NARUC

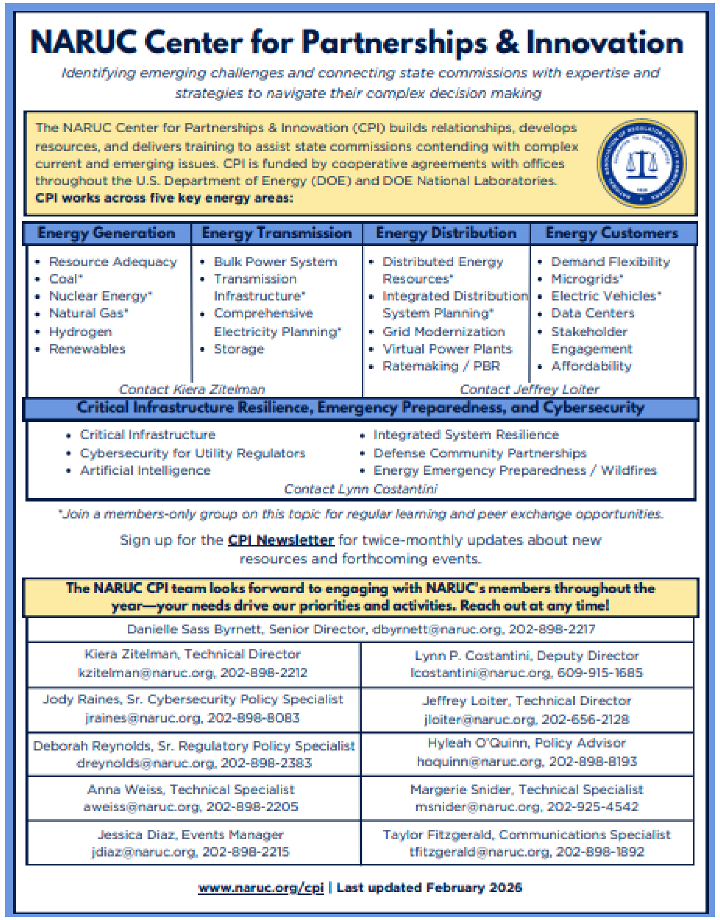
National Association of Regulatory Utility Commissioners

Bulk Power System Learning Modules: Best Practices and Emerging Tools for Managing Large Loads

Long-term Forecasting for Large Loads to Inform Resource and Transmission Planning

April 16, 2026

ABOUT NARUC AND CPI



NARUC Center for Partnerships & Innovation

Identifying emerging challenges and connecting state commissions with expertise and strategies to navigate their complex decision making

The NARUC Center for Partnerships & Innovation (CPI) builds relationships, develops resources, and delivers training to assist state commissions contending with complex current and emerging issues. CPI is funded by cooperative agreements with offices throughout the U.S. Department of Energy (DOE) and DOE National Laboratories. **CPI works across five key energy areas:**

Energy Generation	Energy Transmission	Energy Distribution	Energy Customers
• Resource Adequacy • Coal* • Nuclear Energy* • Natural Gas* • Hydrogen • Renewables	• Bulk Power System • Transmission Infrastructure* • Comprehensive Electricity Planning* • Storage	• Distributed Energy Resources* • Integrated Distribution System Planning* • Grid Modernization • Virtual Power Plants • Ratemaking / PBR	• Demand Flexibility • Microgrids* • Electric Vehicles* • Data Centers • Stakeholder Engagement • Affordability

Contact Kiera Zitelman — *Contact Jeffrey Loiter*

Critical Infrastructure Resilience, Emergency Preparedness, and Cybersecurity

- Critical Infrastructure
- Cybersecurity for Utility Regulators
- Artificial Intelligence
- Integrated System Resilience
- Defense Community Partnerships
- Energy Emergency Preparedness / Wildfires

Contact Lynn Costantini

*Join a members-only group on this topic for regular learning and peer exchange opportunities.

Sign up for the CPI Newsletter for twice-monthly updates about new resources and forthcoming events.

The NARUC CPI team looks forward to engaging with NARUC's members throughout the year—your needs drive our priorities and activities. Reach out at any time!

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www.naruc.org/cpi | Last updated February 2026

UPCOMING EVENTS

Virtual Events

- Bulk Power System Virtual Training Series: April 30; 2:00-4:30pm ET
- Distribution System Planning Peer-Sharing Webinar Series: May 14, June 22, August 13; 3:00-4:30pm ET – Open only to state agency staff (NARUC, NASEO, NASUCA, etc.)
- May Innovation Webinar: May 28, 3:00-4:00 pm ET

In-Person Events

- NCEP Annual Meeting: May 5 to 6, 2026, Charleston, South Carolina
- NARUC Summer Policy Summit: July 19 to 22, Minneapolis, Minnesota

See the full list of events and access registration links at: www.naruc.org/events/event-list/

TODAY'S SPEAKERS

- John D. Wilson, Grid Strategies – "Advancing Long-term Forecasting for Large Loads"
- Sam Walsh, Roselle LLP – "Large Load Flexibility Considerations for State Regulators"
- Hannes Pfeifenberger, The Brattle Group – "Transmission Planning for Large Loads"
- Natasha Henderson, SPP – "High Impact Large Load Interconnection Solutions"

Advancing Long-Term Forecasting for Large Loads

NARUC Bulk Power System Virtual Training

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John D. Wilson and Sophie Meyer, Grid Strategies LLC

April 2026

Load Forecasting Project Team

Background

- Met 6 times, from scope development through to final report review, plus an in-person workshop in October
- Also hosted 17 webinars to better understand existing practices used in load forecasts
- Most active participants were on the editing committee, with substantial content and editorial input from the initial report outline through the final draft

Editing Committee

- Jenny Conde, PG&E
- Jeffrey Deason, LBNL
- Natalie Mims Frick, LBNL
- Christopher Gonzales, SRP
- David Farmer, NRECA
- David Larson, EPRI
- Luke Lavin, NREL
- Molly Mooney, PJM
- Matteo Muratori, PNNL
- Shivani Nathoo, Ontario IESO
- Nina Peluso, Energy Futures Group
- Isabelle Riu, E3
- Lauren Shwisberg, RMI
- Anna Sommer, Energy Futures Group
- Priya Sreedharan, GridLab
- Jeff Sward, RMI
- ESIG Team

Load Growth Over the Decades

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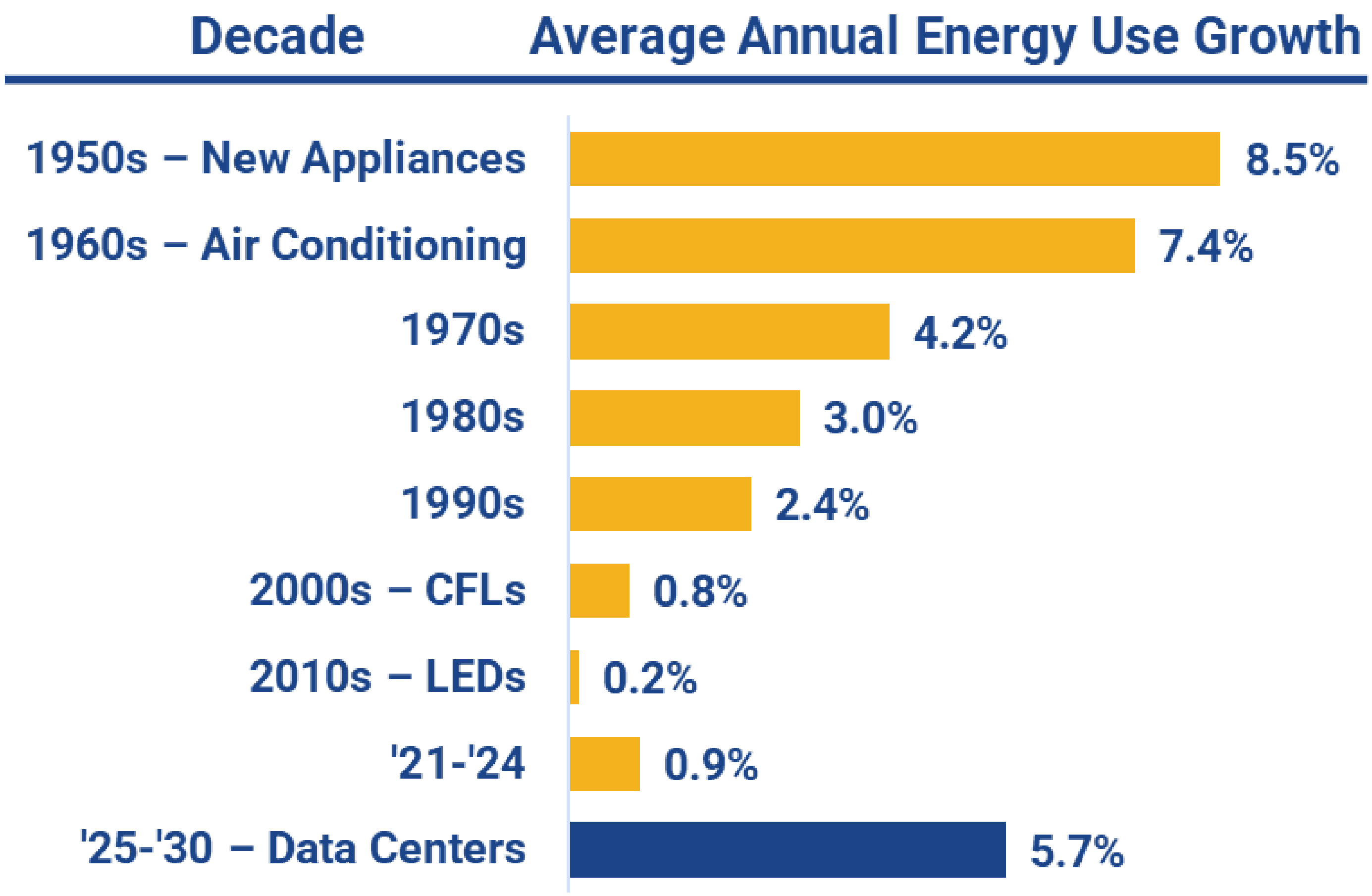
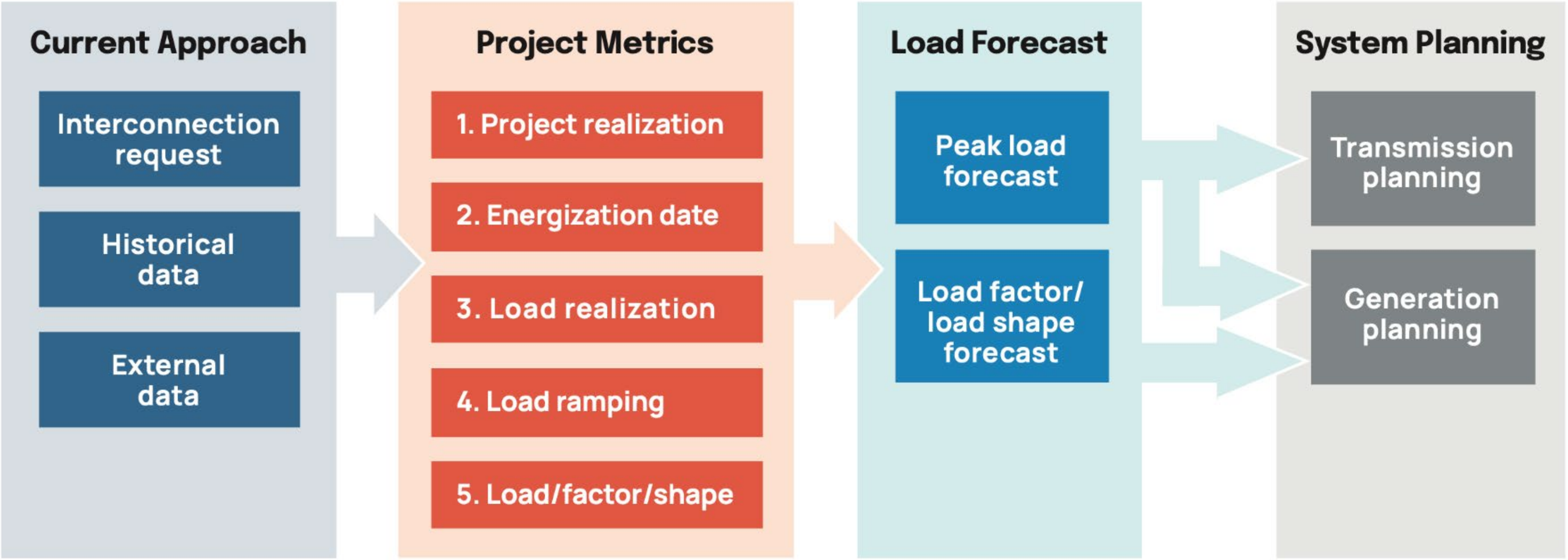


GridStrategies

From Data to Planning



Report Recommendations

1. Use all five large load metrics to create a large load forecast.
2. Develop a consistent framework to differentiate among large load types.
3. Account for uncertainty.
4. Increase certainty through large load financial requirements.
5. Reduce uncertainty in regional large load forecast practices.
6. Improve geographic detail.
7. Seek continuous improvement through forecast validation.
8. Collect large load forecast data in a shared database.
9. Apply consistent load weighting and modeling practices.
10. Adopt forecast standards for load flexibility.

