Long-Term Load and DER Forecasting

Final Task Force Report

ESIG
ENERGY SYSTEMS
INTEGRATION GROUP

Facilitated by Julieta Giraldez, Electric Power Engineers

2024 ESIG DER Working Group Task Force

August 13th, 2025

Long-Term Load Forecasting

ESIG DER Working Group Task Force

Project Objective

Develop, evolve and standardize best practices and next steps for long-term load and DER forecasting that will account for uncertainty in climate change impact on weather, electrification, new large loads and load flexibility

Research Outcomes & Key Questions

1. **Key topic areas**
2. **Use-cases & data sources**
3. **State-of-the-art**
4. **Gaps**

Task Force Members

Consortium of > 30 grid planners, utilities, researchers, software and hardware vendors, consultants, etc.

Find out More

ESIG DER Working Group

Contact: jgiraldez@epeconsulting.com

Introduction

- Long-term load and DER forecasting is performed annually by multiple entities and for multiple use cases in the electric grid planning process
- Traditionally, long-term (10 to 30 years) load forecasts estimated two key metrics: total annual energy and annual peak demand
- Three key changes are challenging this paradigm, including:
  - Variable, weather-dependent, and less-centralized renewable generation to the resource mix
  - Unprecedented load growth from the electrification of the building and transportation sectors, and new large loads such as data centers and manufacturing expansion
  - The increasing adoption of customer-sited distributed energy resources, such as solar PV, BESS, and EVs

Shifts in technology, policy & consumer behavior are fundamentally altering the shape, timing, and location of electricity demand

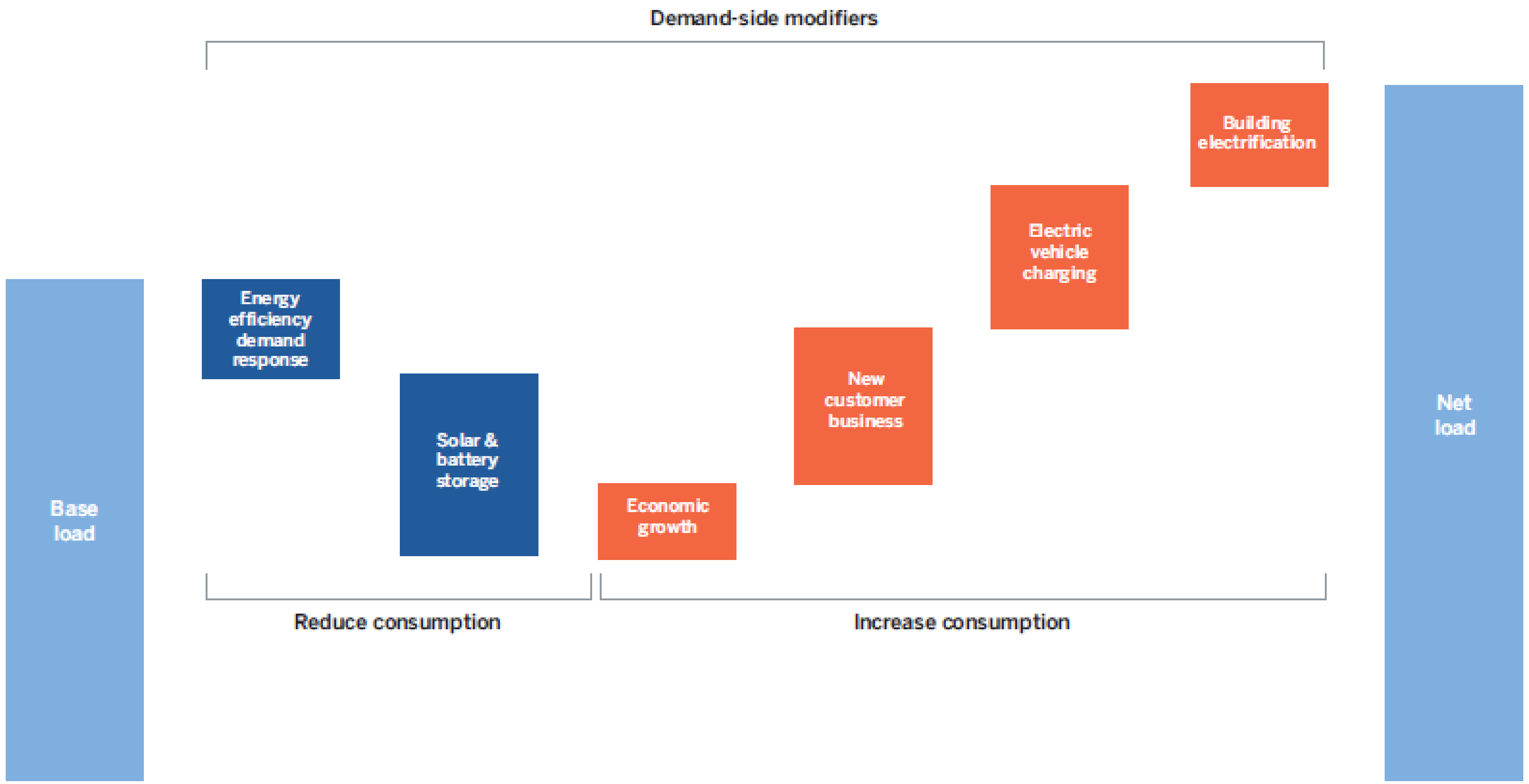
What is the state-of-the-art in Load and DER Forecasting?

