Transmission and Distribution System Planning – Basics

Jose Lara & Vince Westfallen (NREL)

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The authors are solely responsible for any omissions or errors contained herein.

Webinar Series Overview

1) Overview of Webinar Series and Connections to State Planning Efforts
   - **October 14, 2:30-3:30 p.m. Eastern**
   - Juliet Homer & Eran Schweitzer (PNNL)
2) Developing Forecasts - General Overview
   - **October 23, 4-5 p.m. Eastern**
   - Brittany Tarufelli & Allison Campbell (PNNL) and J.P. Carvallo (LBNL)
3) Developing Forecasts – Load Expansion
   - **October 29, 4-5 p.m. Eastern**
   - Sean Murphy & J.P. Carvallo (LBNL) and Christine Holland (PNNL)
4) Developing Forecasts – Distributed Energy Resources
   - **November 6, 2-3 p.m. Eastern**
   - Sean Murphy & Margaret Pigman (LBNL) and Shibani Ghosh (NREL)

Webinar Series Overview

5) Resource Adequacy Analysis – Basics
    - November 10, 3-4 p.m. Eastern
    - Jose Lara, Sebastian Machado, & Rafael Monge (NREL) and Allison Campbell & Eran Schweitzer (PNNL)

6) Transmission and Distribution System Planning – Basics
    - November 13, 3-4 p.m. Eastern
    - Jose Lara & Vincent Westfallen (NREL)

7) The Evolution of Resource Accreditation
    - December 2, 3-4 p.m. Eastern
    - Travis Douville (PNNL)

Transmission

Overview

- Why is modeling in transmission planning important?
- What kinds of modeling matter in transmission planning?
- What are the key challenges in modeling transmission technologies in planning assessment?
- How can we address these challenges?

Transmission Planning Basics

- Transmission planning has evolved dramatically. Historically, utilities built transmission primarily for reliability. Market restructuring and renewable energy integration created new drivers. Today's planning must balance multiple objectives across multiple stakeholders with state and federal oversight.
- Objective based transmission from FERC Order 1000:
  - Reliability projects: Meet NERC standards, mandatory to build and broadly allocated costs. These are discretionary
  - Economic projects: Reduce congestion, lower production costs, must prove benefits. Requite rigorous cost-benefit.
  - Public Policy Projects: Enable state mandates, generation integration.

What about Grid Enhancing Technologies (GETs)?

- Modeling is a key component of evaluating the costs and benefits of all grid technologies.
- GETs can have both reliability and cost benefits for the system.
- How we model transmission portfolios (or any technology) can impact which projects are selected and built in the planning process.

Grid Enhancing Technologies (GETs) are operational technologies

GETs provide value (cost savings, reliability benefits, etc.) by impacting grid operations sometimes at very granular timescales.

The impact of GETs is dynamic and changes based on the operating conditions of the system.

Models that aim to capture the benefits of deploying GETs must include a level of operational details not commonly done in planning processes.

Transmission Reliability Planning Criteria – TPL-001-5.1

Purpose & Applicability	Establishes planning-horizon performance requirements for the Bulk Electric System (BES) to ensure reliable operation under a broad spectrum of system conditions and contingencies. (NERC)	Applies to Planning Coordinators and Transmission Planners. (NERC)
Requirement R1 (System Models)	Entities must maintain system models for their area that reflect projected future system conditions. (NERC)	Models must include existing facilities, planned changes, load forecasts, firm transmission commitments, resources. (NERC)
Requirement R2 (Planning Assessment)	Entities must conduct an annual Planning Assessment of their BES portion using the models and document assumptions and results. (NERC)	Assessments must cover steady-state, stability, and short-circuit analyses per Table 1 category definitions.
Table 1 – Performance Categories	The standard defines multiple "Planning Event Categories" (P0, P1, P2, P3, P4, P5) that correspond to types of system conditions/contingencies and associated performance expectations. (NERC)	For example: P0 = normal conditions; P5 may involve fault plus non-redundant component of protection system failure. (wprcarchives.org)
Footnote 13 (Protection System Redundancy)	Text clarifies that when a non-redundant component of a protection system is involved (in a P5 event), additional requirements apply (e.g., backup clearing times). (wprcarchives.org)	Emphasis on identifying non-redundant protection components, monitoring, reporting, ensuring backup fault clearing.
Extreme Weather & Emerging Risk Considerations	Although the standard covers "extreme events," it has been noted that it does **not explicitly require** modeling extreme heat/cold or large area simultaneous events. (Federal Energy Regulatory Commission)	Regulatory filings (Federal Energy Regulatory Commission) have asked for revisions to incorporate such scenarios.
Implementation / Background	Version 5.1 builds upon earlier versions (e.g., TPL-001-5) and addresses issues like single points of failure in protection systems. (NERC)	Implementation timeline allowed entities time to coordinate with protection engineers, develop procedures for single points of failure, etc.

Options for modeling transmission systems during planning

State of practice

Improved modeling

Ideal case

Improved modeling fidelity and decision making
Increased modeling complexity

Modeling Terminology

Technology portfolio: A collection of projects designed to address a grid need.

- Could include multiple technologies and/or combinations of traditional transmission investments and GETs.

Future scenario(s): a collection of assumptions about future grid conditions.

- This could include policy assumptions, load growth, cost assumptions, fuel costs, and extreme events.

The *ideal* case for transmission planning models: Detailed representation within transmission expansion

Future Scenarios

Technology Portfolios

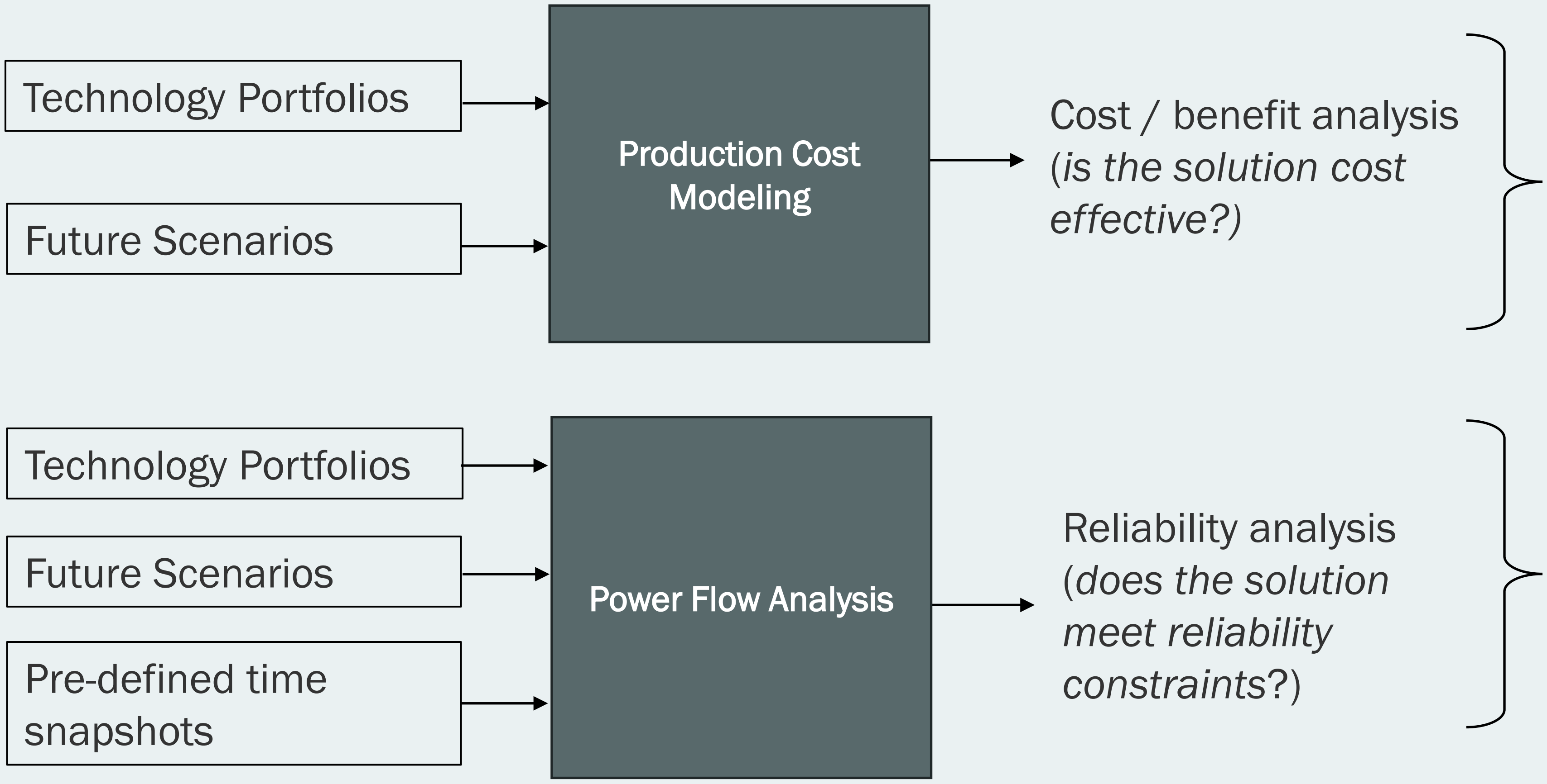
Transmission Expansion Optimization Model

- Nodal AC representation of network
- Detailed operational characteristics and limits of GETs.
- Operator's policies

Optimal technology portfolio and deployment

➢ The modeling and computational challenges for this approach make it currently intractable and not a practical approach.

State of practice for modeling Transmission De-coupled cost and reliability analysis

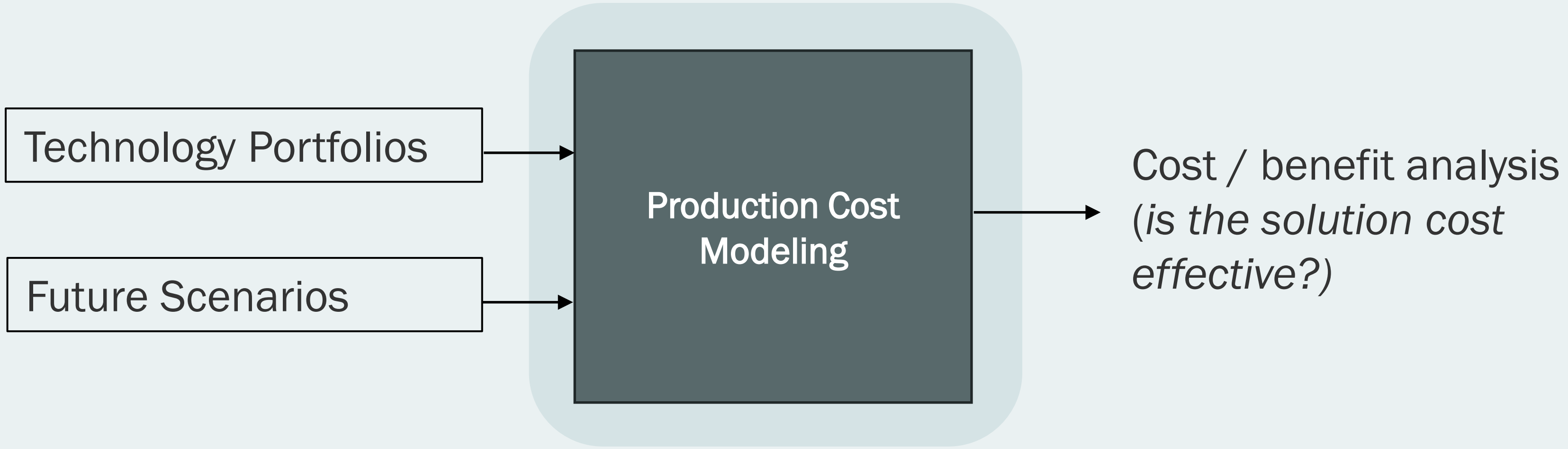


Analysis <u>often</u> conducted by state energy offices, PUCs, etc.