What's Going Well

Large load forecasts are almost never the same as the large load pipeline

… there may be exceptions at smaller utilities

Large load forecasting practices are almost all under active reform

… new practices, in most cases just a few years old

In many cases, forecast practices are aligned with large load type

… industrial and data center loads are forecast differently

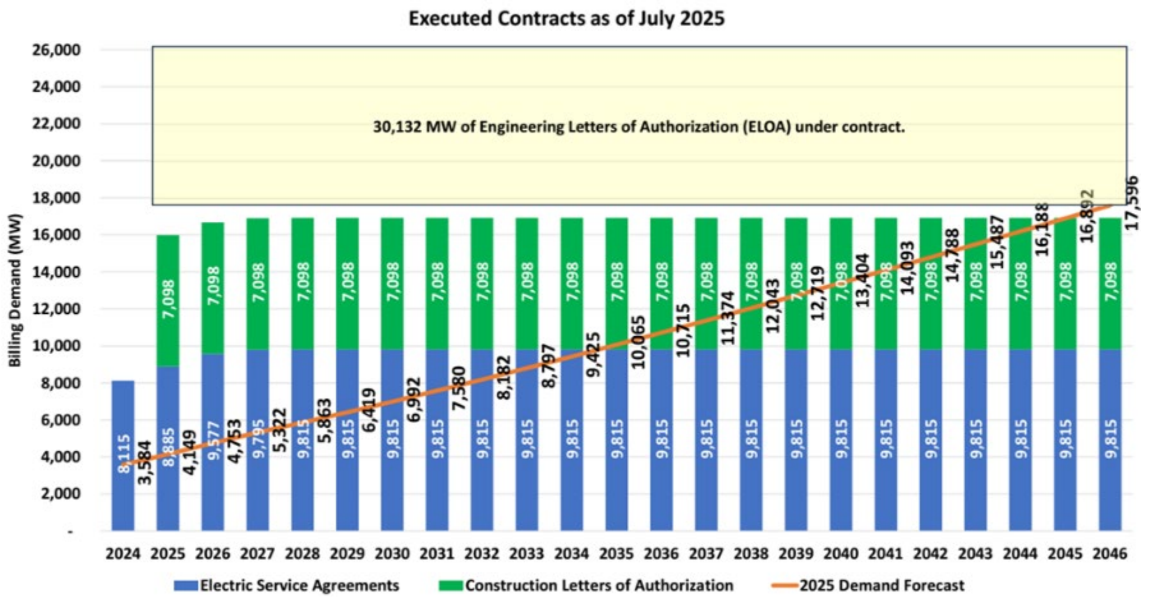
Substantial investments in studying data center loads

… top priority is operational risk,
but front-end planning risk is also a priority

Utility rate tariff reforms are helping to reduce uncertainty

… these reforms do not reduce all sources of risk

Dominion Energy Virginia 2025 Large Load Forecast



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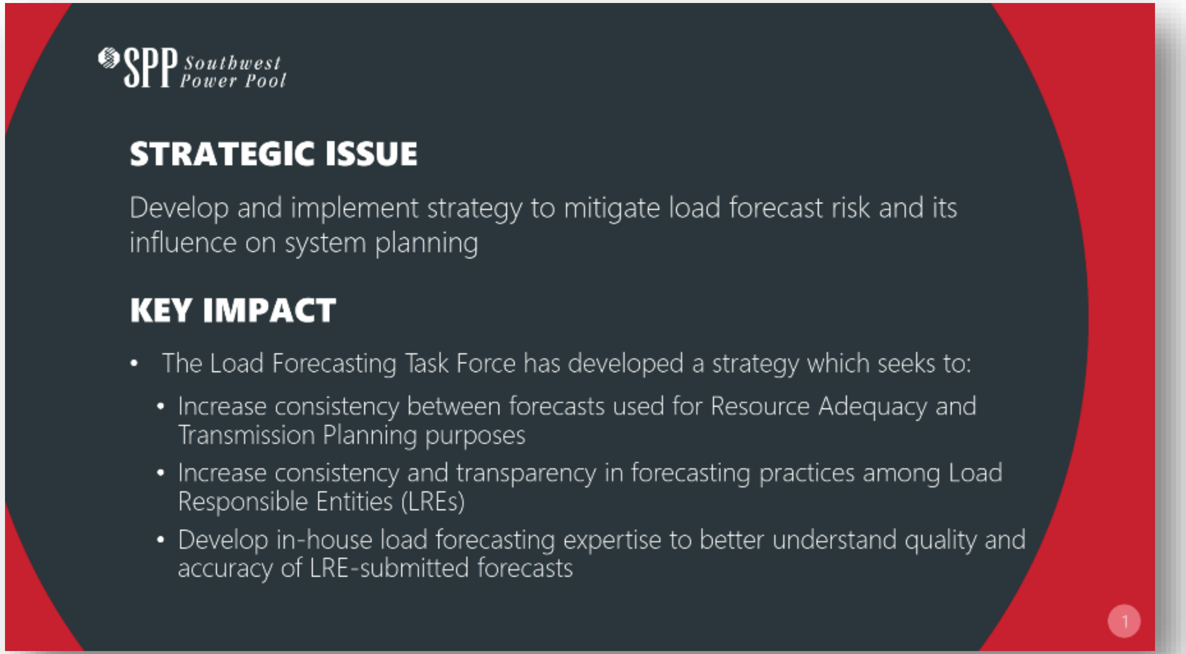

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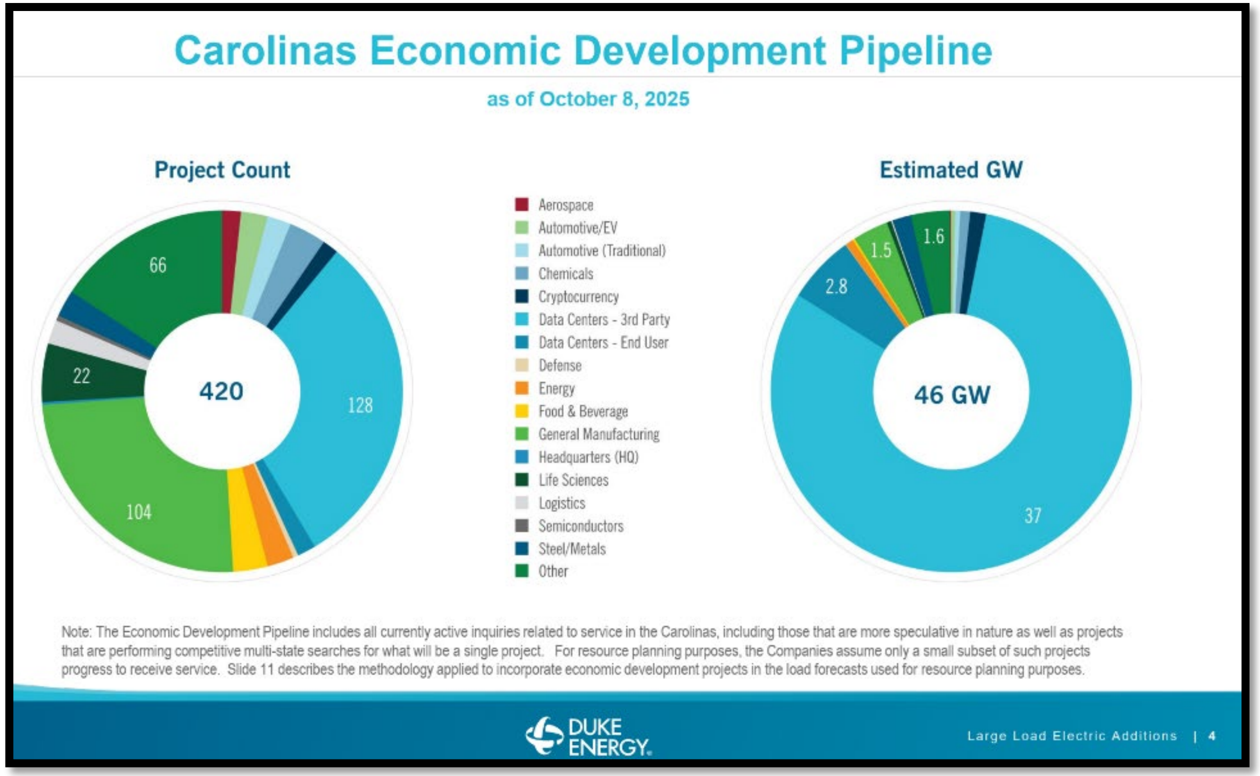

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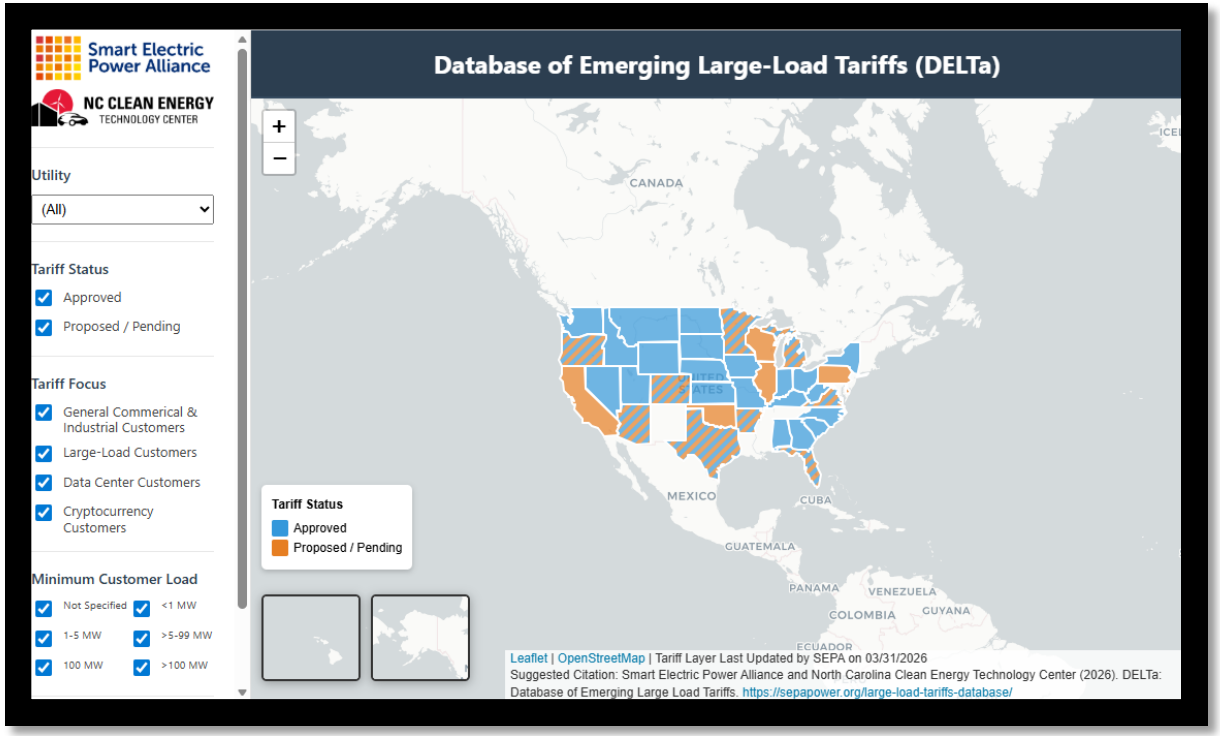

What Needs Improvement

Transparency and consistency

- Large loads are not described or assessed in a consistent manner in load forecasts.

Insufficient data

Particularly an issue for data centers – from multi-tenant to AI

- Early-process customer-supplied data are unreliable in certain respects
- Difficult for many utilities to obtain useful historical data, especially if they don't have a strong history with data centers

Alternative site data not shared

- Planners are only beginning to request information on this topic
- Practices for interpreting these data are probably not yet developed.

Load flexibility is not included

- No forecasts include load flexibility for future large loads
- Load flexibility planning practices may be complicated.

Lack of Consistent Definitions

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Large Load Characteristics and Forecast Metrics

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Project Realization	Energization Date	Load Realization	Load Ramping	Load factor or load shape
The rate at which projects included in the load forecast are placed in service • Often presented as a percentage of project requests expected to come to fruition	The beginning of commercial operation by projects, including anticipated delays	The forecast peak load that the project is expected to require once it's fully scaled up • Often presented as a percentage of requested peak load	The monthly or annual forecast of demand during the startup period of commercial operation • Often presented as a percentage of requested peak load	• **Load factor:** Actual energy use as a proportion of facility capacity • **Load shape:** More detailed information on power needs, for example, an hourly schedule of energy use

Large Load Interconnection Milestones

Customer Information
Preliminary information; not included in official forecasts

Inter-connection Request
Leads to study process and sometimes an inter-connection agreement (IA)

Letter of Authorization (LOA)
Contract initiating transmission and distribution facility design and construction

Electric Service Agreement (ESA)
Contract governing electricity service

Energization
Initialization of billing under ESA

Monitoring
Actual demand is compared to projected demand; may produce load forecast adjustments

Selected Recommendations

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Addressing Back-End Risk

- **How much load? When?** Front-end risks addressed through weighting factors, stochastic modeling, and scenario-based forecast.
- **Back-end risk:** Not currently addressed in load forecasts, either at project level or for systemic risks (correlated loads).
  - If data center forecasts turn out to be a development bubble, could lead to attrition of existing projects.
  - Demand falling below expectations could lead to stranded transmission and generation investments.
  - Recently-adopted tariffs provide some protection, but does not eliminate risks.
  - No studies of how well matched such attrition might be to other future load growth.

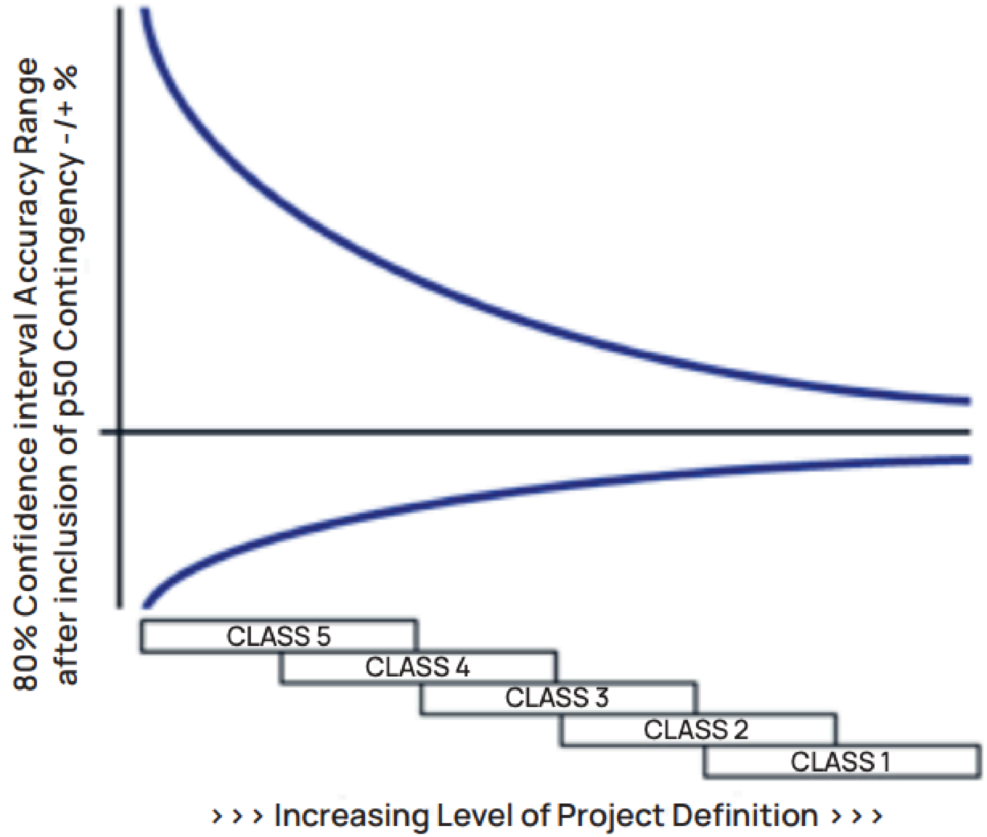
Sharing Large Load Data

- **Default option:** Wait several years until each utility gains experience
- **Commercial vendors:** Load and estimated energization date, probably no load ramping or load factor/shape data
- **Customer privacy is main barrier:** Legally complex to share data, EPRI has made some progress in obtaining data but cannot share widely
- **Steps to a database**
  - Collect data where possible – at least the first four load metrics
  - Simplest metrics first – project realization, load realization, and energization date
  - Define large load types – similar metrics and common characteristics
  - Add complexity – load ramping, load factor and load shapes; more types
- **Design large load forecast validation practices**

Maturity Assessment Framework

NERC Preliminary Draft Reliability Guideline

- Use project milestones to assess project maturity
- Potential model: AACE cost estimate classification system (at right)
- As projects mature towards higher classifications:
  - Weighting factors increase
  - Forecast accuracy range narrows



Thank you!