ESIG

- Entities differ in their ability to implement the load and DER forecasting steps here outlined
  - The sophistication required for different use cases also varies accordingly
- To ensure robust grid planning, uncertainty analysis and scenario planning must complement load and DER forecasting, accounting for a range of potential future conditions and their impact on long-term system reliability

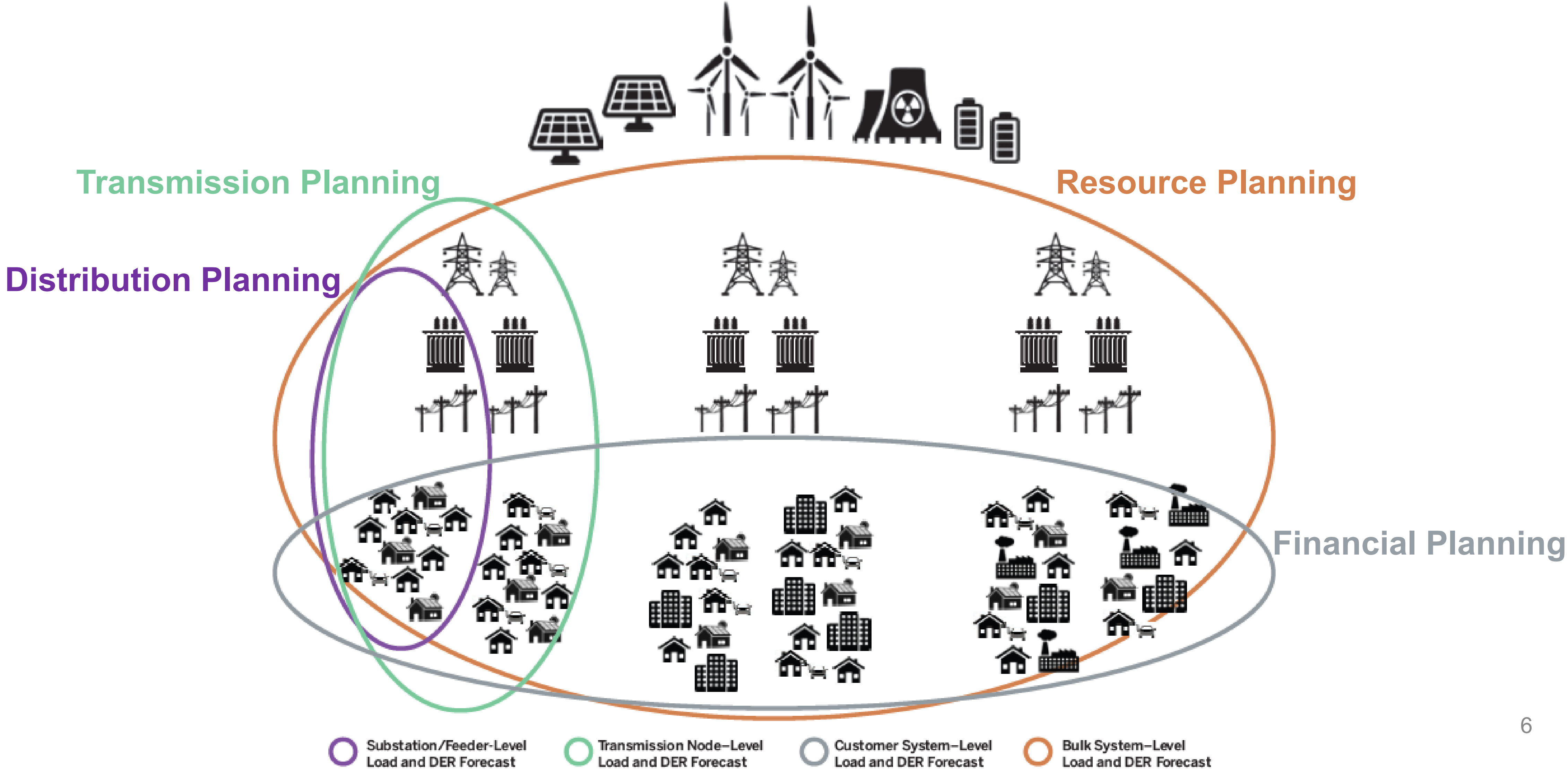
1. **Forecast base load**
   - Back out weather-dependent distributed energy resources such as solar and demand response to determine gross or native base load
   - Extrapolate base load based on historical data and/or weather and economic variables
2. **Adjust base load forecast with exogenous forecasts for new loads**
   - Distribution-level known new customer business growth
   - Bulk system-level large loads
3. **Adjust base load forecast with exogenous forecasts for new consumer-adopted technologies**
   - Distributed energy resources such as solar and battery storage
   - Building and transportation electrification technologies

