NEW YORK STATE | Department of Public Service

ENERGIZE NEW YORK

TECHNICAL CONFERENCE

OCTOBER 30, 2026

Logistics

In-Person:

- Restrooms available outside this room on the 3rd floor.
- If, for whatever reason, we need to evacuate the building, calmly and carefully take one of the two staircases to the Plaza level.
- There will be an opportunity to ask questions during today's panel discussions. For those in person please raise your hand during the Q&A period and we will seek to accommodate you.

Online:

- You should have the ability to **direct questions to the host using the CHAT function.** We're going to respond to as many as we can and will keep track of those that we don't get to.

Today's session will be recorded and posted online

Please keep your participation respectful and on point to the topic presented.

Agenda

10:00 – 10:15 | Welcome and Introduction

Speaker(s): Kevin Luteran, New York State Department of Public Service

Items for presentation and discussion: Overview of proceeding, objectives for tech conference, overview of tech conference schedule, and ground rules and practicalities for participation.

10:20-10:50am | Joint Utilities - Framework for Large Loads

Speaker(s): MD Sakib, National Grid

Items for presentation and discussion: The presentation will share a utility framework for integrating large loads into New York's electric system that preserves reliability, protects existing customers from financial risk, and provides a predicable path for credible projects.

11:00am-11:30pm | Emerald AI - Large Load Flexibility

Speaker(s): Michael Panfil, Emerald A.I.

Items for presentation and discussion: The presentation will provide an example of strategies for data center flexible load deployments and their associated policy considerations.

LUNCH, 11:30-12:30

12:30-3:30pm | Energize Objectives Analysis

Speaker(s): Kevin Steinberger, E3; Andrew DeBenedictis, E3

Items for presentation and discussion: This presentation will outline analysis and initial findings related to reliability, rates, affordability, and strategies to consider in New York.

3:30pm | Closing Remarks

Speaker(s): Kevin Luteran

Overview of Energize NY Proceeding

- Consistent with the Governor's 2026 State of the State address, the Commission issued the Energize NY Development Order on February 12, 2026, in Case 26-E-0045.
- This Order initiated a proceeding to advance a large load interconnection framework, while acknowledging that certain large electric load facilities, such as data centers, often do not provide the same economic development or job creation opportunities relative to other strategic industries.

6 Main Objectives:

(1) Modernize the interconnection process for all building loads

(2) Improve transparency and predictability related to grid upgrades

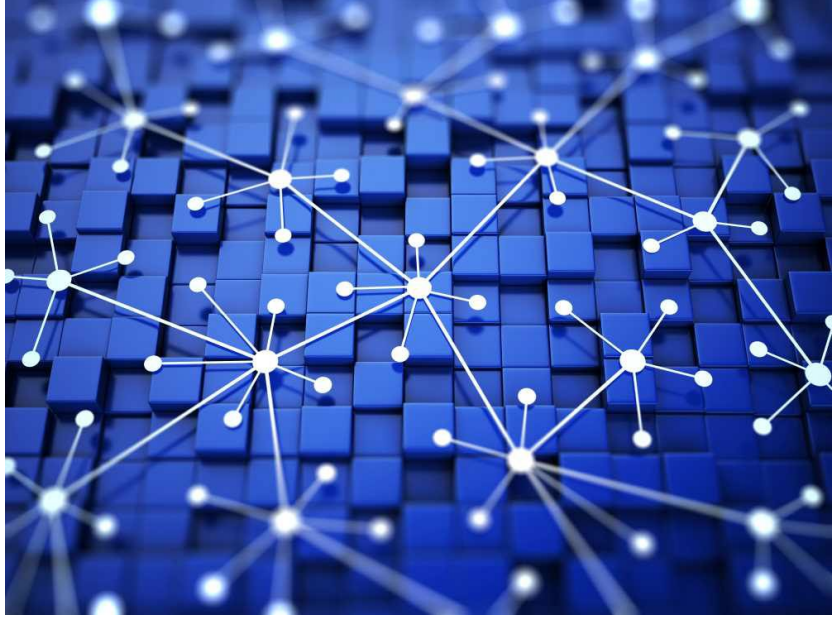
(3) Ensure that data centers and similar facilities bear the cost they impose on the electric system

(4) Provide for the continued reliability of the electric system

(5) Develop programs and policies for the interconnection of large loads that consider the objectives of the Climate Leadership and Community Protection Act

(6) Explore ways in which new large electric load could lead to downward pressure on rates for all customers.

JOINT UTILITIES - FRAMEWORK FOR LARGE LOADS


Technical Conference for Large Loads Proceeding Case 26-E-0045

October 28, 2026

JOINT UTILITIES
OF NEW YORK

WE MUST USE A BALANCED FRAMEWORK TO ENABLE RESPONSIBLE LOAD GROWTH WITHOUT ADVERSELY IMPACTING OTHER CUSTOMERS OR THE RELIABILITY OF THE SYSTEM

Framework

Screen and Study
- Use maturity criteria and coordinated utility and NYISO studies to distinguish credible projects, identify system impacts, and align service with grid readiness.

Serve and Operate
- Provide predictable pathways for firm, phased, or flexible service, supported by enforceable operating limits, communications, and performance requirements.

Allocate and Secure
- Apply **beneficiary-pays** principles, long-term commitments, minimum bills, exit fees, and financial security to protect existing customers.
- **Protect existing ratepayers** from undue cost shift

Risk

Project Uncertainty
- Speculative or duplicative requests may not materialize as forecast, creating stranded-cost exposure if infrastructure is built for demand that does not arrive or persist.

Reliability and Planning Pressure
- Large loads can add significant demand faster than traditional planning processes were designed to accommodate, increasing reliability, resource-adequacy, and infrastructure pressures.

Customer Exposure
- Without fair cost allocation and durable financial commitments, upgrade costs may shift to existing customers.
- Overly restrictive policies also carry risk by discouraging credible loads that could help share fixed system and modernization costs.

Context

Economic Growth
- Beyond data centers, large loads also include advanced manufacturing, semiconductor fabrication, and other major industrial projects.

Broader System Contribution
- Projects such as Micron and Chobani can support jobs, GDP growth, and the tax base, while increased electricity sales can spread fixed system and modernization costs across more customers.

New York Competitiveness
- As other states restrict or struggle to accommodate development, New York can differentiate by offering a clear pathway for responsible investment.

GRID PLANNING SHOULD REFLECT CREDIBLE LARGE-LOAD PROJECTS

*As of September 2026, NYISO's large-load queue included **57 projects representing more than 14.5 GW**, reinforcing the need to distinguish requested load from likely load.*

Initial Request

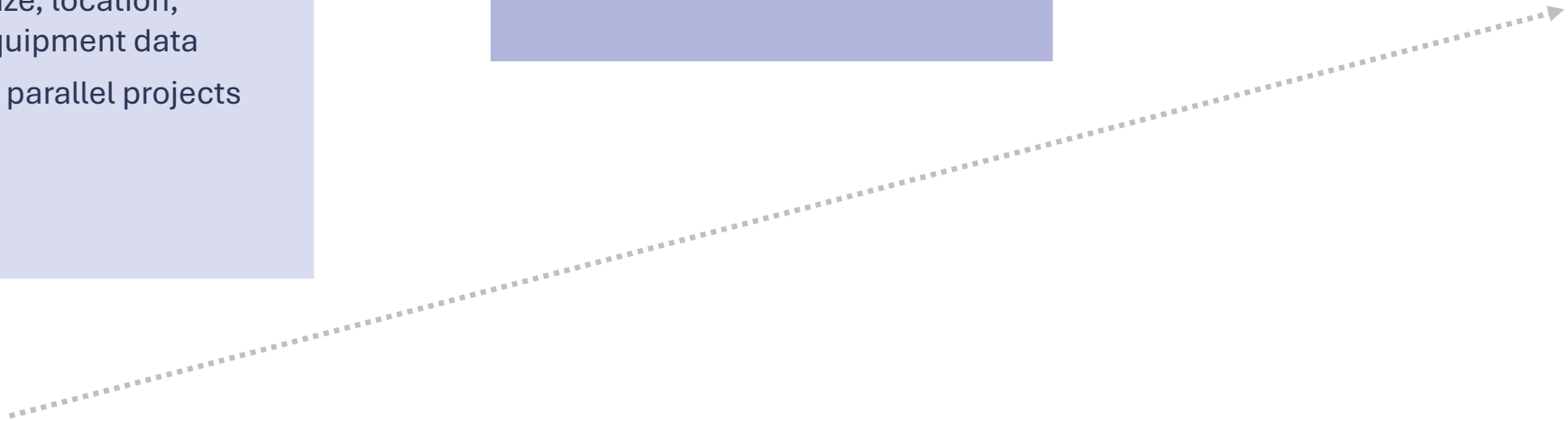
- Preliminary size, location, timing and equipment data
- Disclosure of parallel projects

Development Progress

- Site control, permits and construction milestones
- Realistic energization and ramp schedules
- Seasonal demand projections

Financial Commitment

- Deposits, letters of credit and executed agreements
- Consequences for withdrawal or material changes



LARGE LOADS CAN CONNECT ONLY WHEN THE GRID IS READY TO SERVE THEM RELIABLY

Reliability will be protected through rigorous studies, necessary upgrades, and ongoing operational requirements

Study the impact: NYISO and the affected utilities assess the proposed demand and identify bulk-system and local reliability concerns.

Identify solutions to maintain reliability: Determine the upgrades, operating limits, or other measures needed to address identified reliability concerns.

Confirm readiness: The customer receives only the level of service the grid can reliably support. Full service cannot begin until the necessary upgrades are in place.

Operate reliably: The customer must follow defined operating limits, communication and monitoring requirements, and curtailment or restoration procedures

Flexible service may speed up access to power: Flexible demand and bring-your-own generation can support earlier service but require NYISO and utility studies to confirm reliable operation.

Note: The process outlined above applies specifically to large load projects over 50 MW.

EXISTING CUSTOMERS MUST BE PROTECTED FROM UNDUE RISKS

Protections should continue to address both infrastructure investment and ongoing financial exposure.



Minimum monthly billing

Establishes a revenue floor despite lower utilization.



Separate Rate Class for Large Loads

Aligns rates with the cost of serving large loads to help prevent cost shifts to other customers.



Long-term contract

Aligns customer commitment with the investment horizon. Can include controls such as exit fees.

Five Key Protections



Enforceable milestones

Discourages speculation and sets consequences for delay or modification.

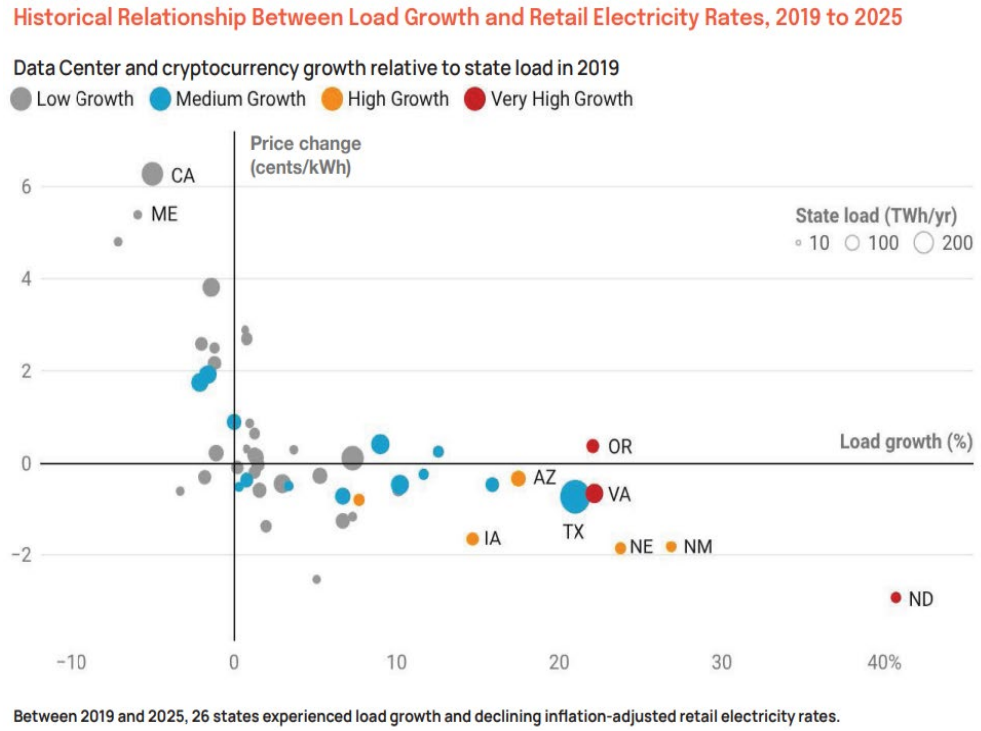


Collateral or financial security

Protects against default or abandonment.

NATIONAL EXPERIENCE PROVIDES EXAMPLES OF BALANCED APPROACHES THAT MINIMIZE RISKS TO EXISTING CUSTOMERS

Benchmarking nationally provides examples where adverse customer impacts of large loads have been successfully avoided, with some cases even provide a net savings to customers.





PG&E reported that large load growth enabled electric rate reductions four times over the prior two years and estimated that each additional gigawatt of load could lower customer bills by roughly 1-2%.



As per E3, Recently approved large load contracts are expected to lower residential costs by approximately 8%, potentially allowing DTE to defer a planned rate request.



As per E3, Entergy customer rates are expected to be 16% lower than they would have been otherwise because of large load customers added to the grid.

Energy Systems Integration Group, Impacts of Large Loads on Electricity Rates: A Primer, May 2026.
E3, Understanding the Drivers of Rising Electricity Rates and the Role of Data Centers (May 2026)

A BALANCED FRAMEWORK MAINTAINS NEW YORK'S COMPETITIVENESS WHILE PROTECTING EXISTING CUSTOMERS



Statewide principles should build on existing utility processes to promote consistency, transparency, reliability, and customer protection, while recognizing that service pathways will vary based on system needs, regulatory requirements, and customer circumstances.

EMERALD AI - LARGE LOAD FLEXIBILITY

Emerald AI | Policy

NY DPS

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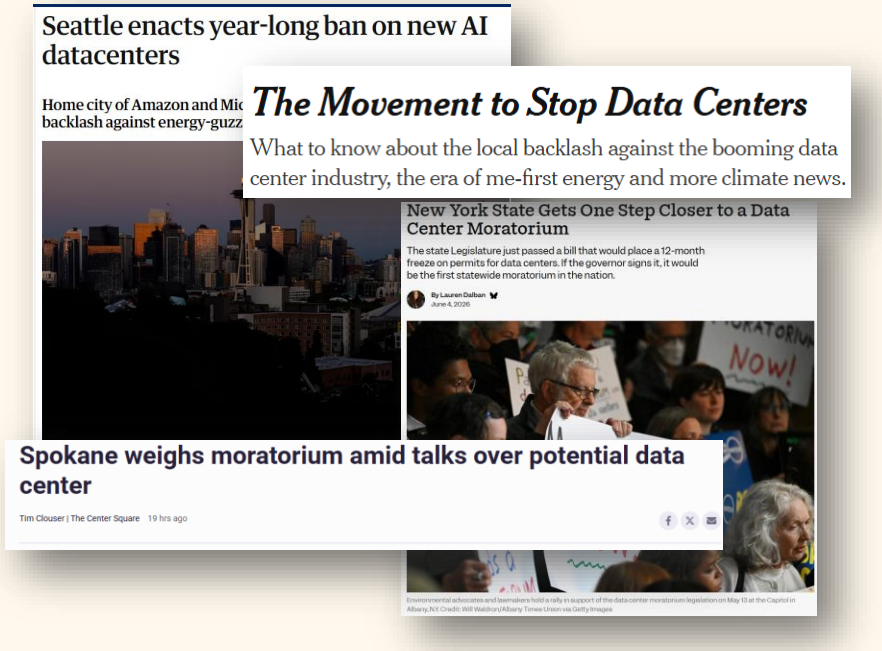
Emerald AI seeks to unlock multitrillion-dollar investments in AI data centers *today* by overcoming power grid bottlenecks

- **Emerald AI makes AI data centers flexible power users through a software-only platform** that orchestrates compute power use and onsite energy resources to bolster grid stability and avoid grid buildout without compromising compute service.
- **The opportunity is massive:** Roughly 100 GW of data centers could be connected to existing grids *today* if data centers had just modest flexibility. Emerald AI aims to enable data centers & cloud providers to speed time-to-power.
- **Emerald AI has completed five commercial demonstrations in partnership with leading energy and AI partners, expanded internationally, and announced a ~100MW commercial deployment with NVIDIA later this year.**
- **Flexibility is the key solution to get data centers access to power now** and will complement other solutions in future.

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1. About Emerald AI

Emerald AI uses software to transform AI Factories



Traditional inflexible data centers are slow to connect and can trigger expensive utility upgrades leading to raising rates for communities

…into power-flexible assets and good grid citizens

Flexible AI data centers



Flexible AI data centers secure larger and faster power connections AND support communities

- Accelerate AI deployment, innovation, competitiveness
- Curb rising energy bills for local communities
- Protect grid reliability
- Integrate clean energy onto grids
- Democratize AI (research labs, startups, universities.)

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Emerald AI is fortunate to be backed by NVIDIA & AI, energy leaders

Institutional Venture Investors

Energy Impact Partners, NVIDIA, EATON, iqt, GE VERNOVA, SAMSUNG, nationalgrid, Lower Carbon Capital, Radical Ventures, salesforce ventures, SIEMENS, DCVC, Energize Capital, Analog Devices, jera, LUMEN, RWE, Olayan, aramco, SABANCI 100

Select Individual Investors

Fei-Fei Li *Professor, Stanford University*	**Jeff Dean** *Chief Scientist, Google*	**Malcolm Turnbull** *29th Prime Minister of Australia*
Chase Lochmiller *CEO, Crusoe*	**Rich Lesser** *Chairman, BCG*	**John Doerr** *Chairman, Kleiner Perkins*

Leadership

Dr. Varun Sivaram *CEO*	Prof. Ayse Coskun Chief Scientist	Aroon Vijaykar *CCO*	Shayan Sengupta *Head of Eng.*	Mansi Shah *Head of Product*
				
• Chief Strategy Officer, Orsted • Sr. Advisor to Sec. Kerry, White House • CTO, ReNew Power	• Professor, Boston University • Director, Center for Information Systems & Systems Engineering	• Sunrun Head of Corp Dev; GM of AEE Solar; VPP & Grid Services • Investor at Partners Group	• Amazon Web Services EC2 Nitro Storage Leader • Led 50+ engineers, managing 1mm specialized GPU servers	• Chief Technologist, VMware • Led $200m+ enterprise data & distributed infrastructure portfolio

Select Advisors

Secretary Gina Raimondo
40th U.S. Secretary of Commerce

David Rousseau
President, Salt River Project

Employee Achievements

400+
Academic Publications

~50%
Team Members with Ph.D.s

As Seen In

AXIOS, The Washington Post, FORTUNE, TIME100 Most Influential Companies, nature, CNBC Squawk Box, Bloomberg, TED, The Times, The Economist, The New York Times

Company DNA

AMD, aws, Berkeley Lab, Crusoe, Fluence, groq, intel, Ørsted, Oracle, Partners Group, Google, Sunrun, vmware

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Emerald, Nvidia and Google launched the AI Energy Management Alliance (AEMA) to shape AI Flexibility

AEMA is the evolution of a coalition that has already shaped the national conversation on load flexibility.

FOUNDING MEMBERS

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NVIDIA

Google

LAUNCH PARTNERS

ANTHROPIC

aes

ANALOG DEVICES

Calibrant

Constellation

FLUENCE
A Siemens and AES Company

GENERATE

GRIDUNITY

nationalgrid

nrg

PassKey

RWE

SPLIGHT

CAMUS
Zero Carbon Grid Orchestration

CLEARPATH ACTION

encord
Plan the Energy Future

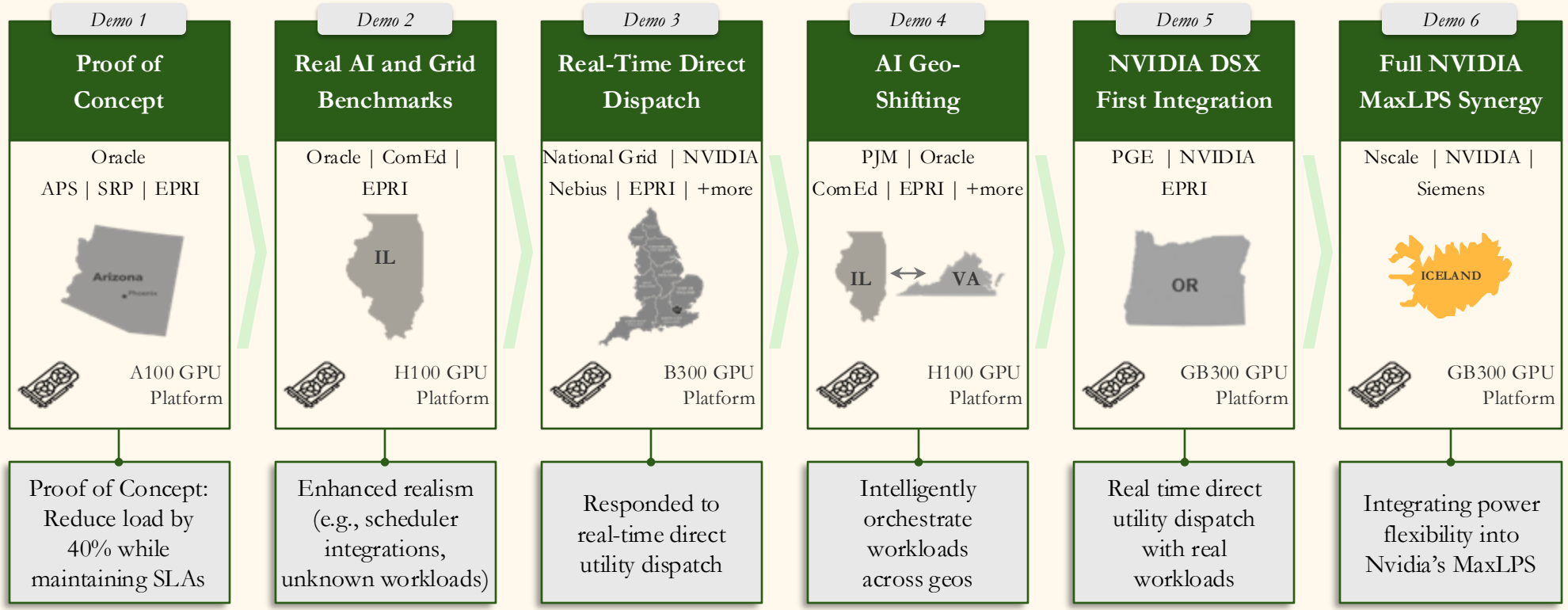
verrus™

voltus

2. Deployments

We have demonstrated an increasing set of AI flexibility capabilities at data centers and in cloud environments around the world

Last 18 months of Demos:
We've proven the tech – from concept to real-time flexibility



Confidential | Do not Disclose

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National Grid & EPRI dispatched compute flexibility in real time at a UK data center being managed by Emerald

AI Inference Clusters in the UK with Nebius Data Centers


THE TIMES

AI start-up helps National Grid to manage data centres' power use

Artificial intelligence will give them flexibility to reduce their electricity consumption at peak times

• EXCLUSIVE





96 NVIDIA B300 GPUs (~*130 kW*) @Nebius DC

New capabilities demonstrated

Live Grid submissions

Utility partner independently sent power targets, without warning

Immediate response

Data center was asked to respond to power targets in real time to simulating a grid emergency

Precision signal following

Following CO2 intensity signals at high temporal granularity (1 minute)

Project Partners

NEBIUS

nationalgrid

EPRI ELECTRIC POWER RESEARCH INSTITUTE

NVIDIA

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Conductor reduces AI cluster power during simulated high load period due to tea kettle use during major TV event breaks in the UK

Goal

Demonstrate that an AI cluster can meet a designated power reduction in response to high periods of electricity use during major TV breaks in the UK

Results

- Successfully reduced cluster power by **35% for 30 minutes surrounding halftime** and for **25% for one hour at the end** of a football match, helping combat the '**TV Pickup**' phenomenon as viewers fire up electric tea kettles during breaks in TV viewing
- Helped ease burden from a National Grid ESO-wide spike of **1 GW at half-time** and **1.6 GW at full-time**

Cluster Power Trace during soccer match (35% and 25% Reductions)



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National Grid seeks to "surprise" and "stress" the system; Emerald Conductor handles grid events with 100% precision and seconds-level response times

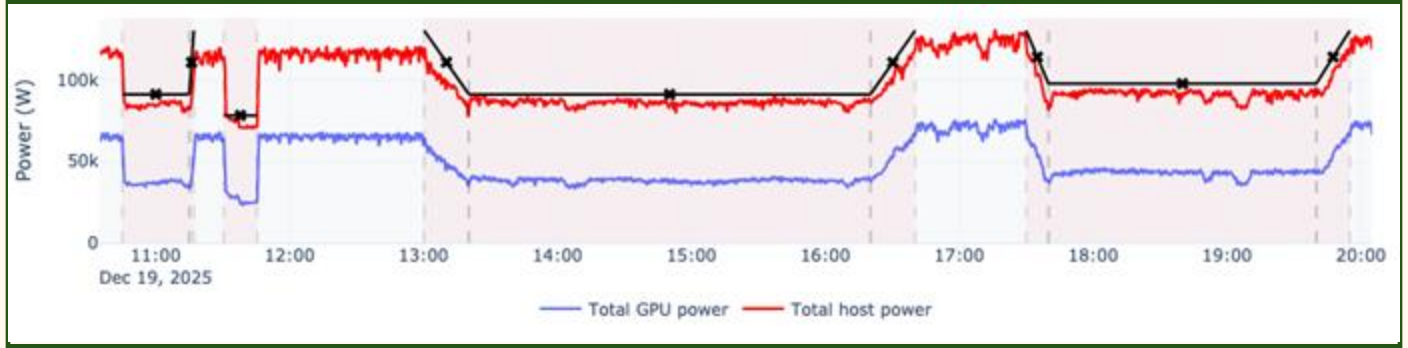
Goal

Reduce AI cluster power in response to grid events submitted by a third party, with no prior knowledge from Emerald AI

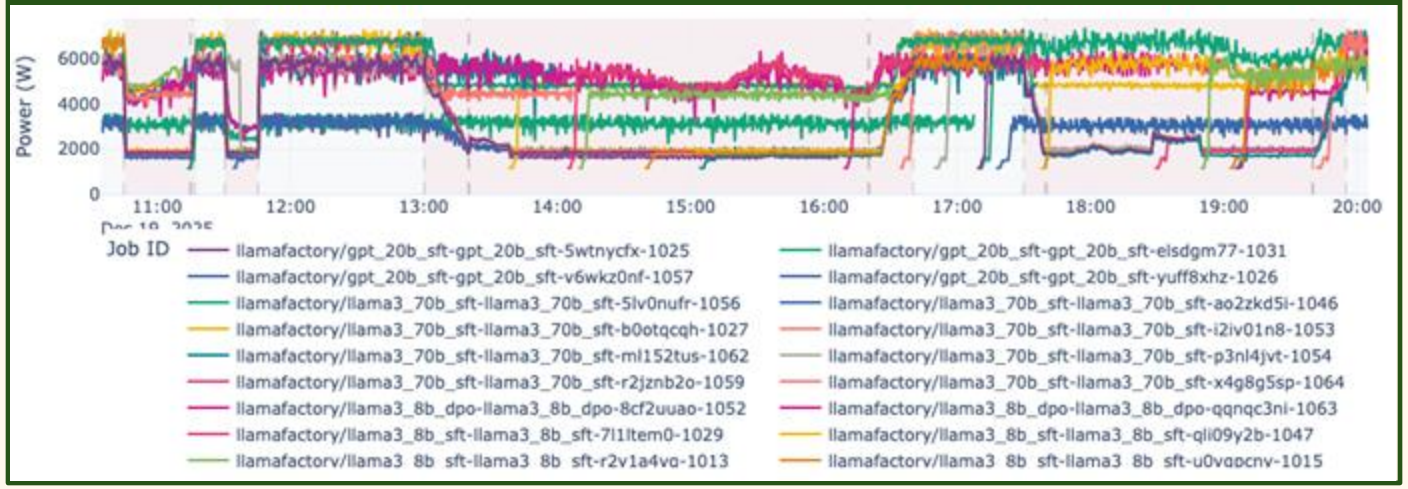
Results

- EPRI & National Grid submitted four events in a 9-hour window for Conductor to respond to
- Two events were **zero lead-time** and **zero ramp-time** - an as-fast-as-possible power reduction to a **30% and a 40% reduction**, respectively
- Emerald AI achieved the two zero-ramp-time power reductions in **under 40 seconds and 80 seconds**
- These events were followed up by t**wo sustained 30+% power reductions for 2-3 hours each**

