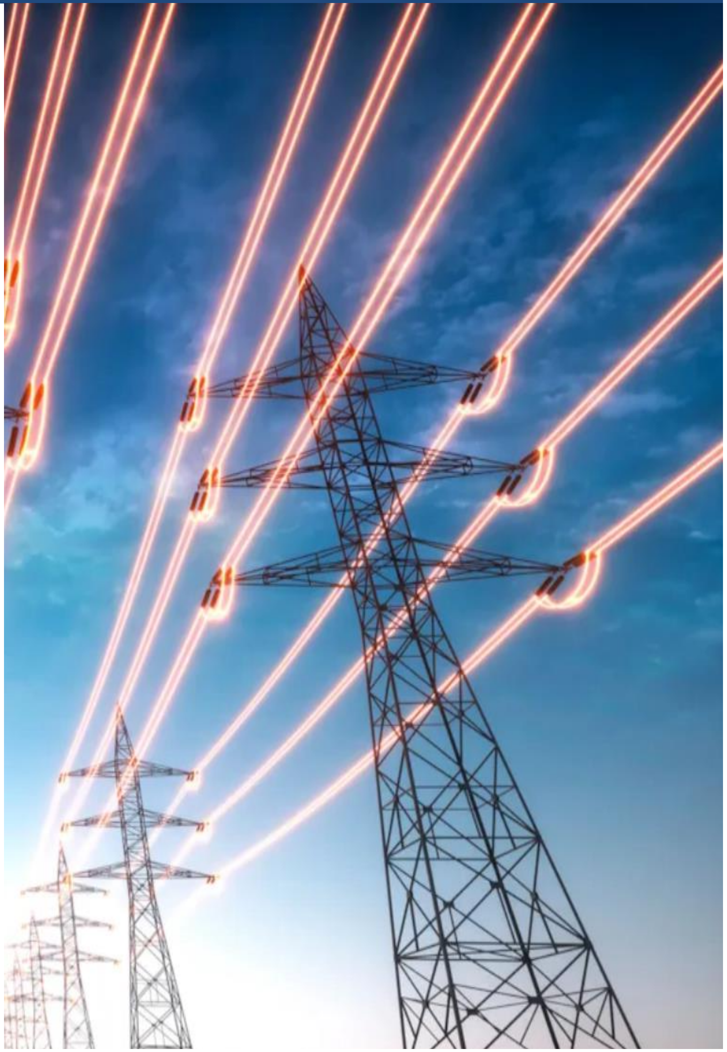
Scenarios and Factors

Order 1920 Requirements on Factors / Scenarios

Transmission Providers (TPs) must provide an opportunity for:

‘stakeholders, including federally-recognized Tribes and states, with a meaningful opportunity to propose potential factors and to provide timely input on how to account for specific factors in the development of Long-Term Scenarios’

FERC Order 1920, Par. 528



FERC Order 1920 Factors

Scenarios: Minimum of 3 showing a range of outcomes, including an extreme weather sensitivity applied to each

Planning Inputs: 7 factors including:

federal, Tribal, state, and local laws and regulations affecting the resource mix and demand;	**Legal**
federal, Tribal, state, and local laws and regulations on decarbonization and electrification;	
state-approved integrated resource plans and expected supply obligations for load-serving entities;	**Utility Planning**
resource retirements;	
trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies;	**Technology / Economics**
generator interconnection requests and withdrawals; *(upgrade in at least 2 cycles in past 5 years)*	**Grid Planning**
utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs	**Corporate Goals**

The Importance of Stakeholder Input

Stakeholder Engagement

Stakeholders should be provided an opportunity to propose factors, and how to account for them. (paraphr.)

FERC Order 1920, Par. 529

Propose Factors

- Relevant factors impacting forecasted generation buildout
- Load patterns / additions impacting transmission & generation buildout

Provide Best Available Data

- Market analysis / economic forecasts
- Ex. NREL ATB, EPRI, VCE
- IRP's, policy, goals
- Other SME data

Accounting & Methodology

- Location specific data, siting methodology
- Weather data
- Economic trends influencing load and gen buildout

Corporate Goals

"We continue to require transmission providers to consider corporate commitments that are likely to affect Long-Term Transmission Needs as part of Long-Term Regional Transmission Planning to the extent that these commitments affect transmission customers' transmission needs, because transmission providers must plan for the needs of all transmission customers on a comparable basis under Order Nos. 888, 890, and 1000."

Par. 303, Order 1920

- Duke Energy forecasts that data center load will grow to 10% of total commercial sales in 2028 from 3% in 2023
- Georgia Power IRP estimating over 36GW's of increased load by the mid-2030's.
- Investor driven sustainability goals:
  - Southern Company – Net zero by 2050
  - Duke Energy – Net zero by 2050

Generation Developers

"we believe that the existence of a large number of interconnection requests in a certain area, even if some of those requests are speculative, indicates that generation developers have an interest in interconnecting resources in that area, which Long-Term Scenarios should take into account."

Par. 473, Order 1920

- Developer insight is critical to understanding hot spots where grid constraints persist in the interconnection process.
- Also can provide deeper insights around site specific resource potential, local ordinances and other inputs that enhance generation expansion siting methodology.
- With Order 2023 implementation there is a greater pool of 'non-speculative' interconnection requests in queues

Public Interest Orgs

"Southeast PIOs note that states do not currently engage in regional transmission planning processes to any meaningful degree, and therefore, the Commission should encourage their participation in shaping and conducting Long-Term Regional Transmission Planning."

Par. 521, Order 1920

- Public interest organizations have a deep history of engagement in Order 1000 SERTP and SCRTP planning areas as well as in state level proceedings.
- Organizations often have experience in other transmission planning regions that are relevant to scenario planning.
- May represent specific viewpoint, and be able to provide data impacting factors and calculation of factors.

Relevant Electric Retail Regulatory Authorities (RERRAs)

“[S]tates must have a meaningful opportunity to provide timely input on the development of Long-Term Scenarios, including factors and data inputs, and to explain how their own policies and planning affect Long-Term Transmission Needs.”

Par 344, Order 1920A

“Furthermore, we clarify that transmission providers must consult with and consider the positions of the Relevant State Entities and any other entity authorized by a Relevant State Entity as its representative as to how to account for factors related to states’ laws, policies, and regulations when determining the assumptions that will be used in the development of Long-Term Scenarios.”

Par 344, Order 1920A

- States Relevant Electric Retail Regulatory Authorities make decisions around the siting and approval of intra-state transmission and generation

- In addition, entities like Public Service or Utility Commissions make decisions to approve Integrated Resource Plans (IRPs) and have a responsibility to ensure fair retail rates for consumers.

Load, Siting and Generation Forecast

Generation Expansion and Siting

- Siting should incorporate state IRP's, public policy, corporate goals and generation projects with GIA's
- To ensure economically efficient expansion, a tool like [EPRI's EGEAS](#)can be useful.
- To accommodate the long-term forecast, there should be a methodology to model resource additions and retirements outside of public resource plans
- [Vibrant Clean Energy's WIS:dom®](#)tool was effective in siting resources for MISO's Futures Scenarios based on:
  - Weather modeling and expected dispatch of RE resources
  - Indicative transmission capacity needed to leverage new generation cost savings

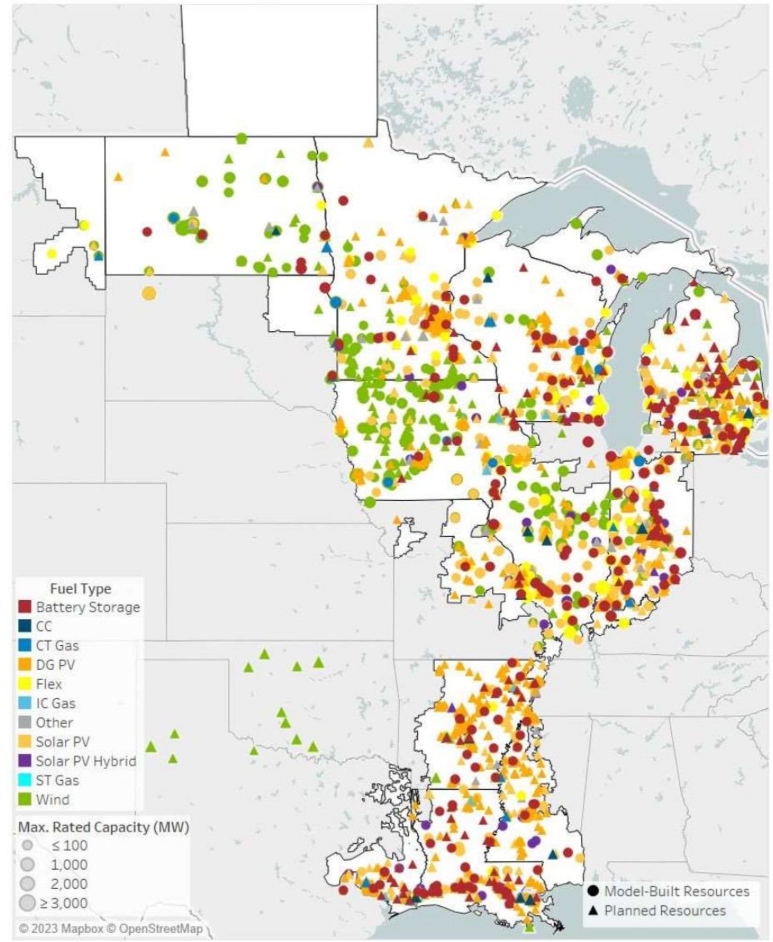
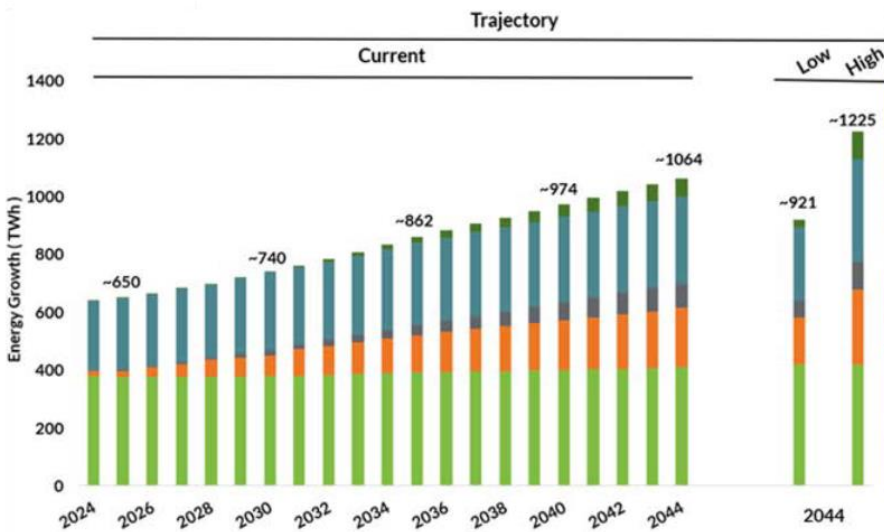


Figure 83: MISO Future 2A Non-EGEAS and EGEAS Expansion Siting

Accounting for Load



	CAGR* % Low-High (2024-44)	Growth** TWh Low-High (2024-44)	Level of Certainty***
Hydrogen	27-32	26-95	
Industry Development & Reshoring	3-7	21-105	
EVs	14-17	54-91	
Data Centers	12-15	149-241	
Building Electrification	0.45-0.54	36-43	

Figure 2: Driver Segmentation Based on Gross Energy in Current Trajectory[1]

Source: MISO

- There are nuances in load growth types, often captured in state IRP’s, but not fully encapsulated
- Location and type, are important inputs into the process that can allow extrapolation across Long Term Regional Transmission Plan (LTRTP) horizon.

Roadmap

Scenario Development Roadmap

Introduction

- Purpose of LTRTP Scenarios and Factors Development
- Solicit stakeholder feedback to seek alignment of vision

Assumptions

- Incorporate feedback, and discuss assumptions / factors chosen by TP, and why, if any weighting is applied to certain factors
- Present LTRTP needs hypothesis
- To validate assumptions, solicit stakeholder feedback on presentation of assumptions / factors chosen, best available data to assess factors, and overall scope of LTRTP Scenarios.

Present Factors

- Present revised assumptions, and present updates incorporating stakeholder feedback.
- Present final factors to be included

Scenario Development Roadmap

Generation Expansion

- Present results of generation expansion and siting, load forecast and siting, as well as generation retirements
- TP's Present Generation and Load Siting Methodology
- To validate assumptions, solicit stakeholder feedback on siting, inputs and assumptions

→

Siting

- Present final siting, incorporating stakeholder feedback.

→

Final Scenarios

- **Present final Scenarios**

Compliance

Beyond Order 1920 Compliance Requirements

Timeline: Because of dramatic shifts in factors influencing the generation mix, load, and transmission needs, Scenarios ***should*** be revisited much more often than what's required in Order 1920A (every 5 years).

In the last 5 years:

- The North Carolina Carbon Planned was passed by the NC legislature
- Planned and forecasted AI and Data Center related load additions end the 'era of flat load growth'
- The Inflation Reduction Act was passed impacting both generation costs, *and* onshoring of manufacturing driving load growth.
- Winter Storms Uri and Elliott, along with Hurricanes Helene, Ian and Ida occurred.

Contact

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FERC Order 1920 Compliance Provides an Opportunity for SERTP to Update its Long-Term Planning Approach

Tyler Fitch

SERTP 1st Stakeholder Input Presentation Meeting

January 29, 2025

Objectives

- Provide an overview of opportunities to strengthen SERTP's planning process, with a specific focus on scenario design and stakeholder engagement
- Clarify the role states and stakeholders could play and the benefits to SERTP's process
- Share relevant examples of how peer regions are approaching scenario design and engagement

Agenda

- Overview of FERC Order 1920 Long-Term Regional Transmission Planning
- Scenario design under Order 1920
    - Scenario construction principles
    - Role of states and stakeholders
- Key Takeaways

RMI's Clean Competitive Grids team works to ensure transmission supports the energy transition.

