Bulk Power System Virtual Learning Modules:

Integrated Electricity Planning Trainings

This three-part trainings series will dive into key concepts of integrated planning, a holistic planning approach to develop affordable, reliable, and robust investment plans by integrating traditionally siloed processes.

***Open to NARUC, NASEO, NASUCA, NGA, NCSL, and NACAA Members**

Spring 2025 Sessions (all hosted virtually from 2:00 to 4:30 p.m. ET):

- **February 13: Integrated Electricity Planning for Different Types of Entities**
- **February 20: System Expansion Modeling: Considering Transmission and Distribution in Capacity Expansion Modeling**
- **March 6: Tools, Data and Processes for Integrated Planning**

Register Now

NARUC
National Association of Regulatory Utility Commissioners

ESIG
ENERGY SYSTEMS INTEGRATION GROUP

About NARUC

- Founded in 1889, the National Association of Regulatory Utility Commissioners (NARUC) is a non-profit organization dedicated to representing the state public service commissions who regulate the utilities that provide essential services such as energy, telecommunications, power, water, and transportation.
- NARUC's members include all 50 states, the District of Columbia, Puerto Rico, and the Virgin Islands.
- Our mission is to serve the public interest by improving the quality and effectiveness of public utility regulation.

About CPI

- 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 the U.S. Department of Energy (DOE) and the U.S. Department of Commerce's National Institute of Standards and Technology (NIST).
- NARUC CPI conducts work across five key energy areas and many topics within each: generation; transmission; distribution; customers; and critical infrastructure preparedness, response, and resilience.
- For more information, visit: https://www.naruc.org/cpi/

Bulk Power System Virtual Learning Modules

- Online series of bulk power system learning modules including topics like resource adequacy, system balancing, load forecasting, interconnection, and many more.
- These resources have been developed by NARUC, with support from the National Association of State Energy Officials (NASEO), the National Association of State Utility Consumer Advocates (NASUCA), and the U.S. Department of Energy. Other partners include Energy Systems Integration Group, Pacific Northwest National Lab, National Renewable Energy Lab, and Lawrence Berkeley National Lab.
- Learning modules website: https://www.naruc.org/core-sectors/electricity-energy/bulk-power-system/bulk-power-system-learning-modules/

Integrated Planning Module 2

System Expansion Modeling

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Matt Schuerger, Senior Fellow, ESIG

NARUC/NASEO/NASUCA Training

February 20, 2025

Energy Systems Integration Group (ESIG)

- ESIG is a member-driven organization that addresses technical challenges for transforming energy systems. We do this through collaboration, education and knowledge sharing.
- >250 members worldwide broadly focused on decarbonization and integration of energy systems
- Workshops, webinars, reports available freely on our website (https://www.esig.energy/) and on YouTube (@EnergySystemsIntegrationGroup). Join our mailing list!
- We create task forces to address topics such as multi-value transmission benefits or grid-forming technology or electrification and these task forces do analysis, run simulations, synthesize best practices, etc. **One of these task forces is on integrated planning!**

Integrated Planning Modules

- Focus is on generation, transmission, distribution and customer load/DERs.
- Not focusing on gas-electric coordination or hydrogen or other energy sectors beyond electrification of heating/transport.
- Schedule
  - Feb 13 – Integrated Planning for Different Types of Entities
  - Feb 20 – System Expansion Modeling: Considering transmission and distribution in capacity expansion modeling
  - Mar 6 – Tools, Data and Processes for Integrated Planning

Today’s speakers

System Expansion Modeling: Considering Transmission and Distribution in Capacity Expansion Modeling

- 2:05p – 2:45pm ET *Integrated System Planning: Opportunities and Challenges for Optimized Planning*
  - **Aaron Burdick**, Director, E3
- 2:45 – 3:25pm ET *New York’s Coordinated Grid Planning Process*
  - **Schuyler Matteson**, Clean Energy Planning Lead, Office of Markets and Innovation, NY Department of Public Service
- 3:25 – 4:05pm ET *Improving Energy Storage Modeling for Long Term Planning: EPRI’s Integrated Strategic Planning Initiative*
  - **Nidhi Santen**, Program/Area Manager, Integrated Energy Systems Planning, EPRI
- 4:05 – 4:30 pm ET Breakout rooms with each speaker
- 4:30pm ET Adjourn

THANK YOU

Matt Schuerger
matt@esig.energy

Integrated System Planning: Opportunities and Challenges for Optimized Planning Across Planning Domains

NARUC/NASEO/NASUCA ISP Training: Session Two

February 20, 2025

Energy+Environmental Economics

Aaron Burdick, Director

Integrated planning background

Energy+Environmental Economics

Motivations for Integrated System Planning

Many forces are driving high investment needs over the coming decades…

- Decarbonization of power system
- Industrial and data center load growth
- Electrification
- Aging infrastructure
- Wildfire risks
- Cybersecurity

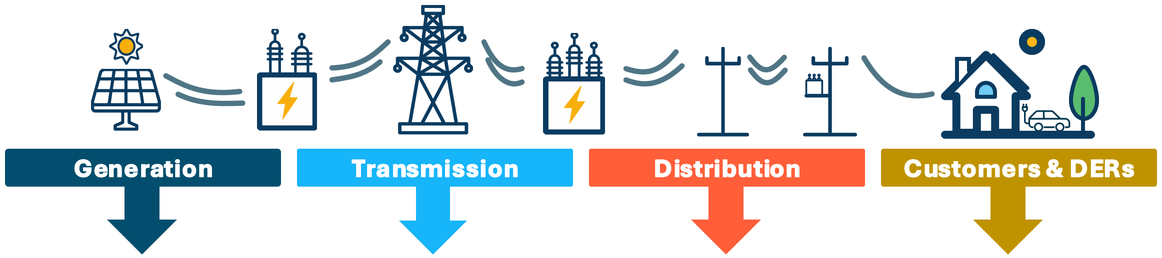
…this creates opportunities and challenges for meeting planning goals:

- Reliable
- Affordable
- Clean

Need to ensure that planning identifies

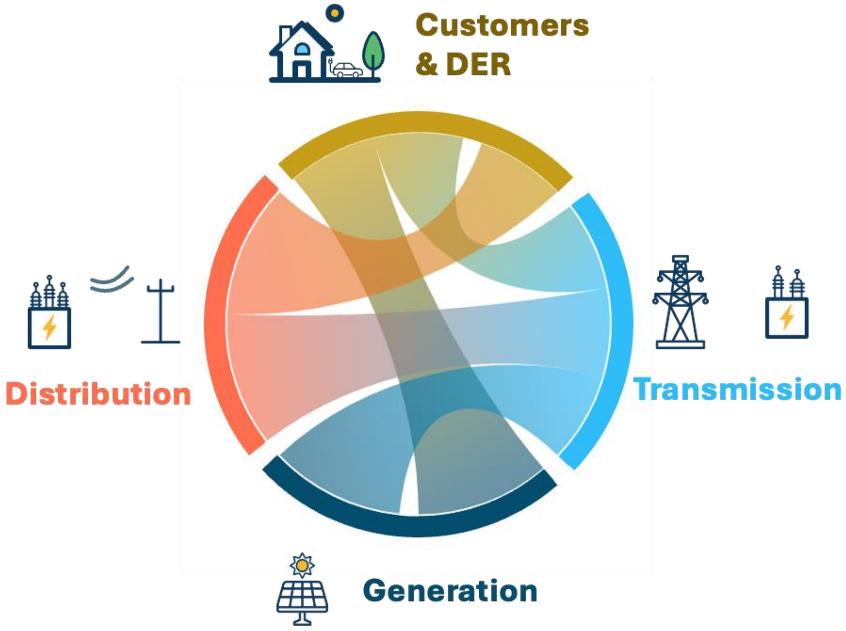
- the right investments…
- in the right locations…
- at the right times

What is integrated planning?



Traditional electricity planning has often been siloed

Siloed planning worked when investments in one planning domain had limited impact on other planning needs – this is no longer the case



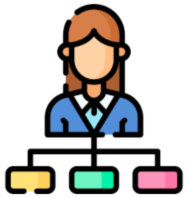
Integrated planning is a holistic energy system planning approach that links traditionally siloed planning processes to develop affordable, reliable, and robust investment plans.

Integrated planning may be coordinated across electric generation, transmission, distribution, and customer loads and distributed energy resources, and may also consider interactions between the electric system and other energy systems.

There are multiple aspects of moving towards integrated planning

Change management and process alignment

Policymakers + Regulators create policy and ensure prudent investments



Utility Leaders provide safe, reliable, affordable, and clean power; new asset approval + cost recovery

Stakeholders meaningfully participate in the planning process

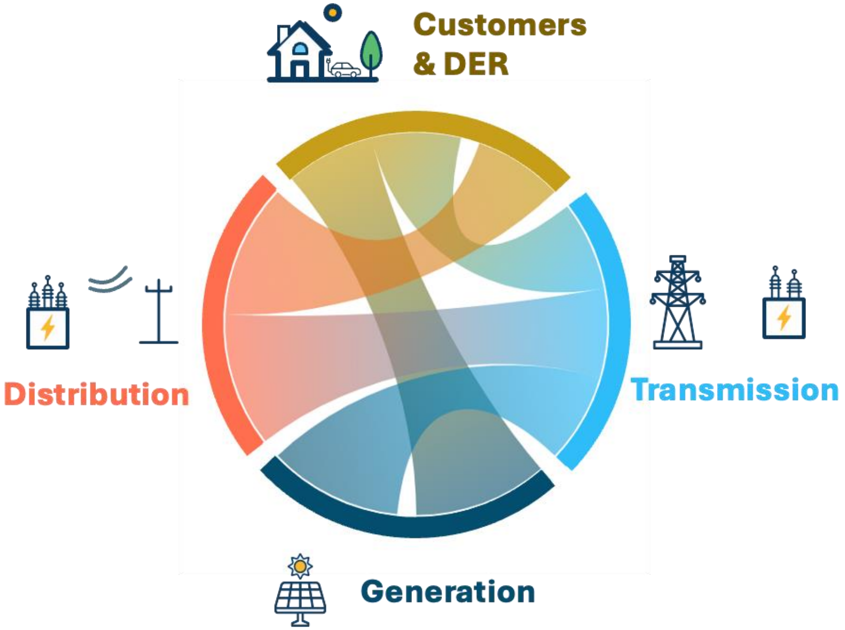
Economic Modelers optimize to ensure least-cost investment + operations

Grid Planning Engineers model grid physics to ensure reliable grid operations

Developers understand where and when their products provide value

Focus of today's presentation

Data and model integrations



- **Common inputs + scenarios**
- **Information flows b/t economic and grid physics models**
- **Co-optimization (when feasible)**

Integrated planning framework

Energy+Environmental Economics

Components of an integrated planning framework

1. **Integration of inputs**: align scenarios, input assumptions, and data as the foundation for integrated planning
2. **Integration of analysis**: use co-optimization and/or iterative processes to reach a holistic set of solutions that meet affordability, reliability, and policy goals
3. **Integration of actions**: use planning results to guide near-term investment actions
4. **Integration of decision-making**: align planning activities with business and regulatory decision-making processes

2. Integration of Analysis

Use co-optimization and/or iterative processes to reach a holistic set of solutions that meet affordability, reliability, and policy goals

+ **There is no "one-size-fits-all" analytical approach for integrated planning**
  • E.g., small island grid vs. RTO wide study, a vertically integrated utility vs planning across organizations in deregulated markets, etc.
+ **The key focus should be on implementing the necessary data linkages between planning models/decisions to ensure an integrated solution that meets all planning objectives**
  • Key data can be produced across the integrated planning process, including:
    – "Upstream" during input development (e.g., resource cost + potential)
    – "Midstream" during model handoffs (e.g., types and locations for generator additions)
    – "Downstream" during implementation (e.g., updated generator additions based on RFP bids)
+ **This may involve expanded use of optimization modeling or may instead focus on inter- or intra-cycle iterations**

Some "handoffs" may be endogenous if more data can be incorporated into economic optimization models

Electricity system planning integrations

1 Forecast system needs

Economywide Energy Systems

Scenarios of electric load growth, including transportation, building, and industrial electrification

- Load & DER Forecasts and Downscaling
- Resource Options Study

2 Identify system solutions

Distribution Studies

- Power flow + Reliability, Asset Health
- Non-wires alternative study

Transmission Studies

- Power Flow / Contingency Analysis, Stability, Reserve Needs
- Nodal Production Cost Modeling

Generation Studies

- Resource Adequacy Study
- Capacity Expansion Optimization
- Production Cost Modeling