Cluster Power Trace *(30%, 40%, 35%, and 30% Reductions)*



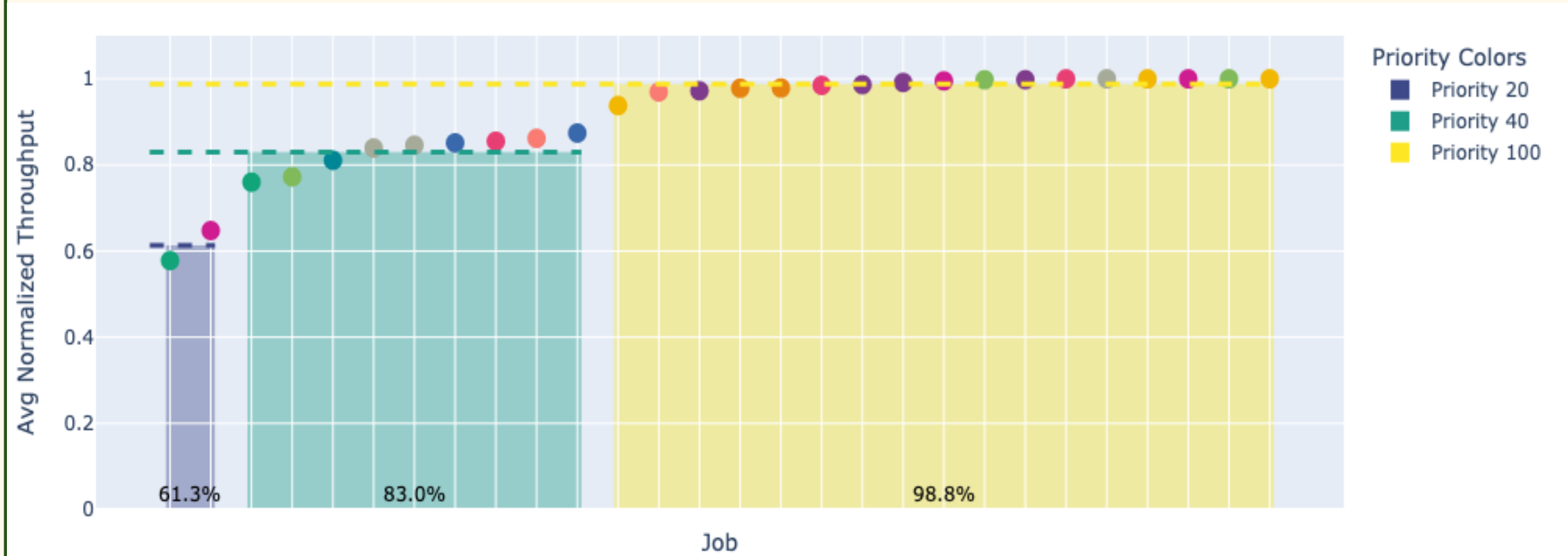
AI Workload Power Traces



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Emerald Conductor protects high-priority workload performance during 10% grid event test

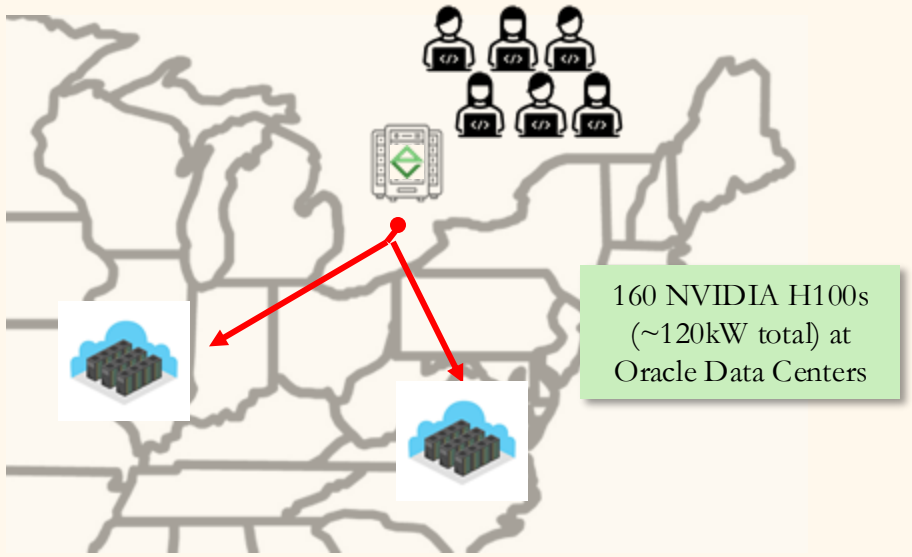
Performance by Job Priority Group



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Across two Oracle data centers in Ashburn and Chicago, we proved geo-shifting of inference workloads and multi-site management

AI Inference Clusters Hosted in Chicago and Virginia



New capabilities demonstrated

Multi-site management

Managed two sites concurrently in two different geographies

Geo-shifting inference

Shifted workloads from a grid constrained site to an unaffected site to reduce load

Integration with NVIDIA Dynamo

Integrated Emerald suite with NVIDIA's Dynamo distributed inference serving platform

Project Partners

pjm · comed AN EXELON COMPANY · Dominion Energy · ORACLE · EPRI ELECTRIC POWER RESEARCH INSTITUTE · NVIDIA

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3. Policy

The Challenge:

America's AI buildout is outpacing the electric grid. Interconnection queues have grown from 70 GW to 380 GW in Texas alone in eighteen months -- **70% driven by data centers.**

ERCOT's large load queue jumped almost 300% last year

The surge has "outgrown the process that was established for reviewing these large loads," an Electric Reliability Council of Texas official said.

Published Jan. 6, 2026

UTILITYDIVE

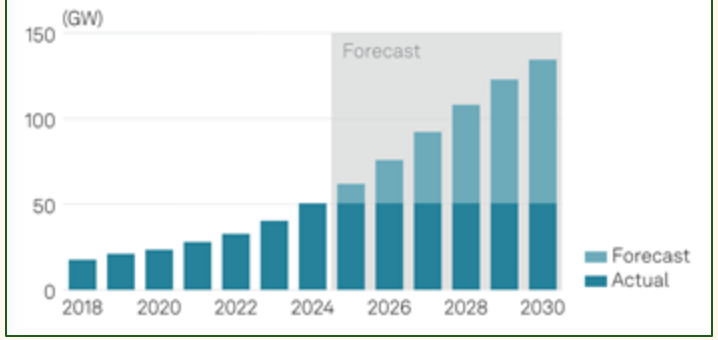


Data Centers' Hunger for Energy Could Raise All Electric Bills



Data center grid-power demand to rise 22% in 2025, nearly triple by 2030

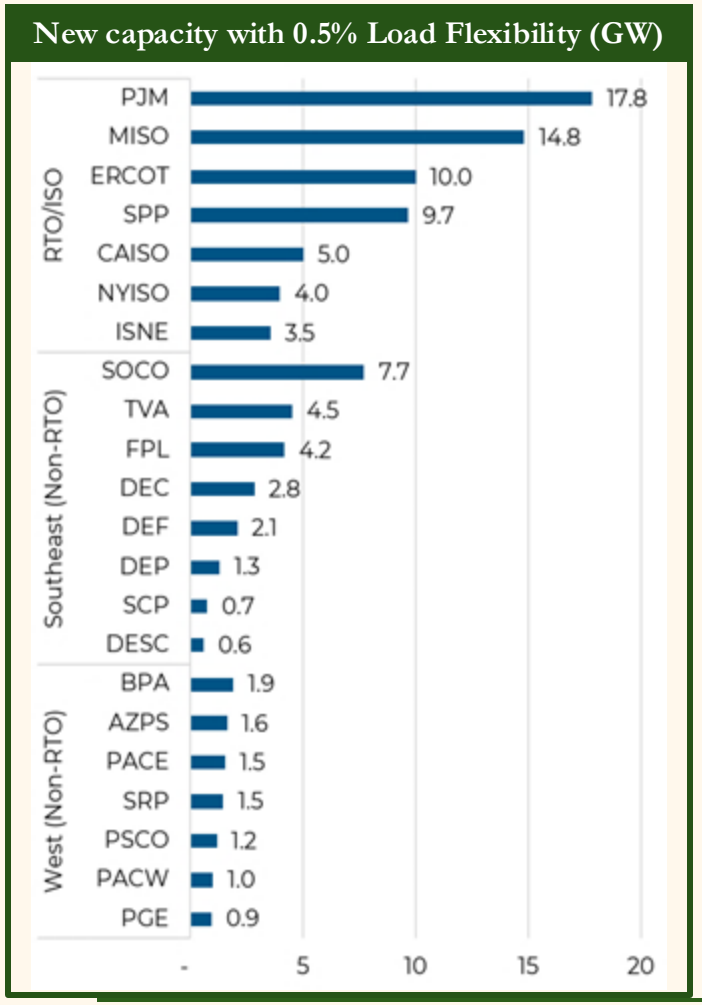
S&P Global



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The fastest path to AI infrastructure runs through flexibility

Roughly 100 GW of new data centers could be connected to US power grids today—without new grid or power plant infra—using just modest load flexibility.



Reliability

Sub-minute emergency response, held autonomously for hours.

Access

Eases grid constraints, increasing grid efficiency and improving interconnection timelines.

Affordability

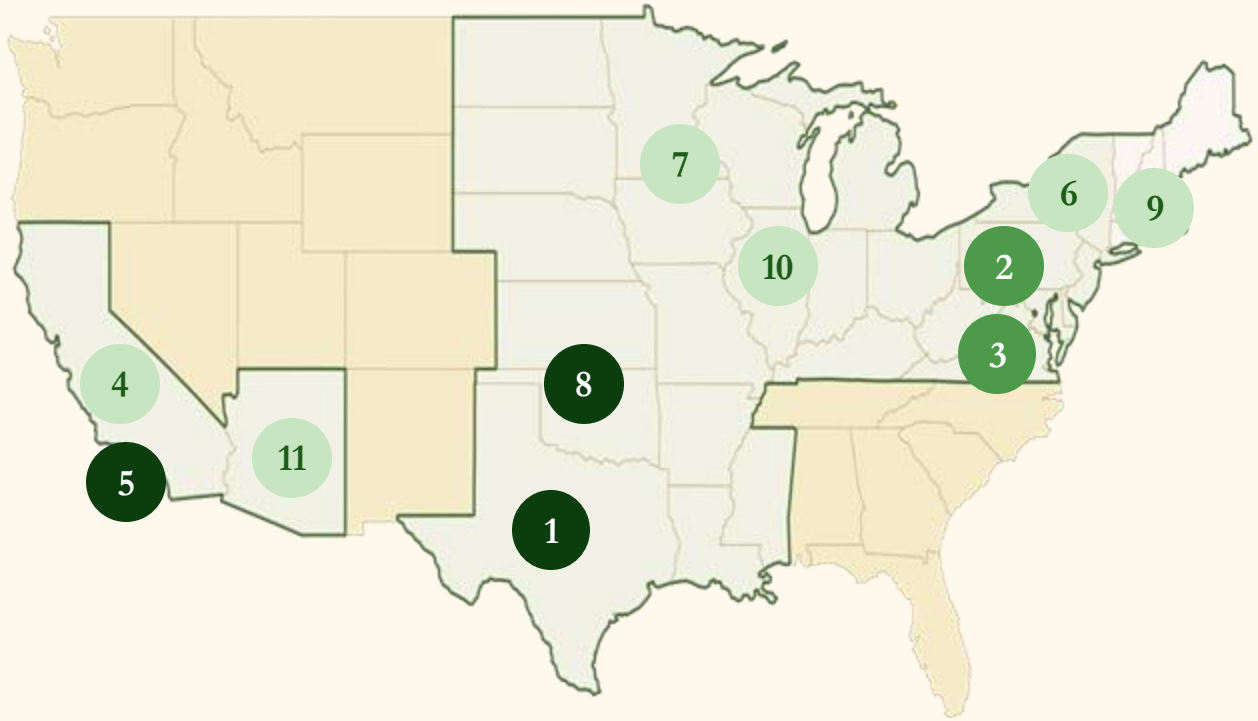
Gets more out of existing grid assets, avoiding costly new buildout.

Source: Norris et al., Duke University, 2025

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Where load flexibility policy is advancing

Policy momentum is broad: across U.S. markets, states, federal regulators, and abroad



FERC, NERC, every major U.S. ISO/RTO, have load-flexibility proceedings open in 2026 — alongside parallel reforms across multiple states and internationally.

U.S. Markets & States

1. **ERCOT / Texas**
   Provisional Controllable Load Resource
2. **PJM**
   Interim Resource Adequacy Service
3. **Virginia**
   Interconnection queues & grid efficiency
4. **CAISO / California**
5. **Silicon Valley Power**
   FLIP Program
6. **NYISO / New York**
7. **MISO**
8. **SPP**
   CHILLS, HILLS, HILLGA, and PALS
9. **ISO-NE**
10. **Illinois**
11. **Arizona**

Federal & International

- **FERC**
  Large Load Show Cause Orders
- **NERC**
- **UK — Ofgem**
- **Japan — METI / TEPCO**

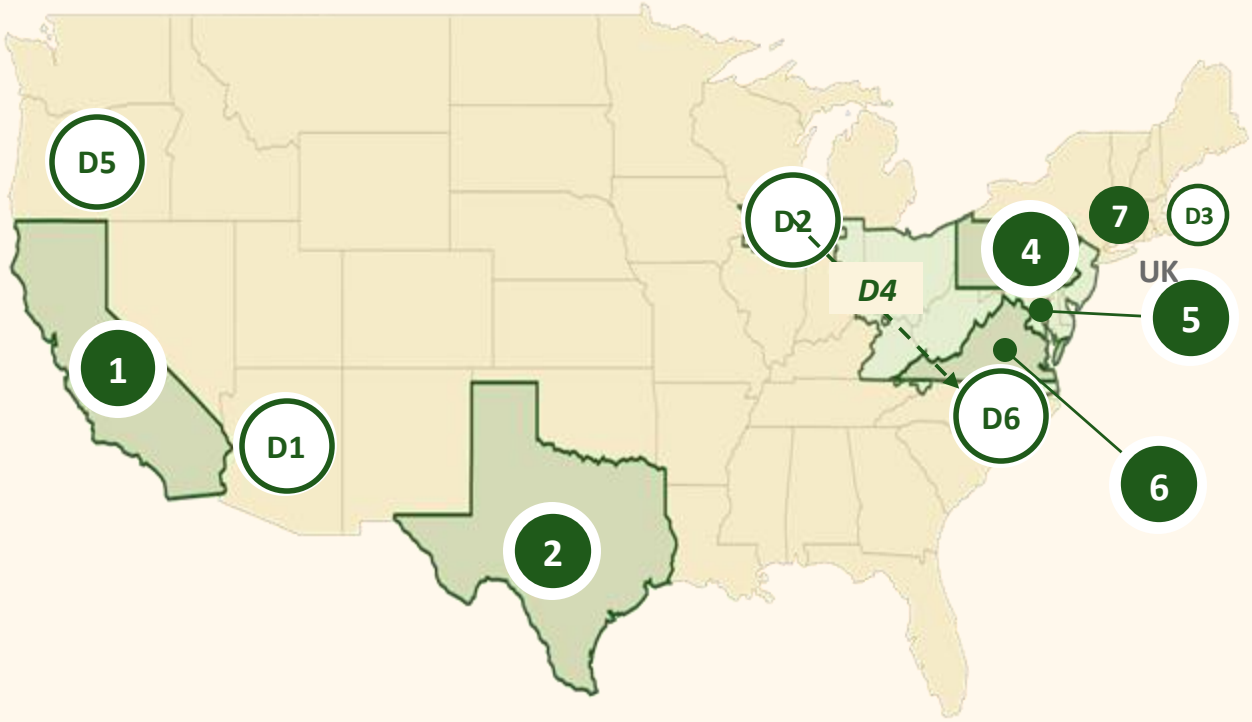
Policy maturity

- High — most mature
- Medium
- Low — emerging
- Not on maturity scale

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Where we've engaged

Here's where flexibility is being decided right now



96 MW power-flexible AI factory in Manassas, Virginia launching **H2 2026** — will serve as the **first commercial-scale reference deployment** of this complete flexibility stack.

Forums

1. **California**
   SVP Program
2. **Texas**
   ERCOT large-load process
3. **PJM**
   Connect and Manage
4. **Pennsylvania**
   State PUC proceedings
5. **Federal**
   FERC + DOE engagement
6. **Virginia**
   State Corporation Commission
7. **United Kingdom**
   Ofgem



Demos

- D1 **Phoenix**
- D2 **Chicago**
- D3 **UK**
- D4 **IL & VA**
- D5 **Oregon**
- D6 **Virginia**

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Modernized Policy is the Key Unlock

Data center flexibility is ready at commercial scale, today. Yet too often, policy barriers impede the grid's ability to benefit from the value and opportunity available.

1 Expedite connection for flexible loads

Create pathways for loads with verifiable flexibility to access power faster, easing queue pressure for all projects.

2 Adopt technology-neutral standards

Evaluate flexibility on measurable outcomes, not prescribed hardware or generation, keeping software-enabled solutions in scope.

3 Benefit from the full value flexibility affords through tailored frameworks

Design programs that are clear, achievable, and predictable.

4 Build on demonstrated models

Scale from existing frameworks -- SVP's FLIP in Santa Clara, ERCOT's PCLR pathway in Texas, CHILLS in SPP - into other geographies.

Well-crafted policy is the critical lever to incentivizing and unlocking flexibility

Design Considerations include…

- Determining firm and flexible allocations
- Defining program goals and dispatch triggers
- Positioning flexibility in the curtailment stack
- Providing historical data, forecast data, and modeling/analytics
- Identifying clear curtailment parameters
- Setting compliance parameters and M&V

Thank you

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LUNCH BREAK

E3 - ENERGIZE NY DEVELOPMENT ANALYSIS

Agenda

12:30 - 12:40	1. Welcome Back and E3 Analysis Context
12:40 – 12:50	2. Overview of New York's Large Load Landscape
12:50 – 1:10	3. Early Insights on Reliability and Policy Impacts
1:10 – 1:30	4. Q&A and Discussion
1:30 – 1:40	5. Break
1:40 – 2:20	6. Early Insights on Electric Rate Impacts
2:20 – 2:40	7. Q&A and Discussion
2:40 – 2:55	8. Potential Strategies to Consider in New York
2:55 – 3:30	9. Q&A and Discussion

Goals of this session

- Share initial insights on resource adequacy risks and regulated rate impacts from large loads
- Provide an opportunity for stakeholders to share feedback on the initial insights from the analysis
- Hear from stakeholders about the issues or topics that are highest priority in this proceeding
- Give stakeholders an opportunity to give feedback on strategies to mitigate the impacts of large loads

Key questions of focus in today's technical conference



What are the **reliability implications** of large load growth, particularly on resource adequacy? What could be high-level impacts on Climate Act **decarbonization goals**?



Under existing tariff structures, what is the **potential ratepayer impact** of new large loads? What are **risks from speculative load?**



What **strategies should NY consider** using to manage reliability and adverse rate impacts from large loads?

Overview of the Large Load Landscape in New York and Nationwide

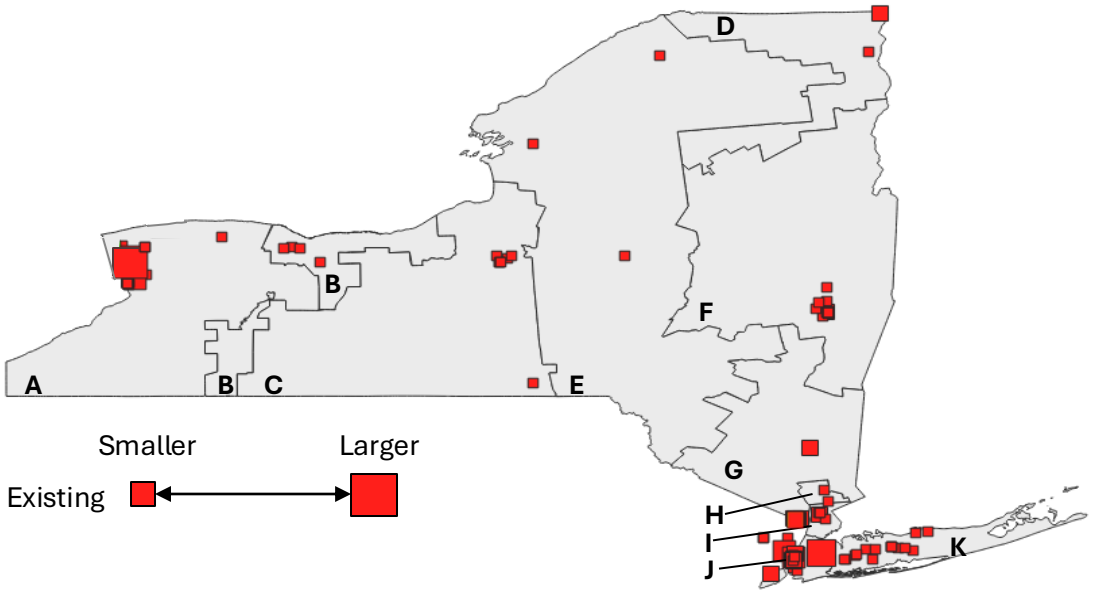


Energy+Environmental Economics

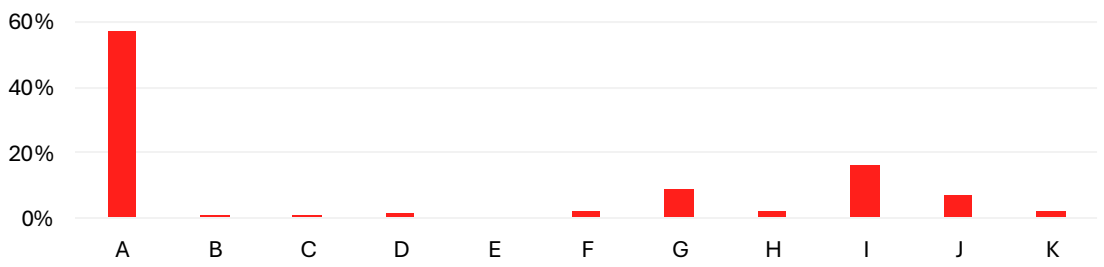
New York's data center market is distributed between NYC area and Western NY

+ **Estimates of NY's existing data center stock ranges from 900 – 1,300 MW[1] (3-4% of NYISO peak)**
  - Smaller compared to leading market like Northern Virginia (8 GW)
+ **New York has 2 distinct data center markets**
  - **New York City area** (existing)
    - Value Proposition: Proximity to the major financial and population hub, which has high data demands
    - Typical Facility: Smaller, older facilities delivering user-focused applications
  - **Western New York** (existing + emerging)
    - Value Proposition: Lower priced land and power, higher generation and transmission availability
    - Typical Facility: Larger, newer facilities with high power requirements (e.g. AI training)

Existing NYISO Data Center Geography



Existing Data Center Load by Zone (% of Capacity)



1. Estimated footprint based on public data, which has gaps due to absence of reporting requirements

Potential implications of large load growth in NY

System Impacts

How does large load growth affect the grid and its existing customers?

- **Rate impacts**: New load can trigger new infrastructure build. Rate design & other risk mitigation is critical to ensure large loads pay their fair share and avoid negative ratepayer impacts
- **Land use and equipment:** Sites compete with other uses, like new generation, which can raise land and equipment costs.
- **Reliability**: Adds need for firm capacity but can fund investments in resilience or local upgrades

Environmental Impacts

What does large load growth mean for local communities and CLCPA?

- **GHG and CLCPA targets**: Increases in demand will make achievement of targets more challenging; can potentially support progress if paired with new clean generation
- **Water use**: cooling needs can be significant but can vary widely by load/facility type
- **Light and noise**: Continuous operations can increase local noise and lighting impacts
- **Air pollution**: Data centers typically have backup generators[1] (e.g., diesel) which can have emissions impacts if they run

Potential Benefits

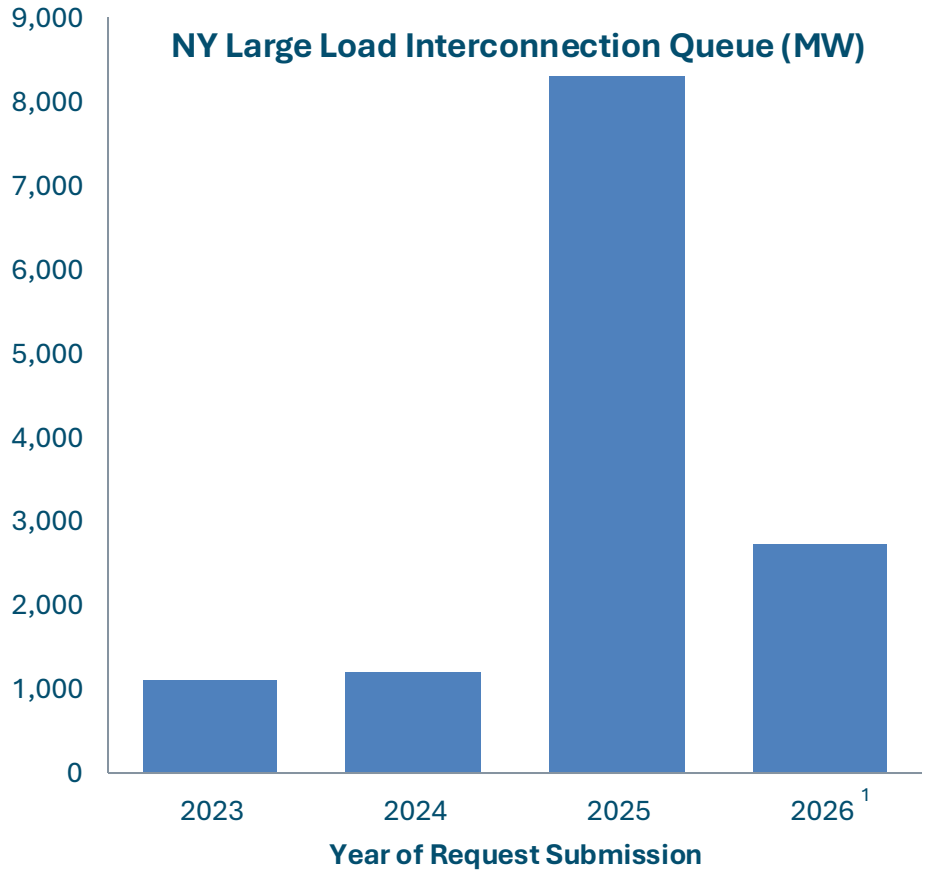
What can New York gain from serving new large loads?