Analysis <u>often</u> conducted by utilities and grid operators.**

*** This diagram depicts the process of evaluating and selecting transmission solutions, which is often part of a larger transmission planning / integrated resource planning workflow.*

Shortcomings of current practice



- Many IRP models use aggregated zonal representations (local flows are not modeled).
- Nodal PCM models often don't reflect reliability constraints internally due to computational cost.

Limited ability to accurately capture the value of a specific alternative

Shortcomings of current practices

Technology Portfolios → Power Flow Analysis

Future Scenarios → Power Flow Analysis

Pre-defined operational snapshots → Power Flow Analysis

Power Flow Analysis → Reliability analysis (*does the solution meet reliability constraints*?)

- Operating base cases
  - 2026–27 Heavy Winter
  - 2026–27 Light Winter
  - 2027 Heavy Spring
  - 2027 Heavy Summer
  - 2027 Light Summer
- Five-year base cases
  - 2031–32 Heavy Winter
  - 2032 Heavy Summer
- 10-year base cases
  - 2036-37 Heavy Winter
  - 2037 Heavy Summer
- Specialized base cases
  - 2027 Light Autumn
  - 2046 Heavy Summer

CASE DESCRIPTION	2026-27 LIGHT WINTER—27LW1-OP		
CASE DUE DATES:	To Area Coordinator: November 7, 2025		
	To WECC Staff: December 5, 2025		
PURPOSE: *Operating Case*—To represent anticipated operating conditions during light load periods.			
ITEMS TO BE PREPARED:	From Case	2025-26 HW3 OP	
	Stability Data	Master Dynamics File	
	Significant Changes	From Existing System	
LOADS:	Expected minimum load for the months of December through February		
TIME:	0300–0500 hours MST		
RATINGS:	As appropriate for temperatures associated with the conditions modeled.		
GENERATION:	HYDRO	THERMAL	RENEWABLE
Canada	Median/Low	--	--
Northwest	Low	Median/Low	--
Idaho/Montana	Median	Median	--
Utah/Colorado/Wyoming	Low	Median	--
Northern California Hydro	Median	--	--
Northern California	Low	Median	--
Southern California	--	Median	--
Arizona/New Mexico/Southern Nevada	--	Median	--
INTERCHANGE	CONDITION	TARGET	% RATING
Northwest to British Columbia (Path 3)	Moderate	1500[1]	50%
Northwest to California/Nevada			
COI (Path 66)	Low	500-1000	10–20%
PDCI (Path 65)	Low	300	10%
Midway–Los Banos S-N (Path 15)	Moderate	3450	64%
Idaho to Northwest (Path 14)	Moderate	>1000	42%
Montana to Northwest (Path 8)	Heavy	1600	73%
Utah/Colorado to Southwest (Path 31, 35, 78)	--	--	--
Southwest to Calif. (EOR Path 49/WOR Path 46)	Moderate	5100/6900	54%/65%
Intermountain to Adelanto DC (Path 27)	Moderate	1600	67%
San Diego to CFE (Path 45)	Low	60	15%
Northern to Southern California (Path 26)	Low	-1000	33% (S-N)

- ➢ Pre-defined time snapshots for reliability base cases include many assumptions.
- ➢ These cases do not guarantee operational security for all operating conditions.

https://www.wecc.org/sites/default/files/documents/meeting/2025/11%20-%20AffleckL%20-%202026%20BCCS.pdf

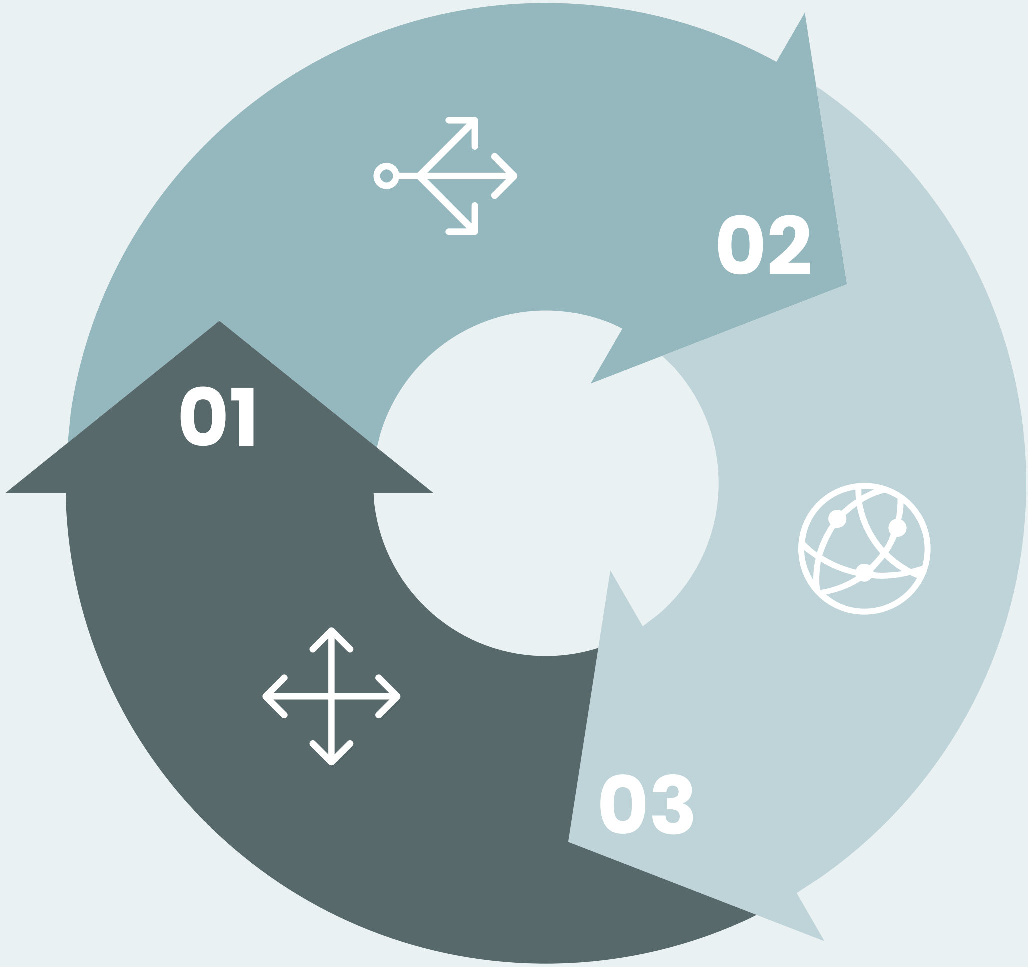
Iterative planning with Power Flow approaches

DISAGGREGATION

Generation (new builds & retirement), storage, and demand disaggregation to nodal.

CAPACITY EXPANSION

Optimal generation & transmission capacity expansion planning (zonal).

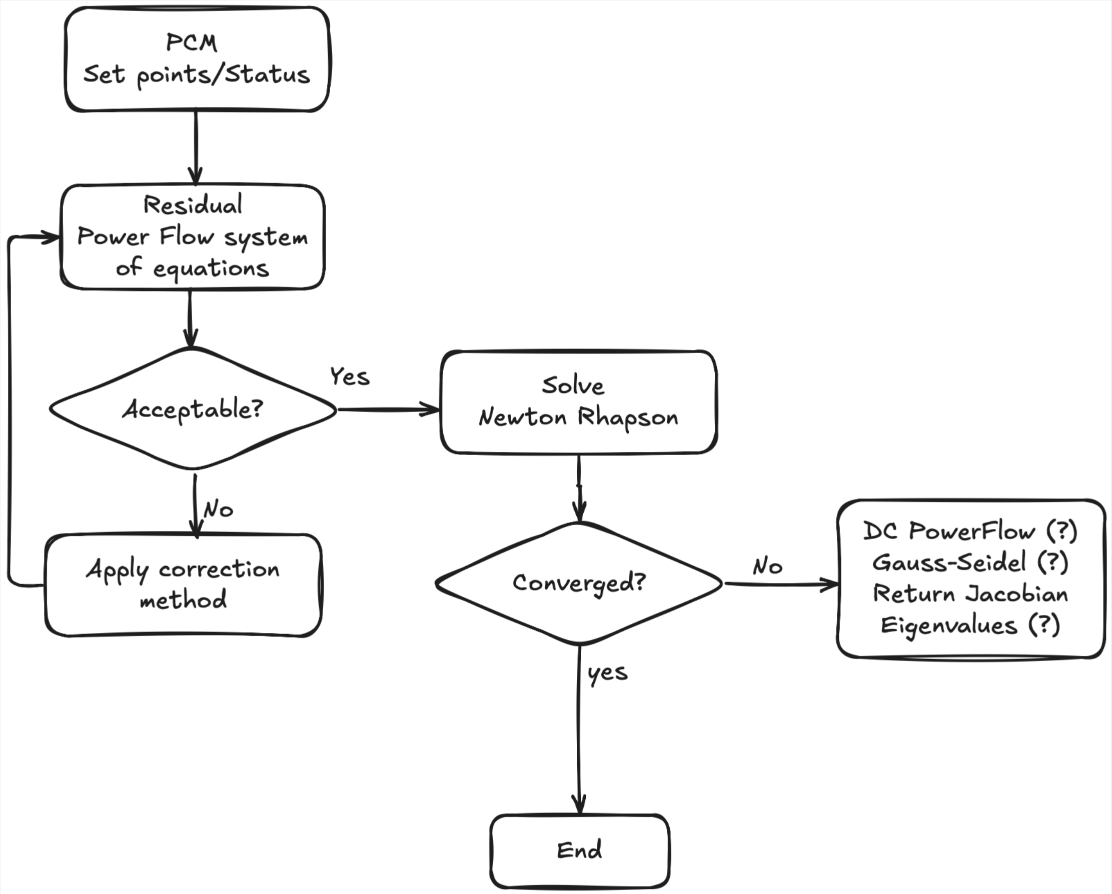


DETAILED TRANSMISSION EXPANSION

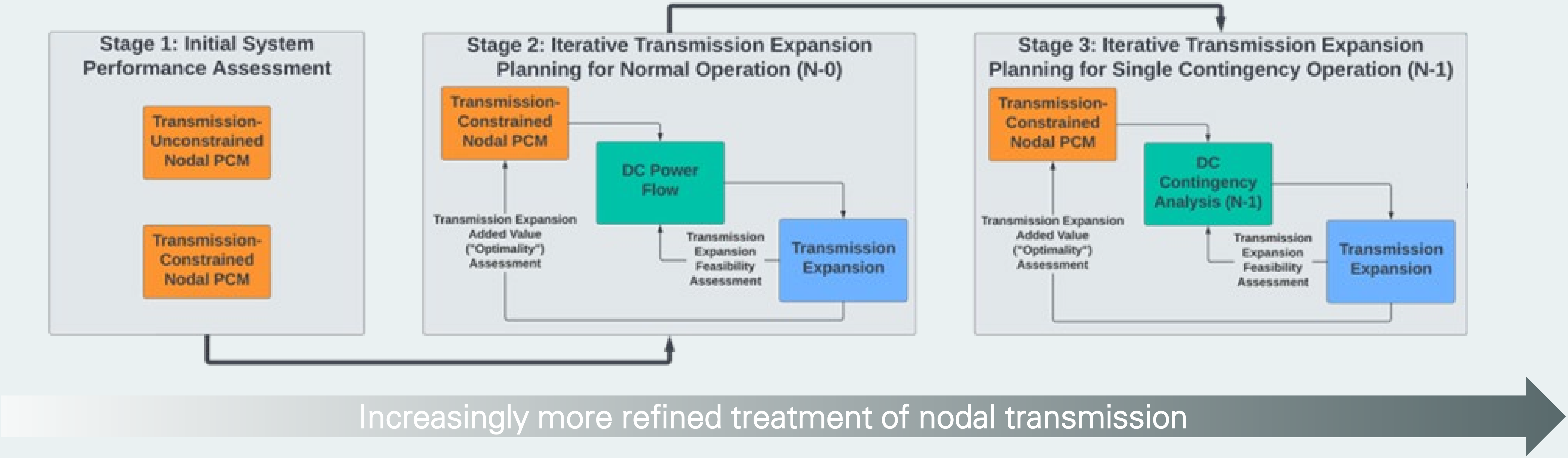
Iterative transmission expansion planning informed by CEM zonal transmission buildout (utilizing nodal PCM and DC power flow).