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Load Forecasts for Regional Planning

	Post-Hoc Adjustment	Scenario Overlay	Regulatory Approach
	Aggregate member forecasts, then adjust	Aggregate member forecasts, then apply scenario overlays	Direct LSE forecasting practices for consistency (in progress)
CEC	-	✓	✓
ERCOT	✓	-	✓
NYISO	-	✓	-
PJM	✓	-	✓
SPP	✓	-	-

Forecast Standards for Load Flexibility

- **Where does load flexibility belong?** Long-term forecast OR supply-side resource?
- **What types of load flexibility belong in long-term load forecasts?** Not all – Operational flexibility can provide critical services:
  - Support to the grid during disturbances on a sub-minute timescale
  - Self service during transmission outages
- For forecasting purposes, treatment varies for transmission, capacity, and energy planning. EPRI has defined five classes of load flexibility. The DCFlex Flex MOSAIC™ classes are:
  - A. Critical Peaking – Responds to *rare* scarcity events of 5 hours or less
  - B. Peaking – Responds to *frequent* scarcity events 5 hours or less
  - C. Prolonged – A + B + responds to *prolonged* events, up to 24+ hours
  - D. Fast – A + B + provide fast response with short notice
  - E. Fully *grid responsive*
- **How to measure load flexibility?** Components of load forecast metric:
  - Measurements of program use (when/how) and effectiveness
  - Forecast of enrollment (customers and capacity commitment)

How States and State-regulated Utilities Can Enable Large Load Flexibility

Sam Walsh
Roselle LLP

NARUC/ESIG Virtual Training Presentation
April 16, 2026

What is large load flexibility?

- Ability to curtail automatically or promptly at the grid operators' signal

How is it achieved technically?

- Reducing/shifting consumption, on-site resources

Why does it matter for affordability and speed-to-power?

- Avoids distribution, transmission and generation infrastructure

Are you talking about interruptibility?

- Not exactly

States have robust authority to enable large load flexibility

States' existing authority

- Distribution-level interconnections
- Retail service terms and tariffs
- State planning processes (e.g. integrated resource planning) and associated load forecasting inputs

Even if FERC asserts jurisdiction over transmission-level interconnection…

- Distribution interconnections remain state-regulated
- Interconnection of loads below threshold size (proposed to be 20 MW) continues to be overseen by states
- Retail service authority is unaffected
- States acting *now* can shape a large volume of in-flight transmission system interconnection requests

The DOE has proposed that FERC assert jurisdiction over large load interconnection to the transmission system — but FERC has not yet acted. Regardless of the outcome, states retain broad authority.

The starting point: define a flexible large load class

- A **flexible large load** makes a binding, enforceable commitment to curtail consumption when directed by the utility or grid operator
- Qualifying commitments should be **voluntary** — not mandated — and made **up front**, in the interconnection process or as a condition of retail service
- Commitments must be **long-term** to support infrastructure planning; temporary commitments have value but do not qualify for the full set of benefits
- Commitments must guarantee minimum curtailment performance across four parameters:

DEPTH	SPEED	DURATION	AVAILABILITY
Min. % of contract capacity curtailed *e.g., 50%+*	Response time to operator signal *e.g., 5–10 minutes*	Min. hours per curtailment event *e.g., 4 hours*	Min. hours available per year *e.g., 2%+ of annual hours*

Four policy domains where states can enable flexibility

Domain	What states can do	Why it matters for utilities
Interconnection	(1) Prioritize study queue for flexible loads; (2) Require utilities to model curtailment commitments in interconnection studies	Avoids overbuilding infrastructure; reduces study costs and timelines; speed-to-power is the strongest incentive for load participation
Ratemaking	Directly assign network upgrade costs; adjust demand charges and minimum billing provisions to reflect lower cost causation of flexible loads	Protects existing ratepayers; sends accurate price signals; reduces stranded asset risk
Load forecasting & planning	Require utilities to disaggregate large load forecasts and embed flexibility commitments in long-term resource and transmission plans	Allows planners to quantify and rely on flexibility; reduces risk of costly overbuilds or underbuilds
Bring-your-own-capacity (BYOC)	Exempt qualifying flexible loads from BYOC obligations, or count curtailment capability as eligible capacity	Avoids inadvertently penalizing investment in flexibility; preserves commercial incentive to curtail

Key takeaways

- **States can act now** — regardless of what FERC does on transmission-level interconnection, states retain broad authority over distribution connections, retail service, rate design, and planning
- **Define Flexible Large Load** — once regulators establish a clear, binding definition of a flexible large load, consistent treatment across all four policy domains follows naturally
- **Rewarding flexibility is not a subsidy** — the goal is accurate cost causation: flexible loads that avoid infrastructure investment should pay less; inflexible loads that trigger it should pay more
- **Speed-to-power is the strongest incentive** — interconnection queue priority is the most commercially powerful tool states and utilities have to encourage voluntary flexibility commitments
- **Urgency matters** — status quo processes will trigger unnecessary infrastructure spend and prevent economic development; states and utilities that act first will shape load that influences their systems for decades

Transmission Planning with Large Loads
Current Practices and Recommendations

A REPORT BY THE ENERGY SYSTEMS INTEGRATION GROUP'S
LARGE LOADS TASK FORCE

PREPARED BY

Johannes P. Pfeifenberger

Warren Lasher

James Okullo

PRESENTED TO

NARUC
National Association of Regulatory Utility Commissioners

APRIL 16, 2025

Brattle

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Agenda / Outline

1. Introduction: Why Large Loads Are a Transmission Planning Challenge
2. How Transmission Planning Works Today: A Primer
3. Three Core Challenges: Silos, Speed, and Uncertainty
4. Actionable Recommendations:
   - Part I: Immediate Actions
   - Part II: Near-Term Process Fixes
   - Part III: Longer-Term Structural Solutions
5. Summary of Phased Best Practices
6. Conclusions and Key Takeaways

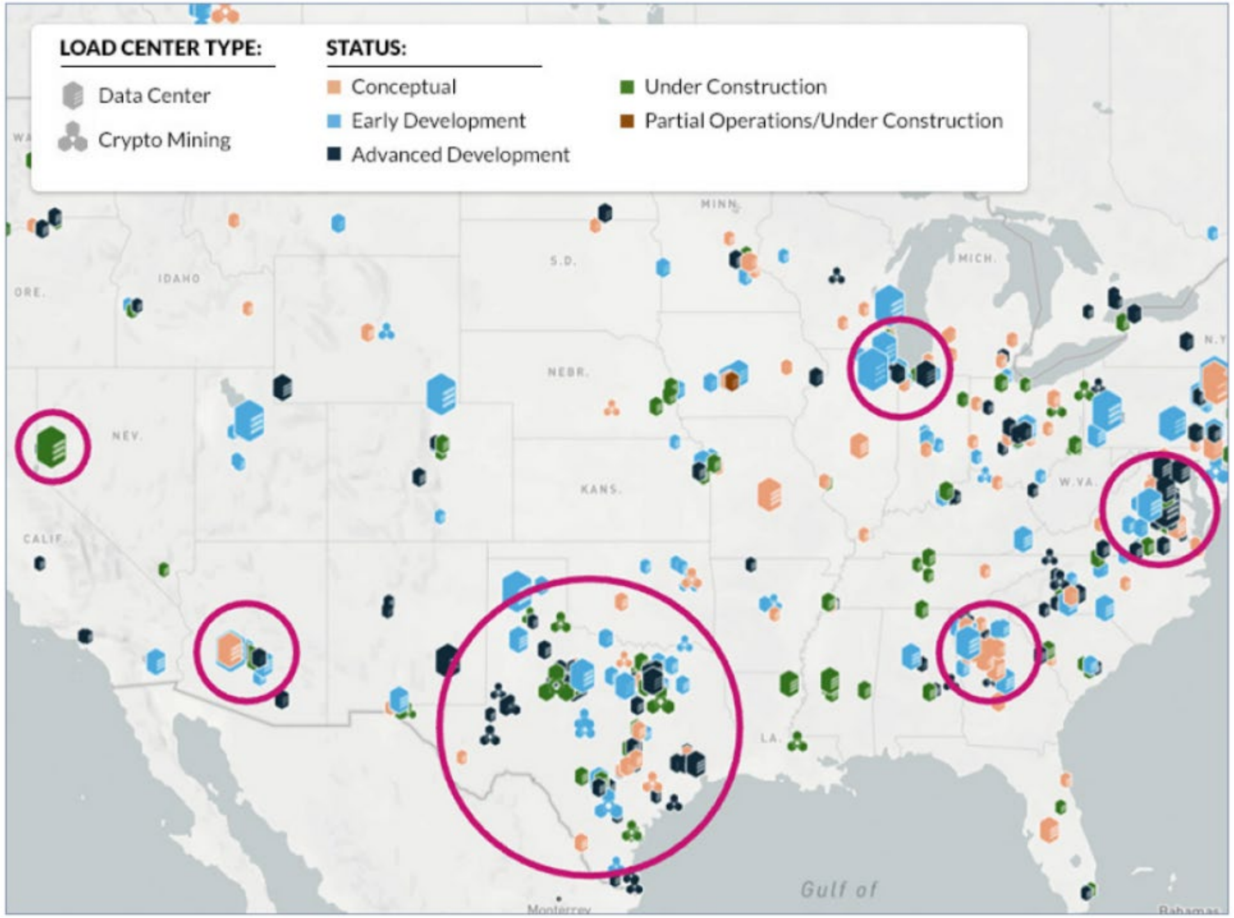
The Scale of the Large Load Challenge

Context:

- U.S. electricity systems face a surge of proposed large loads - primarily data centers - materially different in scale and speed from historical demand growth
- DOE predicts a 25% rise in electric demand by 2030; data center demand may double or triple by 2028
- Individual facilities often exceed 500 MW - comparable to medium-sized urban load centers - with large numbers concentrated in specific geographic areas
- As of January 2026, ERCOT alone had 92 large load projects greater than 1 GW in its interconnection queue

Current planning processes were designed for steady, limited growth - They are a poor fit for loads that develop quickly, affect multi-regional grids, require major new infrastructure, and are difficult to forecast

High Levels of Geographically-Concentrated Data-Center Grid-Interconnected Demand



Source: YesEnergy, "Tracking the Rapidly Transforming Power Grid," December 12, 2025.

Why This Matters

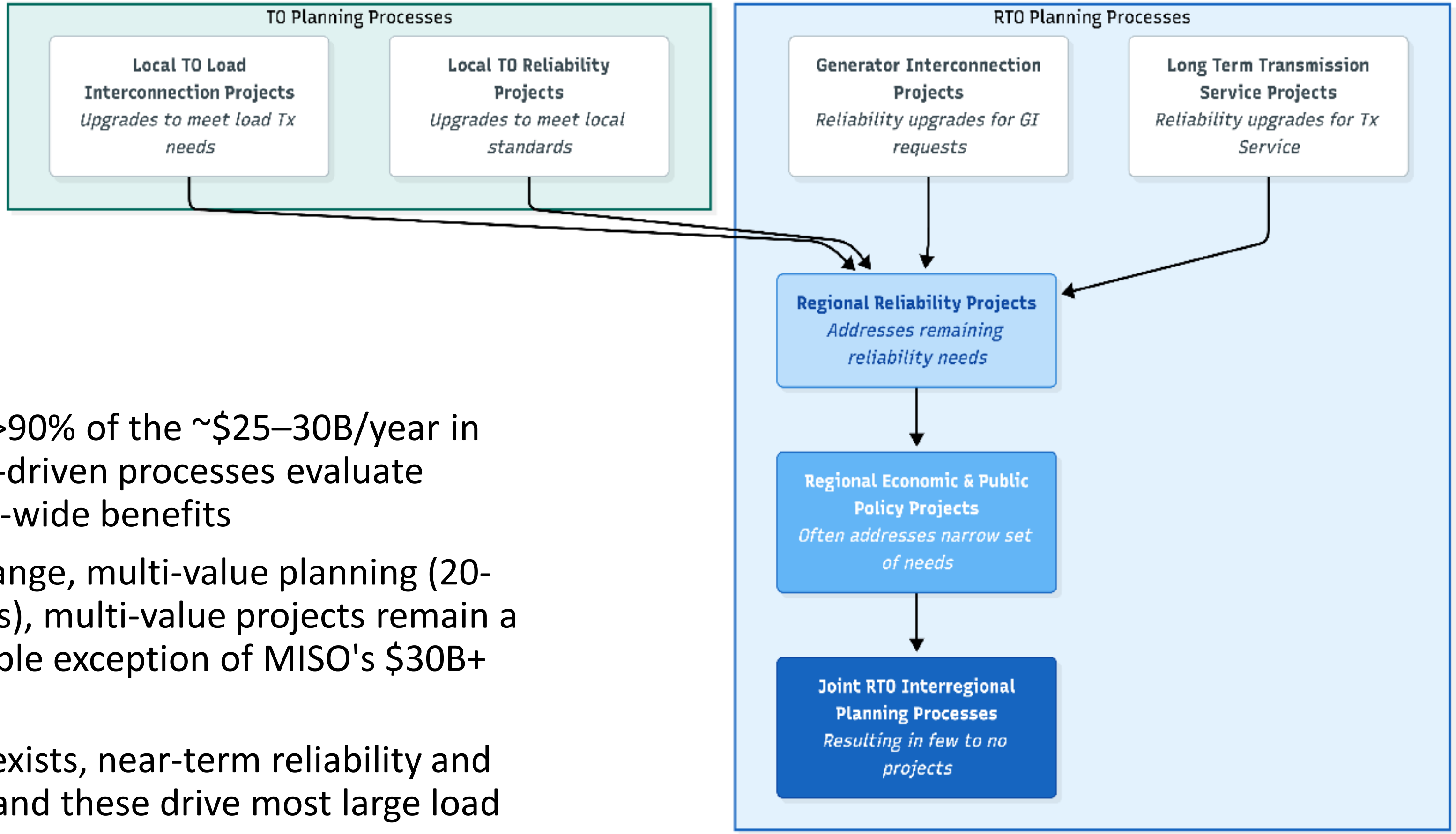
- Insufficient transmission capacity leads to reliability challenges, interconnection delays, and higher congestion costs
- New transmission takes up to a decade to plan and build; poor decisions are expensive and long-lived for ratepayers
- Improved grid planning (including reliance on available near-term options) can both support "speed to market" objectives, better support long-term needs, and address affordability concerns.