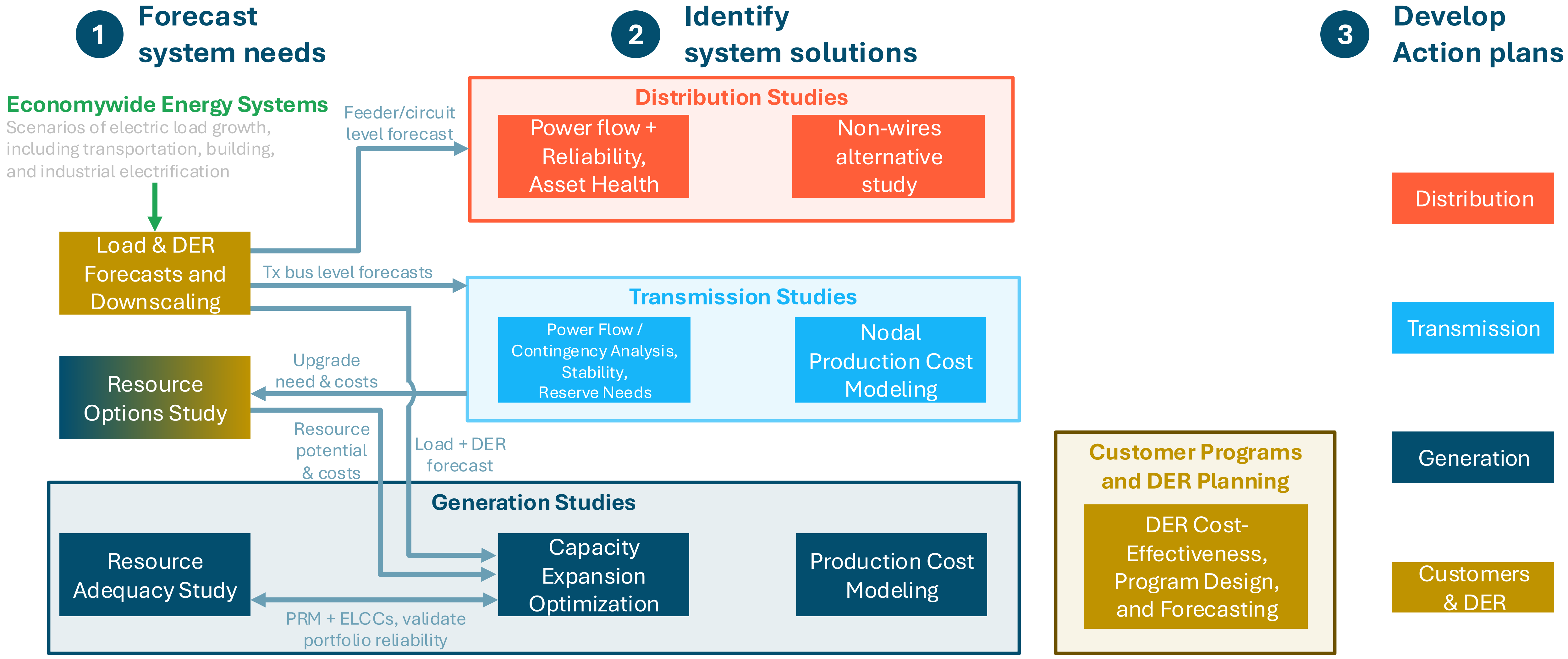
Customer Programs and DER Planning

- DER Cost-Effectiveness, Program Design, and Forecasting

3 Develop Action plans

- Distribution
- Transmission
- Generation
- Customers & DER

Electricity system planning integrations

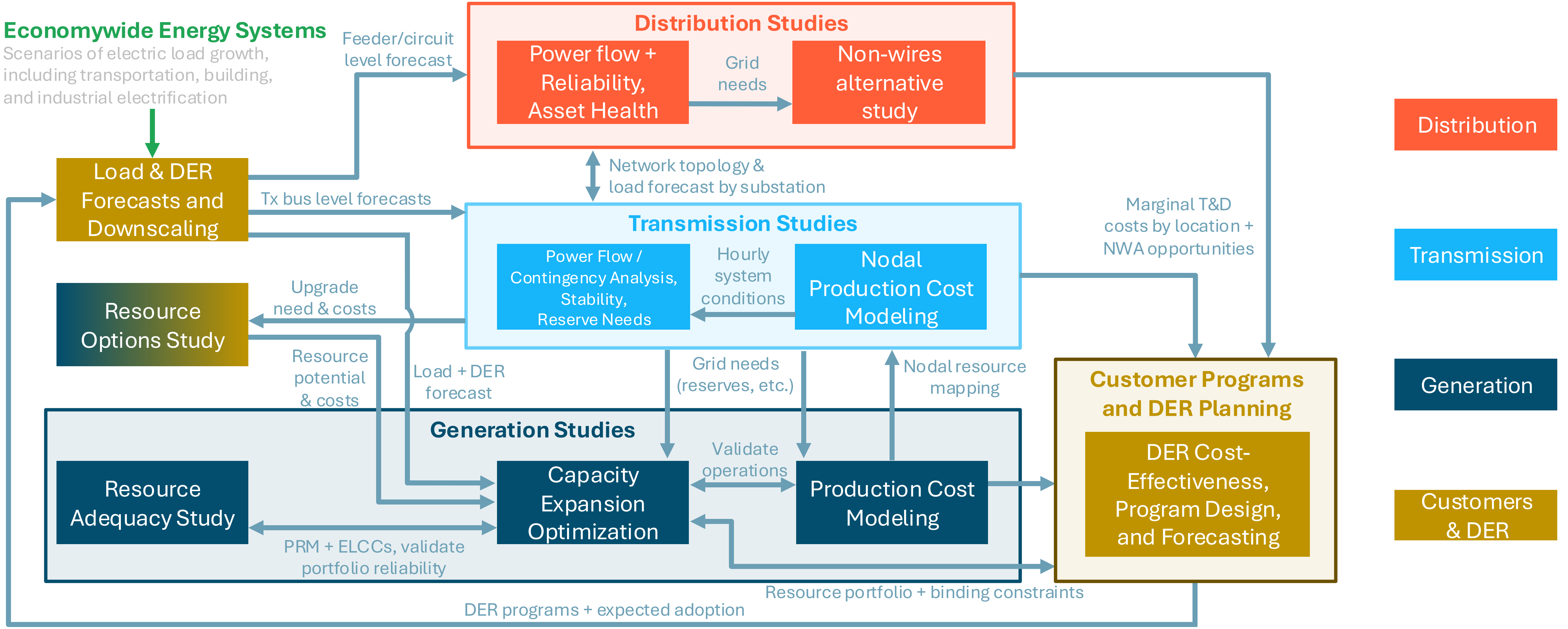


Electricity system planning integrations

1 **Forecast system needs**

2 **Identify system solutions**

3 **Develop Action plans**

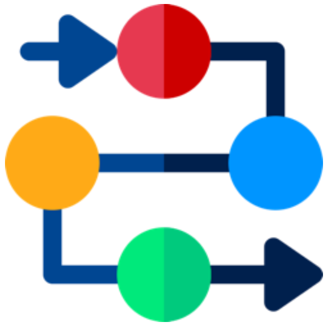


Integrated planning requires multiple modeling processes

Key challenge: how do we balance the complexity of interdependent parts of the system with the practical needs for modeling, decision making, and stakeholder engagement?

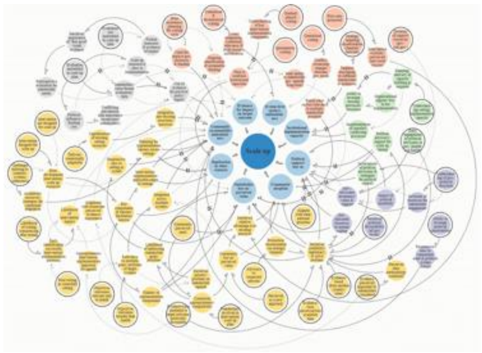
Multiple, coordinated modeling processes

Multiple modeling processes, if coordinated appropriately, can capture the interdependent nature of full system planning



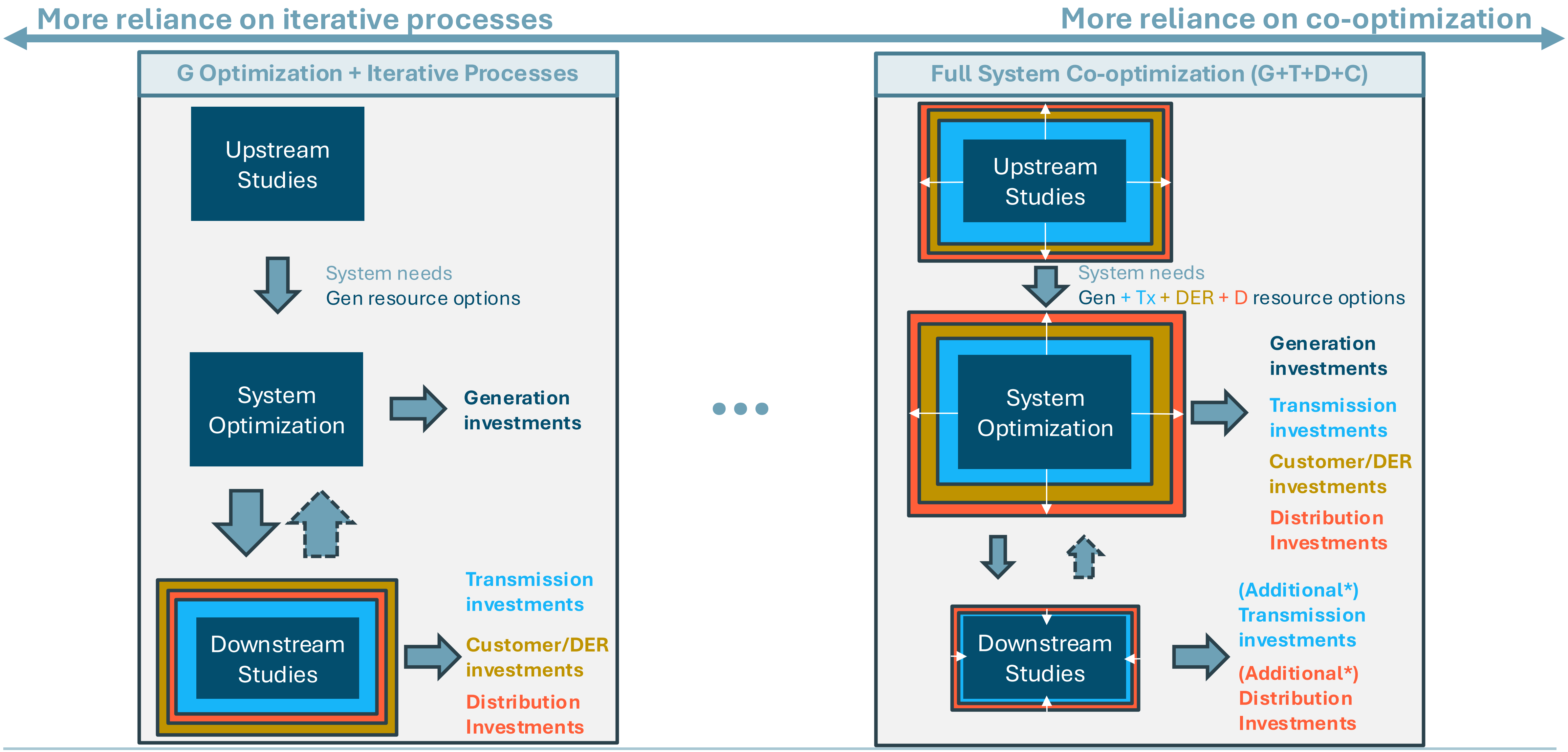
Single model that co-optimizes the full system

Such a model is not feasible for the foreseeable future due to data, modeling, and process constraints



Performing system planning across multiple models allows for tractability, increased transparency for stakeholders and decisionmakers, flexible planning processes with different requirements and timelines, etc.

Integrated planning can rely more heavily on iterative processes or more heavily on co-optimization

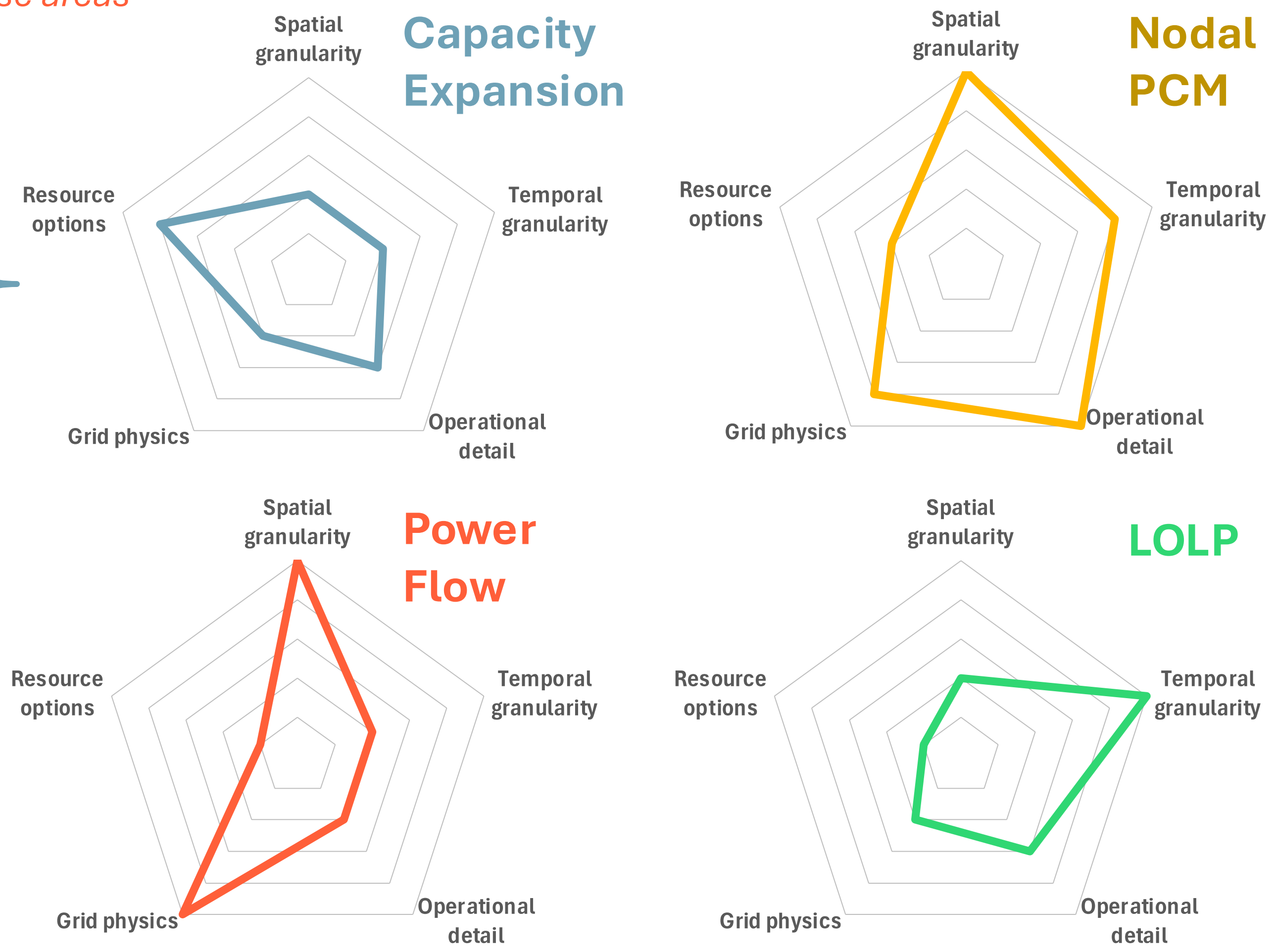


*The full set of T+D grid investments will need to be determined through more detailed and/or granular grid set of analyses (power flow, stability, protection, etc.) than can tractably fit into a system co-optimization.