From Base Load to Net Load



Forecasting demand-side modifiers is essential to accurately predict future energy demand

Load and DER Forecasting Grid Resolution and Use-Cases



About Step 1. Base Load Forecasting

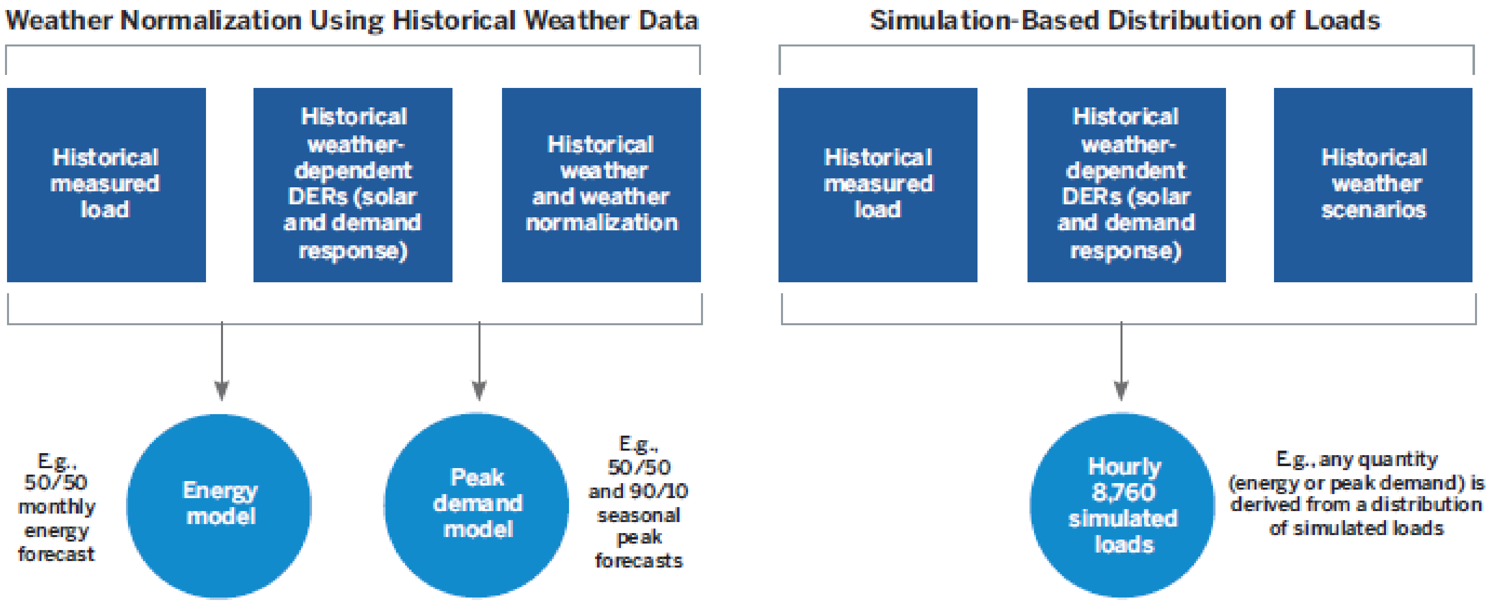
What's the starting point?