Challenge: AC power flow convergence across many operating points

- Bus types (e.g. PV, PQ) can change types based on PCM results.
- Large residuals for initial guess due to simplifications in PCM network representation.
- Distinguishing between numerical failures and system collapse when the power flow fails to converge.
- Determining valid fallback for failed power flow solves.

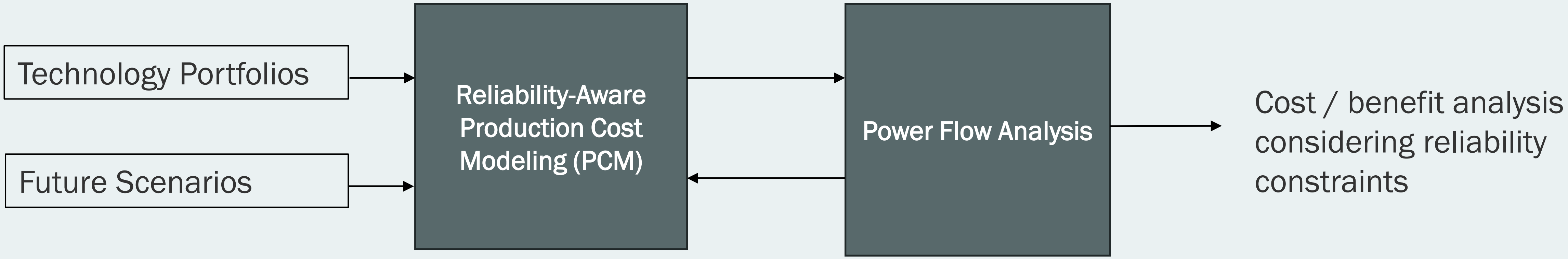


Iterative planning with Power Flow approaches



Transition between steps involves the selection of appropriate operating conditions (snapshots of representative hours from nodal PCM simulations) over which transmission expansion planning is undertaken (this is further described later and is in a process of continuing improvement).

Improved modeling: Reliability-aware Production Cost Modeling + Power Flow



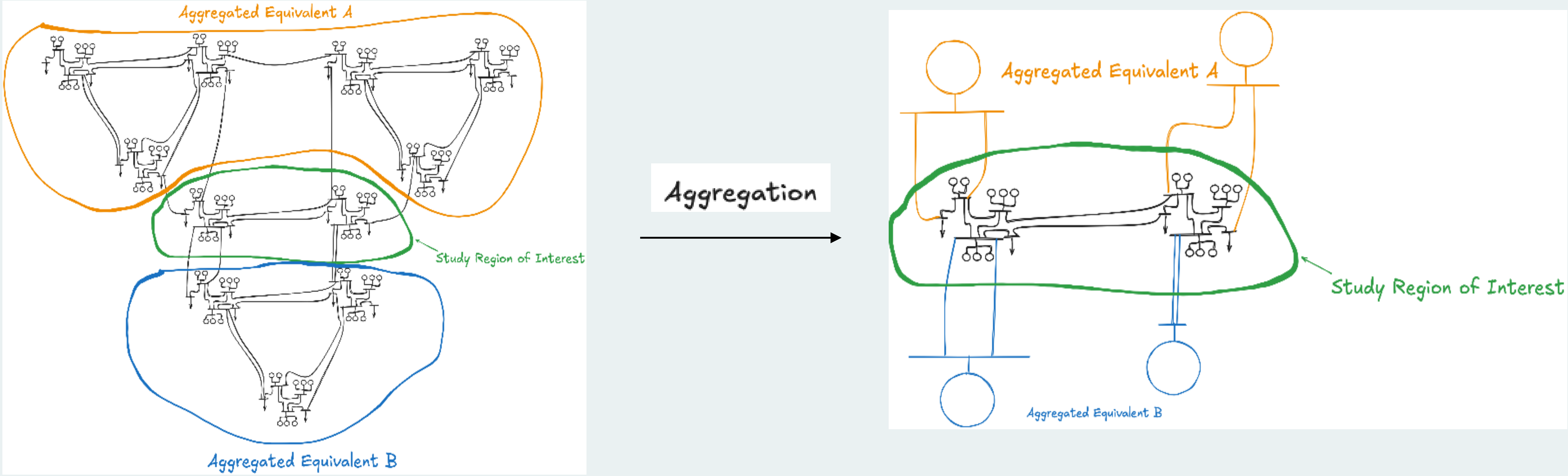
Benefits:

- Reliability-aware (i.e., security-constrained) PCM captures value of transmission portfolios in relieving congestion under contingency.
- Power flow “in-the-loop” captures reliability impact across a wider range of operational conditions. *This change represents a shift in the planning standard away from pre-determined time snapshots.*
- Build consensus among state offices and utilities around a common framework that captures both reliability and cost impacts.

Challenges:

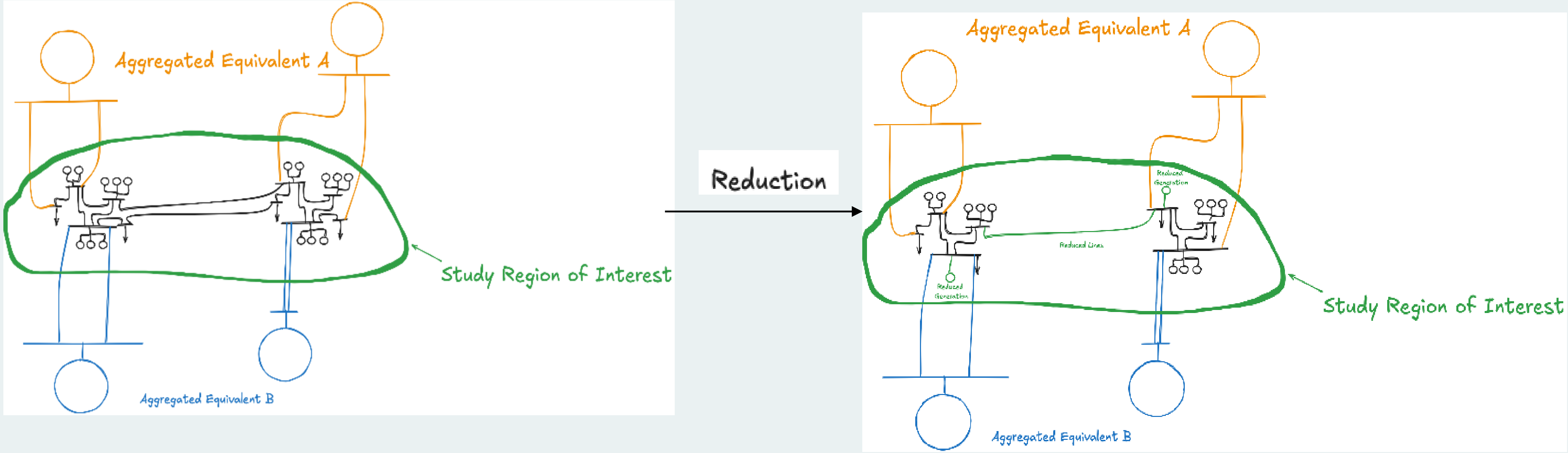
- Ensuring AC Power Flow convergence across many operating points.
- Increased computational burden of security constrained PCM (especially when modeling large, interconnected systems).
- Translation between multiple tools.

Challenge: Security-constrained formulations increase production cost modeling computational demand



- Identify the part of the grid that requires detailed representation while preserving key internal flows.
- Represent key interfaces with the broader interconnection.

Challenge: Security-constrained formulations increase production cost modeling computational demand



- Simplify internal parts of the system that are not expected to affect key planning results
- Examples include removing radial lines, aggregating degree two bus chains, and aggregating parallel lines.

Conclusion

State of practice

Decoupled cost and reliability analysis

Improved modeling

Reliability aware production cost modeling with power flow

Ideal case

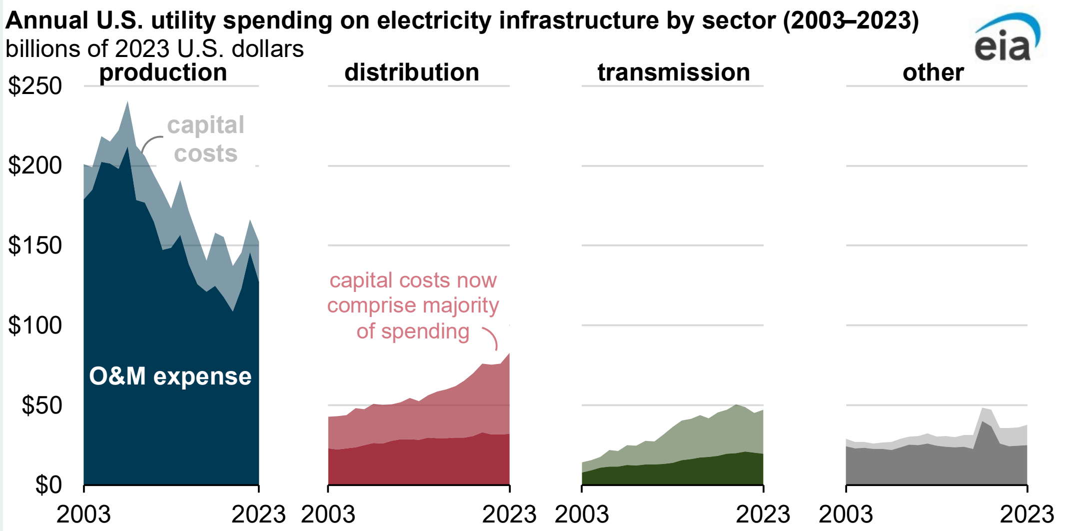
Detailed representation of GETs within transmission expansion.