We actively participate in Western and PJM transmission processes

We publish insights on grid solutions: regional transmission planning, grid-enhancing technologies, federal funding opportunities, and more

We collaborate with PUCs, energy offices, legislators, and utilities

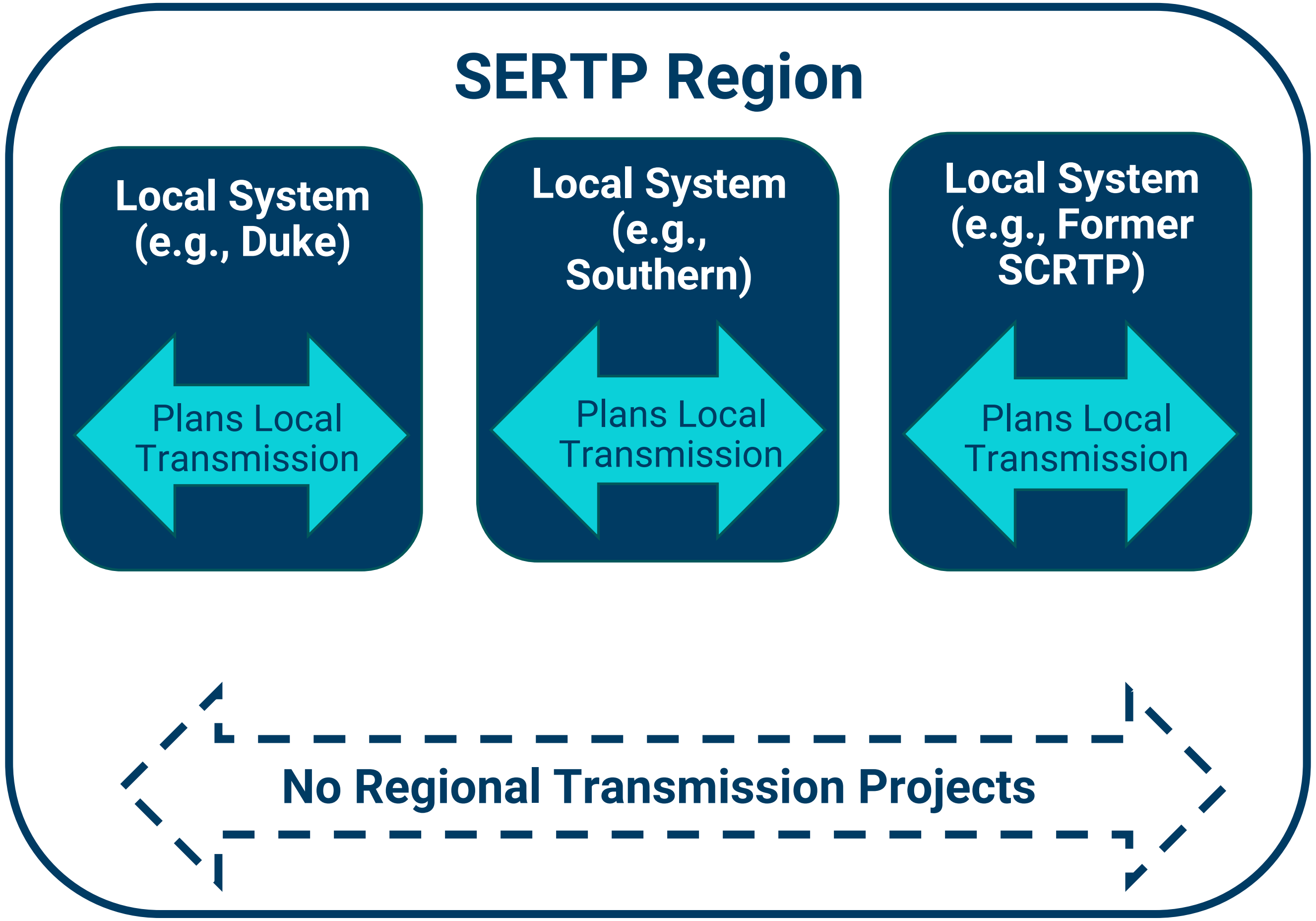
REPORT | 2024
States in Sync
The Western Win-Win Transmission Opportunity
By Tyler Farrell, Charles Teplin

INSIGHT
Understanding FERC's Order 1920
May 29, 2024

REPORT | 2024
Mind the Regulatory Gap
How to enhance local transmission oversight

GETting Interconnected in PJM

SERTP currently uses a "bottom-up" regional planning process that relies on local planning

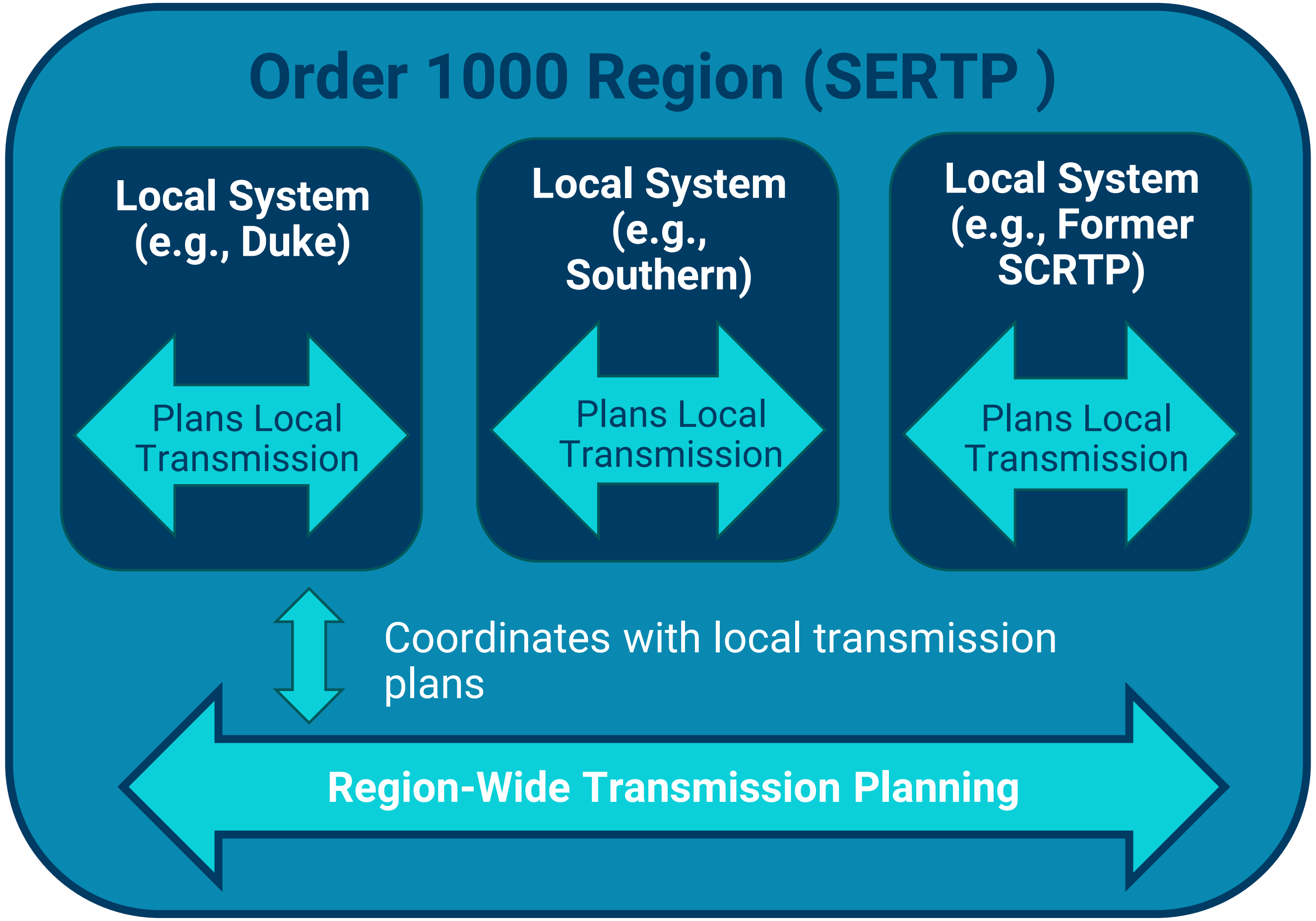


SERTP's Existing Regional Transmission Model

- SERTP combines local 10-year plans to assess if regional projects offer lower-cost reliability
- SERTP's regional planning process has **never** selected a regional transmission project[1]

Source: 1 . https://www.cleanenergygrid.org/wp-content/uploads/2023/06/ACEG_Transmission_Planning_and_Development_Report_Card.pdf.

FERC Order 1920 establishes a process for region-wide planning



- Order 1920's process ***does not supersede local planning,*** but works in parallel and provides benefits that local projects can't access
- Regional transmission projects can deliver local and regional benefits while complementing local transmission and generation projects

Order 1920 presents an opportunity to improve planning process & outcomes for ratepayers

Order 1920 features clear steps and requirements that de-mystify regional transmission planning

FERC Order 1920 Long-Term Regional Transmission Planning Process*

1. Define **Long-Term Scenarios** for regional transmission planning

↓

*2. Identify **Long-Term Transition Needs***

↓

*3. Generate potential **Long-term regional transmission facilities (LTRTFs)***

↓

*4. **Evaluate and select** LTRTFs*

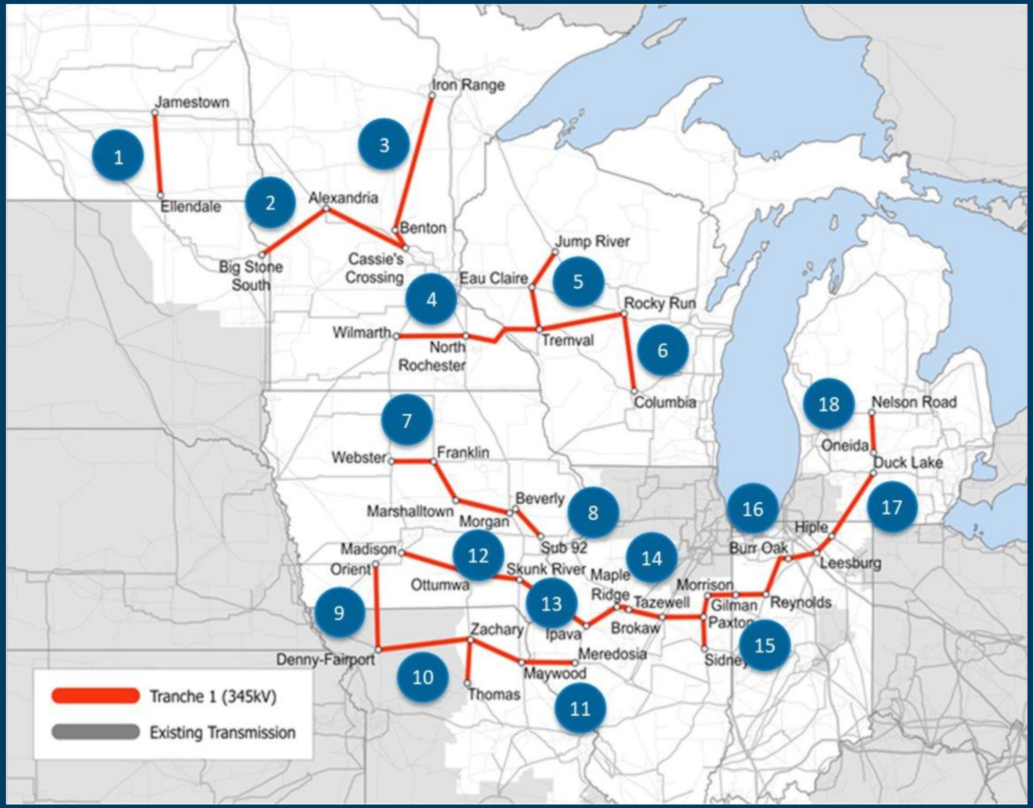
Engagement with relevant state entities and key stakeholders

***Not including cost allocation**

- ***This process is not new.*** The Order 1920 process parallels proven processes already delivering benefits in other regions (e.g., MISO LRTP)
- ***Regional projects (and attendant benefits) are not guaranteed.*** High-quality inputs and policy decisions are required at each stage to yield viable, beneficial projects. Order 1920 also does not require that beneficial projects be built.
- ***SERTP will define its approach in its Order 1920 Compliance filing.*** Setting a high-quality approach from the outset will yield benefits in the future and lead to more benefits for ratepayers, faster.

Case Study: MISO's Long-Range Transmission Planning (LRTP) presents a helpful example

- Launched in 2019, LRTP serves is an exemplar for Order 1920 compliance.
- LRTP develops regional projects across multiple balancing authorities in MISO to ensure future transmission reliability, cost-efficiency, and compliance with state policies, utility goals, and industry trends.
- Like SERTP, many utilities in MISO's territory are vertically integrated and LRTP interacts with utility IRPs.
- MISO already approved two project portfolios (Tranche 1 and 2.1).



Source: https://cdn.misoenergy.org/MTEP24%20Chapter%202%20-%20Regional%20Long%20Range%20Transmission%20Planning658124.pdf

Order 1920 requires several updates to SERTP's current transmission planning process

SERTP Current Process

One set of inputs…

…looking **10 years** in the future…

…using **local transmission plans and generators with interconnection agreements only**…

…**FERC Order 1000** data requirements…

…and **FERC Order 1000** state and stakeholder input requirements.

Order 1920

At least three scenarios, **plus sensitivities**…

…looking **20 years** in the future…

…using **seven well-defined categories of input factors**…

…using **updated FERC 1920 (transparent, "best available") data requirements** …

…and **updated FERC 1920 well-defined state and stakeholder input opportunities.**

Order 1920 requires several updates to SERTP's current transmission planning process

SERTP Current Process

One set of inputs…

…using **local transmission plans and generators with interconnection agreements only**…

agreements only…

…**FERC Order 1000** data requireme

…and **FERC Order 1000** state and stakeholder input requirements.

Order 1920

At least three scenarios, **plus sensitivities**…

…looking **20 years** in the future…

…using **seven well-defined categories of input factors**…

This represents a small fraction of planned capacity in utilities' IRPs

…and **updated FERC 1920 well-defined state and stakeholder input opportunities**.

Next, we'll dive deeper into key scenario design topics

SERTP Current Process

One set of inputs…

…l

1. Scenario Design

…using **local transmission plans and generators with interconnection agreements only**…

…**F**

2. Role of States & Stakeholders

ts…

…and **FERC Order 1000** state and stakeholder input requirements.

Order 1920

At least three scenarios, plus sensitivities…

…looking **20 years** in the future…

…using seven well-defined categories of input factors…

…using **updated FERC 1920 transparent, "best available" data requirements** …

…and updated FERC 1920 well-defined state and stakeholder input opportunities.

Order 1920 lays the groundwork for long-term, scenario-based planning.

Order 1920 long-term scenarios are:

- **Informed** by 7 key factors;
- **"Plausible":** Each "must be reasonably probable, and collectively, … [they] capture probable future outcomes;"
- **"Diverse":** providers "can distinguish distinct transmission facilities or benefits in each scenario."

Individually, each scenario provides a detailed view of transmission needs and benefits

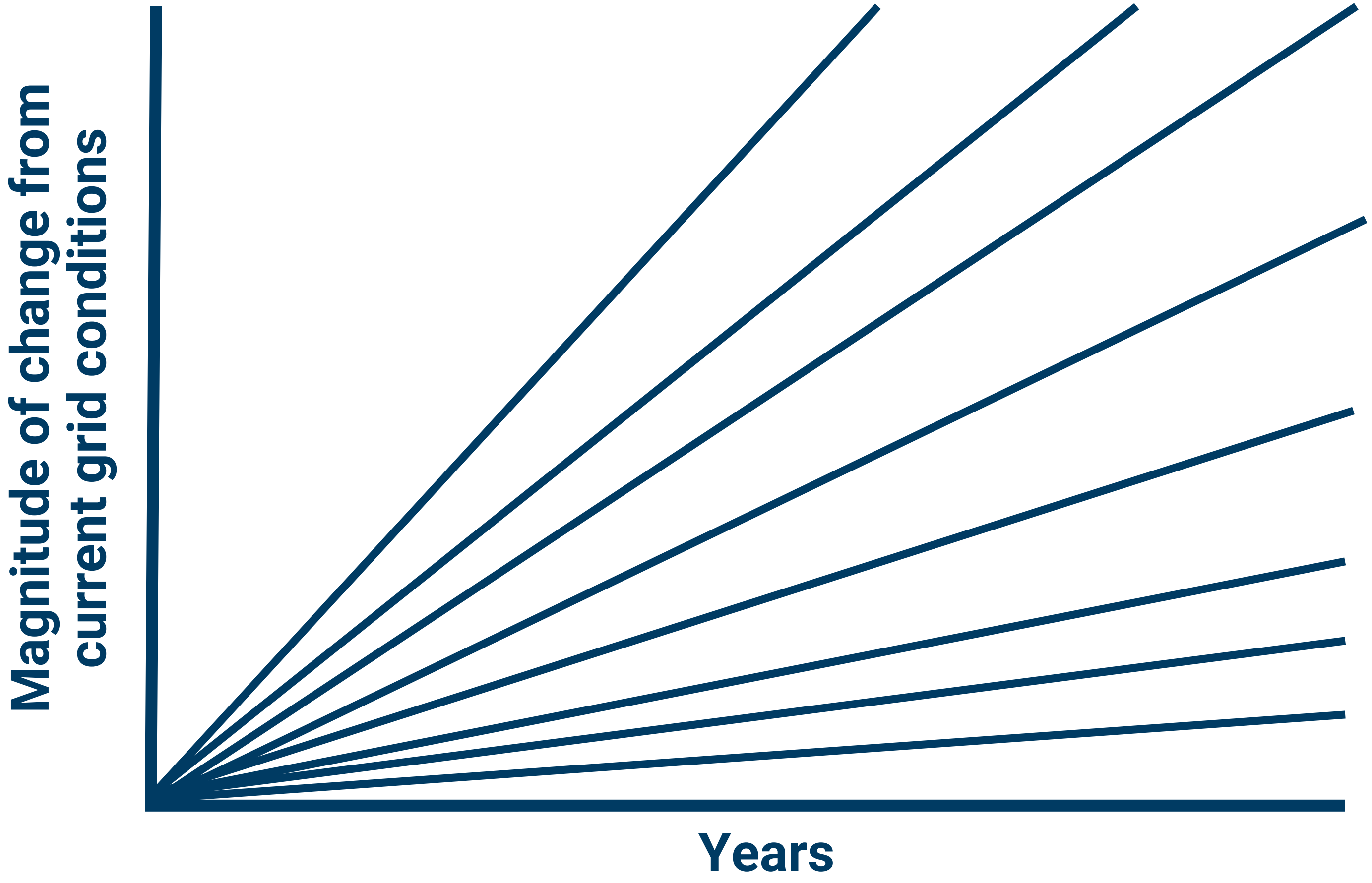
Collectively, they identify solutions that are robust under uncertainty