Entity/Type of Forecast	Measured Historical Load Used in the Forecast	Model Granularity
ISOs'/utilities' resource planning load forecast	Hourly load zone	Model by load zone (1 to 20 zones)
Utilities' financial load forecast	Customer monthly energy consumption and service territory annual peak load or AMI hourly energy consumption	Model by customer class or revenue meter (3 to 30 customer classes or rate types)
Utilities' distribution load forecast	SCADA annual peak load or hourly load AMI annual peak or hourly load	Model by distribution substation and/or feeder (tens to thousands of substations and feeders) Model at the customer level (hundreds to millions of customers)

- Before using historical load data for forecasting, it is often necessary to adjust for existing weather-dependent DERs to ensure accurate representation of native demand
- Most used methods for base load forecasting
  - **Time-extrapolation** models
  - **Econometric and machine learning** models derive relationships between historical load and external variables like weather, economic activity, and population growth
  - **SAE** models incorporate components of an end-use modeling by equipment (e.g., appliances, heating and cooling systems)

Weather, Key Driver of Base Load Forecasting

- Normalization techniques adjust historical load data to account for variations in weather, ensuring that forecasts reflect underlying consumption trends and/or weather extremes



What about forecasting weather we haven’t seen?

ESIG

- Extreme weather events are significant aberrations from typical weather patterns, and there are very limited data in historical records from which load models can derive the associations between extreme weather and corresponding electricity demand
  - Approaches rooted in typical historical data can under-predict these events, and traditional econometric models struggle to predict energy demand during heat waves, polar vortexes, and severe storms
- **Addressing Extreme Weather in Load Forecasting Models**
  - **Expanding training datasets using synthetic weather records**, which allows models to account for conditions beyond the limited scope of historical observations.
  - **Spline regression and non-linear modeling**, which better captures the complex relationships between temperature and electricity demand and can accommodate variations such as the rapid increases in cooling demand during heat waves, the non-linear heating demand response in extreme cold, etc.
  - **Uncertainty analysis using Monte Carlo simulations** plays a crucial role in forecasting extreme weather impacts. By generating thousands of possible weather load scenarios, Monte Carlo methods help assess a range of potential outcomes and quantify the probability of extreme demand spikes.

About Step 2. Adjusting for Known New Loads

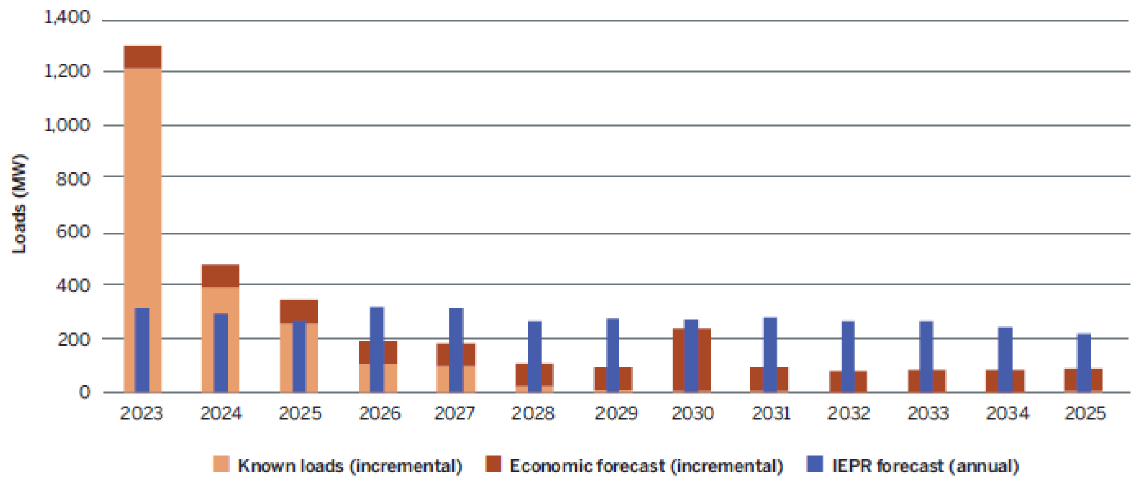
ESIG

- **Known new customer loads** are very often the source of bottom-up data used by **distribution planning** departments to adjust base loads and trigger most of the load distribution capacity projects
  - There are different levels of coordination and sophistication within utilities as to how these new loads are tracked and incorporated into local substation/feeder forecasts
  - A common practice is that known new customer loads are used first as the primary source for adjusting local substation/feeder base load, and then economic percentage growth is added only if the new customer loads doesn't exceed the economic growth