Improved modeling fidelity and decision making
Increased modeling complexity

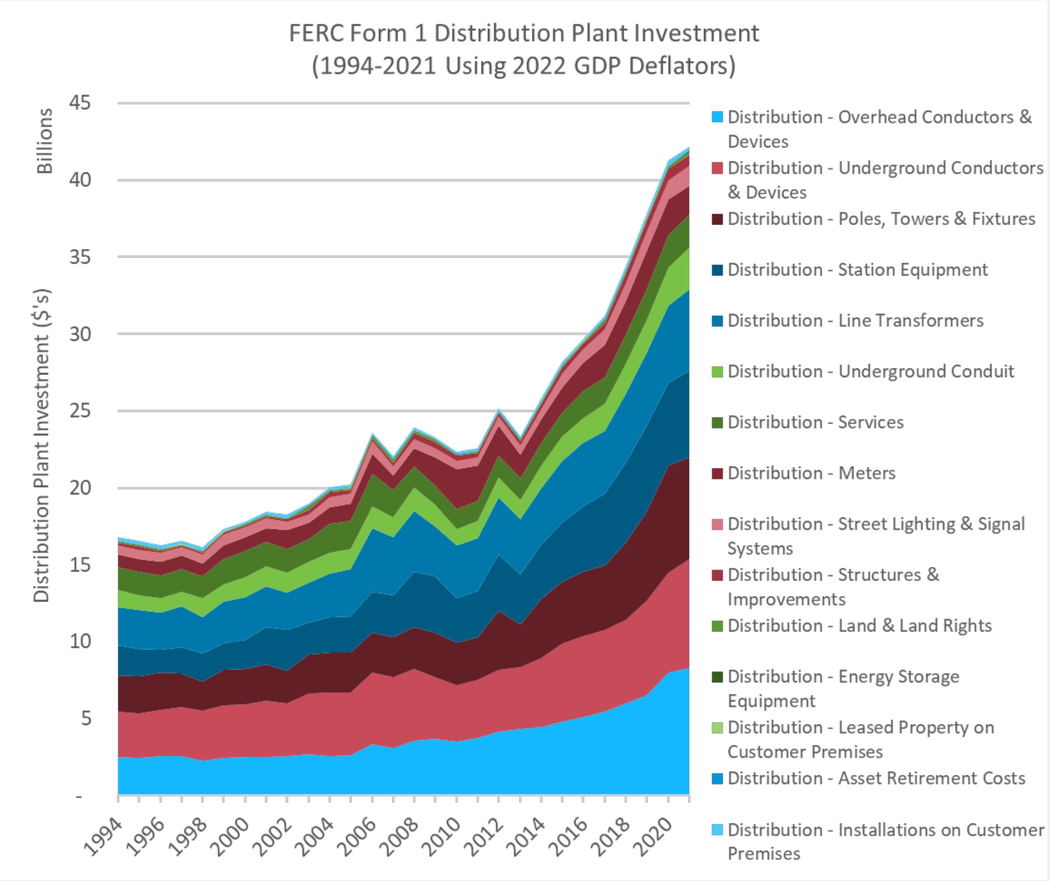
Distribution

Holistic Approach

- Investments in electric infrastructure are driven by new customers, aging infrastructure, resilience investments, and load growth
- Shifting from siloed planning of transmission and distribution systems to an integrated approach



Source: U.S. Energy Information Administration (2024)

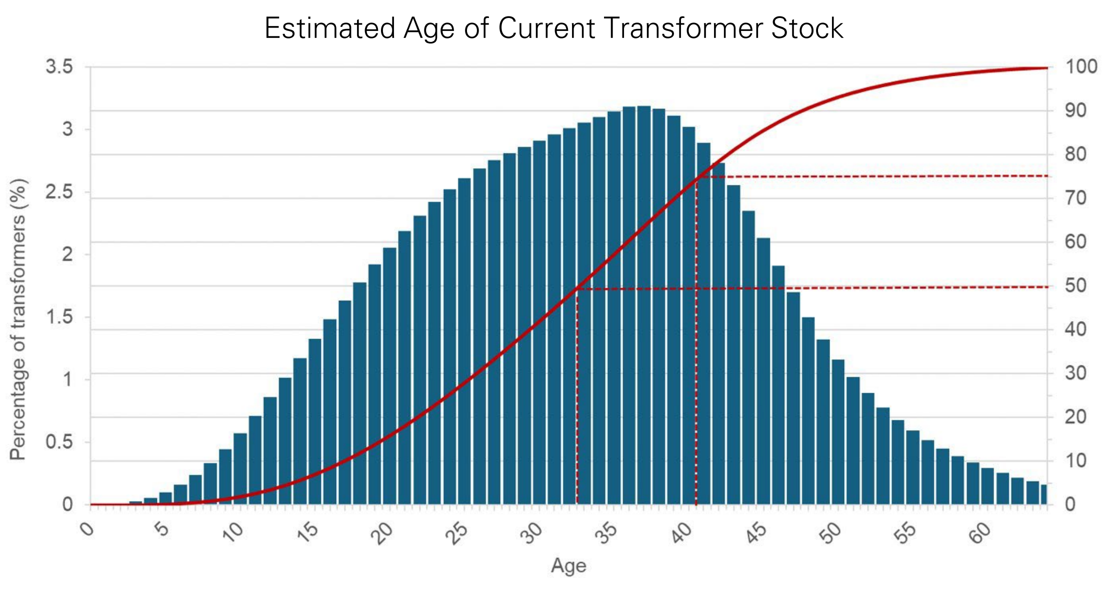


Source: NREL. 2024. Analysis of FERC Form 1. Data accessed from Hitachi Energy's Velocity Suite.

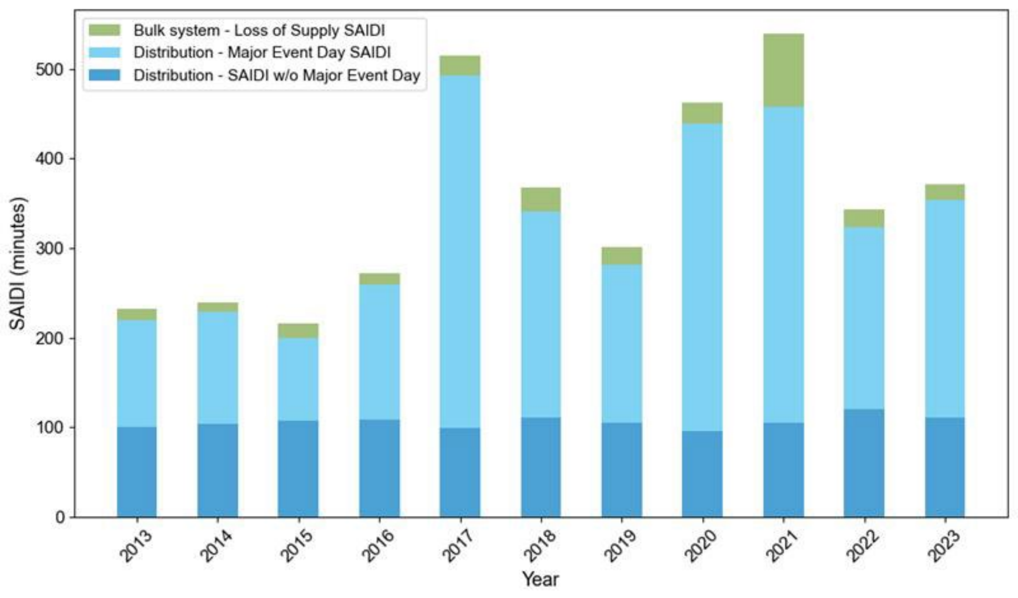
Challenges

Reliability: Aging Infrastructure & Weather

- Hazard response & resilience is driving investment
- Reliability metrics fail to measure the tail risk, intensity, and extent of consequences of major events, and are on their own, are not sufficient to guide resilience investment decisions
- Challenge to quantify relationship of investment to reliability/resilience



Aging infrastructure across both bulk and distribution networks needs to be modernized via strategic investments to enhance reliability and resilience



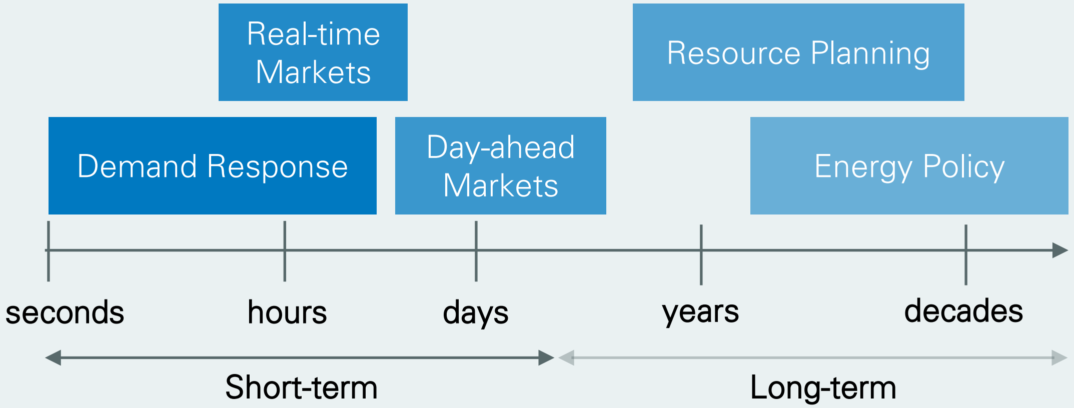
Comparing average SAIDI without Major Event Days (MED), SAIDI from only MED, and Loss of Service with MED shows that distribution outages are the primary contributor to customer disruptions

NREL. 2024. Distribution Transformer Demand: Understanding Demand Segmentation, Drivers, and Management Through 2050. https://www.nrel.gov/docs/fy25osti/92076.pdf.

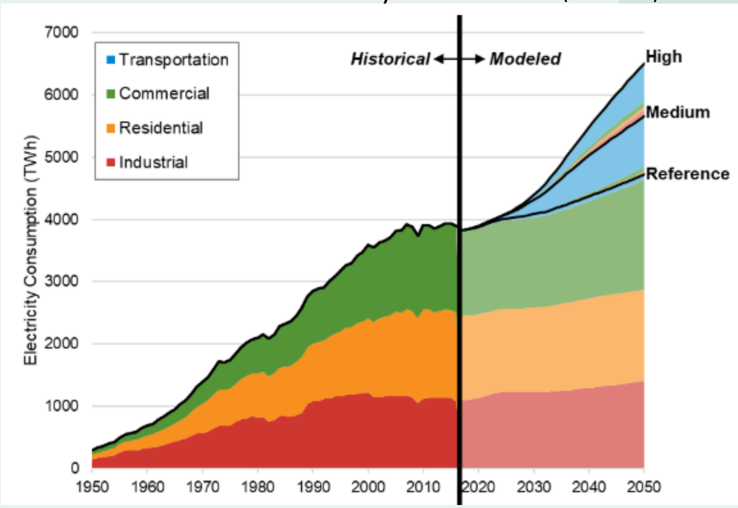
Graph credit: NREL EIA data analysis, Leslie Herding, NREL

Load Growth & Large Loads

- Load growth and large loads necessitates coordinated planning
- For distribution, granularity matters a lot more compared to transmission
- Ability for large G&T and system operators to aggregate utility-level forecasts is critical

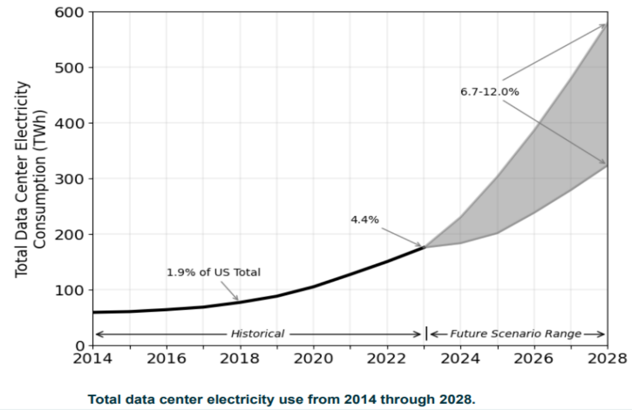


U.S. Annual Electricity Forecast (2016)



National Renewable Energy Laboratory. Electrification Futures Study (EFS). https://www.nrel.gov/analysis/electrification-futures.html.