Order 1920 Factors for Long-Term Scenario Planning

1. Laws & regulations affecting resource mix and demand
2. Laws & regulations affecting decarbonization and electrification
3. State-approved IRPs and expected service obligations for LSEs
4. Trends in fuel and technology costs
5. Resource retirements
6. Generator interconnection requests and withdrawals
7. Utility and corporate commitments and policy goals that affect Long-Term Transmission Needs

https://cleanenergygrid.org/wp-content/uploads/2025/01/Overview-of-1920-and-1920-A-Compliance-Obligations-2024.12.24.pdf

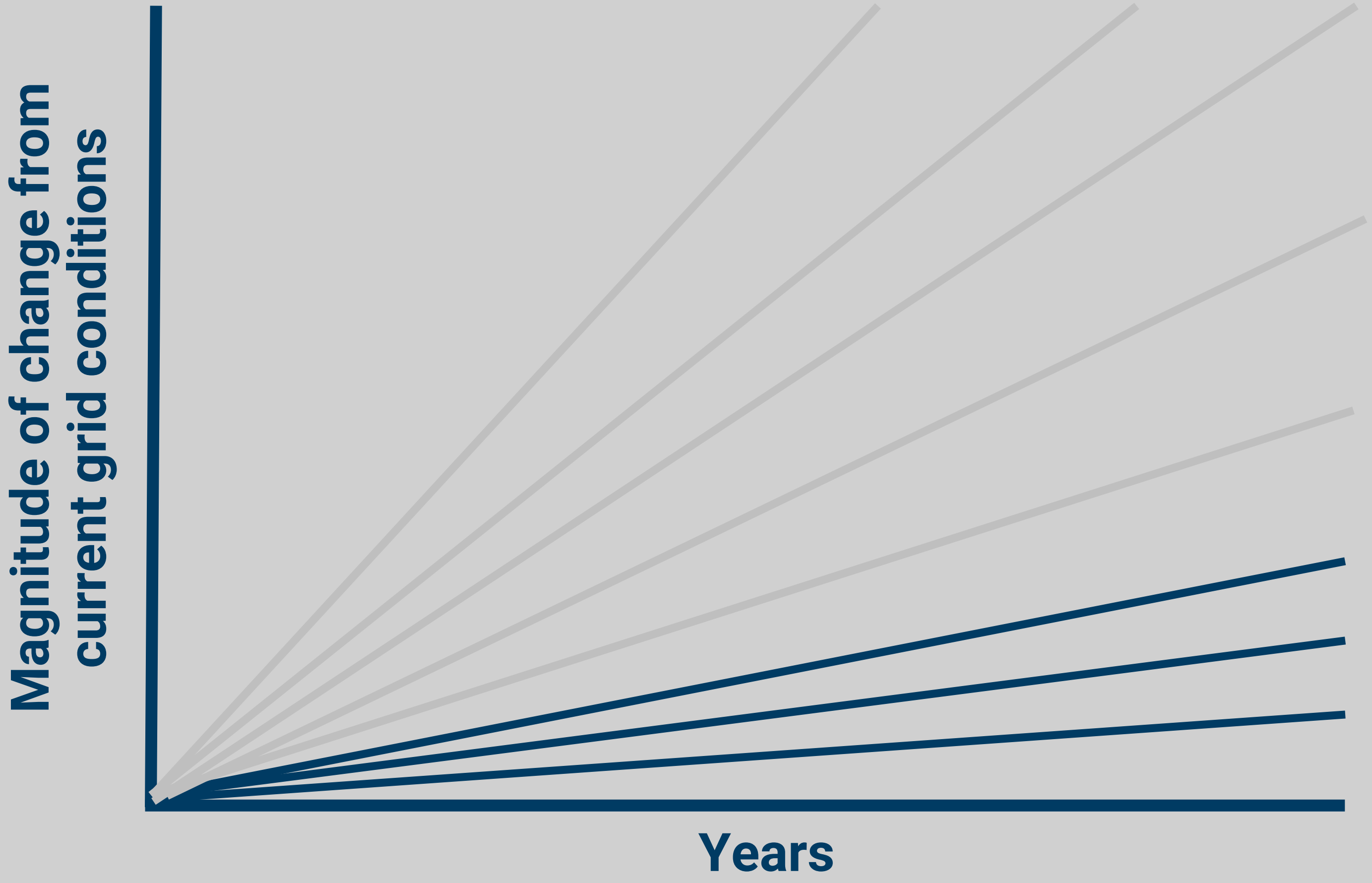
Long-Term Scenarios set the range of possible futures considered in long-term planning



- Together, scenarios should provide insight into a broad but achievable range of values for key inputs
- Long-term transmission planning processes at MISO and AEO use a "bookend" approach that identifies low-change, high-change, and central scenarios.

As an example, scenarios with base, moderate, and high interconnection acceleration could identify a range of transmission projects easing interconnection needs and serving newly interconnected projects

Long-Term Scenarios set the range of possible futures considered in long-term planning



- Together, scenarios should provide insight into a broad but achievable range of values for key inputs
- Long-term transmission planning processes at MISO and AEO use a "bookend" approach that identifies low-change, high-change, and central scenarios.

Tightly-clustered scenarios that show little change from existing grid condition forecasts (e.g., IRP-only scenarios) may under-evaluate potential role and benefits of regional transmission

newly interconnected projects

Case Study: MISO's Futures hedge uncertainty and bookend a range of economic, political, and technical possibilities.

Highlights from MISO's approach

Scenario diversity that bookend potential changes by representing low, moderate, and high levels of electrification, decarbonization, and renewable penetration

Independent regional modeling including an economic resource expansion model that forecasts additional resource needs beyond utility IRPs

Long-term focus with 20-year forecasts that allows scenarios to be used for several planning cycles

Future 1 / 1A

- 100% utility IRPS
- 85% utility/state goals met
- No load growth

Tranche 1

Future 2 / 2A

- 100% utility/state goals met
- 60% emissions reductions by 2040
- 30% load growth by 2040

Tranche 2.1

Future 3 / 3A

- 100% utility/state goals met
- 80% emissions reductions by 2040
- 50% load growth by 2040

Source: https://cdn.misoenergy.org/MTEP24%20Chapter%202%20-%20Regional%20Long%20Range%20Transmission%20Planning658124.pdf
https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

State and stakeholder engagement on scenario design yield broad-based benefits

Benefits of engagement

- Accurately reflect state policy
- Align on scenario inputs
- Flag transmission siting and permitting concerns

Risks that engagement can mitigate

- Scenarios may not reflect reality of state policy
- Planning processes may not be aligned
- Lack of streamlined infrastructure development may lead to costly, repeated planning cycles

In Order 1920 process, states and stakeholders have defined roles in planning development and implementation

SERTP Consultation and Input Requirements

	Compliance Filing	Long-term Scenario Development
States	*"must make **good-faith efforts to consult with and seek support** from"* relevant state entities.	*"must **consult** with states"* on development of long-term scenarios
Stakeholders	*"must **consult** with stakeholders"* in developing compliance for Order 1920	must offer stakeholders ***"a meaningful opportunity"*** to participate in scenario development

In Order 1920 process, states and stakeholders have a meaningful role in planning development and implementation

SERTP Consultation and Input Requirements

	Compliance Filing	Long-term Scenario Development
States	*"must make* ***good-faith efforts to consult with and seek support*** *from"* relevant state entities.	*"must* ***consult*** *with states"* on development of long-term scenarios
Stakeholders	*"must* ***consult*** *with stakeholders"* in develop… compliance for Order 19…	

"Good-faith efforts" are not defined in the Order and will be informed by states' (stated and un-stated) expectations

In Order 1920 process, states and stakeholder have well-defined roles on scenario inputs…

#	Order 1920 Factors	Responsible for Identification?
1	Laws & regulations affecting resource mix and demand	Relevant **State** Entities or their Representatives **& stakeholders**
2	Laws & regulations affecting decarbonization and electrification	**States & stakeholders**
3	State-approved IRPs and expected service obligations for load-serving entities	**States & stakeholders**
4	Trends in fuel and technology costs	**SERTP** (with state & stakeholder input)
5	Resource retirements	**SERTP** (with state & stakeholder input)
6	Generator interconnection requests and withdrawals	**SERTP** (with state & stakeholder input)
7	Utility commitments and policy goals that affect Long-Term Transmission Needs	**States & stakeholders**

States and stakeholders may propose additional factors.

…and SERTP has significant discretion on how inputs are used.

#	Order 1920 Factors	May be discounted by SERTP?
1	Laws & regulations affecting resource mix and demand	No
2	Laws & regulations affecting decarbonization and electrification	No
3	State-approved IRPs and expected service obligations for load-serving entities	No
4	Trends in fuel and technology costs	Yes
5	Resource retirements	Yes
6	Generator interconnection requests and withdrawals	Yes
7	Utility and corporate commitments and policy goals that affect Long-Term Transmission Needs	Yes

SERTP retains broad discretion on how to use input factors and how to weigh various stakeholders' input.

SERTP may also propose additional factors.

Case Study: Stakeholders had multiple opportunities to comment on MISO Futures

Key Details

- 18-month engagement process including 13 public meetings
- MISO Futures were updated based on stakeholder input regarding
  - Load forecasting
  - DER additions
  - Resource siting

Highlights from MISO's approach
Stakeholder collaboration with clear schedule and that ensures scenarios align with state policies, utility goals and emerging energy trends
Iterative updates to integrate new data, stakeholder feedback, and emerging trends

Source: https://cdn.misoenergy.org/MTEP24%20Chapter%202%20-%20Regional%20Long%20Range%20Transmission%20Planning658124.pdf
https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

Takeaways: SERTP's compliance filing can support high-quality scenario planning

Recommendations	
Scenario diversity	**Partner with a diverse set of industry experts** to establish targeted modeling for low, moderate, and high trajectories
Independent regional modeling	**Integrating a regional resource modeling perspective** that forecasts additional needs beyond utility IRPs
Long-term focus	Develop **modular scenario framework** with 20-year forecasts that can be updated incrementally
Stakeholder collaboration	A **stakeholder advisory committee** with **regular workshops** and **clear roles** to ensure alignment
Iterative updates	Schedule **regular scenario review cycles** to incorporate latest data and stakeholder input

A final note: evaluating SERTP's capacity to plan

- While long-term regional planning can generate substantial benefits, it requires ***significant time, effort, and technical capacity.***
  - *Example: MISO's Tranche 2.1 process invested over 40,000 MISO staff-hours and 300 meetings.*

- To ensure neutrality and maintenance of the public interest, ***this planning and analysis capacity should be independent of any single transmission provider.***

- SERTP may not currently have the capacity to implement best-in-class regional planning, but ***the compliance filing represents an opportunity to lay out a roadmap*** for building a more capable and independent regional planning function at SERTP.

Not including cost allocation

States & stakeholders' role in achieving high-quality SERTP planning

During Compliance Development & Filing

- **States** and **stakeholders** can consult with peer regions and experts on high-quality regional transmission planning practices
- **States** can collaborate with **stakeholders** on developing state objectives and priorities for transmission planning
- **States** can initialize conversations with other state entities on cross-state collaboration and joint advocacy
- **States** can begin conversations on building SERTP's long-term independent planning capacity
- Based on states' objectives and priorities, **states** can set expectations for what constitutes "good-faith" efforts to consult and seek approval
- Through consultation process, **states** and **stakeholders** can ask key questions and make proposals for key SERTP planning processes
- In the case that SERTP compliance does not meet expectations, **states** and **stakeholders** can share their evaluations with FERC

During Long-Term Scenario Development

- **States** can collaborate with **stakeholders** on developing high-quality inputs for key long-term scenario input factors (especially categories 1-3)
- **States** and **stakeholders** can set expectations on the range of grid conditions contemplated by long-term scenarios
- **States** can request additional scenarios to evaluate high-priority future grid conditions

*(**States** and **stakeholders** can begin these activities in advance of the formal launch of SERTP's LTRTP process)*

Thank you!

Tyler Fitch
tyler.fitch@rmi.org

Coincident Peaking & Transmission Planning

Presentation to SERTP Stakeholders

January, 2025

Ben Adams
Southern Alliance for Clean Energy

ABOUT SACE

The Southern Alliance for Clean Energy (SACE) is a nonprofit organization that promotes responsible and equitable energy choices to ensure clean, safe, and healthy communities throughout the Southeast. As a leading voice for energy policy in our region, SACE is focused on transforming the way we produce and consume energy in the Southeast.

Electricity Modeling Terms

Analysis of the transmission system typically uses “power flow” modeling. These models have detailed topology of the transmission system, but are not typically used to analyze an entire year or multiple years.

Resource planning typically uses “capacity expansion” and “production cost” modeling, which simulate every hour in a year over multiple years.

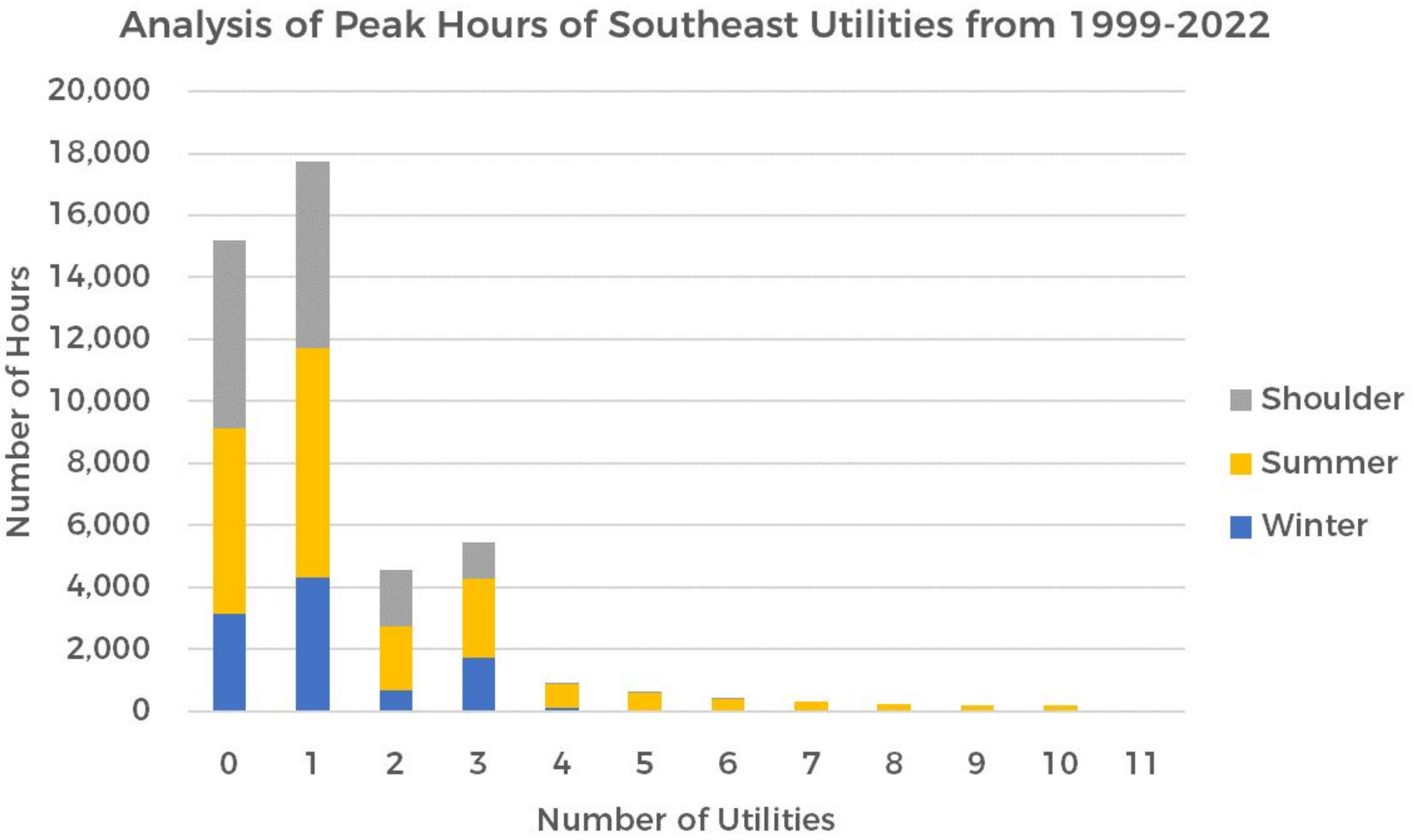
SERTP Peak Evaluation

To date, SERTP has taken a conservative and simple approach to transmission modeling - adding each BA's forecasted peak together without considering whether peaks are likely to be coincident or if there are other situations that may stress the regional transmission system in ways different from how the system would perform if all BAs were to peak at the same time.