There is a lack of process to reconcile local known new customer load growth with system level projected economic load growth

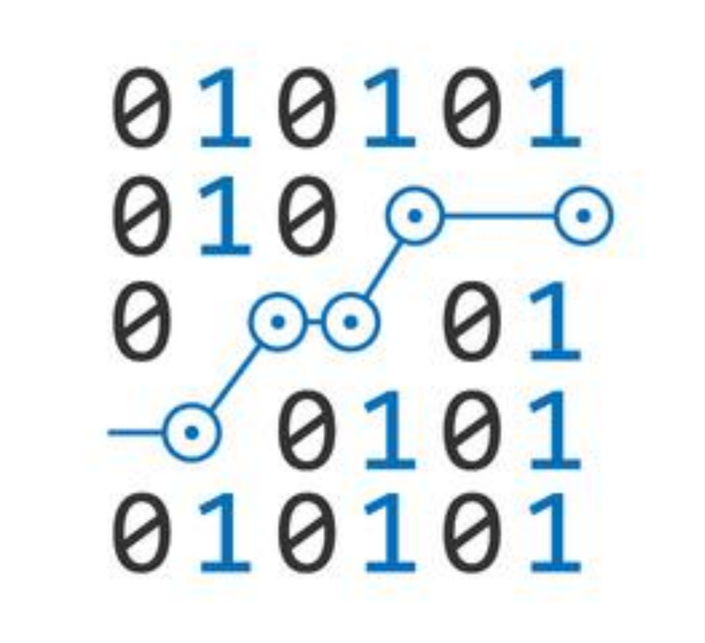
About Step 2. Adjusting for Known New Loads

- New customer business loads are used to forecast years 1-5 and not incorporated into longer-term load forecasts
  - Long-term load growth trends are difficult to determine as these loads are sporadic and unpredictable, making linear regression or extrapolation ineffective



About Step 2. Adjusting for Known Large Loads!

- Forecasting large loads growth has become essential for bulk power system planning, resource adequacy assessments, and transmission expansion
- Data center load growth is the single largest component of growth in utility load forecasts and is expanding at an unprecedented rate
  - There is no formal forecasting model that is used today to forecast large loads, in particular data centers



- Significant uncertainty associated with this category of large loads. Utilities and ISOs often apply derating factors to reflect the uncertainty in data center forecasts.
  - Some ISOs and utilities report full utilization of interconnection requests, while others observe significant underutilization, with actual load reaching less than 50% of requested capacity
  - No standardization in data center reporting/modeling requirements: e.g. "load factor" vs. "capacity utilization", etc.

About Step 3. Adjusting Base Load with DERs

Explicitly modeling the impact of customer technology adoption is essential for long-term load forecasting across all use cases

DERs are introducing a greater need to increase the spatial and temporal granularity of load forecasts to better capture localized adoption and behavior patterns and are further driving the need to perform hourly modeling

Most ISOs incorporate behind-the-meter solar, battery storage, EV charging, and energy efficiency into their long-term load forecasts

Utilities are also increasingly considering DER impacts in financial and resource planning.

While some utilities explicitly account for DERs and electrification in their distribution planning, many still don’t capture these technologies’ effects.