Well-planned transmission improves reliability, lowers generation costs, and reduces delivery costs - every $1 billion in well-planned upgrades may reduce other electricity system costs by $2–3 billion

How Transmission Planning Works Today

- Most planning focuses on local/regional reliability needs over the next decade, using a single "base-case" forecast for challenging (90^{th} percentile) summer and winter peaks
- Planning is siloed into separate processes—each with its own objectives, assumptions, and timelines: load interconnection, generator interconnection, reliability, economic/public policy, and near- vs. long-term planning
- Local/regional reliability projects account for >90% of the ~$25–30B/year in U.S. transmission investment; these reliability-driven processes evaluate project costs but rarely assess broader system-wide benefits
- While FERC Order 1920 now mandates long-range, multi-value planning (20-year studies, 3+ scenarios, 7 benefit categories), multi-value projects remain a small share of total investment, with the notable exception of MISO's $30B+ in LRTP approvals
- Even where multi-value, long-range planning exists, near-term reliability and interconnection processes remain separate—and these drive most large load transmission decisions today

Typical U.S. Transmission Planning Processes in RTO Regions



Source: The Brattle Group

Three Core Challenges - Overview

- Large load growth is revealing three structural weaknesses in existing grid planning:

Functional Silos	Timing Mismatch	Uncertainty
Interconnection, reliability, economic, and long-range processes operate independently with inconsistent assumptions and uncoordinated outcomes	Large loads develop in months to a few years; transmission takes 3–10+ years—creating pressure to rely on near-term fixes that pre-empt better long-term solutions	High attrition, geographic uncertainty, evolving load profiles, and uncertain degree of co-located generation undermine traditional approaches

- These challenges compound: silos block information sharing; urgency drives preference for available quick fixes; uncertainty makes base-case planning unreliable

Challenge #1—Functional Silos

Request → Local Fix → Baseline Shifts → Next Request → Another Local Fix → Broader Solution Now Unjustifiable

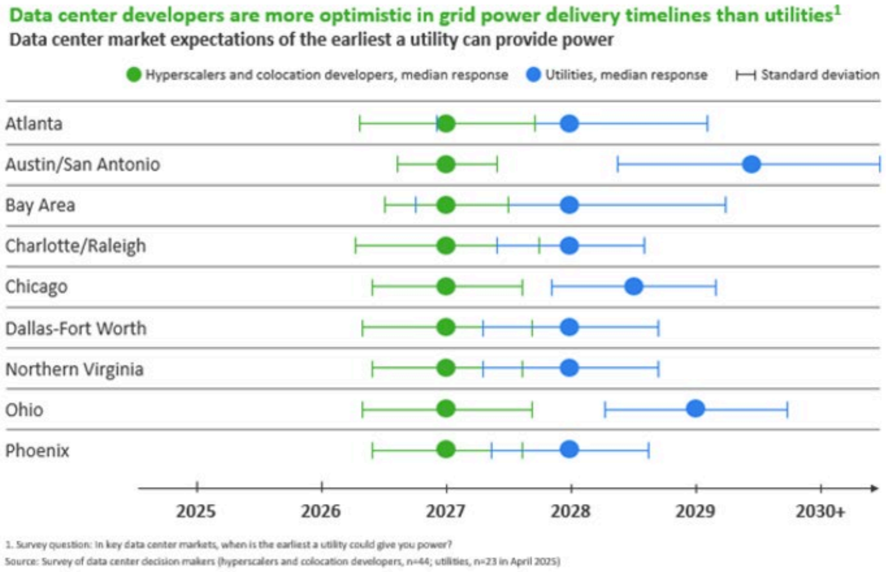
- When planning functions are siloed, large load interconnection decisions shape infrastructure investments without being evaluated against the broader system needs, flexibility, or total cost
- Silos were tolerable when demand growth was limited. Today, a single large load can simultaneously challenge local reliability, regional power flows, congestion, and long-term resource adequacy
- Path dependence: Near-term reliability upgrades quickly become part of the modeled baseline. Shifting the cost-effectiveness of attractive subsequent solutions, which may become infeasible
- Each individual upgrade may look reasonable, but the sequence makes higher-value, longer-term solutions harder to justify. The total costs of piecemeal upgrades exceeds that of a holistic solution.
- Regulatory structures tend to encourage local, utility-driven solutions through siloed processes; coordinated regional planning takes longer and can trigger extended cost-allocation challenges

Challenge #2—Timing Mismatch

- Fast data center timelines: months to a few years.
- Slow grid processes:
  - Transmission planning and construction: 3–10+ years
  - Load and generator interconnection: studies alone take years and constructing the necessary upgrades add years for permitting, siting, procurement, and construction
- Result: persistent pressure to serve new load at a pace faster than the grid expansion can deliver. Quick fixes are chosen that undermine more effective solutions
- Inefficient grid expansion: Interim upgrades are justified as bridges but, once energized, the “quick fixes” reduce the cost-effectiveness of larger projects—which makes efficiently-sized reinforcements harder to approve, and the system accumulates a patchwork of incremental fixes at higher total cost

Planning, Permitting, and Construction Timelines for Transmission and Supply Measures Compared to Large Load Development

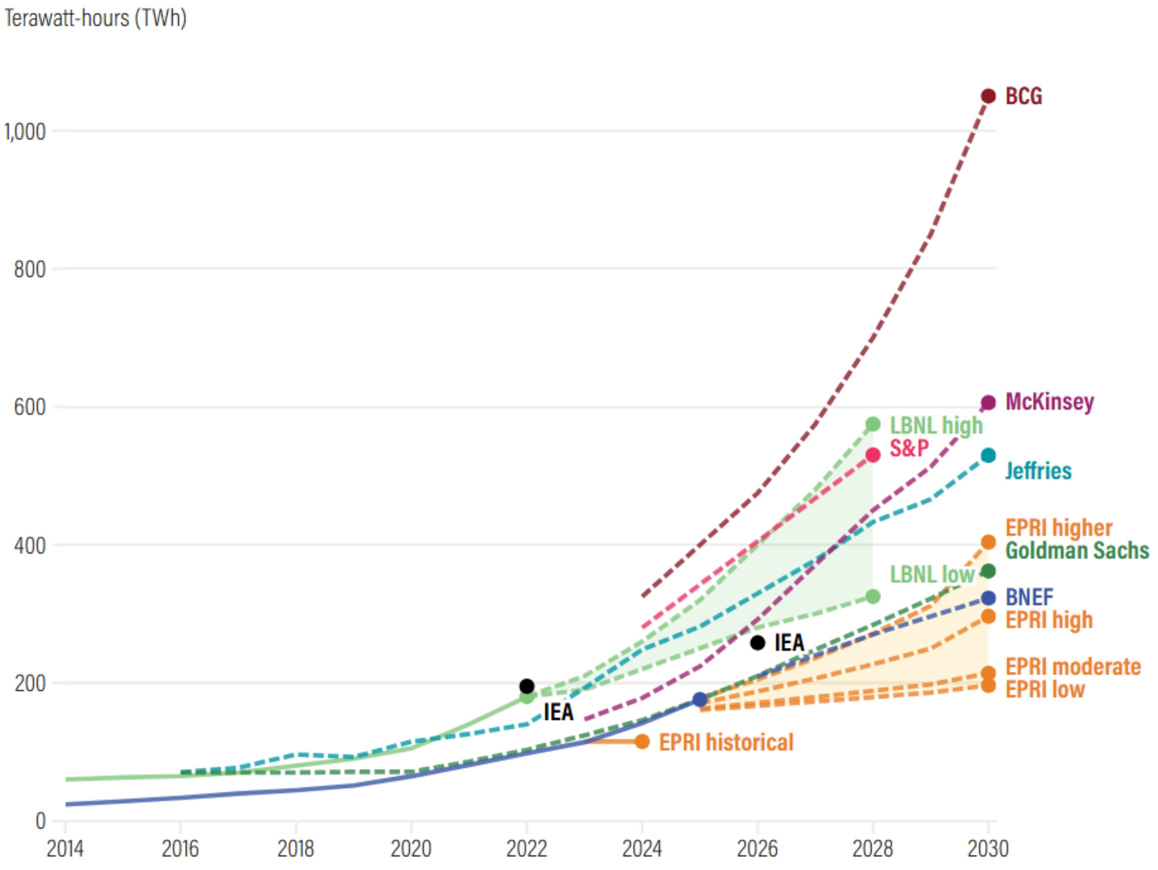
Differing Expectations About Speed to Power Between Data Centers and Utilities



Challenge #3—Uncertainty

- Large loads introduce fundamentally different uncertainty—lumpy, location-specific, fast-moving, and driven by commercial/technology/policy decisions outside planners' control
- Key uncertainties change net grid impact: whether a project materializes (realization risk), where it will succeed (location uncertainty), when it energizes (schedule risk), ramp speed (usage risk), and whether it will be co-located generation (net impact uncertainty)
- Demand forecasts show an extraordinarily wide range—in ERCOT, 232 GW of large loads sought interconnection by 2030, but the operator included only ~50 GW in its 2025 planning cycle
- A single base-case forecast is no longer sufficient—uncertainty must be treated as a core planning consideration

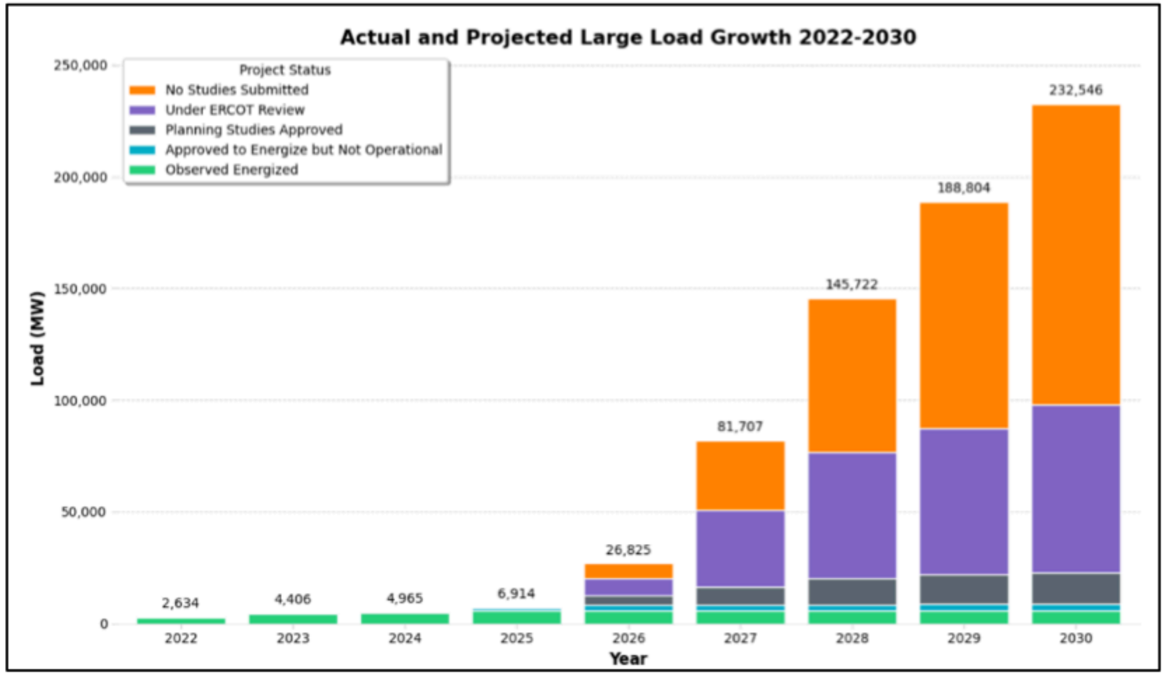
Comparison of U.S. Data Center Electricity Demand Forecasts



Source: Ian Goldsmith and Zach Byrum, "Powering the US Data Center Boom: Why Forecasting Can Be So Tricky," World Resources Institute, September 17, 2025.