Coincident: occupying the same space or time.
~Merriam-webster

SERTP Utilities Rarely Peak at the Same Time

- All 11 SERTP & SCRTP utilities have peaked in the same hour in just 30 hours over 23 years of data, that's 0.065% of hours.
- Most hours (94%) are non-peaking or have 1-3 utilities peaking.



Source: SACE Analysis of FERC 714 data

Planning Beyond One Non-Coincident Peak

If the system is reliable during a single imaginary hour where all utilities peak at the same time, won't it be reliable during all other hours?

Not necessarily

Other situations that could stress the system include:

- Peaks in only one part of the region, i.e. the east or west
- High or low renewable generation scenarios
- Neighboring regions peak but not the Southeast
- Widespread outages of a single resource type, like gas during a winter peak

Examples From Other Regions: MISO

MISO Models and Tools

Model
Powerflow • Current year, 1-year, 2-year, 5-year and 10-year out representations • Peak models for each season • Shoulder models • Light load models • Minimum load model • High and average renewable scenarios
Dynamics • 1-year, 2-year, 5-year and 10-year out representation • Summer and Winter Peak • Summer Shoulder and Spring Light Load • High and Average renewable scenarios

Source: [MISO website]

Table I.1: 2024 Series SERTP Regional Powerflow Models

No.	Season	Year
1	Summer	2026
2	Summer	2029
3	Summer	2034
4	Shoulder	2029
5	Winter	2029
6	Winter	2034

Source: [SERTP 2024 Regional Transmission Planning Analyses Summary]

Examples From Other Regions: NorthernGrid

NorthernGrid, a non-RTO region in the Northwest, uses a combo of power flow and production cost modeling in reliability transmission planning.

> *"Each power flow case's regional transmission configuration was modified to represent 28 unique regional combinations of the submitted regional transmission projects. The combinations ranged from including no to all submitted regional transmission projects. Then, contingency analysis was performed on these power flow cases using 230 kV and above electrical facility contingencies submitted by the Members. Facilities within the NorthernGrid region and adjacent regions were monitored for reliability criteria violations."*
>
> ~ NorthernGrid 2022-2023 Regional Transmission Plan

Conclusion & Recommendations

Forecasts are never 100% right, but some effort should be made to explore potential future scenarios that could stress the regional transmission system. These can be in addition to the current non-coincident peak cases.

Regional planning will have to introduce production cost modeling to evaluate some benefits required by Order 1920, so now is a good time to other ways to integrate modeling.

Recommendations
1. Use hourly modeling to identify cases that stress the transmission system in different ways. 2. Continue to use seasonal peaks, but look at additional base cases.

cleanenergy.org

Southern Alliance for
Clean Energy

Order No. 1920 Stakeholder Presentation

Evaluation Process and Selection Criteria

SOUTHERN ENVIRONMENTAL LAW CENTER

Nick Guidi
Senior Attorney

Order No. 1920 Requirements

General

Transmission providers must “include an evaluation process, including selection criteria, that they will use to identify and evaluate Long-Term Regional Transmission Facilities for potential selection to address Long-Term Transmission Needs.” P 911

The evaluation process must:

1. **Identify Long-Term Regional Transmission Facilities** that address Long-Term Regional Needs
2. **Measure the benefits of the identified** Long-Term Regional Transmission Facilities
3. **Designate a point in the evaluation process** at which transmission providers will **determine whether to select or not select** identified Long-Term Regional Transmission Facilities

Order No. 1920 Requirements

Flexibility

After consulting with Relevant State Entities and stakeholders, transmission providers must propose an evaluation process that “they believe will ensure that more efficient or cost-effective Long-Term Regional Transmission Facilities are selected to address the transmission planning region’s Long-Term Transmission Needs.” P 924

Order No. 1920 Requirements

Minimum Requirements

Transparency

Evaluation processes and selection criteria must:

- Be transparent and not unduly discriminatory
- Culminate in a detailed determination showing why particular solutions were selected or not

Transmission providers must make transparent:

- Methods used to analyze each individual Long-Term Scenario and determine Long-Term Transmission Needs
- Long-Term Regional Transmission Facilities identified to resolve those needs
- Benefits of those Long-Term Regional Transmission Facilities

Order No. 1920 Requirements

Minimum Requirements

Efficiency and/or Cost Effectiveness

The planning process "must result in a regional transmission plan that identifies the Long-Term Regional Transmission Facilities that more efficiently or cost-effectively meet the transmission planning region's Long-Term Transmission Needs." P 957

Transmission providers have "an affirmative obligation to identify Long-Term Regional Transmission Facilities that more efficiently or cost-effectively address Long-Term Transmission Needs". P 957

- Regardless of whether stakeholders or non-incumbent developers propose solutions

Order No. 1920 Requirements

Minimum Requirements

Efficiency and/or Cost Effectiveness

Limitations:

If using a benefit-to-cost ratio, cannot exceed 1.25-to-1.00

May not prohibit the selection of a potential solution based on the anticipated response of a state public utility commission or consumer advocate

Order No. 1920 Requirements

Minimum Requirements

Benefits and Costs

The evaluation process and selection criteria must seek to

- **Maximize benefits**
- **Accounting for costs** over time
- **Without over-building** transmission facilities

May not disregard any of the 7 benefits outlined in Order No. 1920.

- May weigh how likely certain conditions expressed in specific scenarios or sensitivities are to occur

Final determination <u>**must include the estimated costs and measured benefits**</u> of each alternative solution evaluated

Order No. 1920 Requirements
Minimum Requirements

Benefits and Costs

Transmission providers generally have flexibility in the approach they select to weigh costs and benefits

Some potential options:

- Least Regrets – select solutions if they are net beneficial in more than one scenario even if other potential solutions have a higher benefit-cost ratio or provide more net benefits in a single scenario
- Weighted Benefits – select solutions based on their probability-weighted average benefits, after assigning probabilities to each scenario studied

Limitation: may not adopt an approach whereby a solution would not be chosen unless it meets the selection criteria in every scenario and sensitivity

Order No. 1920 Requirements

No Selection Requirement

Order No. 1920 does not require transmission providers to select any particular solution—even where it meets the established selection criteria

<u>BUT</u> nothing in Order No. 1920 prohibits transmission providers from imposing upon themselves a requirement to select facilities in certain circumstances

Critically, selection in the regional transmission plan **<u>does not entitle the developer to site or construct</u>** a facility, nor does it obviate the need for the developer to obtain other state, local, and/or federal permits or authorizations

Role of Relevant State Entities

Transmission providers must consult with and seek support from Relevant State Entities regarding the evaluation process and selection criteria

Must demonstrate on compliance that they made good faith efforts to do so

Current SERTP Evaluation Process and Selection Criteria

Evaluation of More Efficient or Cost-Effective Alternatives (Att. K, section 11.2)

- SERTP Sponsors will look for potential regional projects that may be more efficient or cost effective than local projects included in the regional plan
- Evaluation of these projects based on **effectiveness in addressing transmission needs**
- In assessing whether these alternatives may be more efficient or cost effective, the SERTP Sponsors will consider factors such as:
    - Impact on **reliability**
    - **Feasibility and viability** of construction by the required in-service date
    - **Relative transmission cost** as compared to other alternatives

Current SERTP Evaluation Process and Selection Criteria

Proposed transmission projects for possible selection in a regional transmission plan for regional cost allocation purposes (RCAP) (Att. K, sections 15-17)

Threshold Eligibility (Att. K, section 15)

- Solution must be regional in nature - effectuates significant bulk electricity transfers across SERTP region and addresses significant electrical needs
    - 300 kV or greater
    - Located in the SERTP region
    - Spans at least 50 miles
- Cannot be an upgrade to an existing facility, such as
    - Reconductors
    - Addition/modification/replacement of line structures and equipment
    - Increases to nominal operating voltage
- Must be materially different from projects already under consideration in expansion planning process
    - Significant geographical or electrical differences in the interconnection point or routing

Current SERTP Evaluation Process and Selection Criteria

Evaluation and Potential Selection (Att. K, section 17)

Step 1: Evaluation to determine whether, throughout the 10-year planning horizon, the project

1. Addresses an underlying need
2. Could displace project(s) currently in the regional plan
3. Addresses need for which no project is currently included in the regional plan
4. Requires any additional projects to implement it
5. Reduces or increases real power transmission losses

Current SERTP Evaluation Process and Selection Criteria

Step 2: Benefit-to-Cost Analysis on Planning Level Cost Estimates

- Planning level cost estimates developed
- Project must meet a benefit-to-cost (BTC) ratio of at least 1.25 to 1.00 and no individual utility should incur increased, unmitigated transmission costs.
- Benefits considered – beneficiaries' total costs savings associated with displaced projects
  - If BTC 1 or greater, change in real power transmission losses considered
- Costs considered –
  - Cost of the project itself
  - Cost of additional projects required to implement project
- If the project meets or exceeds the 1.25 BTC, it will move forward

Current SERTP Evaluation Process and Selection Criteria

Step 3: Detailed Transmission Benefit-to Costs Analysis

- Transmission developer to identify detailed financial terms for the project
- More detailed BTC analysis performed, with same 1.25 threshold

Step 4: Jurisdictional and/or Governance Authority Review

- State jurisdictional and/or governance authorities of the impacted utilities will be given an opportunity to review the proposal

Current SERTP Evaluation Process and Selection Criteria

Step 5: Selection

- Transmission provider will select project if it determines it is a more efficient or cost-effective project as compared to alternatives
- Factors to be considered will include:
  - Detailed BTC analysis, which may be updated
  - State jurisdictional and/or governance recommendation
  - Developer's ability to construct by the required in-service date
  - Impacted utilities' ability to construct any necessary facilities
  - Updated qualification information on developer's finances or technical expertise
- Transmission provider will post determination on SERTP website

Proposal – Evaluation Process

- **Transparency and clearly defined milestones throughout process**
  - Assessment of scenarios and sensitivities
  - Development of solutions and alternatives
  - Evaluation of solutions and alternatives
  - Selection decision and full rationale for each
- **Portfolio planning the default**
  - Costs and benefits of long-term solutions should be assessed on a portfolio basis each cycle
  - Maintain flexibility to isolate individual lines for consideration if portfolio doesn’t meet selection criteria
- **Expand and formalize role of the Regional Planning Stakeholder Group (RPSG)**
  - Include diverse sectors to capture different perspectives and considerations
  - Empower RPSG to make formal recommendations on portfolio and alternatives
- **Formalize Relevant State Entity role**
  - Stand up a SERTP Regional States Committee
  - Could help streamline State Agreement Process for cost allocation

Proposal – Selection Criteria

- **Prioritize total net benefits over benefit-to-cost ratio**
  - Maximize the value of transmission over the long term (> 20 years)
  - Value = difference between total benefits and total costs on a present value basis
- **Utilize weighted benefits approach**
  - Select solutions based on their probability-weighted average benefits, after assigning probabilities to each scenario studied
- **If used, lower benefit-to-cost ratio**
  - 1 or 1.15-to-1
- **Consider qualitative criteria**
  - Existing rights-of-way, brownfield, highway/transit corridors
  - Relevant State Entity input
  - Environmental justice impacts
- **Make selection criteria presumptively binding**
  - Require a heightened showing to overcome presumption
  - Contingent upon state siting/permitting approval
  - Provides certainty throughout the planning process
  - Could limit to projects that meet a higher benefits or BTC threshold

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NC SUSTAINABLE ENERGY ASSOCIATION

Policy Supporting Alternative Transmission Technologies in Regional Transmission Planning

1.29.2025

Justin Somelofske, Senior Regulatory Counsel, justin@energync.org

NC SUSTAINABLE ENERGY ASSOCIATION

NC Sustainable Energy Association's mission is to drive policy and market development to create clean energy jobs, economic opportunities and affordable energy that benefits all of North Carolina.

Since 1978

Policy

- Advocacy
- Tracking and Updates
- Coalition Building

- NC Utilities Commission
- NC General Assembly
- Executive Branch

Where We Work

FERC Order 1920 on Alternative Transmission Technologies

- Just and Reasonable, and Not Unduly Discriminatory or Preferential Rates now require considering alternative transmission technologies in Long-Term Regional Planning and Order No. 1000 processes. (O.1920 at P 1197-98).
- Require transmission providers in each transmission planning region to consider the following for each identified transmission need:
  - dynamic line ratings
  - advanced power flow control devices
  - advanced conductors
  - and transmission switching

Benefits of Alternative Transmission Technologies

- Maximize Capacity on existing lines
- Supports Interconnection of New Generation & Minimizes Attrition
- Interim Solution as new lines are under construction and not in service
- Lower cost and a smaller footprint
- Improved Reliability and Resilience

States Investigating Grid Enhancing Technologies

FERC Order 1920-A clarified that transmission providers must consider RSE positions as they relate to accounting for factors related to the various states' laws, policies, and regulations. (O.1920-A at P 275-76).

- States Passing Legislation to Explore ATTs/Gets
  - Colorado (SB23-016)
  - Montana (Code 69-3-714)
  - Maine (SB 589)
  - Virginia (HB 862)
  - Minnesota (HF 5247)
  - California (SB 1006)
  - Massachusetts (S.2967)
  - South Carolina (Pending – SB 909)

Duke Energy Carbon Plan IRP

- Amended Settlement is the foundation of the Commission's [2024 Carbon Plan IRP Final Order]

48. That Duke should continue developing a local transmission plan that focuses on identifying least-regrets transmission system upgrades, including the consideration of GETs, that is (1) beneficial across a range of future scenarios, including system stress scenarios (such as extreme weather), and (2) supports the delivery of multiple future resource additions in a manner that maintains or improves the reliability of the grid;

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 190

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. §§ 62-110.9 and 62-110.1(c)	)))))	ORDER ACCEPTING STIPULATION, GRANTING PARTIAL WAIVER OF COMMISSION RULE R8-60A(d)(4), AND PROVIDING FURTHER DIRECTION FOR FUTURE PLANNING

HEARD: Tuesday, April 9, 2024, at 7:00 p.m., in Courtroom 1-A, Buncombe County Courthouse, 60 Court Plaza, Asheville, North Carolina 28801

Wednesday, April 10, 2024, at 7:00 p.m., in Courtroom 5350, Mecklenburg County Courthouse, 832 East Fourth Street, Charlotte, North Carolina 28202

Tuesday, April 23, 2024, at 6:30 p.m., held remotely via Webex

Monday, April 29, 2024, at 7:00 p.m., in Courtroom 317, New Hanover County Courthouse, 316 Princess Street, Wilmington, North Carolina 28401

Tuesday, April 30, 2024, at 7:00 p.m., in Courtroom D7, Durham County

Relationship Between Local & Regional Planning

- Order No. 1000 Process
  - SERTP sponsors each formulate their own local transmission expansion plans.
    - E.g., through the Carolinas Transmission Planning Collaborative (CTPC)
  - SERTP sponsors submit their local transmission plans for inclusion in the regional plan.
  - SERTP sponsors assess whether any regional transmission project alternatives may address transmission needs more efficiently or cost-effectively than any local transmission projects included in the regional transmission plan. (O.1920 at P 1198; Southern OATT, Att. K at 11.1.1)

Relationship Between Local & Regional Planning, cont'd.

- If the SERTP sponsors determine that a regional alternative would displace the need for a local project, they will compare the costs of the regional alternative to the costs of the local project it would displace.
- Order No. 1920 requires that the SERTP sponsors consider the benefits of incorporating the specified ATTs through this process (O.1920 at P 1199).

Questions?

