Southeast Energy Vision:
Achieving Reliability and Net Zero Emissions while Supporting Rapid Load Growth

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Notice

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Southeast Study Overview

Study Question: How can the Southeast cost-effectively meet growing electricity demand and support net-zero emissions goals by 2050 while maintaining resource adequacy across a wide range of future system conditions?

SERC region faces growing resource adequacy needs as regional demand grows and existing facilities retire. Large loads and weather extremes are creating tighter operational conditions. At the same time, interconnection and construction constraints are delaying new resource deployment.

This study evaluates several key issues for maintaining resource adequacy across the Southeast grid while reducing GHG emissions:

1. How resource adequacy needs evolve, when planning for a range of weather risk, including winter cold snaps and low solar reliability conditions.
2. What resource mix is required through 2040 to maintain reliability and support long-term decarbonization objectives.
3. The value of transmission utilization, regional coordination, and energy transfers in reducing local capacity requirements and system costs.
4. The value of load flexibility in reducing peak capacity needs, shifting demand to periods of renewable availability.
5. The role of firm resources, storage, and demand-side flexibility in maintaining reliability during the most challenging system conditions.

Evaluation: Projection of resource adequacy needs and cost-effective future resource mix in each SERC region through 2040, considering a range of weather challenges

This analysis demonstrates how **SERC-wide regional coordination and greater use of transmission for energy and capacity transfers** can reduce local capacity needs and lower the cost of the optimal resource mix.

Results also show how **load flexibility** can shift demand away from winter peak periods, reducing resource adequacy requirements and support a lower-cost resource portfolio.

The analysis highlights how solar + storage and clean-firm (e.g., nuclear) technologies provide a hedge against winter reliability challenges, particularly during cold-weather periods when solar output is limited.

Study Approach: "Dynamic" resource adequacy with Weather-Reflective Advanced Sampling (WRAS) and Capacity Expansion

We employ a state-of-the-art approach to capacity expansion using Brattle's **gridSIM and WRAS tools** by evaluating reliability needs across 15 years of historical weather conditions, including heat waves, winter cold snaps, and low-solar periods that occur during critical winter reliability events.

Resource adequacy is evaluated on an hourly basis, wherein the system is expanded to maintain reliability by meeting capacity and energy needs in every hour, not just during normalized peak conditions.

Within this framework, we evaluate how various factors (solar + storage, intraregional trade dynamics, higher utilization of firm transfer capability, and load flexibility) can optimally address resource adequacy challenges.

Southeast Energy Vision Study Objective and Scope

Objective: Evaluate the resource adequacy needs and optimal resource mix to meet projected electricity demand and support net-zero emissions goals by 2050 across the Southeast through 2040, while accounting for weather-driven reliability risks, transmission constraints, and regional resource diversity.

Footprint: Three SERC zones (Central, East, Southeast) plus neighboring regions (PJM East, MISO Central/South, Florida) to capture geographic diversity in load and generation resources, with seasonal limits on energy and capacity transfers.

Study Time Horizon: 2024–2040 with hourly balancing over representative multi-day periods capturing heat waves, cold snaps, renewable droughts, in addition to normalized conditions.

Weather and Resource Adequacy Sampling (WRAS): To simulate resource adequacy needs and project optimal resource mix, each model year is represented by 32 weighted 72-hour (3-day) periods drawn from 15 historical weather years to capture and simulate variation in weather and tightness in system conditions.

Key Results: Projections of regional resource mix and hourly generation, energy and capacity transfers, system costs, and key drivers of resource adequacy, including when/where reliability risk occurs (not just peak-based targets).

Regional Scope of Modeling with Energy + Capacity Transfer Limits

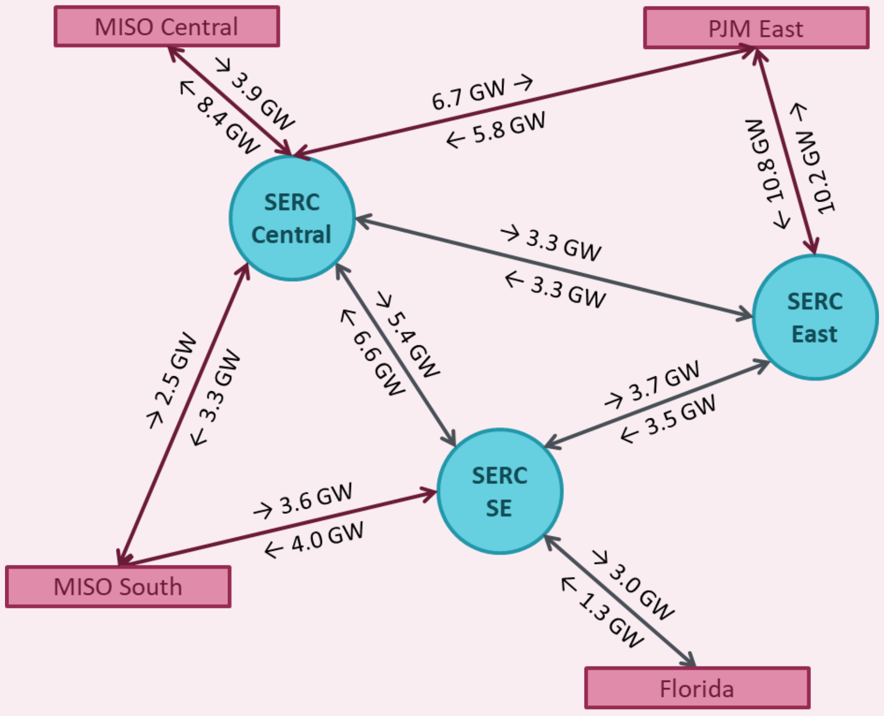
The tables below show simultaneous import limits for each of the three modeled SERC regions.

SERC Central Import Limits		
Season	**Energy**	**Capacity**
Spring	4.1 GW	2.8 GW
Summer	6.4 GW	2.8 GW
Fall	5.7 GW	2.8 GW
Winter	7.4 GW	2.8 GW

SERC East Import Limits		
Season	**Energy**	**Capacity**
Spring	3.4 GW	1.9 GW
Summer	4.5 GW	1.9 GW
Fall	4.0 GW	1.9 GW
Winter	4.2 GW	1.9 GW

SERC Southeast Import Limits		
Season	**Energy**	**Capacity**
Spring	3.6 GW	1.2 GW
Summer	4.5 GW	1.2 GW
Fall	4.0 GW	1.2 GW
Winter	4.2 GW	1.2 GW

The zonal topology shows the simulated maximum hourly path-specific energy transfer capabilities. Together with the simultaneous transfer limits (tables on the left), we model intra- and inter-regional firm and non-firm transfer capabilities of the current SERC transmission system.



gridSIM: Brattle's Next-Gen Capacity Expansion Model

Brattle's Capacity Expansion Model minimizes the net present value of system costs to serve load given resource costs and performance characteristics, transmission, and energy regulations and policies, providing optimized power system build-out and dispatch for given scenario conditions

Co-optimized modeling and pricing of energy and capacity markets

Multi-Zone representation of the Southeast, with power flow within the Southeast and between neighboring RTOs (e.g., MISO and PJM)

Chronological commitment and dispatch to model storage and demand response; state-of-the-art representative days for hourly detail and capturing weather uncertainty and variation

Energy Regulations and Decarbonization Policies will be modeled in a variety of ways – state mandated clean energy policies (e.g., RPS, CES), solar and storage carveouts, emissions regulations, and technology mandates

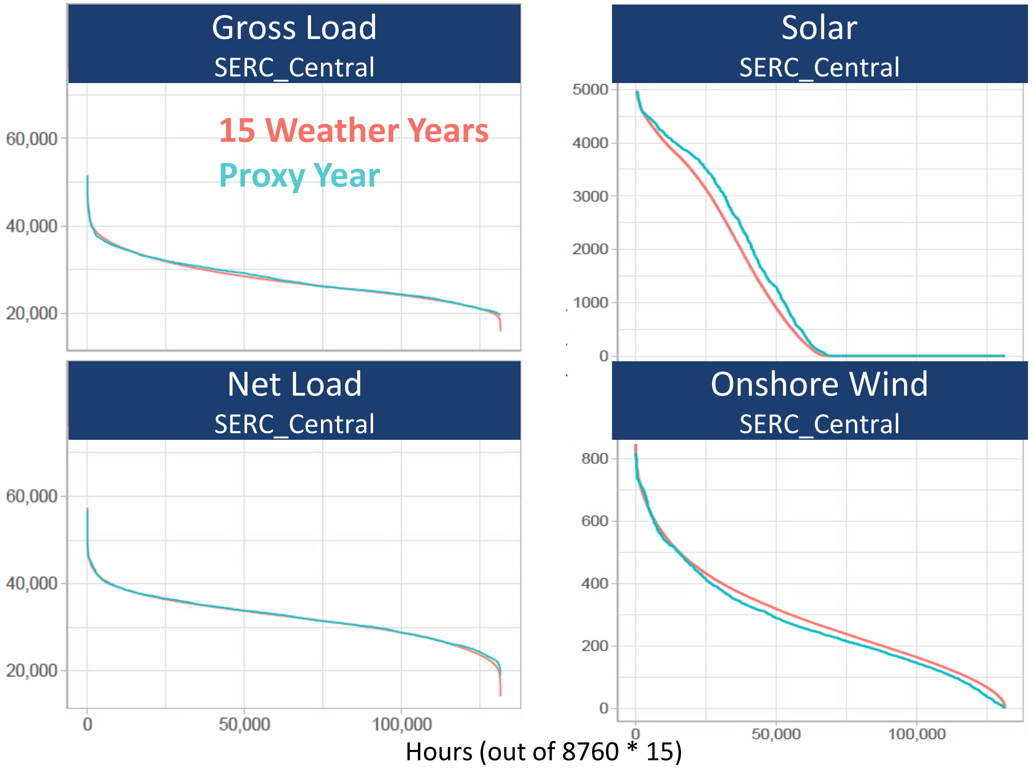
gridSIM

EXECUTIVE SUMMARY

Weather-Reflective Resource Adequacy Sampling (WRAS)

To represent Southeast resource adequacy challenges , we use Brattle's advanced weather sampling, **WRAS,** to develop *proxy weather-years* for each model year comprised of thirty-two frequency-weighted 72-hour long periods, drawn from 15 years of historical weather-year data. The proxy weather-years are constructed to capture the range of load, renewable, and generation outage conditions expected to occur over the course of 15 weather years.

WRAS proxy-year sampling benchmark (illustrative)



Graphs show load and renewable energy duration curves for the modeled proxy year compared to 15 years of historical data.

The close convergence of duration curves means that WRAS-based advanced sampling appropriately captures the full scope of weather variance across 15 years.

- **gridSIM** is used to balance hourly electricity demand (including operating reserves) and supply in each **WRAS-based proxy weather year** to reveal hours associated with resource adequacy risk, which drive optimal future resource investments that satisfy resource adequacy requirement across SERC.
- **WRAS+gridSIM** *dynamically* identifies periods with resource adequacy challenges and how these challenges change as the resource mix and load growth evolve over time.
- **Capacity values (proxy ELCC)** of thermal, renewables, and storage resources determined ***endogenously*** by gridSIM (instead of being a model input) by assessing the optimized contributions of the selected resource additions in meeting load during tight hours.
- Conventional RA representation in utility IRP processes relies on static planning reserve margins and fixed *ex-ante* ELCC assumptions tied to weather-normalized peaks, both of which are expected to change significantly in an increasingly decarbonized and electrified future.

Southeast Scenarios and Sensitivities

We simulate the Southeast through 2040 under a Net Zero Emissions scenario, as well as two sensitivity scenarios with varied transmission and load flexibility assumptions.

In each scenario, we develop projections of optimal resource mix for the study regions through 2040.

Core Scenario[1]	Sensitivity Scenarios		
	Enhanced Transmission		
2050 Net Zero Emissions	***High Transmission Utilization***	***High Transmission Utilization + High Resource Adequacy Regionalization***	**Additional Load Flexibility**
Assumes a linear reduction to 5% of 2024 CO_2 emissions by 2050 (with the remainder met by offsets)	Enhanced coordination among SERC regions for increasing existing transmission utilization during peak system conditions	Enhanced coordination among SERC regions for increasing existing transmission utilization *and* meeting resource adequacy needs	Increased load flexibility equivalent to 6-10% of system peak demand by 2040 (compared to 3-5% DR in 2050 Net Zero scenario)

[1] Note: We also conducted a benchmark assessment of the core scenarios relative to the new resource additions specified in nine SERC utility IRPs. Insights are used for comparison with the Core Scenarios results.

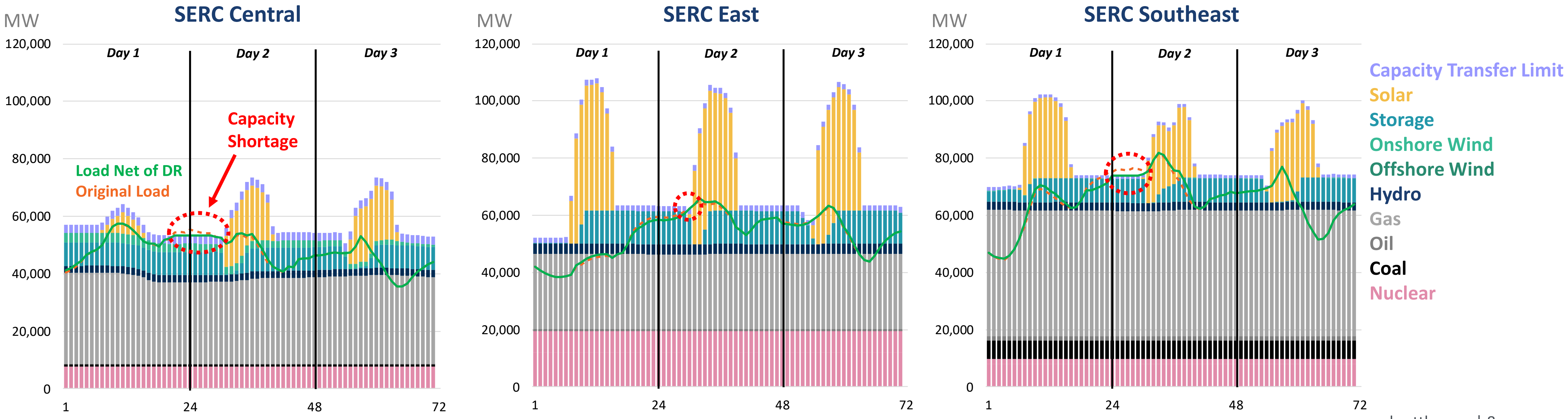
SERC Resource Adequacy Driven by Winter Cold Snaps

WRAS-based approach directly accounts for the Southeast's winter reliability challenges by modeling the tightest system conditions at an hourly granularity, instead of relying on static ELCC projections to value reliability contributions of resources.

While the 2025/2026 NERC Winter Reliability Assessment identifies SERC-East and SERC-Central as elevated winter reliability risk areas, our analysis finds that SERC-Southeast can also experience resource adequacy challenges during winter cold snaps.

- Simulations based on Winter Storm Elliott system conditions demonstrate SERC-Central and SERC-Southeast are tightest during *late night to early morning hours* due to maximum heating needs when temperatures plummet, and risk of elevated cold weather-related unit outages. Since solar generation is absent, reliance on other capacity (e.g., storage, gas and nuclear) is needed.

Hourly Available Capacity during a Winter Peak Day (2040)



Impact of Transmission Utilization on Southeast Resource Mix

We assess the value of utilizing existing SERC transmission through sensitivities:

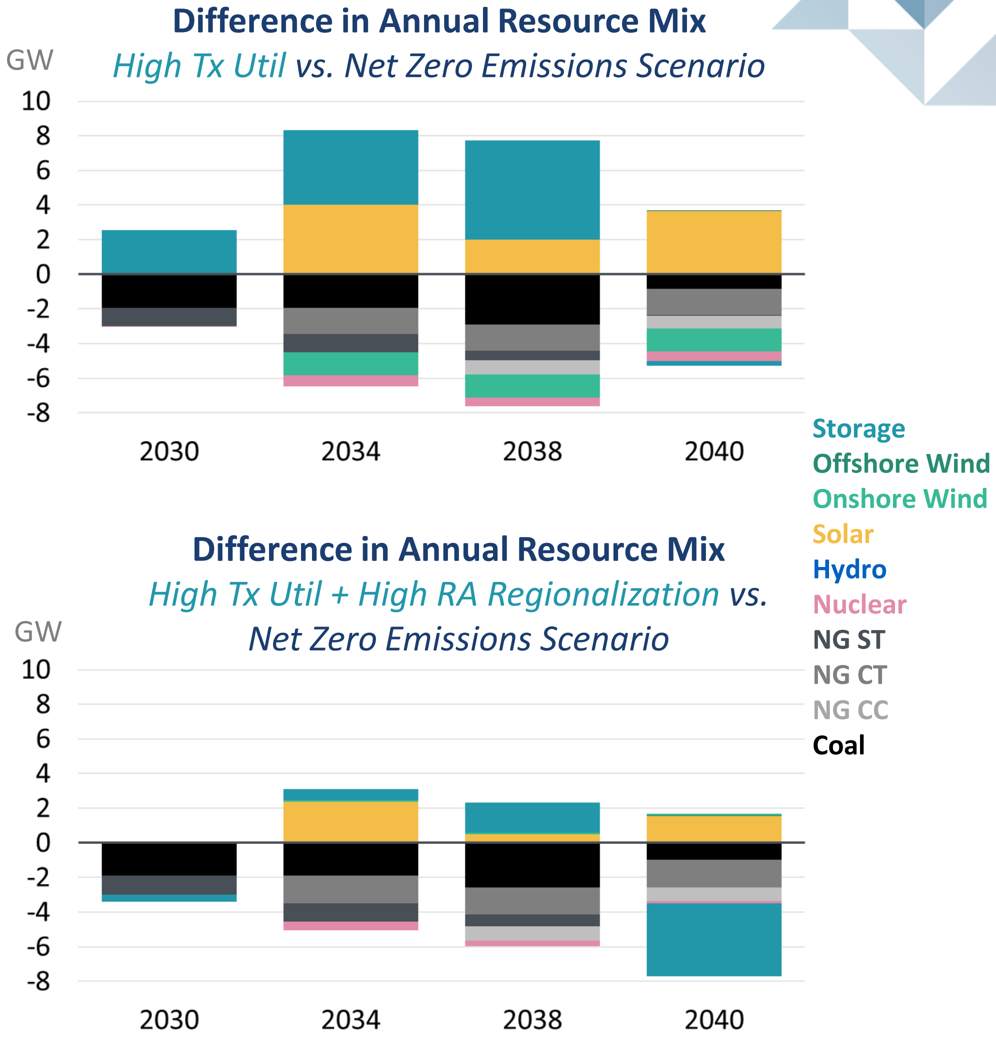
- **High Tx Util sensitivity** assumes higher energy import limits based on NERC-rated transfer limits vs. historical maximum observed imports in the core Net Zero scenario.
- **High Tx Util + High RA Regionalization sensitivity** additionally assumes 50% more capacity imports may be provided by the existing transmission system.

Higher utilization of existing transmission and regional resource adequacy coordination support earlier solar and storage capacity additions and coal retirements, while reducing total generation capacity required by 2040.

- ***Larger energy imports*** enabled by higher utilization of existing transmission replaces firm-dispatchable capacity with more and earlier solar and storage builds.
- ***Larger firm capacity imports*** to meet load during challenging system conditions reduces the need for local capacity to meet resource adequacy.

Higher transfer capability and regional RA coordination result in:

- Reduced local resource adequacy needs by enabling greater sharing of capacity resources across SERC regions during similar but not perfectly coincident reliability events.
- Accelerated fossil retirement, encourages earlier solar expansion, and decreases the need for dispatchable and firming resources including gas, storage, and nuclear *(Bottom).*
- While this analysis evaluates a modest increase in utilization of existing transfer capability, additional intra-SERC transfer capability enabled by transmission expansion or grid-enhancing technologies could further reduce local capacity needs across SERC.*



* Modest resource mix impacts observed in this analysis are directionally consistent with recent evaluations of the Southeast Energy Exchange Market (SEEM), which found that realized trading volumes remain a small fraction of expected volumes and customer benefits have been substantially below initial expectations.

Sources: The Brattle Group, Unlocking the Value of SEEM: Identifying Recommendations to Increase Customer Savings Across the Southeast Region (2026).

EXECUTIVE SUMMARY

Southeast Energy Vision Generation Capacity Outlook

Solar additions must scale up from the current development rate of 4 GW/year to 6-9 GW/year to support Southeast system needs.

- ~110 GW of new solar is cost-effective across scenarios
- Translates to an average solar build rate of 7 GW/year through 2040

Solar is unlocked through its complementary relationship with 26-31 GW of storage capacity by 2040. Wind development is modest.

Southeast is projected to need significant new dispatchable capacity through 2040 for meeting resource adequacy and Net Zero Emissions.

- 27 GW of new nuclear capacity, 29 GW of new NGCC capacity, and 30 GW of storage capacity is needed by 2040 in the 2050 Net Zero Scenario.
- ~100 GW of fossil resources (mostly gas) remain online by 2040.

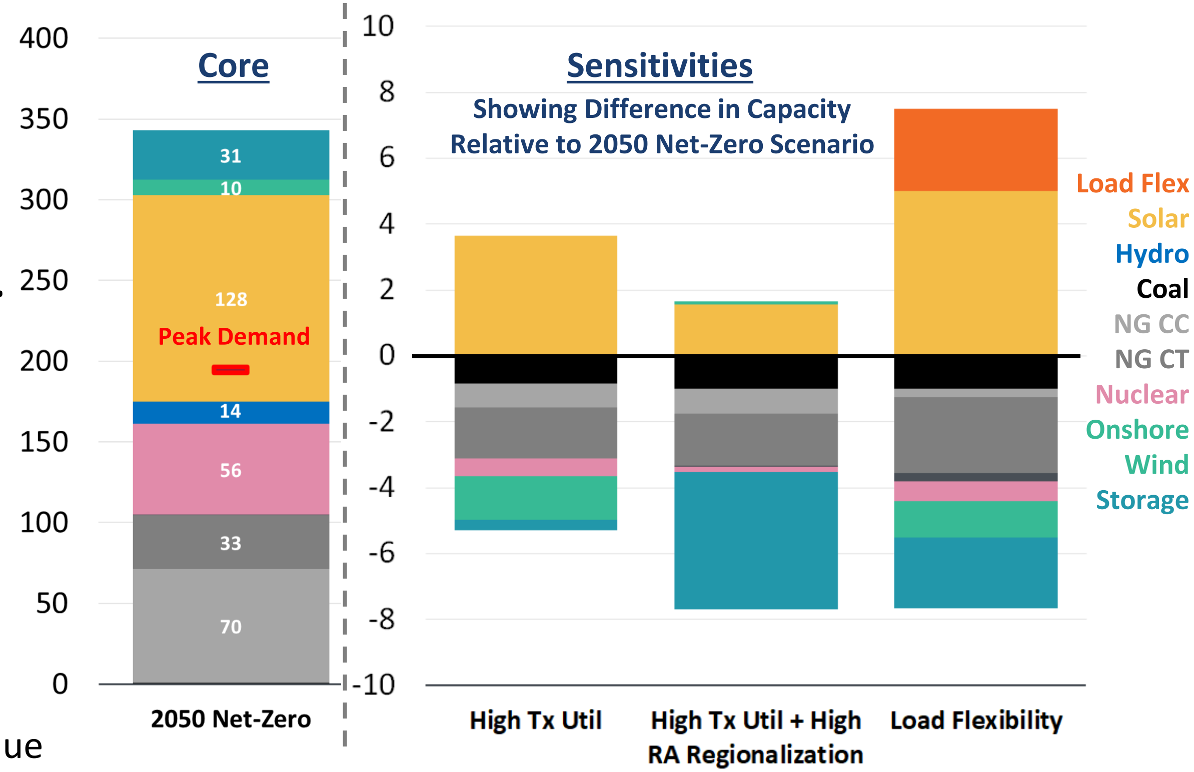
Limited increases in transmission utilization and regional resource adequacy coordination provide economic benefits by reducing local capacity requirements through regional capacity sharing.*

- Greater Tx Utilization reduces capacity buildout by 0.5% in 2040 (1.6 GW).
- While the modeled increase in transfer capability produces modest resource impacts, additional transfer capability could provide greater value by allowing regions to share resources during non-coincident resource adequacy events, reducing the need for local capacity additions.

Increased Load Flexibility reduces capacity buildout by ~1% in 2040, by reducing the need for firm resources in the Southeast.