DER Adoption – Top-Down vs. Bottom-up

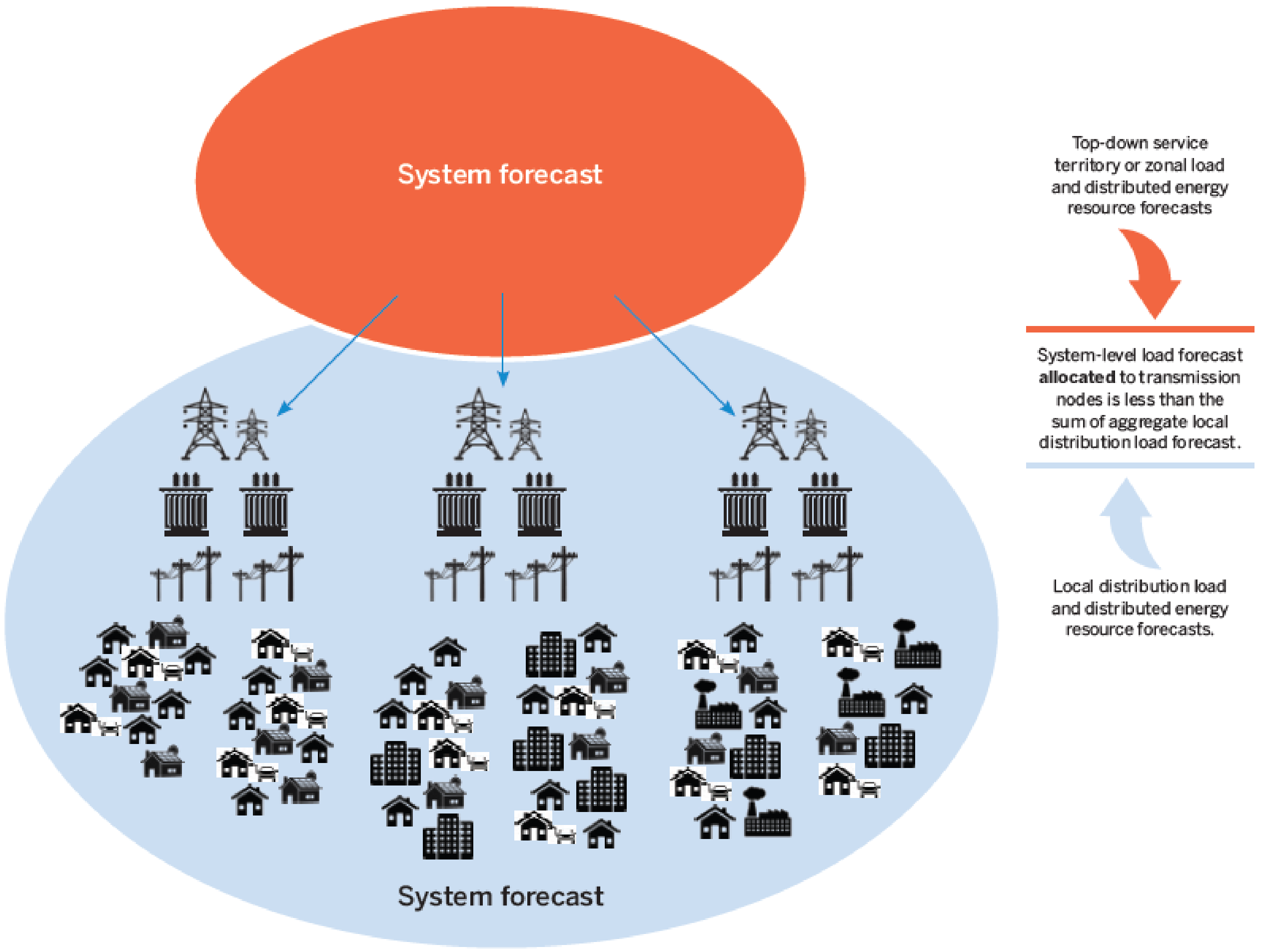
- DER adoption forecasting efforts generally use either a top-down or bottom-up approach
  - Bottom-up approaches are most commonly being used to geospatially disaggregate top-down forecasts or technology targets, rather than as a method to determine a technology system-level forecast
  - A top-down approach cannot model individual-level adoption; however, microlevel indicators are more difficult to collect and process at scale, making top-down models easier to execute

The difference between macro-level (top-down) and micro-level (bottom-up) indicators is their specificity:

- **Micro-level indicators represent the traits of a granular unit— typically a site, building, or a household, but it can also be a spatial area such as a census block**
- **Macro-level indicators represent an aggregate area or customer base, such as a state, service area, or even an entire country**