NC SUSTAINABLE
ENERGY ASSOCIATION

Southeast Regional Transmission Needs and Planning Improvements

SERTP ORDER 1920 STAKEHOLDER ENGAGEMENT MEETING

PREPARED BY

J. Michael Hagerty

Peter Heller

Evan Bennett

PREPARED ON BEHALF OF

CLEAN GRID INITIATIVE

JANUARY 29, 2025

Brattle

Southeast Needs to Invest in its Transmission Infrastructure

Facing accelerated 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
- 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

Current Southeast transmission planning process is **reactive** and **narrow in scope**, leading to (1) inefficient transmission investment, (2) longer timeframes for resource additions, and (3) lower reliability at higher cost

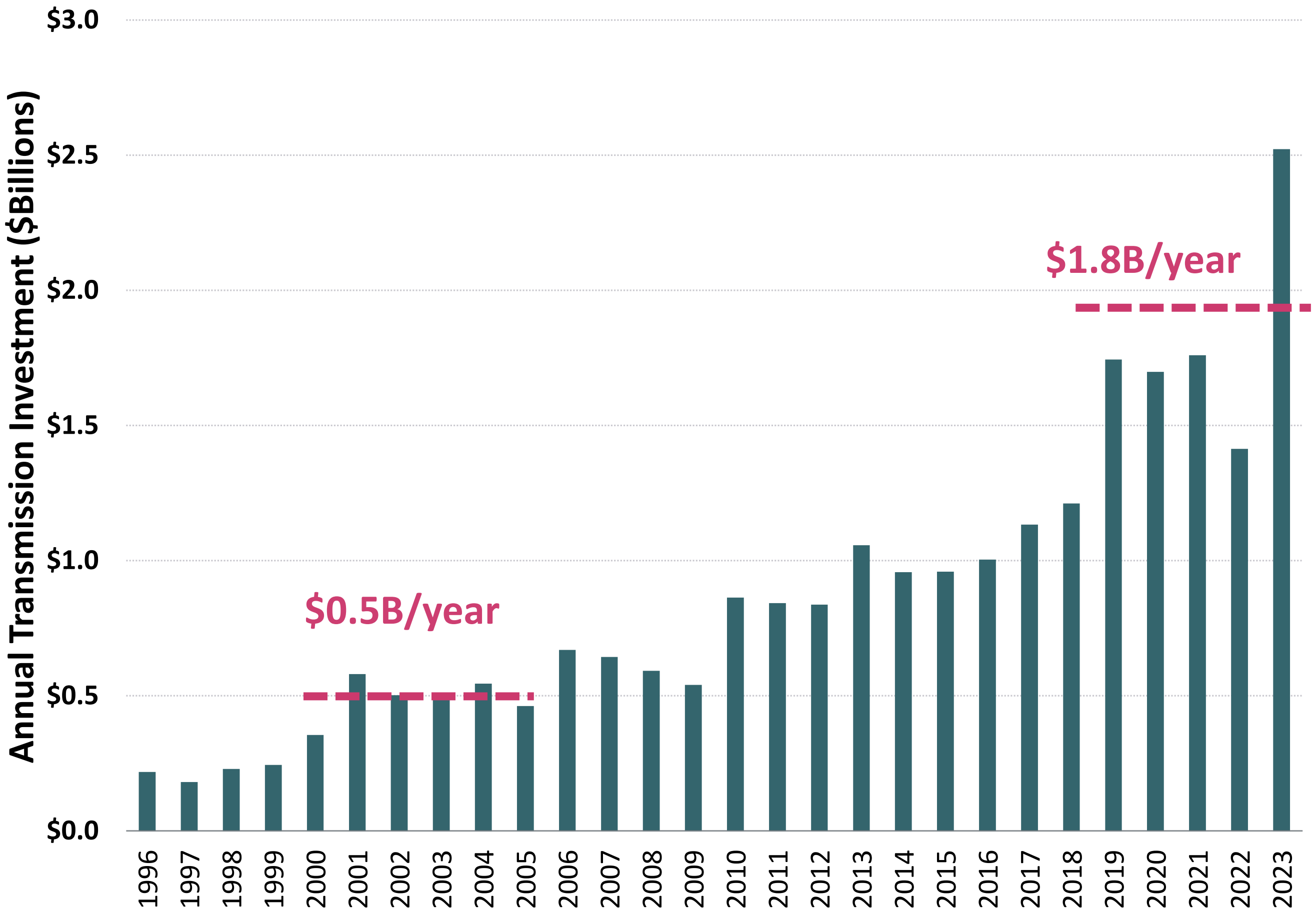
4x Increase in Reliability-Driven Local Transmission Needs

Transmission investment of major investor-owned 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 country) are driven by **local reliability projects** to support load growth, replace aging infrastructure, and generator interconnection

Building local projects can overlook opportunities for more cost-effective transmission upgrades by addressing transmission needs through less-efficient locally-planned projects

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



Sources: The Brattle Group analysis of FERC Form 1 Data

Transmission Needed to Cost Effectively Serve Growing Load

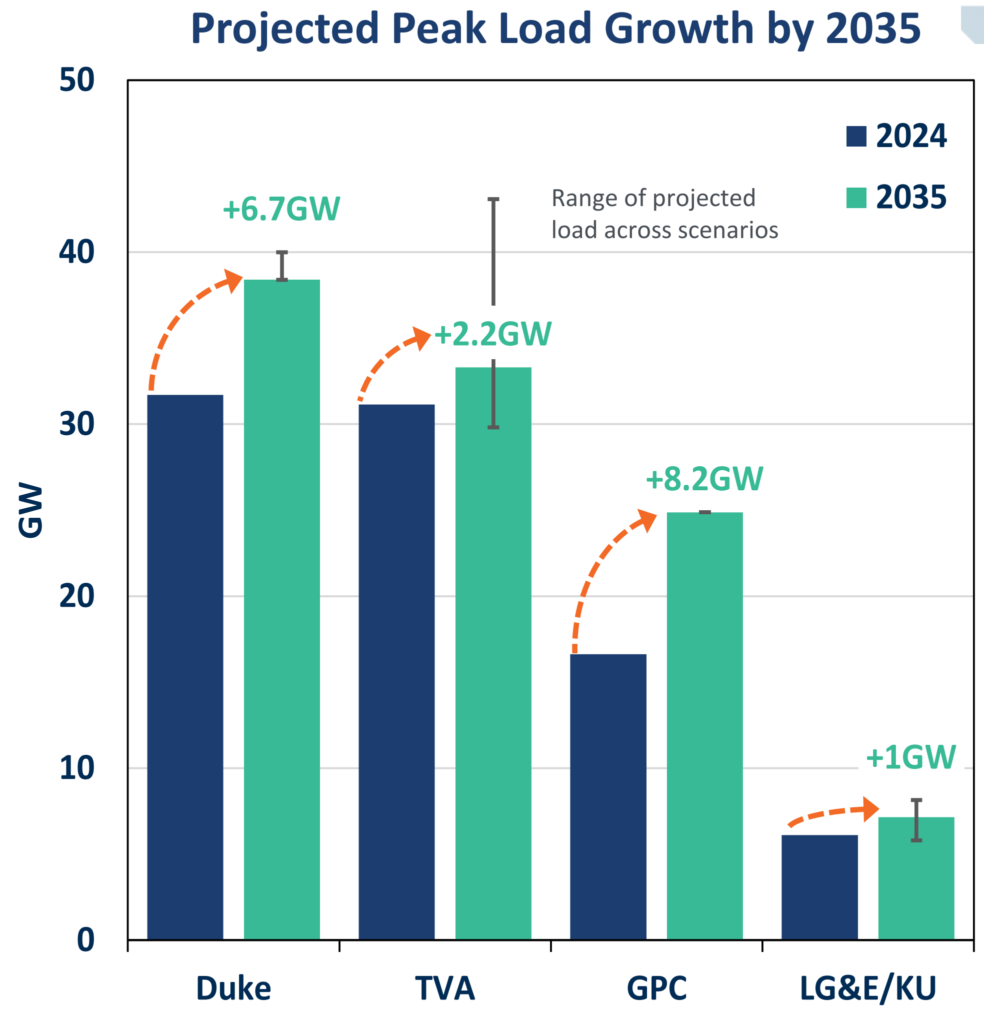
Southeast utilities are projecting 15-35% higher load by 2035 due to new data centers and manufacturing facilities that will drive further transmission system needs

- Duke (DEC/DEP): +7 GW to +9 GW
- TVA: +1 GW to +12 GW across scenarios (base: +2 GW)
- Georgia Power (GPC): +8 GW

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

Effective regional transmission planning can support utilities in meeting multiple needs at an overall lower cost

- Regional transmission planning is comparable to multi-utility capacity sharing agreements in which Southeast utilities have collaborated to collectively manage costs and share the benefits



Regional Transmission Reduces Risks of Extreme Weather

In addition to load growth, recent extreme heat and cold weather events have stressed the Southeast grid and lead to reliability events that could have been avoided with increased regional 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 generation outages, Georgia Power was able to avoid firm load shedding through imports from Florida; similarly, PJM avoided outages across its system by relying on its regional capacity and interregional capacity with MISO to maintain system reliability

Regional and interregional transmission acts as an insurance policy against future extreme conditions by providing access to a wider set of generation resources to serve load that can increase reliability and reduce cost risks for customers

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

Transmission Upgrades De-Risk New Generation Additions

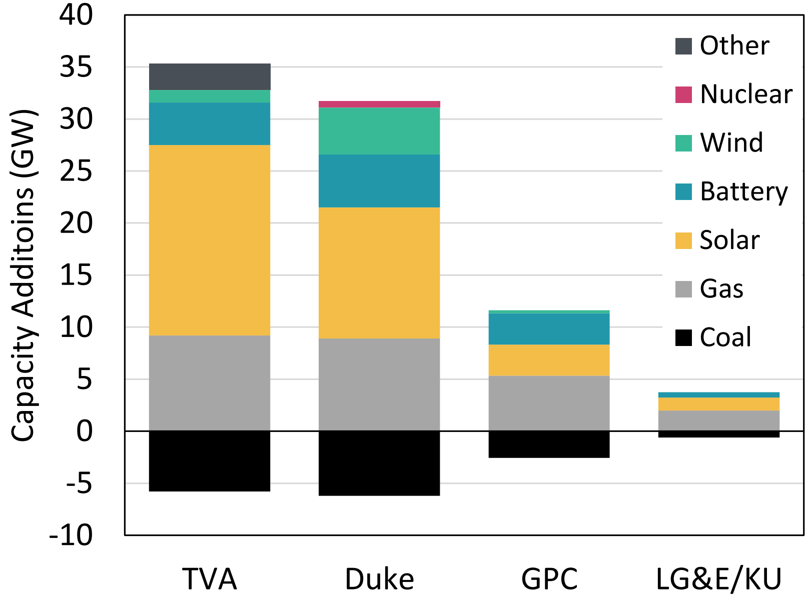
Southeast utilities will need to **interconnect more than 90 GW of new capacity** by 2035 (>10 GW/year) based on recent IRPs

- New generation requires identification and construction of network upgrades prior to interconnection
- Generation resource types are changing due to coal retirements and the addition of new gas, solar, and storage
- New generation resource types and locations will shift flows across the grid and increase regional transmission needs

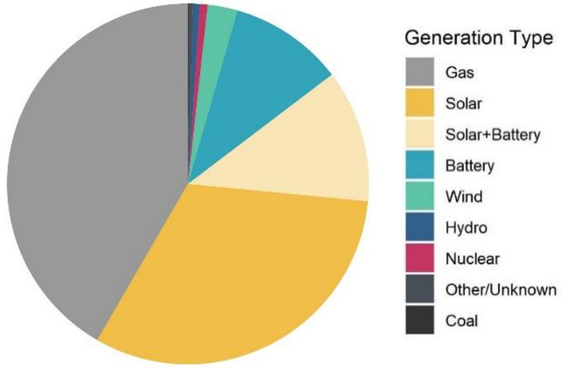
SERTP does not currently study transmission to support the future generation identified in Sponsors' IRPs; instead, higher cost upgrades will be identified based on interconnection studies

Lack of capacity to interconnect resources already identified as needed will slow the pace of generation additions and result in either (1) relying on higher cost resources to serve load or (2) delaying addition of new loads

New Generation Needs in Recent IRPs



Resource Types in Generator Interconnection Queues Across SERTP

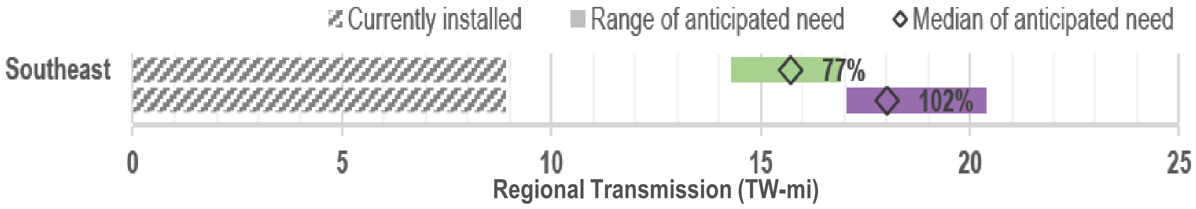


Total: 110 GW

Southeast Transmission Needs Highlighted in Recent Studies

National Transmission Needs Study (2023)

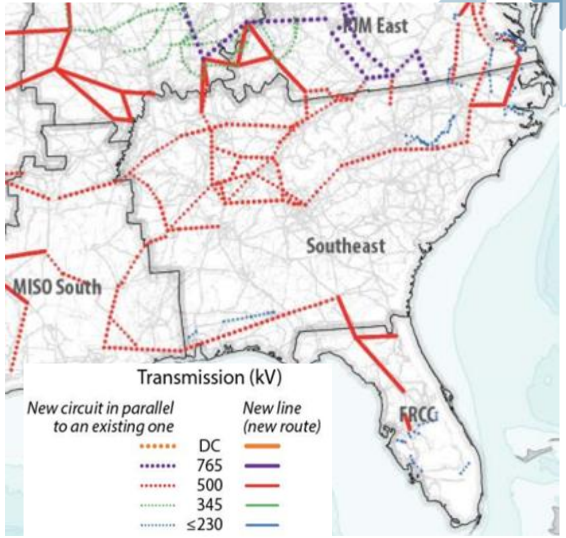
Summarizes 300 future scenarios and sensitivities from 6 independent studies for 2030, 2035, and 2040. By 2035, Southeast will need **7 TW-miles of new within-region transmission** and significant expansion of interregional transmission, ranging from **5.1 – 39.9 TW-miles with neighboring regions**.



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.

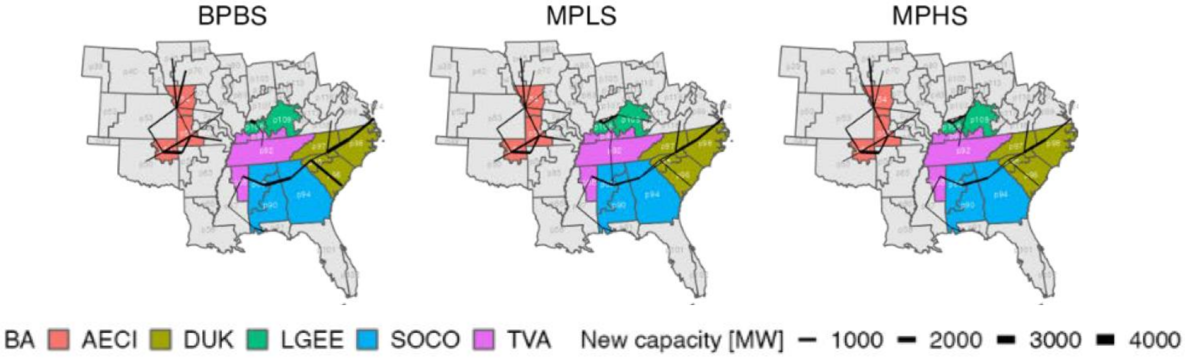
National Transmission Planning Study (2024)

Conducted zonal capacity expansion & 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. **Enables flows across north-south and west-east interfaces to key load centers**.



NREL/LBNL Solar and Storage Integration Study (2024)

Investigates how higher levels of solar and storage impact costs, reliability, and operations in 2035 and the benefits of increased operational coordination among utilities. In lower-solar scenarios, **most additions were regional.**



NREL/LBNL Solar and Storage Integration Study (2024)

Transfer capability analysis between pairs of neighboring transmission planning regions and recommended "prudent" interregional transmission additions to maintain reliability. Transmission expansion into the SERC-E region (DEC/DEP and SCRTP) **is justifiable based on reliability alone**: 2.5 GW by 2033 from the Southeast region and 1.6 GW from PJM to alleviate resource deficiencies in the region.