Economic optimization in capacity expansion already requires key tradeoffs for computational tractability

Integrated planning will require expanding detail in these areas

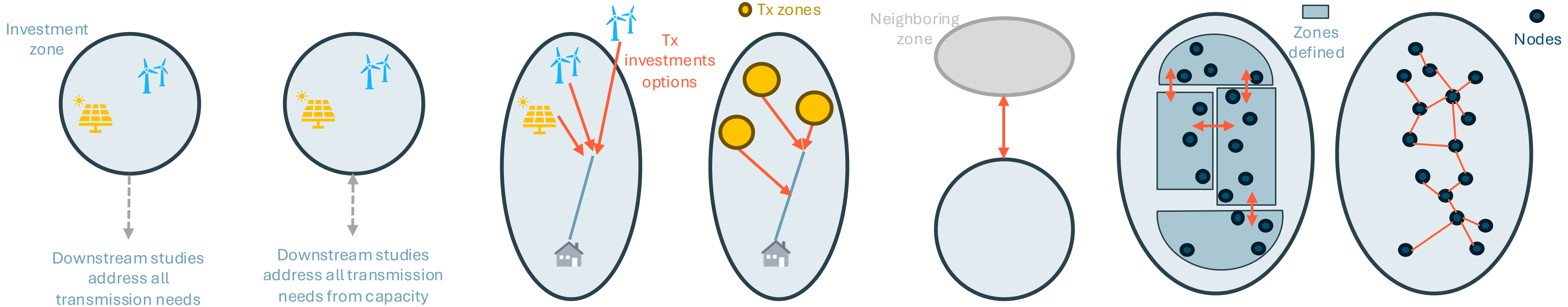
+ **Key tradeoffs in capacity expansion:**
  - **Spatial granularity**: typically zonal, nodal siting addressed in downstream models
  - **Temporal granularity**: representative days or weeks from broader datasets
  - **Operational detail**: approximations of economic dispatch
  - **Grid physics**: limited detail, simple zone-to-zone transfers limits
  - **Resource options**: multiple candidate resource technologies (some aggregation, often linear not integer variables)
+ **Key methods were developed to overcome these limitations:**
  - Linearized investment + economic dispatch
  - PRM + ELCCs
  - Day sampling methods
+ **Adding new decision variables + constraints for integrated planning will also involve consideration of key trade-offs**



G+T: Integration Options for Co-optimized Investment

Note: methods are not mutually exclusive. They can be combined within the same capacity expansion problem.

	No integration	Iteration	Resource or Tx zone limits		Hourly flow constraints (pipe + bubble representation)		
	One-way flow	G<>T Iterative Process	Resource specific constraints	Tx zones	Inter-zonal	Intra-zonal (aggregated nodes)	Nodal
Cap. Ex. Model Dispatch	Zonal	Zonal	Zonal	Zonal	Inter-zonal	Intra-zonal (aggregation of full network nodes)	Nodal
Cap. Ex. Model Tx Limits	None	None	Resource-level	Tx zone level (across resources)	Inter-zonal hourly flow	Intra-zonal hourly flow	Nodal hourly flow



Downstream studies address all transmission needs from capacity expansion resource additions

Downstream studies address all transmission needs from capacity expansion resource additions, but include feedbacks to adjust the generation mix (or siting) based on results

Resource level can vary from inter-connection to new tie-lines and are useful for connecting a single resource type

Tx zone level limits allow for diversity to maximize Tx utilization (e.g., adding solar, wind, storage together) and Tx studies for major RE zones

Allows for study of large-scale BA<>BA level upgrades, including impact on investment and production costs

Captures intra-zonal constraints but aggregates nodes to limit data needs and runtime impacts

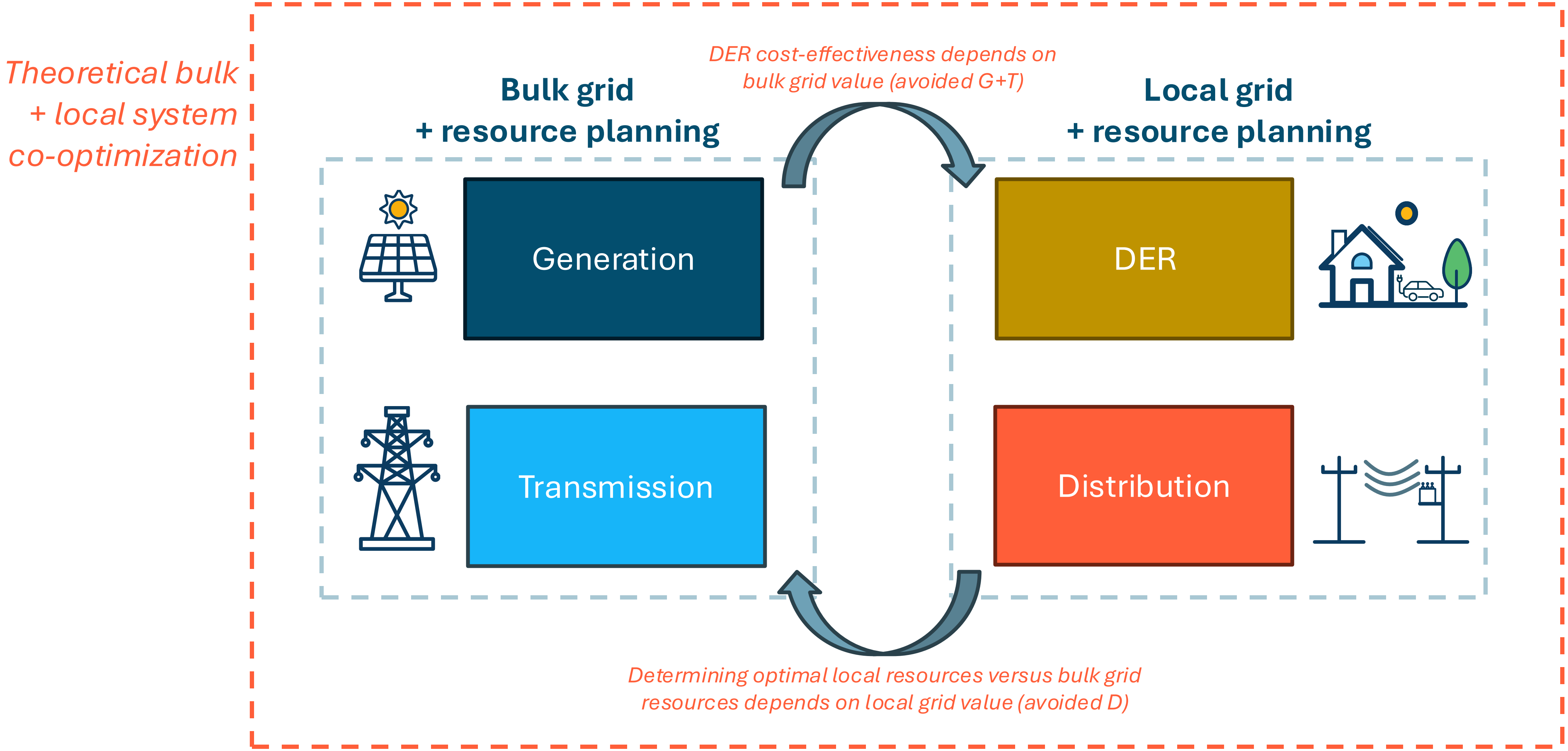
Captures full network model nodal level constraints; requires modeling nodal level dispatch, which vastly increases runtime

Limits of Economic Optimization for Transmission Planning

… and why some iteration will still be needed

- **Economic optimization can feasibly support co-optimization of generation and transmission, including identification of economic candidate transmission upgrades**
- **That solution still requires validation in more detailed "downstream" transmission models**
  - **Nodal PCM:** security constrained economic dispatch and DC power flow in full network model may surface addition economic upgrades to address congestion
  - **AC power flow**: captures a more robust view of power flow and impacts on thermal overloading, voltage, etc.
  - **Contingency analysis**: captures grid impacts of G or T outage events (N-1, N-2, etc.)
  - **Stability**: captures sub-second dynamic response during disturbance events
  - **Resource adequacy and resiliency analyses**: considers the RA or resilience value of transmission during extreme events
- **These "downstream" transmission analyses will lead to identification of additional transmission investments beyond those selected in capacity expansion**
  - They also can feedback back information to capacity expansion and/or production cost simulations to ensure consistency with transmission reliability (e.g., dispatch limits, inertia constraints, etc.)

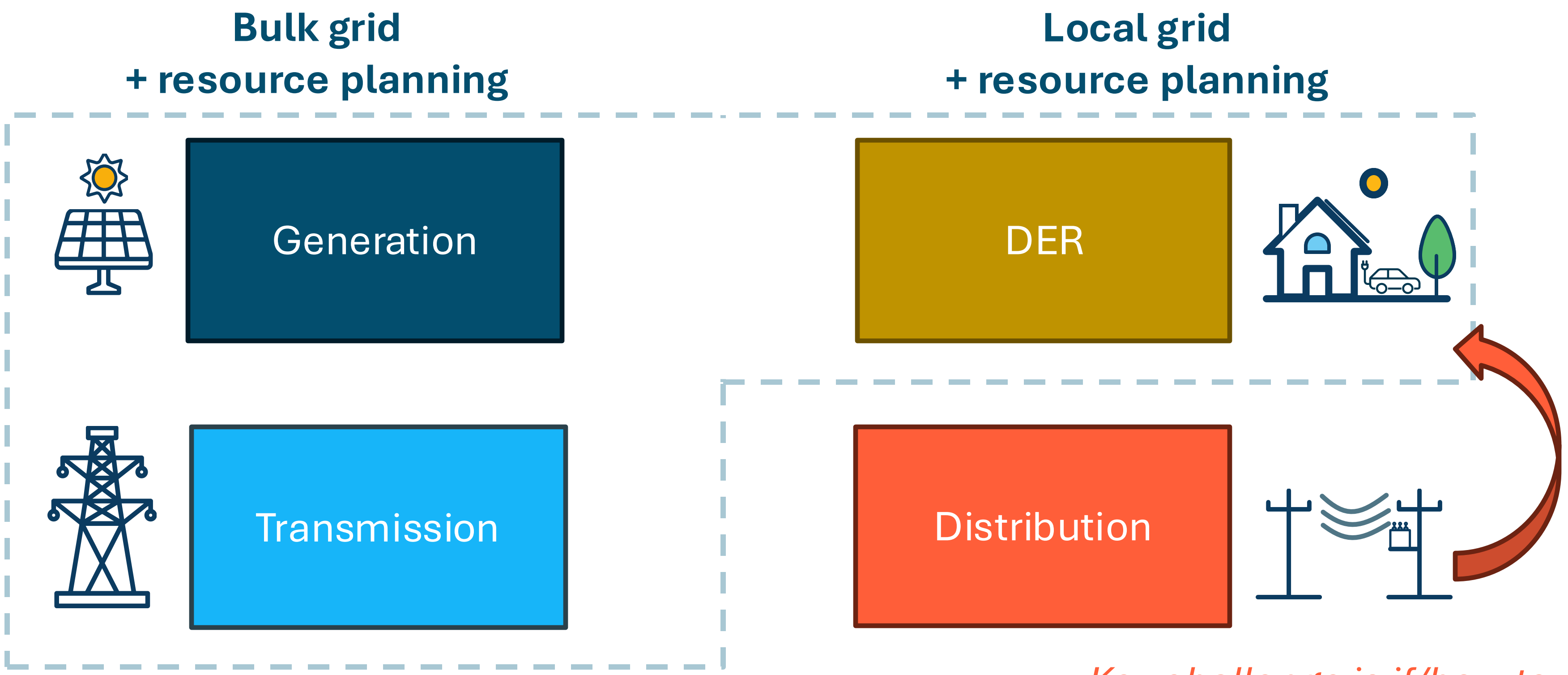
Determining optimal bulk grid versus local grid investments requires integrated planning



* See LBNL's work in this area: https://emp.lbl.gov/research-areas/integrated-distribution-system-2

G+T+DER co-optimization is feasible, but incorporating granular distribution level local values has been a major challenge

DERs can be (and have been) co-optimized against bulk grid G+T investments in capacity expansion



Key challenge is if/how to characterize the local grid value of DERs given the scale of the distribution system

* See LBNL's work in this area: https://emp.lbl.gov/research-areas/integrated-distribution-system-2

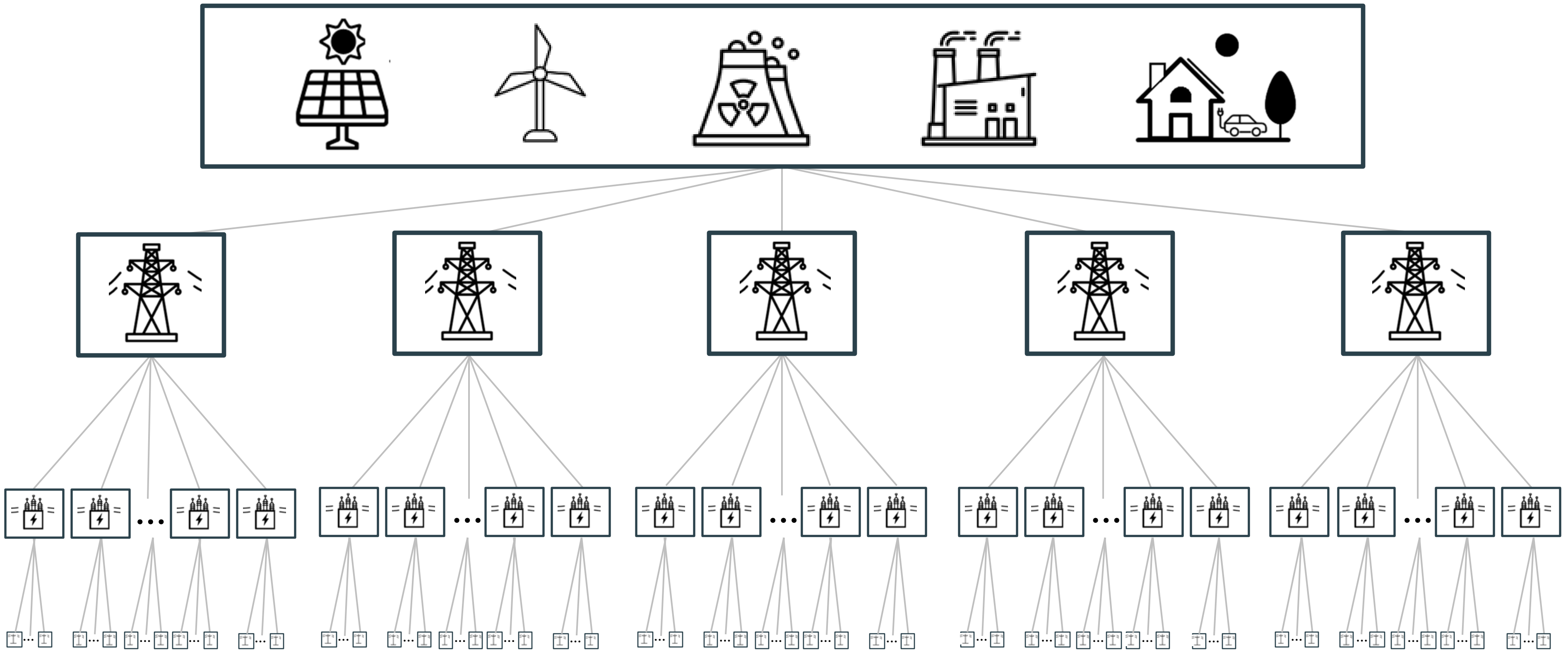
Incorporating local grid value is a challenge due to the scale of the distribution system