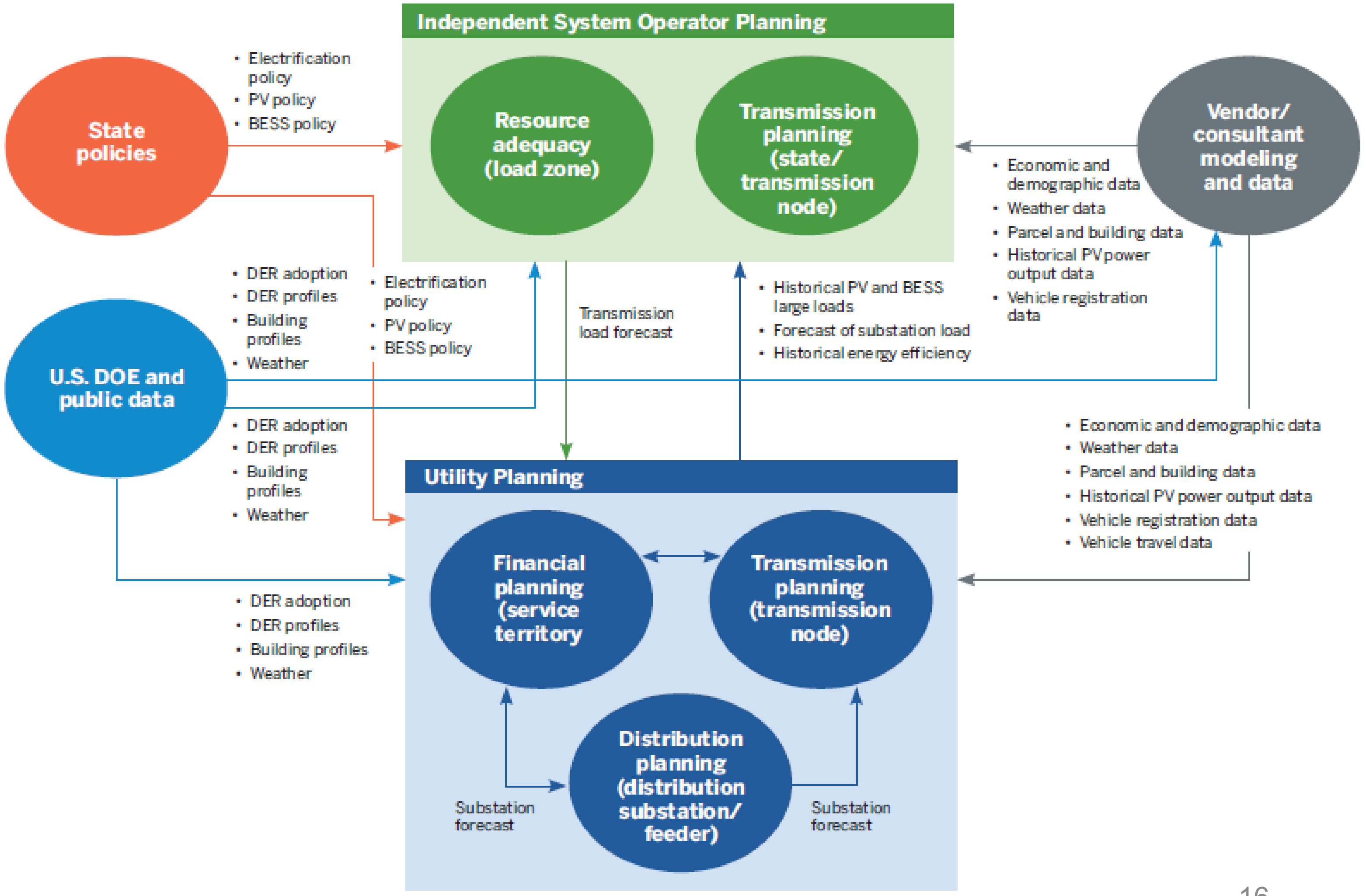
Reconciliation of Different Load and DER Forecasts

- To improve alignment between system and local distribution forecasts, planners must address three key challenges:
  - **Forecast components:** What base load assumptions and exogenous load and DER factors are included in system and local forecasts?
  - **Forecast reconciliation:** How do non-coincident local peaks relate to system-wide coincident peak demand, and how do contribution factors impact forecast accuracy?
  - **Forecast allocation:** How are system-level load and DER forecasts distributed to higher-resolution grid areas, such as transmission nodes and distribution substations, and what are the risks of misallocation?