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)

Regional Transmission Planning vs. Local Planning and IRPs

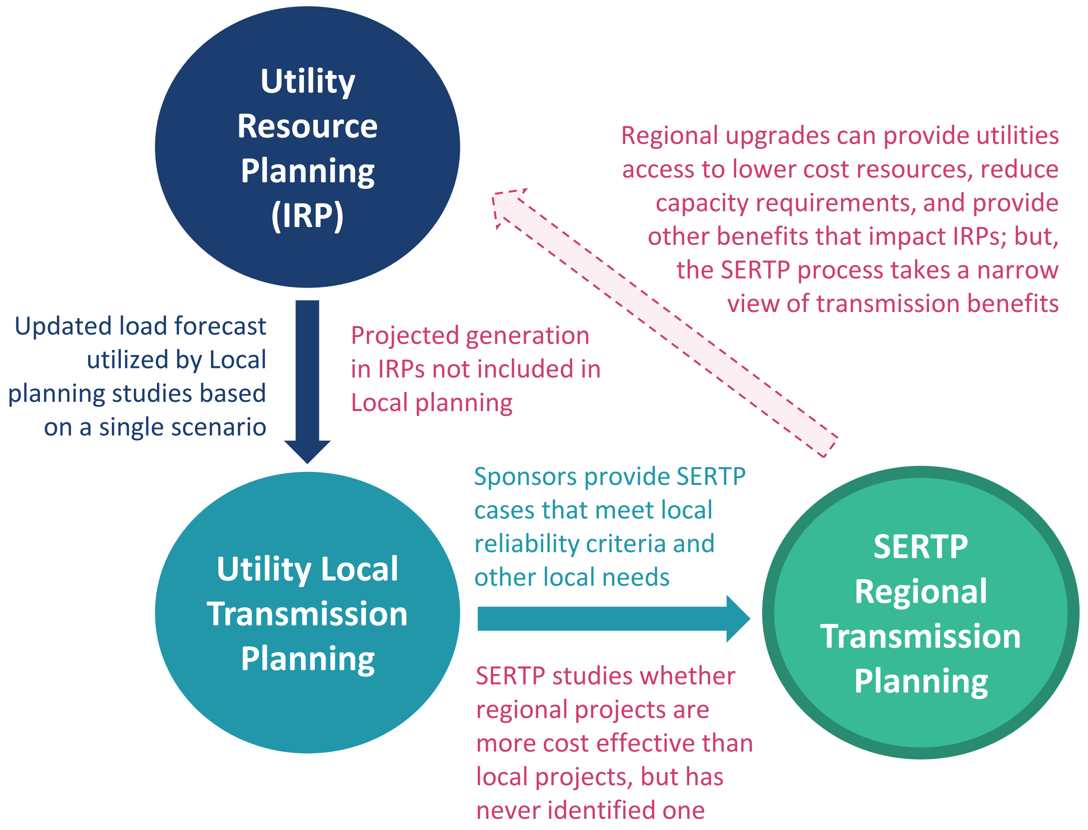
SERTP's regional planning models reflect system conditions studied in each Sponsors' local transmission planning study

- Each Sponsor completes local transmission planning that incorporates the latest load forecast and a limited set of generation additions (i.e., resources with IAs) and retirements
- Sponsors identify local upgrades needed to resolve reliability violations based on NERC criteria
- Duke studies future scenarios and multi-value upgrades via the CTPC MVST local planning process, but the cases it provides to SERTP are based on its local reliability study

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

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

Coordination across Resource Planning and Transmission Planning



SERTP Assumptions are not Aligned with Local Resource Planning

SERTP models system conditions based on Sponsor-provided assumptions:

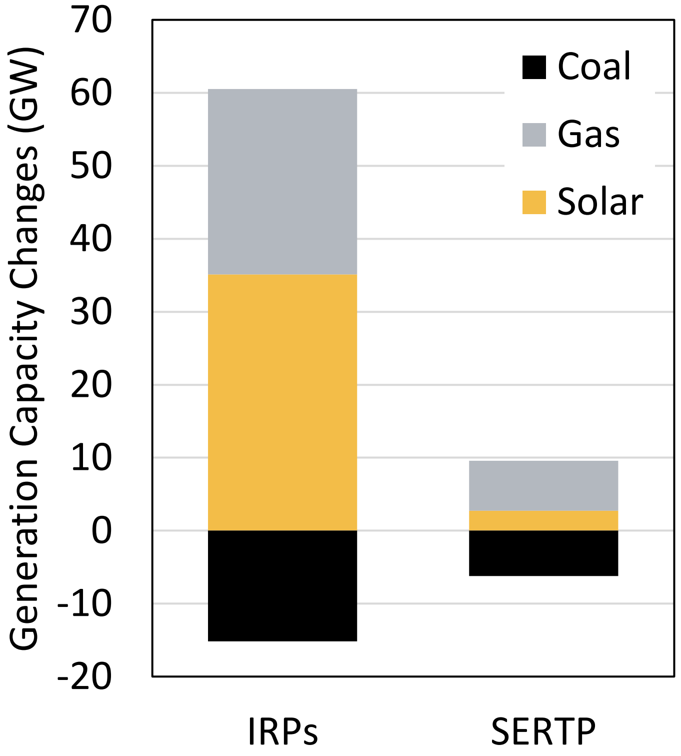
- Load forecasts, which are aggregated into cumulative non-coincident peak summer and winter forecast
- Some changes in generation capacity (including EE and DR)
- Transmission commitments that source/sink across two NERC BAAs

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

- SERTP regional model only includes 8% of solar additions, 27% of gas additions, and 41% of coal retirements identified in the latest TVA, Duke, GPC, and LGE/KU IRPs by 2035
- In some cases, utilities are not including resources that they already requested approval from its state commissions for construction
- SERTP includes hypothetical “proxy units” to ensure there are sufficient resources to meet load, instead of utilizing available IRP portfolios

SERTP’s single future scenario does not assess how the regional system could adapt to uncertainties in future changes (e.g., high growth scenarios or rapidly evolving generation resource mixes)

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



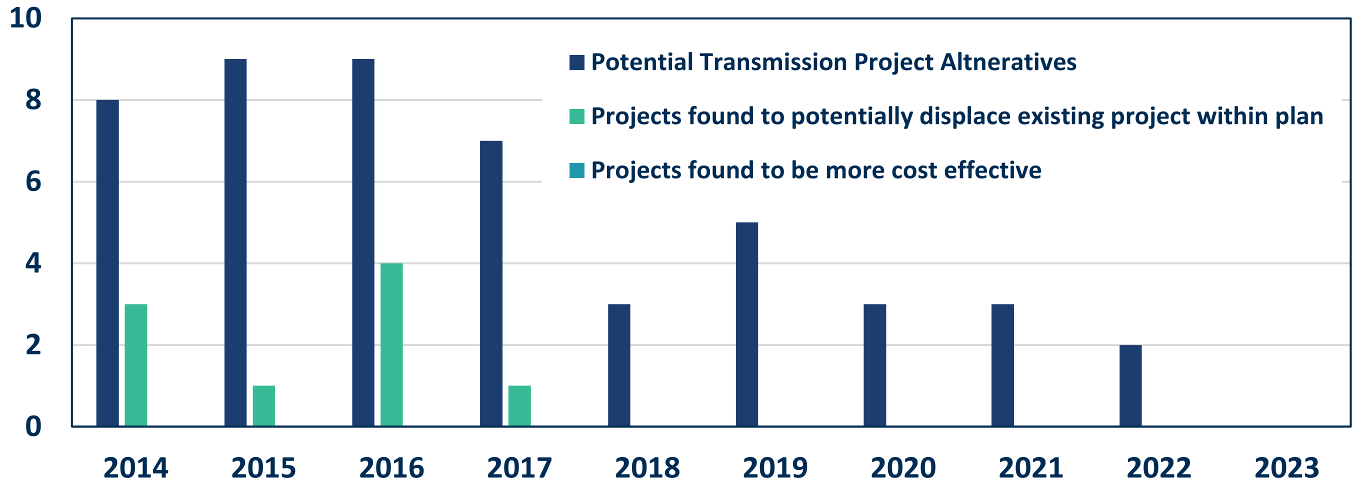
SERTP Has Not Identified Cost-Effective Regional Projects

Based on the 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



Total: 49

Potential displacement: 9

More cost effective: **0**

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 Can Build on Order 1920 to Improve Regional Planning

FERC Order 1920 better aligns regional planning with industry-wide best practices that have been implemented across the country for comprehensively assessing long-term regional transmission needs

Southeast utilities will need to update its 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

SERTP is in the process of developing its Order 1920 compliance filing and seeking input from stakeholders; in parallel, SERTP is conducting an engagement period with Relevant State Entities

Framework for Improved SERTP Regional Planning Process

Experience across the industry over the past 10-20 years provides several 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: the anticipated generation mix, public policy mandates, load levels, and load profiles 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 takes into account all transmission needs for a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme 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

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

Enhanced SERTP Regional Transmission Planning will Reduce Costs and Increase Reliability of the Southeast Grid

Implementing the following recommendations will improve SERTP transmission planning and support the development of cost-effective regional projects to supplement local transmission projects

Improve Existing SERTP Planning Process

1. **Increase transparency** of SERTP planning input assumptions and study results (inc. project costs)
2. **Engage state commissions/ agencies** to identify needs to reduce customer costs and address state energy policies
3. Expand solutions studied to reflect a **least-cost "loading order"** that maximizes existing grid, upgrades existing lines, and build new lines

Expand SERTP Planning Capabilities

4. Develop **multiple future scenarios to plan for a range of** load growth and generation resource outlooks
5. Identify congestion and quantify production cost savings via **regionwide production cost model**
6. Account for **comprehensive set of cost savings & other benefits** when analyzing regional upgrades

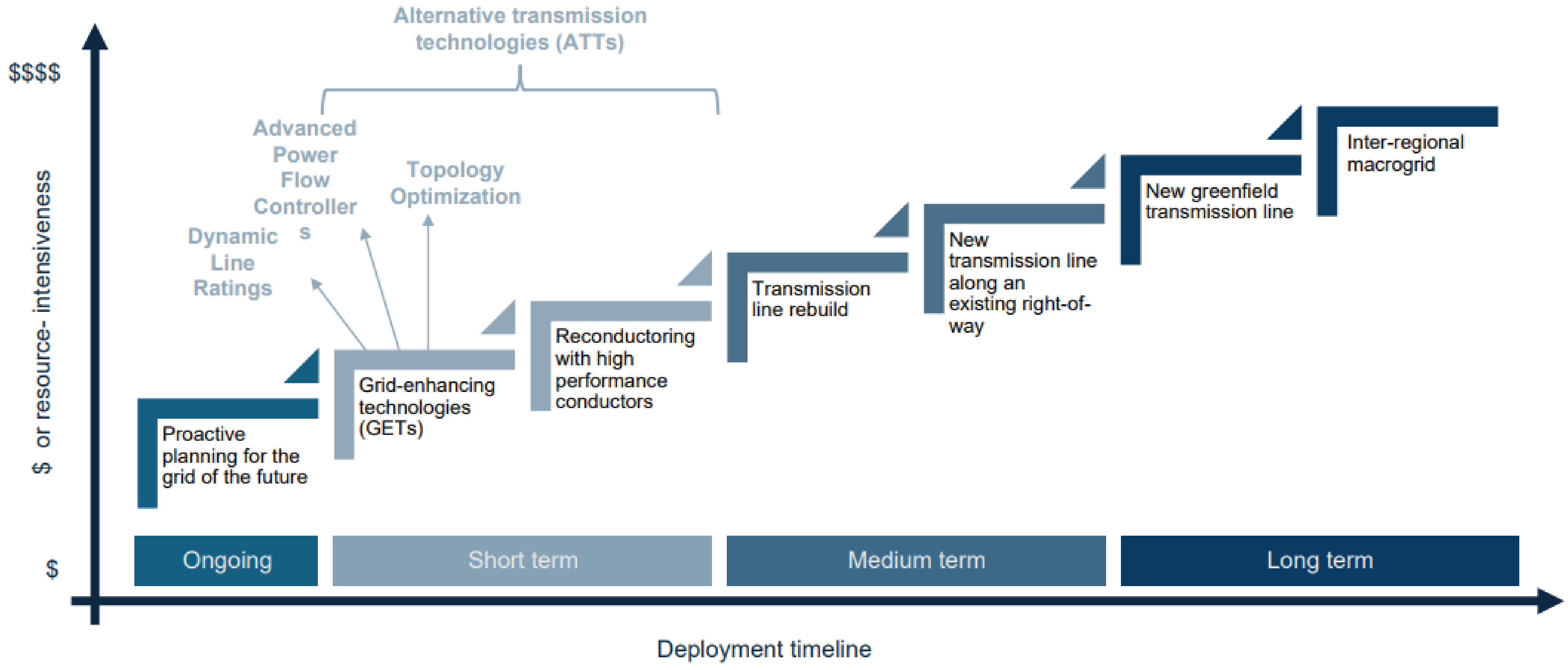
Implement Comprehensive & Proactive Planning Process

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

Expand Solutions to Reflect a Least-Cost “Loading Order”

Serving near-term load growth while maintaining an affordable system requires planners to:

- Maximize the capability of the existing grid using GETs and Remedial Action Schemes (RAS)
- Proactively identifying upgrades to the existing system and new builds to add capability



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

Study Broader Set of Regional Cost Savings of Transmission

SERTP can take advantage of the best practices developed across the industry over the past 20 years for estimating transmission benefits

- Analytical approaches for quantifying transmission benefits have been documented in a report submitted to FERC in the ANOPR process and highlighted in Order 1920
- Regional planners have implemented these analyses in studies to justify major investments in regional transmission

Additional approaches continue to be developed to 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

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

Planners Identified Upgrades based on Expanded Cost Savings

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*
   - capacity benefit
   - energy cost 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 Analysis

(DPV2 example)

Quantified

1. **production cost savings*** and reduced energy prices from both a societal and customer perspective
2. mitigation of market power
3. insurance value for high-impact low-probability events
4. capacity benefits due to reduced generation 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 PPTN Analysis

(AC Upgrades)

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

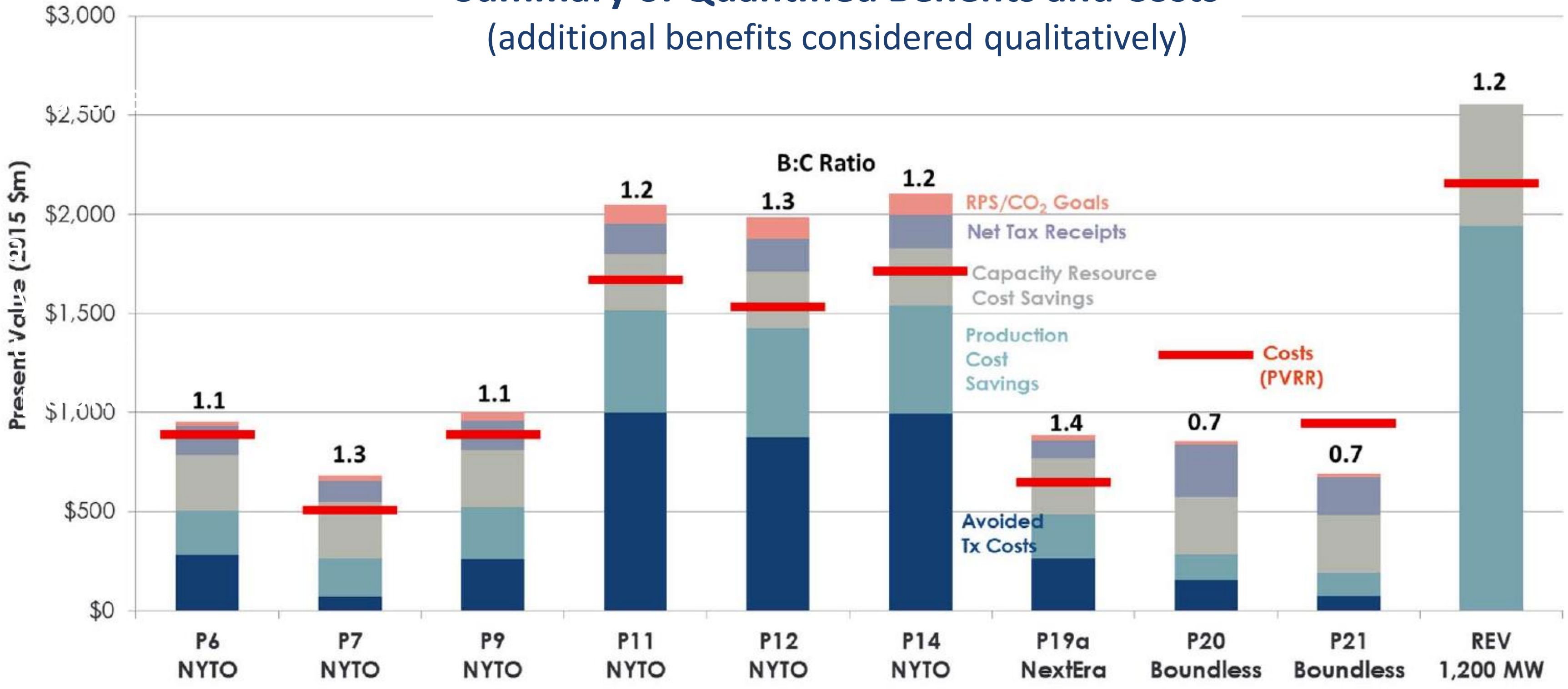
(Newell, et al., Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades, September 15, 2015)