- **Tax revenue**: Property tax is likely the largest potential fiscal benefit but varies with local policies (e.g., sales tax exemptions)
- **Jobs & economic development**: Some load types create more jobs than others and many are short-term construction rather than long-term ops
- **Rate Impacts**: Purposefully designed rates and programs may support ratepayer benefits
- **Community investment**: ESD's voluntary framework provides benefit for host communities

1. Emergency backup generators are only used to restore power if grid power is interrupted; they may not be used for peak shaving or demand response

Overview of large loads today in New York

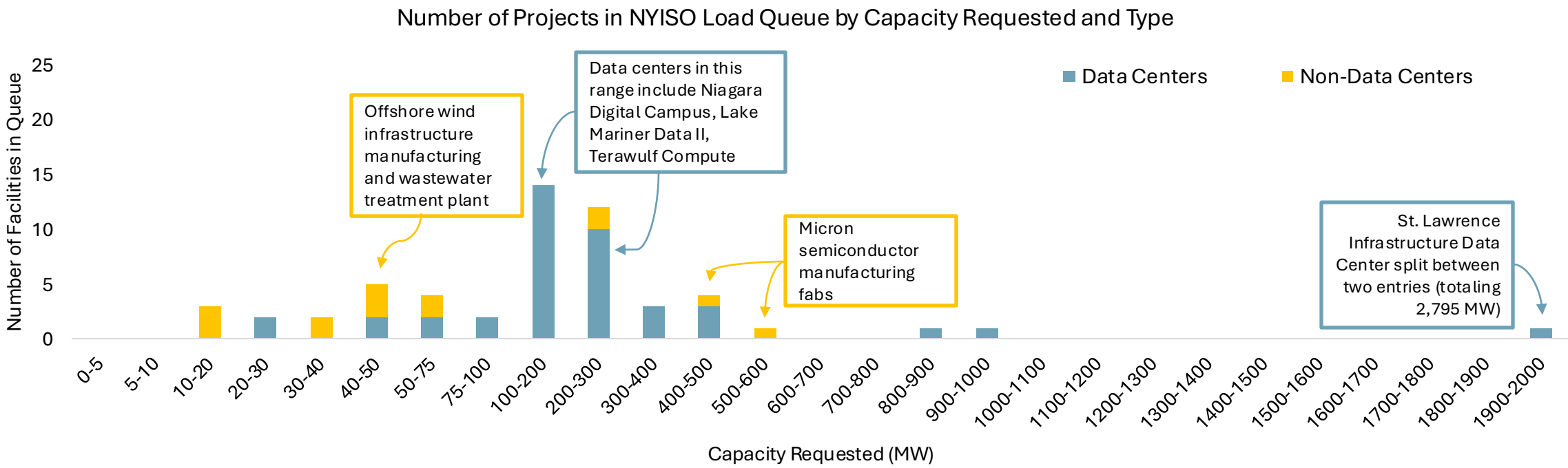
- Existing large load portfolio in New York includes manufacturing and data centers
- Steep increase in large load requests has major implications given system size (NYISO peak: 31.5 GW)
- Large load siting primarily driven by economic factors (e.g., land and electricity prices, tax incentives) and other criteria (e.g., human capital, proximity to fiber networks)
- Load growth arriving during a time of grid transition, as utilities work to replace aging infrastructure, electrify and integrate clean resources under CLCPA



1. Through Q3

Average large load request is 253 MW but spans a wide range

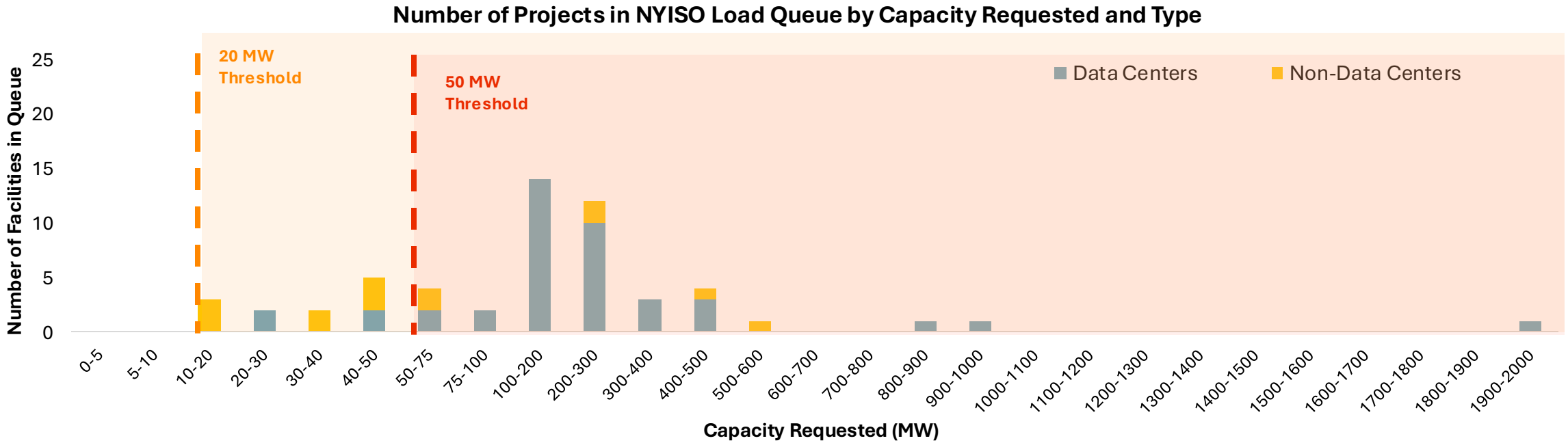
- 90% of the NYISO large load interconnection queue is data centers, which request 290 MW on average
- Other loads include semiconductor manufacturing, mixed-use developments, and logistics hubs, which request 122 MW on average



Note: Data as of August 2026

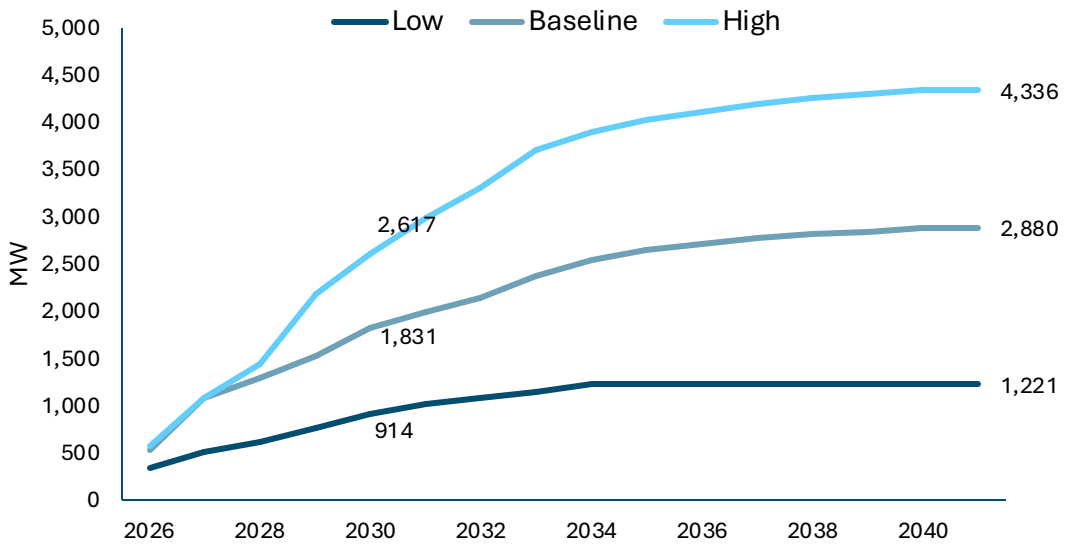
Applying proposed New York large load definitions to the queue yields different results

+ **There are multiple proposed large load definitions in New York which would yield different results when applied to the NYISO queue. Two of the key ones include:**
  - **20 MW:** large load definition in New York Responsible Data Center Development Act (A11560 / S10642)
    - In Oregon, facilities of ≥20 MW are categorized in a separate rate class with at least 10 years and minimum payment commitments
  - **50 MW**: the threshold in Governor Hochul's Executive Order – covers 85% of queue
    - In PA, the model tariff from the PA PUC includes a minimum demand charge and CIAC requirements for loads ≥50 MW

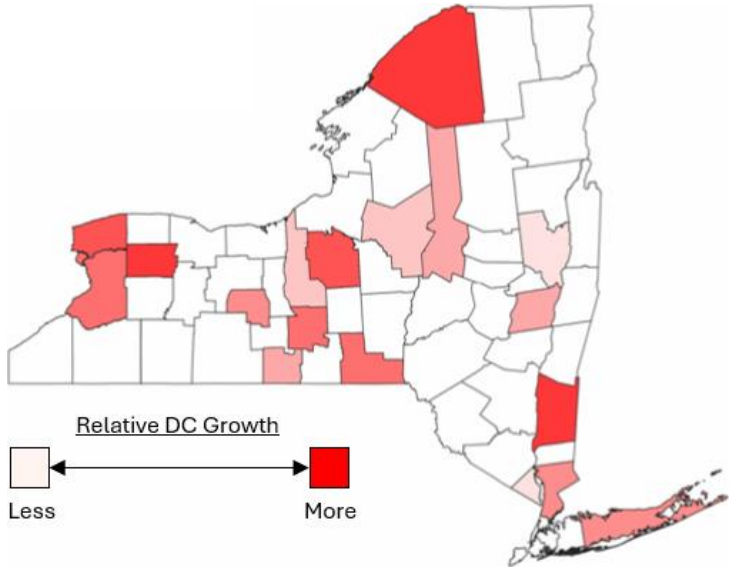


The scale of potential large load growth is highly uncertain

NYISO Gold Book Forecast: Large Load Summer Peak Demand



NYISO Large Load Queue Requests by County (GW)



+ **NYISO large load queue has 13 GW of interconnection requests[1] by 2030 – about 40% of NYISO's 2026 summer peak (31.5 GW)**
  - Queue volume orders of magnitude higher than NYISO's 2026 Gold Book,[2] expecting total large loads to be 1 to 2.6 GW by 2030 depending on scenario
  - Geographically, requests clustered in western and upstate New York, likely due to lower priced land and power
+ **But queue unlikely to materialize in full, and utilities have reported attrition rates of 11-38% for large loads[3], which can be due to**
  - **Speculative requests**: duplicate applications (both from developers "shopping" for sites amidst longer interconnection timelines and relatively low upfront costs), and early-stage projects lacking financing or site control that are unlikely to materialize
  - **AI demand uncertainty**: Scale and pace of technology adoption will share future capacity needs

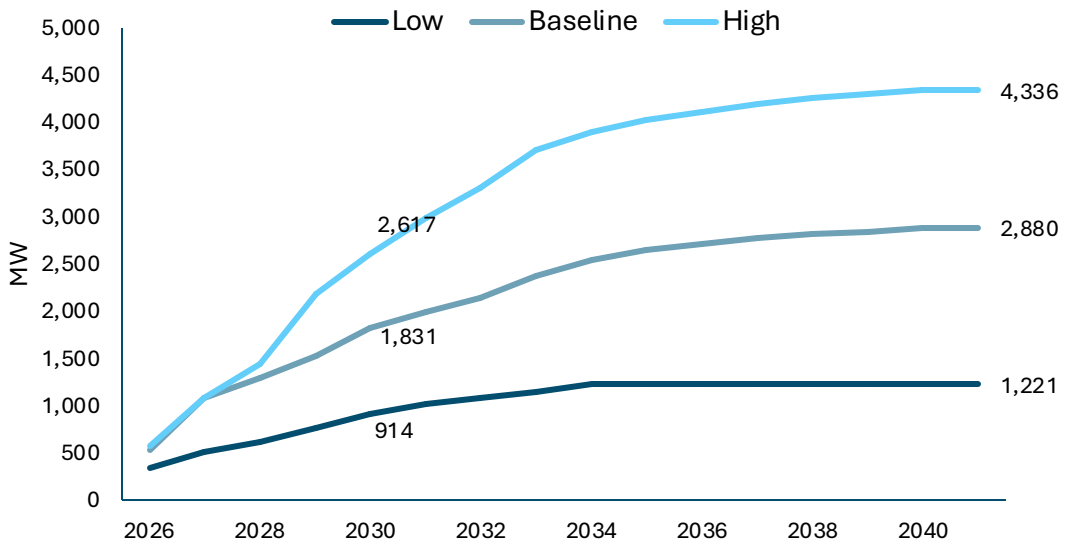
Factors observed across U.S., not unique to NY

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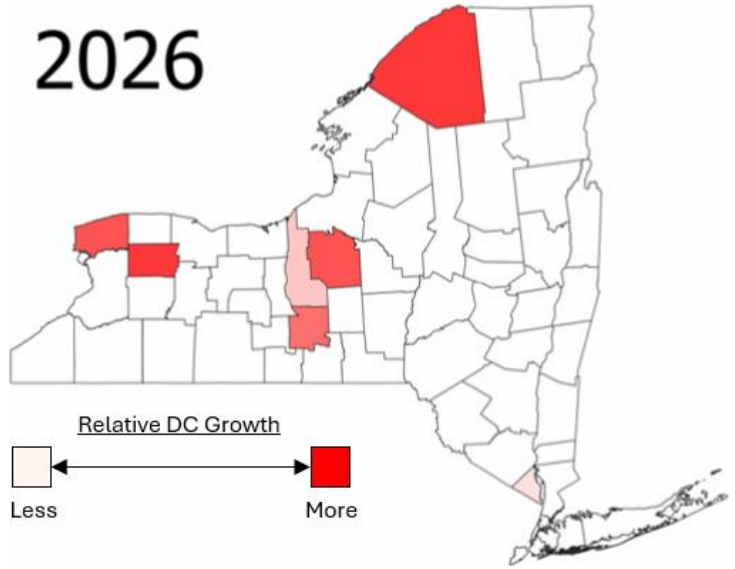
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Cumulative NYISO Large Load Queue Requests by County



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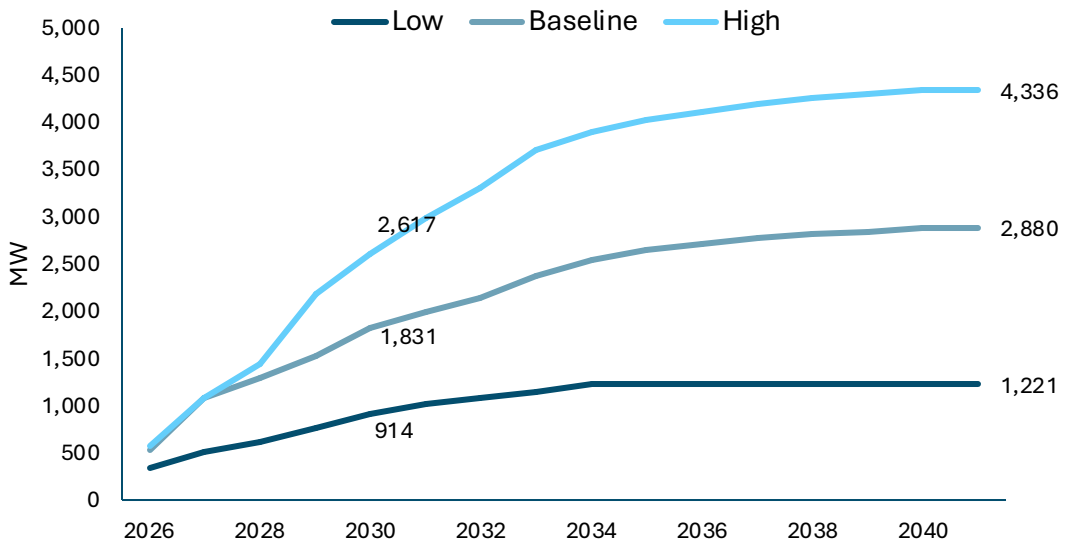
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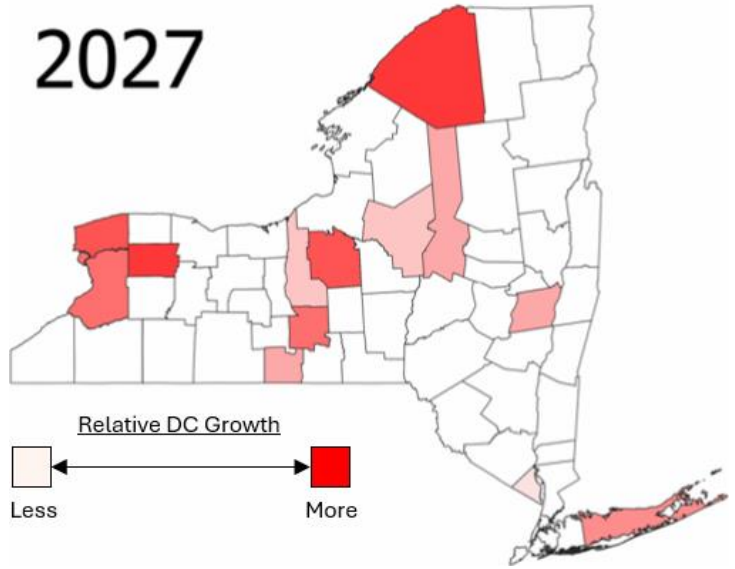
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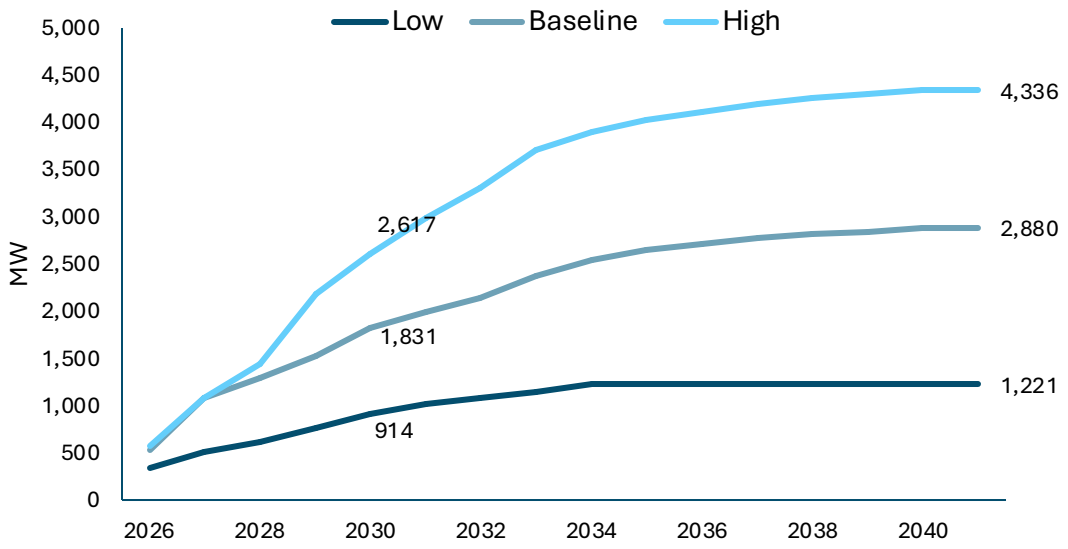
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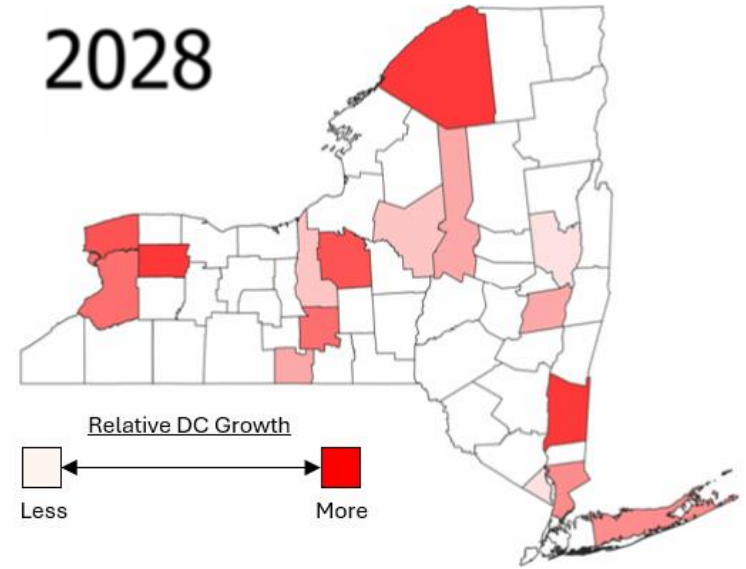
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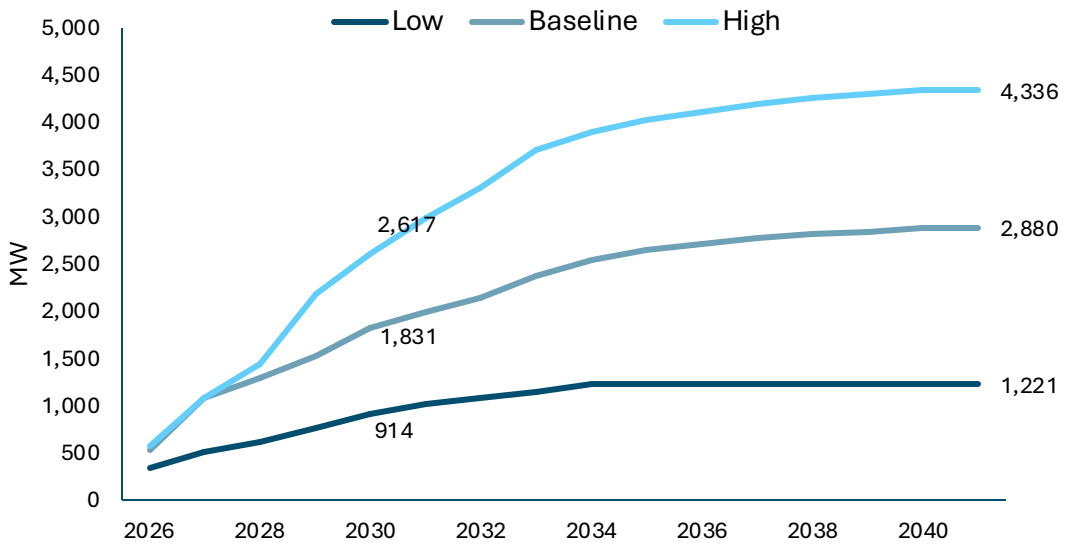
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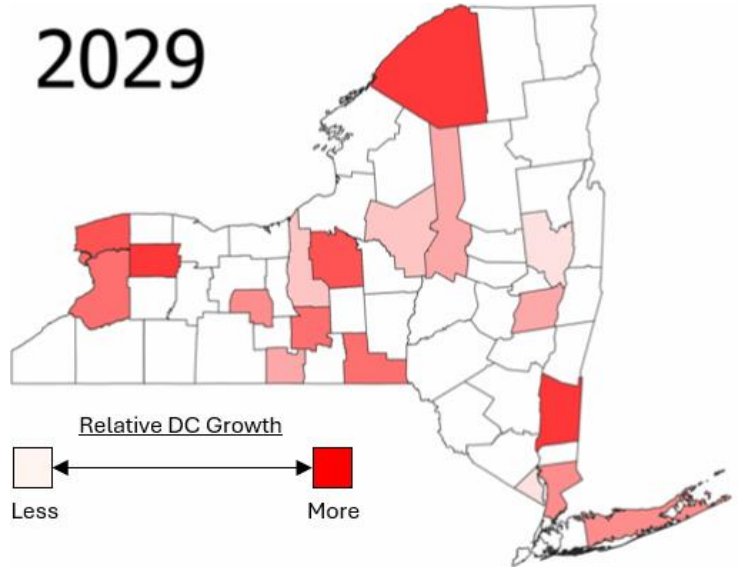
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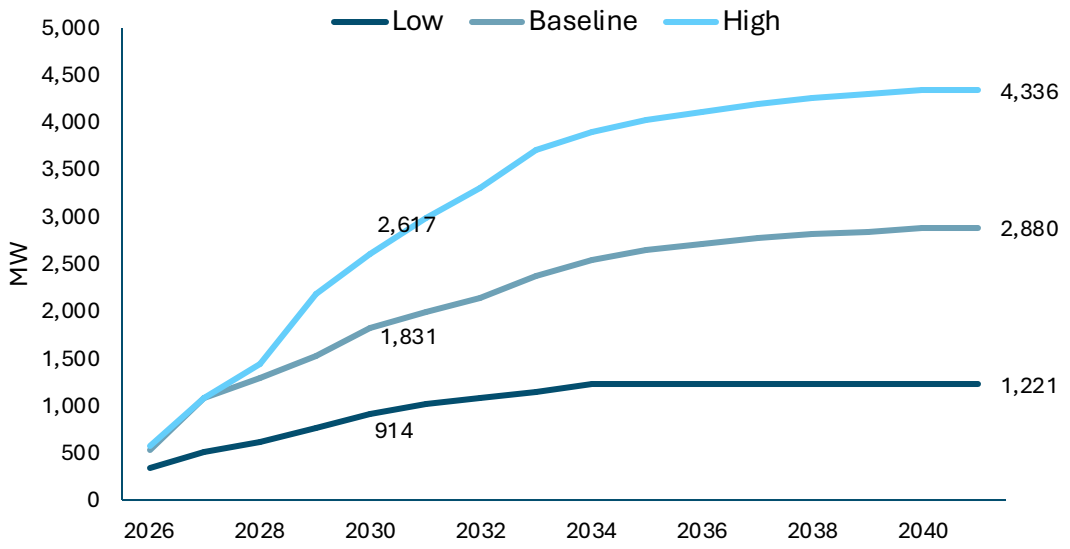
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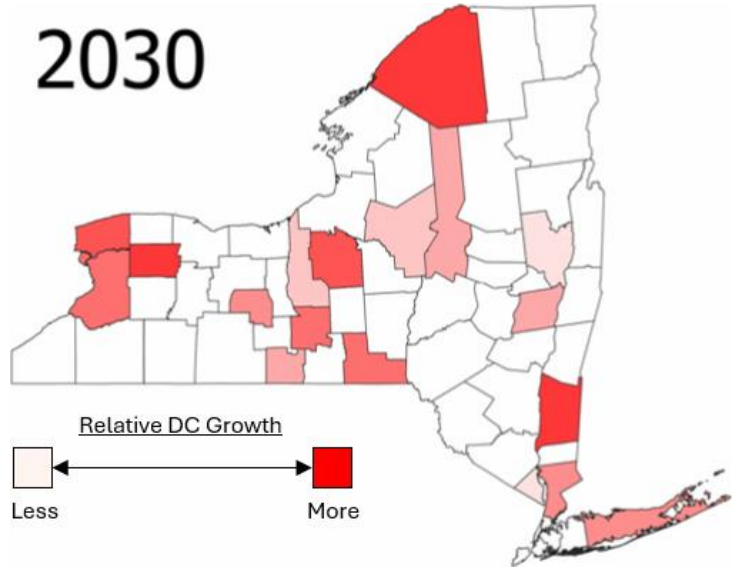
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Early Insights on Reliability Impacts



Energy+Environmental Economics

Large load growth can impact multiple aspects of reliability planning. Today's focus is on large loads' potential impact on resource adequacy