1 system

10s of
Tx zones

100s of
Dx substations

1000s of
Dx feeders



Diversified coincident peak load

Increasing spatial granularity

Individual connected non-coincident peak load

Key challenge: It is unlikely to be computationally tractable in a system-wide optimization to capture distribution level constraints and solutions (e.g., 1000s of candidate storage options)

While DERs can be optimized in capacity expansion, key considerations should be recognized

+ DERs can be optimized directly against supply side resources to determine bulk grid value

- **Sourcing mechanisms matter for appropriateness of co-optimization**: forecast adoption via tariffs vs. ability to optimize programs or targeted solicitations

- **Resource options need to be measured relative to a baseline**: DER and flexible load potential, cost, and system benefits should be measured relative to baseline load forecast

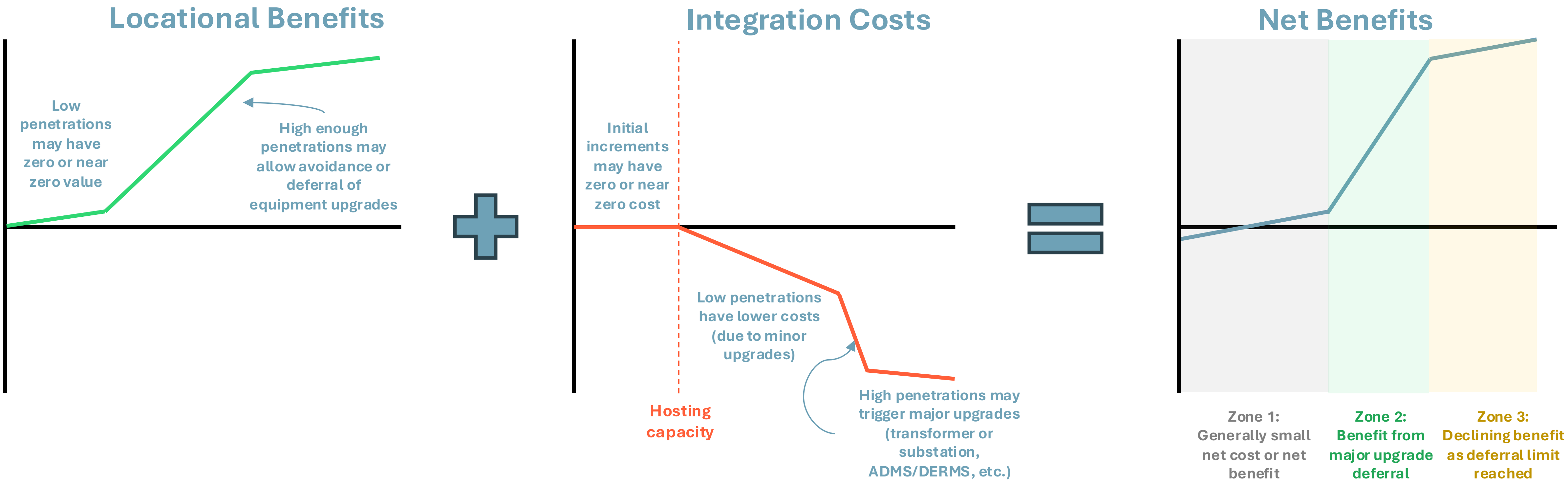
- **Least-cost optimization provides one perspective on DER cost-effectiveness**: measure vs. portfolio-level; societal cost impacts versus participant costs or ratepayer cost shift impacts

- **Locational costs + benefits are challenging to capture**: avoided transmission can be captured if co-optimization with bulk grid G+T; accurately capturing distribution costs and benefits poses tractability challenges

Locational net benefits can be high for certain resources in certain locations but are quite challenging to capture

+ What is the locational value of DERs and flexible loads?

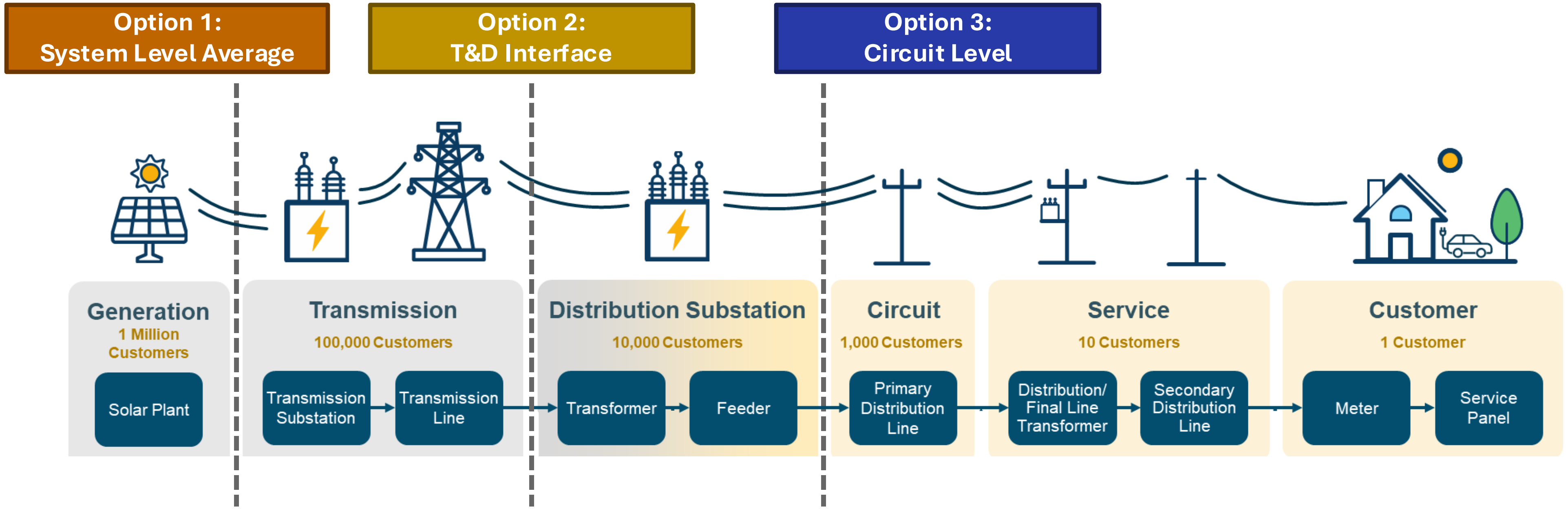
- Locational grid benefits (avoided or deferred capital spend on substations or other upgrades)
- Grid integration costs (replacing protection equipment, transformer/substation upgrades, operational controls, etc.)



Key challenges: A) each DER has a different cost curve on each distribution circuit, B) combinations of DERs + evolving load shapes will have interactive effects, and C) deferral opportunities are time dependent (DERs must be operational before planned wires upgrade)

Integration cost curve adapted from NREL, Paul Denholm, "Overview of NREL's Approach to Integrating Distribution-Sited Resources in the LA100 Study", ESIG Integrated Planning Workshop, October 21, 2024

Locational Value: Spatial Granularity Tradeoffs



Low granularity
Highly imprecise measure of locational value
Computationally tractable

(e.g., "peanut buttering" of average distribution values)

Medium granularity
Imprecise measure of locational value
May be computationally tractable

(e.g., T&D interface L/R dispatch or distribution planning area parameterized locational supply curve)

High granularity
Precise measure of locational value
Computationally intractable

(e.g., circuit level L/R dispatch or parameterized locational supply curve)

Avoided Cost Alternative Approach

Marginal avoided costs for DER program cost-effectiveness, forecasting, and tariff design

Forecasted Loads and DERs

Capacity Expansion
- Generation
- Transmission
- Optimized DER*

Resource portfolio → **Production Cost Modeling** → Hourly avoided energy + A/S

RA capacity value

Policy value (RPS, GHG reduction, etc.)

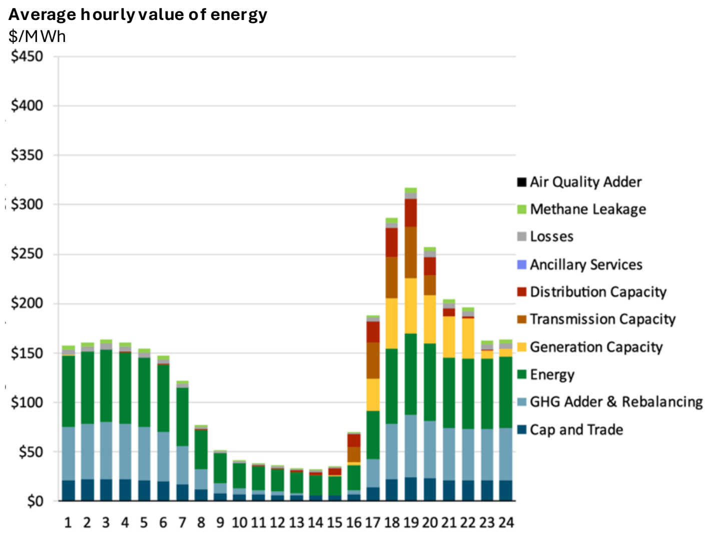
Transmission
- Nodal PCM
- Power flow / stability

Avoided Tx value (avoidable investments, time periods, marginal costs)

Distribution
- Power flow / reliability
- Non-wires alternatives

Avoided Dx value (avoidable investments, time periods, marginal costs)

Hourly Avoided Costs



DER Cost-Effectiveness + Adoption Models
- EE Cost-Effective Portfolio Goals
- DG Adoption
- DR + flex load programs

Note: this process allows for creation of granular locational avoided costs and/or targeted NWA opportunities. Multiple sourcing methods may be used to capture these values depending on the location and nature of the need (locational programs, solicitations, direct build, etc.). To the extent those values will be sought out via sourcing of additional DERs, those additional resources can then be fed back into the forecast for G/T/D planning processes to assess residual needs.

* Incremental DERs can still be optimized above forecasted DERs if desired

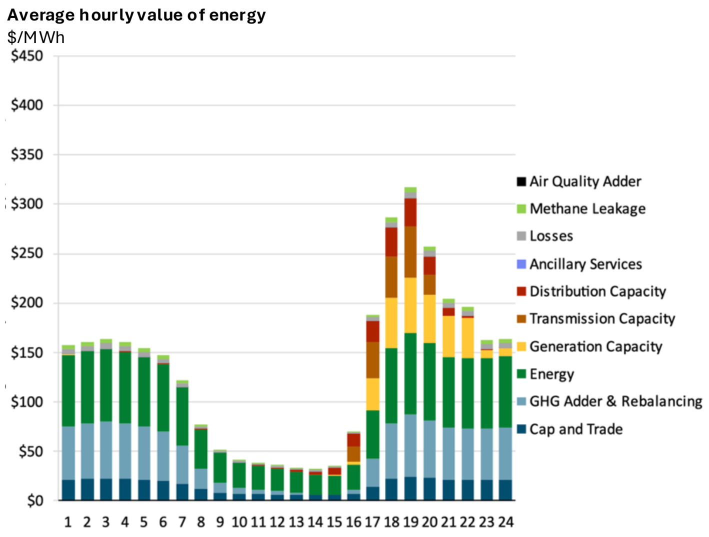
Avoided Cost Alternative Approach

Use economic optimization within integrated D+DER models, informed by bulk grid avoided costs

+ **Instead of using local values to inform a larger full system co-optimization, bulk grid values can be used as inputs into more targeted integrated distribution system planning models**
  - IDSP models can consider optimized DER investment and operations (versus traditional grid investments), considering only DER costs incremental to their bulk grid value

Bulk grid + resource planning

(Bulk Grid) Hourly Avoided Costs

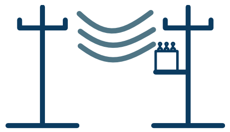


Bulk grid value + performance requirements (RA, etc.) →

Local grid + resource planning

DER

Distribution



Substation or feeder level economic optimization

D-grid investments vs. incremental DER investment/operational changes

Summary conclusions for incorporating T/D/C into generation capacity expansion optimization

+ **Transmission can and generally should be integrated into generation planning capacity expansion**
  - Tradeoffs regarding spatial granularity and model runtime
  - Continued need for downstream studies
+ **Distribution investment decisions are not necessary (nor feasible) to integrate with capacity expansion**
  - Intractable spatial granularity for 1000's of individual circuits
  - Distribution studies can identify local costs and benefits for DERs… but there are no existing methods to parameterize this (with full locational detail) into systemwide capacity expansion
+ **Customer-DERs and flexible loads can be integrated into capacity expansion, but require key considerations in doing so**
  - What DERs to forecast vs. optimize, how to measure cost-effectiveness, and how much local value can tractably be included
  - Hourly avoided costs for DER cost-effectiveness are a tractable alternative method to co-optimization