Data Center Forecast (2016)



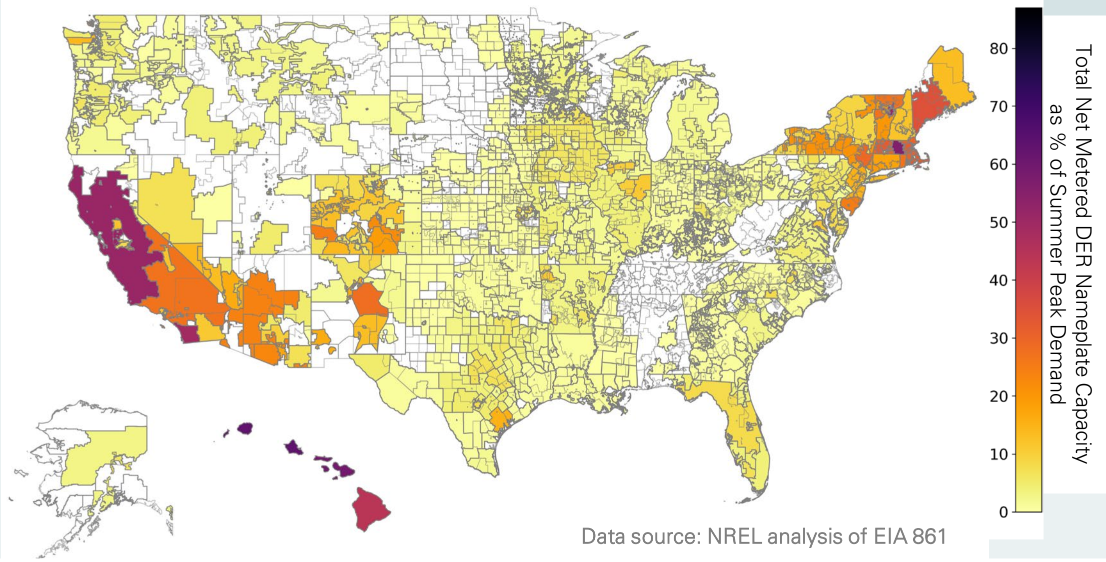
Berkeley Lab. 2024. 2024 United States Data Center Energy Usage Report. Link

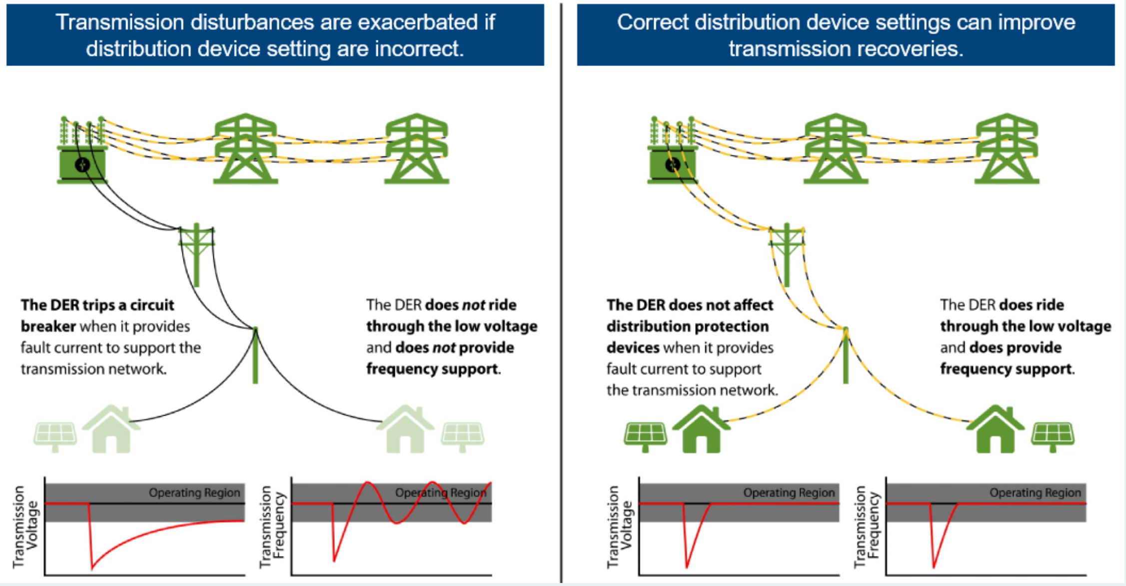
Content credit: Michael Blonsky, "Advanced Load Forecasting." Utility and Grid Operator Resources for Future Power Systems Webinar Series. NREL

DER Integration

- "Do nothing" and "do no harm" are low consequence strategies at low adoption levels where widespread loss of DERs is inconsequential to distribution or bulk power system operations
- More proactive strategies can help alleviate future risks for high DER adoption scenarios, as per IEEE 1547-2018
- FERC Order 2222 facilitates participation of DERs in regional electricity markets through aggregators/virtual power plants (VPPs)

Net Metered DER Capacity as Percentage of Summer Peak Load





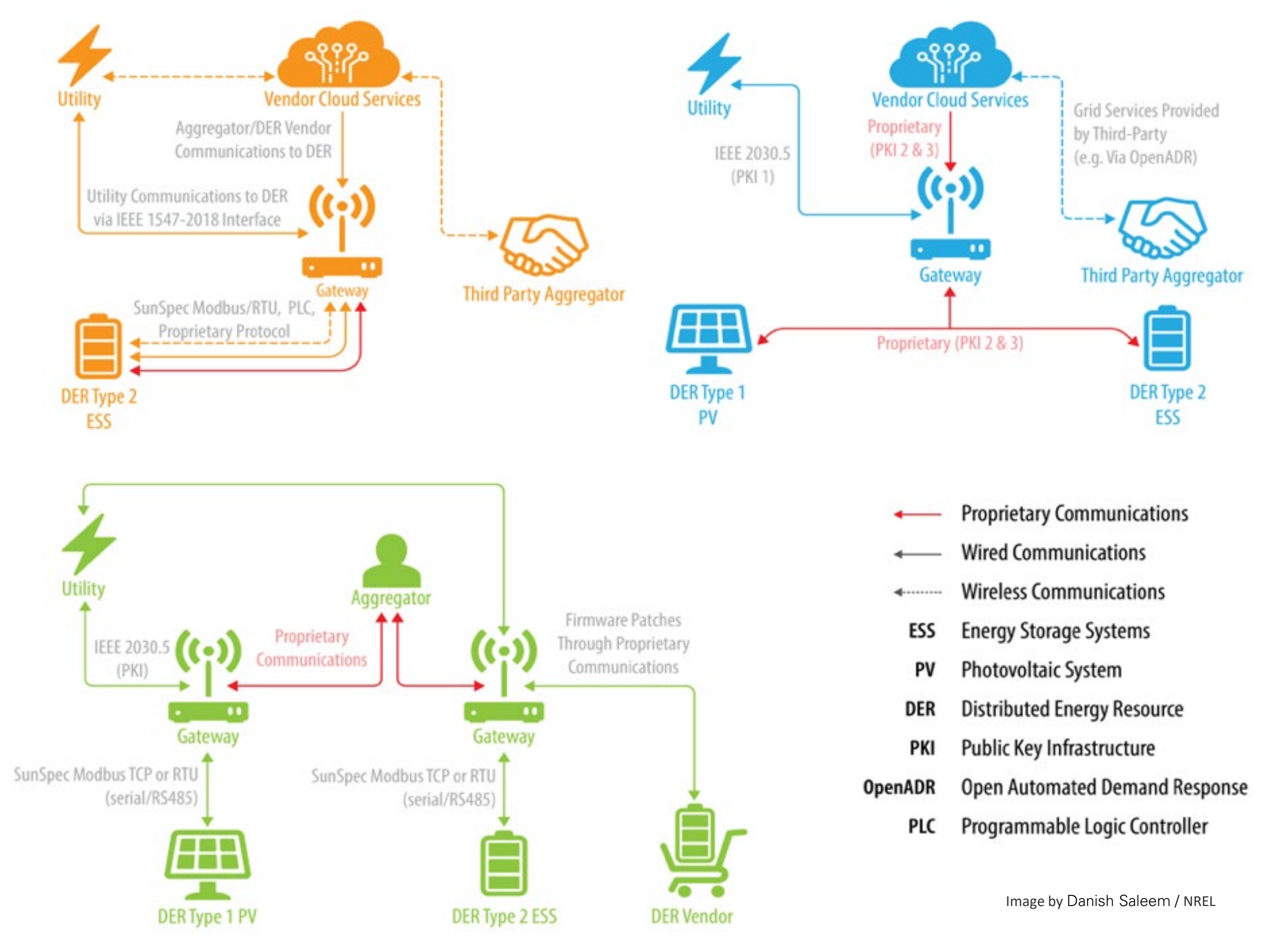
Grid Modernization Laboratory Consortium et al., "Fast Grid Frequency Support from Distributed Energy Resources"

Image and Content Credit: Jeremy Keen, Aadil Latif, and Kapil Duwadi

Cybersecurity

- Unique cybersecurity challenges for DERs (e.g., cross-organizational security and risk distribution)
- Rooftop and small solar capacity in the US was approximately 53 GW in 2024
    - None of which is required to follow NERC Critical Information Protection Standards
    - No widely recognized alternative cyber compliance standard for rooftop solar/DER
- Utilities implements cybersecurity protocols, but bigger risk is at bulk system aggregated at scale

Potential Architectures for Projected Future DER Systems



DER ecosystem is complicated, with varied actors across the board with lots of communications beyond those of traditional utilities

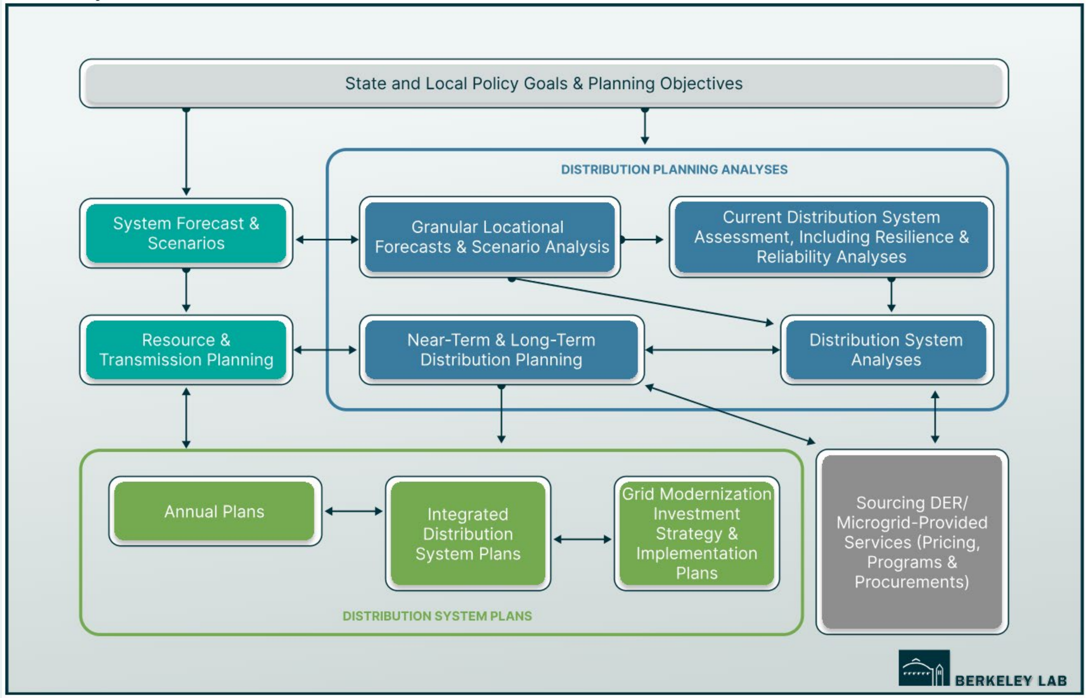
Content credit: Nik Urlaub. “Distribution Cybersecurity: Cybersecurity Considerations of Distributed Resources”. Utility and Grid Operator Resources for Future Power Systems Webinar Series. NREL