2040 SERC-Wide Resource Mix (GW)

Net-Zero Scenario and Sensitivities



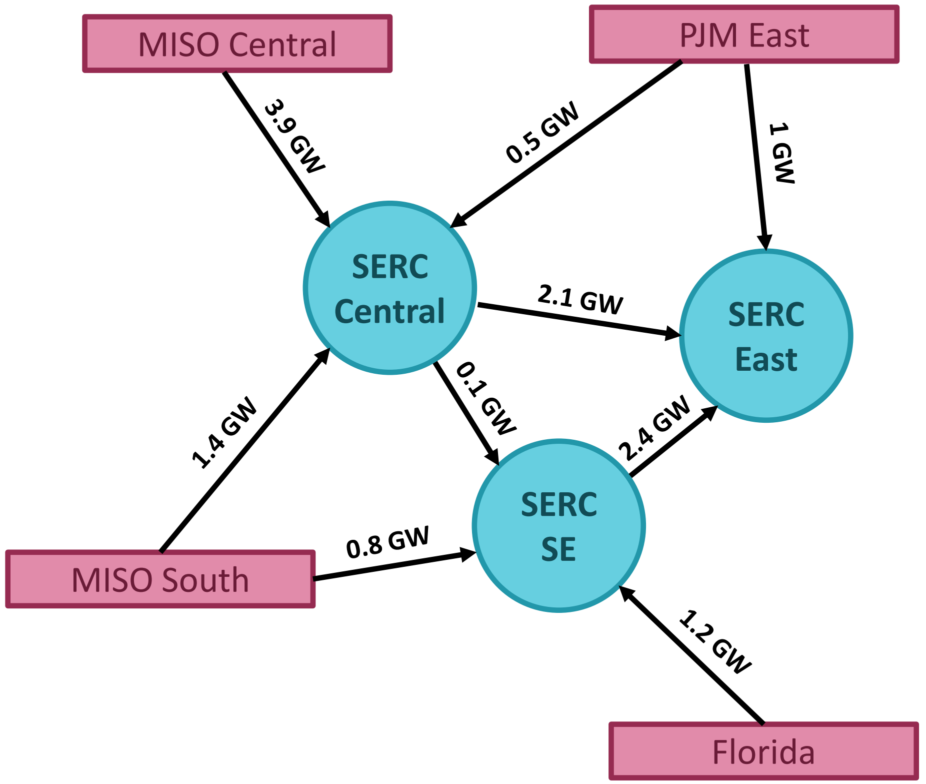
Note: SERC-wide 2040 peak load projections of 198 GW is based on NERC annual growth rates from NERC Electricity Supply and Demand (2024 ESD), adjusted for updated annual energy projections in the TVA (SERC-Central) and GPC (SERC-Southeast) 2025 IRPs, to account for recent load growth projections.

** Sensitivities assume existing transmission can be utilized at NERC-rated transfer limits, increasing energy transfer capability by ~1.9 GW on average across regions relative to historical peak utilization levels. Capacity import capabilities that can count toward each region's RA targets increased by ~1 GW.*

Transmission Reduces In-Region Firm Capacity Needs, Including During Winter Resource Adequacy Challenges

Example: Average Cost-Effective Transmission Flows Across Top Resource-Adequacy-Challenged Hours in 2040

High Tx Util + High RA Regionalization



The top RA-constrained hours are defined based on the resource supply cushion, calculated as all available resources plus the capacity import limit, minus the RA requirement. All of the top RA hours occur during Winter cold snap period.

** Consistent with 2025/2026 NERC Winter Reliability Assessment, which shows both East and Central as winter reliability risk areas subject to elevated risk during extreme weather events.*

SERC's transmission system enables efficient trades to take advantage of regional diversity during resource adequacy challenges, including with neighboring regions

- Resource adequacy risk in SERC is concentrated in winter (cold-snap conditions)
- During these tight hours, the existing transmission system provides RA value by accessing geographic diversity, including with imports from MISO, PJM and FL
- In the Net Zero Core Scenario, SERC is able to import **~6.8 GW** from MISO, PJM, and FL during the top RA-constrained hours in 2040, indicating RA value of non-firm imports
- In the higher transmission utilization sensitivity, feasible imports increase to **7.5 GW** (+10%), offsetting higher cost resources in SERC

During resource adequacy challenges, transmission supports constrained subregions, including SERC-Central and SERC-East, by increasing regional imports from MISO, PJM, Florida; SERC-Southeast remains less import-dependent due to its larger dispatchable fleet.

- During other tight weather periods, the geographic diversity benefits enable different flow patterns to support resource adequacy within SERC regions.
- In the higher transmission utilization sensitivity, energy imports in 2040 during the tightest hours increase most in SERC Southeast and SERC East, while imports to SERC Central changes modestly. Relative to Net Zero scenario, imports to:
  - SERC-Southeast increase by +63% (2.3 GW vs. 1.4 GW)
  - SERC-East increase by +106% (5.4 GW vs. 2.6 GW)
  - SERC-Central increase by +12% (5.8 GW vs. 5.1 GW)

Geographic Diversity Enables Efficient Energy Trades to Support Reliability During 2040 Winter Cold-Snap

Geographic diversity enables variation in inter-zonal energy flows across a tight three-day cold snap in 2040

SERC Central:

- Imports during Day 1 and overnight periods on Days 2–3.
- Exports surplus solar generation during daylight hours to SERC-East and SERC-Southeast.

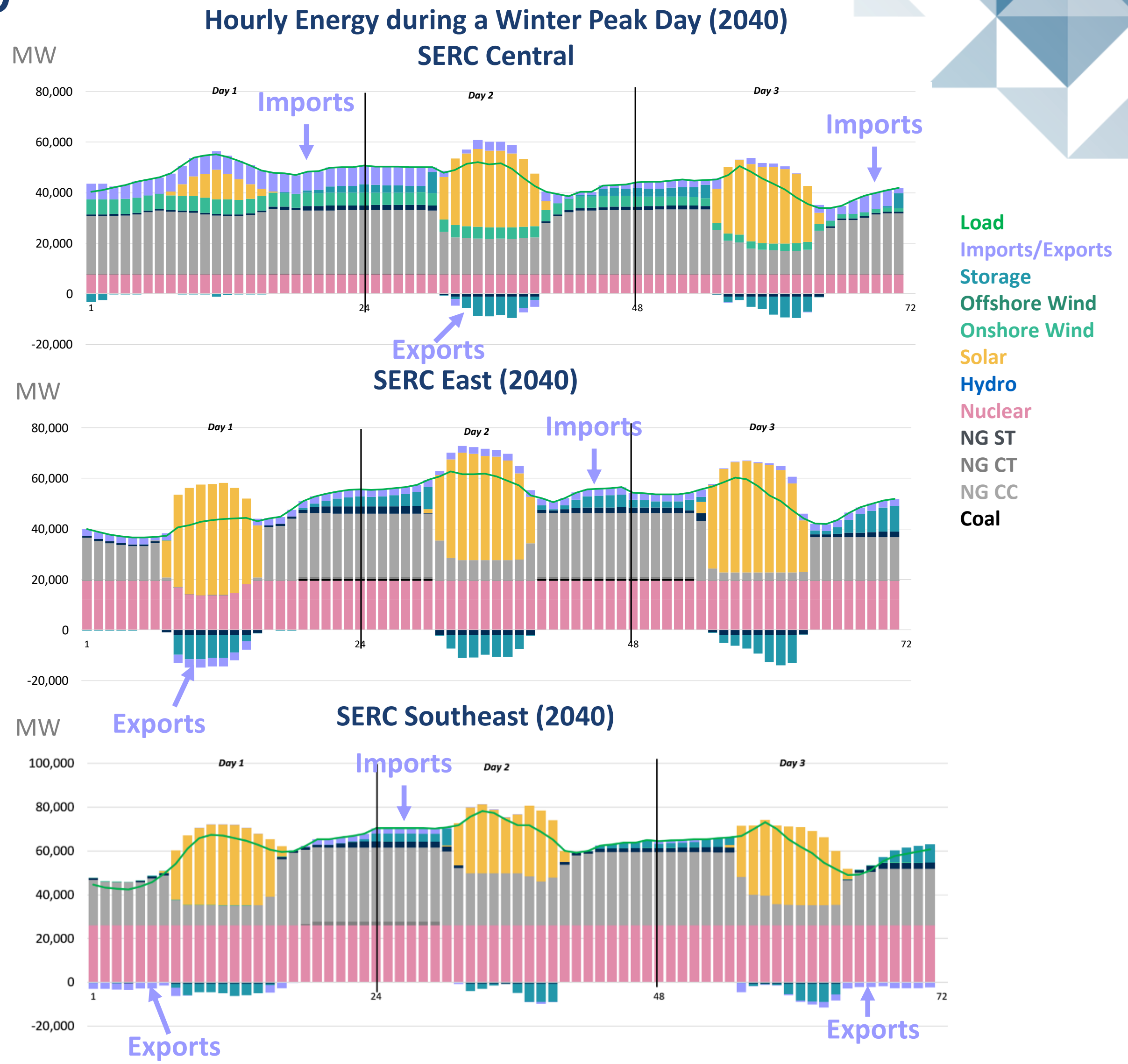
SERC East:

- Relies on imports throughout much of the event, particularly during overnight hours.
- Exports to SERC-Central during daytime solar hours when local solar output is strongest.

SERC Southeast:

- SERC-Southeast relies on imports during the first overnight period and remains largely self-sufficient thereafter due to its larger dispatchable fleet.

The variation in import and export patterns highlights the value of geographic and temporal diversity during winter reliability events.



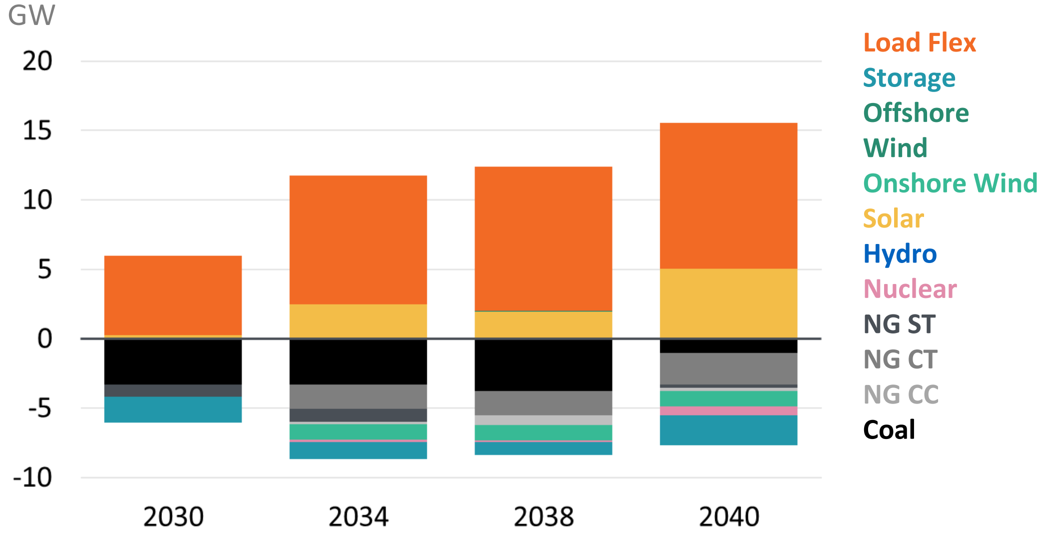
Note: 72-hour charts illustrate hourly energy and import mix under the High Tx Util + High RA Regionalization sensitivity. This simulation allows for load flexibility ranging from 3-5% of peak demand across regions.

Load Flexibility Accelerates Retirements and Limits Additions

Load flexibility reduces the need for firming resources and increases the share of solar in SERC

- Load flexibility is represented as a 4-hour energy-shifting resource with energy shifts within the same 24-hour period; its dispatch can be staggered to create demand reduction during longer periods.
- The modeled flexibility is relatively modest, increasing dispatchable demand response by about 10 GW from current levels (~2-5% of peak load) to 6-10% by 2035, with only a portion deployed during rare reliability events.
- Simulations demonstrate that the additional load flexibility is dispatched during one three-day long cold-snap period (with an occurrence probability of 1-in-15-years), shifting demand from high system peak hours to solar generating hours.
- Additional load flexibility reduces the reliability-driven needs for 7 GW of resources (including coal, gas, battery, and nuclear capacity) and shifts renewable energy additions from wind to solar.
- We project that the simulated level of load flexibility has a breakeven capacity cost of approximately $80/kW-yr.
- Future load growth from data centers is included in the analysis, but data center load flexibility is not explicitly modeled, suggesting additional potential to reduce resource adequacy needs beyond the impacts shown here.

Difference in Annual Resource Mix:
Load Flex vs. Net Zero Emissions Scenario



Key Conclusions and Planning Implications

Load flexibility and enhanced transmission utilization (1) improve system reliability, (2) facilitate higher renewable and storage investments, (3) allow for earlier retirement of aging fossil generation, and (4) reduce total system needs

- **Load flexibility** moves high system peak demand to align with solar generating hours, improving solar value. Overall, more load flexibility results in less local capacity investment needs, enables the retirement of aging fossil resources, and reduces the cost of meeting 2050 Net Zero trajectories
- **Greater utilization of existing transmission via improved regional coordination** among SERC regions in meeting resource adequacy reduces the local capacity need for each subregion and increases the value of solar and storage development
- Higher regional energy and capacity imports enabled by transmission result in **lower-costs, accelerated fossil retirement**, increase solar investment, and decrease the need for local dispatchable firming resources (reduced need for storage and nuclear)

Resource adequacy risk is winter-peaking in the Southeast; planning for multi-day cold snaps becomes essential, revealing the value of firm local capacity and import (firm + non-firm) contributions enabled by transmission

- **Natural gas capacity** is added across the footprint to meet load growth and replace retiring coal plants, but also increases fuel risks
- **Solar + storage** becomes the default clean-peaker pathway, as storage fills the niche of dealing with the growing operational importance of resource readiness, with cold weather correlated forced outage risk of the region's thermal fleet being an important risk consideration
- **Clean-firm technology such as nuclear**, provides a hedge against winter ELCC erosion and renewable drought conditions, particularly in regions (East and Southeast SERC) exposed to high risk of solar output variability and less access to economic wind resources
- **Complementary relationship of** solar, wind, and storage increases accredited capacity of SERC's resource portfolio. With more solar/wind, storage can charge during more hours, increasing their contribution to maintaining reliability during challenging system conditions, especially low-solar winter days

Clean, firm resources, especially nuclear, support a more cost-effective resource portfolio and enable decarbonization at lower cost

- SERC region would require significantly larger amounts of renewables and storage if clean, firm technologies are not available at scale
- Load flexibility and improved transmission coordination reduces challenges of meeting load growth while shifting to lower emissions systems

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Study Regions and Model Topology

Southeast Zones (gridSIM Model Zones)

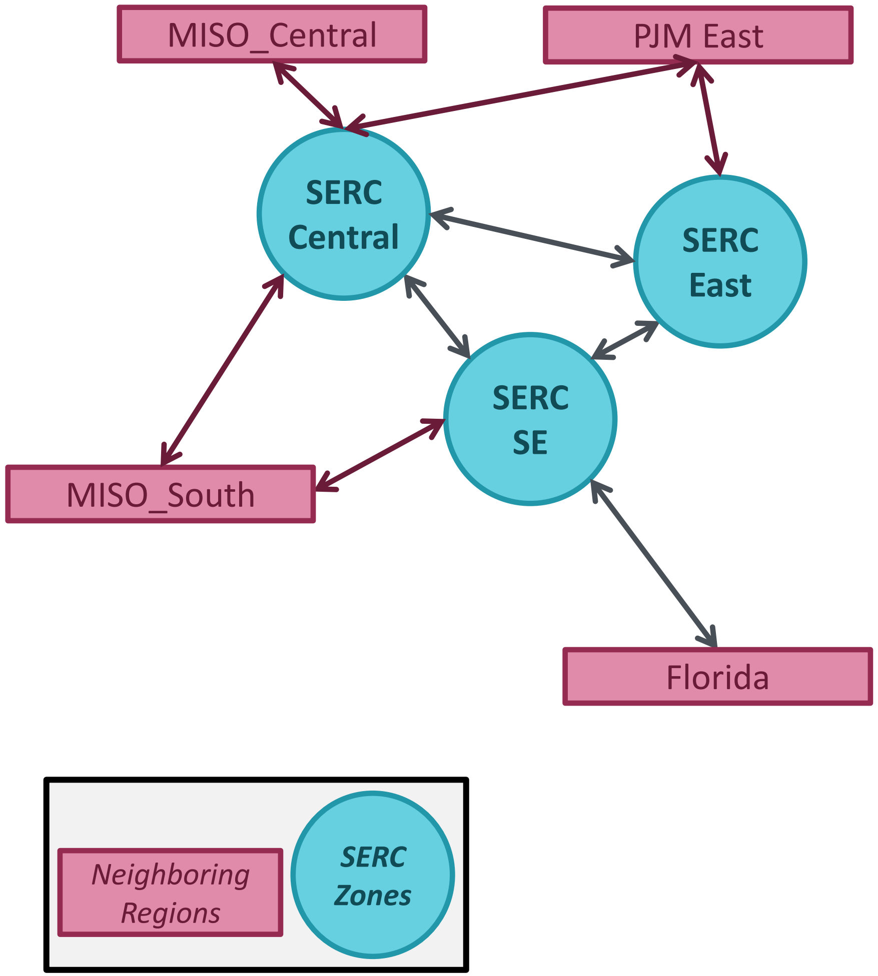
The southeast zones **optimizes future resource mix** based on:

- Historically observed load data to develop forecasted zonal load data across multiple weather years
- Existing and planned zonal capacity data (establish going-in position)
- Transmission export/import limits that constrain energy and capacity flows between zones
- Zonal renewable costs and generation profiles across multiple weather years to account for weather-related uncertainty

Neighboring Regions (to capture geographic diversity)

To capture geographic diversity in generation and capacity across SE, gridSIM optimizes generation and transfer (based on reduced form representation) to/from Southeast, given projected resource mix based on publicly available data:

- Forecasted load and aggregated capacity data
- Zonal renewable generation profiles and unit costs
- Interties with transmission limits based on historical flows



Included IRP Data

We use IRP data from each region's major utilities as useful data points for this study. The study accounts for the proposed builds and retirements for the following SERC members **indicated** below.

	SERC Central	SERC East	SERC Southeast
Utilities	**LG&E and KU (2024 IRP)**	**Duke Energy Carolinas (2023 IRP)** **Duke Energy Progress (2023 IRP)** **Dominion Energy South Carolina (2024 IRP)**	**Alabama Power Company (2025 GPC IRP)** **Georgia Power Company (2025 GPC IRP)** **Mississippi Power Company (2025 GPC IRP)**
Municipals and Federal/State Systems	Owensboro, KY Municipal Utilities **Tennessee Valley Authority (2025 IRP)**	Fayetteville Public Works Commission North Carolina Eastern Municipal Power Agency North Carolina Municipal Power Agency #1	Alabama Municipal Electric Authority Municipal Electric Authority of Georgia
Cooperatives	Big Rivers Electric Corporation East Kentucky Power Cooperative	**Santee Cooper (2024 IRP)** French Broad Electric Membership Corporation North Carolina Electric Membership Corporation Old Dominion Electric Cooperative	Georgia System Operations Corporation Georgia Transmission Corporation Oglethorpe Power Corporation PowerSouth Energy Cooperative South Mississippi Electric Power Association

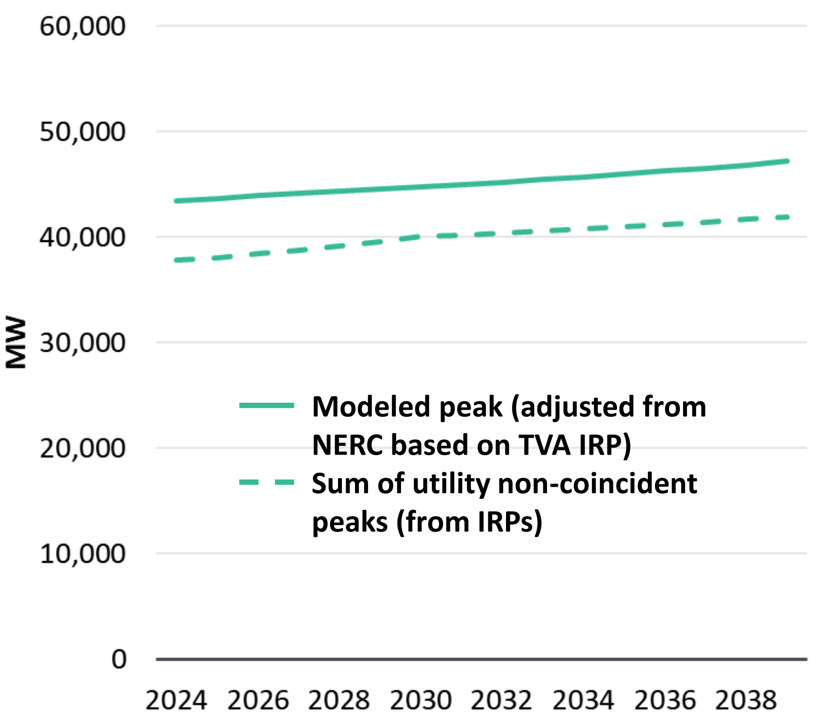
Regional Electricity Supply and Demand

- **Regional Load**
  - Peak and energy demand growth based on NERC's Electricity Supply and Demand (ES&D) database (inclusive of both utilities and municipalities/cooperatives).
  - Adjusted upward to align with more recent Georgia Power and TVA Power IRPs.
- **Regional Capacity Expansion Based on Utility IRPs**
  - **Existing Capacity:** included all resources in Velocity Suite's Generating Unit Capacity dataset (inclusive of both utilities and municipalities/cooperatives)
  - **Future Capacity Additions:**
    - For investor-owned utilities, included proposed builds and retirements from published IRPs
    - Due to limited data on how the rest of the region will expand capacity (e.g., municipal utilities and electric co-ops), allow gridSIM to expand regional capacity consistent with how utilities are expanding their resource mix across generating technologies

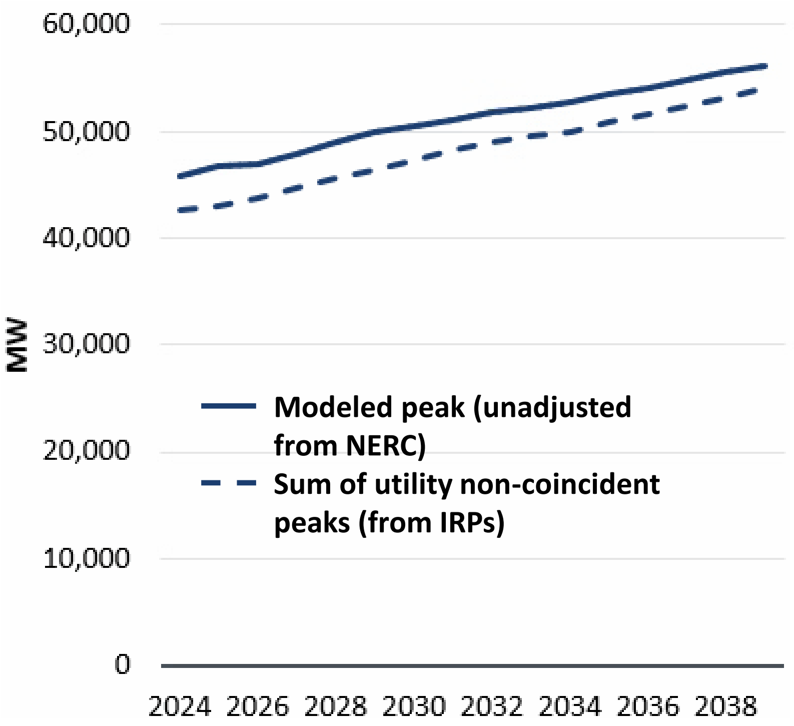
Utility Load Covers Large Portion of Regional Peak Demand

The figures below show NERC regional peaks compared to utility peak forecasts. For SERC Central and SERC Southeast, we have adjusted the load forecast upward based on more recent IRP data.