Getting started

Key steps to create an integrated planning process

Walk

- Determine integrated planning objectives
- Perform a gap assessment for existing planning processes
- Align key inputs and develop integrated scenarios
- Better connect existing analytical processes

Jog

- Adapt stakeholder engagement plans to support an integrated planning process
- Consider organizational re-alignment and/or formalized agreements between planning organizations
- Consider new opportunities for co-optimization or co-simulation methods across planning domains

Run

- Develop new analytical methods and tools to facilitate planning integrations

Lots of "low hanging fruit" before you get to system co-optimization

Forthcoming ESIG Integrated Planning Whitepapers

ENERGY SYSTEMS INTEGRATION GROUP

ESIG has organized an Integrated Planning task force, focused on drafting the following whitepapers by spring 2025:

1. **Foundations of Integrated Planning:** core components of an integrated planning framework
   - Defines integrated planning
   - Describes components of an integrated planning framework
     - 1) Integration of inputs, 2) integration of analysis, 3) integration of outputs, 4) integration into decision making processes

2. **Integrated Planning Guidebook:** practical recommendations for today's planners to increase integration across domains
   - Practical recommendations for: customer/DER planner, distribution planner, transmission planner, generation planner, planning organization leadership
   - Presents a walk/jog/run approach for increasing integration

3. **Optimization for Integrated Planning:** opportunities and limits to use optimization for integrated planning
   - Existing practices for generation capacity expansion
   - Theoretical full system co-optimization: problem formulation (new data, constraints, etc.), benefits and challenges
   - Practical alternatives to endogenous co-optimization and practical steps for planners performing co-optimization

encoord

Department of Public Service

New York's Coordinated Grid Planning Process

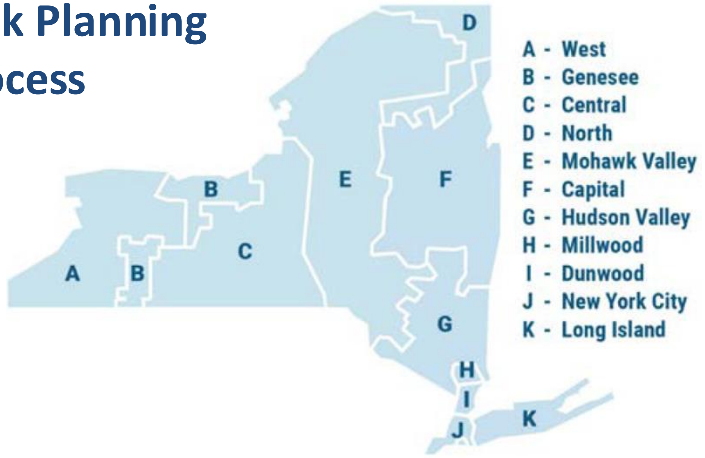
February 20, 2025

Background

- Climate Act – 100% zero carbon electricity by 2040
- Accelerated Renewables Act
  - directs PSC and the JU to identify bulk, local transmission, and distribution system upgrades needed to meet CLCPA
  - requires JU to have plans in place for these investments
- New requirement to plan for the 20-year time horizon
- May 2020 order directed JU to propose changes to existing planning processes that would identify necessary upgrades for the long term
- 20-E-0197

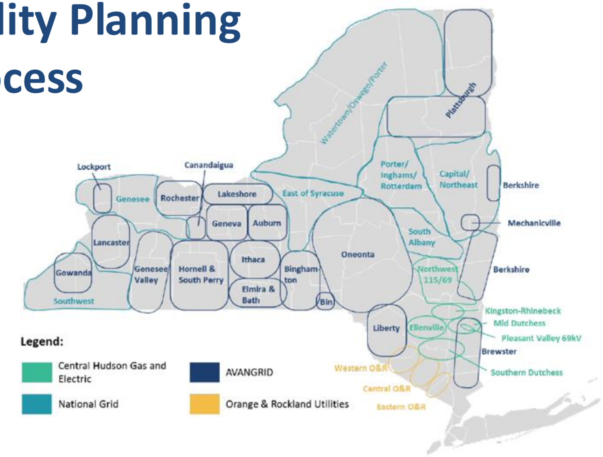
Bulk versus local transmission upgrades

Bulk Planning Process



- Congestion between 11 New York Control Area Load Zones = Bulk Need
- Solutions identified w/competitive solicitation

Utility Planning Process



- 37 Local Transmission Areas Upstate in PGS
- Solutions that move renewables onto or from bulk system

CGPP should identify optimal mix of local & bulk T&D upgrades, including advanced tech.

NEW YORK STATE OF OPPORTUNITY. | Department of Public Service

Key Elements of the Process

- Energy Policy Planning Advisory Council (EPPAC) – stakeholder advisory group, unprecedented coordination with external parties
- Repeating study on a 3-year cycle
- Several stages of work
  - Stage 1 – collect data, develop **capacity expansion model**, select three scenarios for analysis, produce initial capacity expansion results
  - Stage 2 – build power flow and short circuit models
  - Stage 3 – local area studies and solutions development
  - Stage 4 – scrutinize solutions to identify interactions and conflicts
  - Stage 5 – least cost assessment, with limits and local transmission upgrades added to the capacity expansion model
  - Stage 6 – least cost plan report, including recommendations for cost effective investment

Capacity Expansion Modeling Overview

- Most important part of the process
  - Determines the resource mix and likely grid needs for the rest of the planning process
- Philosophy: Realism
  - More constraints vs. less, minimize post-processing
- Utilizing PLEXOS, run by NYISO

Capacity Expansion Model Inputs

- Load Forecast – *NYSERDA*, VERY important
- Existing generation mix - *NYISO*
  - Type, costs, age, operational parameters, etc.
- New Generator Information - *NYSERDA*
  - type, capital cost, fixed and variable cost, availability, timelines, operational parameters, etc.
- DER and load flexibility forecast - *NYSERDA*
- System representation – *NYISO/JU*
  - Headroom, transmission limits, external territories

Unique Inputs

- Renewable resource Supply Curve and build limits/rate
  - Location, cost, MWs of LBW, PV, OSW
- Headroom
  - Intra-zone MW availability
  - $/kW cost to increase (15% multiplier per GW)
- Hydrogen production
  - Both in load forecast and optimized for power use
- Flexible Loads
  - ~3 GW of loads assumed to be shiftable by up to 12 hours (mostly managed charging)

Capacity Expansion Outputs

- Optimized:
  - Mix of generation resources by zone
  - Operation of storage, flexible resources, and electrolysis
  - Additional headroom requirements
- Requiring Iteration:
  - DER mix, quantity, location
  - Bulk interface increases

Modeling Wish List

- More Production Cost and reliability modeling
  - Want to make sure build mix is sufficient for real-world dispatch and extreme events
- Bulk transfer limit optimization
  - Currently need sensitivities to test relaxation of interfaces, may be other capabilities to unlock in PLEXOS
- Co-optimization of distribution resources
  - DERs are input, not candidate resources (though some nuance here since model doesn't know local T from D and utilities have leeway in their siting methodology)
  - Would require a lot more data and orders of magnitude more computing resources
- Full chronology, in as many hours as possible
  - "Representative days" limits storage value/accuracy and LDES
  - Must choose starting SoC, and no inter-day optimization, may be other capabilities to unlock in PLEXOS

Please reach out with questions!

Schuyler Matteson

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Improving Storage Modeling for Long-Term Planning

Insights from EPRI's Integrated Strategic Planning Initiative and Related Research Activities

Nidhi Santen, Ph.D., Program/Area Manager (nsanten@epri.com)
Karen Tapia-Ahumada, Ph.D., Senior Technical Leader
Silas Swanson, Research Staff
Energy Systems and Climate Analysis Group

February 20, 2025
NARUC/NASEO/NASUCA Integrated Planning Training: System Expansion Modeling

ABOUT US

Nonprofit
Founded in 1972 and chartered to serve the public benefit, with guidance from an independent advisory council.

Thought Leadership
Systematically and imaginatively looking ahead to identify issues, technology gaps, and broader needs that can be addressed by the electricity sector.

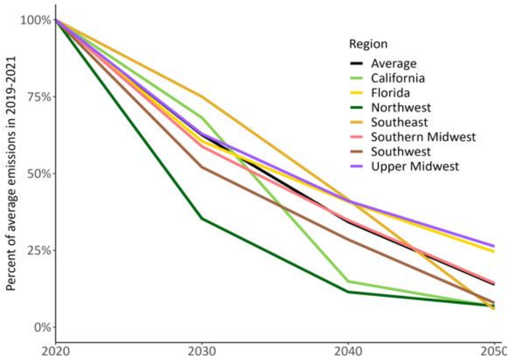
Independent
Objective, scientific research leading to progress in reliability, efficiency, affordability, health, safety, and the environment.

Scientific and Industry Expertise
Provide expertise in technical disciplines that bring answers and solutions to electricity generation, transmission, distribution, and end use.

Collaborative Value
Bring together our members and diverse scientific and technical sectors to shape and drive research and development in the electricity sector.

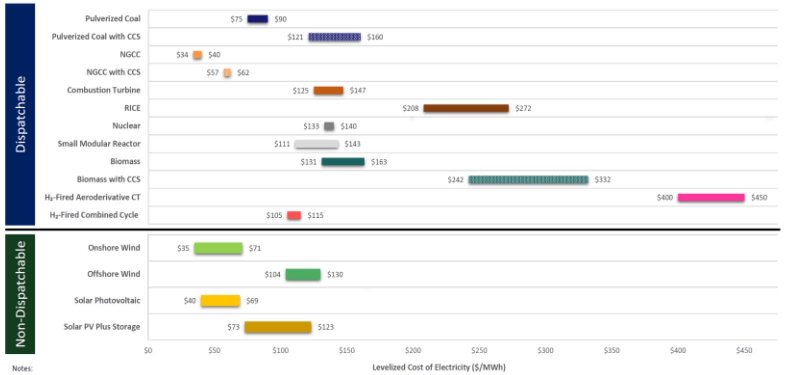
Today's Electric System Resource Planning Challenge:
A Precarious Balancing Act

Net-Zero CO_2 Transition



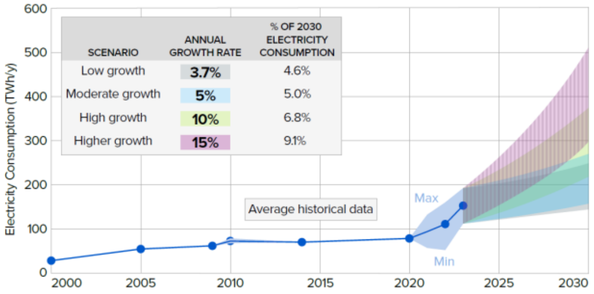
CO_2 targets by U.S. region based on a sample of recent 110 IRPs (EPRI [State of Resource Planning] Report, December 2023)

Future Technology, Policy, & Market Uncertainty



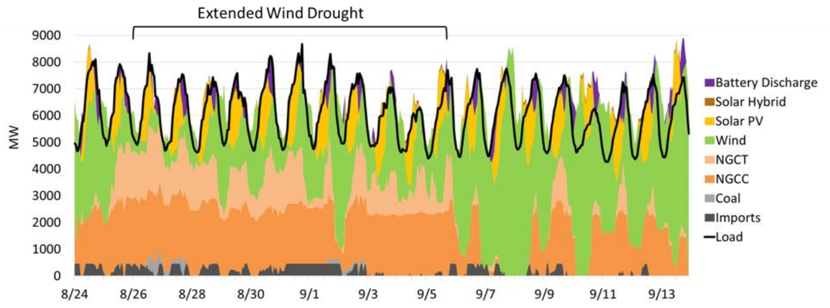
Estimated Range for 2035 LCOEs by Technology Category (EPRI [Generation Technology Options] Report, July 2024)

Unprecedented Load Growth



Projected U.S. data center load growth through 2030 (EPRI [Powering Intelligence] Report, May 2024)

Climate Resilience & Extreme Events



A 2035 planning scenario showing system-specific future wind droughts (P178 [Planning for Dark Doldrums] Report, March 2024)

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EPRI's Resource Planning 2025 Research Areas

Energy Transition
Develop tools and methods for net-zero and energy transition planning, and existing asset management decisions

Scenario Development
Provide independent, region-specific generation and storage technology cost & performance inputs

Portfolio Optimization
Develop and support long-term resource portfolio optimization methods to integrate G/T/D/load resources

Undertaking comprehensive research to assist members effectively address present and future challenges in long-term resource planning

Technology Readiness
Provide market outlooks and technology readiness for key energy transition technologies (e.g., advanced nuclear, CCS, energy storage)

Planning under Uncertainty
Provide scalable processes and open-source methods for portfolio planning under policy, technology, and market uncertainties

Extreme Event Planning
Provide methods to identify resource portfolios robust to future climate, weather, and potential extreme events