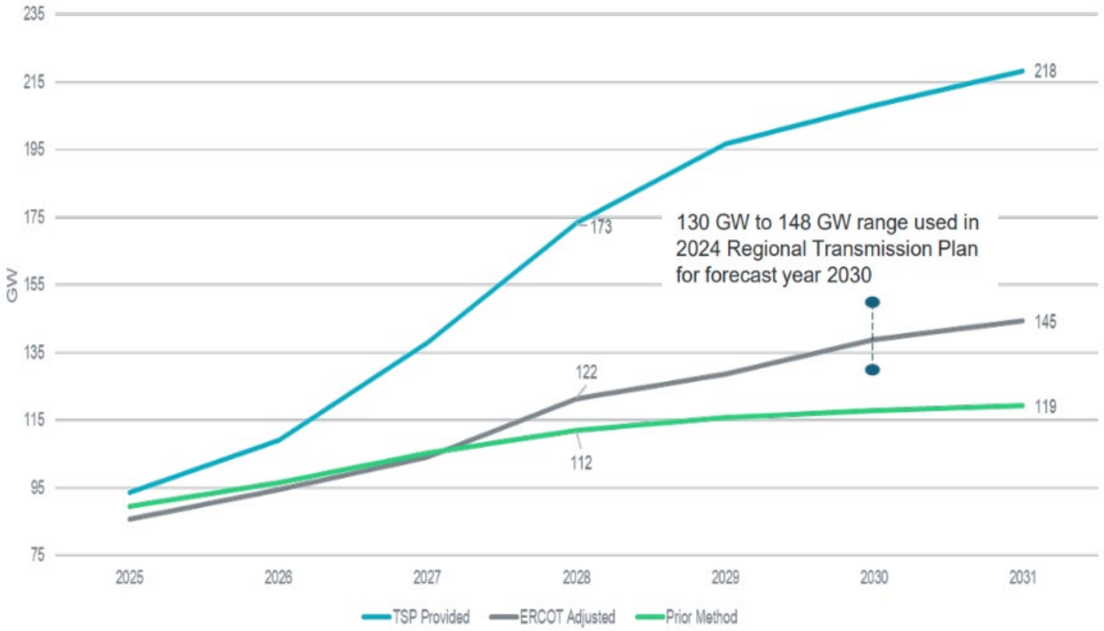
Challenge #3—Uncertainty

Actual and Projected Large Load Projects in ERCOT from 2022–2030



Source: ”ERCOT Monthly”, January 2026

ERCOT’s Forecasts of Total Electricity Demand



Source: ERCOT. Slide 10 of Item 8.1: Long-Term Load Forecast Update

From Challenges to Solutions—Recommendations

Current planning processes must be revised to address the core challenges identified

- Recommendations are organized in three (parallel) phases:

Phase I	Improve grid visibility, widen near-term solution sets, and make flexible service arrangements usable in planning
Phase II	Replace single-base-case planning with scenario analysis; test near-term upgrades for how well they preserve longer-term options
Phase III	Move beyond project-by-project reinforcement toward pro-active, consolidated, multi-driver planning

- The goal is to identify (1) what regions can do now for near-term results, (2) what process changes are capable to yield improved intermediate-term results, and (3) what structural changes are needed if growth continues for better long-term planning results.

Part I - Headroom Visibility and Near-term Tools

- Grid visibility: Improve and publish where on the existing grid load can be served, and under what conditions—planners and developers currently discover constraints too late
  - Headroom studies should cover multiple operating conditions (summer, winter, net-peak, shoulder, light-load, high-transfer) and multiple service structures (firm, non-firm, with/without RAS, with/without co-located resources)
  - Results should be public, consistent, and stakeholder-oriented—distinguishing fast-service areas from areas requiring material new transmission
- Grid-enhancing technologies (GETs): Topology optimization, power flow controls, dynamic line ratings—new capacity in months at far lower cost
- Advanced transmission technologies (ATTs): High-performance conductors can double line capacity without new towers
- Operational controls such as remedial action schemes (RAS) can accelerate interconnection by creating headroom on the existing grid (but must be well-defined, rigorously studied, and carefully governed)

Part I—Flexibility, Co-Location, Shared Assumptions, Automation

LOAD FLEXIBILITY

- Large loads can reduce grid-facing demand via load adjustments, backup generation, storage, or co-located generation—but should only be credited in planning when operationally enforceable and reflected in interconnection agreements

CO-LOCATION

- Co-located loads and generation ("energy parks"): Controllable hybrid (load + generation) facilities that limit net grid impacts to they can quickly—SPP's HILLGA framework, MISO's proposed ZGIA process, PJM's NF-CDS, and ERCOT BYOG/PCLR are exploring these models

SHARED ASSUMPTIONS

- Shared assumptions: A common, version-controlled large-load dataset should be used across interconnection, reliability, and long-range studies—not separate assumptions for each planning function
- Common scenarios of plausible futures should bracket projected uncertainties

AUTOMATION

- Modernize and automate study workflows to reduce manual bottlenecks

Part II—Scenario-Based and Least-Regrets Planning

- The base case can no longer be treated as a "best estimate" for designing transmission solutions—large load uncertainty demands a different approach
- Use "futures-based" planning for uncertainty, which other industries have employed for decades

Multiple Futures

Scenario planning examines several plausible futures and tests how plans perform against them—scenarios are not predictions but alternatives that break the assumption that the future mirrors current trends

FERC Order 1920 requires scenarios for long-term planning, but near-term reliability planning rarely uses them—under large load conditions, even 10-year reliability planning needs scenario analysis

Test Solutions across Futures

Flexibility (scalability) of solutions becomes a measurable source of system value

Example: AEMO's Integrated System Plan (ISP) process

Select Least-Regrets Solution

Least-regrets planning: Select solutions that perform well across futures and limit downside risk

Over-building can strand capital; under-building can cause high cost of inadequate infrastructure and requires repeated incremental upgrades, often at higher total cost and associated with significant delays

Under-building in the face of uncertainty can be more costly than over-building. Best to commit to a flexible, scalable solution

The Math of Least-Regrets Planning—An Example

- Example: Future interconnection needs range from 800 MW to 1,600 MW to 2,400 MW across three scenarios
- Three solutions:
  - **A: Single-circuit 500kV**—$500m (optimal for 800 MW)
  - **B: Double-circuit 500kV**—$600m (optimal for 1,600 MW; can operate as single circuit initially)
  - **C: 765kV**—$800m (optimal for 2,400 MW; can operate at 500kV initially)
- If Solution A is chosen but 2,400 MW materializes, ultimate cost reaches $1.1b (highest total cost outcome)
- Solution C has the least regret: max regret of $200m vs. Solution A's max regret of $400m
- **Takeaway: The "least-cost" option carries the greatest regret risk; flexible, scalable solutions reduce the cost of being wrong**

Planning for Interconnection Needs in Three Scenarios

	Future 1	Future 2	Future 3	
Need	800 MW	1600 MW	2400 MW	
Optimized Transmission Solutions				
Solution A	**1x500kV**			single-circuit 500kV line is optimal for Future 1
Solution B		**2x500kV**		double-circuit 500kV line is optimal for Future 2 (can initially be operated as single circuit)
Solution C			**765kV**	765kV line is optimal for Future 3 (can initially be opterated at 500kV)
Cost of Optimized Solutions				
Cost A	**$500m**			
Cost B		**$600m**		($550 if initially built as single-circuit line on double-circuit towers)
Cost C			**$800m**	($650m if operated at 500kV initially; plus $150m for transformation)

Evaluation of How Each Solution Performs in All Three Futures

	Future 1	Future 2	Future 3	
Outcome if Actual Future is different from Optimized				
Solutions A+	**1x500kV**	+1x500kV	+2x500kV	Need to add another 500kV line (or 2x500kV line) if Future 2 (or Future 3) is realized
Solutions B+	op as 1x500kV	**2x500kV**	+1x500kV	Need to add another 500kV line if Future 3 is realized; solution oversized for Future 1
Solutions C+	op at 500kV	765kV	**765kV**	Solution oversized in Futures 1 and 2; operated at 500kV in Future 1 (saves $150m in transformation

Ultimate Cost				**Weighted Average Cost**	**Other considerations**
Cost A+	**$500m**	$1000m	$1100m	$866m	ROW for up to 1x500kV and 2x500kV
Cost B+	$550m	**$600m**	$1100m	$750m	ROW for up to 2x500kV plus 1x500kV
Cost C+	$650m	$800m	**$800m**	$750m	ROW for single 765kV line only

	Future 1	Future 2	Future 3	
Maximum Regret (i.e., added cost of being wrong)				
Regret A	0	+$400m	+$300m	Regret: up to $400m extra due to underbuilt solution
Regret B	+$50m	0	+$300m	Regret: $300m extra due to underbuilt solution for F3; $100m overbuilt in F1
Regret C	+$150m	+$200m	0	Regret: up to $200m due to overbuilt system

Flexible Transmission Solutions / Benefit-Cost Analyses

- **Flexible 230kV aging line rebuild:**
  - Standard rebuild: $800m
  - "345kV-ready" with double-circuit towers: +$100m
  - Later conversion to 345kV adds 1 GW headroom for +$100m
  - Second circuit can be added for $150m
  - Total Cost: $1b to $1.15b

  Without proactive design: spend $800m on rebuilt then a later add greenfield lines at $1–2b
- **CAISO HVDC-ready design**: Interconnect 1,600 MW of offshore wind with option to scale to 3,300 MW and 8,000 MW via "HVDC-ready" 500kV design and pre-acquired rights of way
- **ERCOT CREZ:** Single-circuit lines with double circuit towers were not cheapest solution, but offered fast and cost-effective expansion

Scenario-based Benefit-Cost Analysis:

- For interconnection and reliability-driven projects, scenario-based, least-regrets planning can focus on project costs (as in the examples discussed so far).
- To implement scenario-based least-regrets planning in the context of multi-value solutions, the focus needs to shift from reducing costs to maximizing net benefits (to minimize total system costs)
- **Example: ATC's analysis of Paddock-Rockdale line**
  - Scenarios presenting 6 plausible futures
  - Multi-benefit analyses similar to Order 1920 requirements
  - Benefits fell $56m short of $136m project cost in one scenario; but savings exceeded project costs by $100-700m in other scenarios
  - Result: $375m in average savings across scenarios
    - Maximum regret of building the project: $56 million
    - Maximum regret of not building it: $700 million

Part III—Proactive Holistic planning … Development zones

Request-by-Request Planning (fragmented, costly)

- Current planning processes:
  - Identify grid upgrades for individual clusters of generator interconnection request
  - Identify grid upgrades for (mostly individual) load interconnection requests
  - Identify grid upgrades for other immediate and 5-10 year reliability needs under current "base case" projections

  Result: a piecemeal, fragmented grid expansions that tends to cause delays and be more costly in the long-term

When the number of individual requests stack up, the question shifts: keep responding with incremental upgrades or plan around longer-term growth and a broader set of future transmission needs?

Proactive, Holistic Planning (planned, scalable)

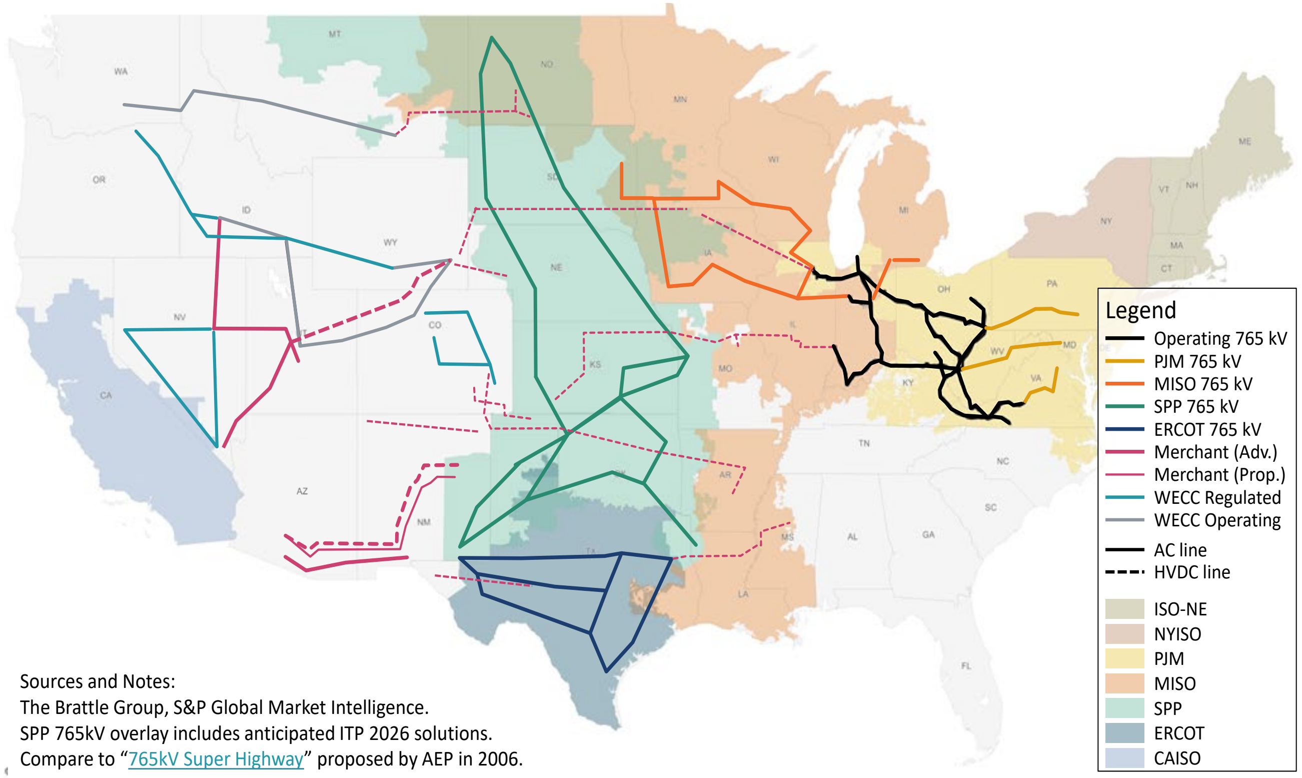
- Proactively address needs: jointly plan for all projects in an area that meet objective milestones—eliminate individual studies and restudies; identify more cost-effective "at scale" solutions
- Holistic, multi-value planning: Size solutions for full long-term range of plausible needs with staged expansion—more robust solutions that reduce need for piecemeal incremental upgrades
- Take advantage of development zones

Development zones: Work with state policy makers to designate development zones for large loads and generation (modeled after Texas CREZ or Illinois REAP) to reduce locational uncertainty and enable proactive grid planning

Part III—Coordinated Interregional Planning

- Full consolidation or siloed local and regional remains uncommon
  - SPP's proposed Consolidated Planning Process (CPP) is the exception. It would replace separate planning process and enable proactive creation of projected transmission capacity needs
  - SPP’s CPP is proposed to include interregional planning
- Interregional value has to be considered explicitly:
  - Resource adequacy, extreme weather resilience, and energy trading of interregional projects offers unique value in addition to also addressing regional and local needs
  - Regional 765kV overlays in MISO, PJM, SPP, and ERCOT could be linked to support future interregional transfers and add and large load interconnection headroom
- Interregional solutions should be also evaluated for addressing identified all local/regional needs so they are not preempted by local/regional projects
- Challenges remain: multi-regional planning complexity, cost allocations, and multi-jurisdictional permitting

Planned and Proposed High-Voltage Transmission Overlays and HVDC Lines



Sources and Notes:
The Brattle Group, S&P Global Market Intelligence.
SPP 765kV overlay includes anticipated ITP 2026 solutions.
Compare to “765kV Super Highway” proposed by AEP in 2006.

Source: Pfeifenberger, Interregional Transmission and Benefits from Improved Planning, December 2025. Note that the northern portions of SPP’s proposed 765kV overlay have been proposed for SPP’s 2026 planning cycle but are not yet approved. The shown “operating” and proposed “regulated” transmission projects in WECC are operated at 500 kV.