+ **The pace and scale of large load growth in New York needs to be managed to ensure continued reliability**
  - Current NYISO large load queue is 13 GW, which is 40% of NYISO' forecasted 2026 summer peak (31.5 GW)
+ **This analysis provides an initial assessment of potential resource adequacy (RA) implications from large load growth in 2030 through 2040**
  - E3 assessed what resources are needed to maintain system reliability under two load growth scenarios, informing the timing and scale of additional resource needs and role of strategies such as load flexibility
+ **This analysis identifies potential strategies for New York based on current planning**



Distribution System Reliability

Ensure distribution systems are planned to enable delivery of electricity to loads even under severe contingency conditions



Transmission System Reliability

Ensure transmission systems can deliver electricity from generators to distribution systems under steady state and dynamic contingency conditions



Resource Adequacy

Ensure sufficient generation resources are available to meet load with an acceptable level of reliability across a broad range of load conditions while accounting for generator outages, weather impacts on loads & resources, and other constraints on generator availability



Operational Reliability

Maintain system reliability in reatime operations by balancing loads with generation while maintaining sufficient operating reserves to meet flexibility needs and respond to contingencies



Resiliency

Anticipate, respond to, and recover from extreme unexpected events and systemic shocks to any and allparts of the electricity system, including extreme weather events and cyber threats

Reliability planning processes are evolving to address the accelerating pace of system change

+ **Through the Comprehensive System Planning Process (CSPP), the New York electricity system is planned to meet applicable reliability standards**
  - NYISO, the Transmission Owners, the PSC, and NYSRC all have a formal role in various elements of reliability planning
  - Reliability planning takes place on a short-term (quarterly) and long-term basis, and addresses multiple components of bulk system reliability including transmission security and resource adequacy
+ **These processes work in tandem with wholesale market signals to ensure that system needs are met**
+ **However, the pace of system change is challenging and compounded by load growth uncertainty**
  - Work is underway to evolve these processes to account for heightened uncertainty

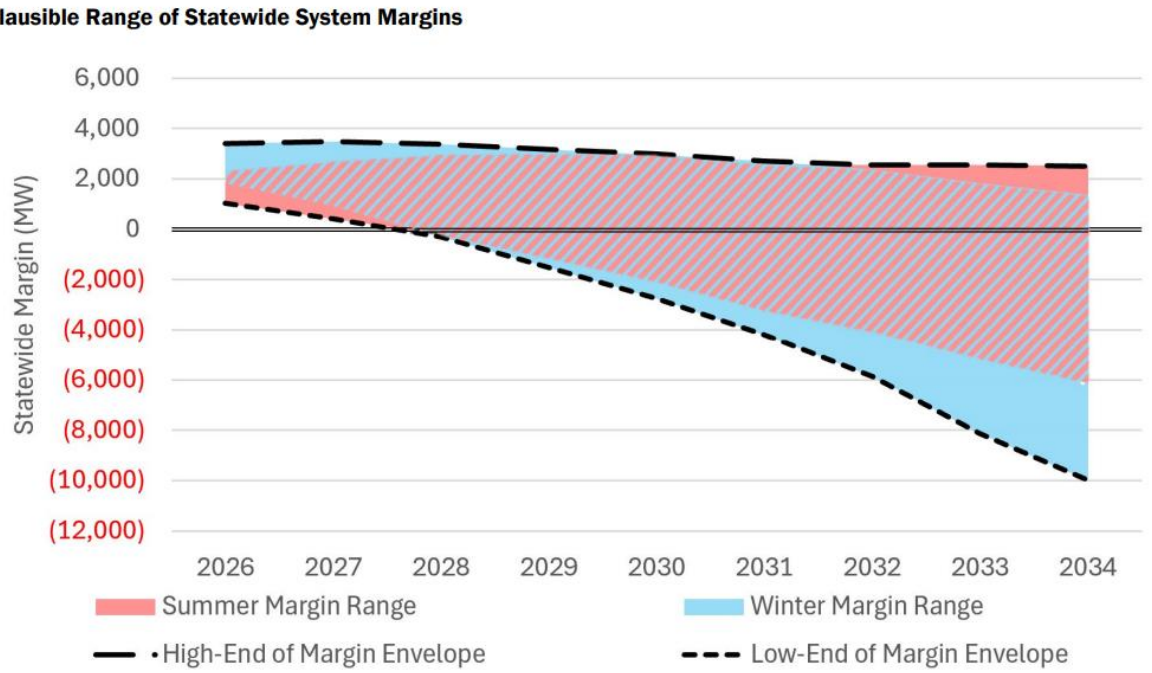
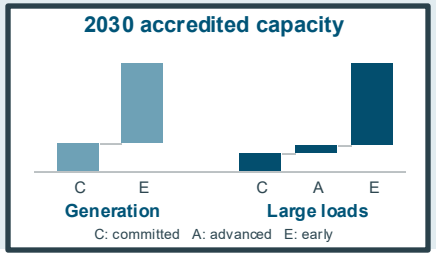


Figure Source: [NYISO Comprehensive Reliability Plan]

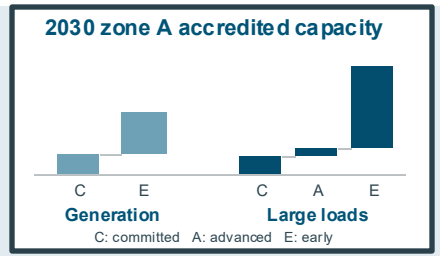
Goal: Identify the risks large loads may pose to system reliability, with a focus on resource adequacy

Preliminary insights on reliability impacts

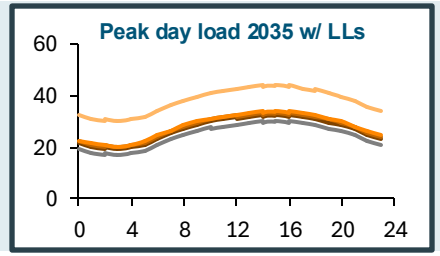
1. Committed new generator capacity exceeds committed new large loads in 2030, but broader queue volume poses large tail risk



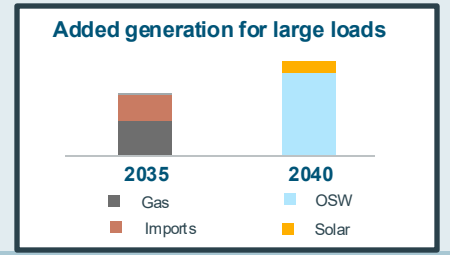
2. Concentration of data center interconnection requests may raise local supply challenges or impact interzonal power flows



3. Many of the planned large loads likely have flat load shapes and are expected to increase load evenly across most hours, exacerbating reliability risk in already constrained periods



4. The incremental generation resources needed to maintain resource adequacy and policy goals in a high large load growth scenario, include gas and imports in 2035 and offshore wind in 2040

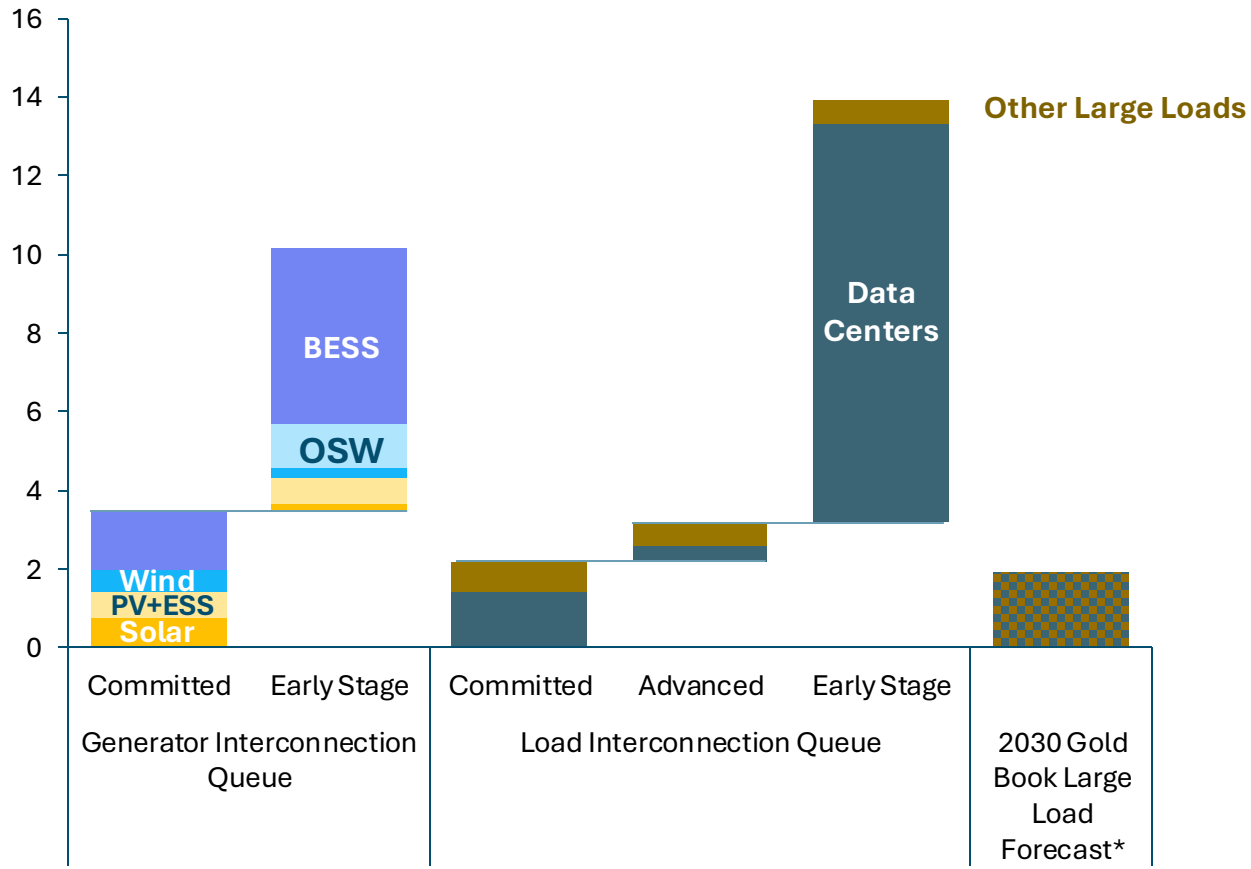


Queue balance analysis: committed generator capacity exceeds committed large loads in 2030, but broader queue volume poses large tail risk

- **Current NYISO load queue contains large loads across a range of operational readiness**
  - "Committed" resources/loads are more likely to energize, having received approvals and accepted cost allocation
  - "Advanced" have completed initial feasibility study but still require a facilities study
  - "Early stage" loads are farthest from energization; may be pending scoping and feasibility studies, and some may be speculative
- **While most large loads are in "early stage" of development process, this presents significant risk if more large loads materialize than expected**
  - E.g., In PJM, a large proportion of the large loads requesting interconnection are expected to materialize
  - Risk is exacerbated by uncertainty around AI and lack of historical track record on large loads in NY

Note: NYISO Interconnection process applies to generator interconnections > 5 MW, and currently applies to load interconnections that are either:
>10 MW connecting at a voltage level of >=115 kV
>80 MW connecting at a voltage level <115 kV
These thresholds may be updated as part of new interconnection procedures in the future.

Resource & Load Capacity Additions in Interconnection Queues (Accredited Capacity GW)

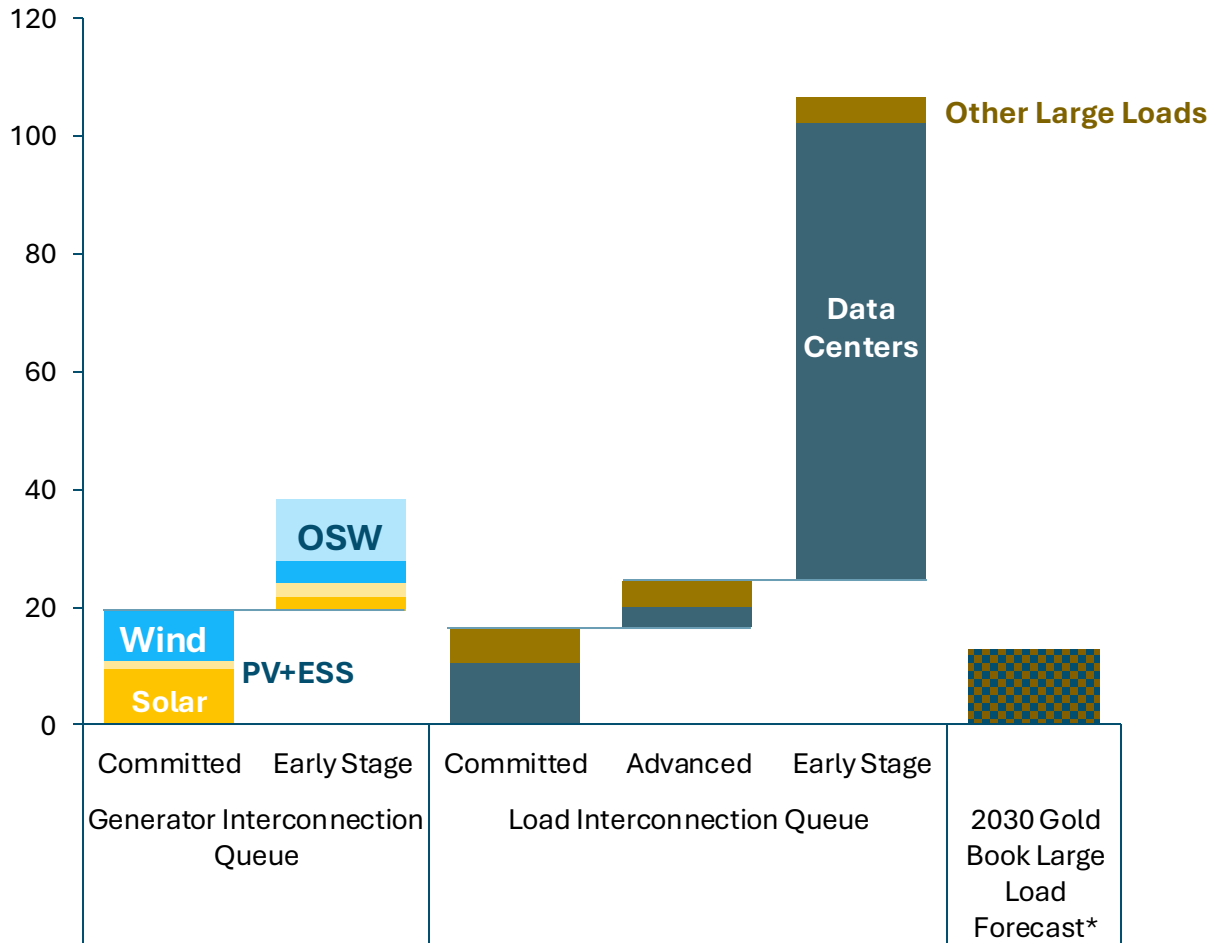


Note: Queue projects reflect projects COD by end of 2030 aside from offshore wind. Accreditation is based on NYISO's published CAFs; for storage, early-stage projects receive a derate to their CAFs based on ELCC saturation effects derived from the SEP.

Queue balance analysis: committed generation and committed load additions are aligned from an energy perspective, but broader queue poses tail risk

- From an energy perspective, committed generation resources in the queue align with committed large load demand
- However, there is a tail risk if the broader large load queue materializes (i.e., if early stage loads far outpace resources in the queue)
- Gaps between new demand and the deployment of new clean energy resources may increase reliance on existing thermal fleet, complicating policy achievement

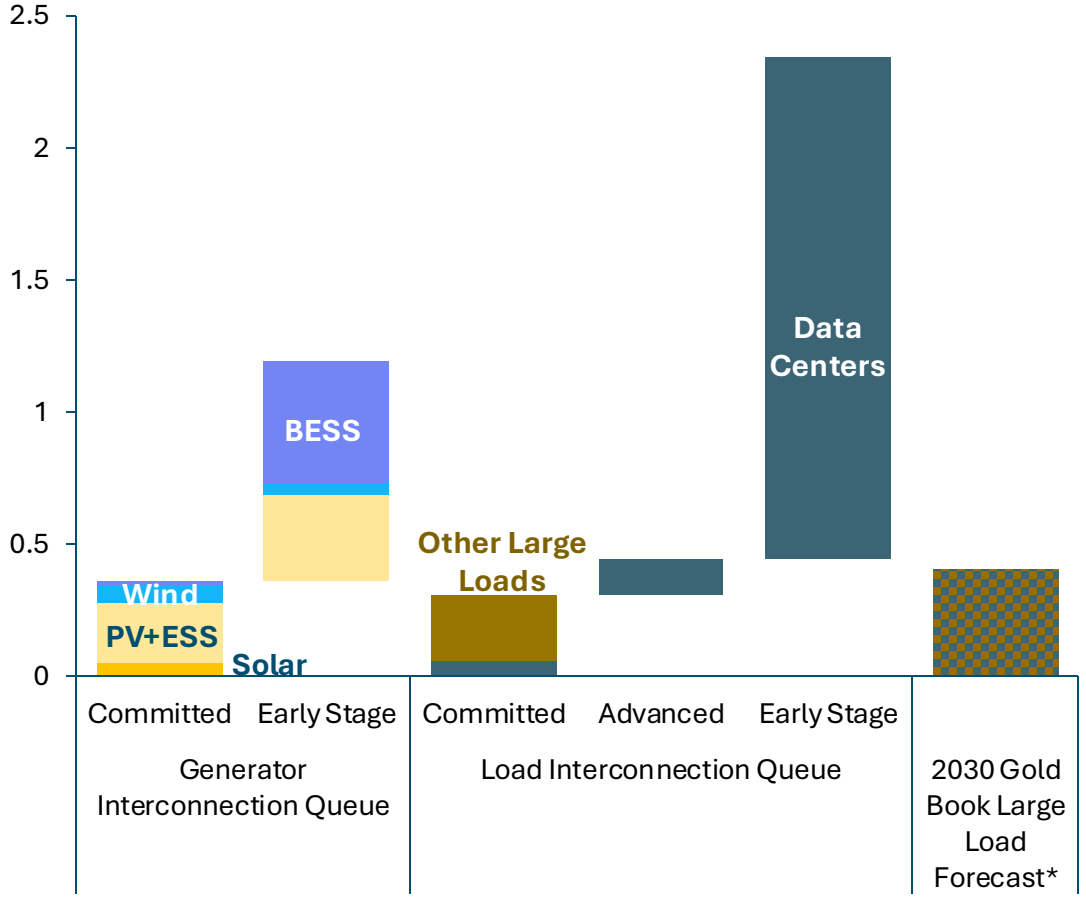
Resource Generation and Annual Load Additions in Interconnection Queues (TWh)



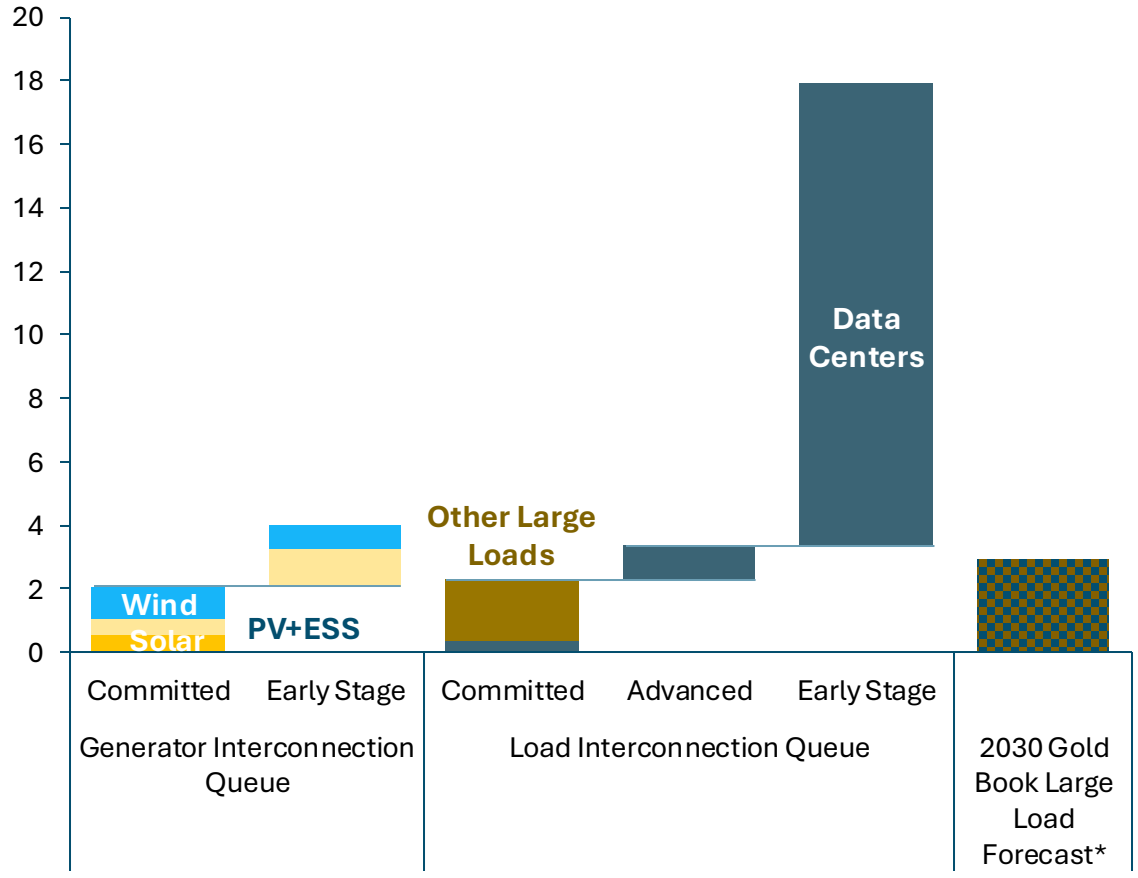
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Queue balance analysis: concentration of data center interconnection requests may raise local supply challenges or impact interzonal power flows

Zone A Resource and Load Capacity Additions in Interconnection Queues (Accredited Capacity GW)

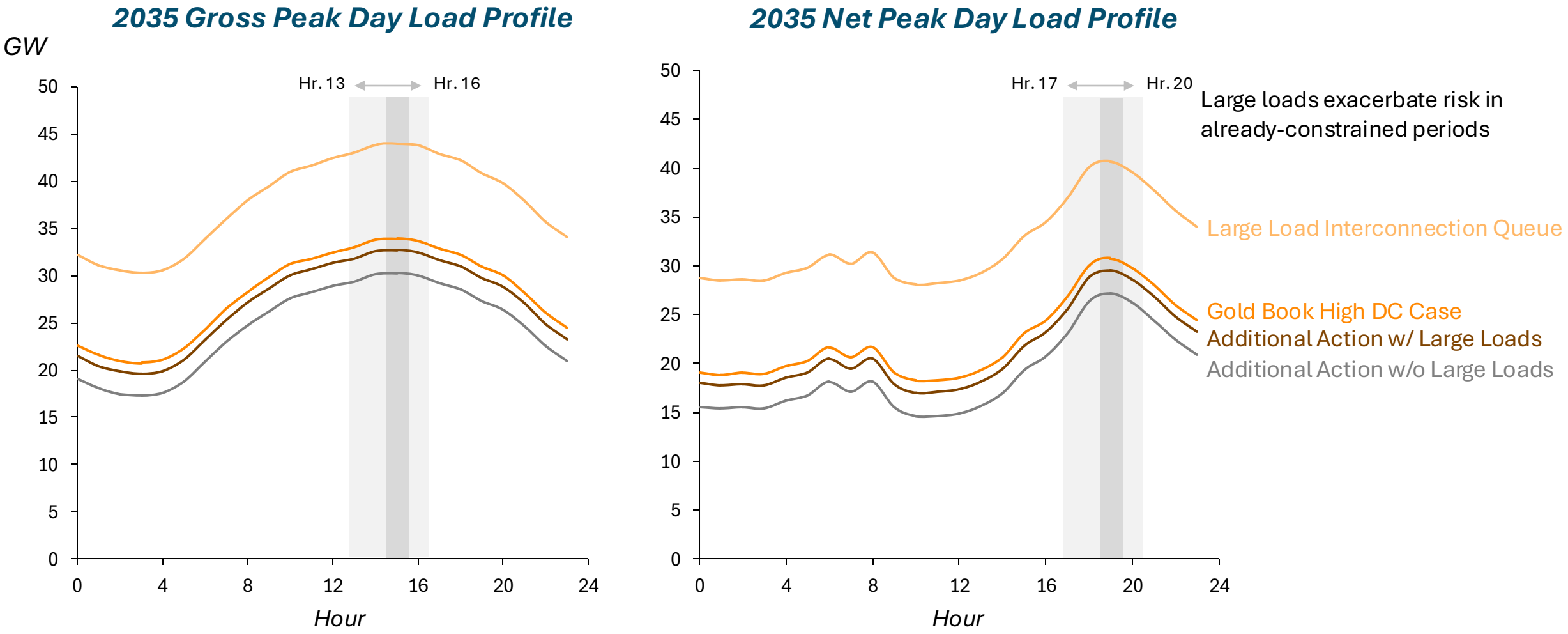


Zone A Resource Generation and Annual Load Additions in Interconnection Queues (TWh)



Note: All queue projects COD by end of 2030. Accreditation is based on NYISO's published CAFs; for storage, early-stage projects receive a derate to their CAFs based on ELCC saturation effects derived from the SEP.

Mid-term insight: large loads are expected to increase load evenly across all hours, exacerbating risk in already constrained periods

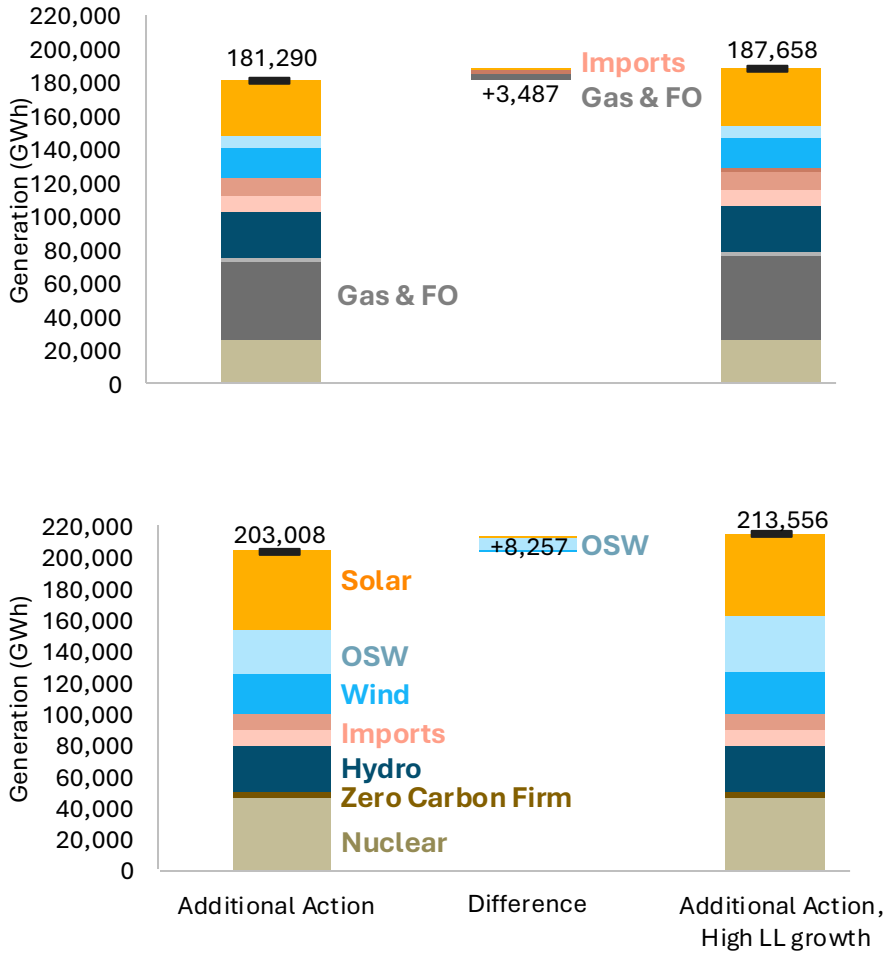


Net Peak = AA gross load on peak day - AA renewable resource output on peak day + varying levels of LL growth
Note: renewable output is the same across scenarios

Long-term insight: large load growth has implications for decarbonization goals, with near-term reliance on additional gas generation

- **Compared the New York State Energy Plan's "Additional Action" and "Additional Action with High Large Load Growth" modeling scenarios to assess the incremental annual generation needed by resource type to serve large loads**
  - "Additional Action" incorporates current policies (e.g., EV policies, clean energy deployment) and assumes additional policy support for continued market adoption; also includes large load growth consistent with Gold Book Baseline projections.
- **Because Tier 1 renewable build limits are already binding, incorporating incremental large-load growth beyond what is already projected would mean relying on additional gas generation in the near term (2035) and higher-cost renewables over time (2040) to stay on track with policy goals**
- **In 2035, the incremental generation needed for accelerated large load growth could be met almost entirely by additional gas generation (+3,500 GWh)**
- **By 2040, that incremental generation increasingly shifts to offshore wind and distributed solar, at a higher marginal cost of clean energy development**

Annual Generation by Resource Type[1]
2035 (*top*) and 2040 (*bottom*)



[1]*Source: NYSERDA, Pathways Analysis Technical Supplement: Key Drivers and Outputs (Annex 2, April 2026), sheets 'Additional Action' and 'Additional Action - Large Loads', Annual Fuel Mix (Energy) table. energyplan.ny.gov/Supplemental-Analysis*

Q&A and Discussion



Energy+Environmental Economics

Discussion Questions – Reliability Analysis



What reliability issues are the highest priority for you?