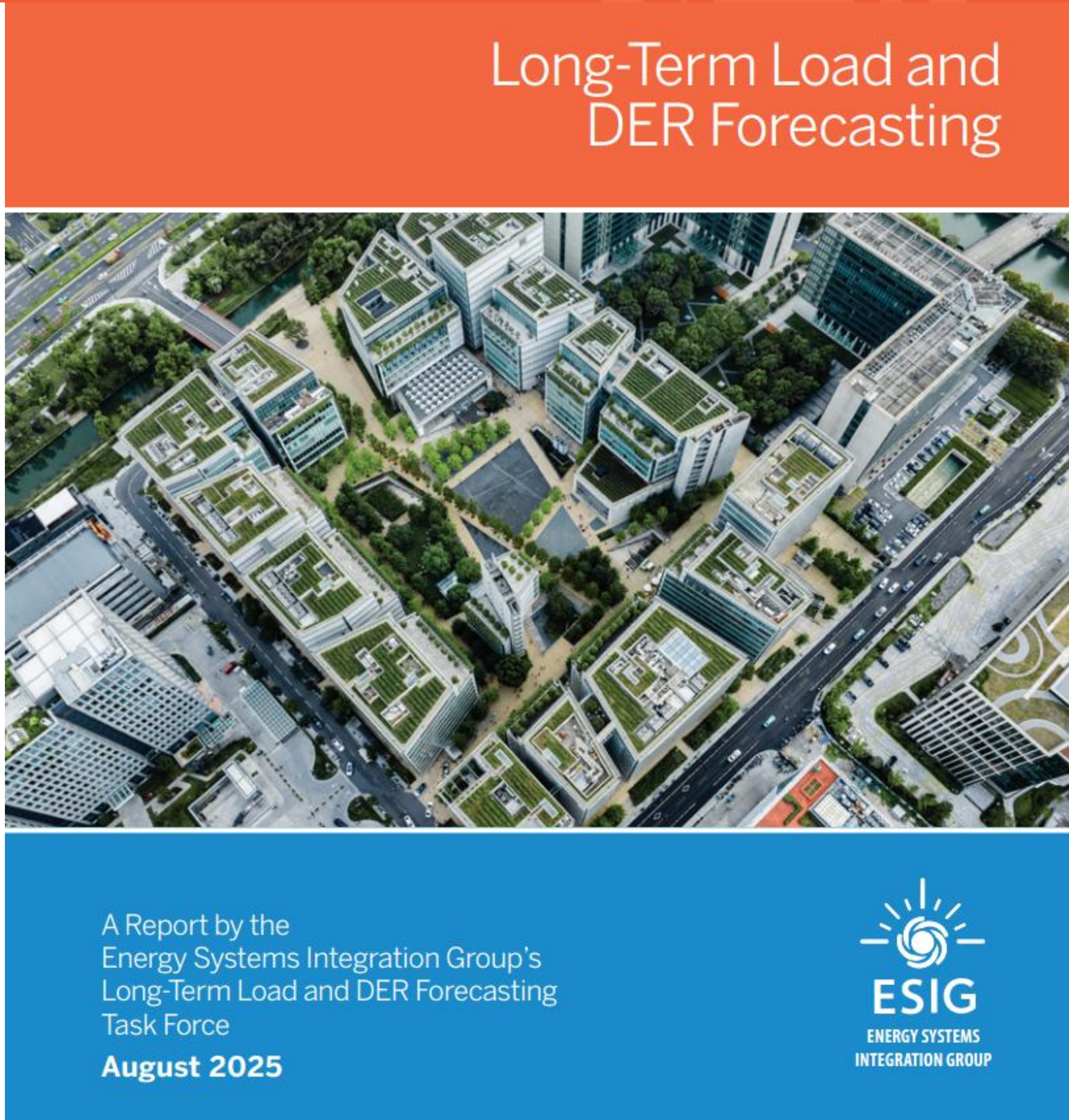
Areas of Coordination

- Enhanced data-sharing within and across state agencies, utilities, ISOs, and regional planning entities can improve forecasting accuracy



Key Take-Aways

- Energy planners need high-resolution, time-based forecasts to capture the realities of a changing grid, including correlated impact of weather on both demand and generation
- Greater geographic granularity can address several forecasting challenges
- Incorporating climate change models into forecasting remains complex
- Scenario planning is essential for capturing uncertainty
- Coordination across forecasting entities is increasingly critical through integrated planning approaches
- Reconciliation between top-down and bottom-up forecasts is important
  - Known new customer loads, transportation electrification and solar must be carefully integrated/allocated into forecasts and use-cases



THANK YOU

Julieta Giraldez, Electric Power Engineers

jgiraldez@epeconsuting.com