Summary—Phased Best Practices (Phases 1 & 2)

Phase 1

1. Maximize existing assets; minimize lock-in of bad decisions
2. Measure and publish near-term headroom and locational signals
3. Deploy GETs, ATTs and operating measures to address immediate needs
4. Credit flexibility and co-location (when operationally enforceable)
5. Use a common set of scenarios and large-load projections and across all studies
6. Adopt a proactive, consolidated study process before piecemeal investments lock in more costly outcomes
7. Automate work flows and study processes

Phase 2

1. Use scenarios representing plausible future to bracket projected uncertainties in every planning cycle
2. Develop least-regrets metrics for comparing solutions across multiple futures to value flexibility and mitigate the risk of under/over investment
3. Link interconnection, reliability, near-term and long-term planning for developing more robust solutions
4. Confirm that solutions are "future-proof" before approving major upgrades—document whether cost-effective expansion options are preserved

Summary—Phased Best Practices (Phase 3)

Phase 3

1. Build holistic grid solutions that address transmission needs beyond individual interconnection requests; identify and stage backbone projects
2. Encourage and take advantage of "development zones" for large loads and generation (such as CREZ, REAP)
3. Implement consolidated (multi-driver) planning
4. Evaluate local, regional, and interregional solutions for their ability to holistically address all identified needs
5. The shift required: evolve deterministic, base-case-driven planning to holistic, scenario-based, least-regrets decision-making—not abandoning existing frameworks, but using them to holistically address all projected transmission needs

Conclusions and Key Takeaways

- Large loads are arriving far faster than planning and infrastructure can serve them—that gap is not closing
- Current planning processes—built for slow, predictable growth—are structurally mismatched to loads that are large, fast, clustered, and uncertain
- Siloed planning processes, development speed mismatches, and uncertainties compound one another, tempting regions to rely on reactive, piecemeal fixes that lead to delays and higher costs
- The path forward:
  - Create headroom visibility and deploy a wider set of available near-term solutions
  - Rely on proactive scenario-based planning and least-regrets decision-making—even for near-term decisions
  - Develop scalable, flexible grid solutions that preserving future expansion options
  - Deploy holistic (including interregional) planning and solutions instead of reactive, piecemeal approaches
  - Develop shared assumptions and automate workflows across all planning functions
- Implementable through phased actions—requires collaboration among regulators, planners, utilities, and states

Plan for speed and long-term flexibility—not project-specific, short-term workarounds that increase costs and limit long-term options

Thank You! Comments and Questions?

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The views expressed in this presentation are strictly those of the authors

LARGE LOAD IN SPP

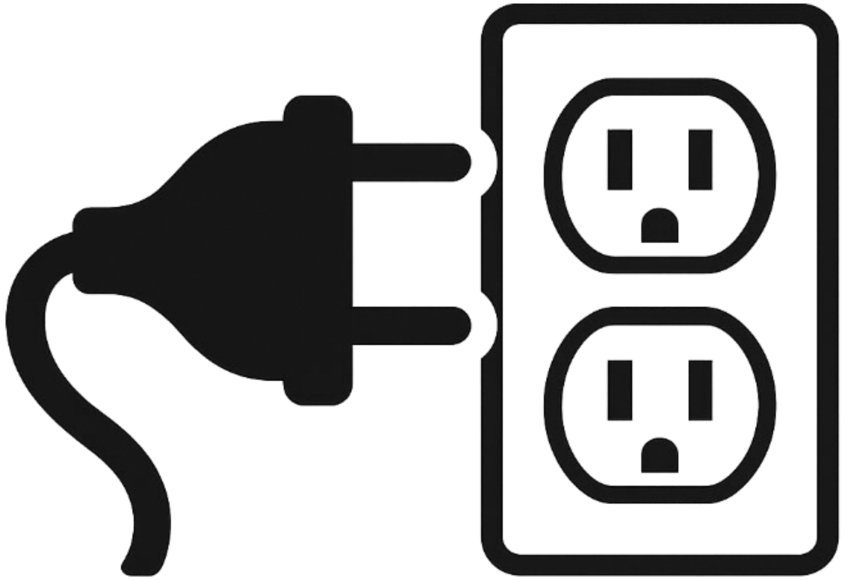
2026

DISCUSSION PREVIEW

- Load connection for ALL load
- High Impact Large Load (HILL)
- High Impact Large Load Generation Assessment (HILLGA)
- Conditional HILL (CHILL) and Price Adaptive Load (PAL)

SPP LOAD CONNECTION OPTIONS FOR ALL LOAD

SPP LOAD CONNECTION OPTIONS (ALL LOAD)



- ALL load must have transmission service
- Only Transmission Customers with load serving authority (utilities) are eligible to execute AQ/AX transmission service agreements
- SPP requires sufficient generation to exist for new load to connect with transmission service
  - Organic load growth
  - Modification to current delivery point
  - AQ if generation exists
  - AX if generation does not (service does not start until generation comes online)

ATTACHMENT AQ

CURRENT LOAD ADDITION PROCESS W/ CURRENT SUFFICIENT DESIGNATED RESOURCES

Assess the impact of delivery point changes

Must demonstrate sufficient Designated Resources

Cost Allocation: Base Plan Funding (BPF)

BPF: Load Ratio Share (12 CP)
345 kV: 100% Regional
230 kV: 67% Zonal/33% Regional
69 kV: 100% Zonal

Delivery Point Network Study: 60-90 Calendar Days

90 Calendar Days for HILL

Preliminary Assessment:

10 Business Days

ATTACHMENT AX

CURRENT PROVISIONAL LOAD CONNECTION PROCESS FOR FUTURE DESIGNATED RESOURCES

- Analyze the impact of load additions using customer's existing plus planned generation
- Study Timeframe: 60-90 Calendar Days
- Provisional Load Process Agreement
- Cost Allocation: 100% Directly Assigned Upgrade Cost, then Base Plan Funding for remaining cost

STUDY ANALYSES FOR ALL LOAD REQUESTS

Steady-State

- Monitored elements
  - SPP Facilities: 69 kV
  - First-Tier Companies: 100 kV and above
- Contingencies
  - SPP and First-Tier Companies
- Apply SPP Criteria and North American Electric Reliability Corporation (NERC) Reliability Standards

Short-Circuit

- Three-Phase Fault
- Calculate short-circuit currents within five (5) buses of load

Stability

- Fast Fault Screening
  - Critical Clearing Times
  - If issues occur, perform transient stability

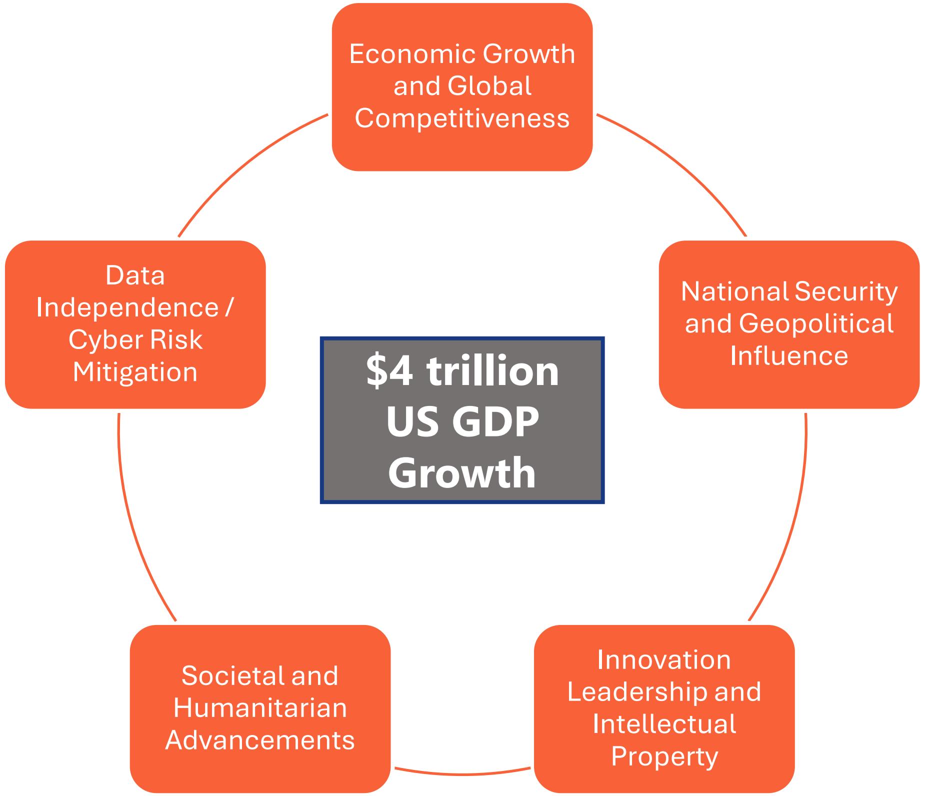
STUDY MODELS FOR ALL LOAD REQUESTS

Steady-State	Short-Circuit	Stability

• Integrated Transmission Planning (ITP)
  • Years 1, 2, 5, and 10
    • Light-Load
    • Summer Peak
    • Winter Peak
	• ITP
	  • Year 5
	    • Summer Peak
		• Transmission System Planning
		  • Years 2 and 10 (Summer Peak or Winter Peak)
		    • Based on Transmission Customer's Seasonal Peak

HIGH IMPACT LARGE LOAD (HILL)

AI DRIVEN LARGE LOAD GROWTH



Opportunity	Impact	Challenges	Impact
Accelerates economic GDP growth	AI could add **$15 trillion** globally and **$4 trillion** in the US by 2030	Job displacement risks	Up to **30% of US jobs** could be automated by 2030
Drives global innovation	US produces **~30% of AI research papers** worldwide	Ethical & privacy concerns	**60% of consumers** worry about AI privacy
Strengthens national security	US AI defense spending estimated at **$18 billion** annually	Geopolitical competition	China invested **$70 billion** in AI by 2025; global race risks
Attracts top global talent	US hosts **7 of the top 10 universities for A.I.**	Environmental & energy strain	AI data centers projected to use **5-8% of US electricity by 2030**; may drive **2-7% annual increases in electricity rates**
Benefits multiple sectors (healthcare, manufacturing)	AI could boost healthcare productivity by **40%**	Industry concentration risks	Top 5 US tech firms hold **>75%** of AI patent share

Opportunities exist for the U.S. to lead in the AI and Technology revolution

OTHER TYPES OF LARGE LOAD

Load Type	Description	Typical Size (MW)	Typical Voltage	Load Profile	Ramping Ability	Appetite for Demand Response
Data Centers	Facilities for computing infrastructure for data processing & storage	10 – 100+	13.8 kV – 230 kV	Flat, continuous, 24/7 operation	Low	Low
Cryptocurrency Mining	High-power computing for blockchain operations	5 – 100+	13.8 kV – 230 kV	Flat, responsive to price signals	High	High
Manufacturing (Heavy Industry)	Steel, cement, and auto plants	20 – 500+	69 kV – 345 kV	Cyclical, shift-based	Low	Low
EV Charging Hubs	High-power fast-charging stations	1 – 50	13.8 kV – 115 kV	Peaky, high during travel demand	Medium	Medium
Waste/water Treatment	Water intake, pumping, and treatment	5 – 100	13.8 kV – 115 kV	Generally flat with time-of-day variation	Low	Low
Mining Operations	Extraction and primary processing of minerals	10 – 300+	69 kV – 230 kV	Shift-based, varies with production	Low to Medium	Medium
Oil & Gas Facilities	Refineries, LNG, compressor stations	10 – 500+	69 kV – 345 kV	Continuous with routine maintenance	Low	Low
Green Hydrogen Production	Electrolysis facilities for hydrogen generation	20 – 300+	69 kV – 230 kV	Controlled, linked to renewables or pricing	High	High
Agricultural Processing	Grain drying, food processing, cold storage	5 – 50	13.8 kV – 69 kV	Seasonal with steady processing demand	Medium	Medium
Battery Energy Storage (BESS)	Grid-scale battery systems	10 – 500+	13.8 kV – 230 kV	Dynamic, driven by grid needs	Very High	Very High

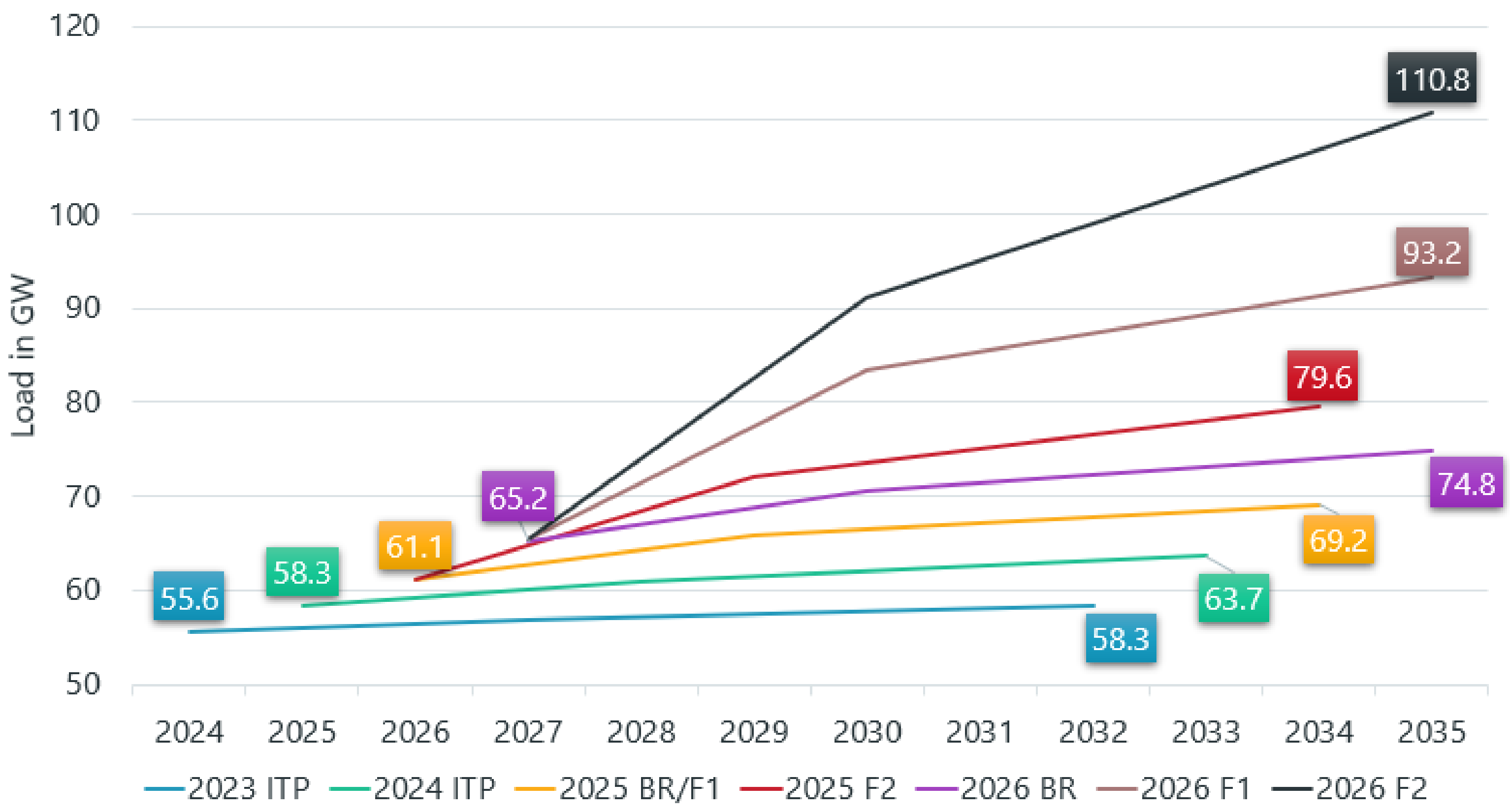
Not just A.I.: other large loads are contributing to rapid demand growth

DEMAND GROWTH AHEAD

2025 and 2026 Planning models includes large load growth in both futures at varying levels

SPP (and the industry) continue to see large load projections grow

Proactive transmission investment will ensure SPP is ready to serve this load growth



LOAD OF THE FUTURE?