Does this analysis address those highest priority issues?



Are there other reliability or policy considerations you would like to raise to Staff?

Insights on potential rate impacts



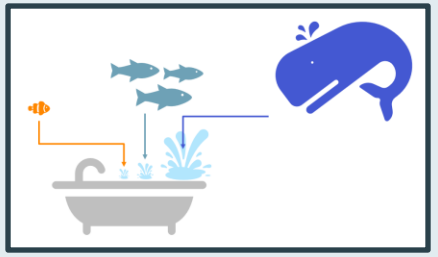
Energy+Environmental Economics

Goal: Identify how large loads may pose risks to regulated rates and identify what strategies can be used to mitigate those risks

Preliminary insights on rate impacts

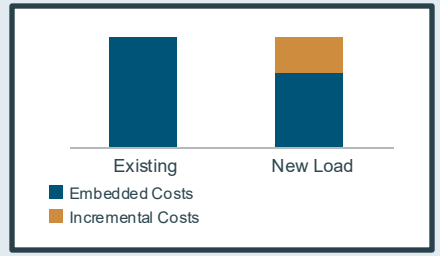
1

The scale and speed of large load growth can disrupt existing rate and cost allocation frameworks, with the potential to impose costs on other customers



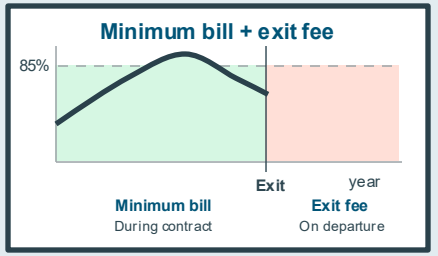
2

New large loads can support positive affordability outcomes when costs are purposefully assigned and risks are mitigated



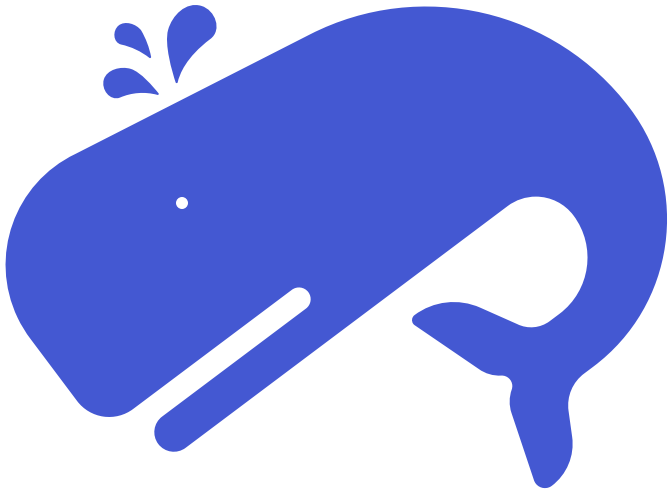
3

Effective strategies for mitigating cost shift risks include new large load rate classes, dedicated cost allocation, minimum bills, and exit fees

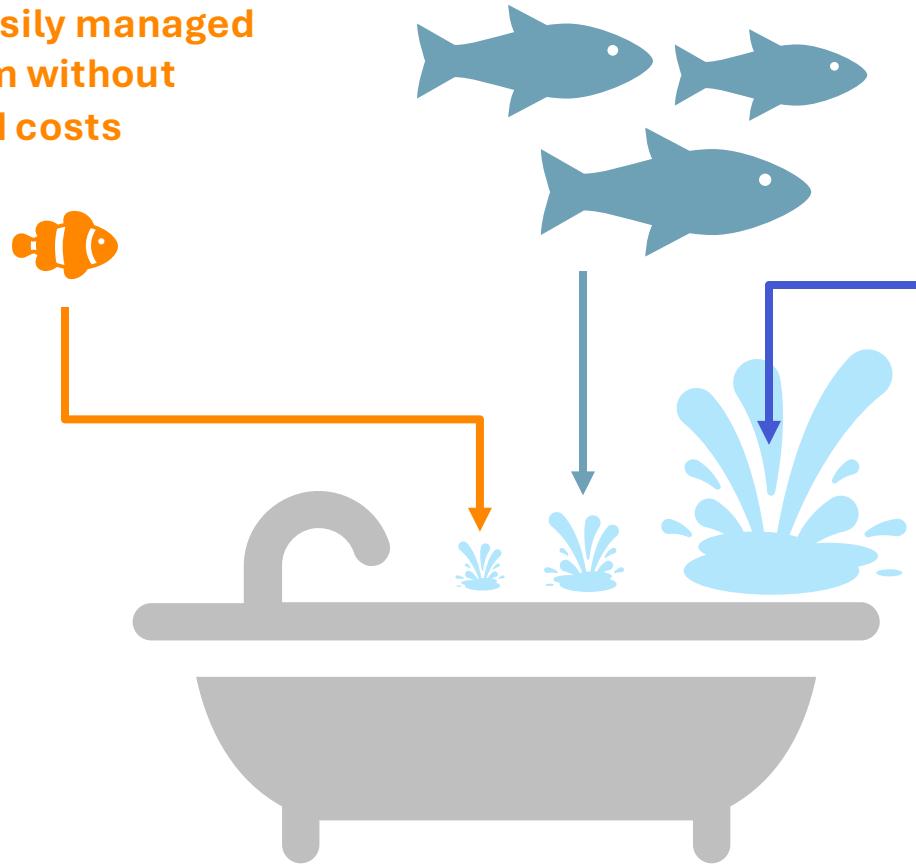


The scale and speed of large load growth can disrupt existing rate and cost allocation frameworks

Larger loads likely incur fixed costs, but impacts on system can be limited with gradual integration and targeted protections



Incremental loads are easily managed within the existing system without incurring significant fixed costs



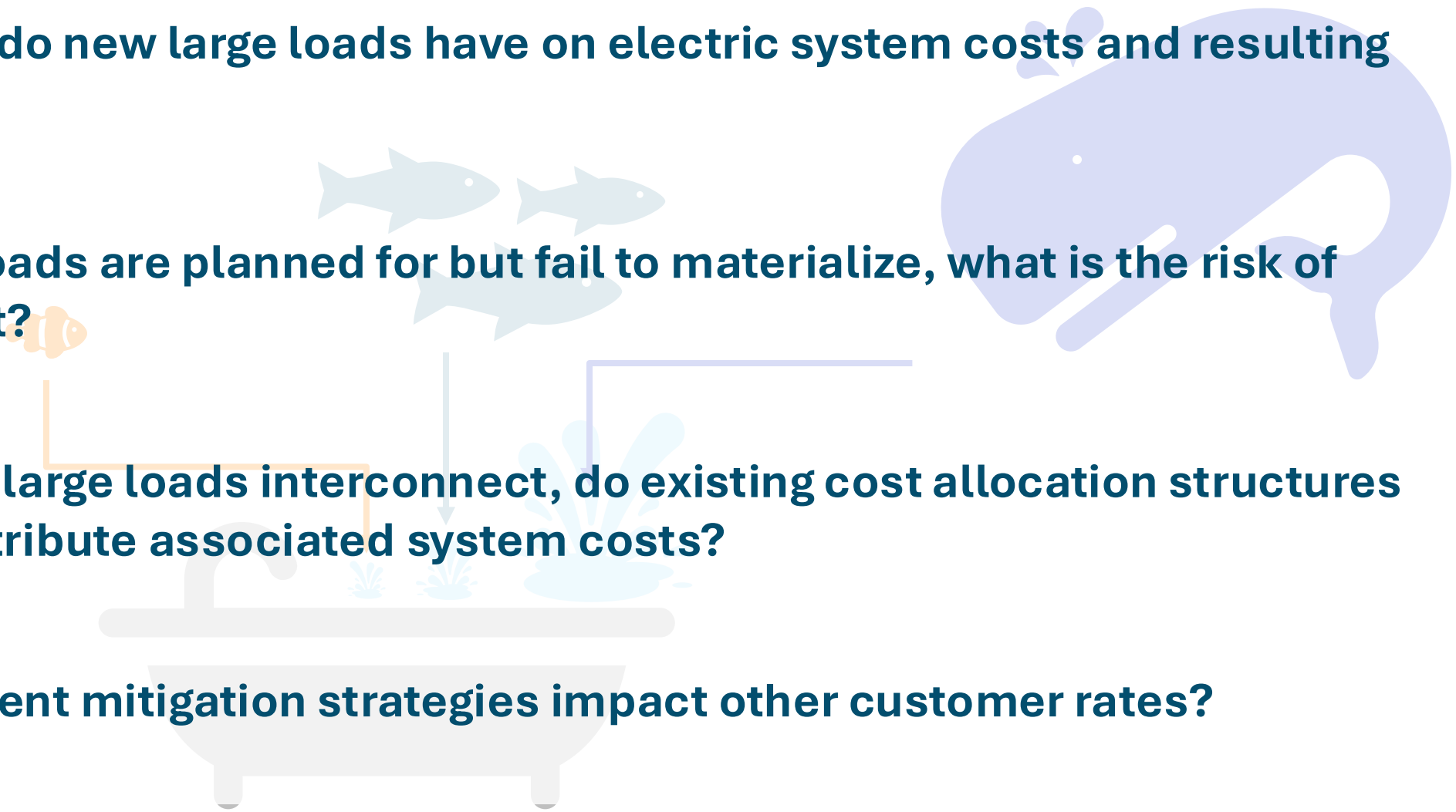
Transformational loads can disrupt the system and require significant new infrastructure investment

Structural inefficiencies can make it difficult to quickly reach new equilibria under transformational load growth

Graphic Source: JLARC

The scale and speed of large load growth can disrupt existing rate and cost allocation frameworks

- What impact do new large loads have on electric system costs and resulting rates today?
- If new large loads are planned for but fail to materialize, what is the risk of stranded cost?
- As additional large loads interconnect, do existing cost allocation structures equitably distribute associated system costs?
- How do different mitigation strategies impact other customer rates?



Graphic Source: JLARC

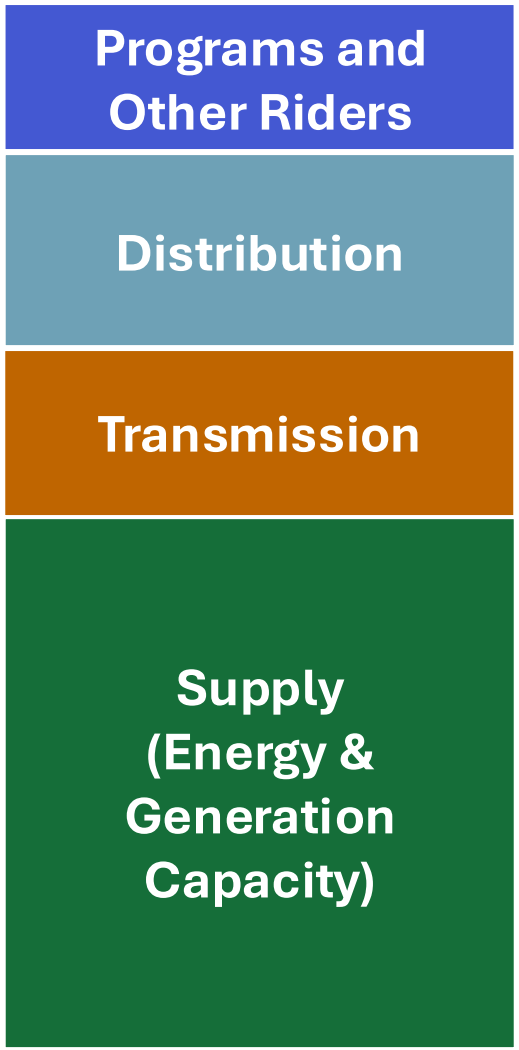
New loads increase both the total system cost and the load over which those costs are collected

$$\text{Customer Rate} = \frac{\text{Revenue Requirement}}{\text{Billing Determinants (Load)}}$$

The customer impact depends on which grows faster

Rates rise ⬆	Rates fall ⬇
if the revenue requirement increases more than the load that shares it	if the load increases more than the revenue requirement it must recover
$\frac{\text{Old rate } 100}{100} \rightarrow \frac{\text{New rate } 120}{110} = +9\%$	$\frac{\text{Old rate } 100}{100} \rightarrow \frac{\text{New rate } 110}{120} = -8\%$

Electric bills cover costs of grid hardware, supporting labor, program funding, and electricity itself



Funding for bill assistance, energy efficiency, clean energy, etc.
Service provided by: Variety of state and utility programs

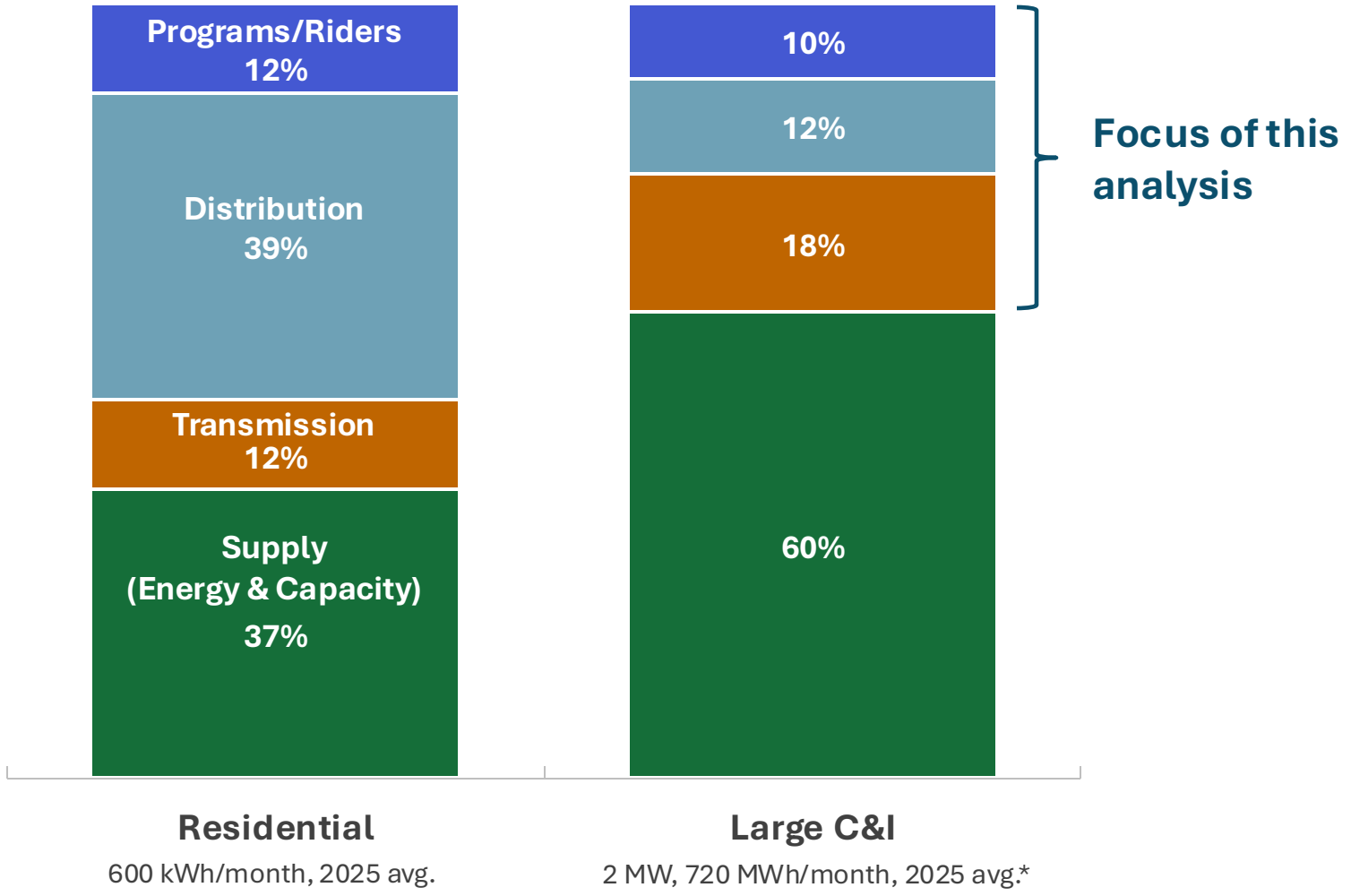
Cost of building and operating distribution system delivering electricity to homes and businesses
Service provided by: Utilities

Cost of building and operating transmission system connecting generators & distribution systems
Service provided by: Utilities, NYISO

Wholesale cost of electricity generated or procured
Service provided by: Utilities, municipal aggregation, or competitive supply

Rate analysis does not assess large load impacts on supply bill components

Sample Customer Bill Breakdown



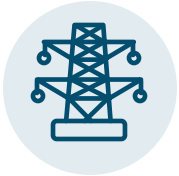
*Note: not all loads in the Large C&I class are distribution connected. This represents a typical bill for a 2MW load

New large loads can support positive affordability outcomes when costs are appropriately assigned and risks are mitigated



Creating Downward Rate Pressure on Delivery Rates for Other Customers

- If large loads pay their incremental costs *and* contribute to embedded costs, fixed system costs can be spread over a larger base of kWh sales and create downward pressure on delivery rates for other customers[1]
- But it does not guarantee overall rates will decline as there may be countervailing upward pressure on the supply portion of rates when additional generation is not present to offset the increased load



Supporting Grid Investments and New Generation

Large loads can fund critical transmission and distribution investments to improve system reliability and anchor and de-risk emerging clean resources



Contributing to Policy Goals

Large loads can help pay for policies and programs that benefit other customers or society as a whole

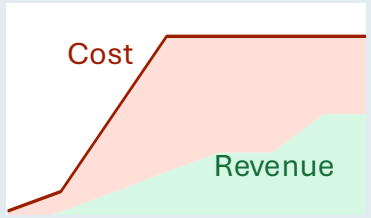


Delivering Community Benefits

Host communities can gain through community investment to fund local priorities such as housing, workforce, and childcare

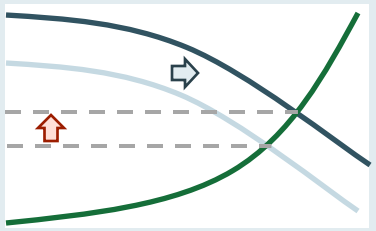
1. While use of this additional margin is at the utility's discretion and subject to regulatory approval, if no action is taken, additional margin naturally reduces rates as the utility needs to collect less revenue from other customers, creating downward rate pressure on delivery rates.

New large loads can also pose risks to affordability



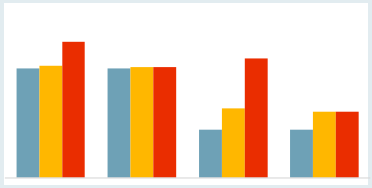
Project/Load Realization Risk

- Can include speculative requests, slow load ramping, or early exits which can result in underutilized and/or stranded assets



Supply Cost Impact Risk

- Rapid demand growth and tightening markets push up supply costs in the short run, raising costs for everyone

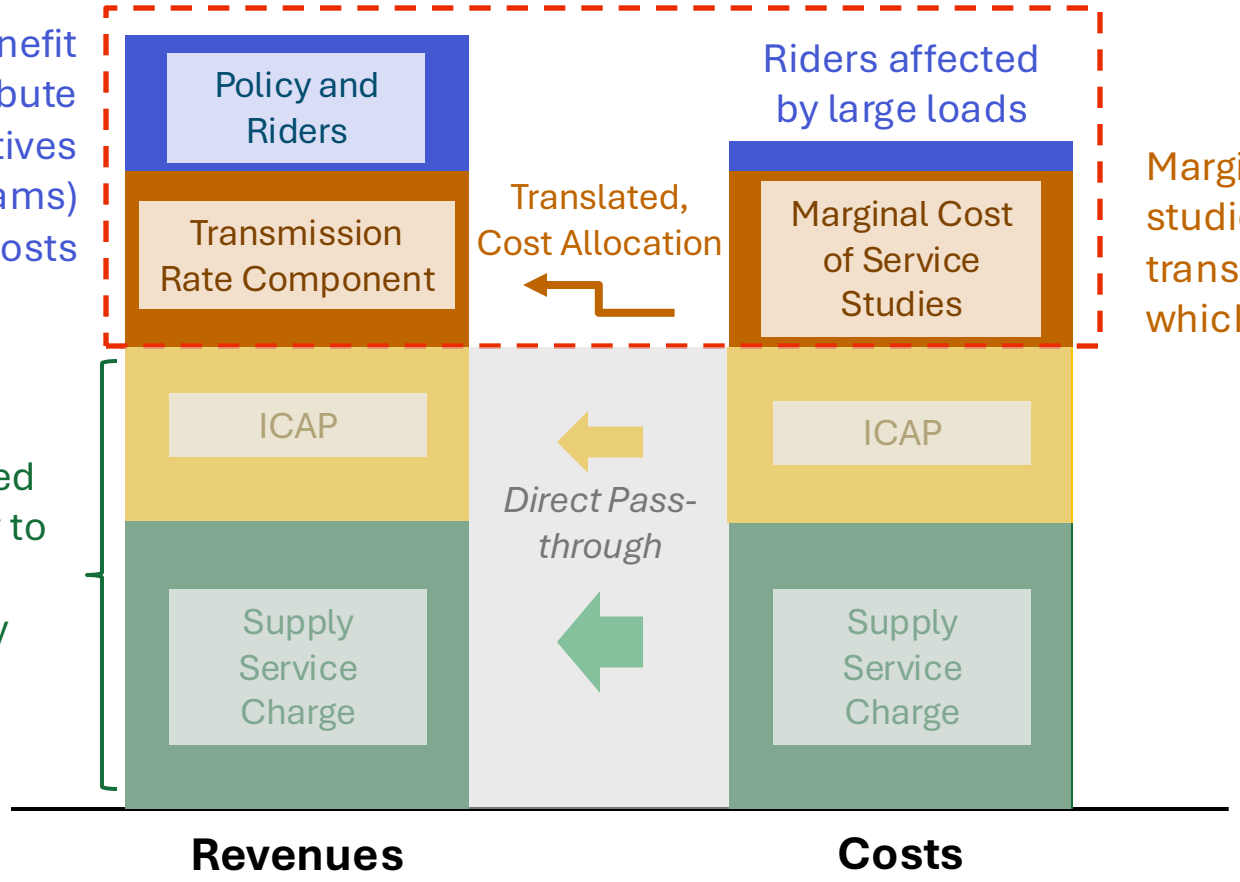


Cost Allocation and Cost Shifting Risk

- Incremental costs passed into the revenue requirement by new large loads can increase bills for other customers

Near term affordability impacts are determined largely by how much revenue large loads bring in vs. the costs they incur

Large loads may benefit ratepayers where they contribute revenues toward policy objectives (e.g., low-income programs) without adding equivalent costs

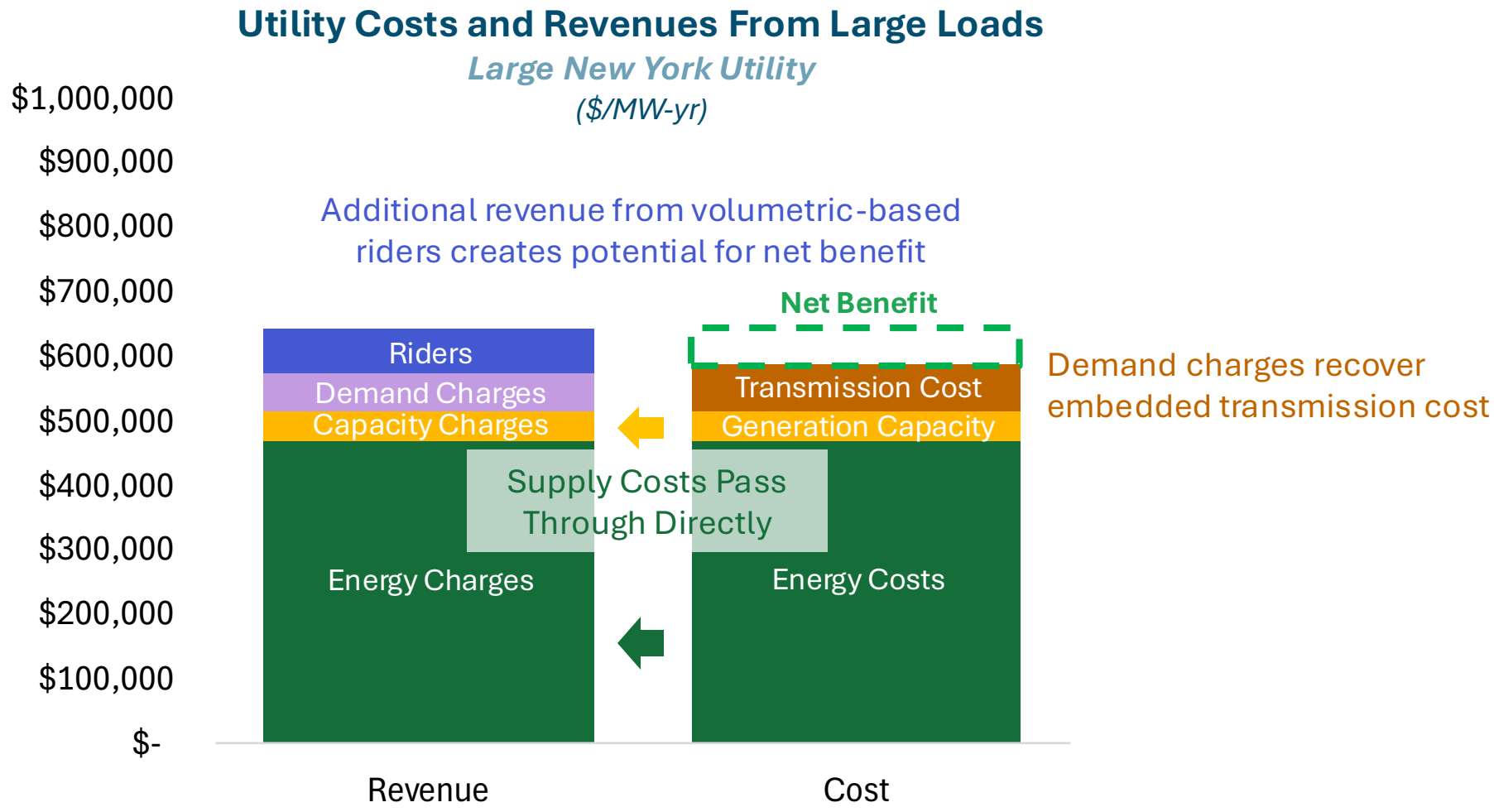


Marginal cost of service studies indicate the cost of transmission investments, which are translated into rates