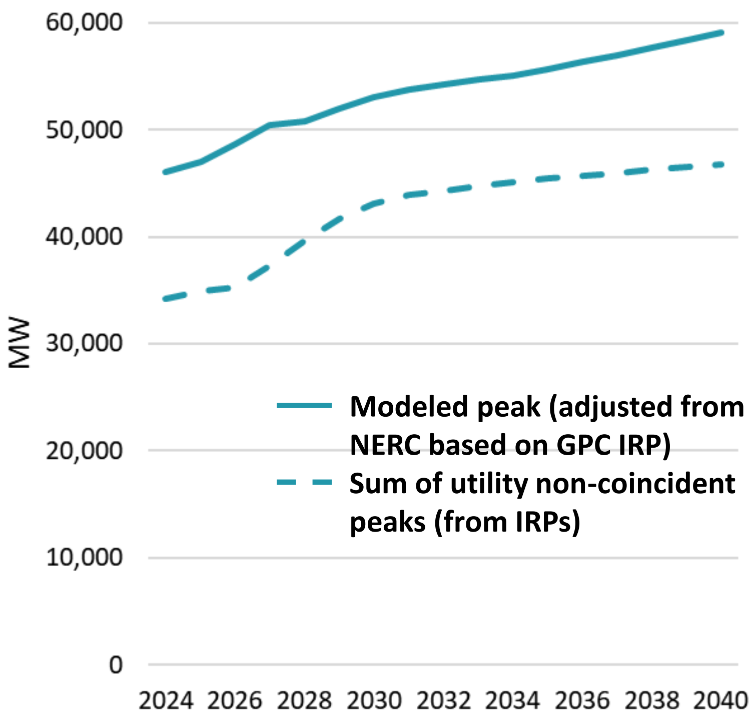
Peak Demand Forecast: SERC Central



Peak Demand Forecast: SERC East



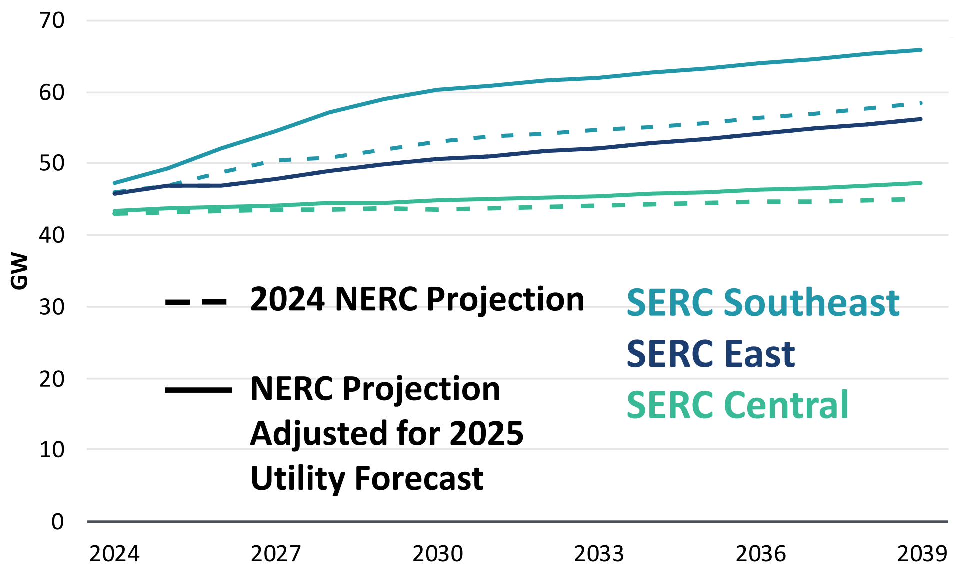
Peak Demand Forecast: SERC Southeast



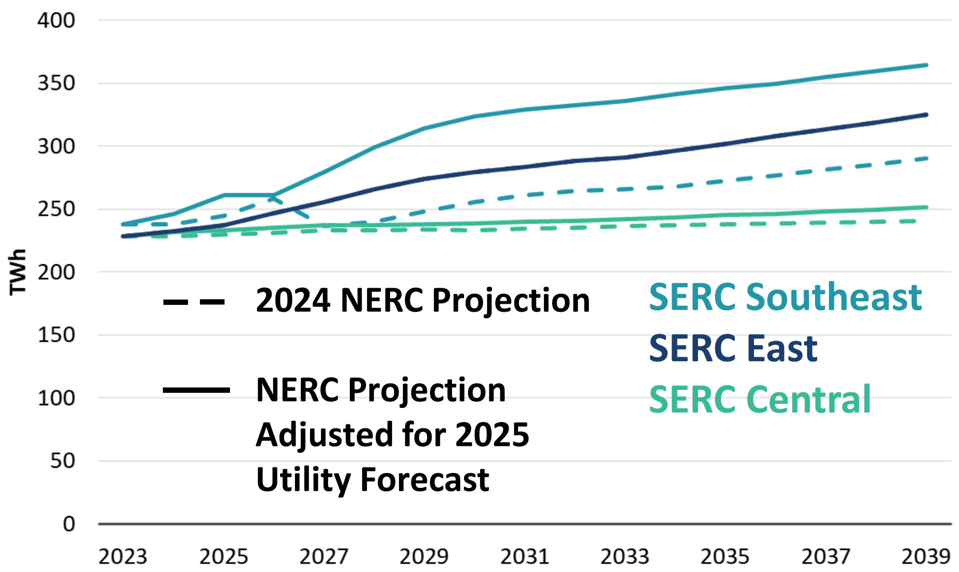
Projected Load Growth

NERC annual growth rates from NERC Electricity Supply and Demand (2024 ESD), adjusted for updated annual energy projections in the TVA (SERC-Central) and GPC (SERC-Southeast) 2025 IRPs, to account for recent load growth projections.

Peak Demand Forecast



Annual Energy Demand Forecast



Transmission: Energy Flow Limits Based on Historical Interchange

- **Energy transfers between modeled regions** are constrained based on maximum historical interchange by season between 2015-2024 (EIA).
- **Energy flow into/out of modeled regions** is modeled using a similar approach.
  For each of the SERC regions:
  - Hourly gross imports/exports are constrained by seasonal historical maximum, capturing the limited interchange between regions in SERC.
  - *Energy imports during peak system tightness days are limited to historical levels of energy imports on which the day is modeled.*
- **Average interchange levels between modeled SERC regions and neighboring markets (PJM-East, MISO-South, MISO Central and SERC Florida)** are constrained by season and hour to be consistent with average historical interchange levels.

Transmission: Capacity Transfer Limits based on Historical Imports

Capacity import limits are initially defined based on NERC's Interregional Transfer Capability Study (ITCS) study, which provides limits for 2024 summer and 2024/25 winter.

However, historical energy imports into SERC show that gross imports during peak hours are *significantly lower than capacity transfer limits defined based on the ITCS study.*

As such, we have limited capacity imports during peak periods to be consistent with the minimum of historical import levels and NERC-informed capacity transfer limits.

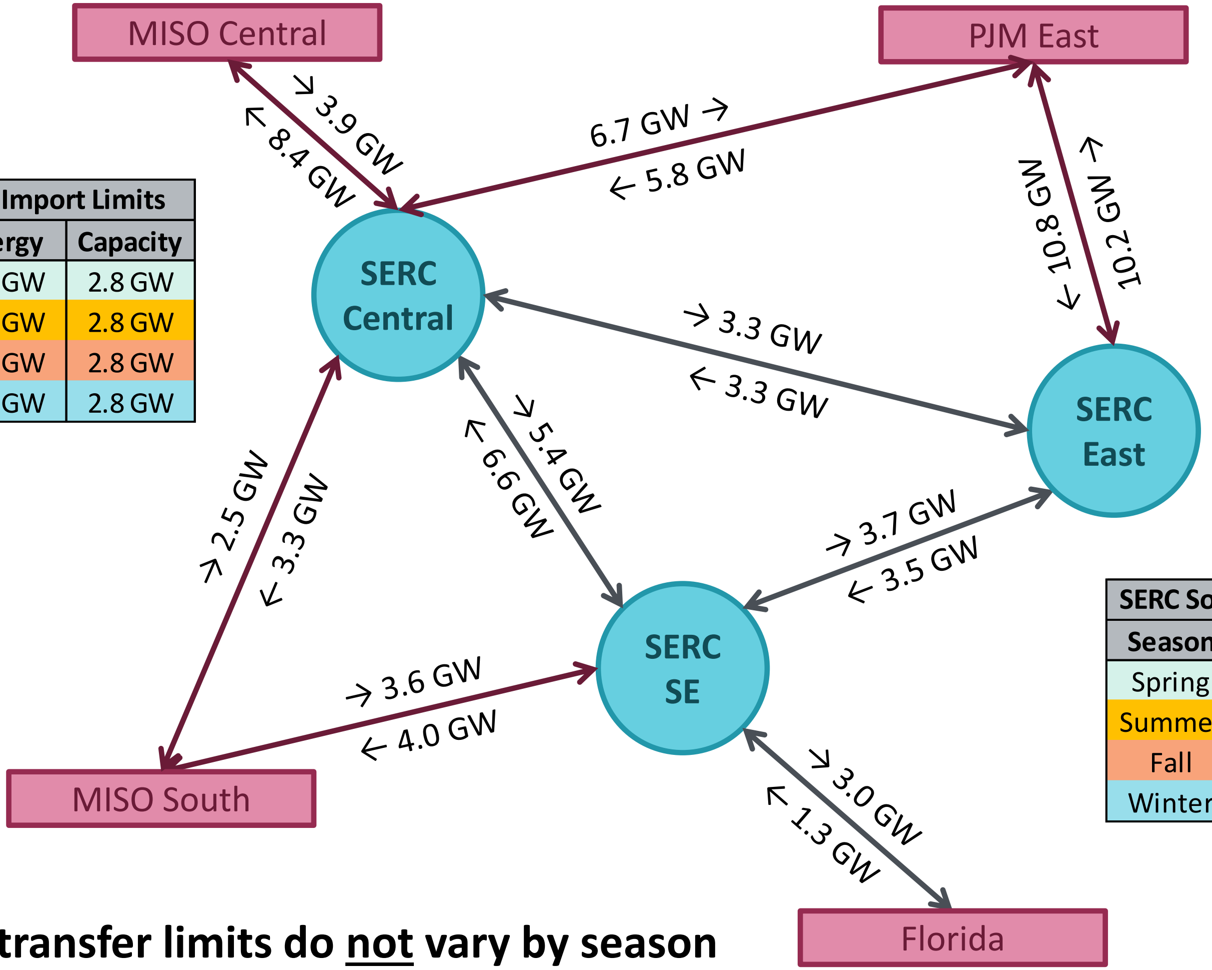
NERC Capacity Import Limits vs. EIA Historical Gross Imports

	SERC Central	SERC East	SERC Southeast
NERC ITCS Total Import Interface Limits			
Winter	8.4 GW	5.5 GW	6.5 GW
Summer	6.9 GW	7.0 GW	4.9 GW
EIA Historical Maximum Gross Imports			
Average Winter	8.4 GW	5.5 GW	6.5 GW
Winter Peak	7.4 GW	4.2 GW	4.2 GW
SERC Central Extreme Winter Peak	7.4 GW	2.9 GW	2.5 GW
SERC East Extreme Winter Peak	4.0 GW	2.4 GW	3.0 GW
SERC Southeast Extreme Winter Peak	3.3 GW	2.3 GW	3.0 GW
Average Summer	6.9 GW	7.0 GW	4.9 GW
Summer Peak	4.6 GW	1.9 GW	1.2 GW
SERC Central Extreme Summer Peak	4.2 GW	2.5 GW	1.2 GW
SERC East Extreme Summer Peak	2.8 GW	2.4 GW	2.8 GW
SERC Southeast Extreme Summer Peak	4.6 GW	2.7 GW	1.8 GW

= Regional Capacity Transfer Limit

Transmission: Modeled Hourly Energy Flow Limits

SERC Central Import Limits		
Season	**Energy**	**Capacity**
Spring	4.1 GW	2.8 GW
Summer	6.4 GW	2.8 GW
Fall	5.7 GW	2.8 GW
Winter	7.4 GW	2.8 GW



SERC East Import Limits		
Season	**Energy**	**Capacity**
Spring	3.4 GW	1.9 GW
Summer	4.5 GW	1.9 GW
Fall	4.0 GW	1.9 GW
Winter	4.2 GW	1.9 GW

SERC Southeast Import Limits		
Season	**Energy**	**Capacity**
Spring	3.6 GW	1.2 GW
Summer	4.5 GW	1.2 GW
Fall	4.0 GW	1.2 GW
Winter	4.2 GW	1.2 GW

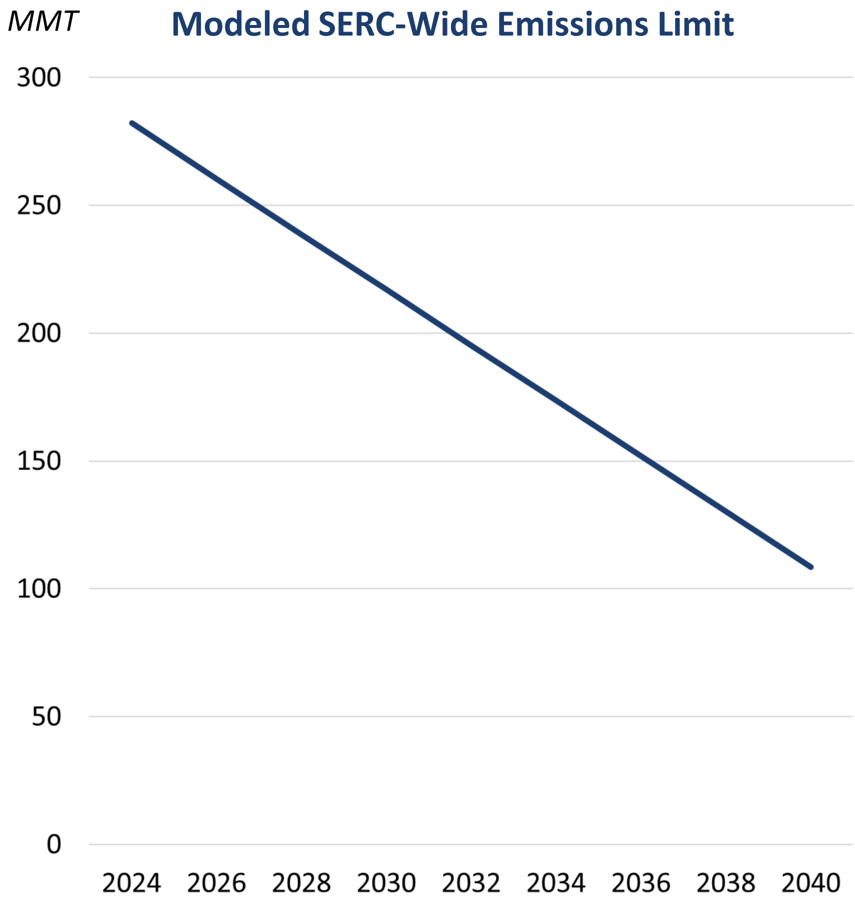
*** Bilateral energy transfer limits do <u>not</u> vary by season**

Carbon Dioxide Emissions Limits

gridSIM optimizes generation capacity to simulate regional resource mix consistent with modeled emissions trajectories.

2050 Net Zero Emissions Trajectory a linear reduction in emissions from 2024 historical levels to zero emissions by 2050. We assume 5% of emissions can be met by offsets in 2050.

- Study's time horizon is 2040, as most IRPs do not specify plans beyond 2040.
- Based on the 2050 Net Zero rate of emissions reduction, emissions goals in 2040 correspond to *42%* of 2024 emissions levels.



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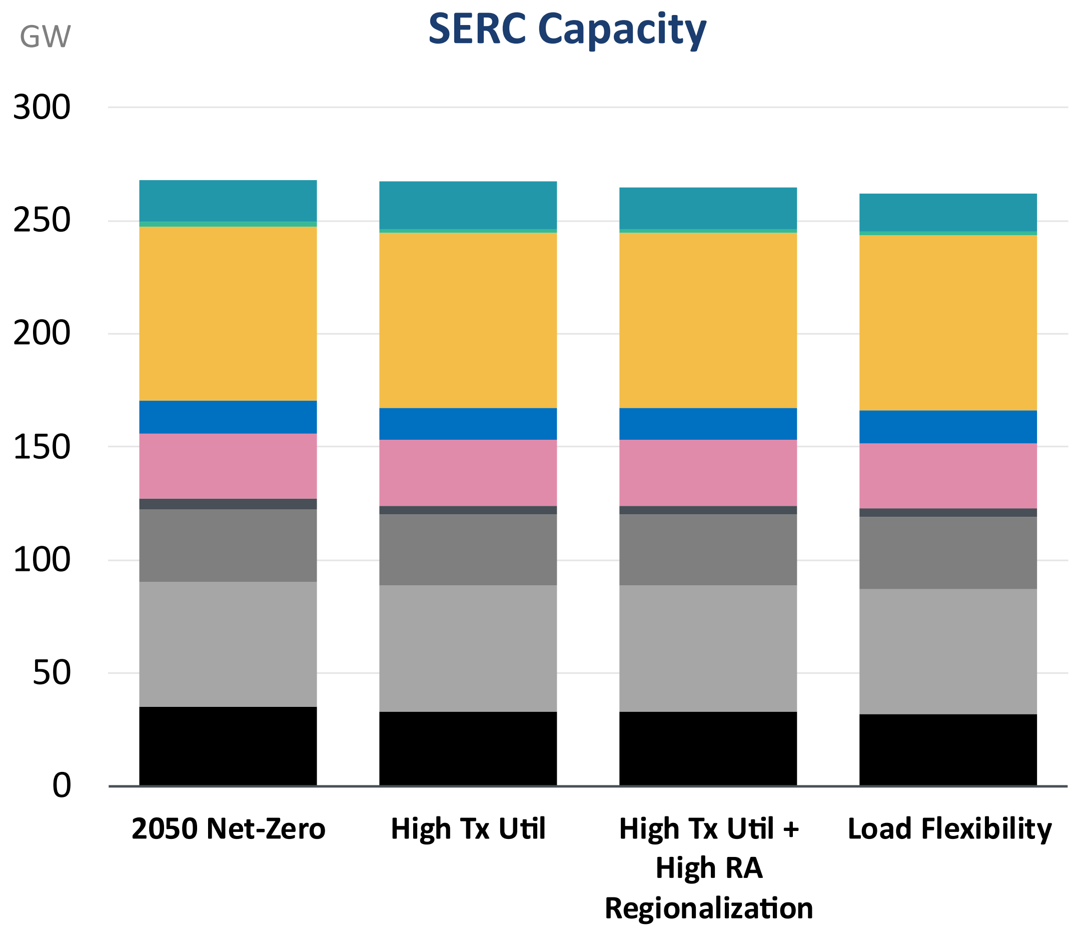
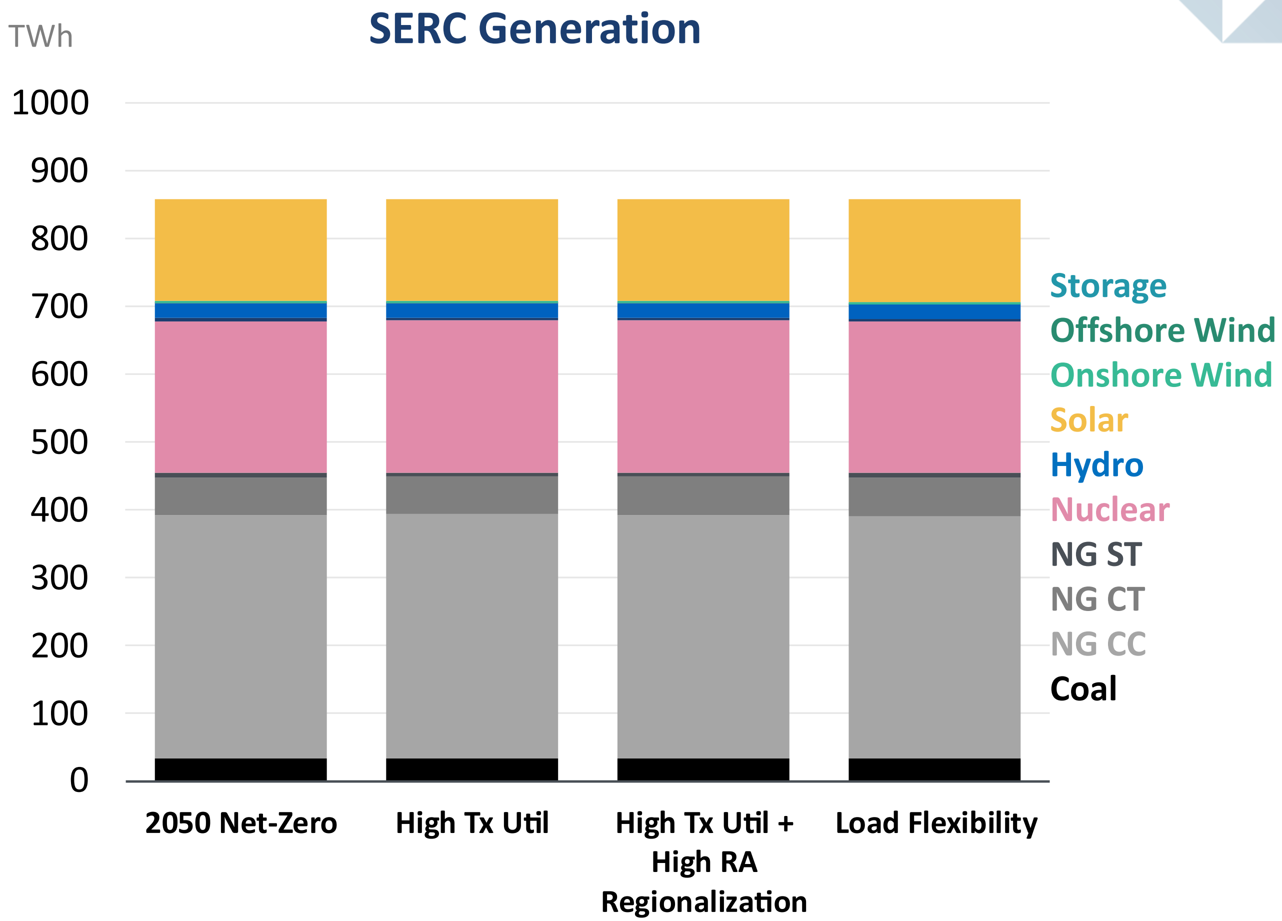
Scenario Descriptions

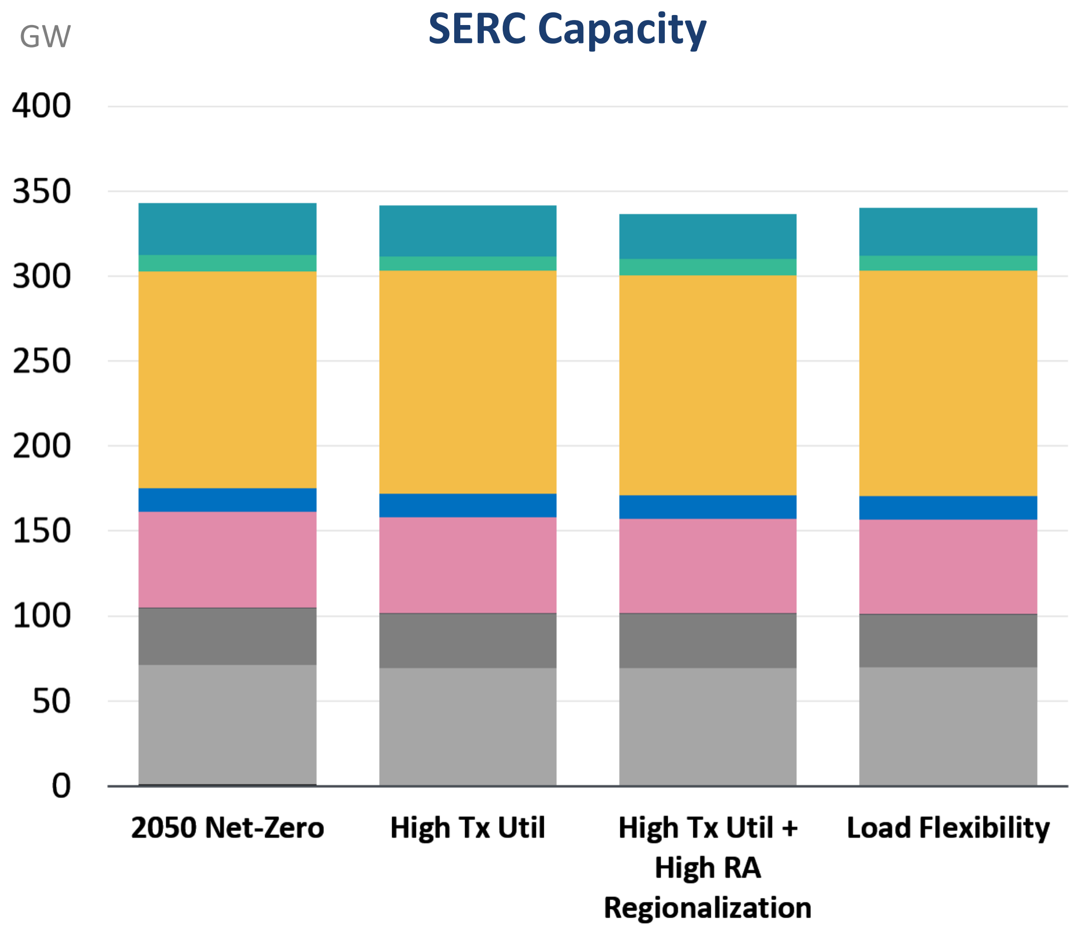
Scenario	Builds	Retirements	Emissions Limit	Tax Credits
2050 Net-Zero Emissions Scenario	Expansion based on utility IRPs through 2025, model builds are endogenous thereafter	Based on utility IRPs, with additional model retirements allowed	Net-zero by 2050	PTC and ITC for resources built by 2032
2050 Net-Zero Emissions Scenario: Enhanced Transmission Utilization Within SERC	gridSIM-optimized capacity expansion assuing efficient intra- and inter-zonal transmission planning within SERC	Based on utility IRPs, with additional model retirements allowed	Net-zero by 2050	PTC and ITC for resources built by 2032
2050 Net-Zero Emissions Scenario: Load Flexibility	gridSIM-optimized capacity expansion assuming flexible load equivalent to 5-10% of system peak demand	Based on utility IRPs, with additional model retirements allowed	Net-zero by 2050	PTC and ITC for resources built by 2032