Key Resource Planning & Storage Modeling Efforts

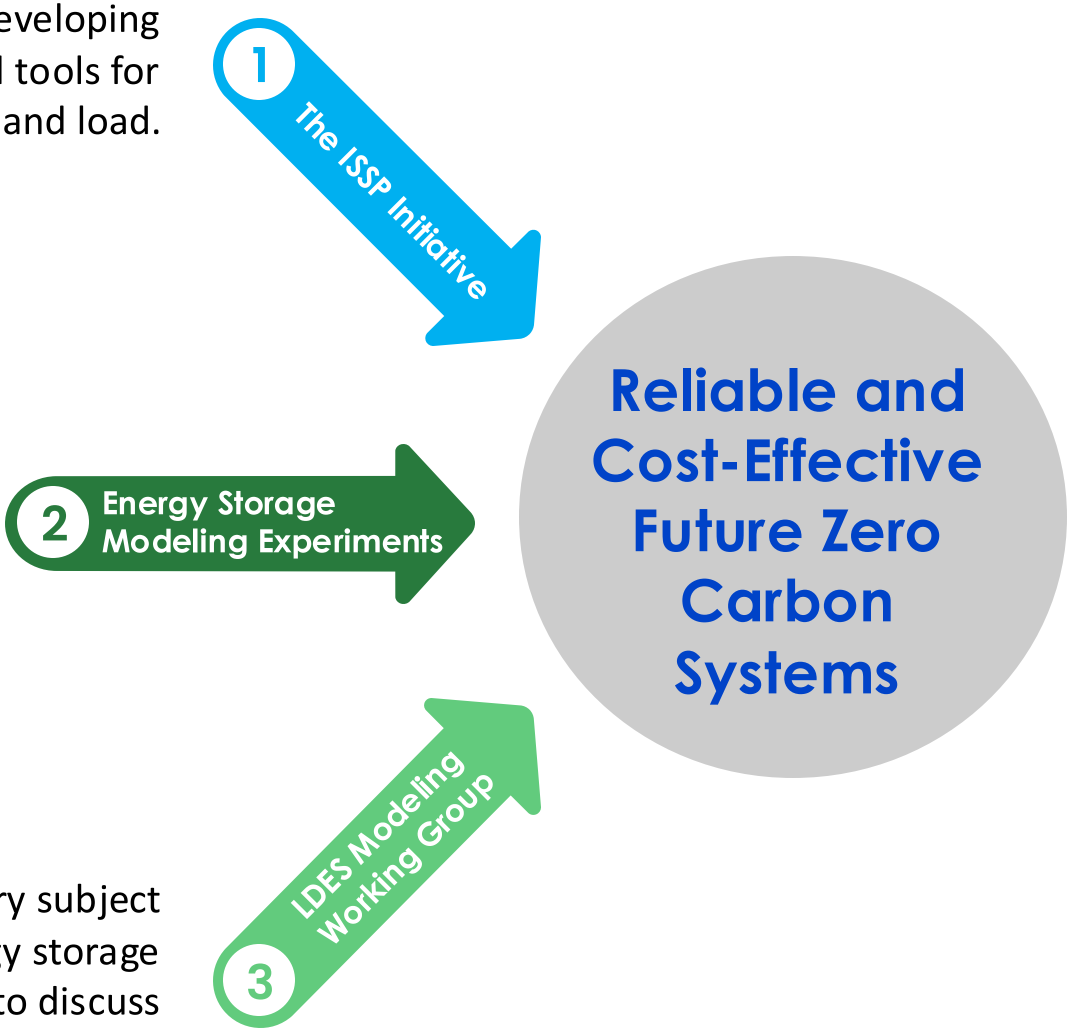
Motivation

To help improve methods for incorporating energy storage in the long-term system planning of high-renewable, zero carbon energy systems

EPRI's research hub for developing seamless frameworks and tools for planning across G/T/D and load.

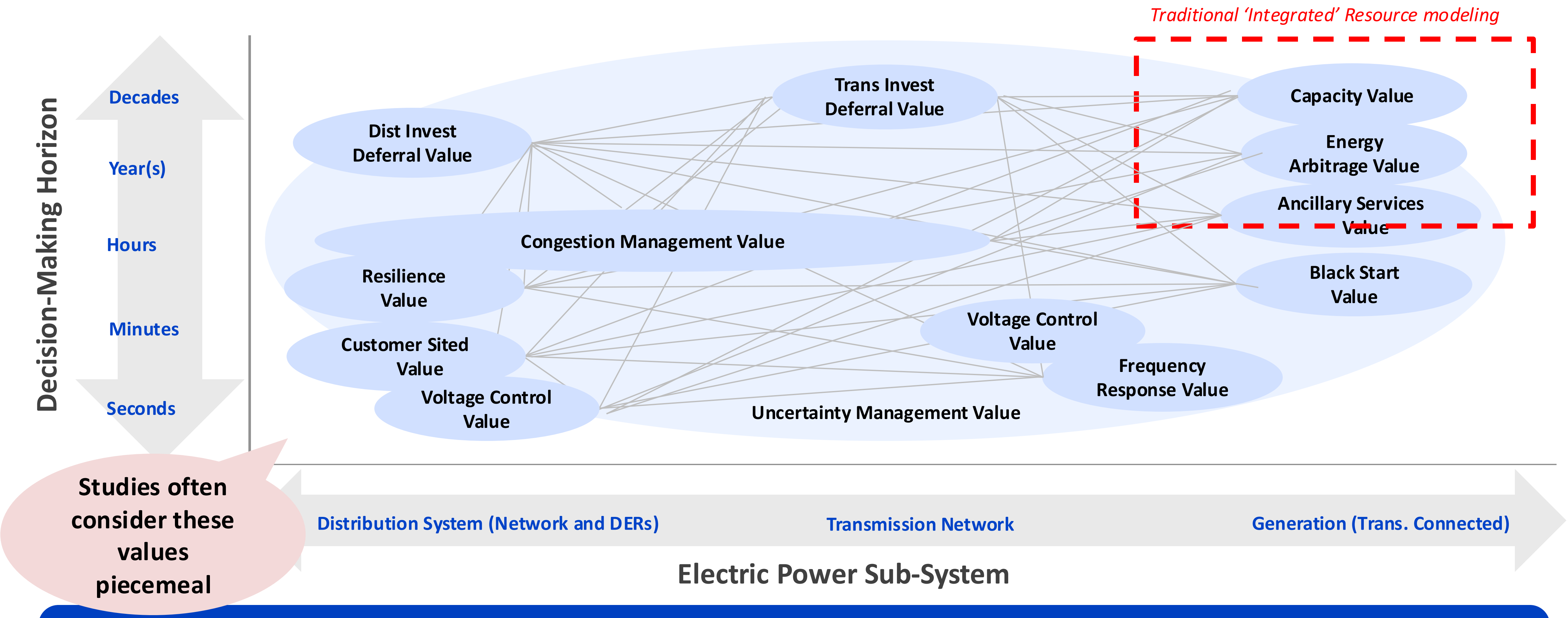
Ongoing foundational research examining the features of models and modeling choices that affect energy storage planning choices.

A collaborative forum of industry subject matter experts in energy storage technology and modeling to discuss challenges and best-practices.



The Integrated Strategic System Planning (ISSP) Initiative

Illustration: The Value of Energy Storage—A 'Simple' Question?

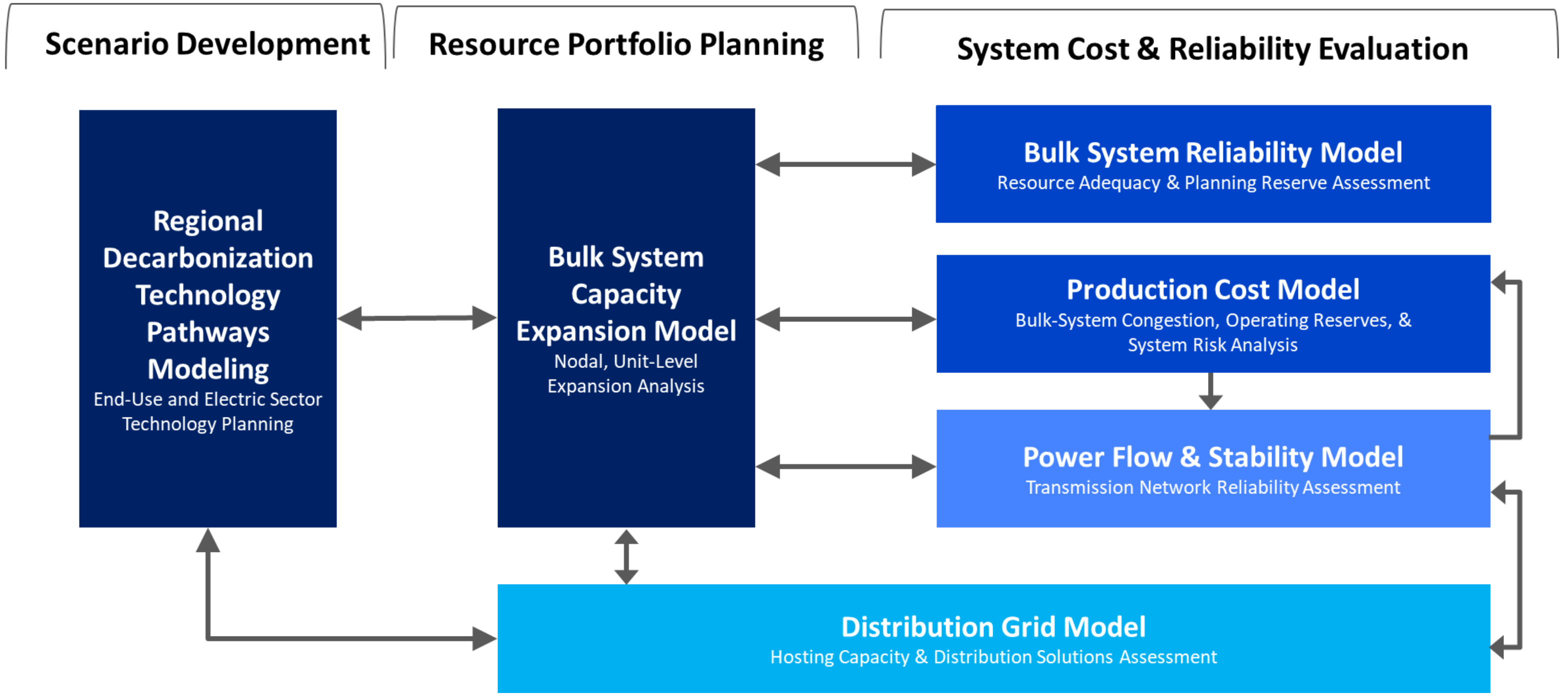


Inter-dependent values in advanced energy systems require a more integrated energy systems planning approach

Integrated Energy Systems Planning Framework & Toolbox

EPRI's Integrated Strategic System Planning (ISSP) Initiative developed a resource planning framework and supporting analytical toolbox. Using a series of soft-linked existing power system modeling tools, the framework is generalizable and may be used for more comprehensively planning reliable, low-carbon future resource portfolios across electric power system supply, delivery, and end-use.
www.epri.com/issp

*Using a coordinated modeling framework for holistic planning highlighted that **current planning paradigms may be insufficient to fully assess the level and type of storage high renewable & zero carbon systems need.***



One Toolbox* & a Range of Coordinated Modeling Tools

Model Type	Tool	Primary Objective(s) in ISSP Demonstration Study	Generation Scope	Transmission Scope	Distribution & DER Scope	Temporal Resolution
Regional Technology Pathways Model	US-REGEN	Regional End-Use and Electric Sector Technology Planning	Aggregate resources	Zonal "pipe and bubble network"	Aggregated end-use technologies & DERs explicitly modeled	120 representative time slices per year
Power System Capacity Expansion Planning Tool	PLEXOS	System-specific G&T Expansion Analysis	Individual existing and new generators	Nodal	End-Use & DERs modeled via load adjustments	48 time slices per year, using statistical fitting to the load duration curve
System Reliability Assessment Tool	PLEXOS	Resource Adequacy & Planning Reserve Assessment	Individual existing and new generators	Zonal	End-Use & DERs modeled via load adjustments	1 year, 8760 hours
Production Costing Tool	PLEXOS + EPRI Scheduling & Dispatch Tool	Bulk-System Network Congestion, Operating Reserve, & System Risk Analysis	Individual existing and new generators	Nodal	End-Use & DERs modeled via load adjustments	1 year, 8760 hours & snapshots
Power Flow Model	PSS®E	Transmission Network Reliability Assessment	Individual existing and new generators	Nodal	DERs modeled via load adjustments	1 year, snapshots
Distribution Grid Model	EPRI DRIVE	Hosting Capacity & Distribution Solutions Assessment	No bulk-system	124 feeders 11 substations	End-use technologies and DERs explicitly modeled	1 year, 8760 hours

* This toolbox shows specific named tools used for the ISSP demonstration study; the actual ISSP framework is tool agnostic and can accommodate many different available named tools within each of the overall model types

Overview of the ISSP New York Demonstration Study

Goals

- **To provide a demonstration of the process** to link resource planning and grid operations simulation tools for integrated planning of supply, delivery, and end-use systems.
- **To deliver insights for reproducing and implementing the ISSP framework** at electric utilities and other entities engaged in planning
- **To identify knowledge gaps and ongoing planning challenges** for future research

Framing Research Questions

- What mix of supply, delivery, and demand-side resources can support NY cost-effectively meeting a nation-wide zero-CO_2 electric sector target by 2035?
- Can a more reliable and/or cost-effective portfolio be identified by using an integrated planning approach?
- How do these results compare to BAU?