Supply costs are passed directly from the utility to large loads, mitigating risks of under-recovery

Policy Objectives & Other Riders
Transmission
Generation Capacity
Energy

Under today's conditions, large loads may contribute more to utility revenues than costs, driven by program and policy riders



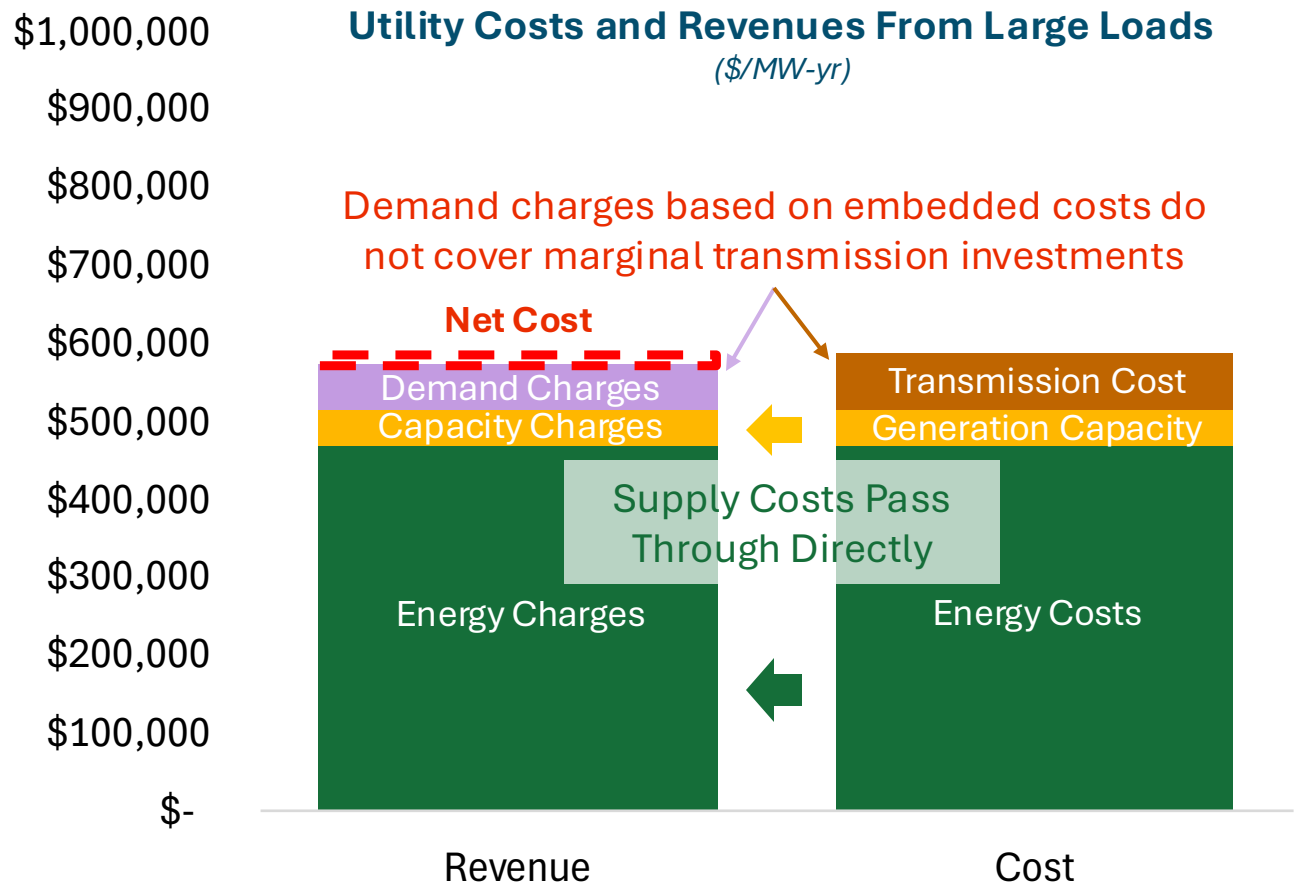
Assumed 1 GW of new load under current rates for the existing large load class and published marginal cost of service studies. NYCA zone

Depiction of Riders is simplified - large loads would also contribute to a subset of rider costs, such as REC obligations

However, demand charges designed to collect embedded infrastructure costs fall short of recovering marginal costs of new transmission

+ When Riders are taken out of the picture, current large load rates do not fully recover incremental costs

- Each individual cost component should ideally be made whole on its own, without relying on over-recovery elsewhere
- Future rates should consider reflecting or including a marginal cost component

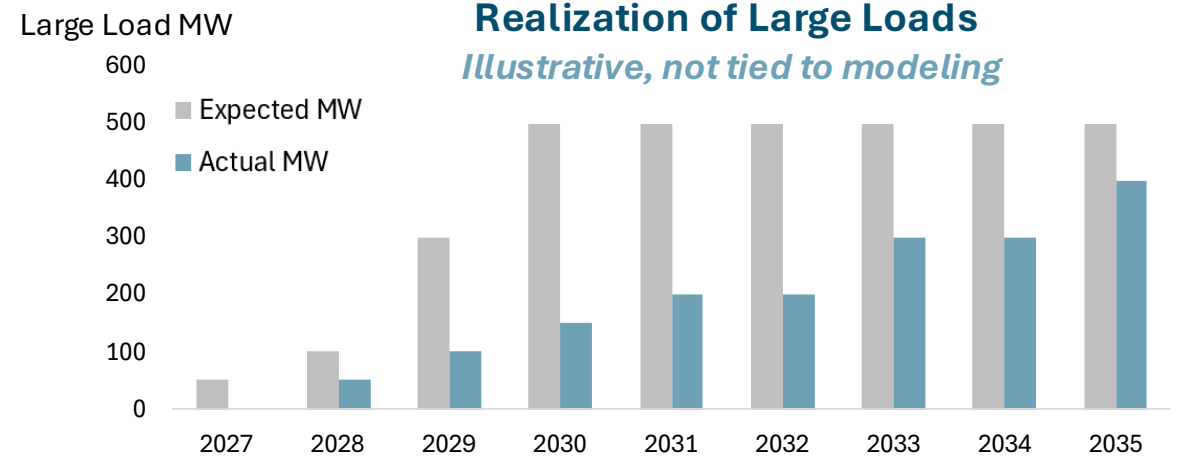


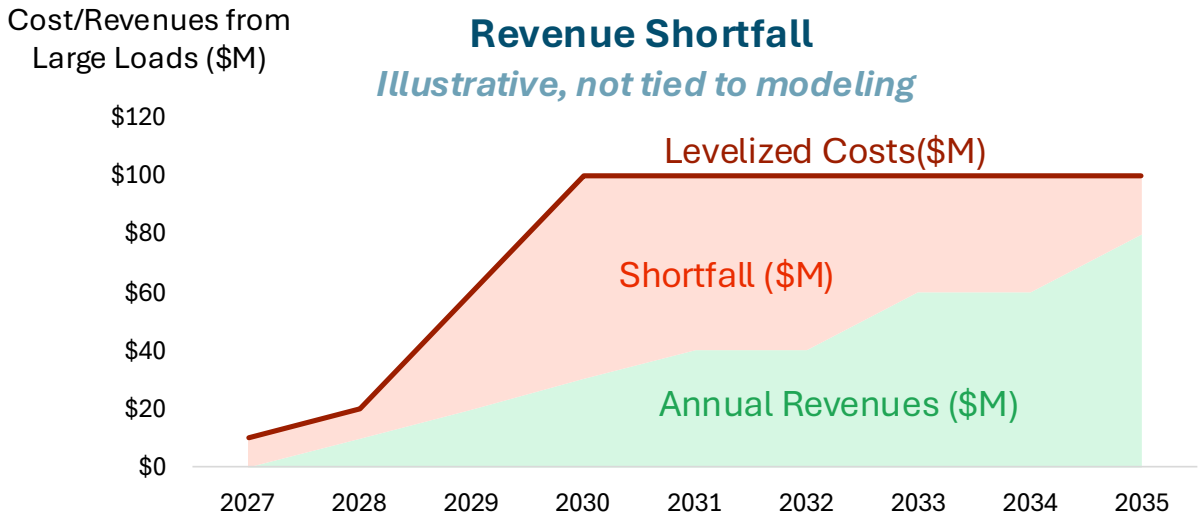
Assumed 1 GW of new load under current rates for the existing large load class and published marginal cost of service studies. Generic Large New York Utility, NYCA zone

When large loads do not materialize in line with expectations, there can be further risk for recovering costs

+ Two key risks:

- **Speculative requests** are from loads unlikely to materialize (e.g., duplicative requests, projects lacking credible financing)
  - Can clog queues, incur administrative costs, and pose stranded asset risk
- **Load realization risk and default** occur when actual scale of load growth, timing and/or ramp differs from initial requests and forecasts
  - Results in costs incurred for underutilized or stranded assets
  - Cost allocation frameworks may then under-recover marginal costs from large loads, while other customers pay the difference

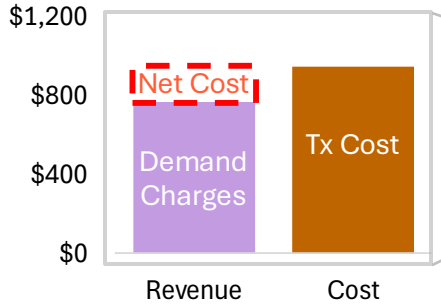




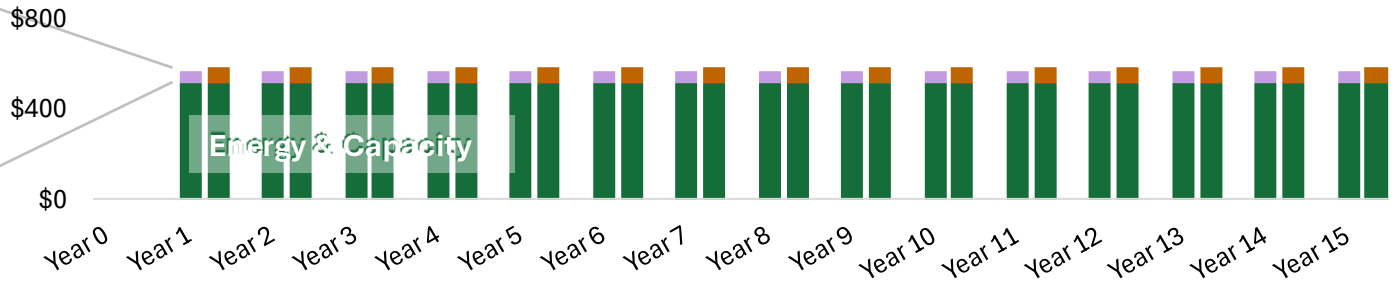
If large loads do not show up, the cost of the transmission buildout to serve these loads may be borne by other ratepayers

Load shows up as expected

NPV: Transmission Only ($/kW)



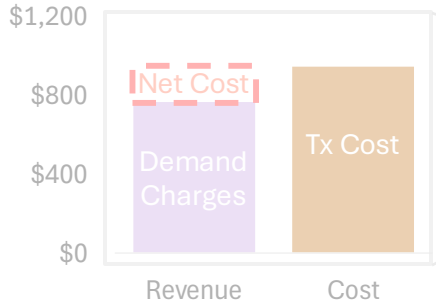
Annual Revenues and Costs ($/kW)



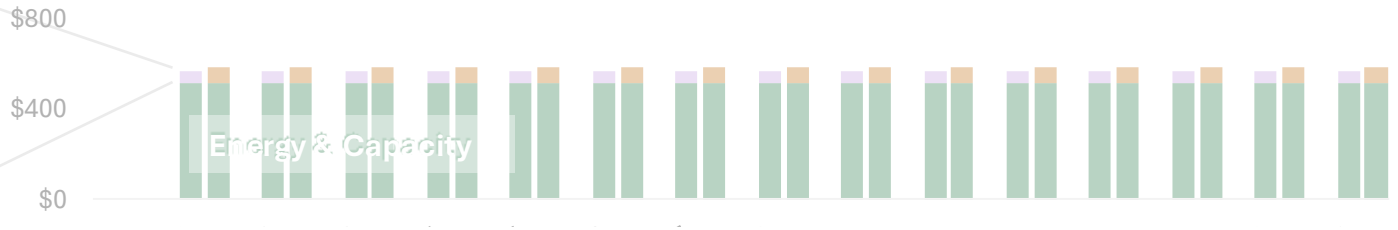
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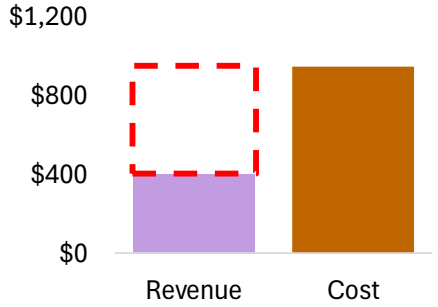


Annual Revenues and Costs ($/kW)

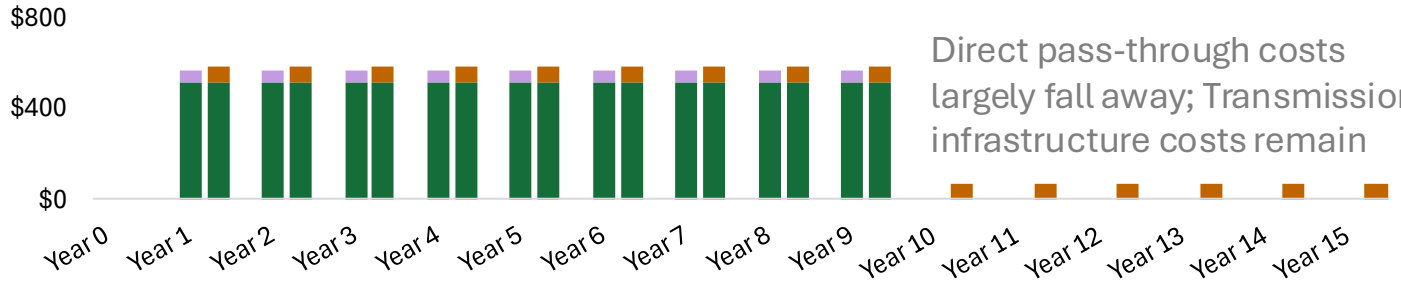


Load exits early (Year 10)

No mitigation measures



Other ratepayers pay for 58% of the rate-based transmission built to serve large loads



Direct pass-through costs largely fall away; Transmission infrastructure costs remain

If large loads do not show up, the cost of the transmission buildout to serve these loads may be borne by other ratepayers

NPV: Transmission Only ($/kW)

Annual Revenues and Costs ($/kW)

Load shows up as expected

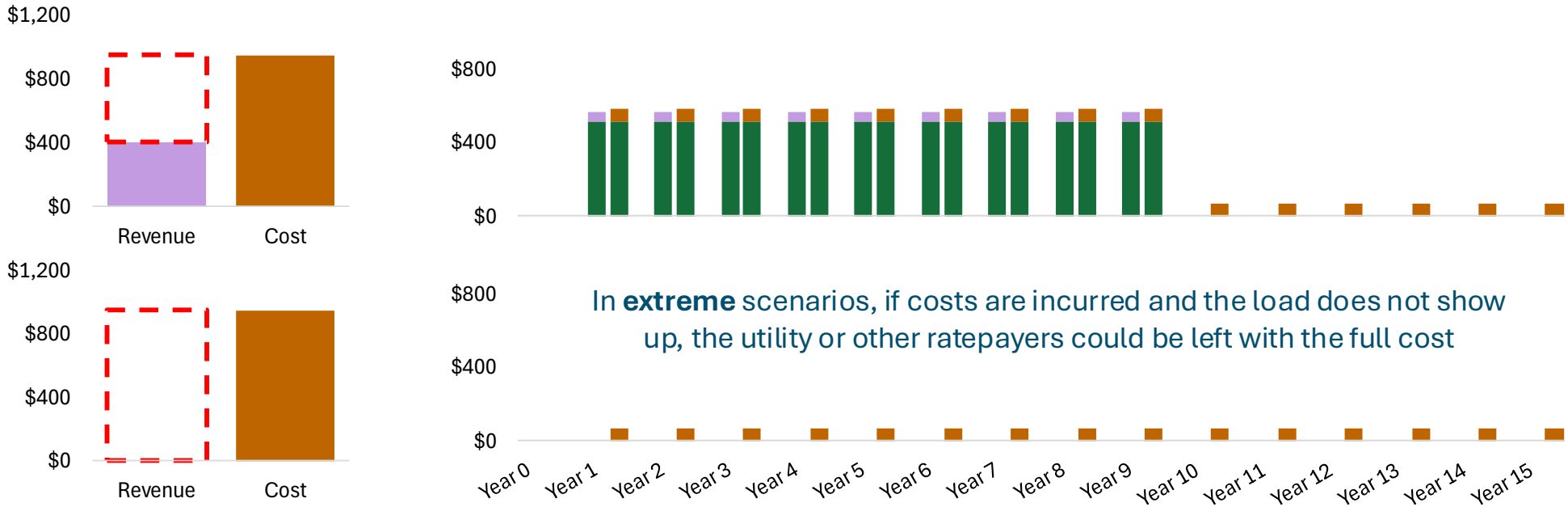


Load exits early (Year 10)

No mitigation measures

Load does not appear

No mitigation measures



In **extreme** scenarios, if costs are incurred and the load does not show up, the utility or other ratepayers could be left with the full cost

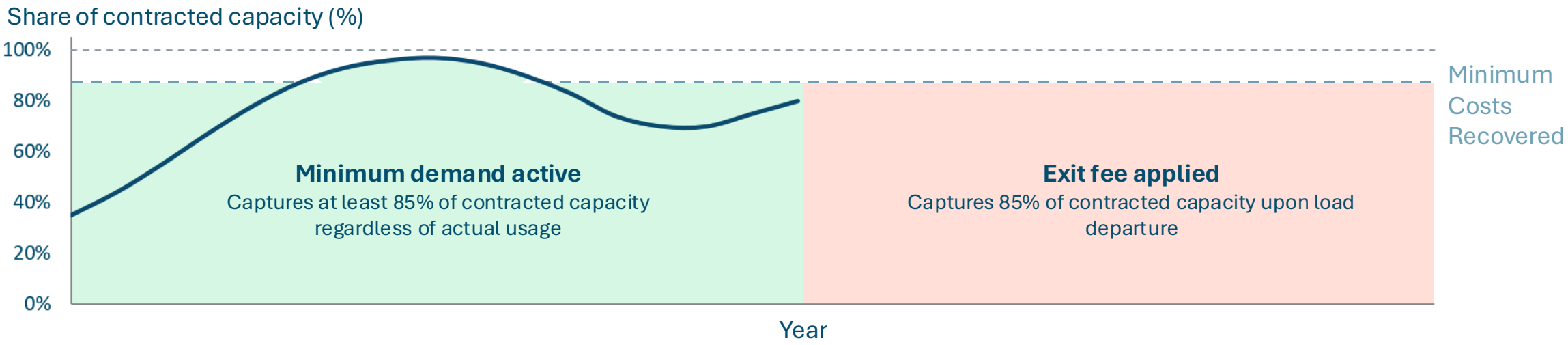
Minimum demand charges and exit fees mitigate load realization risk by guaranteeing large load revenue to pay for upgrades

Minimum Demand Charge

- **Description**: The customer is billed on the greater of actual demand or a fixed % of contracted capacity.
- **Purpose**: Guards against lower-than expected usage. Revenue will not collapse if the load ramps slowly or runs light.
- **Conditions Modeled:**
  - **Minimum demand**: 85% of contracted capacity
  - **Contract term**: 15 years

Exit Fee

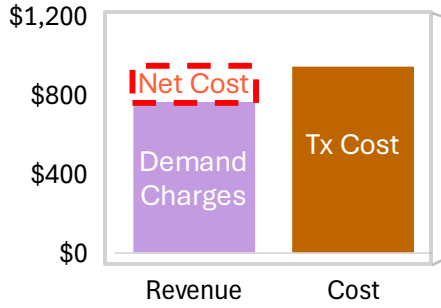
- **Description**: If the customer leaves before the term ends, all remaining minimum demand charges are paid.
- **Purpose**: Guards against early departure. Fee settles the rest of the contract rather than shifting it to other customers.
- **Conditions Modeled**:
  - **Departure at yr 0**: 100% upfront payment, no discount
  - **Departure after yr 0**: realized demand charges and remaining portion of exit fee, both discounted to today



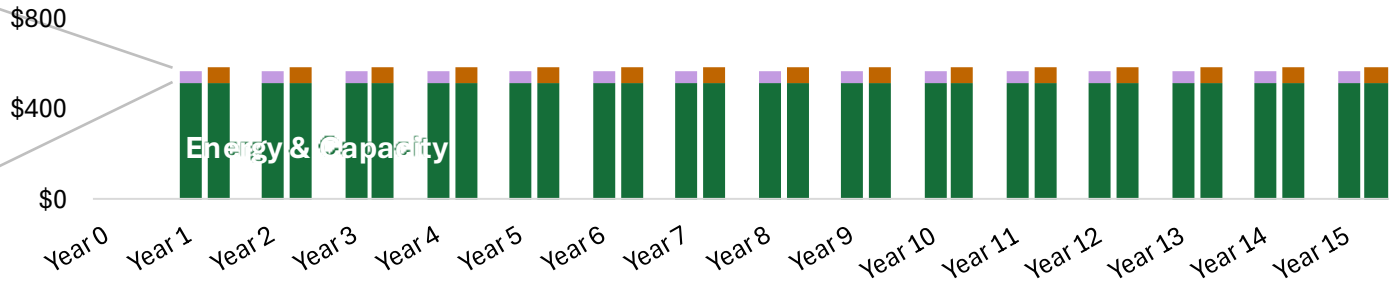
Exit fees can help mitigate stranded costs when load departs early or doesn't show up at all

Load shows up as expected

NPV: Transmission Only ($/kW)



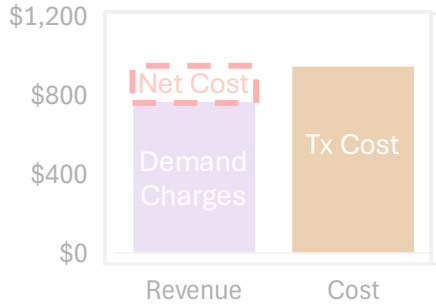
Annual Revenues and Costs ($/kW)



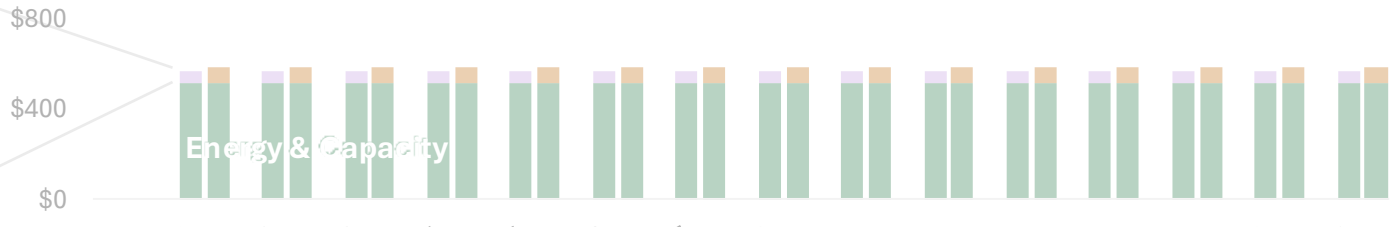
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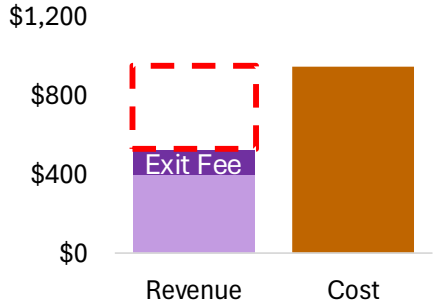


Annual Revenues and Costs ($/kW)



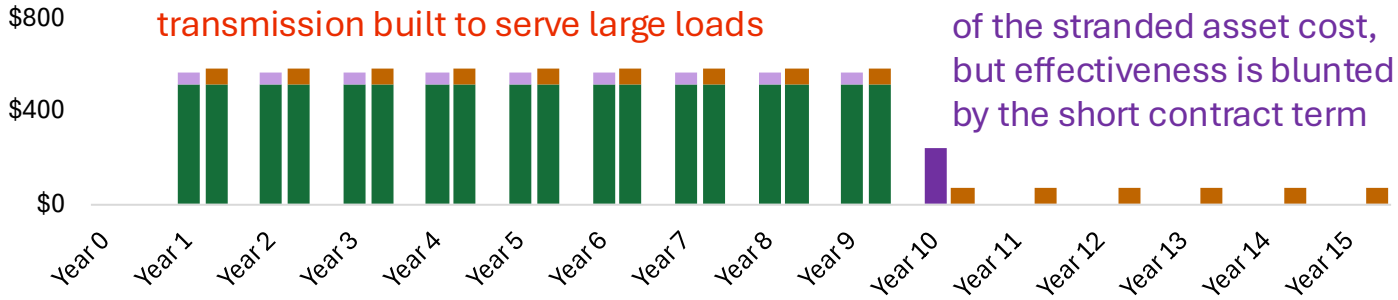
Load Exits Early (Year 10)

Exit Fees Applied



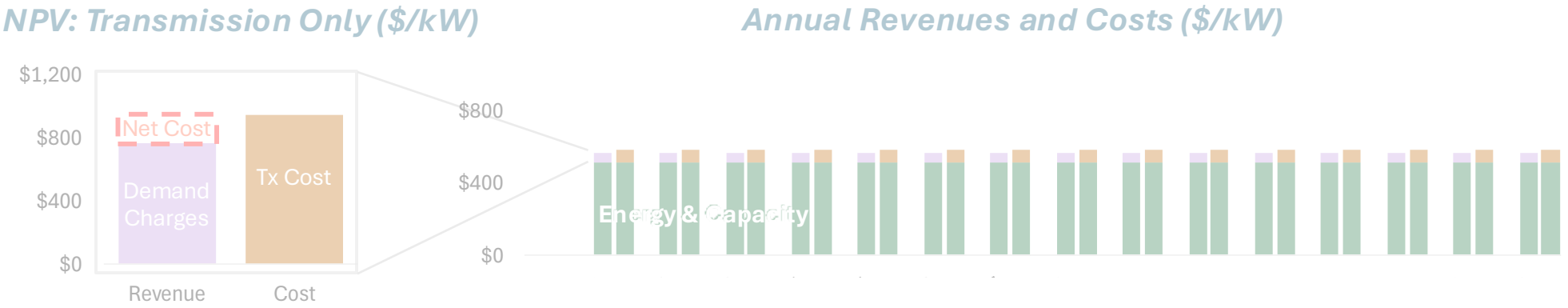
Other ratepayers pay for 44% of the rate-based transmission built to serve large loads