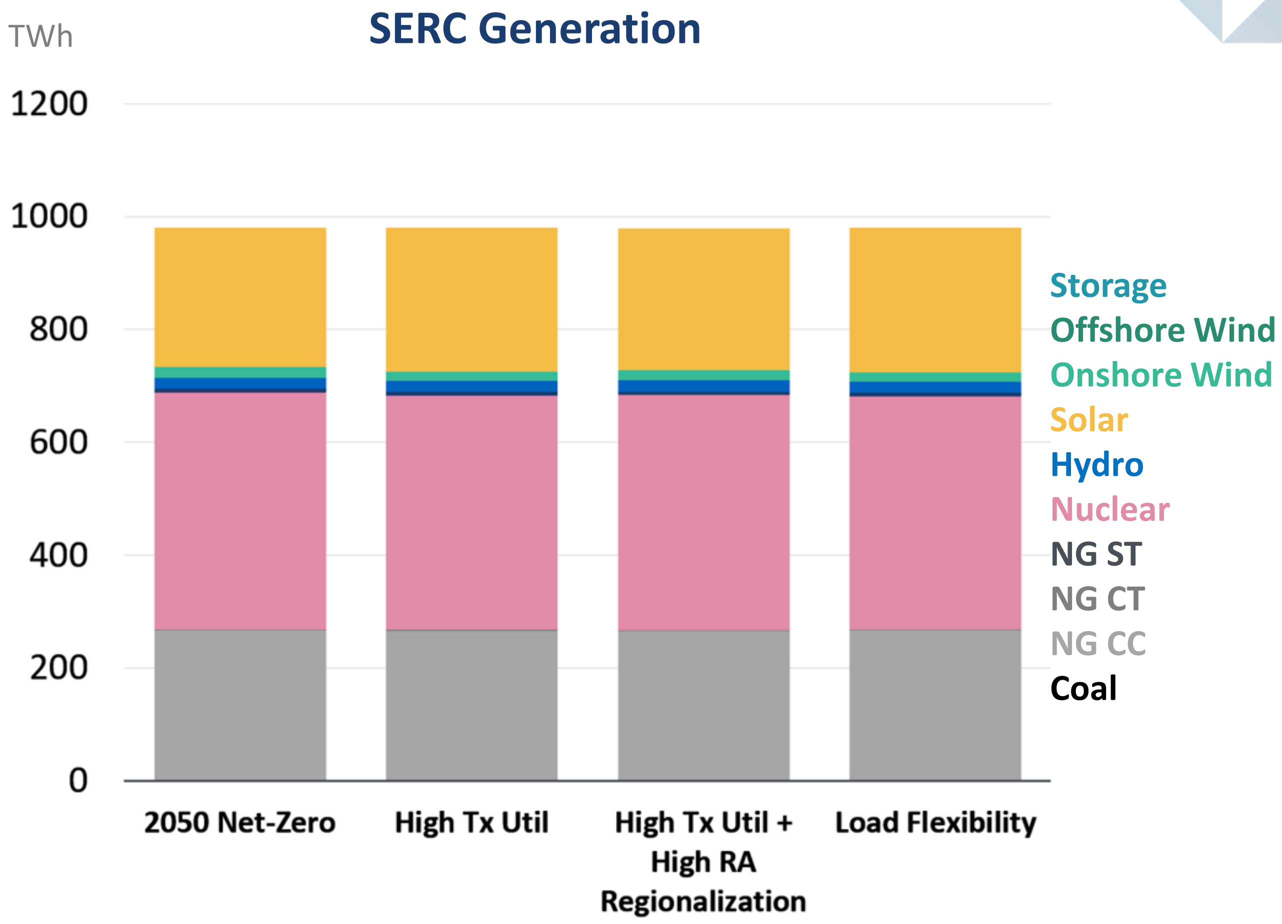
2030 Capacity and Generation by Scenario





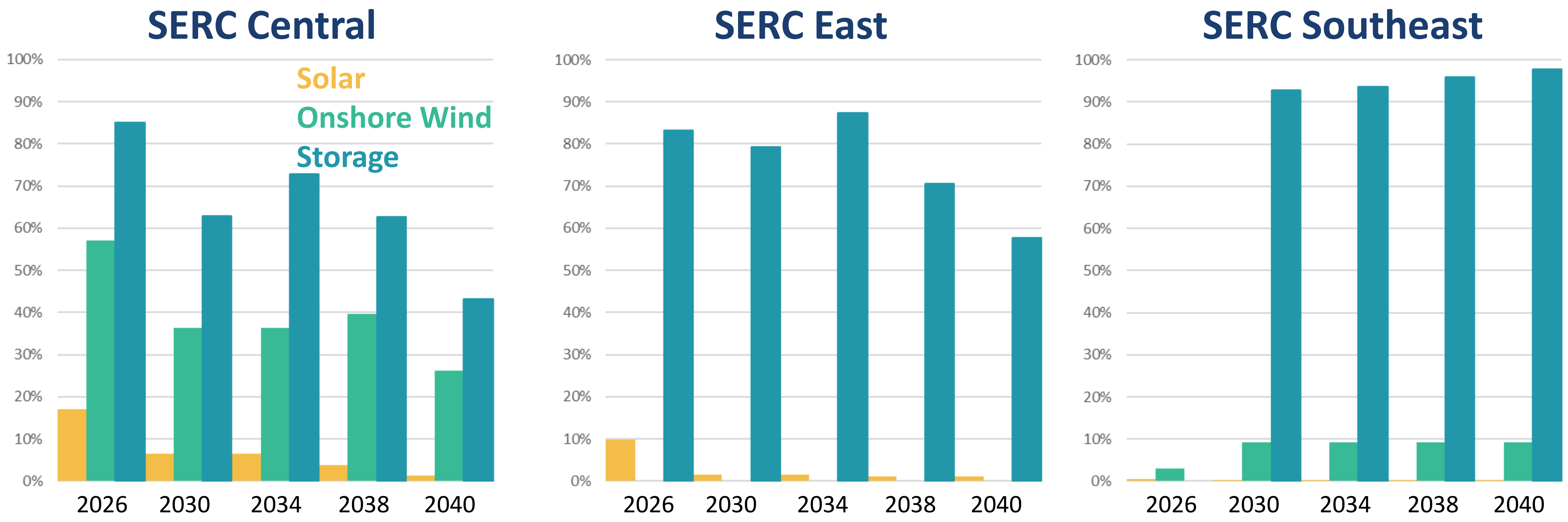
2040 Capacity and Generation by Scenario





Resource Proxy ELCCs for Net Zero Scenario

ELCC for storage and renewable resources decline across model years as solar expansion shifts RA constrained hours to other periods. Solar and wind have lower ELCC in East and Southeast, while storage provides greater reliability value.



Note: The top RA-constrained hours are defined based on the resource supply cushion, calculated as all available resources plus the capacity import limit, minus the RA requirement. All of the top RA hours occur in Winter. Implied proxy ELCCs not reported for wind in SERC East because the simulations do not project any wind development.

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Detailed results:

2050 Net Zero Emissions Scenario

GRIDSIM-OPTIMIZED RESOURCE MIX MEETING REGIONAL DEMAND & 2050 NET ZERO EMISSIONS

Resource Mix Across SERC

Solar builds increase SERC-wide, especially in SERC-Central and Southeast with less aggressive reference emissions goals.

- A total of 112 GW of solar built by 2040 across SERC (~7 GW/year).
- The majority of solar builds take place in SERC Central and Southeast.
- 75 GW more solar builds than specified in *IRP-specified planned additions*.*

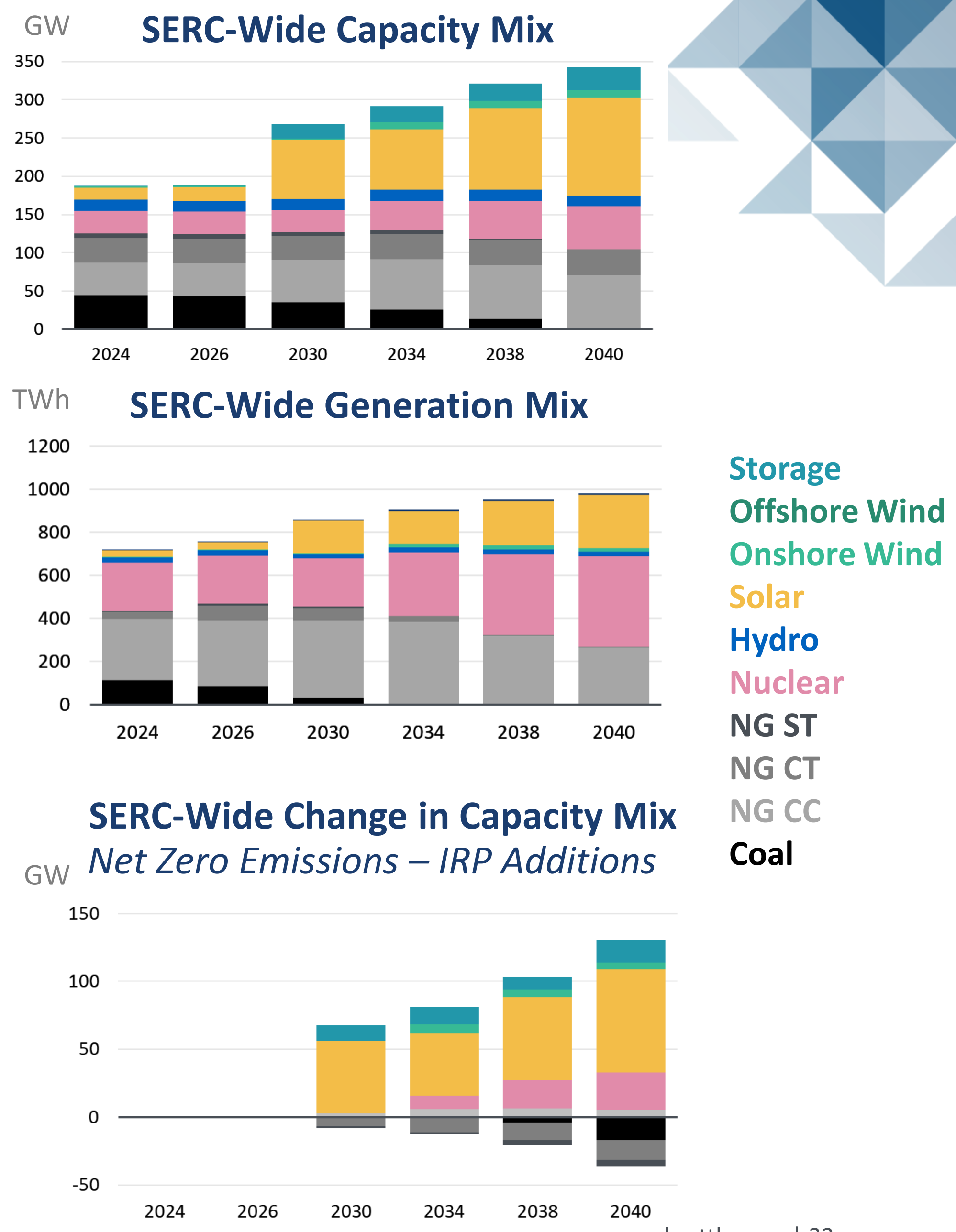
Cleaner imports and more renewable builds increase the on-peak value of storage.

- 30 GW of storage built across SERC by 2040, ~18GW more storage builds than in IRP-specified storage additions.
- Increased renewable generation and its complementary relationship with storage increases capacity value (ELCC) of storage.
  - Storage resources can charge during more hours and at a higher rate, increasing their contribution to meeting peak load, especially during low-solar winter days.

Clean transition and reliability risk under extreme weather accelerate fossil retirement, and bring more/earlier nuclear builds

- Particularly in regions (East and Southeast) exposed to high risk of solar output variability and, where wind technology is not viewed as economic.
- 27 GW of nuclear builds by 2040 across SERC.

** Regional aggregation of utility IRP-specified resource additions in the nine utility IRPs reviewed in this study.*



Additional Fossil Capacity Retirement

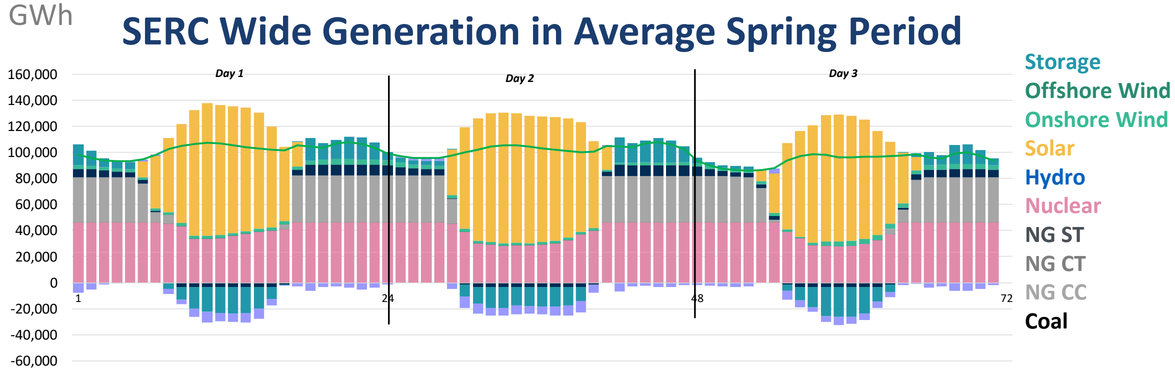
Over 40 GW of fossil capacity retired by 2040 (primarily Coal and NG ST), replaced by around 30 GW of NG CC and CTs.

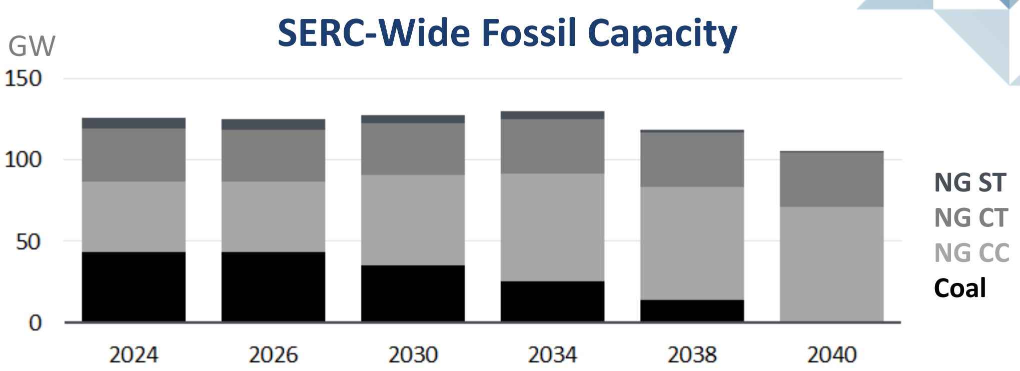
- 30 GW less fossil capacity online in 2040 compared to IRP-specified retirement plans (17 GW more coal retirement; 13 GW less gas capacity).
- 70 GW of NG CC and 33 GW of NG CTs remain in 2040.
- Around 1 GW of coal remains online by 2040.

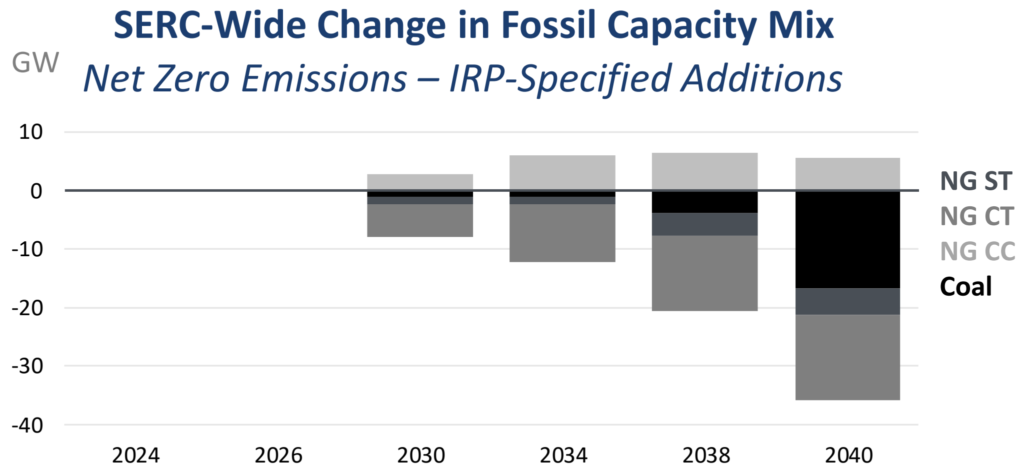
Fossil resources are reduced from 61% of the generation mix in 2024 to only 27% by 2040.

- Fossil capacity retained largely for resource adequacy purposes.
- NGCC capacity factor drops from 75% (2024) to 43% (2040).

Less emitting new NGCCs replace existing fossil capacity, generating during hours in which solar declines.







Nuclear and Firm Builds

Total gridSIM builds of new nuclear in the 2050 Net Zero Emissions scenario are similar to the IRP plan buildout of clean, dispatchable resources. New nuclear capacity in this study accounts for both SMR and large nuclear technology (e.g., AP-1000).

- gridSIM builds **~27 GW** of new nuclear capacity in SERC between 2034-2040.
- IRP portfolios build **~19 GW** of SMR + other dispatchable resources across portfolios by 2040.
- TVA builds up to 10 GW of nuclear SMR (and **12 GW** total new nuclear) by 2050 in their high energy demand and emissions constrained scenarios.
- Several of Duke's resource portfolios build up to **3 GW** of nuclear SMR by 2038, and Dominion's 85% CO2 Build Plan adds around **900 MW** between 2040-2050. For Duke, all new CTs selected after 2039 are assumed to be operated on 100% hydrogen.
- Southern Company builds **4.8 GW** of large nuclear units (AP-1000) by 2044 in their Emissions Limited (EL) scenario. They also allow CC w/ CCS builds beginning in 2037 and build **7.5 GW** by 2044 in the EL scenario.

Detailed results:

2050 Net Zero Emissions Scenario

Increased Transmission Utilization

GRIDSIM-OPTIMIZED RESOURCE MIX MEETING REGIONAL DEMAND & 2050 NET ZERO EMISSIONS

Modeling Increased Transmission Utilization & Regionalization

SERC is dominated by vertically integrated utilities, planning and operating largely within their own balancing areas.

- This limits regional coordination in energy and capacity transfers, which can result in more conservative capacity planning, slower solar + storage buildout, and heavier reliance on local gas for reliability insurance.
- **Existing transmission may be currently under utilized:**

Region	Season	Modeled Hourly Import Limit (Maximum Historical Import Levels)	NERC Rated Simultaenous Import Transfer Capability	Maximum Historical Energy Import Transfer Capability Utilization	Import Contribution to RA (Maximum Historical Import Levels During Peak Tightness)
SERC Central	Spring	4.1 GW	8.4 GW	49%	2.8 GW
	Summer	6.4 GW	6.9 GW	93%	
	Fall	5.7 GW	6.9 GW	82%	
	Winter	7.4 GW	8.4 GW	88%	
SERC East	Spring	3.4 GW	5.5 GW	63%	1.9 GW
	Summer	4.5 GW	7.0 GW	65%	
	Fall	4.0 GW	7.0 GW	58%	
	Winter	4.2 GW	5.5 GW	77%	
SERC Southeast	Spring	3.6 GW	6.5 GW	55%	1.2 GW
	Summer	4.5 GW	4.9 GW	93%	
	Fall	4.0 GW	4.9 GW	82%	
	Winter	4.2 GW	6.5 GW	64%	

Modeling Increased Transmission Utilization & Regionalization

We examine the impacts of higher utilization of existing transmission and regional coordination in meeting resource adequacy, represented in our modeling as follows:

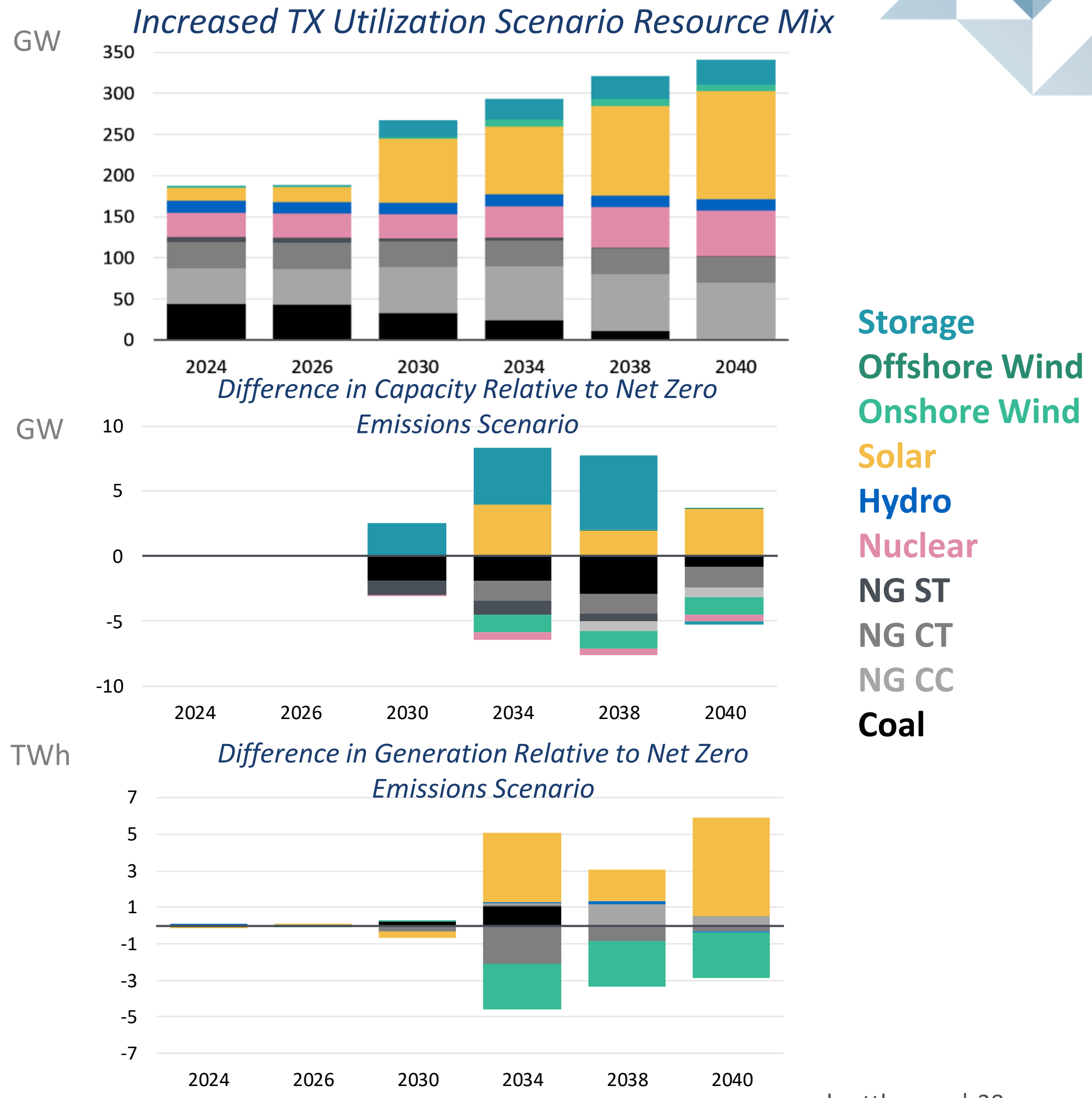
- Increase each SERC region's hourly simultaneous **energy** import limits from historical import levels to Total Import Interface Limits specified in NERC's ITCS study.
  - Represents increase in energy transfer capability through better use of existing transmission, letting renewable power move from where it's cheapest to where it's needed.
- Increase by 50%, the **capacity** import capabilities that can count toward each region's RA targets.
  - Represents coordination among SERC regions in sharing the burdens of meeting RA goals, reducing the need for each region to carry high, independent reserve margins.

Impact of Higher Energy Imports Via Improved TX Utilization

Better utilization of transmission lines and stronger regional coordination in SERC incentivizes earlier solar + storage builds, and less generation capacity in 2040.