- Large Loads, including High Impact
- Feedback we heard
  - High Load Factor
  - Low Load Factor
  - Flexibility to offer
  - Need 24/7 Up time
  - Monthly Service needed
  - Hourly service desired
- Other areas of the country and the world have experienced reliability issues
  - Fast ramps
  - Unexpected tripping due to system interactions

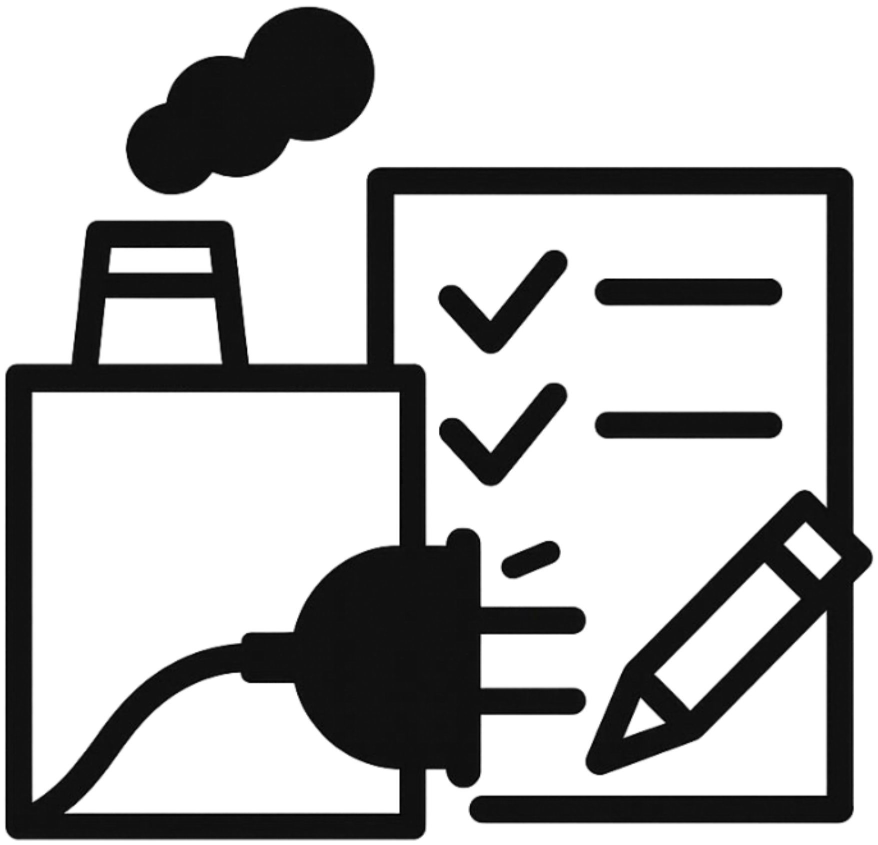
Load is growing quickly and has new characteristics

HIGH IMPACT LARGE LOAD (HILL)

Definition	• A new commercial or industrial load, or increase in commercial or industrial load, at a single site connected through one or more shared Points of Interconnection (POIs) or delivery points
MW Threshold	• Less than or equal to 69 kV: Greater than or equal to 10 MW • Greater than 69 kV: Greater than or equal to 50 MW
Exclude	• Electric Storage Resource
Requirements	• Register in Market • Evaluated by existing Tariff study processes and under new supplemental study processes • SPP Ride-through Requirements Compliance
Perform within 90 Calendar Days	• Transient Stability considering SPP HILL ride through requirements • Electromagnetic Transient (EMT) Screening • Short-Circuit Ratio and Critical Clearing Time • Note: If issues occur, perform full EMT analysis

HIGH IMPACT LARGE LOAD GENERATION ASSESSMENT (HILLGA)

HIGH IMPACT LARGE LOAD GENERATION ASSESSMENT (HILLGA)



- Behind the meter: connected to wires that are non-jurisdictional to SPP and will never inject beyond the load at the point of interconnection
- Load Limited Interconnection Service (LLIS): within 2 buses of load and generation may not exceed the HILL load it is supporting

PATH 1: BEHIND THE METER NON-WIRES JURISDICTIONAL

- Previously generation over 5 MW would be required to go through the full generation interconnection (GI) process (DISIS)
- Now generation configured for zero injection onto the transmission system can be studied in 90 days by SPP or an equivalent stability study done by the TO
- Generation greater than 10 MW must be market registered
- Separate metering required for each load and generator
- If study shows potential impacts to the transmission system, the generation must either be studied under the full GI process or sponsor necessary upgrades
- No net metering for transmission billing purposes

PATH 2: HILLGA LOAD LIMITED INTERCONNECTION SERVICE (LLIS) ATTACHMENT BB

- HILL and generation are in same "local area"
  - Using no more than 5 substations
  - Using no more than 2 transmission lines
  - Each load within 2 substations of generation
  - Generation can connect to more than one HILL
- Generation is required to limit output to the amount of HILL(s) considered in the agreement
- Total capacity of Generating Facility(ies) in HILLGA Request(s) for a specified HILL ≤ HILL Request load × Max (110%+PRM ,125%)
- Path to Firm: Service is interim for 5 years, which should be sufficient for the generation and load to be considered planned sites and subject to the planned CPP GRID-C fee
- Any developer can submit HILLGA LLIS, however there must be a demonstrated relationship with a HILL load

CONDITIONAL HIGH IMPACT LARGE LOAD (CHILL) SERVICE & PRICE ADAPTIVE LOAD (PAL)

CHILL SERVICE & PAL

- Transmission service is required for ALL load in SPP
- Attachment AQ and AX grant 8760 firm transmission service per FERC proforma language
- Allowing “flexible load” service requires the ability for SPP to curtail service when the flexibility to serve the flexible load does not exist on the transmission system
- Demand Response (DR) load currently grants firm transmission service, as DR load often desires transmission to be built and maintained and base plan funded in a manner consistent with firm load. DR curtailment is generally based upon price and is not based on firm or non-firm priority. CHILL load is designed to be curtailed prior to all firm load and with mitigated impacts to firm load and generation.

WHAT IS CONDITIONAL HIGH IMPACT LARGE LOAD SERVICE (CHILLS)? ATTACHMENT BC

Definition	• New type of transmission service available to HILL for serving Conditional High Impact Large Load (CHILL)
Goal	• Another path to connect Large Loads
Conditions	• Curtailable, Non-Conforming Load • Up to 1 year • After 1 year, path to Long-Term Service (up to 7 years)
Evaluation	• Attachments AQ & AX (firm) • Curtailable in Markets (non-firm)
Phase 2	• Under development

"CHILL OUT" OPTIONS

All CHILL curtailed during EEA2

OPITION 1: Connect CHILL to system if has adequate generation but is contingent on transmission upgrades:

- Customer has executed AQ agreement and has sufficient Designated Resources
- CHILL will be curtailed when transmission limitations are realized
- CHILL will be curtailed during system CHILL curtailments

OPTION 2: Require accredited equivalent HILLGA generation for CHILL

- CHILL would not have service until HILLGA reached Commercial Operations
- No limit on amount as the CHILL would be supported by HILLGA
- CHILL curtailed if generation is not available and/or if there was a net impact to the transmission system during system CHILL curtailments
- EXAMPLE: If you have 100MW CHILL, 100% wind support at 20% accreditation= 500MW of nameplate wind; 100% gas support at 90% accreditation = approx. 110MW nameplate gas

CHILL CONCERNS AND NEXT STEPS

- Impact to market pricing (more load=higher prices)
- Impact to run hours on limited/permit limited resources

Two key concerns that drove the requirement for supporting generation ("covered CHILL")

- Inability to take HILLGA outages: future changes anticipated
- Some stakeholders still desire to allow some amount of uncovered CHILL

Covered CHILL concerns

STAKEHOLDER CONCERNS FOR CHILL → ANOTHER PRODUCT?

- Some large load have expressed the desire for:
  - Permeant curtailable load transmission product that does not require Designated Resources (CHILL is temporary, 5-7 yrs)
  - Payment of transmission based on usage not reservation (for low load factor, highly flexible loads)
  - Ability to use storage to manage ramp and ride through requirements (not a resource for injection rights or for Resource Adequacy)

- SPP is considering a Price Adaptive Policy (PAL)
  - Only pulls power when there is excess energy on the system.
  - To avoid resource adequacy impacts, this load could not negatively impact generation that is permit hours limit (i.e. load studied in the LOLE but no increase to the planning reserve margin)
  - Could be effectuated through price as "price sensitive" or through projected dispatch stack
- Storage not injecting into the system may be eligible

QUESTIONS?

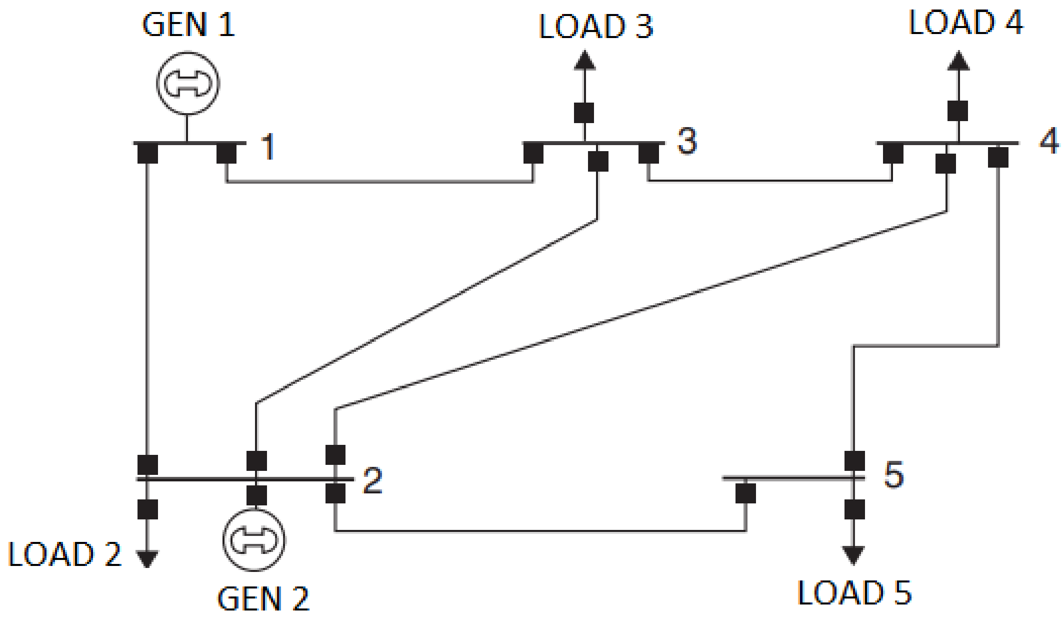
APPENDIX

LOAD HOSTING CAPACITY TOOL

Provide available transfer capability (ATC) data to Transmission Customers and Transmission Owners

Determine maximum load amount able to connect at each bus on SPP's Transmission System

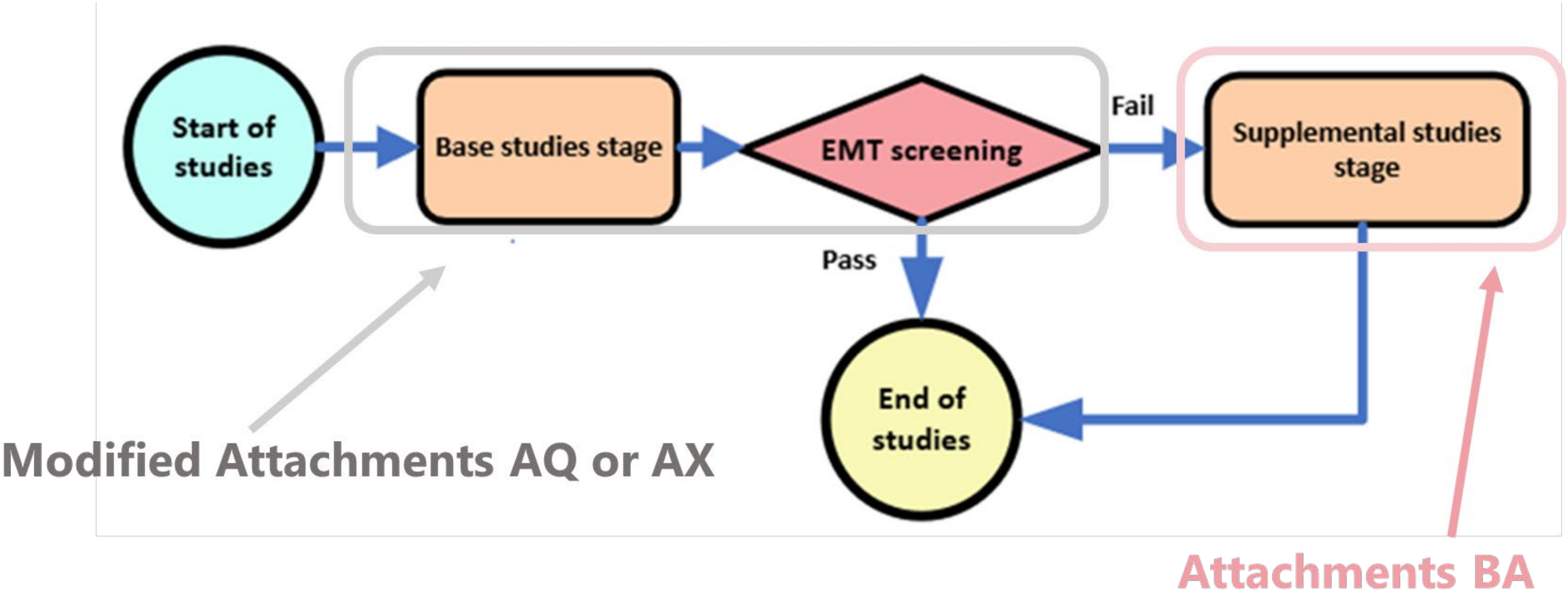
Create platform for data availability and update monthly