Solutions and Planning Innovations

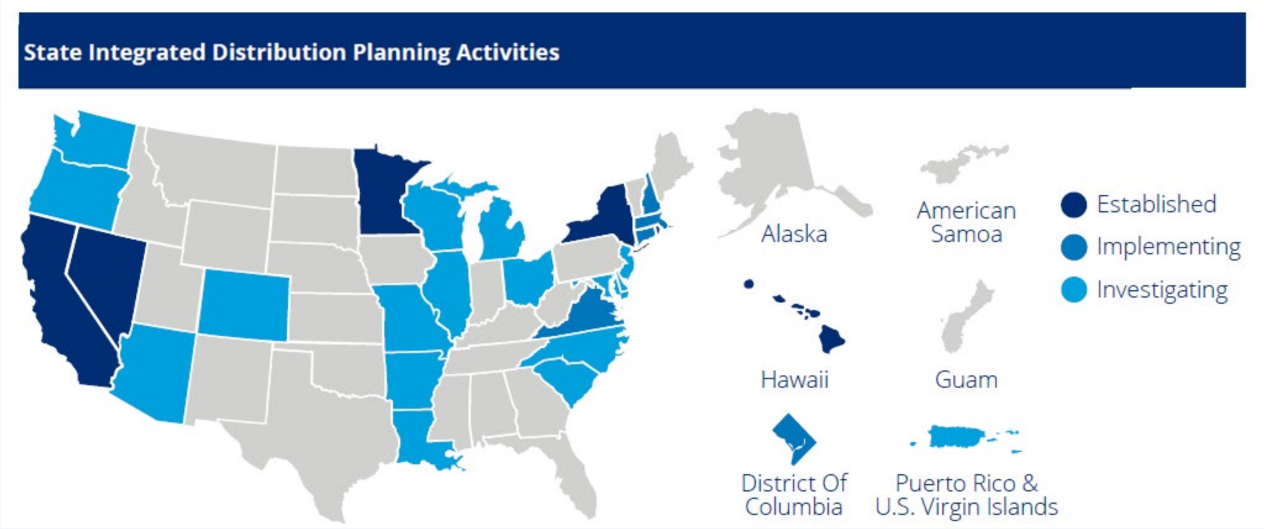
Integrated Distribution Planning

"An Integrated Distribution System Planning (IDSP) process provides a decision framework for developing holistic infrastructure investment strategies for local electricity grids. The planning process involves the determination of grid system requirements that are needed to achieve reliability, resilience, safety, affordability, and other objectives, such as equity and decarbonization."

Source: U.S. Department of Energy. 2025. "Integrated Distribution System Planning" https://www.energy.gov/oe/integrated-distribution-system-planning.



Source: Berkeley Lab. 2025. "Integrated Distribution System Planning." https://emp.lbl.gov/projects/integrated-distribution-system-planning.

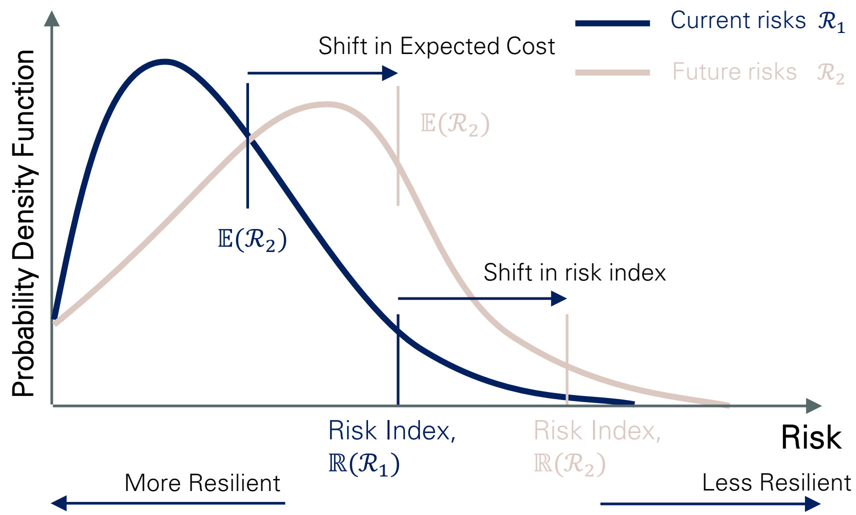


Source: Smart Electric Power Alliance (SEPA). 2020. "Integrated Distribution Planning: A Framework for the Future." https://sepapower.org/resource/integrated-distribution-planning-a-framework-for-the-future/.

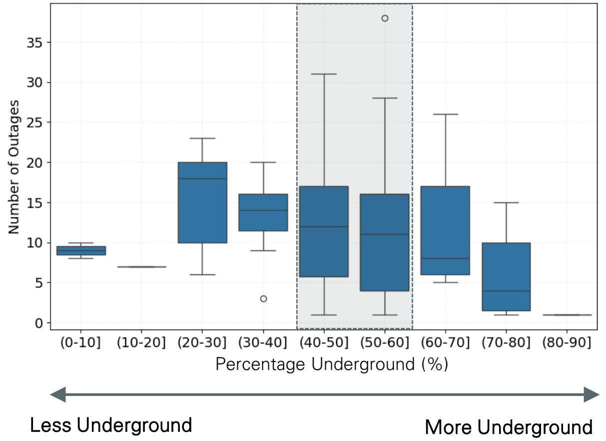
Resilience Planning

Hazard Characterization | Impact Assessment → Investment Prioritization | Risk and Cost-Benefit Analysis → Resilience Valuation and Investment Performance

System risk components (probability, vulnerability, consequence) evolve over time

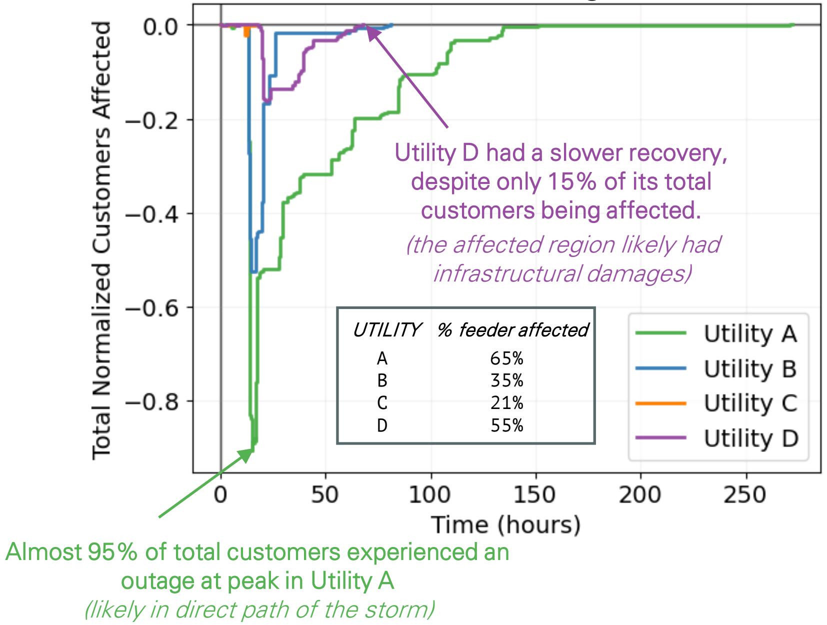


Feeders with Underground Segments vs Power Outages



Feeders with 40-50% and 50-60% underground segments had similar outage frequencies, suggesting diminishing returns and targeting undergrounding in vulnerable areas

Comparison of Performance Metrics for Utilities Within a Region



Content credit: Abodh Poudyal. "Weather-Driven Resilience for Distribution Systems." Utility and Grid Operator Resources for Future Power Systems Webinar Series. NREL

Advanced Load Forecasting

Bulk System Forecasts
Load growth
Efficiency
Demand response

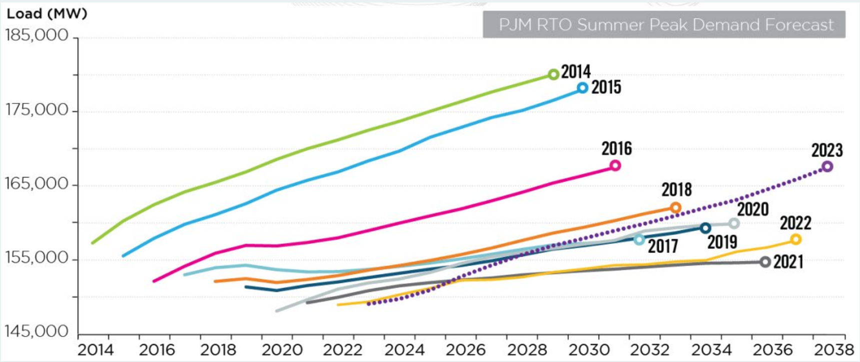
Five–20-year horizon
Peak demand + annual energy

Distribution Forecasts
Load growth
Efficiency

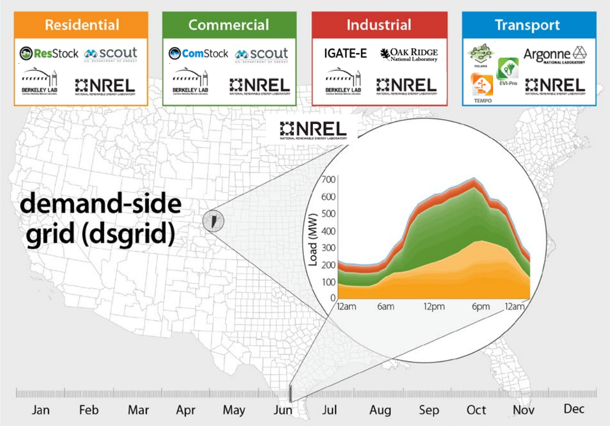
Three- to five-year horizon
Peak demand only

Integrated Forecasts
Load growth
Efficiency
Electrification
Demand flexibility
DER adoption
Weather event impacts