- Enhanced transmission utilization smooths out solar variability across larger geographies, and enables renewable power to move from where it is cheapest to where it is needed, improving project viability.
- Storage can efficiently shift solar output across regions and time, reduce transmission congestion, and take advantage of increased price spreads driven by enhanced regional coordination.
- Increased storage additions and more storage charging opportunities result in greater storage ELCC, accelerating fossil retirement.
- **Creates the strongest solar + storage pathway.**

SERC-Wide Resource Mix

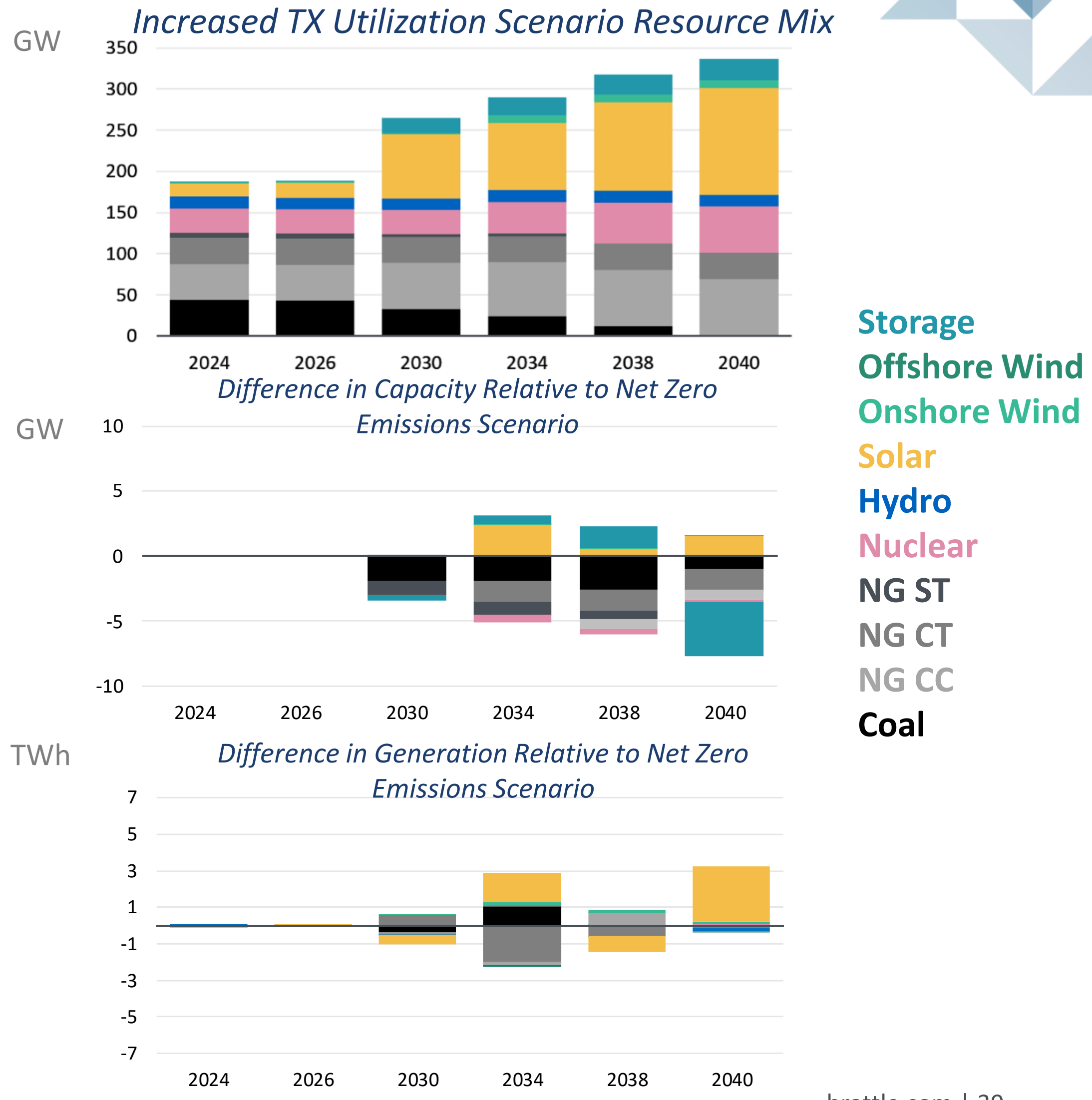


Higher Energy and Capacity Imports Via Regional TX Coordination

On top of higher energy imports, enhanced coordination among SERC regions in meeting resource adequacy reduces the local capacity need for each region.

- Higher energy imports incentivizes earlier solar and storage builds by better balancing the supply of solar generation with electricity demand across SERC.
- Higher capacity imports through regional coordination can allow utilities to rely more on capacity import capabilities to meet load during reliability events, reducing the need for as much local capacity to meet resource adequacy.
- Higher energy and capacity imports result in more and accelerated fossil retirement, encourage earlier solar+storage expansion, and decrease the need for dispatchable and firming resources like storage and nuclear.

SERC-Wide Resource Mix



Additional Fossil Capacity Retirement

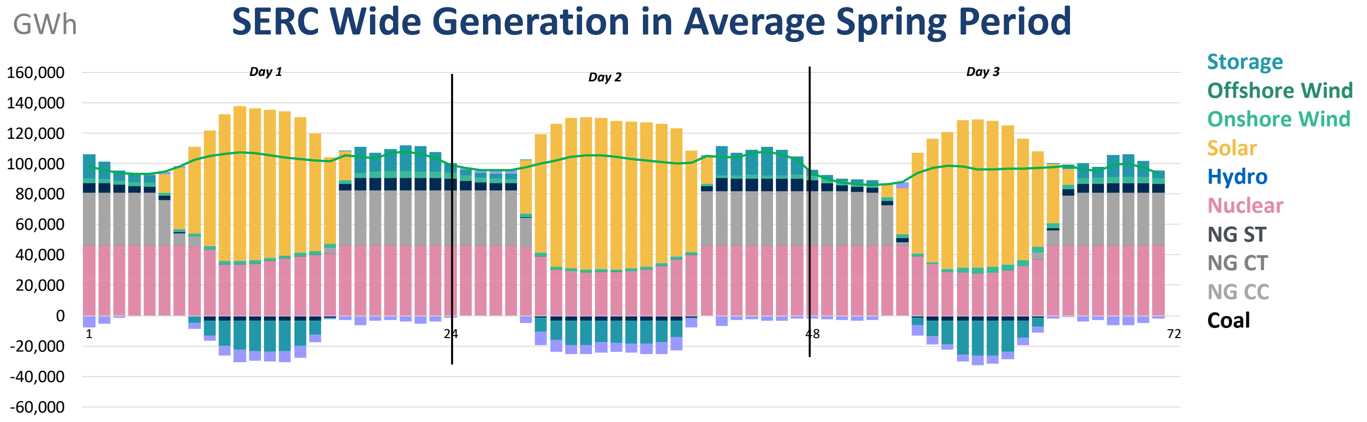
3.4 GW less fossil capacity online by 2040 compared to the Core Net Zero Scenario; 33.7 GW less fossil capacity compared to IRP-specified resource mix.*

- 1 GW more coal retirement; ~2.4 GW less gas capacity relative to Net Zero.
- 17.7 GW more coal retirement; and 16 GW less gas capacity than IRP-specified resource mix.

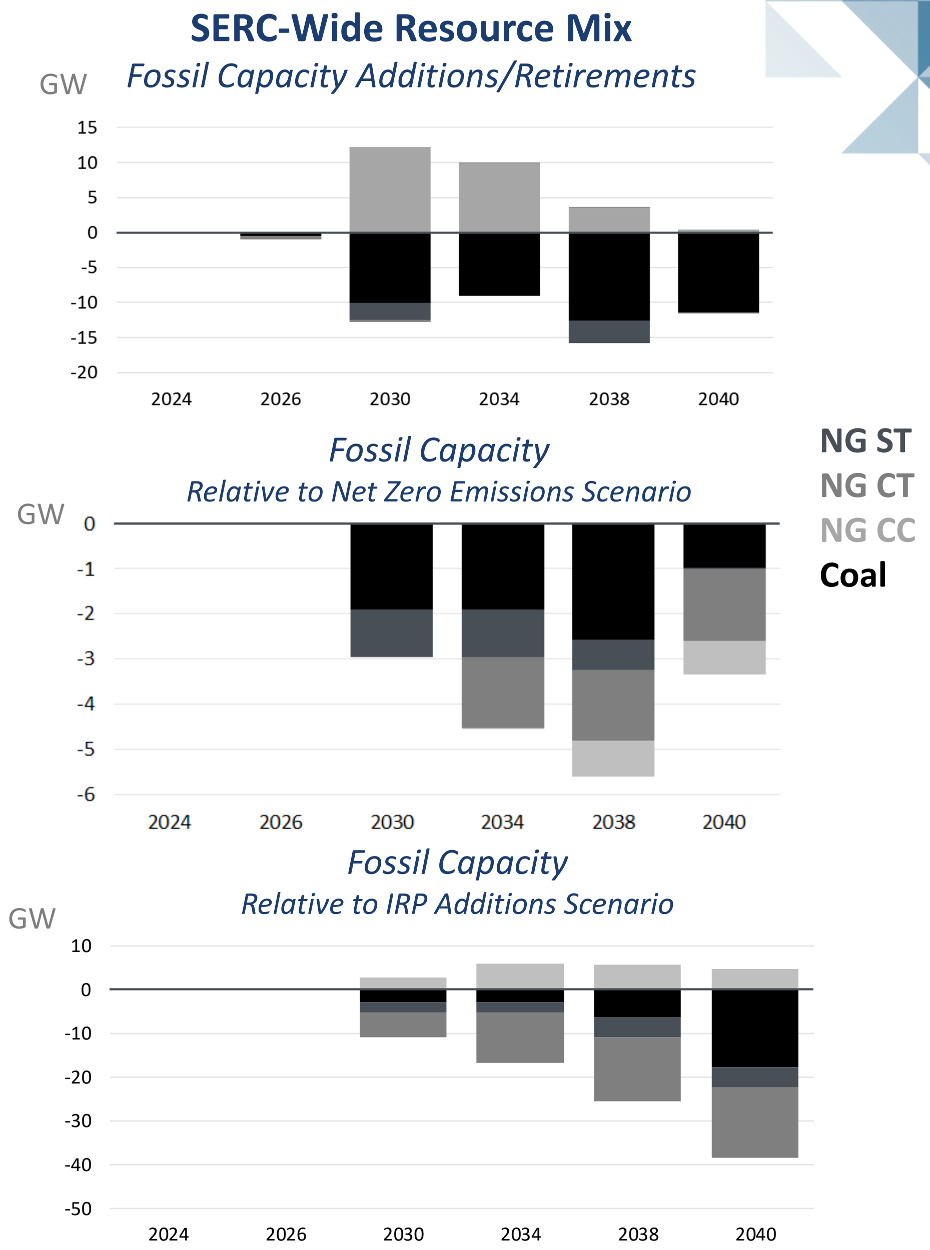
Slightly higher utilization of fossil capacity due to reduced builds.

- Fossil capacity retained largely for resource adequacy purposes.

Less emitting new NGCCs replace existing fossil capacity, generating during hours in which solar declines.



* *Regional aggregation of utility IRP-specified resource additions in the nine utility IRPs reviewed in this study.*



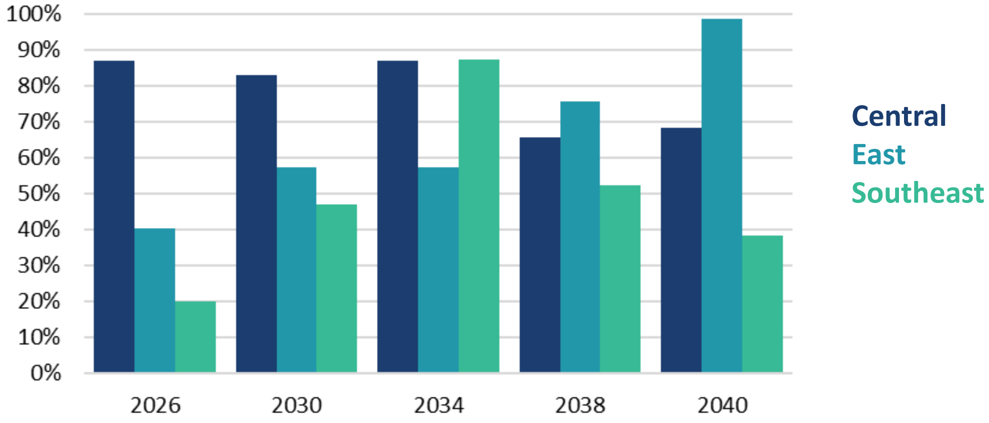
Proxy ELCC of Non-Firm Imports

Proxy ELCCs for non-firm imports represent the average utilization of uncommitted transmission capability across the top RA-constrained hours.

- Despite each region meeting its own resource adequacy needs, transmission with neighbors increases reliability during resource adequacy challenges.
- Transmission utilization for non-firm energy imports into SERC-East during RA-challenged hours increases steadily through 2040 as the regions adds solar and demand grows.
- In the Central and Southeast regions, energy imports during RA challenges peaks around 2034. After 2034, these regions increasingly rely on dispatchable resources – NGCC plants (Central, Southeast) and nuclear (Southeast) – leading to greater local resource utilization.
- The proxy ELCC of transmission for non-firm imports can vary significantly over time based on system conditions.

Proxy ELCC of Non-Firm Imports

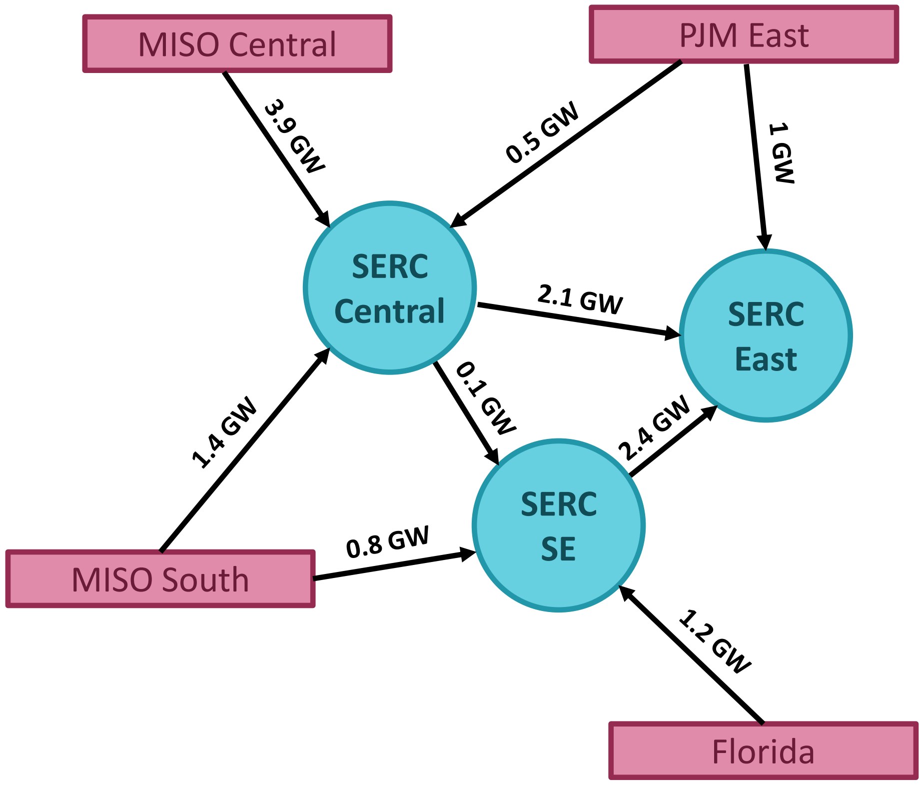
Improved TX Utilization (Higher Energy Imports)



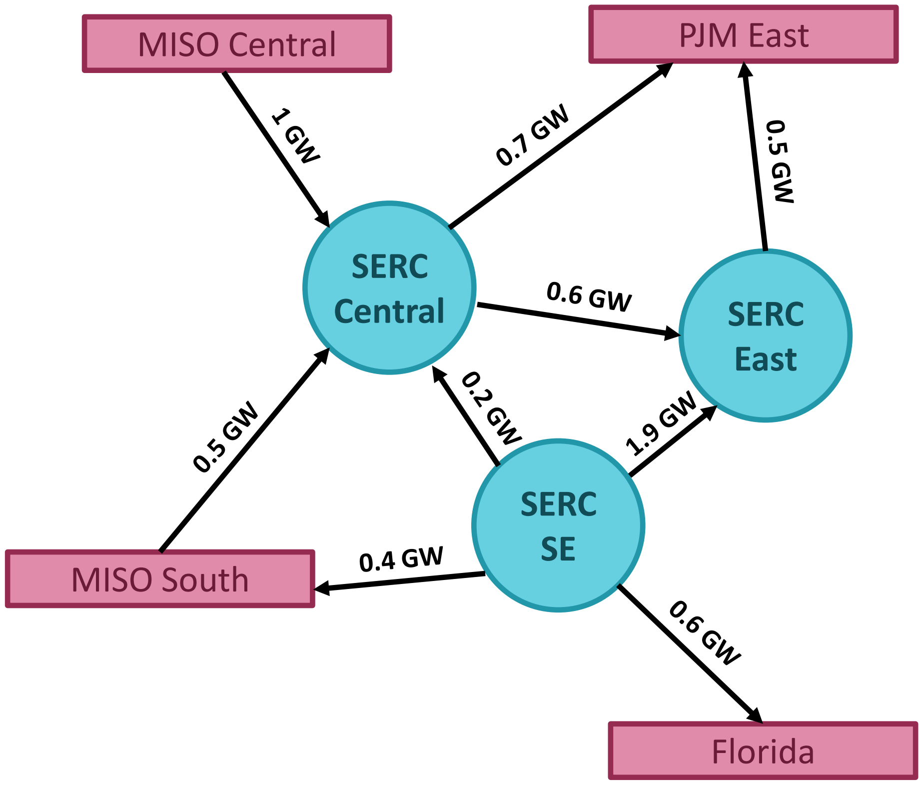
The top RA-constrained hours are defined based on the resource supply cushion, calculated as all available resources plus the capacity import limit, minus the RA requirement. All of the top RA hours occur in Winter.

Average Transmission Utilization

Average Flows Across Top Resource Adequacy Challenged Hours
Regional TX Coordination



Average Flows Across Full Year
Regional TX Coordination

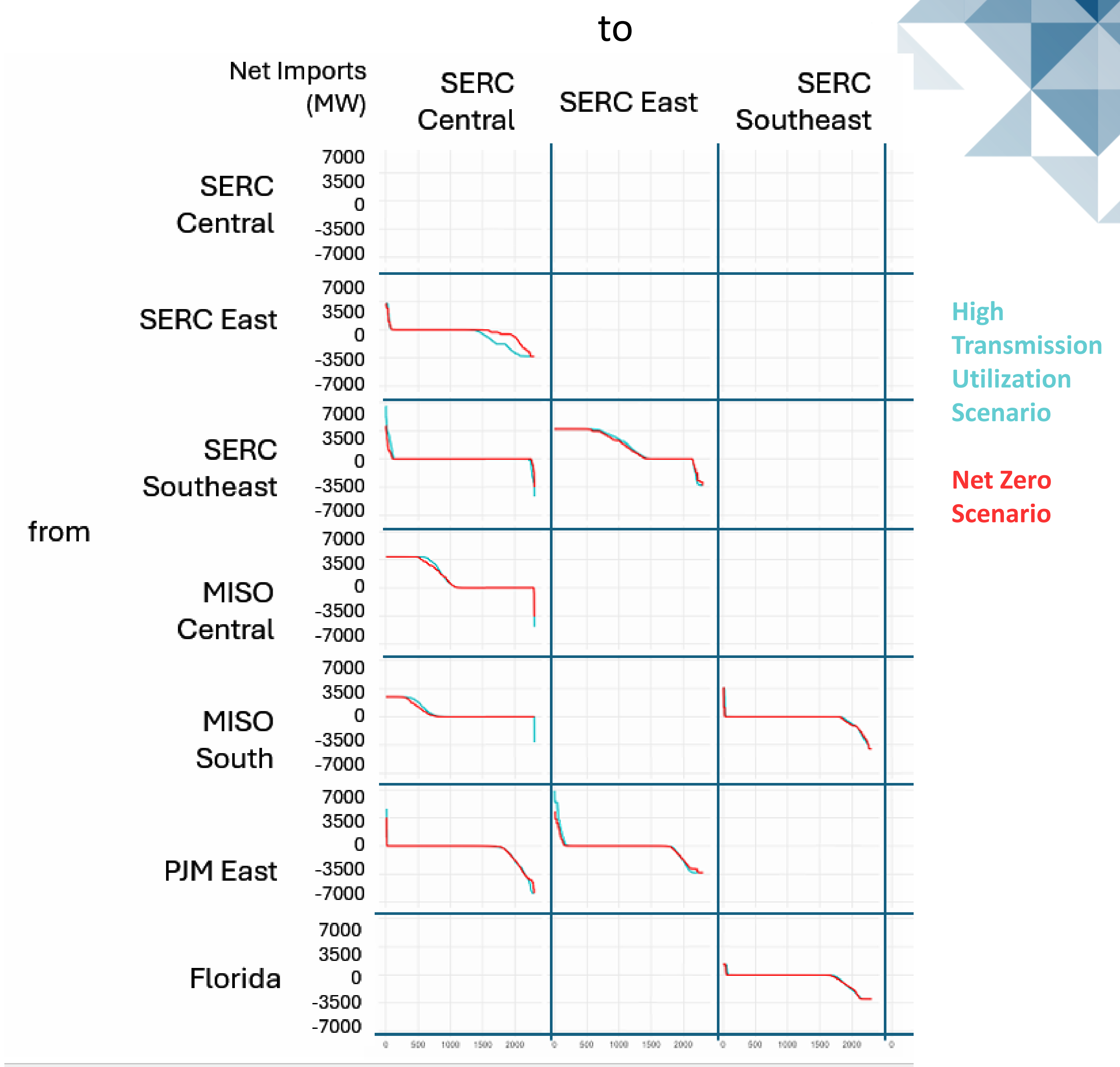


The top RA-constrained hours are defined based on the resource supply cushion, calculated as all available resources plus the capacity import limit, minus the RA requirement. All of the top RA hours occur in Winter.

Net Import Duration Curves

Interzonal net energy flow duration curves are illustrated on the right.

These reflect efficient interzonal trade dynamics, particularly during the tightest system conditions.



Detailed results:

2050 Net Zero Emissions Scenario

Increased Load Flexibility

GRIDSIM-OPTIMIZED RESOURCE MIX MEETING REGIONAL DEMAND & 2050 NET ZERO EMISSIONS

Demand Flexibility Parameters

This sensitivity evaluates the value that load flexibility provides to resource adequacy relative to other grid capacity options.

- To simulate this assessment, we assume 17 GW of load flexibility capacity across SERC regions is allowed to dispatch for a maximum of 4 hours at a time to reduce load. To evaluate the technical potential of load flexibility across various programs, further studies need to be conducted, recognizing barriers that need to be overcome to mobilize the assumed levels of megawatts.
- Load flexibility is modeled with an upfront cost of $100/kW-yr and dispatch cost of $1000/MWh.
  - Our analysis shows that the break-even cost for load flexibility such that total system NPV does not increase relative to the core Net Zero scenario is $80/kW-yr.
- Load flexibility can be dispatched at less than the maximum amount of GW capacity, allowing it to dispatch for longer durations by staggering which portion of the capacity is dispatched at a time.
  - We see the maximum dispatch of load flexibility during our extreme winter peak model days, where it dispatches up to around 12 hours consecutively overnight.
  - No more than 8 GW of load flexibility is dispatched simultaneously, demonstrating how the 17 GW total is spread across hours of greatest RA need.
  - This extreme peak day is modeled as a one-in-fifteen-years incident, so dispatch of this magnitude would be extremely rare.

Modeling Demand Flexibility

Flexible demand in gridSIM broadly represents a range of load modification options:

- Emergency demand side response that reduces load when grid is under stress
  - E.g., Large customer demand response
- Demand flexibility; i.e., the strategic use of appliances, electric vehicles and other BTM resources to shift the timing of electricity demand and restore balance to the grid during peak events.
  - E.g., Smart HVAC control, EV vehicle to grid (V2G) programs; battery

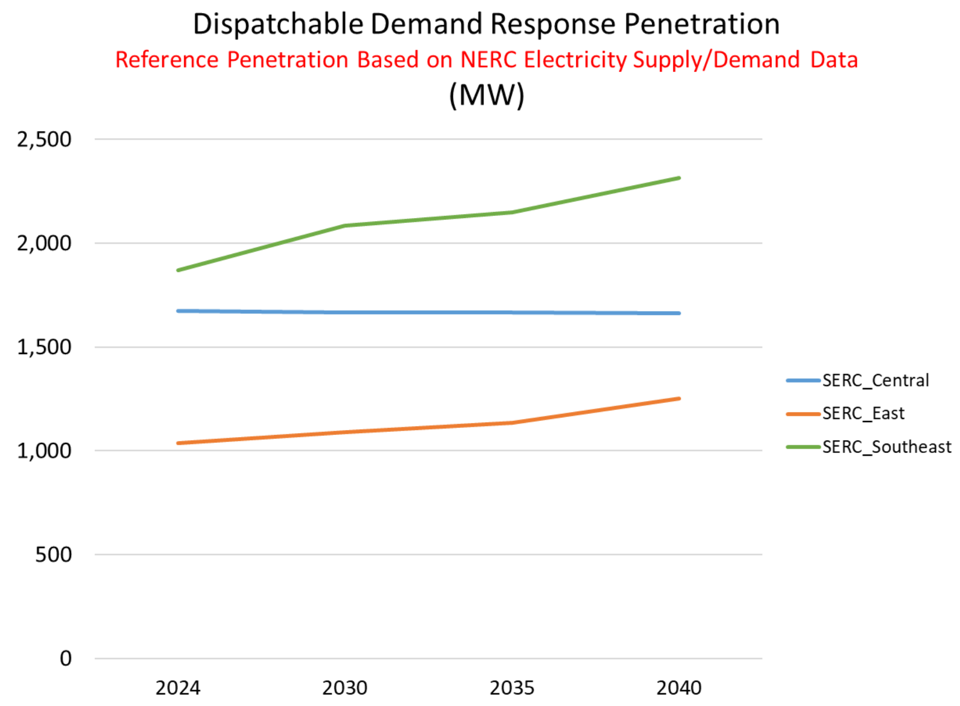
Current Load Data in gridSIM Modeling Accounts for Following:

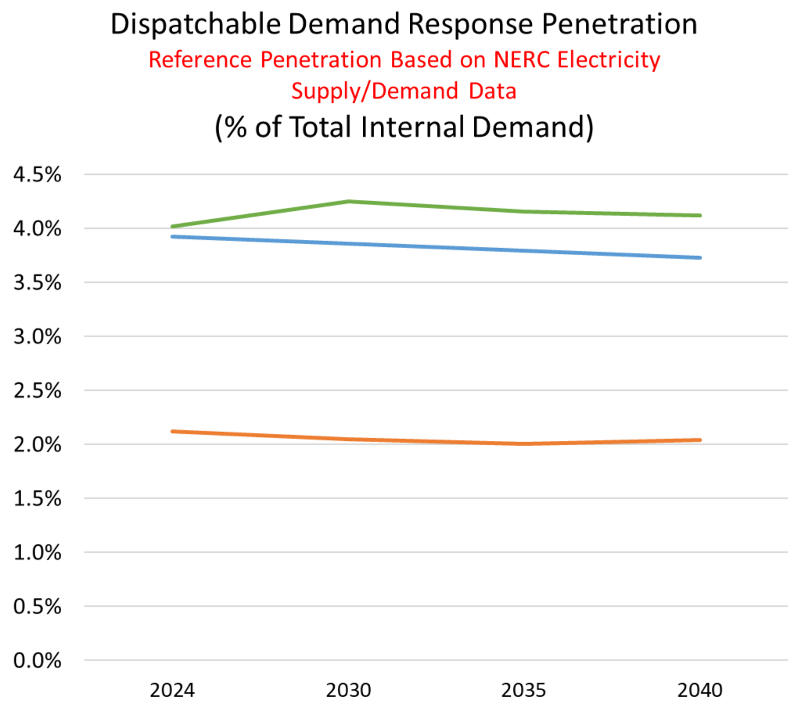
- Hourly load shape, which is based on FERC 714 utility specific data, accounts for historical net energy which already accounts for impact of EE and DR programs
- We model future peak and total energy using NERC's projection of **Total Internal Demand**, which adjusts for passive demand resources that are not dispatchable. Examples include energy efficiency measures, such as the use of energy-efficient appliances and lighting, advanced cooling and heating technologies, and passive behind-the-meter generation such as solar power.
  - **Our load projection does not account for Controllable Capacity Demand Response used to reduce peak load!**

Reference Levels of Grid Flexibility

NERC's Electric Supply and Demand (ESD) data collects at the region level, dispatchable demand response capacity for 2024-2033. Post 2034, DR shares projected based on historical growth.