Research Outputs

- Project technical reports, slide decks, and webcasts
- Python script packages for automating data transfer processes between models
- PCM-Power Flow model data transfer tool

Limitations

- Does not aim to develop quantitative results for policymaking or planning in NY
- Does not co-optimize planning across G, T, D & end-use (leverages existing tools)

NY Demonstration Study Scenarios

Assumptions	Reference	Decarbonization + Accelerated Electrification
	"Business-as-usual" with no additional decarbonization technology or policy drivers	Rapid U.S.-wide decarbonization, driven by policy and high electrification

Environmental and CO_2 Policies	All major "on the books" federal, regional, and state environmental and climate policies
	• Includes New York's SB6599 (CLCPA)
		Reference, plus
		• U.S. electric sector is zero carbon by 2035
		  • No negative emissions or offsets permitted
		  • Interim 80% carbon-free by 2030 target
		• U.S.-wide carbon pricing over the rest of the economy, consistent with a U.S. 50x2030 goal

Technology	Default EPRI inputs for technology cost and performance	Reference, plus • Faster diffusion of electrified consumer technologies: • Accelerated heat pump adoption • Accelerated turnover of existing end-use equipment • Lower cost and higher performance electric vehicles and heat pumps

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Regional Technology Pathway Modeling Objectives

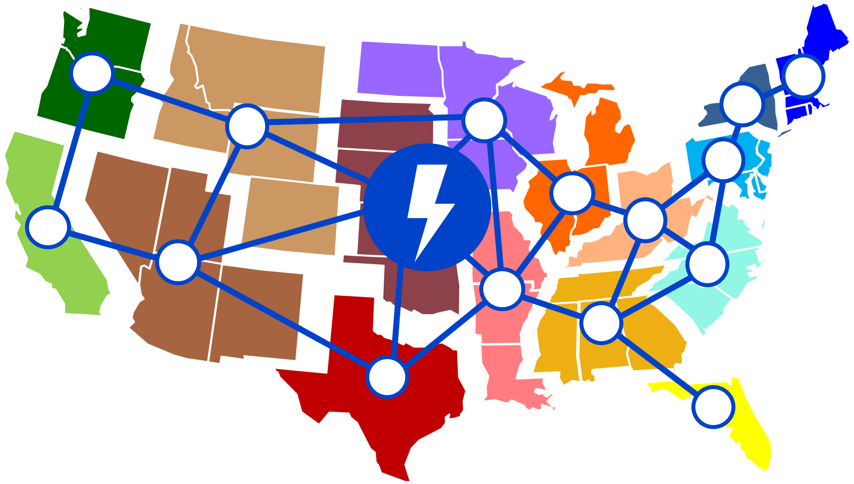
- Optimal decarbonization portfolios should consider potential impacts of multi-state markets, environmental credit trading, neighboring high-renewable systems, electrification, and more.
- Assessing a broad range of low and zero-carbon technology solutions and their market potentials is also beneficial for efficient planning
  - More granular capacity expansion planning models are not typically designed to feasibly solve over the full range of possible new resource investment choices (due to dimensionality burdens)
- Coordinated modeling between the end-use and electric sectors can provide a consistent set of electricity loads and optimal technology “blocks” (GW) for modeling scenarios

US-REGEN

Regional Economy, GHG, and Energy

Regional Decarbonization Technology Pathways Modeling

Electric Generation



Detailed representation of:

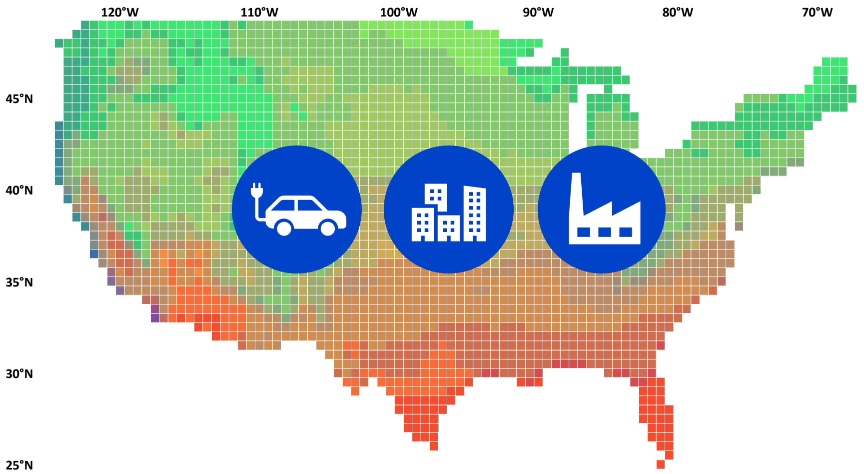
- Energy and capacity requirements
- Renewable integration, transmission, storage
- Federal, regional, and state-level policies and constraints

Synchronized

Hourly Load, Renewables, and Prices

Model Outputs:
Economic equilibrium for generation, capacity, and end-use mix
Emissions, air quality, and water

Energy Use



Detailed representation of:

- Customer heterogeneity across end-use sectors
- End-use technology trade-offs
- Electrification and efficiency opportunities

Documentation, articles, and reports available at https://esca.epri.com

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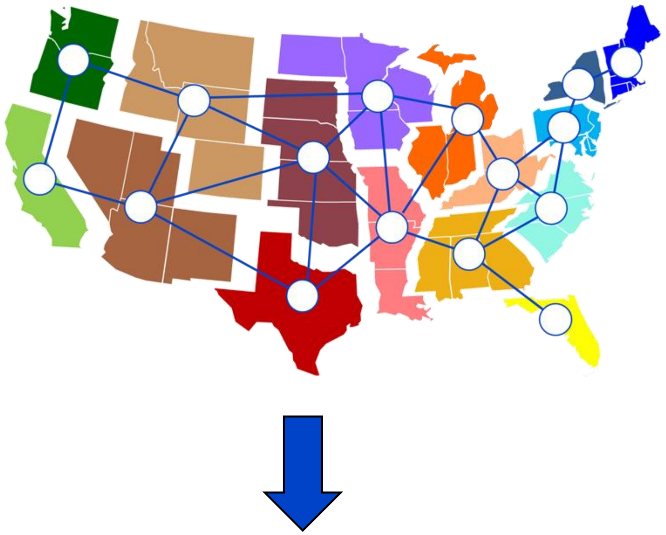
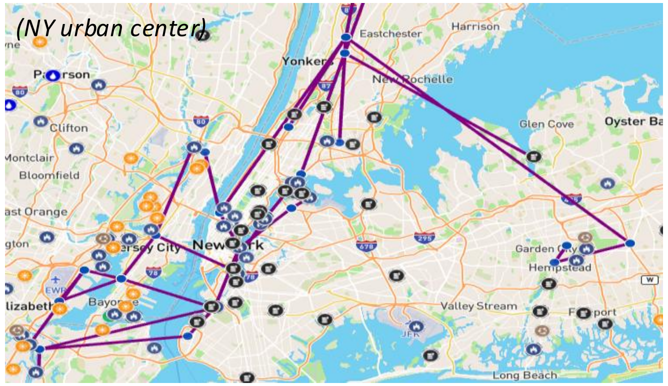
Nodal Capacity Expansion Modeling Objectives

- Detailed power system reliability studies benefit from each generating unit in a system being represented by its physical location and engineering/operating characteristics, and the transmission network lines between them and localized loads.
- We use Energy Exemplar's long-term capacity expansion planning model (PLEXOS-LT Plan) and inform it with US-REGEN scenarios to develop a power system model with the unit-level detail and system topology required for the system cost and reliability evaluations in this study.
- For this study, PLEXOS-LT Plan is configured as a nodal model, optimizing the generating capacity portfolio as a mixed integer program to site discrete units across nodes.
- PLEXOS-LT Plan is run several times throughout the study; the next slides show the initial portfolio used for further reliability study.





Regional technology planning models provide a critical starting point for detailed unit-level capacity expansion and operations analyses

System Cost & Reliability Evaluation Process and Tools

- Five analytical steps are used to comprehensively assess the reliability of the bulk (G&T) system, and identify potential economic and reliability driven reinforcements (e.g., opportunities for deficiency correction)
- All models use the same set of input data and assumptions, originating from the initial LT Plan resource portfolios and/or PCM simulations

1 Resource Adequacy—Planning Reserve Assessment
- PLEXOS Production Cost Modeling Monte Carlo Tool

2 Resource Adequacy—Storage Assessment
- PLEXOS Production Cost Modeling Monte Carlo Tool

3 Tx Network Congestion Assessment
- PLEXOS Production Cost Modeling Tools

4 Operating Reserves & Risk Assessment
- EPRI Generic PCM Model
- DynADOR
- DynADCR

5 Tx Network Reliability Assessment
- EPRI HiLS Clustering Algorithm
- PSS®E

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ISSP Cost & Reliability Evaluation Feedbacks: Planning Analysis Recommendations for the NY Demonstration Reference Scenario

Evaluation	Description	Key NY Study Finding(s)	Recommended Planning Actions
1	Resource Adequacy—Planning Reserve Assessment	• Resource portfolio failed minimum LOLE target of 0.1 days/year • High risk periods of unserved energy (e.g., high load, low wind during summer peaks)	• Increase minimum required planning reserve margin in CapEx from 8% to 16%
2	Resource Adequacy—Storage Assessment	• Significant LOLE benefits of longer duration storage	• Increase duration of candidate batteries available in CapEx (4x)
3	PCM—Transmission Network Congestion Assessment	• Notable lines with significant congestion and overloading • High variation in system wide prices	• Allow CapEx model to consider economic transmission upgrades for all congested lines (22 new line candidates)
4	Operations Reserves & Risk Assessment	• Reference scenario passed key flexibility and contingency requirement tests	• None (Note, performed a sensitivity analysis to show a case where the CapEx would need to be re-run)
5	Transmission Network Reliability Assessment	• 20 lines and 3 transformers need upgrades to make the system N-1 secure (plus 24 lines and 2 trans. For N-0)	• Reliability-driven candidate transmission reinforcements are recommended for CapEx

ISSP Cost & Reliability Evaluation Feedbacks: Planning Analysis Recommendations for the NY Demonstration Zero CO_2 Scenario

Green text highlights key differences from Reference

Evaluation	Description	Key NY Study Finding(s)	Recommended Planning Actions
1	Resource Adequacy—Planning Reserve Assessment	• Resource portfolio failed minimum LOLE target of 0.1 days/year • High risk periods of unserved energy (e.g., high load due to heating on winter nights)	• Start with higher (16%) PRM from Reference Scenario final portfolio and check sufficiency; explore other solutions (e.g., storage) to complement PRM needs
2	Resource Adequacy—Storage Assessment	• Significant LOLE benefits of longer duration storage	• Increase duration of candidate batteries available in CapEx by 30%
3	PCM—Transmission Network Congestion Assessment	• Notable lines with significant congestion and overloading • High variation in system wide prices	• Allow CapEx model to consider economic transmission upgrades for all congested lines (37 new line candidates)
4	Operations Reserves & Risk Assessment	• Reference scenario passed key flexibility and contingency requirement tests	• None (Note, performed a sensitivity analysis to show a case where the CapEx would need to be re-run)
5	Transmission Network Reliability Assessment	• 17 extra circuits *in addition to those required under Reference* for N-1 required to secure the Decarbonization portfolio	• Reliability-driven candidate transmission reinforcements are recommended for CapEx

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Key Lessons Learned (So Far) **from EPRI's ISSP Research**

Use regional technology pathways models to develop sound initial scenarios. The set of technologies that are optimal to deploy for a given system, and the optimal time to deploy them, are influenced by complex and interacting factors that are best informed by analytical tools that can capture the dynamics of inter-related regions, potential future policies, and technology readiness levels.

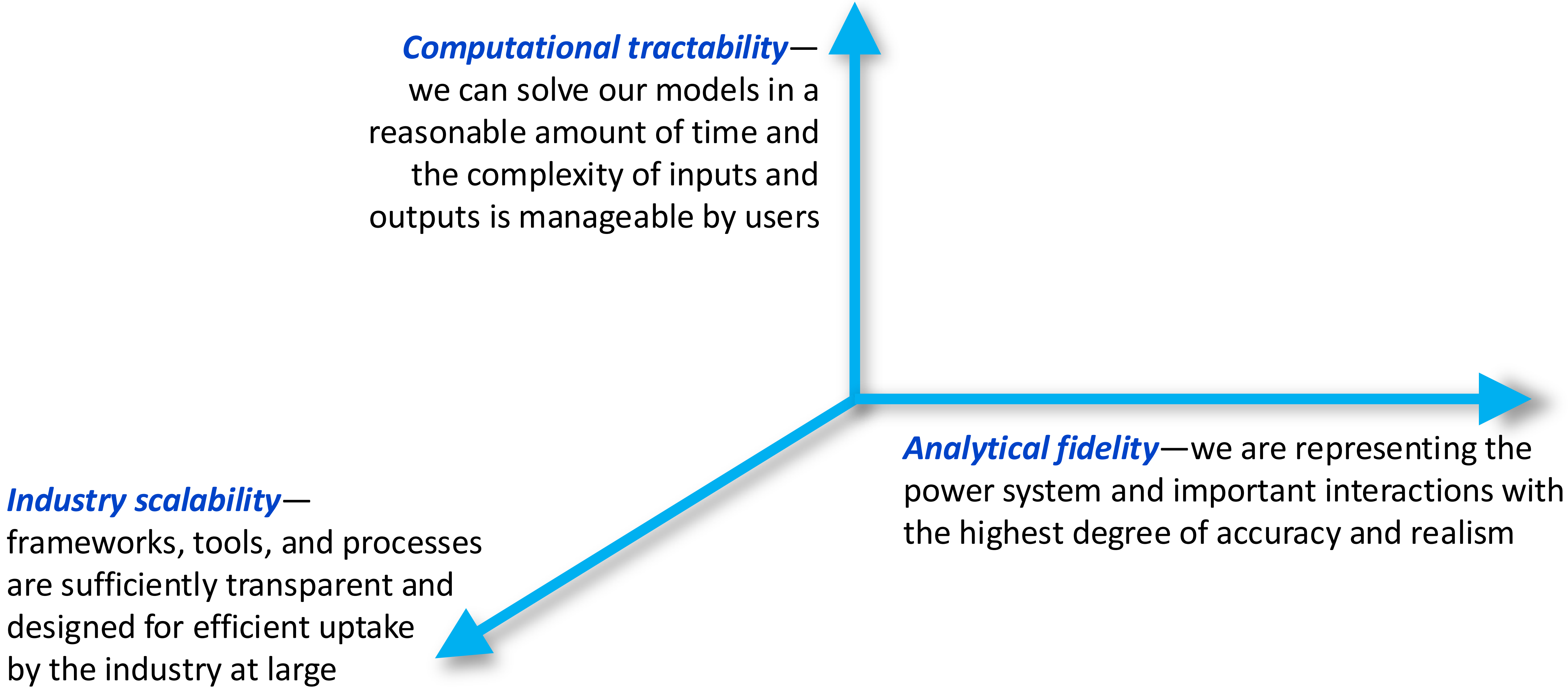
Move the siting of new generation and/or transmission resources to earlier in the planning process. Early collaboration between generation planning & transmission planning teams can facilitate developing candidate integrated portfolios. Starting with an informed siting strategy provides an efficient way to identify storage and other locational resource options for reliability support.

It is essential to evaluate network reliability as part of a holistic planning process. Leveraging intelligent period sampling techniques and novel processes to create ac power flow models from production cost modeling study results can be very beneficial to finding final robust resource portfolios.

Automate, automate, automate. Automating processes for data adjustments and transfer between models can reduce errors and provide a more efficient means for integrated system planning analysis.

Foundational Storage + Integrated Planning Modeling Experiments

Balancing Integrated Planning Toolbox Dimensions



Energy Storage Modeling in Practice—Common Simplifications

Temporal simplifications include on-peak and off-peak days with a limited number of hours per day; typical weeks; one or two chronological weeks per month.

Regional network aggregation (copper plate) seems to be the preferred approach, with or without a link to outside markets. For large-scale models, hourly interregional energy limits between balancing areas are also used.