Three- to 20-year horizon
Hourly resolution
Customer resolution



PJM. 2023. 2022 Tennessee Infrastructure Report

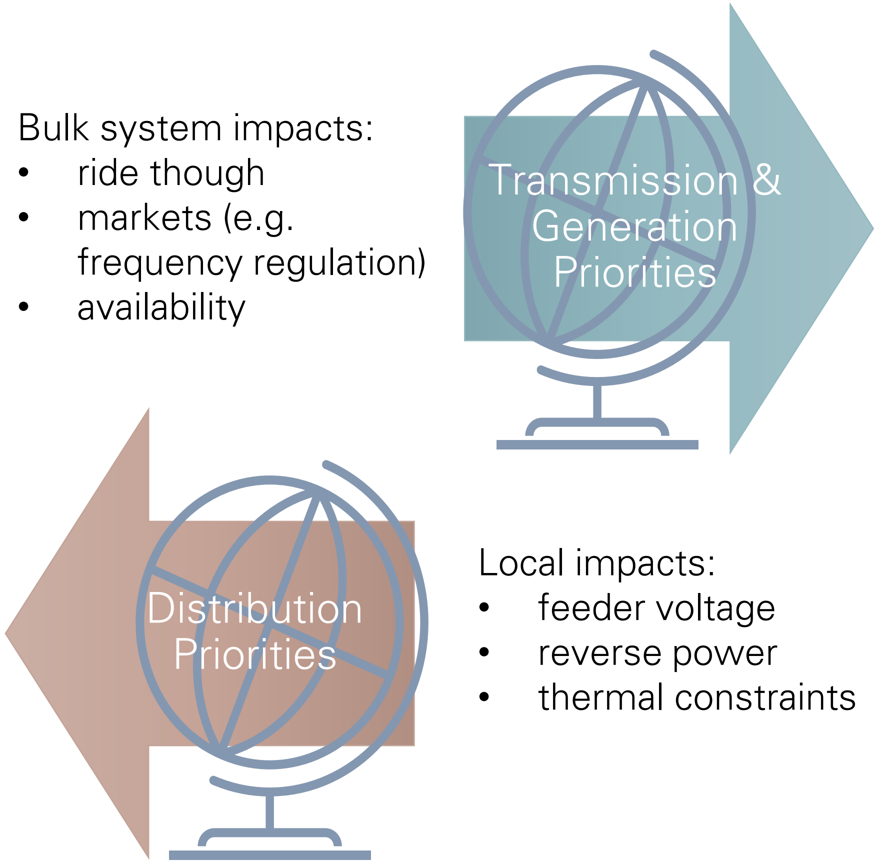


Content credit: Michael Blonsky, "Advanced Load Forecasting." Utility and Grid Operator Resources for Future Power Systems Webinar Series. NREL

DER Interconnection for T&D

Distribution interconnection standards and grid codes provide the baseline requirements for all resources on the grid that are not on the bulk system but may have bulk system impacts

- Bulk System priorities need to be identified and satisfied via local control when possible, during interconnection
- Standardize DER performance for higher confidence that DERs in all regions of bulk system to simplify modeling, monitoring, and verification
- Elements of DER interconnection standards are important for the bulk system but not critical for the distribution system (e.g., frequency)
- Flexible interconnection utilizes DER control schemes to manage export to stay within grid constraints
- Combined T&D study when large volume of DERs, large loads, high DER penetration

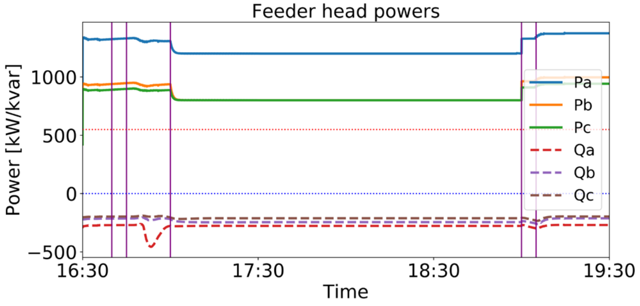


VPPs and DERMS

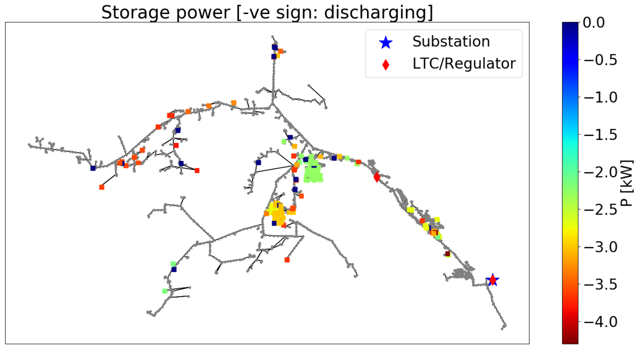
* VPP: Virtual Power Plant
* DERMS:

- While demand response programs like TOU rates influence customer behavior indirectly, VPPs actively control/manage and dispatch DERs
- VPPs and DERMs aggregate and manage DERs to provide grid services which contribute to the overall reliability of the system
- Both enable better coordination between DERs on the distribution side and the needs of the bulk power system

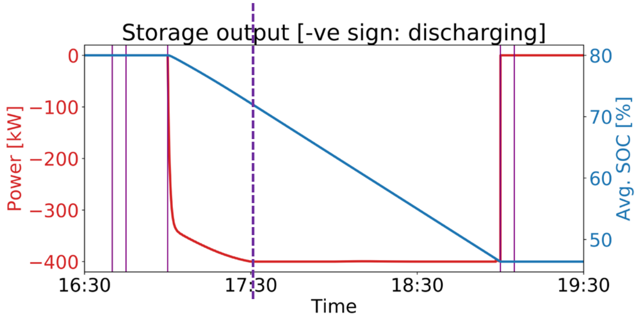
VPP implemented in Holy Cross Energy (HCE)'s distribution system



DERMS Peak Load Management target powers: 1200 kW, 800 kW, and 800 kW for Phase A, B and C



The colored dots indicate the locations of both photovoltaic (PV) systems and batteries



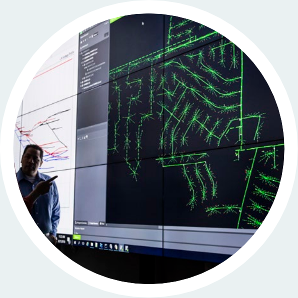
The project aimed to demonstrate the VPP's peak demand management by setting substation power targets and dispatching residential battery storage, achieving a 400-kilowatt power reduction.

Connor O'Neil. 2019. "Small Colorado Utility Sets National Renewable Electricity Example Using NREL Algorithms." NREL. Dec. 10, 2019. URL: https://www.nrel.gov/news/features/2019/small-colorado-utility-sets-national-renewable-electricity-example-using-nrel-algorithms.html
Padullaparti, Harsha, Annabelle Pratt, Ismael Mendoza, Soumya Tiwari, Murali Baggu, Chris Bilby, and Young Ngo. "Peak Demand Management and Voltage Regulation Using Coordinated Virtual Power Plant Controls." IEEE Access 11, 130674–130687. URL: https://www.nrel.gov/docs/fy24osti/81105.pdf

Content credit: Harsha Padullaparti. "Virtual Power Plants and Distributed Energy Resource Management Systems." Utility and Grid Operator Resources for Future Power Systems Webinar Series. NREL

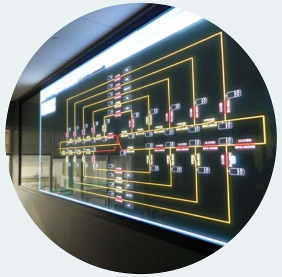
Grid Modernization and Automation

Advanced Distribution Management System: The Roadmap to a Smart-Grid



Geospatial Information System (GIS)

- Visualization
- Interface



Distribution Management System (DMS)

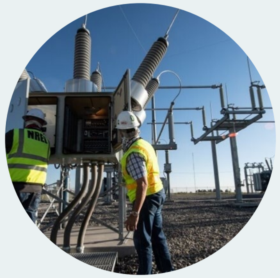
- State estimations
- System operations
- Automation

Advanced Metering Infrastructure (AMI)

- Smart meters
- Data management

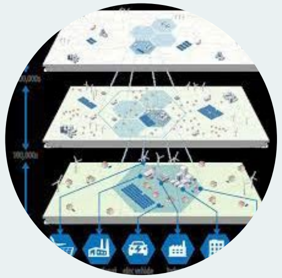
Outage Management System (OMS)

- Switching order management
- AMI and call management



Supervisory Control and Data Acquisition (SCADA)

- Data acquisition
- Monitoring



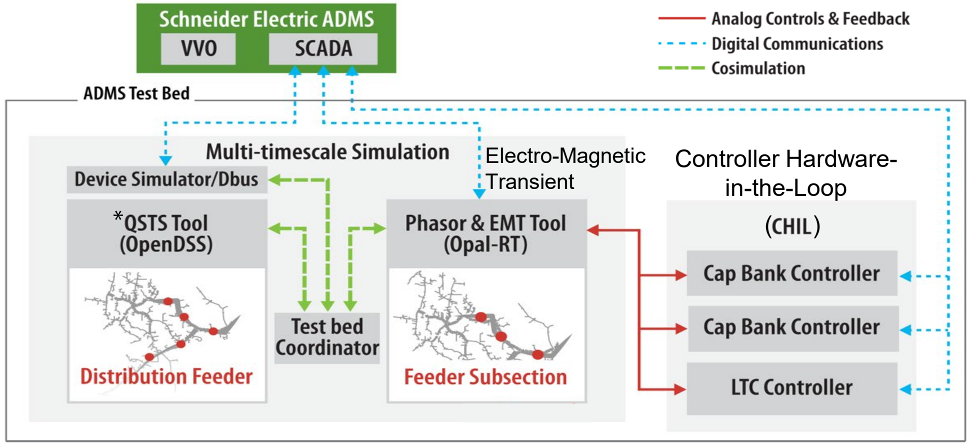
Applications Requiring GIS, DMS, OMS & SCADA

- Fault Location, isolation, and system Restoration (FLISR)
- Volt/Var optimization (VVO)

Content credit: Ismael Mendoza, Annabelle Pratt, Murali Baggu. "Advanced Distribution Management System (ADMS)." Utility and Grid Operator Resources for Future Power Systems Webinar Series. NREL

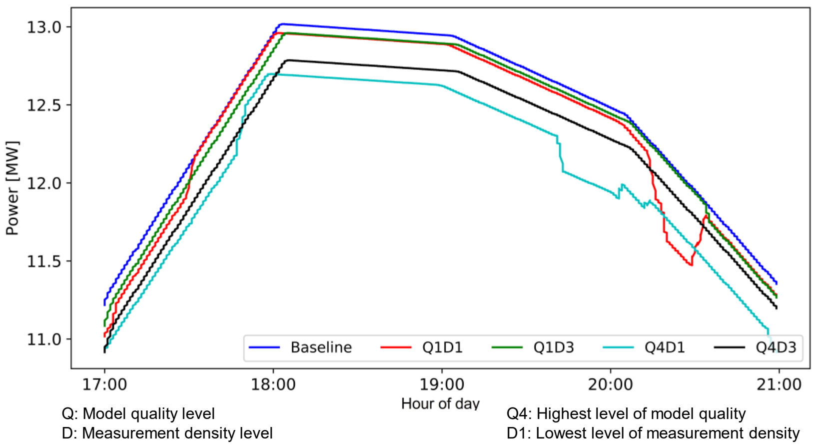
NREL's ADMS Test Bed

NREL project to evaluate the impact in the performance of the ADMS Volt Var Optimization application with various levels of data remediation and additional telemetry



QSTS: Quasi-Static Time Series
LTC: Load Tap Changer
VVO: Volt/VAR Optimization
SCADA: Supervisory Control and Data Acquisition
EMT: Electromagnetic Transient

Feeder head power demand curves for all scenarios



Mendoza, Ismael, Annabelle Pratt, Harsha V. Padullaparti, Soumya Tiwari, and Murali Baggu. 2024. Model Quality and Measurement Density Impact on Volt/Volt Ampere Reactive Optimization Performance. *Energies* 17(15): 3707. https://www.mdpi.com/1996-1073/17/15/3707