We convert active MW DR levels into DR shares of system peak.

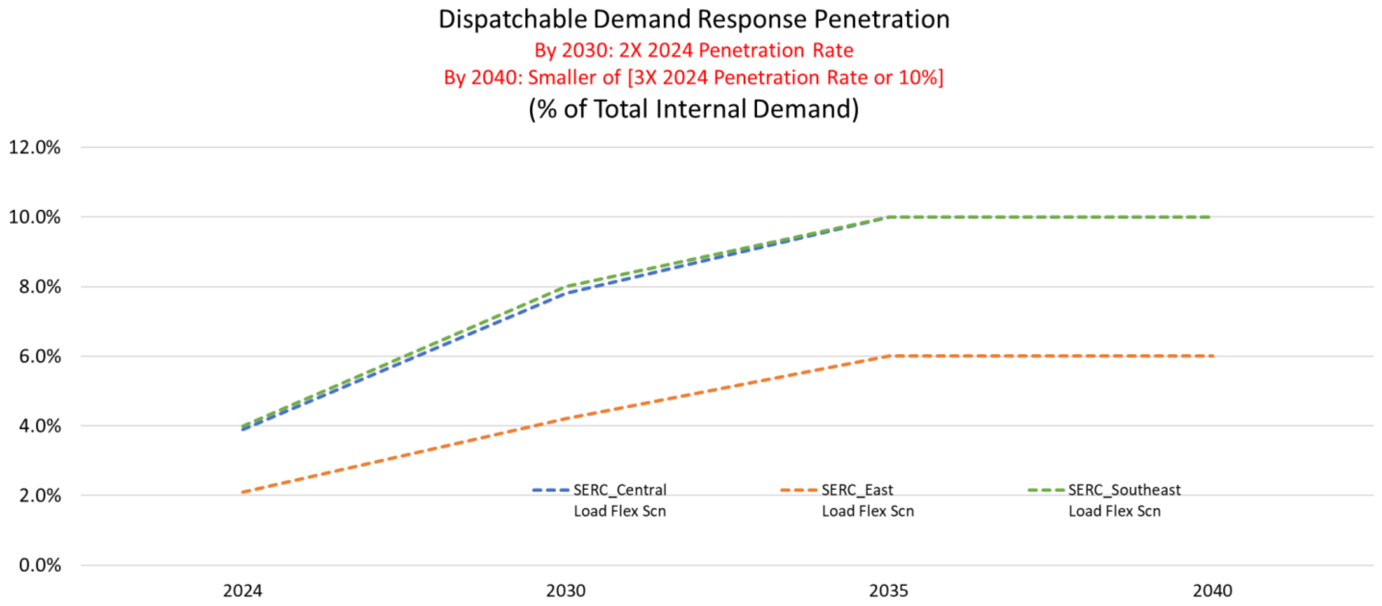




Dispatchable Demand Response in Flexible Load Scenario

Increased Load Flexibility Scenario assumes:

- Double 2024 DR shares by 2030.
- Reach 10% (Central and Southeast) and 6% (East) by 2035.
- Post 2035 maintain 10% and 6% dispatchable DR shares.
- 17 GW total DR in 2040 (3.7 GW East, 5.5 GW Central, 7.8 GW Southeast)



Resource Mix Across SERC

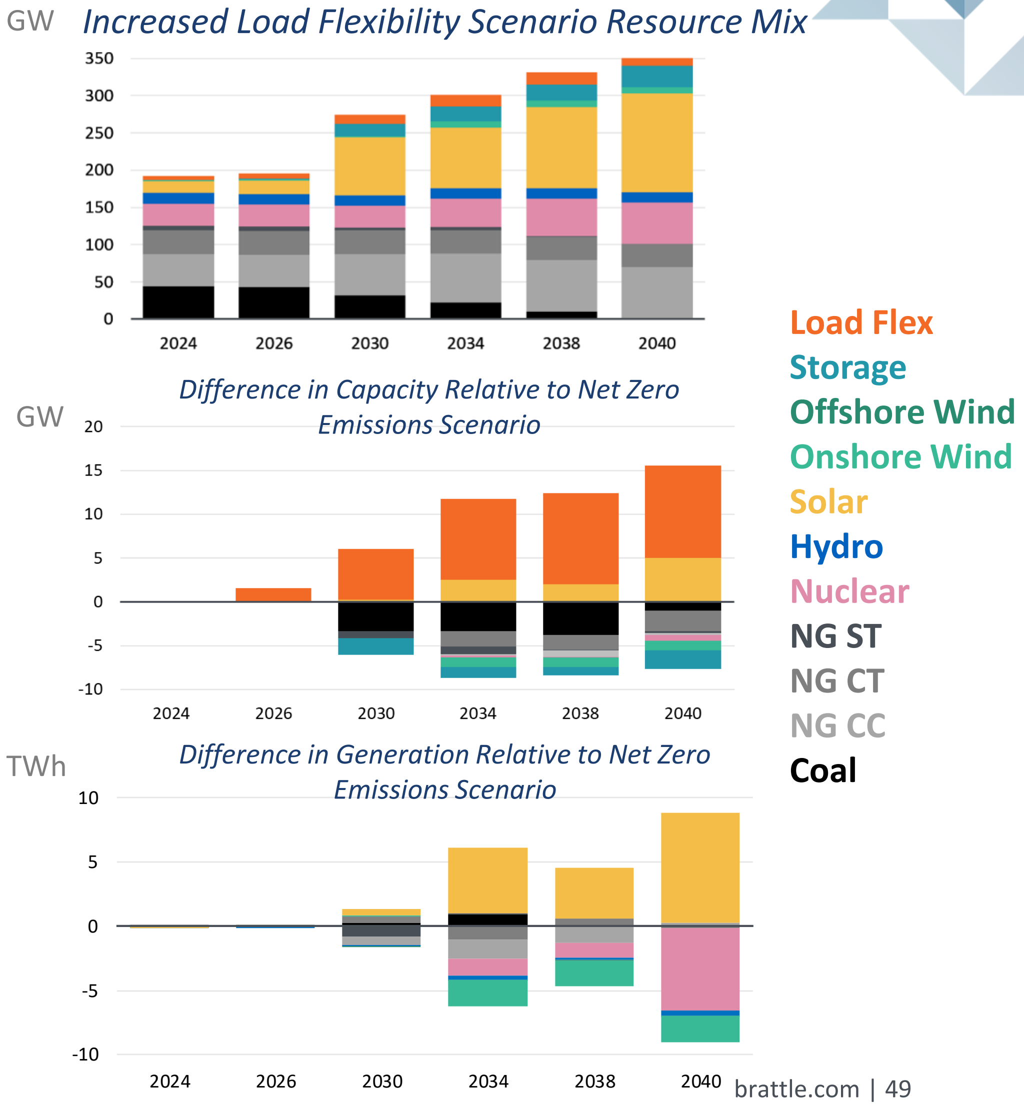
Load flexibility moves high system peak demand to align with solar generating hours, incentivizing more solar builds.

- Load is shifted from early winter morning hours (when solar generation is least available) to solar generating hours.
- Because load can shift toward solar generating hours, less need for storage as using solar power directly is more efficient than storing it in a battery and using it later, as energy is lost in the storage process.
  - Similarly, less nuclear builds due to less need for firm, dispatchable resources.
- Wind additions also decrease, as load shifting helps avoid the costly process of siting turbines high enough to harvest high wind speeds.

More grid flexibility results in less resource additions and faster retirement of emitting resources.

- Less resource additions needed as flexible load reduces system peak and hence resource adequacy requirements.
- Compared to the Net Zero Emissions scenario, coal and other fossil resources retire faster. All coal and gas STs retired by 2040.
- The modeled flexibility case is relatively modest, increasing dispatchable demand response from ~2-5% today to 6-10% by 2035.
- Future data center load growth is modeled, but potential data center flexibility is not, suggesting additional upside beyond the results shown.

SERC-Wide Resource Mix



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- 17.8 GW more coal retirement; and 16.4 GW less gas capacity than IRP-specified resource mix.

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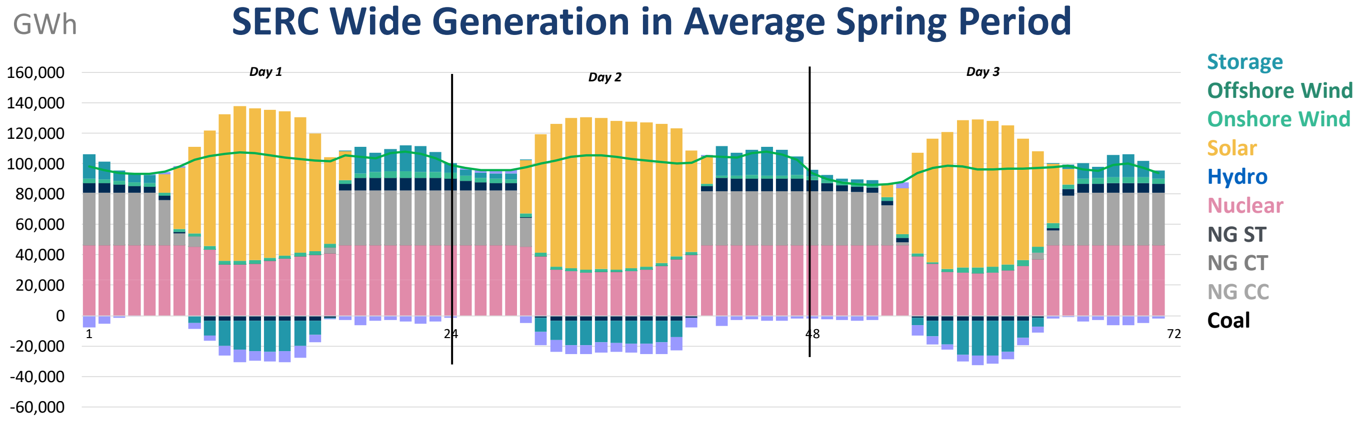

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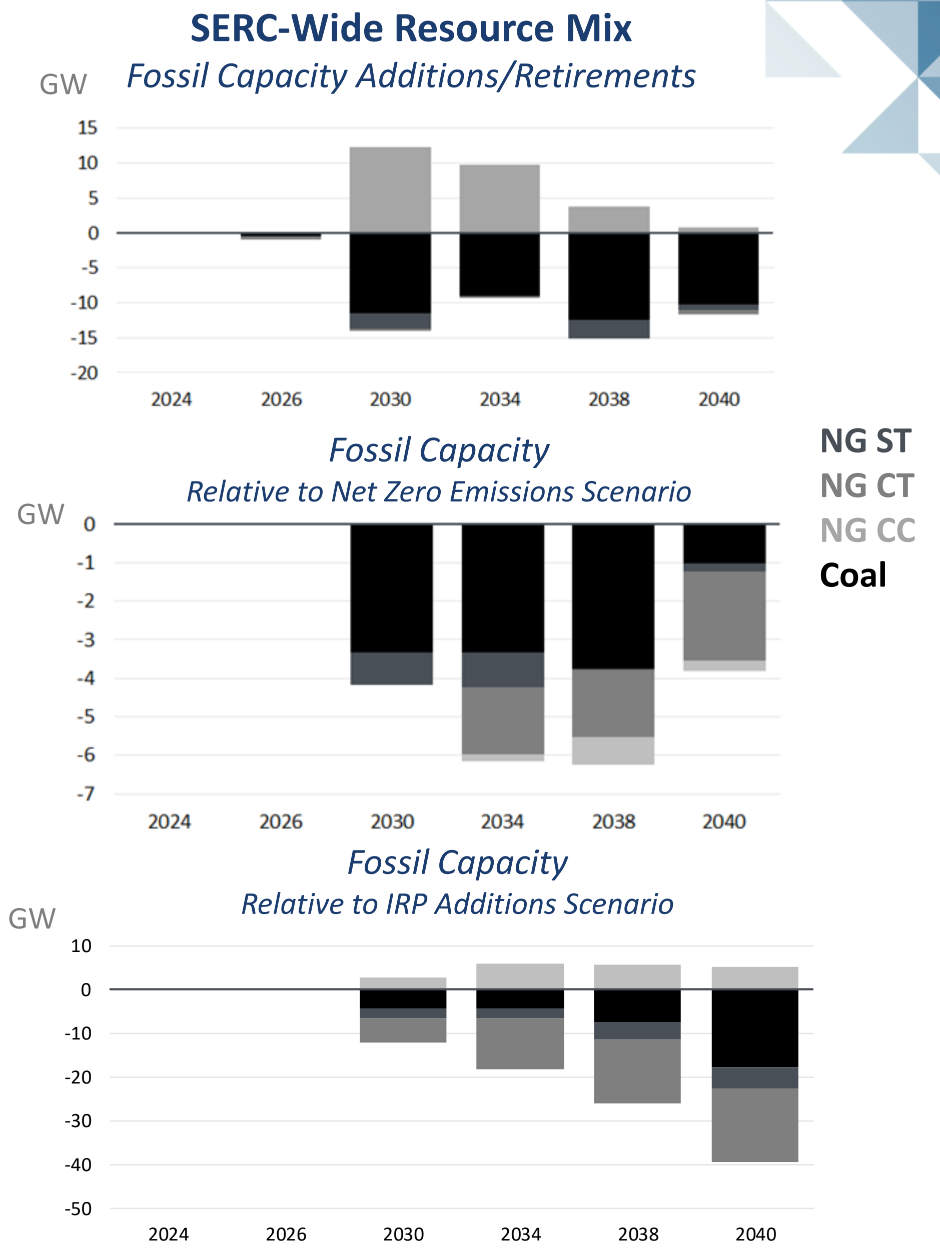
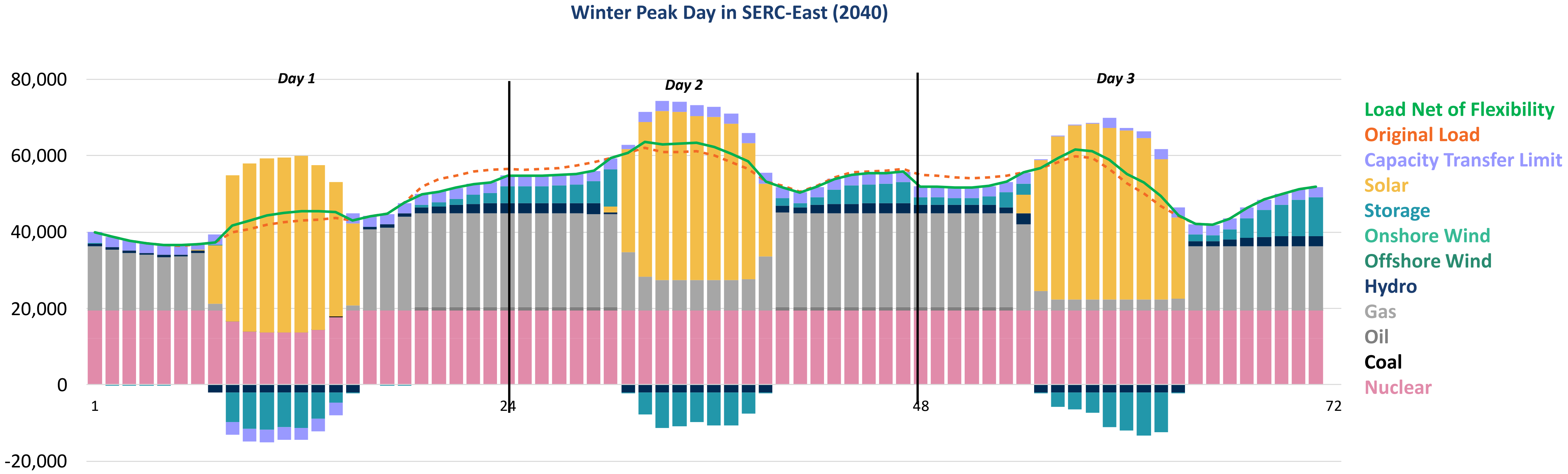


Flexible Load Moves Toward Solar Generating Hours



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Capacity Expansion using **gridSIM**

INPUTS

Supply
- Existing resources
- Fuel prices
- Investment/fixed costs
- Variable costs

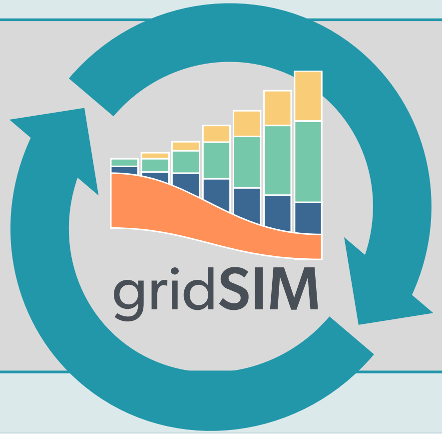
Demand
- Weather-reflective (hourly) proxy year
- Hourly energy and capacity needs

Transmission
- Zonal (energy and capacity) limits
- Intertie limits

Regulations, Policies, Market Design
- Capacity market
- Carbon pricing (RGGI)
- State energy policies and procurement mandates

gridSIM OPTIMIZATION ENGINE

Objective Function
- Minimize NPV of Investment & Operational Costs



Constraints
- Market Design and Co-Optimized Operations
  - Capacity
  - Energy
- Regulatory & Policy Constraints
- Resource Operational Constraints
- Transmission Constraints

OUTPUTS

Annual Investments and Retirements

Market Prices

Hourly Operations and Resource Adequacy Challenges

Emissions and Clean Energy Additions

Weather and Resource Adequacy Sampling (WRAS)

Brattle's WRAS tool creates a **weather-reflective proxy year** with appropriately probability weighted multi-day periods reflecting the range of load, renewable, and generation outage conditions that are expected to occur over the course of 15 weather years. WRAS greatly enhances the representation of resource adequacy challenges (and the evaluation of solutions to address them) in capacity expansion and production cost simulations, including in power grids with high load growth and high shares of weather-dependent resources.

INPUTS

15 weather years of system-wide and zonal data:

- Load forecasts for weather years
- Wind, solar, and hydro profiles (including multi-day renewable droughts and variable hydro conditions) for weather years
- Planned and forced generation outages (including high hot/cold weather outages)

OUTPUTS

- Proxy year composed of multi-day proxy periods (or proxy weeks)…
- … that reflects the renewable, load, and generation outage conditions that are expected to occur over many weather years
- Load and renewable/hydro generation profiles for each of the multi-day proxy periods
- Weights for each proxy period that reflect the expected frequency over entire weather sample

Resource Adequacy Approach

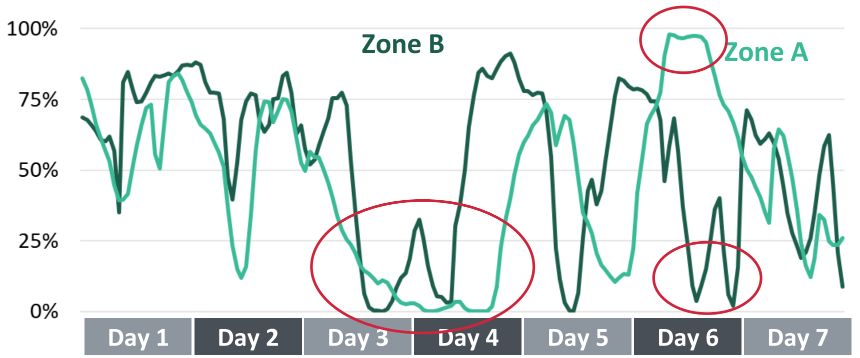
Conventional approach to considering resource adequacy in expansion modeling:

- Based on forecasted **normalized summer peaks plus planning reserve margins**
- **Capacity accreditations** based on **ELCC values** (specified as a function of resource shares)
- Challenge: requires a lot of assumptions (about the nature of future resource adequacy challenges, ELCCs, and planning reserve margin) that will change significantly in an increasingly decarbonized and electrified future

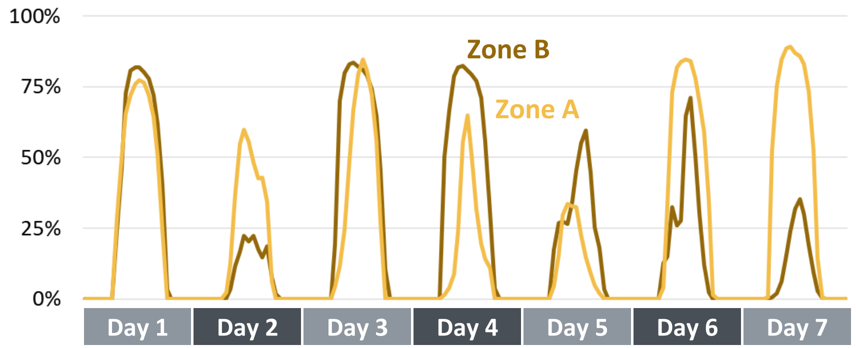
"Dynamic" hourly approach to resource adequacy

- Create a **proxy weather year** based on load and renewable data for **15 weather years and cold snaps** to approximate the expected future challenges SERC may experience
  - Heat waves, cold snaps, renewable droughts
  - Realistic seasonal, daily, hourly variations
- Each model year is represented by **32 three-day periods** that capture representative conditions across all weather years. These periods span four seasons, typical summer and winter peak periods, and extreme weather periods that represent heatwaves and coldsnaps
  - Each 3-day period has a different probabilistic weight consistent with 8760 hours in 15+ weather years
- The simulation balances supply and demand in every hour, including **operating reserve requirements.** This identifies when resource adequacy challenges could occur in the future
  - Future risk likely concentrated in certain months and hours outside of summer peaks
  - The model will choose generation investments and technologies capable of meeting needs
- The results inform when the existing RA frameworks may need to be modified in the future (but will need to be confirmed through probabilistic LOLE analyses with SERVM)

Example Week: Hourly Wind Profiles



Example Week: Hourly Solar Profiles



Note: Renewable profile shown for a sample week to highlight hourly and geographic variation in the 15-year dataset. Profile expressed as hourly generation % of nameplate capacity.