Exit fees recover a portion of the stranded asset cost, but effectiveness is blunted by the short contract term



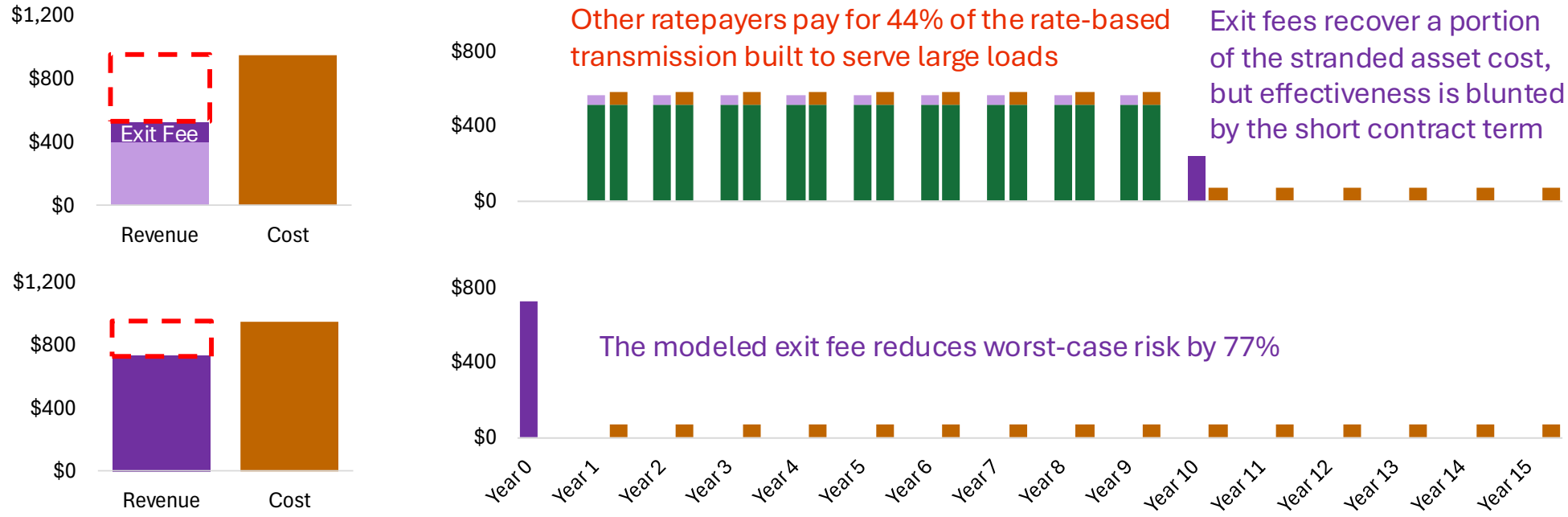
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Load Exits Early (Year 10)

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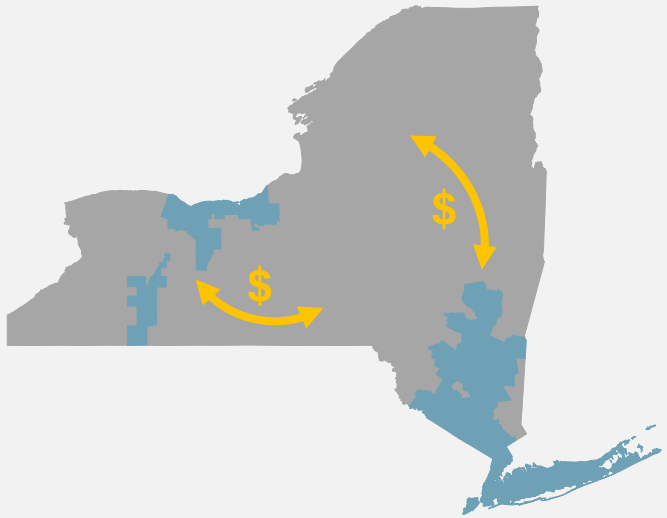


Load Does Not Appear

Exit Fees Applied

As additional new large loads materialize, there may be impacts at multiple scales due to increasing loads and new system costs

Impact to New York ratepayers outside of utilities with new large loads



Impact to ratepayers in utilities with new large loads who are outside of the Large Load class

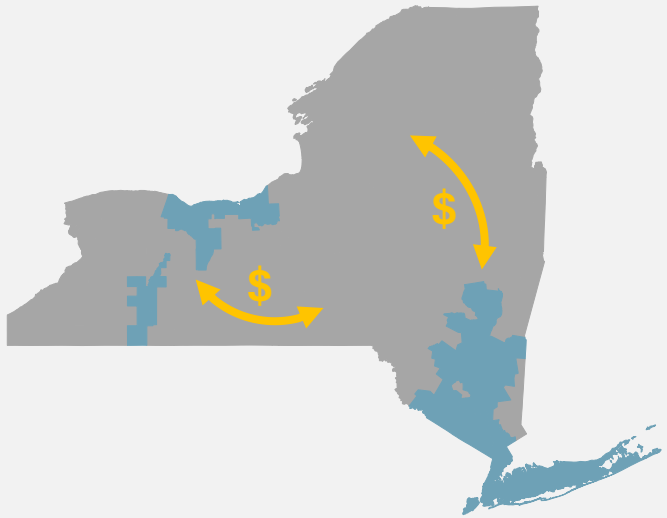


Impact to existing Large Load class customers in utilities with new large loads, as opposed to the new large loads themselves



Customers of utilities not experiencing new large load growth may still be impacted by tightening markets

Impact to New York ratepayers outside of utilities with new large loads

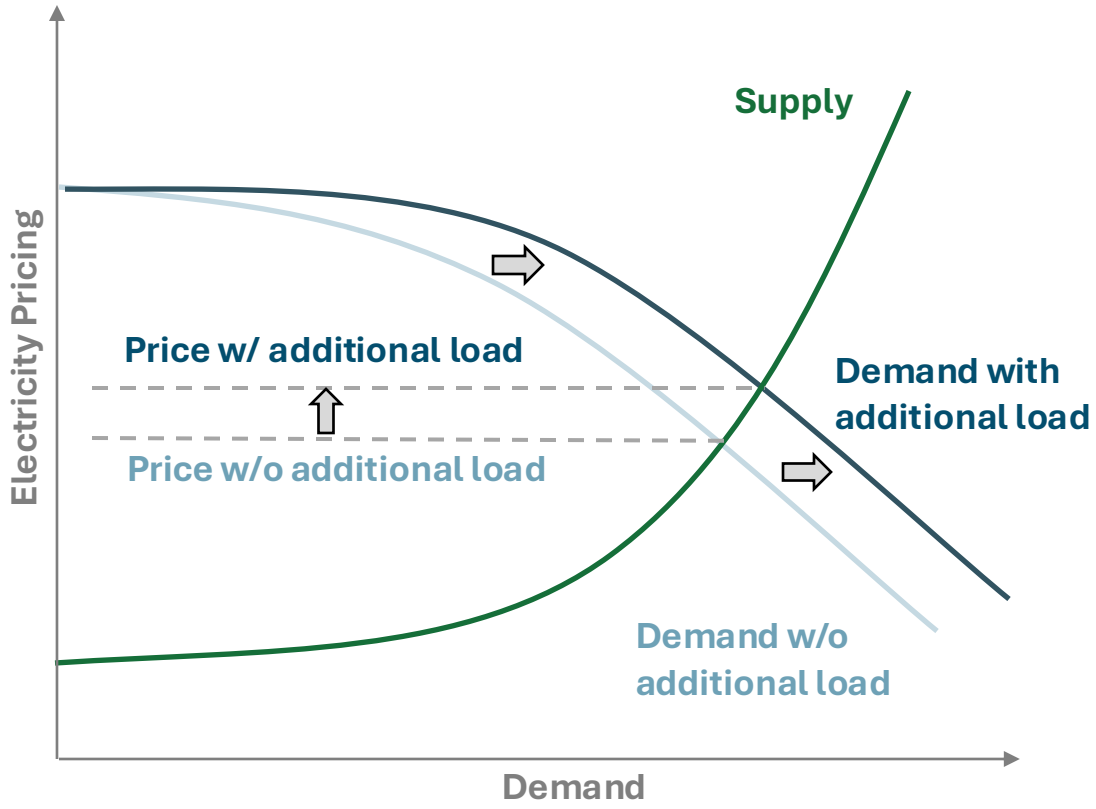


Programs and Other Riders	No direct increases to riders due to new large loads; secondary impacts (Renewable Energy Standard increasing with load) too small and uncertain to quantify
Distribution	New large loads generally expected to connect upstream of distribution system, creating no new distribution costs
Transmission	Allocation of existing statewide transmission costs is largely fixed; allocation of new costs is uncertain, but expected to only impact utilities experiencing load growth
Supply (Energy & Capacity)	Energy and Capacity markets are expected to tighten due to increased demand; but supply costs not subject to allocation challenges (pass through)

Large loads can affect electricity pricing by shifting the demand curve

- **New generation takes years to plan and build, so supply is largely fixed in the short-term**
- **New large loads increase demand.** When large load users connect, total demand for electricity and capacity increases (the demand curve moves to the right)
- **Higher demand on the same supply curve raises prices.** Energy and capacity clears at higher prices, which applies to every customer buying from the market, not just new large loads.

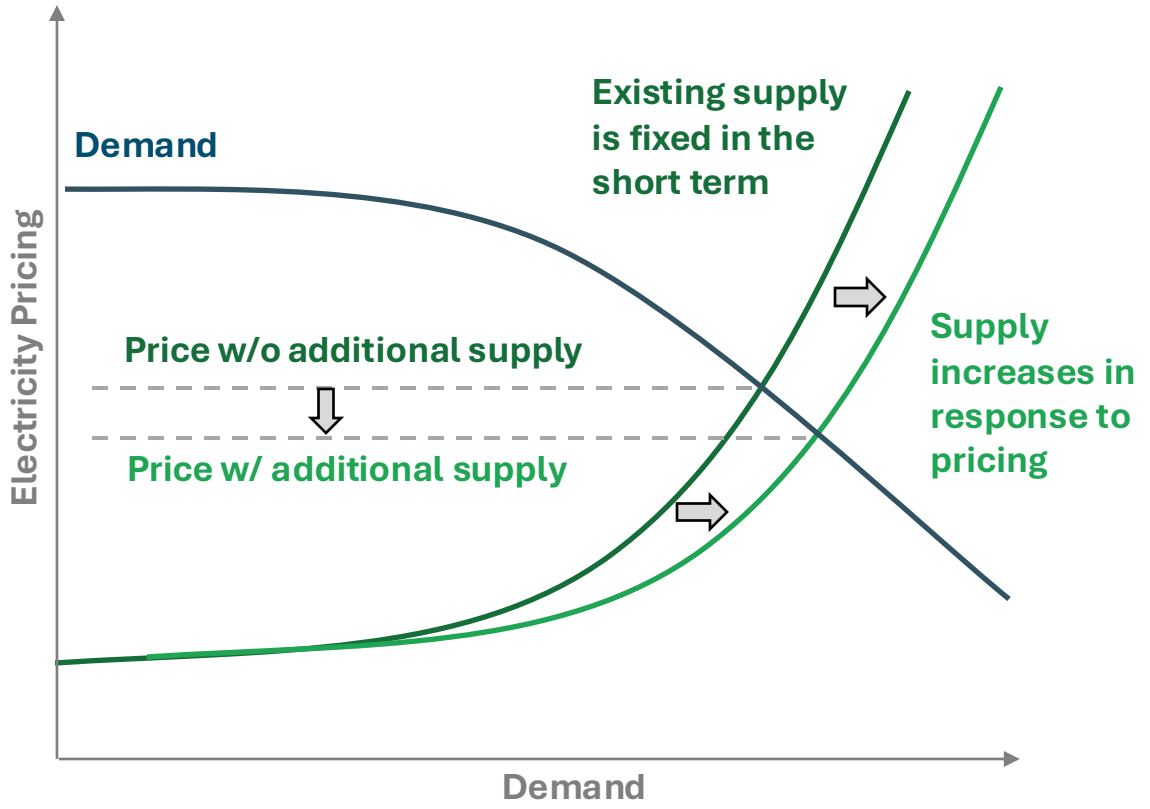
Illustrative Indirect Impact on the Demand Curve



Higher wholesale prices incentivize new supply over time

- **Prices settle back over time.** Higher prices incentivize new generation, which can eventually bring prices back into equilibrium. The timing of new demand compared with new supply determines the magnitude and duration of the price increase.
- **Fixed price retail or bi-lateral contracting allows customers to manage price volatility.** Customer exposure to higher market prices depends on extent to which they are hedged, e.g. through fixed price contracts.

Illustrative Indirect Impact on the Demand Curve



Customers in other rate classes may be impacted by both new transmission costs and changing allocation factors

Impact to ratepayers in utilities with new large loads who are outside of the Large Load class

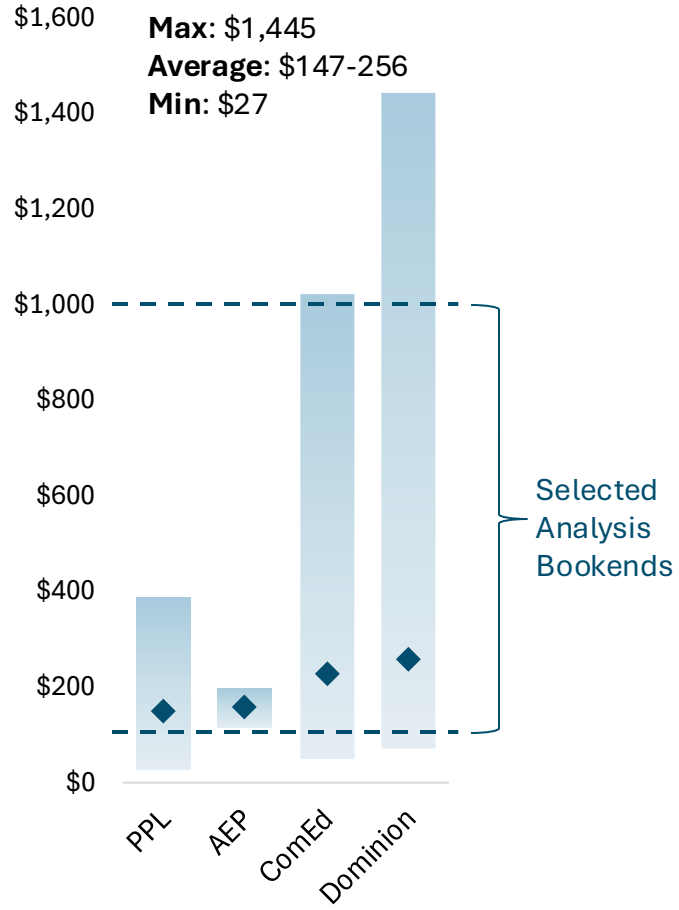


Programs and Other Riders	No direct increases to riders due to new large loads; secondary impacts (Renewable Energy Standard increasing with load) too small and uncertain to quantify
Distribution	New large loads generally expected to connect upstream of distribution system, creating no new distribution costs
Transmission	Potential impacts due to both allocation of incremental costs and reallocation of embedded costs among classes
Supply (Energy & Capacity)	Energy and Capacity markets are expected to tighten due to increased demand; but supply costs not subject to allocation challenges (direct pass through)

System upgrade costs vary widely

- **Many costs are identified by transmission owner's planning processes rather than NYISO, but the allocation to large loads vs. other ratepayers is an inexact process**
- **Transmission network upgrade costs range widely and are project specific**
  - PJM transmission costs range from $30-1,500 /kW, or about $20-125 /kW-yr
    - Current New York transmission marginal cost of service is ~70 $/kW-yr, so costs are likely to fall in the middle or upper end of the range
- **E3 modeled a range of costs that could be passed to ratepayers to reflect uncertainty in cost magnitude and allocation**
  - Approach focuses on impacts once costs are assigned, regardless of underlying cost drivers

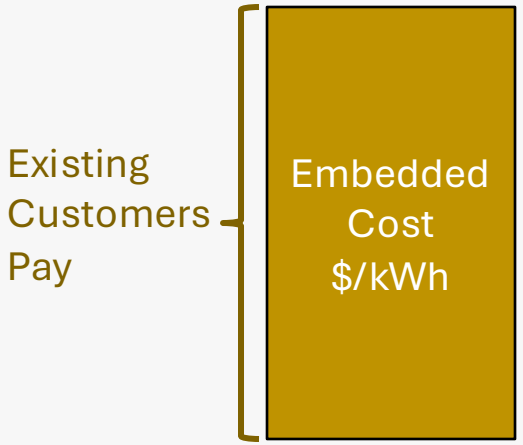
2025-2026 PJM Load Growth-related Transmission Costs assigned to Ratepayers ($/kW)



Adjusting transmission cost allocation can ensure customers in other rate classes avoid negative impacts

2. New Customers come with incremental costs

1. **Before** new large loads interconnect



Status Quo

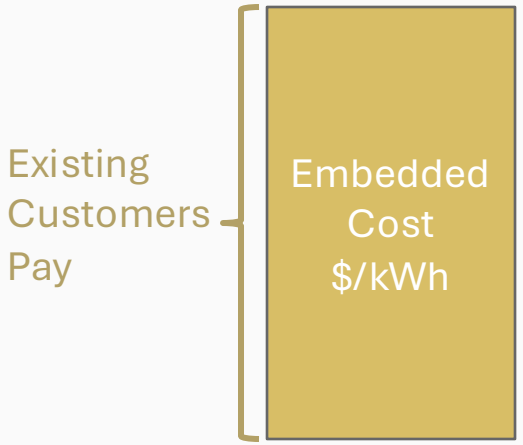
3. **When** new large loads interconnect: Incremental costs are rolled into the Revenue Requirement and all costs are reallocated across all customers

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Status Quo

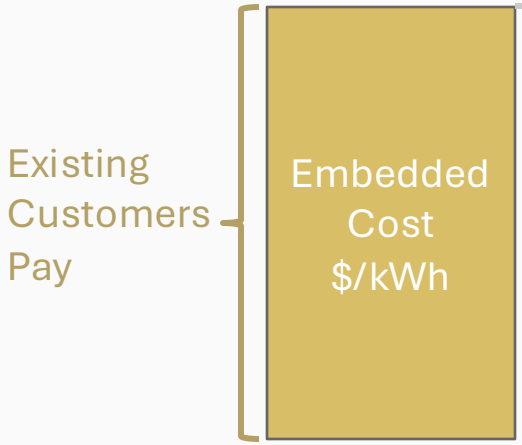
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Adjusting transmission cost allocation can ensure customers in other rate classes avoid negative impacts

2. New Customers come with incremental costs

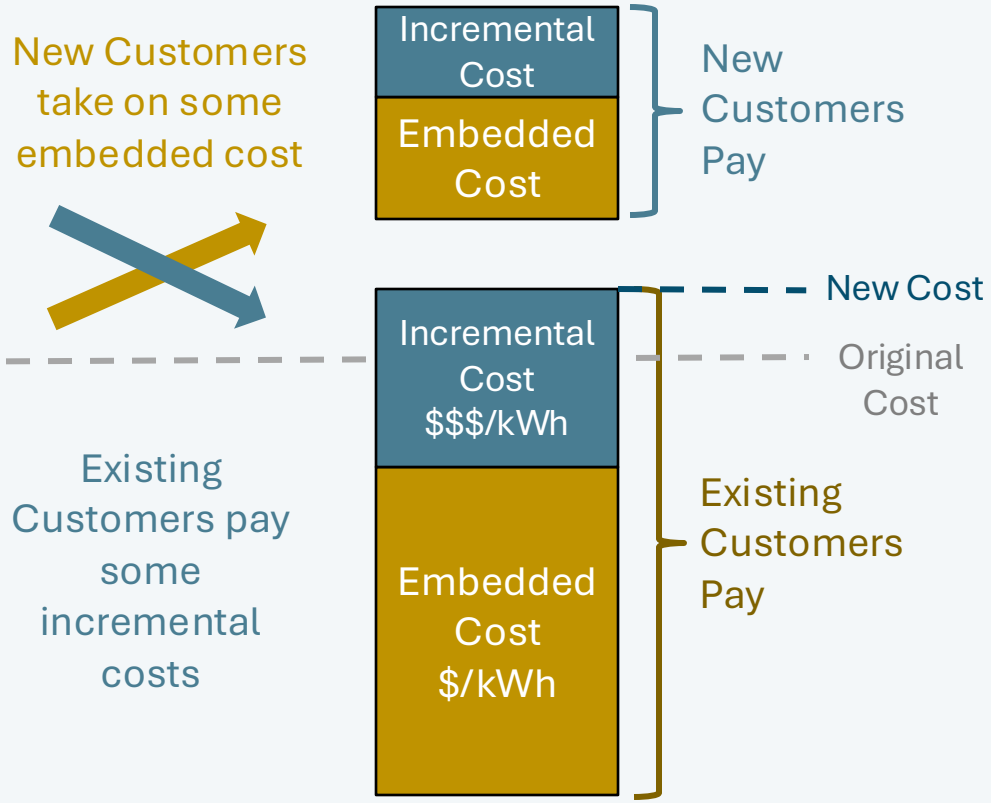


1. **Before** new large loads interconnect



Status Quo

3. **When** new large loads interconnect: Incremental costs are rolled into the Revenue Requirement, and all costs are reallocated across all customers

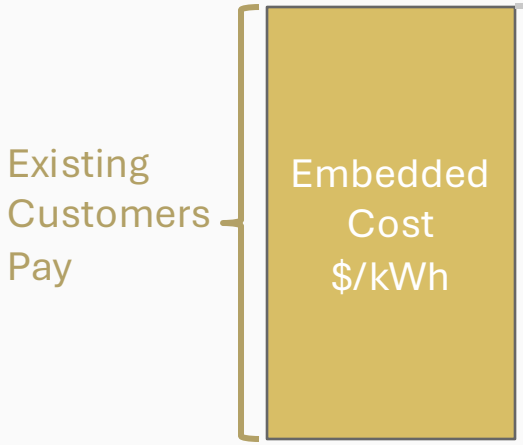


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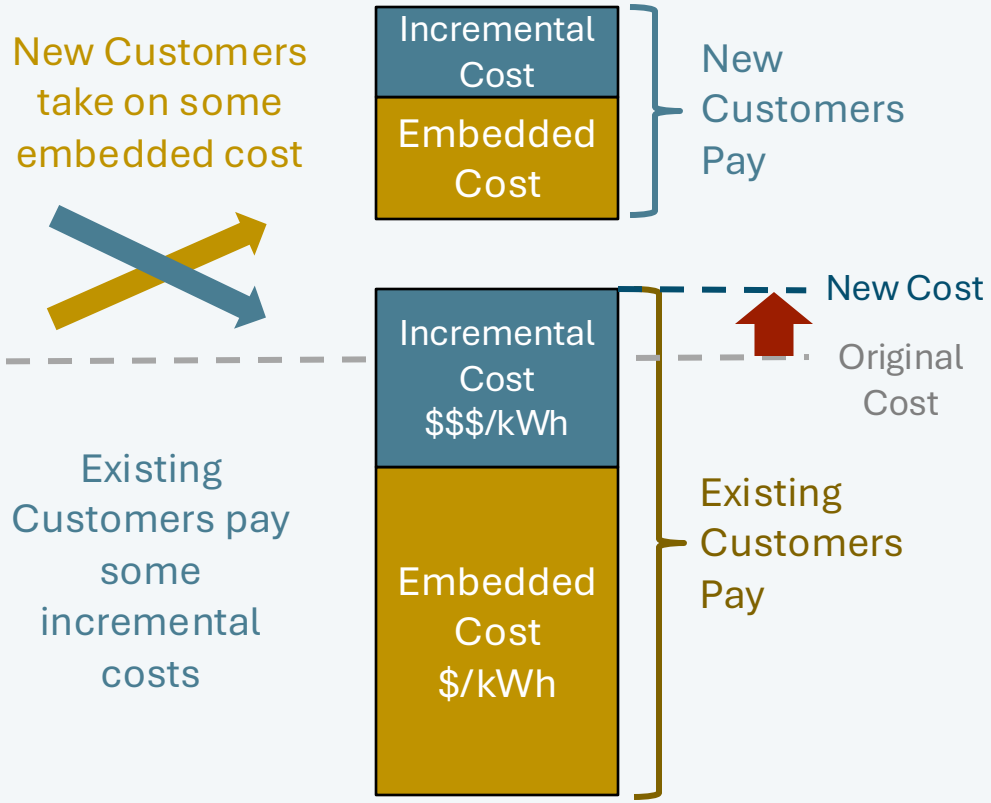


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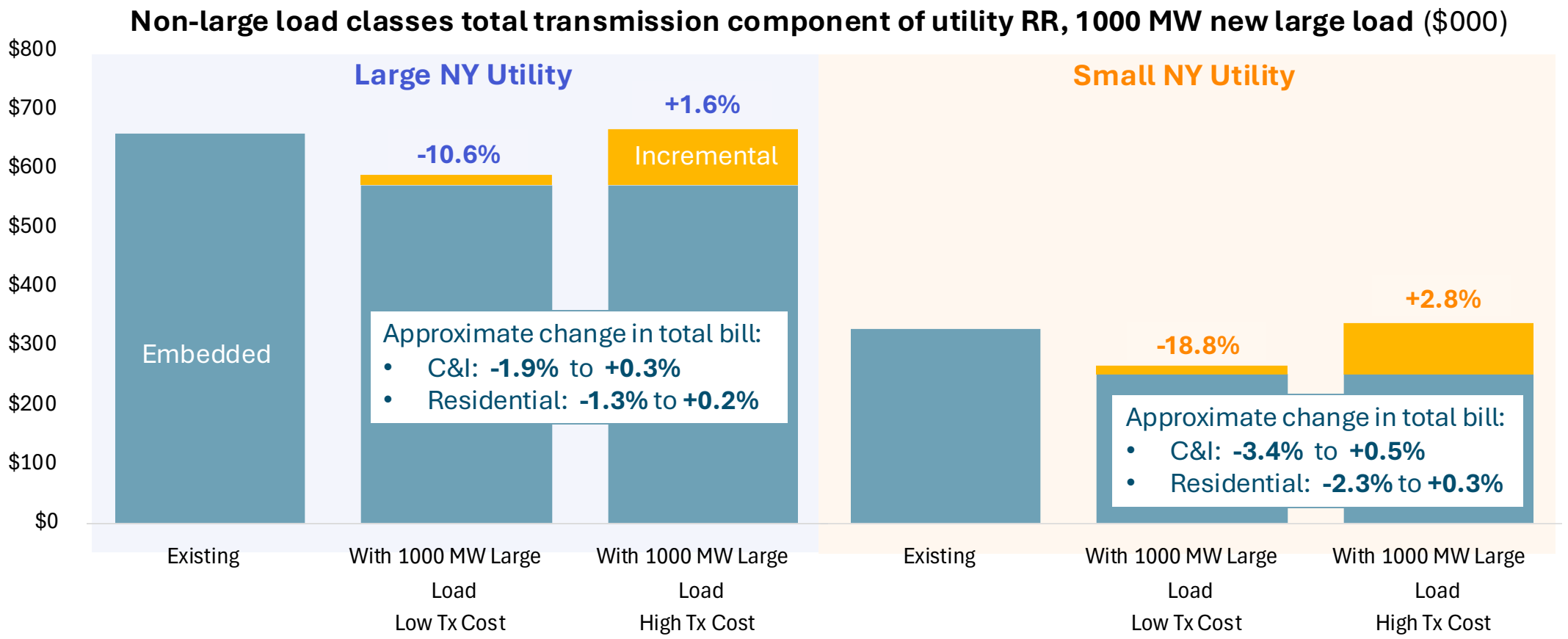