Capacity value for storage is normally determined exogenously for various levels of deployment. Resource adequacy models are employed to determine effective load carrying capability (ELCC) curves for each storage tier which are later used as inputs.

All approaches and simplifications have disadvantages, and modelers need to weigh the tradeoffs between fidelity (i.e., improved representation) and model tractability

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Trade-offs in Spatiotemporal Resolution vs. Complexity

- Key common simplification methods to reduce the planning model's temporal dimension, optimization period, and representation of the transmission network **result in significant variation in storage portfolios.**

- These simplifications (aimed at reducing lengthy run times in capacity expansion models) may lead to inaccurate evaluations, potentially resulting in **either underestimation or overestimation of storage resources** and even other generation technologies in planning studies.

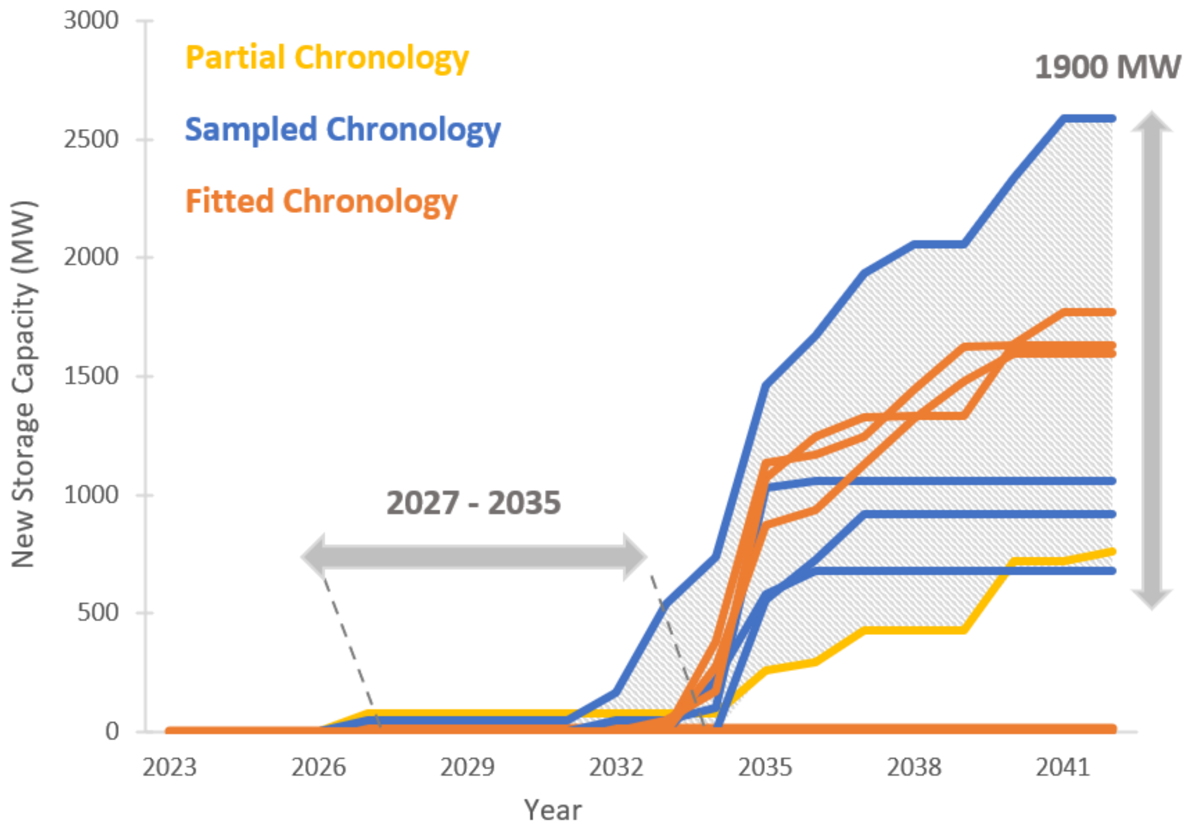


Figure1. Comparison of new storage capacity (MW) across three low-carbon resource portfolios, using different temporal resolution modeling strategies

Source: "Assessing Temporal and Spatial Modeling Choices for Energy Storage in Long-Term Resource Plannings," Product ID 3002028963

Trade-offs in Spatiotemporal Resolution vs. Complexity (cont.)

- **Finer temporal granularity—with chronology—drives higher shorter duration storage deployment**; temporal simplifications may overlook peak and off-peak pricing periods crucial for accurately valuing energy storage.
- **Simultaneously modeling the transmission network can help mitigate future congestion** issues by identifying optimal storage locations and deployment timing.
- **(Not shown) Myopic models with shorter optimization periods may result in lower storage deployment**. These models miss anticipating later carbon targets and thus the need to retire fossil and build more renewables and storage.

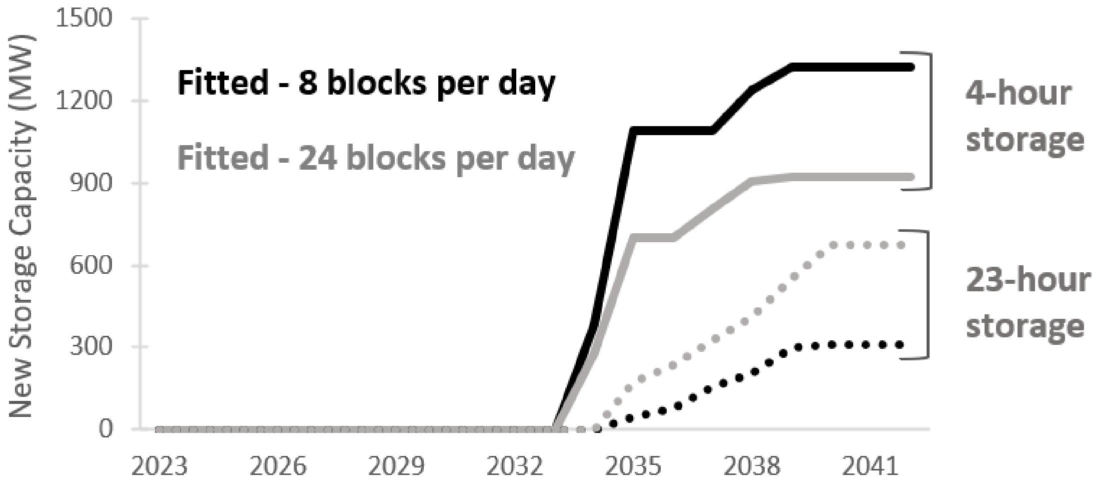


Figure 2. Comparison of storage deployment by capacity (MW) under different temporal resolutions

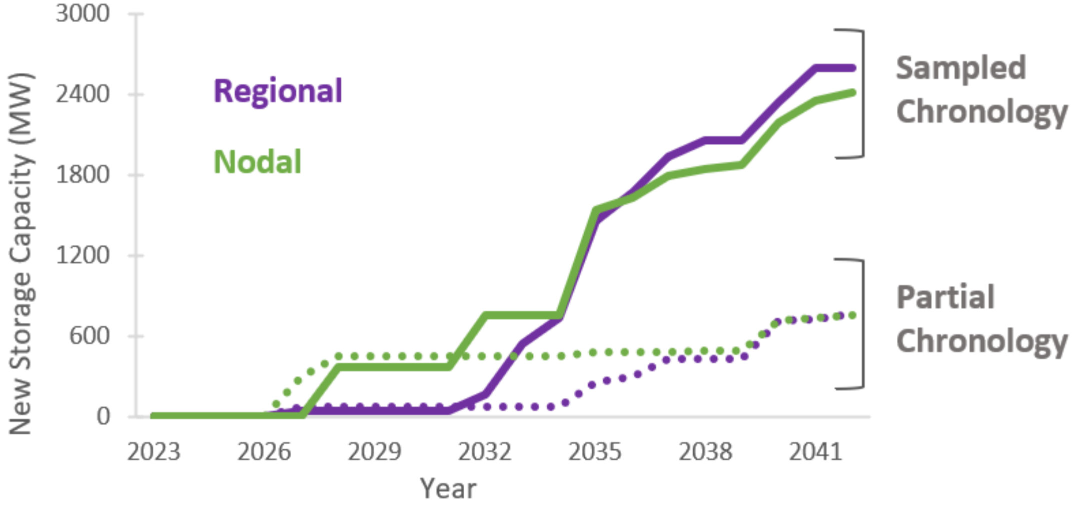


Figure 3. Comparison of storage deployment by capacity (MW) between nodal and regional approaches

Source: "Assessing Temporal and Spatial Modeling Choices for Energy Storage in Long-Term Resource Plannings," Product ID 3002028963

Long Duration Energy Storage (LDES) is Amplifying the Existing Complexities of Storage Modeling

How to configure LDES if information is limited?
Substantial uncertainty exists for new storage technologies regarding capital cost trajectories, storage capabilities, and operational use, which can be used to benchmark the outputs of the models used by resource planners.

How to implement longer chronologies necessary for evaluating LDES effectively?
Computationally expensive temporal models are needed to capture multi-day and multi-month charging dynamics, especially when capturing a wide range of weather and load conditions over extended horizons.

How to determine LDES capacity contribution to meet planning reserve margins?
LDES may provide firm capacity during periods of high stress in the grid, but adequacy values are highly dependent on the resource mix, especially their interaction with other storage and renewable resources.

EPRI LDES Modeling Working Group

EPRI LDES Modeling Working Group

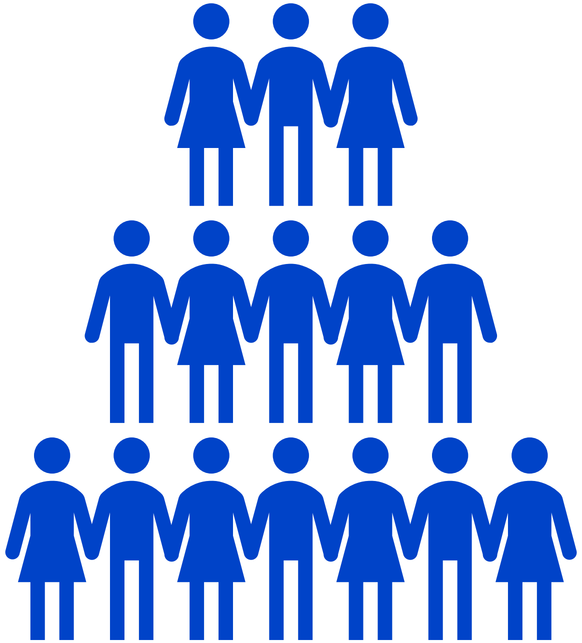
Objective: Collaboratively Identify key challenges and best practices for including LDES (storage 10h+) in long-term resource planning models and processes

TOPICS

1. Choosing an appropriate **temporal resolution** in capacity expansion models
2. Choosing an appropriate **spatial resolution** in capacity expansion models
3. Tradeoffs in **iterating** between capacity expansion planning and operations simulation models
4. Tradeoffs between **co-optimizing** generation and storage vs. **exogenous selection** of LDES after optimizing generation resources
5. Tradeoffs and **computational tractability of translating technology specific modeling** to an electric company planning model
6. How to represent all **LDES value streams** and select **essential characteristics** of LDES technologies to include in long-term planning models
7. How to **co-optimize LDES with medium and short duration** technologies, alongside the rest of the portfolio.
8. Incorporating reliability modeling, **capacity accreditation**, and weather data

EPRI LDES Modeling Working Group Participants

- Argonne National Laboratory
- Ascend Analytics
- The Brattle Group
- Carnegie Mellon University
- IIT Comillas University
- E3
- Echogen
- EPRI
- encoord
- Energy Dome
- Energy Vault
- Energy Exemplar
- ESS
- Form Energy
- GridPath
- Hydrostor
- Malta
- Pacific Northwest National Laboratory
- PSR
- Sandia National Labs
- Synapse Energy Economics
- Telos Energy
- National Renewable Energy Laboratory
- UC San Diego
- Yes Energy



Academia, National Labs, Tool Developers, Storage Developers, Industry Research

LDES Modeling Working Group Developments & Debates

Teams across industry and research have proposed new approaches for modeling LDES

Technology Specificity	**Technology Agnostic**: Facing uncertainty, use a single set of LDES costs, and allow the model to independently size power and energy capacity	OR	**Technology Specific**: LDES technologies have a wide range of round-trip efficiencies, durations, and costs, and storage developers have fixed configurations.
Weather and Load Years	Run capacity expansion with **multiple weather and load years**, and select resource mix from the range of results, or co-optimize across separate weather year inputs	OR	Construct a **single synthetic year of weather and load** data by sampling across multiple historic weather+load years to capture a full range of challenging conditions
Iterate with Operational Models	Pass a portfolio between capacity expansion and operational simulation and **adjust reserve margin if a portfolio cannot operate reliably**, then re-solve expansion step.	OR	Pass a portfolio between capacity expansion and operational simulation, re-solve with **adjusted reserve margin and modeler's choice to set fixed capacities for LDES** (or all peaking capacity) after first iteration.
Capacity Accreditation	Capacity value of energy storage changes with the surrounding system. Some models **re-solve for capacity accreditation values** after each time-step, others calculate an **hourly operating reserve**	OR	Standard approach to use **exogenous capacity accreditation curves** and re-solve the entire planning horizon with new curves if needed
Foresight and Markets	Run models with **perfect foresight**, to calculate full system value of LDES, knowing that current price signals and weather forecasts don't allow assets to optimally anticipate every shortfall and extreme event	OR	Price-taker models with limited foresight show LDES missing most events where expansion model expected it to discharge. Add a 'soft penalty' price to **incentivize storage to hold charge to anticipate reliability events**

LDES Aspirations Grounded in Greater Operational Detail

There are many potential benefits of LDES but also underlying challenges to incorporating details from resource adequacy assessments and reliability modeling into long-term capacity expansion tools where they are needed.

- LDES selected to replace fossil-fuel assets
- LDES offers support through extreme events
- LDES as a hedge against seasonal hydro and wind variability

- Detailed chronology
- Multiple weather years
- Improved Capacity Accreditation
- Enhanced Feedback with Operational Simulations

Computational Tractability

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Questions?

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