Application of WRAS

WRAS is a Brattle-developed approach for capacity expansion planning and production cost simulations that allows for greatly enhanced resource adequacy modeling with reasonable computational effort:

- Feasibly compliments production cost and capacity expansion modeling by relying on multi-day proxy periods with respective weights to represent 8,760+ hours of data
- Allows for hourly resource adequacy modeling when integrated in capacity expansion modeling with combined hourly approach to resource adequacy (instead of the traditional planning reserve margin, normalized load, and static ELCCs)
- Eliminates the need for simplistic or computationally expensive projections of ELCC through endogenous modeling of resource accreditation within a capacity expansion or production cost simulation that captures full weather conditions
- Identifies periods with resource adequacy challenges over a 15-40 available weather years – and how challenges change with evolving resource mixes and load growth over time
- Meaningfully informs the relative severity of energy shortfall across the identified reliability events (severity of reliability events), especially because WRAS includes the tail-events of challenging weather, load, and generation outages.
- Overall, WRAS yields more realistic expansion planning and market simulation results:
  - Realistic, resource-adequate, and more resilient (scenario-based) projections of generation expansion
  - Realistic wholesale power prices (zonal or nodal), reflecting real-world scarcity conditions, resilience challenges, and geographic diversity
  - Realistic congestion prices and congestion-related costs
  - Realistic estimates of future generation investment and operating costs
  - Realistic benefit-cost analyses for transmission planning and market reforms

WRAS Accounting for Weather-Related Uncertainties

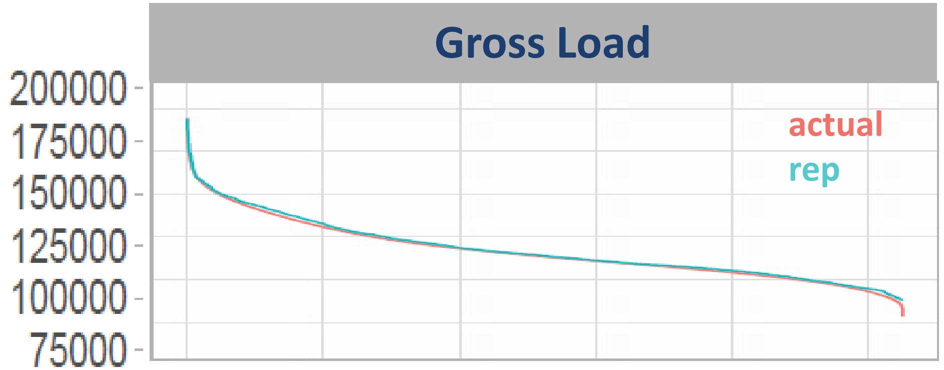
GridSIM models representative periods instead of 8760 observations for each year

- Periods selected based on k-means clustering of multiple variables such as gross load, net load adjusted for planned outages, solar hourly capacity factor, and wind hourly capacity factor profiles of a study year

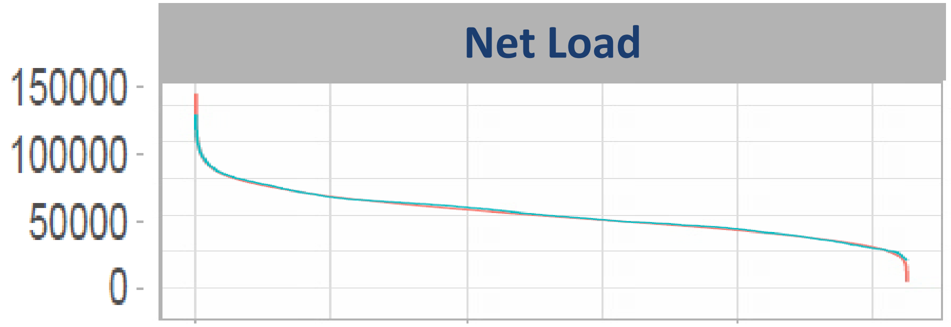
Weather uncertainty accounted for by simulating synthetic profiles for a "proxy year" that reflects numerous weather years

- 15 weather years of load and renewable data represented by a single proxy year, comprised of up to 32 three-day periods
- Each period has a weight based on the frequency at which periods with similar conditions occur during the entire 15-year sample
- As a check on the true representativeness of the selections made by our time sampling algorithm, we apply the period "weights" (i.e. the number of periods every period is representative of) to the selected representative periods and expand it to produce 15x8760 hourly profiles. We then benchmark them against the actual 15-year profiles.
- We see that the proxy year shapes (load, renewable profiles) map closely to the last 15 years. Our peak day selection methodology ensures that we capture the highest gross and net load days.

Draft Representative Period Sampling Result

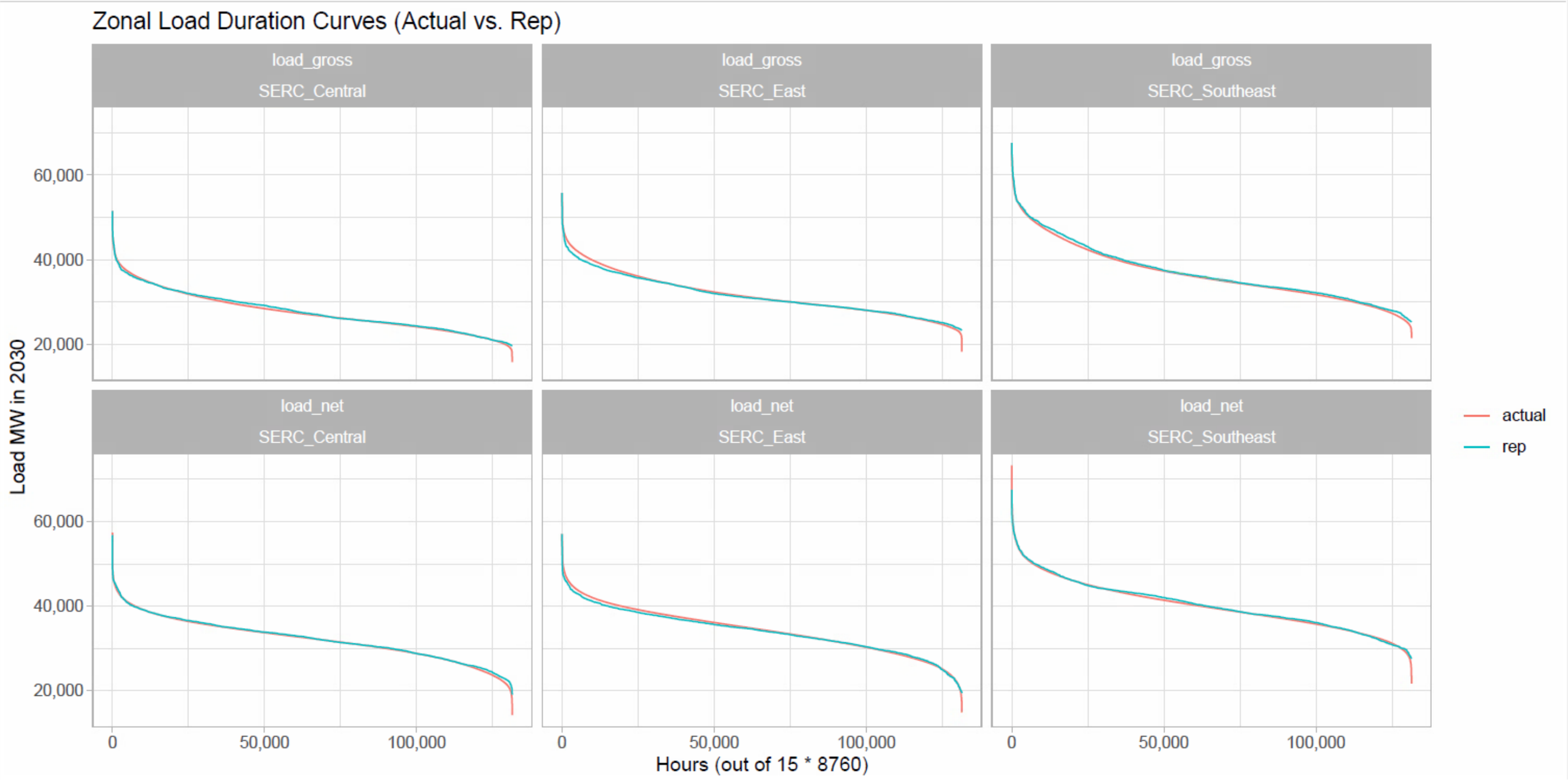


*Hours (out of 8760 * 15)*



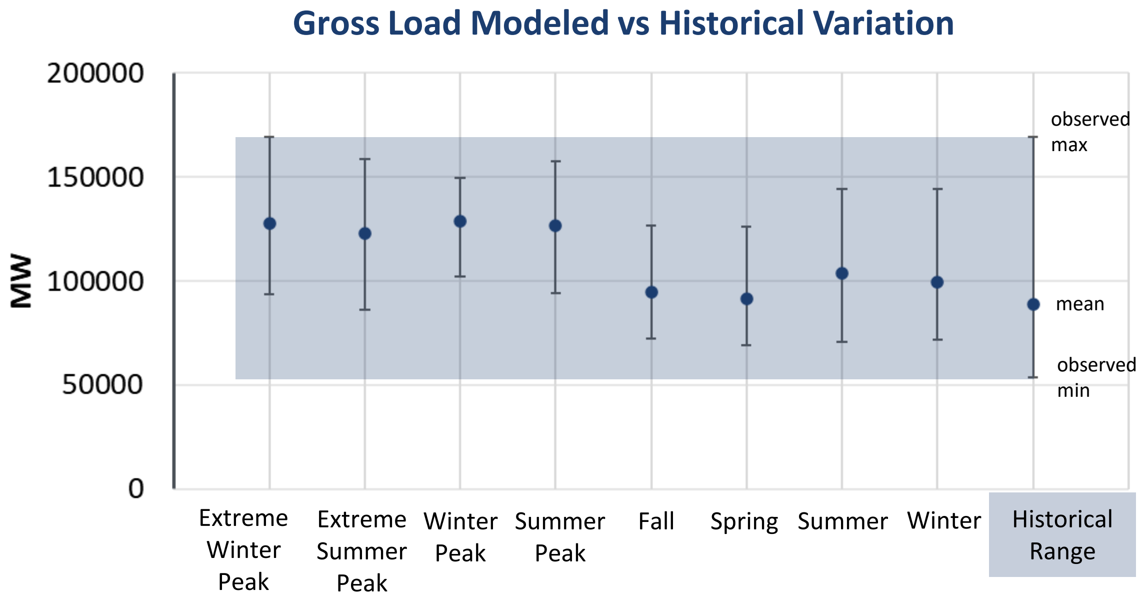
*Hours (out of 8760 * 15)*

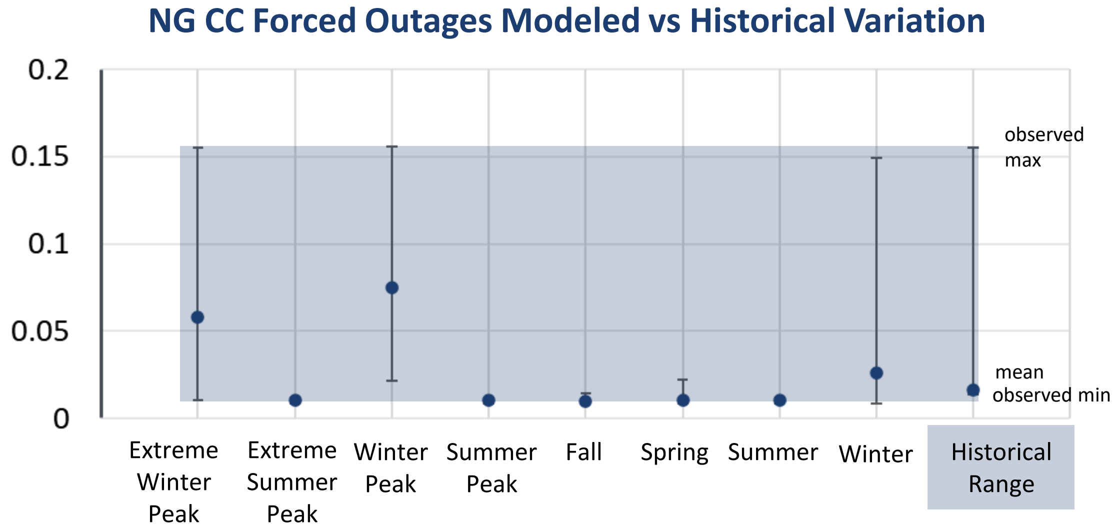
WRAS Capturing Load Variability: Zonal Load Duration Curves



- Duration curves demonstrate the variability captured within our model year.
- Our model year in blue is compared to the magnitude of values in the actual historical data (last 15 years).
- Comparing the top left and the bottom right of each duration curve, we see that we are capturing the highest net load hours well, with less emphasis placed on capturing low net load hours.

gridSIM Captures Historical Load and Forced Outage Variation

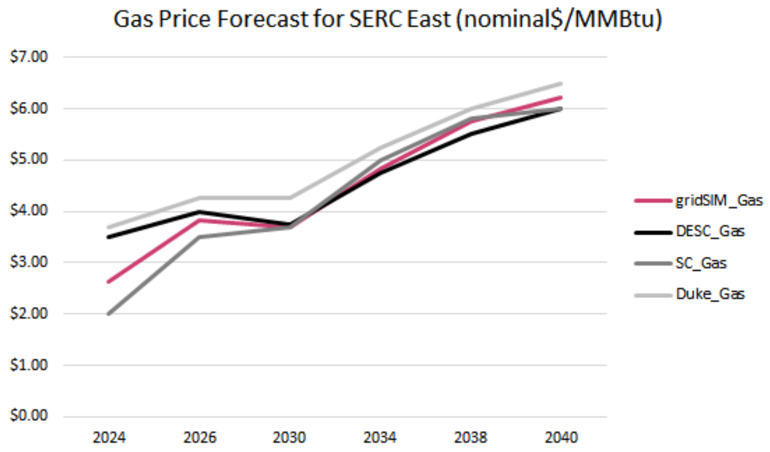


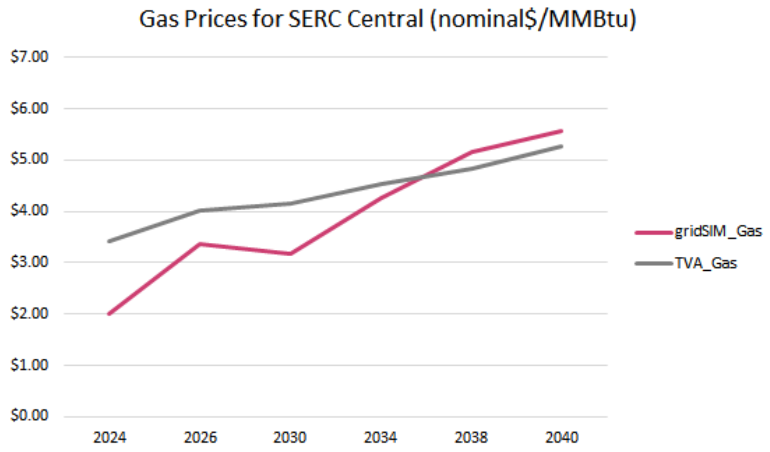


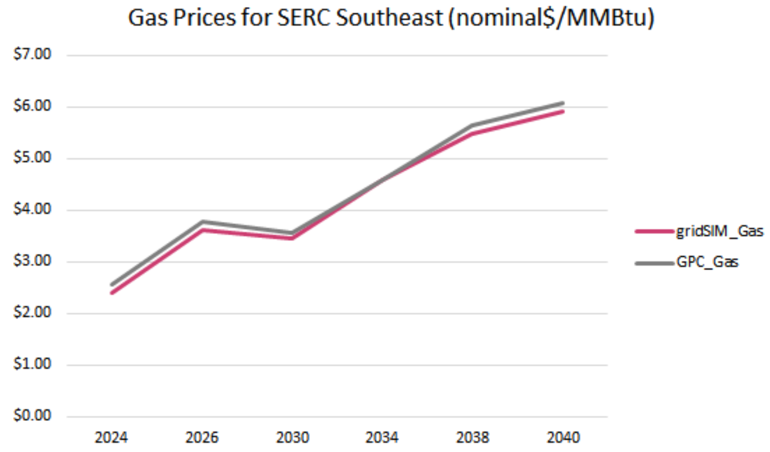
- Dots represent average values, with whiskers extending to indicate observed maximum and minimum values.
- The historical range is represented by the bounds of the blue shaded area, with all modeled year observed values falling within that range.
- These plots indicate that our extreme winter/summer days in our model year capture the tightest load and have the highest NG CC outages.

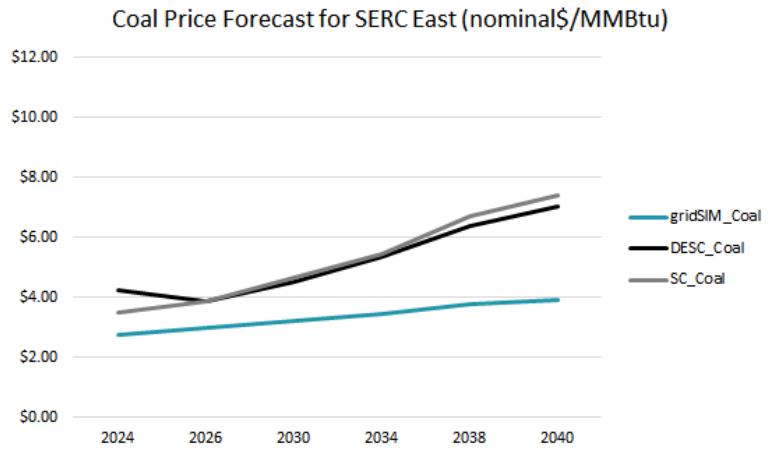
Fuel Price Projections

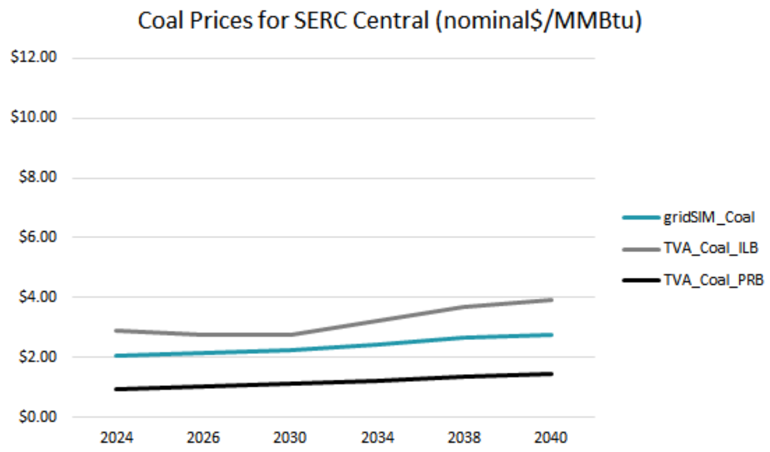
Fuel price projections help explain why coal generation increases between 2024 and 2026

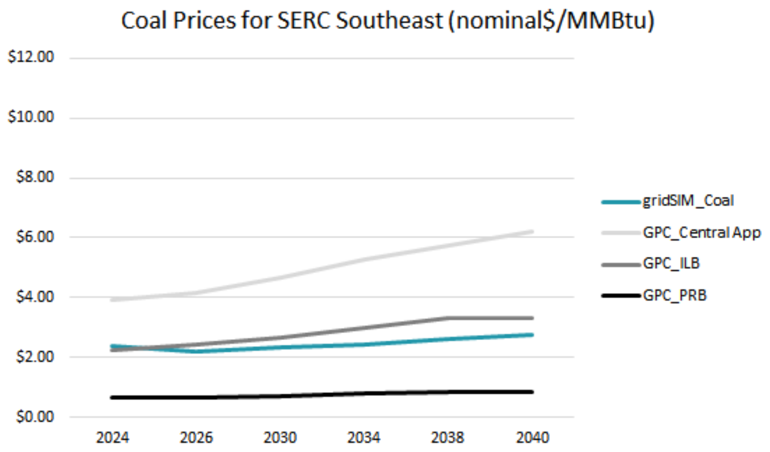












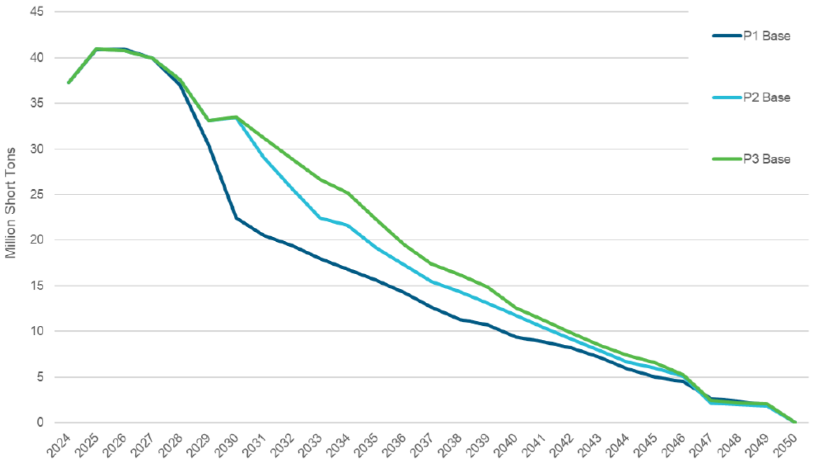
Emissions Trajectories are Defined Based on IRPs

Utility	IRP Emissions Trajectory (Reference Scenario)	Utility Emissions Goals (Net Zero Scenarios)
Tennessee Valley Authority	Sourced from Scenario 6A (Reference w/ Greenhouse Gas Rule, Baseline Utility Planning). Reduction of approx. 53% from 2024-2040.	80% reduction by 2035 (from 2005 baseline) and Net Zero by 2050. (Note: IRP scenario does not reach Net Zero by 2050)
LGE & KU	No defined emissions trajectory in IRP, instead uses modified version of emissions goal (72% of goal is achieved).	80% reduction by 2040 (from 2010 baseline)
Duke Carolinas	Sourced from P3 Base scenario. Emissions reach Net Zero by 2050.	70% reduction by 2035 (from 2005 baseline)
DOM South Carolina	Sourced from 2024 Reference Build Plan. Emissions reach 44% reduction from 2005 levels by 2050.	Net Zero by 2050. (Note: IRP scenario does not reach Net Zero by 2050)
Santee Cooper	Sourced from 2024 Portfolio with PPAs. Emissions reach 47% reduction from 2005 levels by 2040.	70% reduction by 2030 (2005 baseline) and Net Zero by 2050. (Note: IRP scenario does not reach Net Zero by 2050)
Georgia Power	No defined emissions trajectory in IRP, instead uses modified version of emissions goal (72% of goal is achieved).	50% reduction by 2030 (from 2007 baseline) and Net Zero by 2050
Alabama Power	No defined emissions trajectory in IRP, instead uses modified version of emissions goal (72% of goal is achieved).	50% reduction by 2030 (from 2007 baseline) and Net Zero by 2050

Note: emissions trajectories for neighboring regions set based on NREL Cambium. 72% of goal is achieved for utilities with no defined IRP Emissions Trajectory based on comparison between IRP trajectory and stated emissions goal across other utility regions.