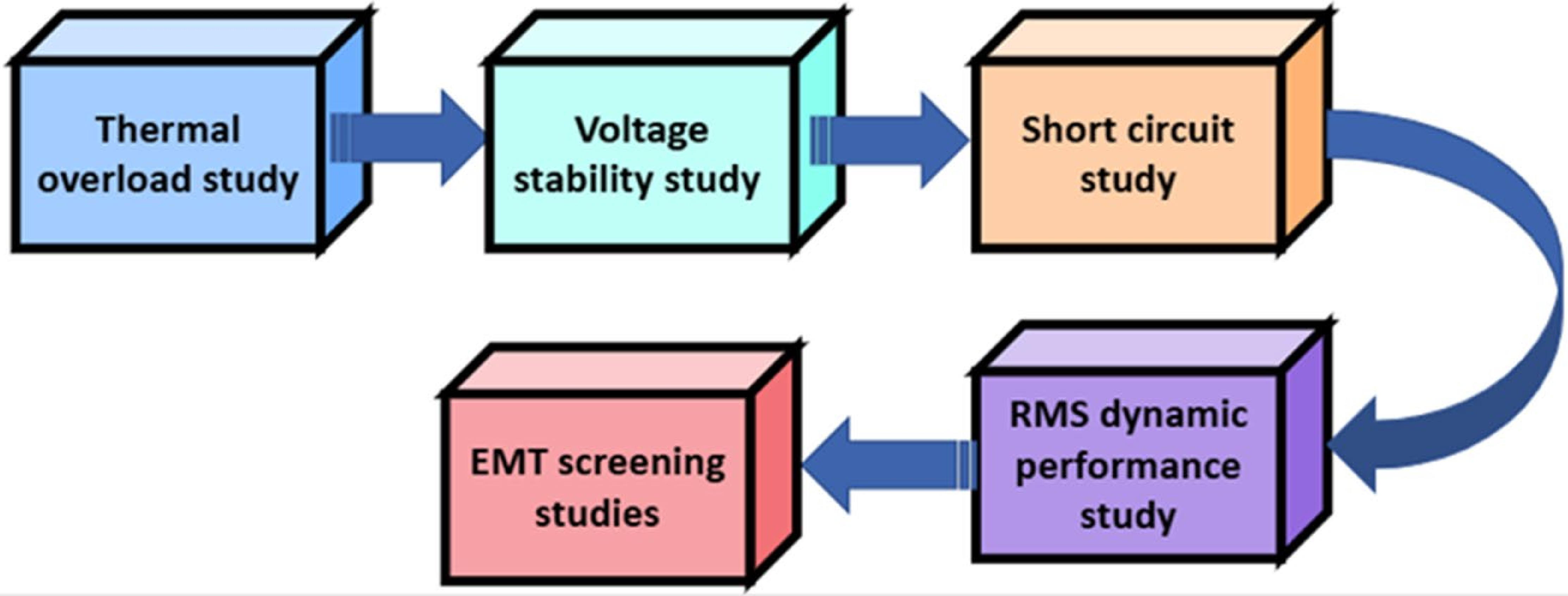
*Pending stakeholders' approval

	HILL/HILLGA Firm Service Policies				Flexible Intermittent Policies	
	HILL (for Load) *MOPC (Aug 21) BOD (Sept. 4)*		HILLGA (for Generation) *MOPC (Aug 21) BOD (Sept. 4)*		Phase 1 *Phase 1 (Jan '26)*	***Phase 2*** *Phase 2 (Apr '26)*
Service and parameters	**AQ Process** For LSEs with sufficient gen; load willing to wait on upgrades	**AX Process** For LSEs acquiring gen; load willing to wait on upgrades	**Common Bus** For supporting gen to be built behind a common bus with HILL	**Local Area** For supporting gen to be built behind a common bus with HILL	**CHILL** For large load willing to take curtailable service without sufficient gen	***PAL*** *For any load willing to take curtailable service to protect market prices*
Typical Customer	Heavy industry, mining, refineries data centers with continuous demand		Load-owned or partnership	LSE or developer-owned	Data centers with scalable operation	*Crypto Mining or Battery*
Time to study	90 days	90 days	90 days	90 days	90 days	*90 days*
Tx Cost allocation	Upgrades are base plan funded	Directly assigned until firm service acquired for new gen	Directly assigned	Directly assigned	Directly assigned	*Directly assigned*
Service Limit	No limit	No limit upon new	Gen will not be injected to the grid	Gen limited to HILL's need & system capacity	Curtailable for reliability (RA or Tx)	*Curtailable for price or reliability*
Length of Service	Permanent status	Permanent status	Permanent, or grid injection w/ DISIS/CPP	5-year limited status: must pursue DISIS/CPP	7-year CHILL status (after study complete), must pursue AX/AQ	*TBD*
Demand Response	Eligible resource	Eligible resource	N/A	N/A	Not eligible	*Not eligible*
Tx costs					Monthly / unreserved usage?	*Flow-based*

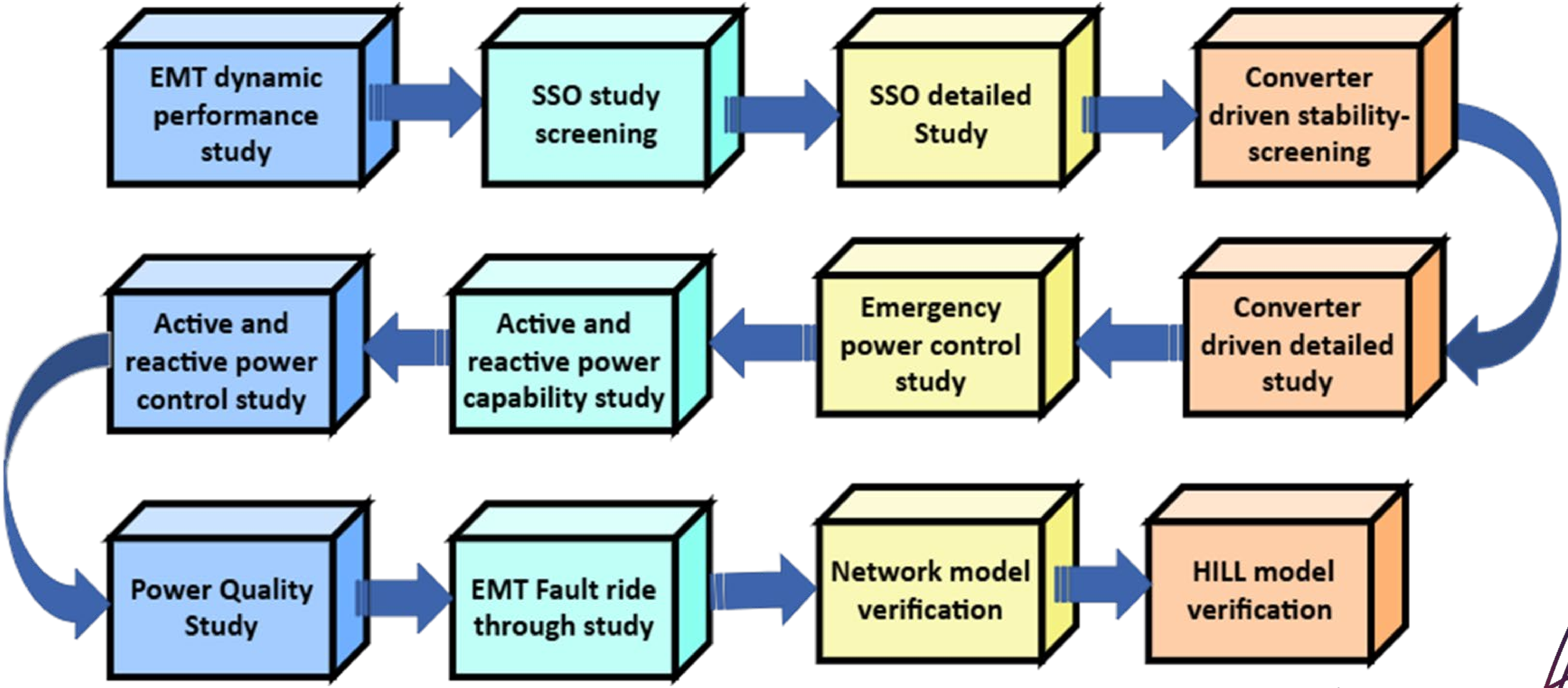
RECOMMENDED HDPS STUDIES



BASE STUDIES STAGE



SUPPLEMENTAL STUDIES STAGE



RIDE-THROUGH PERFORMANCE: HILL

Voltage Ride-Through (ITIC curves)

Table 1. HILLs RMS Voltage Ride-Through Requirements as Measured at POI[2]

Root Mean Square Voltage (p .u. of nominal at POI)	Minimum Ride-Through Time (Seconds)
V>1.20	N/A (May ride-through or trip)
1.10<V≤1.20	0.50
0.90≤V≤1.10	Continuous operation, no trip.
0.80≤V<0.90	2.00
0.50≤V<0.80	0.50
V<0.50	0.15

Transient Overvoltage Ride-Through (IEEE 2800)

Table 2. HILLs Transient Overvoltage Ride-Through Requirements as Measured at POI[4]

Instantaneous Phase to Phase or Phase to Ground (p.u. of nominal at POI)[a]	Minimum Ride-Through Time (milliseconds)[b]
V>1.80	May ride through or trip
V>1.70	0.2
V>1.60	1.0
V>1.40	3.0
V>1.20	15.0

a Specified voltage magnitudes are the residual voltages with surge arresters applied.
b Cumulative time over a 1-min time window4

Frequency Ride-Through (proposed PRC-001)

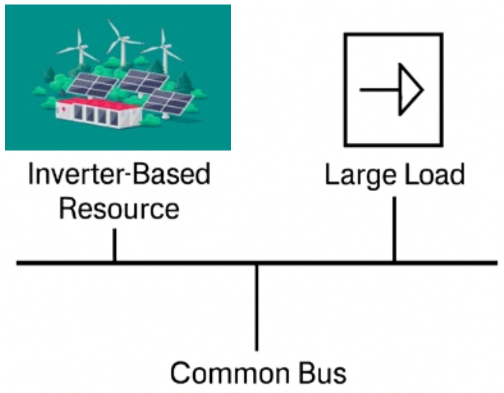
Table 3. HILLs Frequency Ride-Through Requirements as Measured at POI[5]

System Frequency (Hz)	Minimum Ride-Through Time (Seconds)
f≥61.8	May Trip
f≥61.2	299
f≤ 61.2 and f≥ 58.8	Continuous
f< 58.8	299
f< 57.0	May trip

RIDE-THROUGH PERFORMANCE: RESOURCES PAIRED WITH HILL

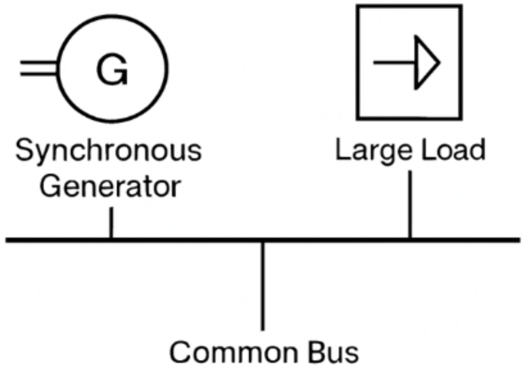
If IBRs paired with HILL:

- Based on IEEE 2800-2022 Clause 7, requirements adopted by SPP



If Synchronous generator, Synchronous condenser, Type 1 and Type 2 wind turbines paired with HILL:

- Based on PRC-024-4 requirements (currently on version 3)



AQ, AX, AND HILL FINANCE COMPARISONS

Item	AQ	AX	HILL
Non-Refundable Study Deposit	N/A	N/A	$10,000
Study Deposit	$10,000	Billable after study completion	$125,000 EMT: $200,000

Proposed Revision: Billable after study completion

HIGH IMPACT LOAD GENERATION ASSESSMENT (HILLGA)

ATTACHMENT BB HILLGA PROCESS

Evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The HILLGA is part of HILL process that studies: 1) the proposed load, 2) the proposed Generating Facility to follow the proposed load, and 3) the combination of the supported proposed load and proposed Generating Facility to follow the proposed load.

HILLGA study is unique in that the study timeline is faster 90 Calendar Days and the load and generating facility together.

DISIS AND HILLGA FINANCES COMPARISON

Item	DISIS		HILLGA	
Cash Application Fee	$10,000		$20,000	
Cash Study Deposit	$35,000 +$1,000/MW	> 0 MW < 80 MW	$250,000 flat fee	up to 500 MW
	$150,000	≥ 80 MW < 200 MW	$500,000 flat fee	> 500 MW
	$250,000	≥ 200 MW		
Security Deposit(s)	$4,000/MW at application	Financial Security (FS) 1	$8,000/MW at application	FS 1
	The greater of 10% or $4,000/MW at Decision Point 1	FS 2		
	20% of Total Upgrade Cost Allocation per Phase Two Report at Decision Point 2	FS 3		

DISIS AND HILLGA STEADY-STATE MODEL COMPARISON

DISIS Steady-State and Stability Models (Base from ITP)	HILLGA Steady-State and Stability Models (Base from ITP)

• Year 2
  • Summer Peak
• Year 5
  • Light Load
  • Summer Peak (STB)
  • Winter Peak (STB)
	• Year 5
	  • Summer Peak
	  • Winter Peak

Same SCRCCT screening will be performed for DISIS and HILLGA. If further EMT/PSCAD is required that is outside the 90 days.