* Fairly consistent across RTOs

New York's Multi-Value Transmission Planning Process

New York DPS modified its regional planning process by mandating that a **full set of benefits be considered**, resulting in approval and competitive solicitation of two major upgrades to the New York transmission infrastructure that have reduce costs across the state

Summary of Quantified Benefits and Costs
(additional benefits considered qualitatively)



Source: "Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades," September 15, 2015

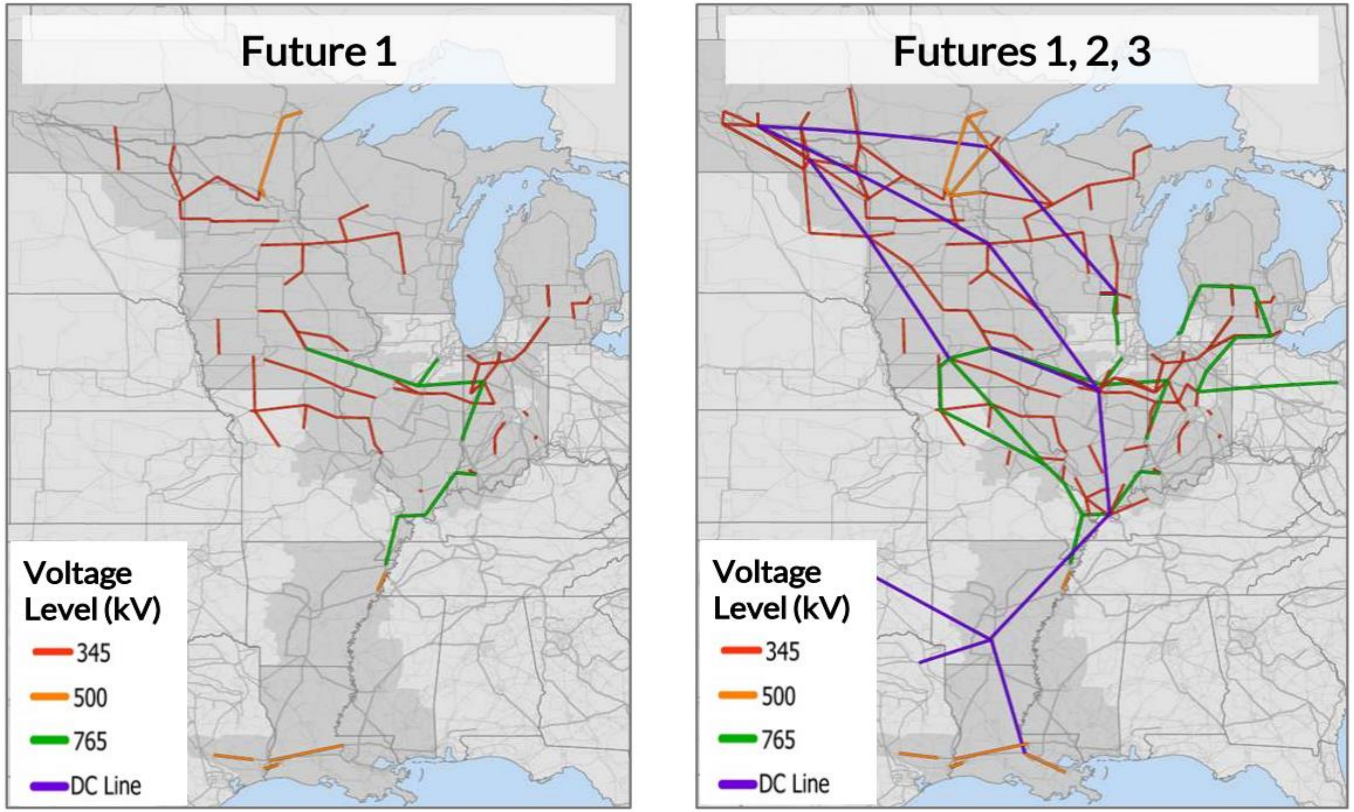
Example: MISO Long-Term Transmission Planning (LRTP)

MISO's LRTP Tranche 1 and 2 efforts evaluated 20-year reliability, economic, and policy needs for a diverse set of plausible "Futures" (scenarios) that accounted for uncertainty in load growth and generation

MISO's 2022 LRTP Process

1. Develop scenario-based Futures with resource forecast and Siting
2. Development of planning models utilizing Futures
3. Identify potential transmission issues
4. Proposals for solutions to issues
5. Evaluate the effectiveness of various solutions
6. Recommend preferred solutions for MTEP implementation
7. Apply appropriate cost allocation

MISO's Identified Long-Term Transmission Needs



Source: MISO LRTP Roadmap March 2021

Example: MISO Long-Term Transmission Planning (LRTP)

Scenario-based LRTP resulted in a first tranche of a new "least regrets" portfolio of multi-value transmission projects (MVPs)

MISO 2022 LRTP RESULTS

- Tranche 1: $10 billion portfolio of proposed new 345 kV projects for its Midwestern footprint
- Supports interconnection of 53,000 MW of renewable resources
- Reduces other costs by $37-70 billion
- Portfolio of beneficial projects designed to benefit each zone within MISO's Midwest Subregion
- Postage-stamp cost allocation within MISO's Midwest Subregion

MISO 2022 LRTP, Tranche 1 Projects

Source: 3-29-22 LRTP Presentation (misoenergy.org)

Example: CTPC/Duke Multi-Value Strategic Transmission (MVST)

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 updated its local planning tariff to include MVST and is implementing the first MVST study:

- Modeling **3 future scenarios** based on Duke's projected load and IRP-developed generation portfolios
- Consideration of **GETs, advanced conductors, Remedial Action Schemes (RAS), and storage**
- Evaluation of a **portfolio of transmission upgrades** over the **full life of the assets**
- Quantifying **multiple benefits of transmission**: (1) avoided capacity costs, (2) capacity and energy savings from reduced losses, (3) congestion and fuel savings, (4) avoided customer outages, and (5) avoided transmission investment

Clarity in the face of complexity

Brattle

COST ALLOCATION OF TRANSMISSION PROJECTS IN SPP

CLINT SAVOY

SERTP STAKEHOLDER ENGAGEMENT SESSION

JANUARY 29, 2025

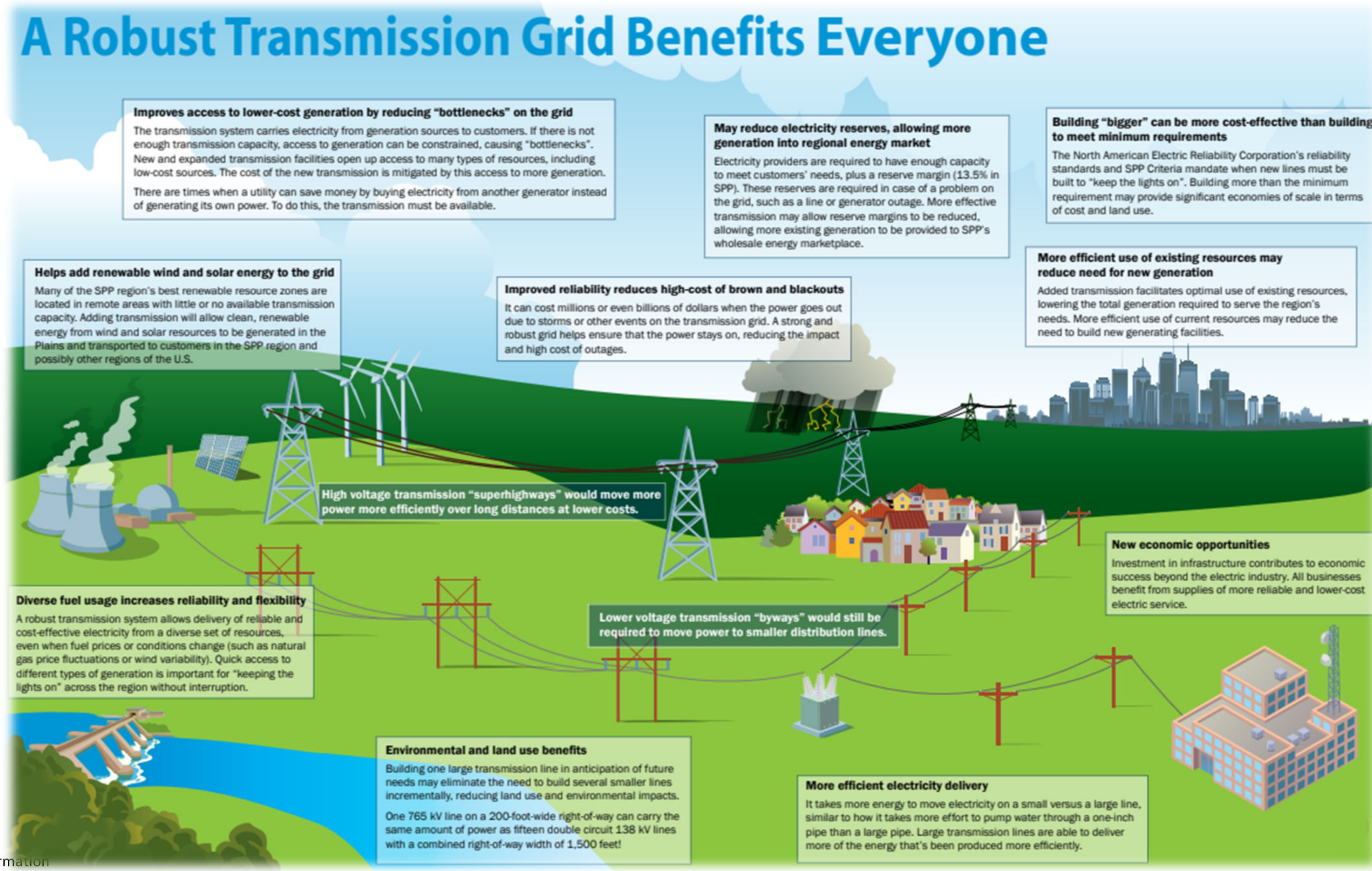
Who benefits from a robust transmission grid?

Who makes cost allocation decisions for the SPP Transmission System?

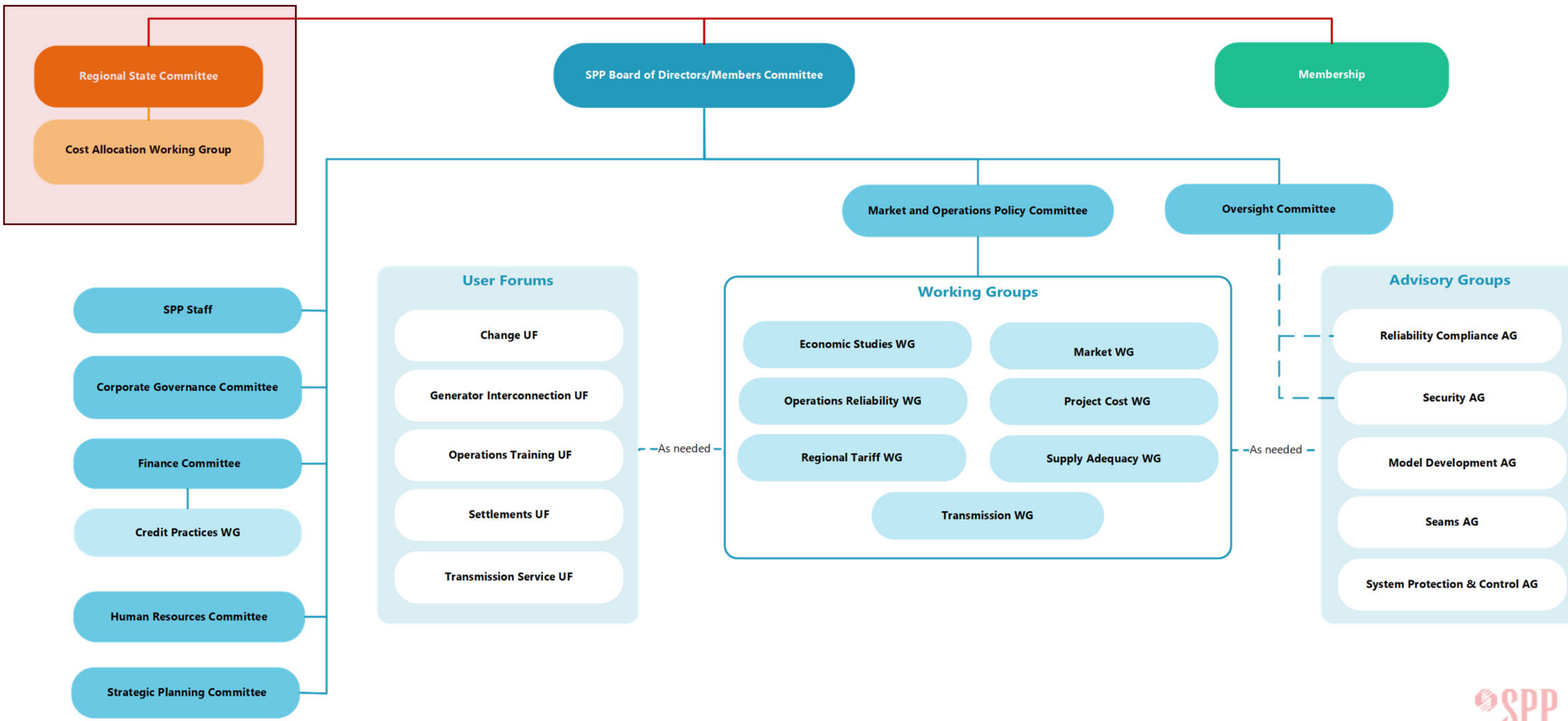
What processes do allocable costs come from?

Who pays for transmission projects from the different processes?

How do we ensure benefits are commensurate with costs?


A Robust Transmission Grid Benefits Everyone
Improves access to lower-cost generation by reducing "bottlenecks" on the grid
The transmission system carries electricity from generation sources to customers. If there is not enough transmission capacity, access to generation can be constrained, causing "bottlenecks". New and expanded transmission facilities open up access to many types of resources, including low-cost sources. The cost of the new transmission is mitigated by this access to more generation.
There are times when a utility can save money by buying electricity from another generator instead of generating its own power. To do this, the transmission must be available.
May reduce electricity reserves, allowing more generation into regional energy market
Electricity providers are required to have enough capacity to meet customers' needs, plus a reserve margin (13.5% in SPP). These reserves are required in case of a problem on the grid, such as a line or generator outage. More effective transmission may allow reserve margins to be reduced, allowing more existing generation to be provided to SPP's wholesale energy marketplace.
Building "bigger" can be more cost-effective than building to meet minimum requirements
The North American Electric Reliability Corporation's reliability standards and SPP Criteria mandate when new lines must be built to "keep the lights on". Building more than the minimum requirement may provide significant economies of scale in terms of cost and land use.
Helps add renewable wind and solar energy to the grid
Many of the SPP region's best renewable resource zones are located in remote areas with little or no available transmission capacity. Adding transmission will allow clean, renewable energy from wind and solar resources to be generated in the Plains and transported to customers in the SPP region and possibly other regions of the U.S.
Improved reliability reduces high-cost of brown and blackouts
It can cost millions or even billions of dollars when the power goes out due to storms or other events on the transmission grid. A strong and robust grid helps ensure that the power stays on, reducing the impact and high cost of outages.
More efficient use of existing resources may reduce need for new generation
Added transmission facilitates optimal use of existing resources, lowering the total generation required to serve the region's needs. More efficient use of current resources may reduce the need to build new generating facilities.
High voltage transmission "superhighways" would move more power more efficiently over long distances at lower costs.
New economic opportunities
Investment in infrastructure contributes to economic success beyond the electric industry. All businesses benefit from supplies of more reliable and lower-cost electric service.
Diverse fuel usage increases reliability and flexibility
A robust transmission system allows delivery of reliable and cost-effective electricity from a diverse set of resources, even when fuel prices or conditions change (such as natural gas price fluctuations or wind variability). Quick access to different types of generation is important for "keeping the lights on" across the region without interruption.
Lower voltage transmission "byways" would still be required to move power to smaller distribution lines.
Environmental and land use benefits
Building one large transmission line in anticipation of future needs may eliminate the need to build several smaller lines incrementally, reducing land use and environmental impacts.
One 765 kV line on a 200-foot-wide right-of-way can carry the same amount of power as fifteen double circuit 138 kV lines with a combined right-of-way width of 1,500 feet!
More efficient electricity delivery
It takes more energy to move electricity on a small versus a large line, similar to how it takes more effort to pump water through a one-inch pipe than a large pipe. Large transmission lines are able to deliver more of the energy that's been produced more efficiently.