IRP Emissions Trajectories for SERC East

Duke IRP Emissions Trajectory



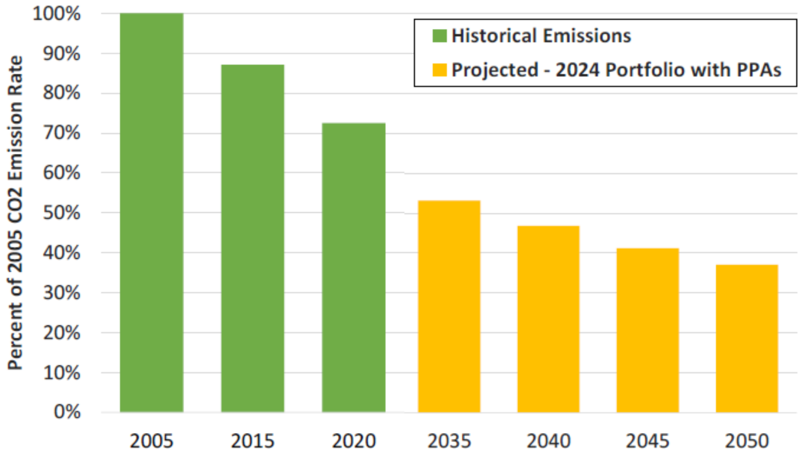
2023 Duke IRP, Chapter 3, Figure 3-11 (P3 Base)

Dominion IRP Emissions Trajectory

Core Build Plans 2050 CO_2 Emissions (Ktons) of the Core Build Plans			
	Market Scenario		
Build Plan	**Reference**	**High Fossil Fuel Prices**	**Zero Carbon Cost**
Updated 2023 Reference Build Plan	8,560	8,556	8,587
2024 Reference Build Plan	8,291	8,286	8,315
High Fossil Fuel Prices Build Plan	7,972	7,967	7,996
Zero Carbon Cost Build Plan	10,602	10,600	10,650
85% CO_2 Reduction Build Plan	2,925	2,924	2,925

2024 Dominion IRP, Table 24 (2024 Reference Build Plan)

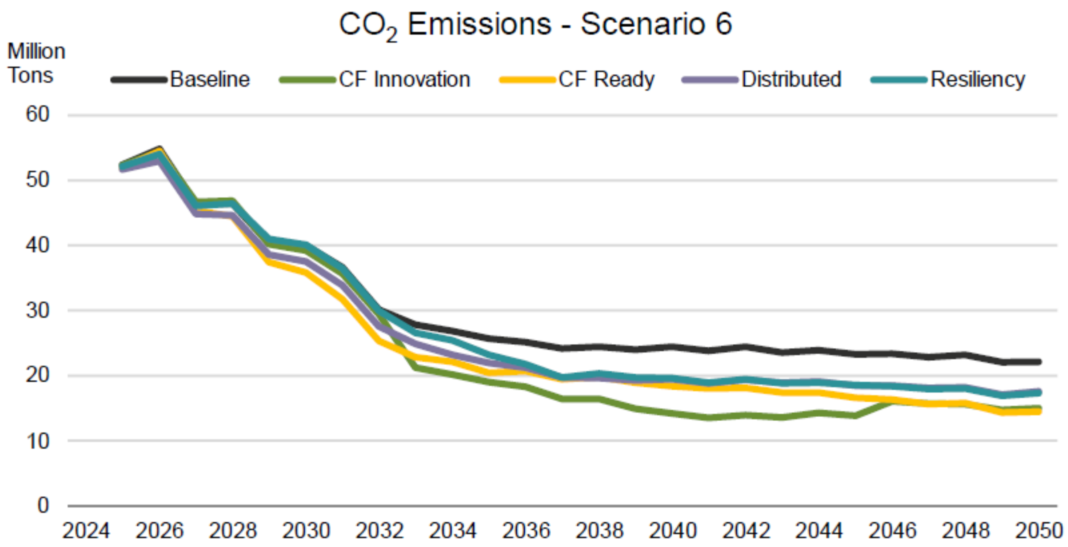
Santee Cooper IRP Emissions Trajectory



2024 Santee Cooper IRP, Figure 23

IRP Emissions Trajectories for SERC Central

TVA IRP Emissions Trajectory



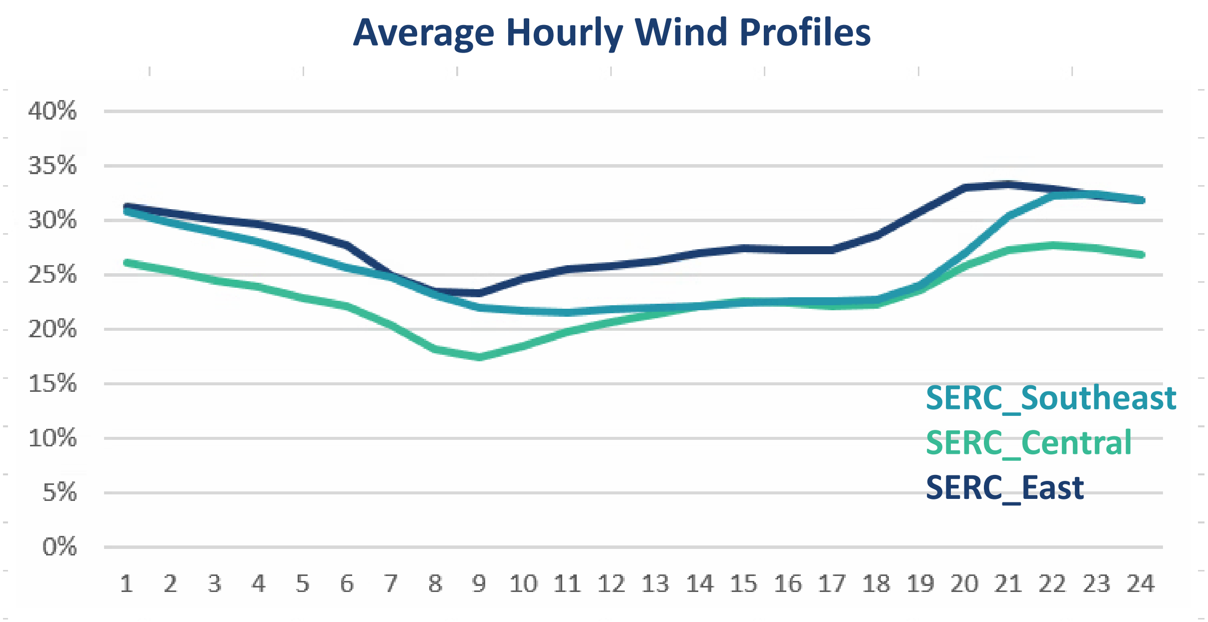
2025 TVA IRP, Figure J-6, Scenario 6 (Baseline with GHG)

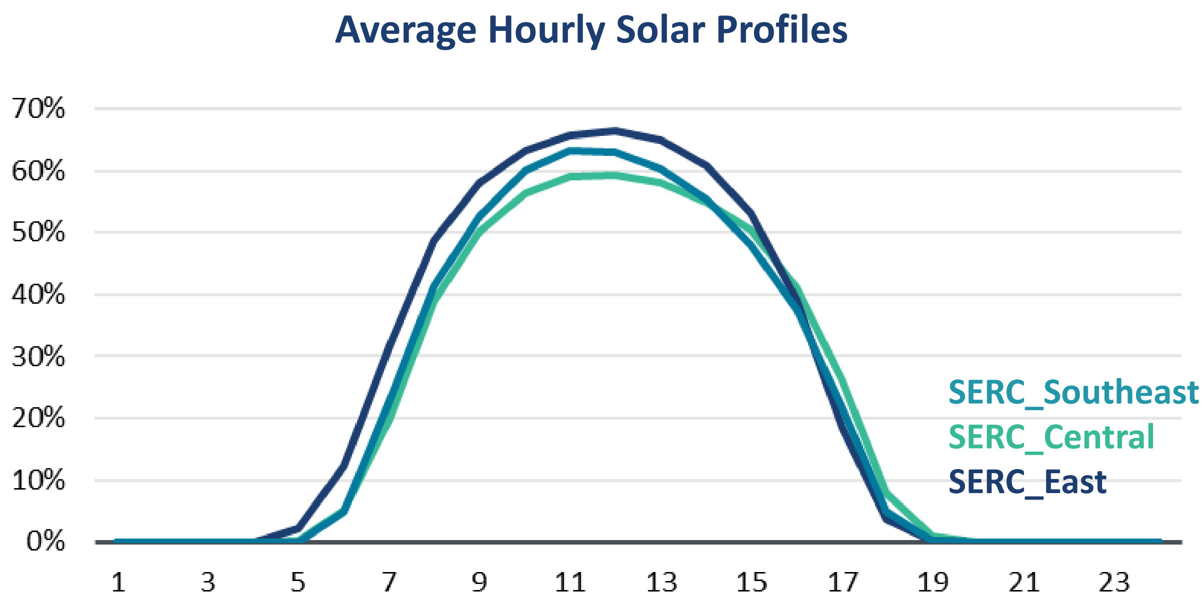
Tax Credits Assumed in Study

- In this study, IRA tax credits are modeled for eligible resources built by 2032.
  - PTC equal to $21.90/MWh (2023$) is available for solar, onshore wind, and nuclear.
  - ITC equal to 30% of investment cost is available for offshore wind and battery storage.

- Under OBBBA, solar and wind projects must begin construction before July 5, 2026, or be placed in service before January 1, 2028, to be eligible to receive tax credits.
  - There is a four-year safe harbor if construction begins before July 5, 2026, and the project is completed by the end of 2030, but additional ownership and FEOC provisions apply.
  - Tax credits for nuclear and battery storage are phased out between 2034-2036 under OBBBA.

Wind and Solar Profiles by Region

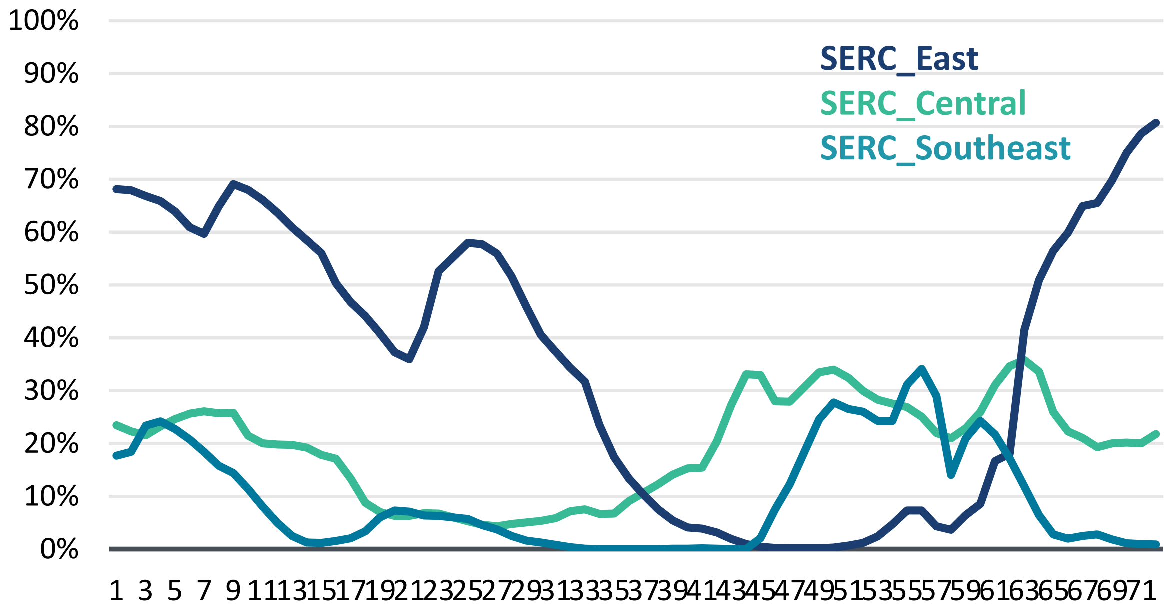




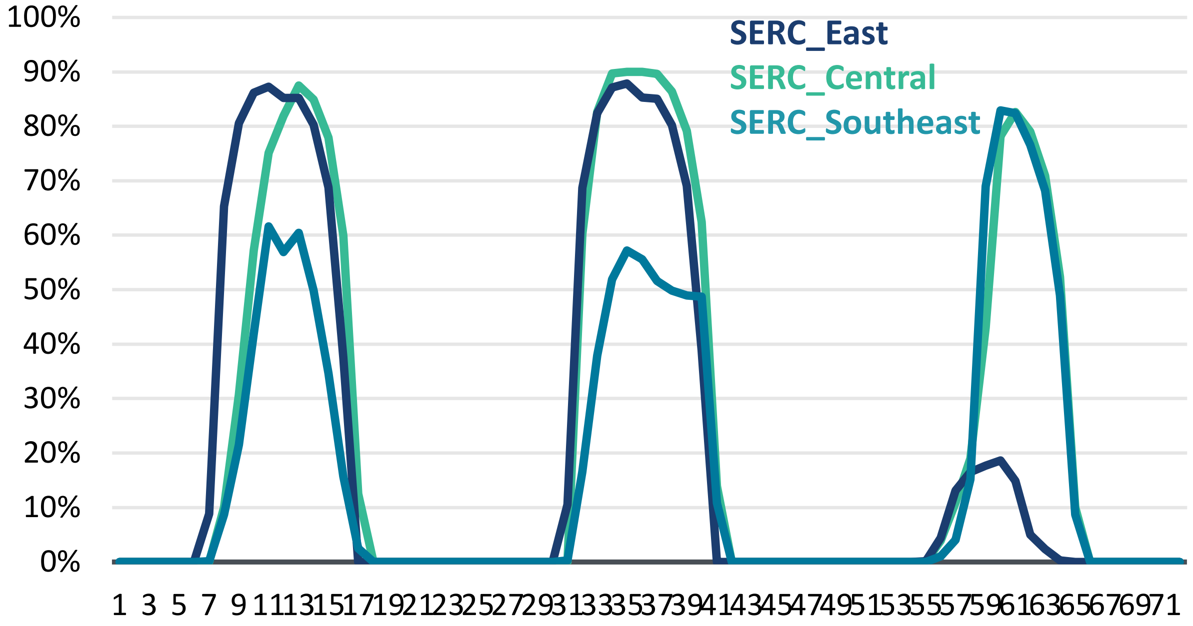
Wind and Solar Profiles by Region

- We use cluster sampling to select the most representative coordinates for solar and wind output based on mean and standard deviation to capture geographic diversity of renewables.
- Profiles are picked from Renewables.ninja database, which simulates hourly capacity factor profiles based on historical wind speeds and solar irradiance inputs.

Extreme Winter Peak Day Hourly Wind Profiles

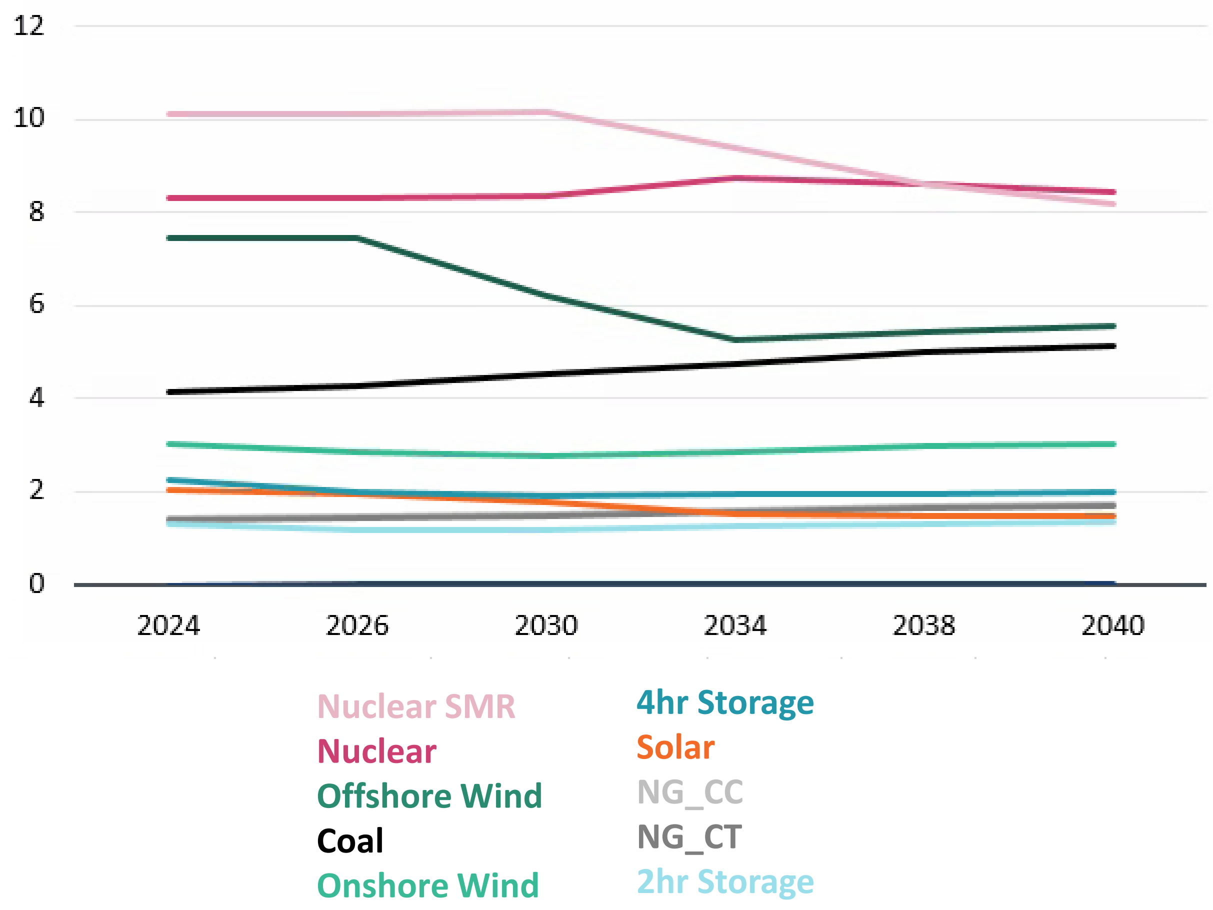


Extreme Winter Peak Day Hourly Solar Profiles



Cost Assumptions

Adjusted CAPEX Values (thousands of nominal $/kW)



- NREL ATB 2024 Costs, storage, Gas CT and CC overnight costs scaled to 2024 PJM Cone Report study (Sargent & Lundy)
  - Renewable technologies (solar, onshore/offshore wind) also scaled using storage scalar
- Reconstructed CAPEX regionalized specific to PJM using (LBNL interconnection costs + ATB interconnection costs + adjusted OCC) * (ATB construction financing factor)
- Regional multiplier of PJM capital costs → SERC capital costs inferred from EIA regional technology pricing and applied to bring prices to SERC specific values

Cost Assumptions

Resource costs based on methodology described on prior slide are higher than utility IRP cost assumptions. All IRPs we reviewed used NREL ATB as their main source for capex cost assumptions.

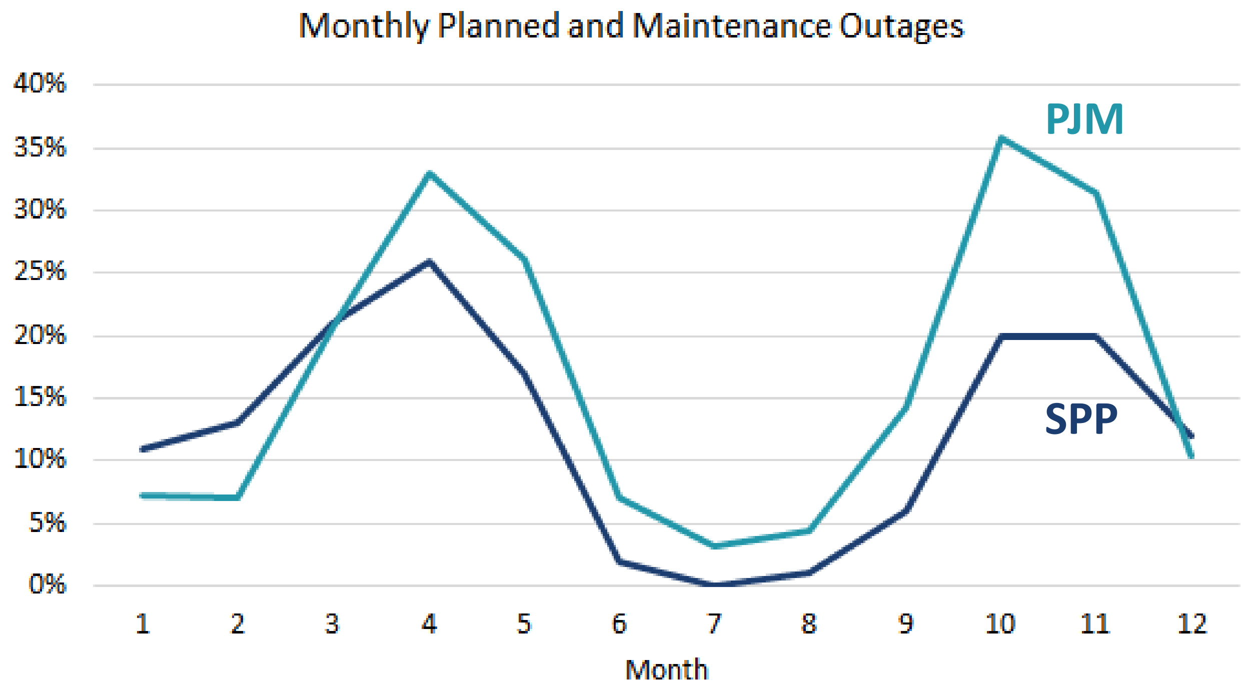
Comparison between gridSIM Resource Costs and Utility IRPs (2024$/kW-yr)

Resource	gridSIM (2030 build year)	TVA (2025 IRP)	Dominion (2024 IRP)	Santee Cooper (2024 IRP)	LG&E/KU (2024 IRP)
Gas CC	$1,310	$1,372	$1,226	$1,335	$1,850
Gas CT	$1,273	$1,642	$1,471	$1,848	$1,427
Solar	$1,508	$1,300	$1,375	$1,554	$1,659
4hr Storage	$1,623	$1,445	$1,784	$1,860	$1,788
Offshore Wind	$5,330		$4,135	$3,556	
Onshore Wind	$2,367	$1,625 to $3,171		$1,951	
Nuclear	$7,207				
Nuclear SMR	$8,767	$17,949	$12,335	$7,033	

Note: Georgia Power IRP costs redacted from document.
Build year assumptions for IRP costs not specified.

Planned Outages Assumptions

Updated planned outages based on historical SPP planned outages from FERNS report. SPP outages are based on average 2006-2020 planned outages. This update resulted in lower average planned outages, particularly in shoulder seasons.



Forced Outages Assumptions

1) Run regional temperatures through the PJM regression.

2) Adjust outages based on the following scalars, calculated from the NERC SRA and WRA reports. SERC outages are adjusted downwards (relative to PJM), and MISO outages are adjusted upwards. Summer/fall are adjusted based on the summer scalar and winter/spring are adjusted based on the winter scalar.

NERC Summer Outages

Region	Anticipated Resources (GW)	Typical Forced Outages (GW)	Forced Outage (% of Total Capacity)	Fossil Resources (% of Total Capacity)	Forced Outage (% of Fossil Capacity)	Summer Scalar (% of PJM)
PJM	183.1	13.9	7.6%	68%	11.2%	100.0%
MISO	146.3	14.2	9.7%	65%	15.0%	133.5%
SERC-C	50.6	3.0	5.9%	85%	7.0%	62.3%
SERC-E	52	1.4	2.7%	64%	4.2%	37.5%
SERC-FL	63.7	2.7	4.2%	80%	5.3%	47.3%
SERC-SE	64.5	0.9	1.4%	74%	1.9%	16.8%

NERC Winter Outages

Region	Anticipated Resources (GW)	Typical Forced Outages (GW)	Forced Outage (% of Total Capacity)	Fossil Resources (% of Total Capacity)	Forced Outage (% of Fossil Capacity)	Winter Scalar (% of PJM)
PJM	183.7	16.0	8.7%	68%	12.9%	100.0%
MISO	139.5	21.5	15.4%	65%	23.7%	184.7%
SERC-C	53.5	2.3	4.3%	85%	5.1%	39.3%
SERC-E	55	1.1	2.0%	64%	3.1%	24.3%
SERC-FL	63	2.5	4.0%	80%	5.0%	38.6%
SERC-SE	62.4	0.9	1.4%	74%	1.9%	15.2%

SERC Central: Proxy ELCC estimates of Non-Firm Imports

Modeled Limits (MW)

	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA
Energy Import Limit	7,400	7,400	8,400	8,400
Capacity Import Limit	2,800	2,800	2,800	4,200

Average Imports across Top RA Hours

	All Regions				*SERC Only*			
	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA
2026	6,877	6,851	7,295	7,292	95	105	157	156
2030	5,570	6,575	6,953	5,127	173	149	180	76
2034	5,136	6,546	7,305	5,058	68	51	220	69
2038	6,818	4,914	5,502	5,255	29	0	1	74
2040	5,325	5,148	5,742	5,776	1	0	1	1

Non-Firm ELCC

	All Regions				*SERC Only*			
	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA
2026	93%	93%	87%	87%	1%	1%	2%	2%
2030	75%	89%	83%	61%	2%	2%	2%	1%
2034	69%	88%	87%	60%	1%	1%	3%	1%
2038	92%	66%	66%	63%	0%	0%	0%	1%
2040	72%	70%	68%	69%	0%	0%	0%	0%
Average	**80%**	**81%**	**78%**	**68%**	**1%**	**1%**	**1%**	**1%**

The top RA-constrained hours are defined based on the resource supply cushion, calculated as all available resources plus the capacity import limit, minus the RA requirement. All of the top RA hours occur in Winter.

SERC East: Proxy ELCC estimates of Non-Firm Imports

Modeled Limits (MW)

	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA
Energy Import Limit	4,200	4,200	5,500	5,500
Capacity Import Limit	1,900	1,900	1,900	2,850

Average Imports across Top RA Hours

	All Regions				*SERC Only*			
	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA
2026	1,952	1,903	2,220	2,216	1,326	1,246	1,572	1,569
2030	2,268	2,406	3,144	3,057	1,585	1,729	2,130	2,189
2034	2,622	2,525	3,143	2,898	1,823	1,786	1,198	1,191
2038	2,694	2,645	4,161	4,105	1,635	1,667	2,749	3,072
2040	2,717	2,649	5,423	5,444	1,561	1,525	4,275	4,458

Non-Firm ELCC

	All Regions				*SERC Only*			
	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA
2026	46%	45%	40%	40%	32%	30%	29%	29%
2030	54%	57%	57%	56%	38%	41%	39%	40%
2034	62%	60%	57%	53%	43%	43%	22%	22%
2038	64%	63%	76%	75%	39%	40%	50%	56%
2040	65%	63%	99%	99%	37%	36%	78%	81%
Average	**58%**	**58%**	**66%**	**64%**	**38%**	**38%**	**43%**	**45%**

The top RA-constrained hours are defined based on the resource supply cushion, calculated as all available resources plus the capacity import limit, minus the RA requirement. All of the top RA hours occur in Winter.

SERC Southeast: Proxy ELCC estimates of Non-Firm Imports

Modeled Limits (MW)

	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA
Energy Import Limit	4,200	4,200	6,500	6,500
Capacity Import Limit	1,200	1,200	1,200	1,800

Average Imports across Top RA Hours

	All Regions				*SERC Only*			
	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA
2026	1,299	1,298	1,298	1,298	0	0	2	2
2030	1,175	1,403	3,045	2,845	506	630	2,219	2,018
2034	1,186	2,461	5,666	5,584	487	1,575	4,419	4,338
2038	1,403	2,463	3,387	3,380	424	1,172	1,905	1,905
2040	1,333	1,429	2,477	2,336	61	6	169	122

Non-Firm ELCC

	All Regions				*SERC Only*			
	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA	IRP Reference	2050 Net Zero	High Tx Util	High Tx Util + High RA
2026	31%	31%	20%	20%	0%	0%	0%	0%
2030	28%	33%	47%	44%	12%	15%	34%	31%
2034	28%	59%	87%	86%	12%	38%	68%	67%
2038	33%	59%	52%	52%	10%	28%	29%	29%
2040	32%	34%	38%	36%	1%	0%	3%	2%
Average	**30%**	**43%**	**49%**	**48%**	**7%**	**16%**	**27%**	**26%**

The top RA-constrained hours are defined based on the resource supply cushion, calculated as all available resources plus the capacity import limit, minus the RA requirement. All of the top RA hours occur in Winter.