If the incremental cost per unit is higher than the embedded cost, existing customers pay more than before

If the incremental cost is lower, existing customers pay less

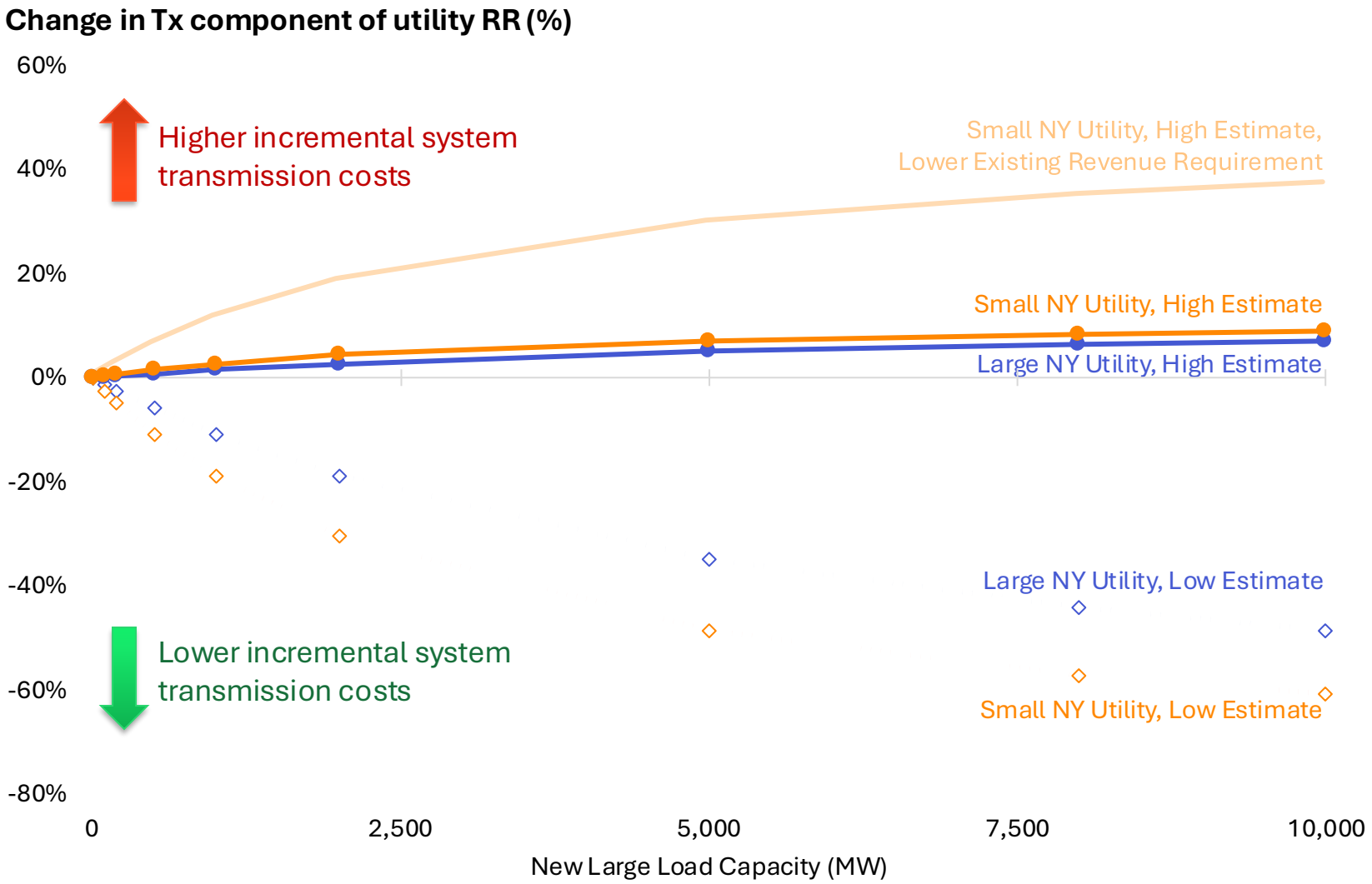
New large loads dilute existing costs but also socialize new transmission costs across non-large load customers

Chart shows the transmission revenue requirement of all *other* classes: **Embedded** = share of the existing system after the load takes its share; **Incremental** = share of the new transmission cost



Assumptions: Existing large load class, no ratepayer protection, no CIAC, NYCA zone.

High penetrations of large loads amplify dynamics seen at lower penetrations, especially in smaller peak-load jurisdictions



+/- 50% impact on transmission costs corresponds to +/-6% in rate impacts

Impacts are muted for larger utilities and for utilities with larger revenue requirements

Not a load growth forecast. Assumes constant load for other classes and full pass-through of allocation shares
"Low" = $100/kW incremental transmission cost; "High" = $1,000/kW

Adjusting transmission cost allocation can ensure customers in other rate classes avoid negative impacts

2. New Customers come with incremental costs

New Customer Incremental Cost $$$/kWh

1. **Before** new large loads interconnect

Existing Customers Pay

Embedded Cost $/kWh

Status Quo

3. **When** new large loads interconnect: Incremental costs are rolled into the Revenue Requirement, and all costs are reallocated across all customers

New Customers take on some embedded cost

Existing Customers pay some incremental costs

Incremental Cost

Embedded Cost

New Customers Pay

New Cost

Original Cost

Incremental Cost $$$/kWh

Embedded Cost $/kWh

Existing Customers Pay

Adjusting transmission cost allocation can ensure customers in other rate classes avoid negative impacts

2. New Customers come with incremental costs

New Customer Incremental Cost $$$/kWh

1. **Before** new large loads interconnect

Existing Customers Pay

Embedded Cost $/kWh

Potential Play

3. **Specified categories of new customers pay for a high share or all incremental costs and their share of embedded costs**

New Customers take on some embedded cost

Incremental Cost

Embedded Cost

New Customers Pay

Original Cost

New Cost

Existing Customers pay little to no incremental costs

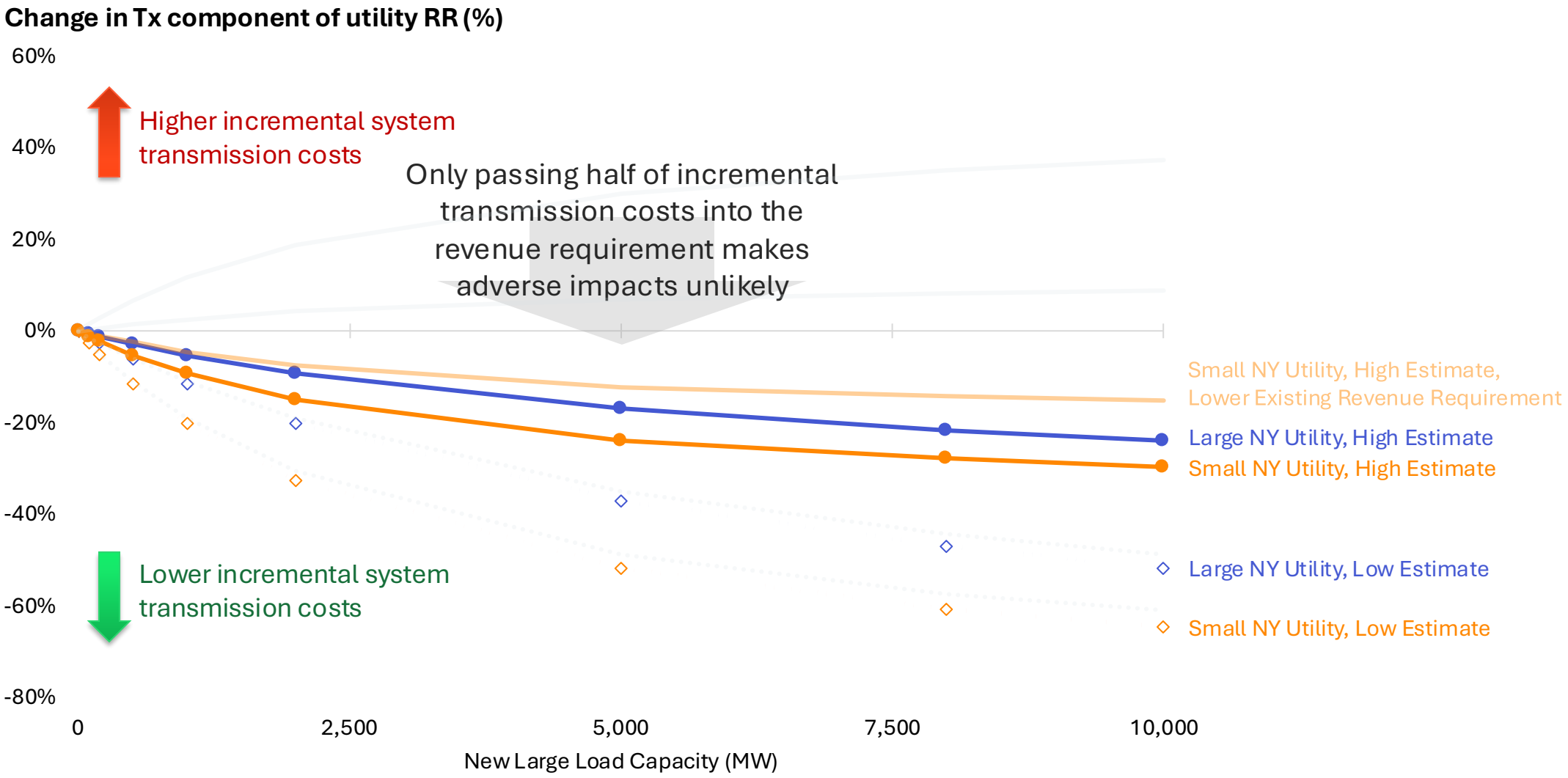
Embedded Cost $/kWh

Existing Customers Pay

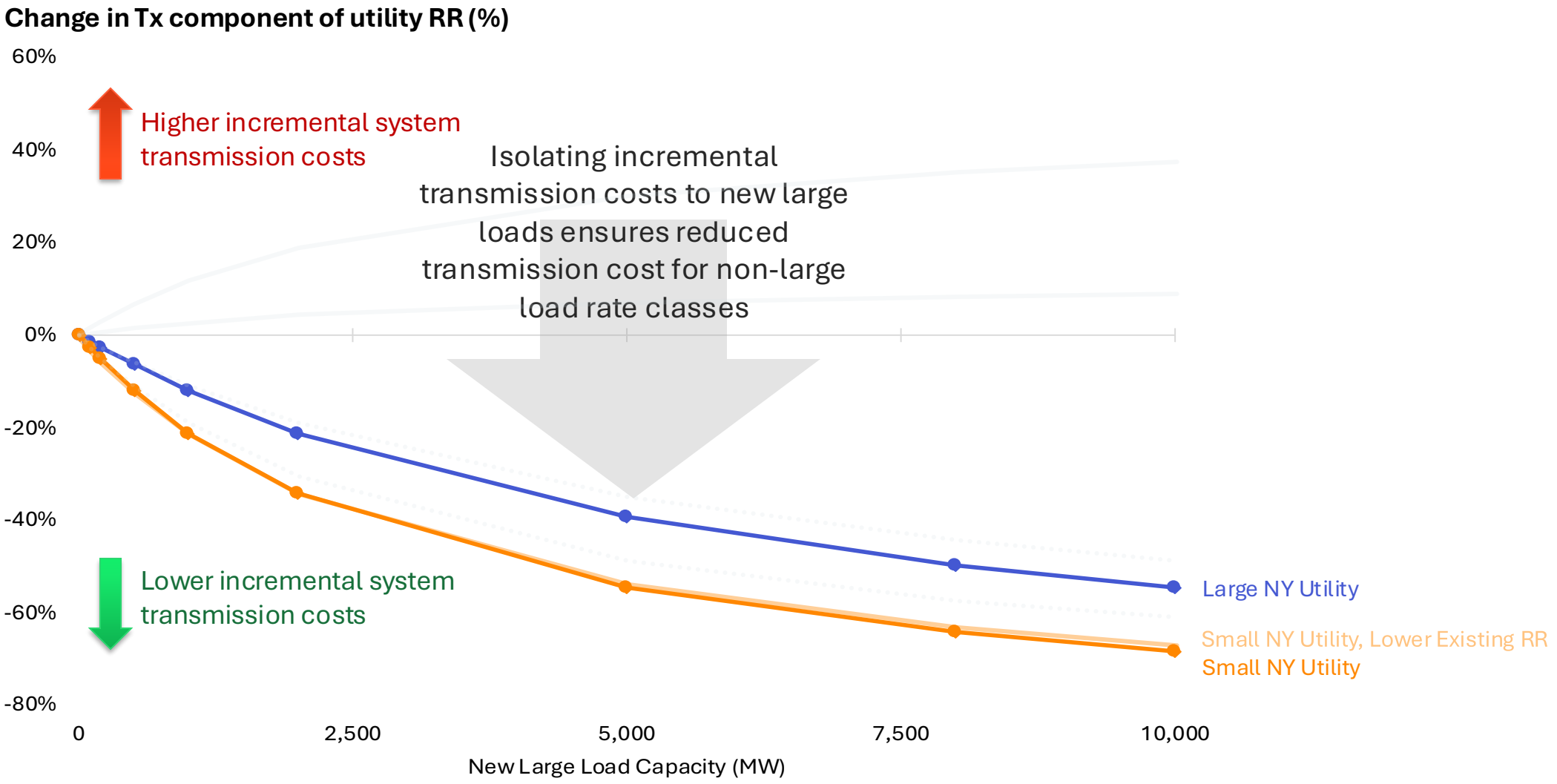
Existing customers pay their original amount or pay less

The Senate Permitting Reform Bill provides a pathway for this structure to be enacted nationally

High penetrations of large loads amplify dynamics seen at lower penetrations, especially in smaller peak-load jurisdictions



High penetrations of large loads amplify dynamics seen at lower penetrations, especially in smaller peak-load jurisdictions



Existing customers in broadly defined large load classes may be unduly assigned additional transmission costs

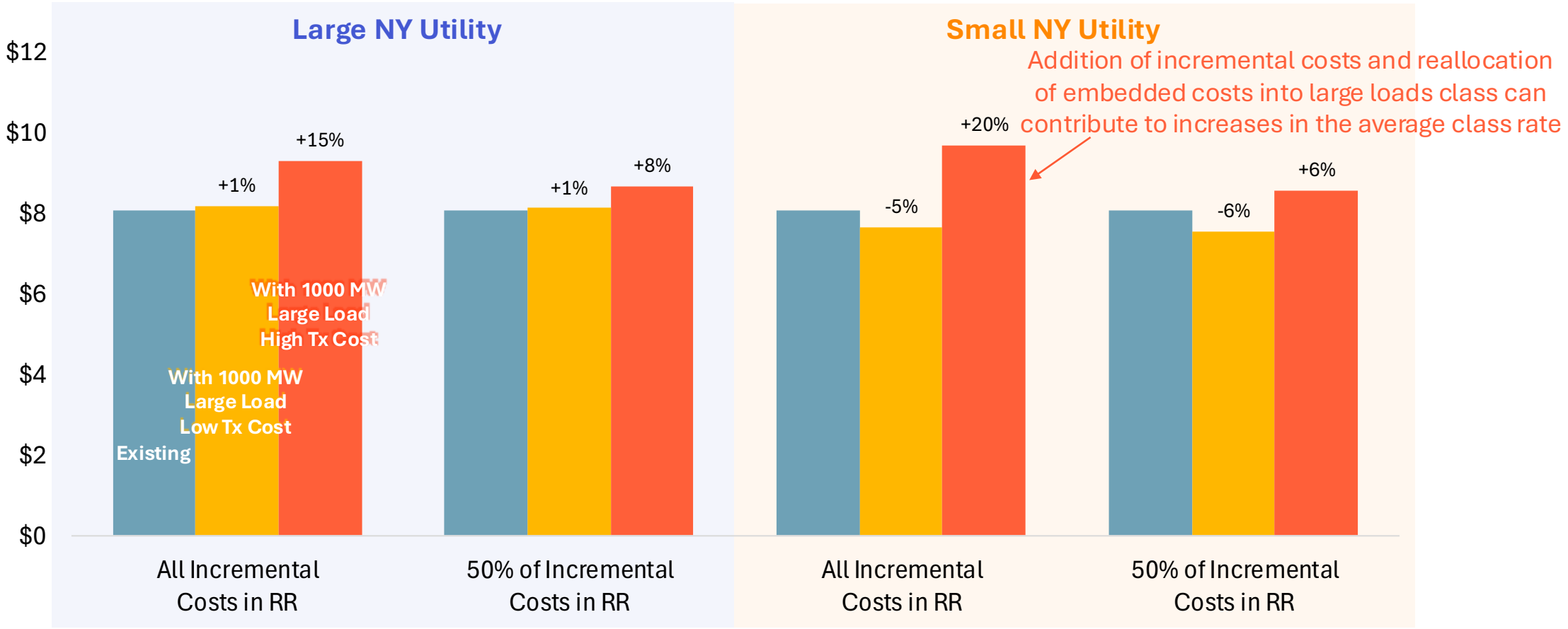
Impact to existing Large Load class customers in utilities with new large loads, as opposed to the new large loads themselves



Programs and Other Riders	No direct increases to riders due to new large loads; secondary impacts (Renewable Energy Standard increasing with load) too small and uncertain to quantify
Distribution	New large loads generally expected to connect upstream of distribution system, creating no new distribution costs
Transmission	Potential impacts as class cost allocation factors increase due to increase in class load
Supply (Energy & Capacity)	Energy and Capacity markets are expected to tighten due to increased demand; but supply costs not subject to allocation challenges (direct pass through)

Existing large customers are at risk for cost increases due to new large load growth regardless of incremental transmission cost allocation

Cost of service for *Existing* (transmission-level) large customer class ($/kW-month)



A dedicated rate class provides utilities with a more precise set of tools for managing new large loads

+ **The creation of a new rate class targeting large loads with specific characteristics (e.g. high load factor, peak load > X MW) would allow utilities to better isolate the impacts of new large loads from existing large loads**
  - Such a class could encompass a combination of some existing and new large loads, potentially with provisions to ease in the pre-existing customers over time

Core benefits:



Reduces impact of new large loads on rates for existing large customers with different characteristics



Improves efficacy of protective safeguards
- **e.g., Minimum demand charges or exit fees**



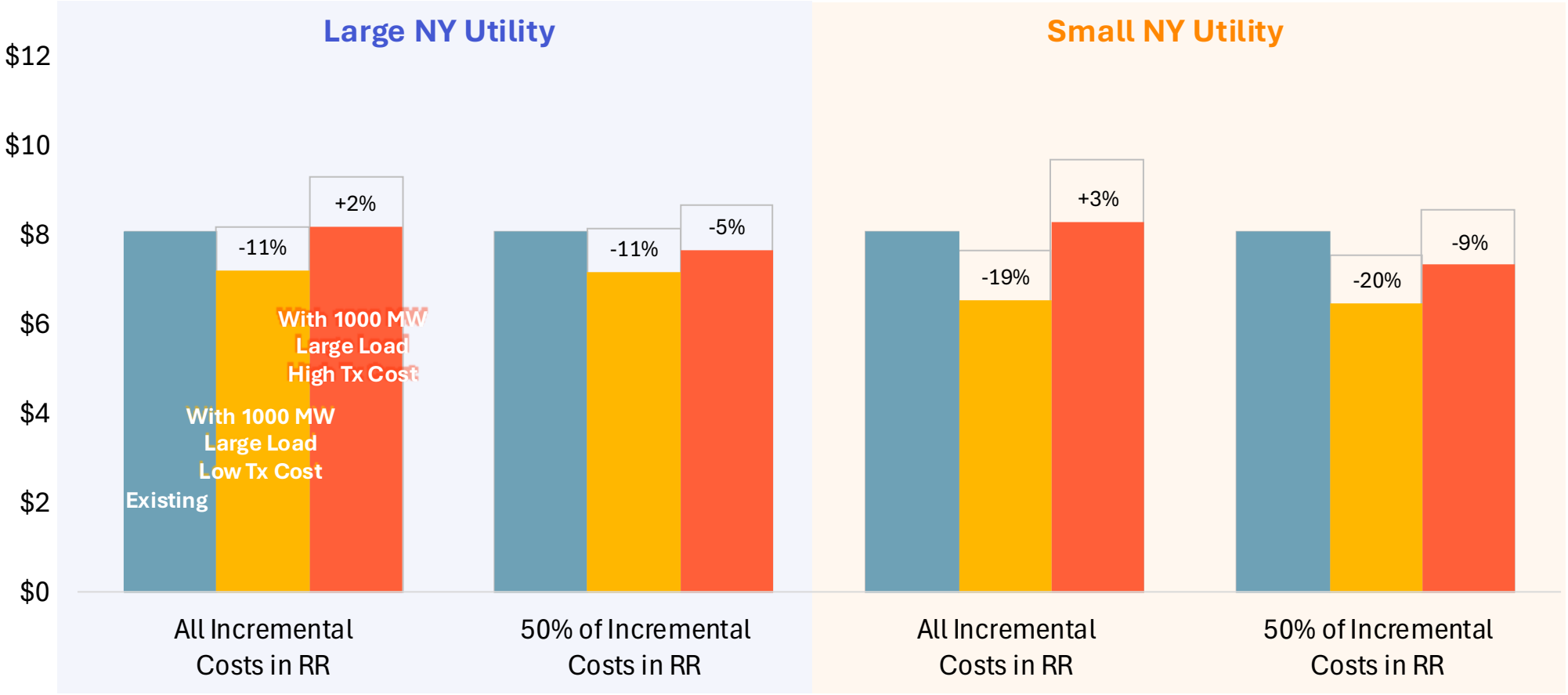
Allows rates structures to be tailored for improved cost recovery



Allows for easier targeting of load flattening or other programs to large loads in each the existing and new rate classes

Isolating new large loads in their own rate class reduces the risk of negative impacts to existing large loads

Cost of service for *Existing* (transmission-level) large customer rate class* ($/kW-month)



Note - Not depicted here: cost of service allocation for the newly created class. Existing customers that move into the new rate class based on their load characteristics would see cost allocation based on the new class's cost determinants

Q&A and Discussion



Energy+Environmental Economics

Discussion Questions – Rate Analysis



What aspects of rates and affordability are highest priority to you?



Does this analysis address those highest priority issues?



What other information should Staff consider?

Technical Analysis: Potential Strategies to Consider in New York

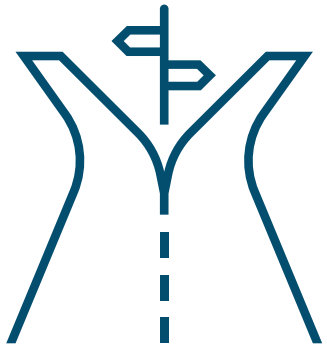


Energy+Environmental Economics

Strategy approach & goals

Approach

+ **Uncertainty in future large load growth and evolving policy and market conditions call for an adaptable approach to managing risks**
+ **The scale and pace of load growth are key drivers of the magnitude and urgency of potential ratepayer and system impacts**
  - **Near-term "least regrets"** strategies provide a starting point
  - **Additional strategies** if higher levels of load growth materialize



Goals

Identify strategies that address large load risks across multiple areas including cost allocation, load realization, resource adequacy, and T&D risks.

Ensure that each strategy provides incremental value and avoid duplicative strategies.

Least regrets strategies to consider in the near-term

Create New Rate Class
(e.g., extra large load)

Affordability | Cost Allocation Risk | Load Realization Risk

Isolate large load risk and add terms to protect existing customers:

- Min. bill: 85% contract demand
- Min. contract: 15 years
- Exit fee: 100%/remaining min. bills
- Transmission cost allocation: assign incremental costs to new loads

MAIN IMPLEMENTER

- Utilities

OTHER KEY STAKEHOLDERS

- DPS develop guidance
- PSC approves tariffs

BENCHMARKS

- Min. bills typically ≥80% demand
- Min. term range 10-20 years
- Exit fees cover remaining min. bills

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Add Interconnection Milestones/Deposits

Affordability | Customer Risk, Speculative Risk

- Increase early upfront deposits in interconnection process
- Require disclosure of similar interconnection requests in NY

MAIN IMPLEMENTER

- Utilities

OTHER KEY STAKEHOLDERS

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BENCHMARKS

- Major markets (Dominion, ComEd) require ~2x NY deposits
- Texas requires disclosure of similar requests

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Monitor Queues and Adjust Forecasts

Affordability | Customer Risk, Speculative Risk

Reliability | RA Risk

- Monitor gen/load queue attrition rates given tail risk
- Invest in risk-weighted & scenario load forecasting

MAIN IMPLEMENTER
- Utilities monitor in their territory
- NYISO monitors systemwide

OTHER KEY STAKEHOLDERS
- DPS can set requirements and provide guidance

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Identify Priority Development Areas

Affordability | Supply Cost Risk

Reliability | T&D Risk/Cost

Combine grid headroom maps with state priorities (e.g., brownfields) for "win-win" sites

MAIN IMPLEMENTER
- NYSERDA coordinate analysis

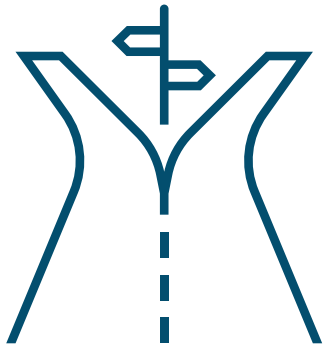
OTHER KEY STAKEHOLDERS
- Empire State Development, NYISO, utilities provide data
- Governor's Office guide priorities

BENCHMARKS
- Michigan's extra tax incentives for brownfield redevelopment

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Potential Metrics to Monitor

- Large load growth on a systemwide and utility level
- Large load interconnection queue relative to current system peak
- Load attrition
- Effectiveness of risk mitigation measures in tariff and interconnection process

Additional strategies to consider as load growth and associated risks increase over time

+ **Depending on pace, scale, and concentration of load growth, additional strategies should be considered to help manage risks**
  - On a systemwide level, this could include if the NYISO Gold Book "High" case seems to be materializing
  - On a utility level, this could include load growth exceeding a defined share of existing system demand and/or available grid headroom



Increase Speed/Frequency of Cost of Service Studies

Affordability | Cost Allocation Risk

- Infrequent and slow updates may cause cost shift depending on pace/scale of growth
- Monitor rate components expected to be impacted (e.g., transmission) closely

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BENCHMARKS
- Key finding from VA JLARC Study

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Incentivize Load Flexibility

Affordability Cost Allocation Risk

Reliability RA Risk, T&D Reliability

- Incentivize non-firm service (e.g., faster interconnection)
- Facilitate large load funded residential flexibility programs to create capacity & direct benefits

MAIN IMPLEMENTER
- Utilities

OTHER KEY STAKEHOLDERS
- Large loads fund
- NYSERDA and NYISO design and implement

BENCHMARKS
- SPP's CHILLS pathway
- PG&E-Google SHARE pilot, NJ Data Center Fair Share Act

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Require Load Flexibility

Affordability Cost Allocation Risk

Reliability RA Risk T&D Reliability

Require large loads to curtail during grid strain

MAIN IMPLEMENTER
- Utilities

OTHER KEY STAKEHOLDERS
- DPS develop guidance
- NYISO defines/coordinates during grid strain

BENCHMARKS
- Texas' Senate Bill 6 requires most new large loads to curtail in emergencies

Q&A and Discussion



Energy+Environmental Economics

Discussion Questions – Strategies



What are your thoughts on the proposed approach to strategy development?



Are there other strategies that should be considered?



Are there other signposts that should be monitored?