SPP ORGANIZATION STRUCTURE



AUTHORITY OF THE RSC

4 Areas of Authority	Description	Used
Cost Allocation	Whether participant funding will be used for transmission enhancements & whether license plate or postage stamp rates will be used for the regional access charge	13
Financial Transmission Rights (FTRs)	FTR allocation, where a locational price methodology is used; and the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights	3
Planning for Remote Resources	Whether transmission upgrades for remote resources will be included in the regional transmission planning process and the role of transmission owners in proposing transmission upgrades in the regional planning process	3
Resource Adequacy	Determine the approach for resource adequacy across SPP	9

"As the RSC reaches decisions on the methodology that will be used to address any of these issues, SPP will file this methodology pursuant to Section 205 of the Federal Power Act. However, nothing in this section prohibits SPP from filing its own related proposal(s) pursuant to Section 205 of the Federal Power Act." – SPP Bylaws § 7.2

WHAT PROCESSES DO ALLOCABLE COSTS COME FROM?

Member-driven, regional studies

Integrated Transmission Planning

- Annual planning cycle
- Near-and long-term needs
- Economic & reliability needs
- Costs determined by SPP highway/byway methodology

Interregional Projects

- Collaborate with neighboring regions on joint projects
- Regional new transmission split between each organization
- JTIQ new transmission costs split by service customer and load

Customer-Initiated, Customer-Focused studies

Generation Interconnection Studies

- Determines transmission needed to connect new generation to grid
- Direct assigned shared costs of study and new transmission

Aggregate Transmission Service

- Determines transmission needed for firm service request
- Eligible for some base plan funding for shared costs of new transmission
- Study costs shared amongst customers

Sponsored Upgrades

- Provides a path for new transmission facilities not identified in any other planning processes
- Direct assigned costs for study and new transmission

Delivery Point Addition or Modification

- Provides transmission needs to connect load additions or modifications
- *New transmission costs are base plan funded
- *Study costs direct assigned to customer

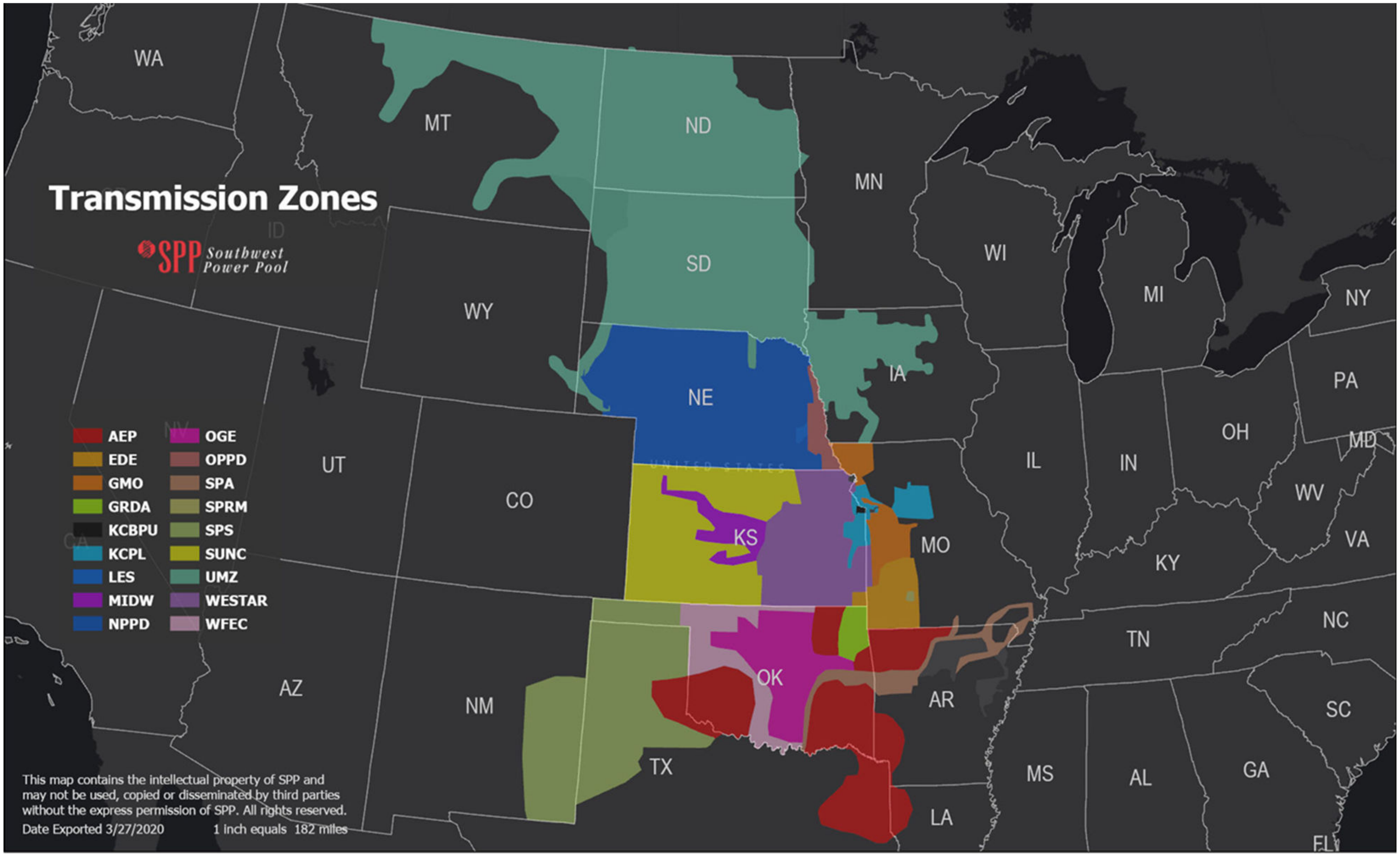
WHO PAYS FOR TRANSMISSION PROJECTS?

- **Sponsored**: Project owner builds and receives credit for use of transmission lines
- **Directly-assigned**: Project owner builds and is responsible for cost recovery and receives credit for use of transmission lines
- **Highway/Byway**: Most SPP projects paid for under this methodology

Voltage	Region Pays	Local Zone Pays
300 kV and above	100%	0%
above 100 kV and below 300 kV	33%	67%
100 kV and below	0%	100%

Regional Cost Allocation Review Process

- SPP periodically performs a review of the zonal benefits and costs associated with transmission upgrades funded under the Highway-Byway method
- Performed every 6 years, increased from every 3 years ~2016
- Adjustments to costs allocated to zones with <1.0 B/C ratio may be made
- Regional Allocation Review Task Force (RARTF) guides SPP staff's conduct of the study process


Transmission Zones
SPP Southwest Power Pool
AEP
EDE
GMO
GRDA
KCBPU
KCPL
LES
MIDW
NPPD
OGE
OPPD
SPA
SPRM
SPS
SUNC
UMZ
WESTAR
WFEC
WA
MT
ND
MN
SD
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Date Exported 3/27/2020
1 inch equals 182 miles

WHAT QUESTIONS DO YOU HAVE?

APPENDIX

ADDITIONAL DETAILS

ACTIVITIES OUTSIDE SPP'S SCOPE

- Transmission siting
- Generation planning/siting
- Transmission/generation construction
- Transmission/generation permitting

REVISED BASE PLAN -"HIGHWAY/BYWAY"

- Applies to Network Upgrades directed for construction by SPP after June 2010
- The ATRR total is about $590 million, of which $212 million is allocated to zones and $379 million is allocated to the region
- Who bears the cost:

• Voltage < 100 kV	100% to the Zone of construction
	- Within Zone, Base Plan Zonal LRS
• 100 kV < Voltage < 300 kV	67% to the Zone of construction
	- Within Zone, Base Plan Zonal LRS
	33% allocated with Region-wide LRS
• Voltage > 300 kV	100% allocated with Region-wide LRS

- Tariff sections: Att. J, Sec. III; Att. H, Tables 1 and 2

BASE PLAN WIND POWER EXCEPTION

- When a Transmission Customer with service from a wind power project requires an upgrade located in a different Zone from the Transmission Customer's load, the following allocation is followed:
  - Voltage < 300 kV — 33% directly assigned to the Customer; 67% allocated with region-wide LRS; 0% to a zone
  - Voltage > 300 kV — 100% allocated with region-wide LRS

- Tariff reference: Att. J, Sec. III.A.4

DIRECT ASSIGNMENT

- Engineering and Construction (E&C) Cost
  - Generator Interconnection Network Upgrades
    - Compensation available through Att. Z2 (ILTCRs and credits)
  - Interconnection Facilities, which are sole-use upgrades
    - Compensation not available through Att. Z2
- Revenue Requirements Over a Specified Term
  - Service Upgrades
  - Sponsored Upgrades (maximum of 20 years)

REVENUE CREDITS AND ILTCRS

- Attachment Z2 provides potential compensation for entities that bear directly assigned costs for Network Upgrades (Upgrade Sponsors)
- For upgrades approved under agreements by or before July 1, 2020, the compensation can be either revenue credits from subsequent transmission service utilizing the upgrade or Incremental Long-term Transmission Congestion Rights (ILTCRs)
- For upgrades under agreements after July 1, 2020, the compensation can be only through ILTCRs
- Revenue Credits under Attachment Z2
  - The revenue credits from subsequent service are funded through three sources: Base Plan funding, PTP revenue not used to fund upgrade construction, and direct assignment charges
  - The Base Plan funded portion of revenue credits is about $36 million annually, of which $13 million is allocated to zones and $23 million is allocated to the region

SPP COST ALLOCATION FOR INTERREGIONAL PROJECTS & OTHER TRANSMISSION PROVIDER PROJECTS

- The ATRR associated with the costs allocated to the SPP Region for approved Interregional Projects are allocated on a region-wide basis.
  - Includes SPP's allocated portion of the ATRR for Interregional Projects constructed within the SPP Region and/or within other Interregional Planning Regions
- The cost allocation for SPP's allocated portion of the ATRR for projects constructed in collaboration with another Transmission Provider, but that do not qualify as Interregional Projects (e.g., Morgan Transformer Project), is determined on a project-by-project basis.

- Tariff sections: Att. J, Sec. VI; Att. H, Sec. I.2; Att. O, Section VIII

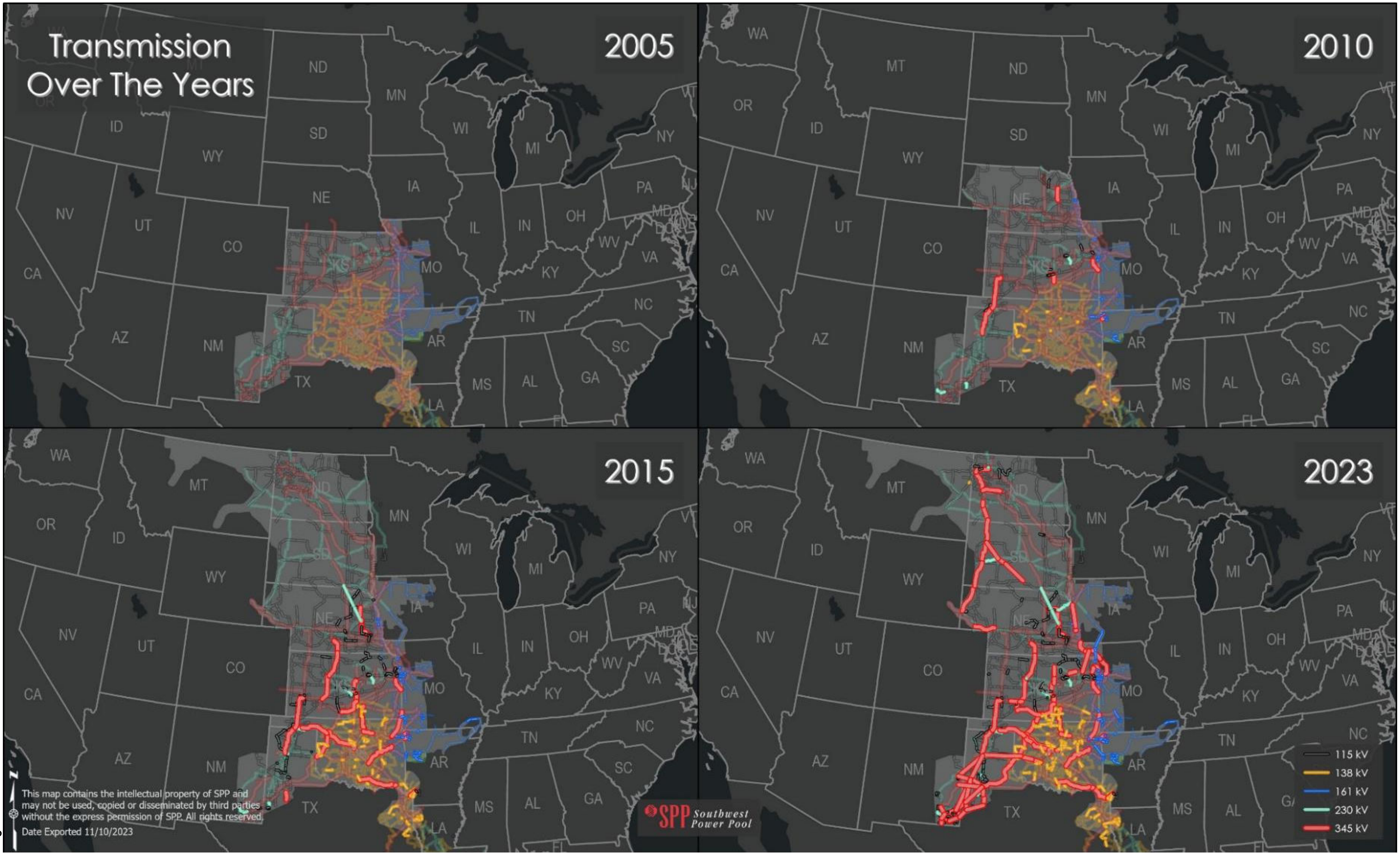
REGIONAL COST ALLOCATION REVIEW

- Attachment J, Sec. III.D provides a process to review the zonal benefits and costs associated with transmission upgrades funded under the Highway-Byway method
- After implementation of the Highway-Byway method in 2010, the Regional Cost Allocation Review (RCAR) was to be conducted every 3 years
- After the first two studies, the interval between studies was changed to 6 years
- The Regional Allocation Review Task Force (RARTF) guides SPP staff's conduct of the study process
- Several zonal benefit metrics have been used to compare against zonal cost:
  - Adjusted production cost, Avoided reliability projects, Capacity savings from reduced losses, Reduced transmission outage costs, Reliability benefits, Increased wheeling revenues, Reduced energy losses, and Point-to-point revenue from service sinking outside of SPP.

VALUE OF TRANSMISSION

SPP's regional transmission expansion planning creates real value for our members

- **$3.35 billion:** 2015-2019 installed transmission
- **$5.19 billion:** 40-year net present value of ATRR cost
- **$27.2 billion:** Net present value of quantified benefits
- **5.24 to 1**: Benefit-to-cost ratio



Transmission Over The Years
2005
2010
2015
2023
115 kV
138 kV
161 kV
230 kV
345 kV
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Date Exported 11/10/2023
SPP Southwest Power Pool