Key Insights

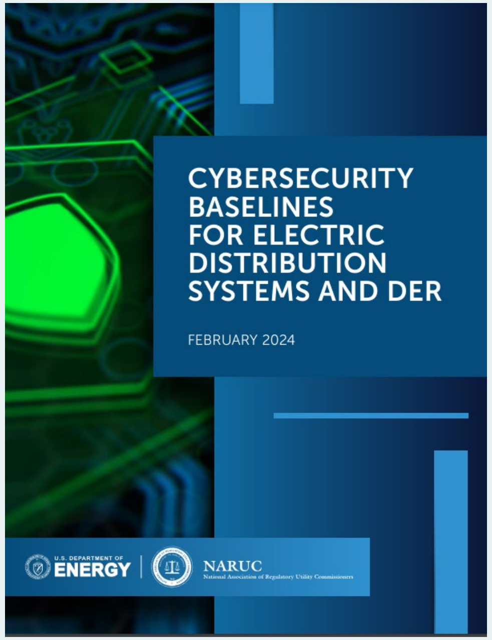
- ADMS implementation is a multiyear process.
- The model accuracy is an essential piece to the effectiveness of the ADMS.
- Improve sensing strategy
- Workforce development
- Scalability and flexibility

Content credit: Ismael Mendoza, Annabelle Pratt, Murali Baggu. "Advanced Distribution Management System (ADMS)." Utility and Grid Operator Resources for Future Power Systems Webinar Series. NREL

Cybersecurity

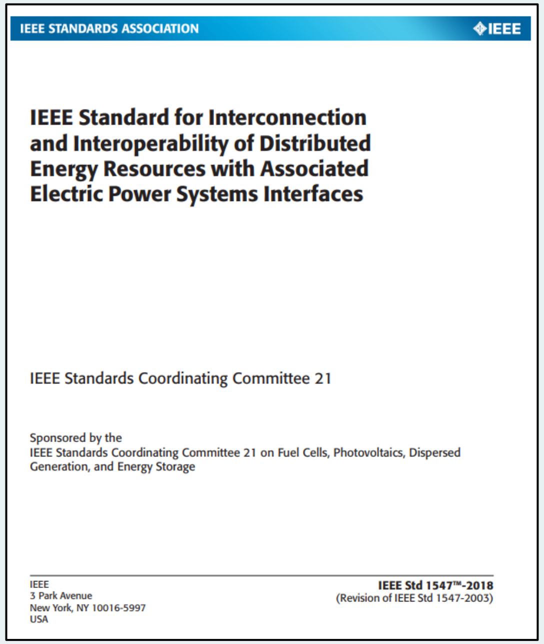
NARUC Cybersecurity Baselines

- Validating Cybersecurity Controls: Ensuring that there are actual cybersecurity requirements for DER vendors and suppliers.
- Log Collection and Storage: Implementing systems that collect logs about DER activities and store them appropriately.
- Device Access Control
- Incident Reporting: Ensuring that relevant entities are appropriately notified if an event occurs



IEEE 1547

- IEEE 1547.3 standard focuses on cybersecurity for the interconnection of DERs, offering comprehensive considerations, recommendations, testing, and commissioning guidelines
- Communication protocols between DERs and utility control systems, ensuring integration and coordination.


IEEE STANDARDS ASSOCIATION IEEE

IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

IEEE Standards Coordinating Committee 21

Sponsored by the
IEEE Standards Coordinating Committee 21 on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage

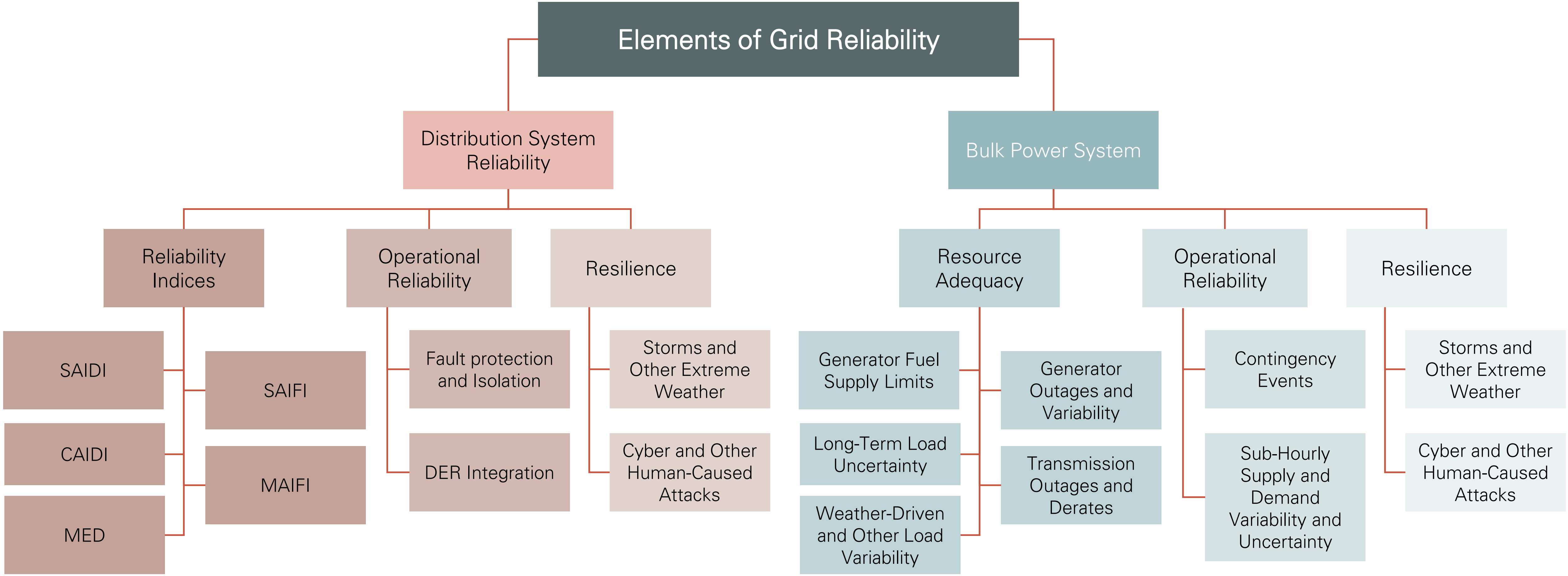
IEEE
3 Park Avenue
New York, NY 10016-5997
USA

IEEE Std 1547™-2018
(Revision of IEEE Std 1547-2003)

Content credit: Nik Urlaub. “Distribution Cybersecurity: Cybersecurity Considerations of Distributed Resources”. Utility and Grid Operator Resources for Future Power Systems Webinar Series. NREL

Planning Transmission & Distribution Together

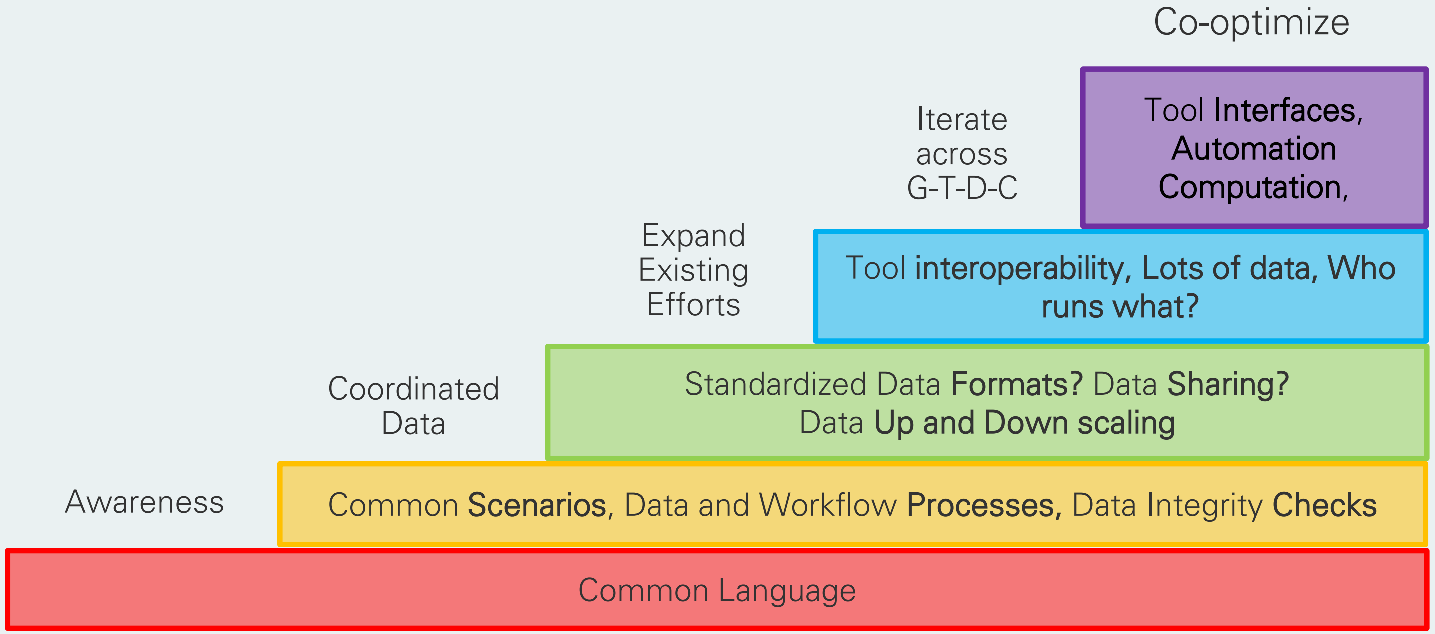
T&D Reliability



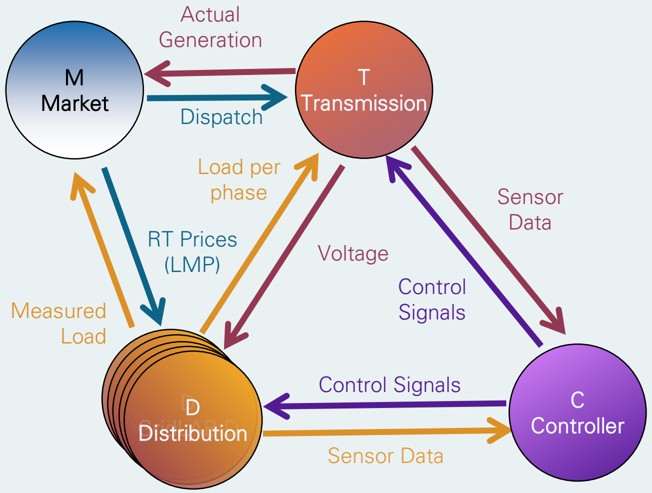
Adapted from Paul Denholm. "Resource Adequacy". Utility and Grid Operator Resources for Future Power Systems Webinar Series. NREL

T&D Planning

- Capacity and grid stability: DERs and IBRs on the distribution side can impact system stability for the bulk system
- FERC 2222: VPPs and DERMs can provide services to the bulk power system
- Distribution Planning: Advance distribution planning to harmonize with the longer timeframes
- Goal: Reduce overall costs and increase system reliability/resilience



T&D coordination via a range of increasingly sophisticated approaches



Co-simulation enables simulating arbitrary combinations of physical/engineering and control/market tools

Content credit: Bryan Palmintier. "Transmission and Distribution Coordination". Utility and Grid Operator Resources for Future Power Systems Webinar Series. NREL

DOE-funded Resources and Assistance for State Energy Offices and Regulators Program

https://StateTAProgram.lbl.gov

Help Desk

- Online intake form w/ rolling review
- SME provides up to **4 person-hours of support**
- Intake form and support available now

Expert Match

- Online intake form w/ rolling review
- SME provides up to **100 person-hours of support**
- Intake form and support available now

Deep Dive

- Detailed application form in planned ~6-month cycle
- Team of SMEs provide **100+ person-hours of support**
- Detailed online application available soon

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Extra slides