MI POWER GRID

Making the Most of Michigan's Energy Future

Integration of Resource, Distribution, and Transmission Planning

Advanced Planning Stakeholder Meeting

December 16, 2020

MPSC

Michigan Public Service Commission

Workgroup Instructions

1. This meeting is being recorded.

2. Please be sure to mute your lines.

3. There will be opportunities for question/comments after each of the sections identified in the agenda. Please type questions into the chat function or use the “raise hand” function during this time. We will open it up to those on the phone after those using the chat function.

4. Questions will be addressed at the end of each presentation segment.

5. We will be requesting comments, after all the meetings, which will be posted to the webpage.

6. The presentations for all the meetings are posted to the Advanced Planning webpage.

7. If you are having technical difficulty, please contact Jon DeCooman at DeCoomanJ@michigan.gov.

MI POWER GRID

Making the Most of Michigan's Energy Future

Agenda Items		
1:00 pm	Introduction	Roger Doherty (MPSC)
1:15 pm	System Forecasting for Energy Planning – MISO Perspective	Aditya Prabhakar (MISO)
1:55 pm	Distribution Forecasting	Curt Volkmann (GridLab)
2:35 pm	Break	
2:40 pm	Forecasting DER/EVs Techniques & Tools	Brady Cowiestoll (NREL)
3:20 pm	Forecasting DERs Economic Valuation	Tom Eckman (LBNL)
4:00 pm	Closing	Roger Doherty (MPSC)
4:10 pm	Adjourn	

MPSC
Michigan Public Service Commission

MI POWER GRID

Making the Most of Michigan's Energy Future

Aditya Jayam Prabhakar, MISO

Advanced Planning Stakeholder Meeting

December 16, 2020

MPSC

Michigan Public Service Commission

System Forecasting for Energy Planning

MI Power Grid Stakeholder Session:
Integration of Resource/Distribution/Transmission Planning

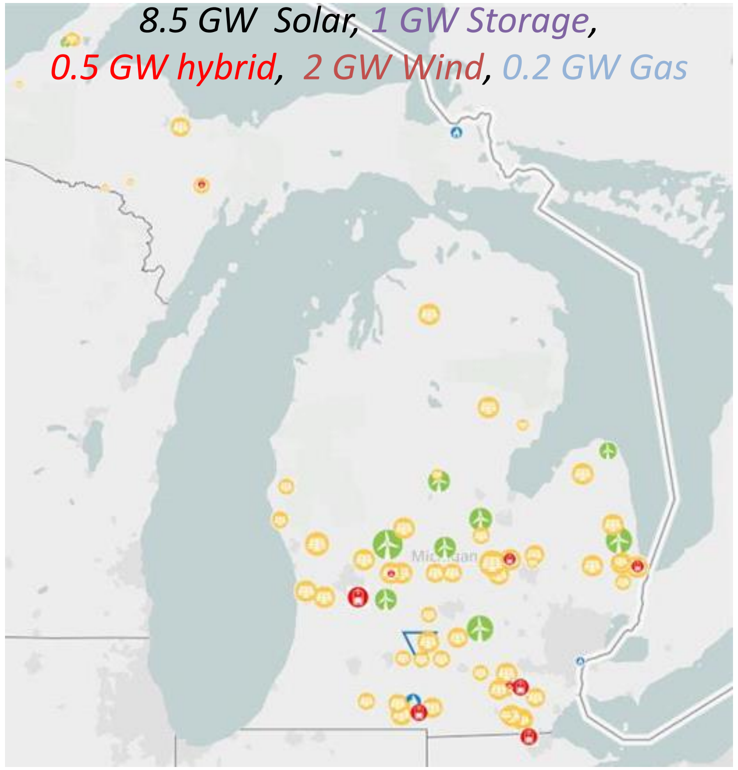
December 16th, 2020

MISO's generation fleet continues to experience significant changes due to a combination of factors

	2005	2020*
Coal	76%	33%
Gas	7%	~35%
Wind	~0%	12%
Solar	~0%	~0%

2020* - November 2019 – October 2020

Generator Queue



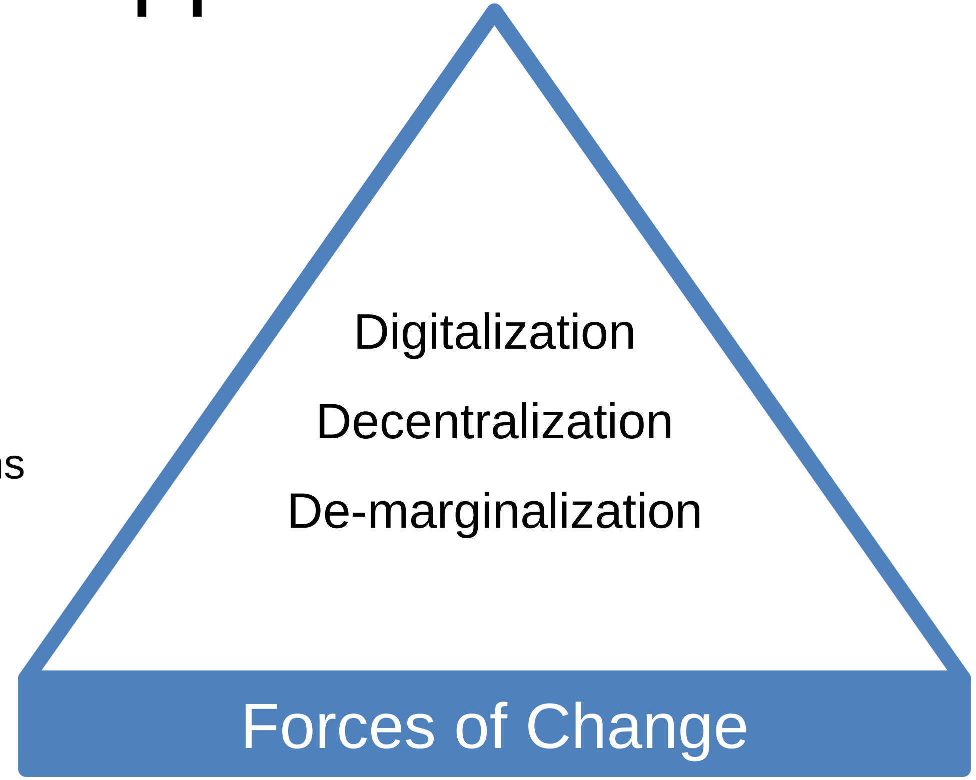
Coal Gas Wind Solar Other Battery Storage

Increasing magnitude & rate of change drives need for shift in approach to maintain reliability

<u>Digitalization</u>

New classes of and controls for electric consuming devices

- Grid management from digital controls integrated into distribution and bulk operations



<u>Decentralization</u>

Migration from large stations to smaller distributed resources

- DER (storage, solar, EVs, DR, IoT)
- Closer coordination with distribution networks

<u>De-marginalization (low / no marginal costs)</u>

Substantial growth of renewables, non-price sensitive DERs, and continued availability of nuclear and hydro

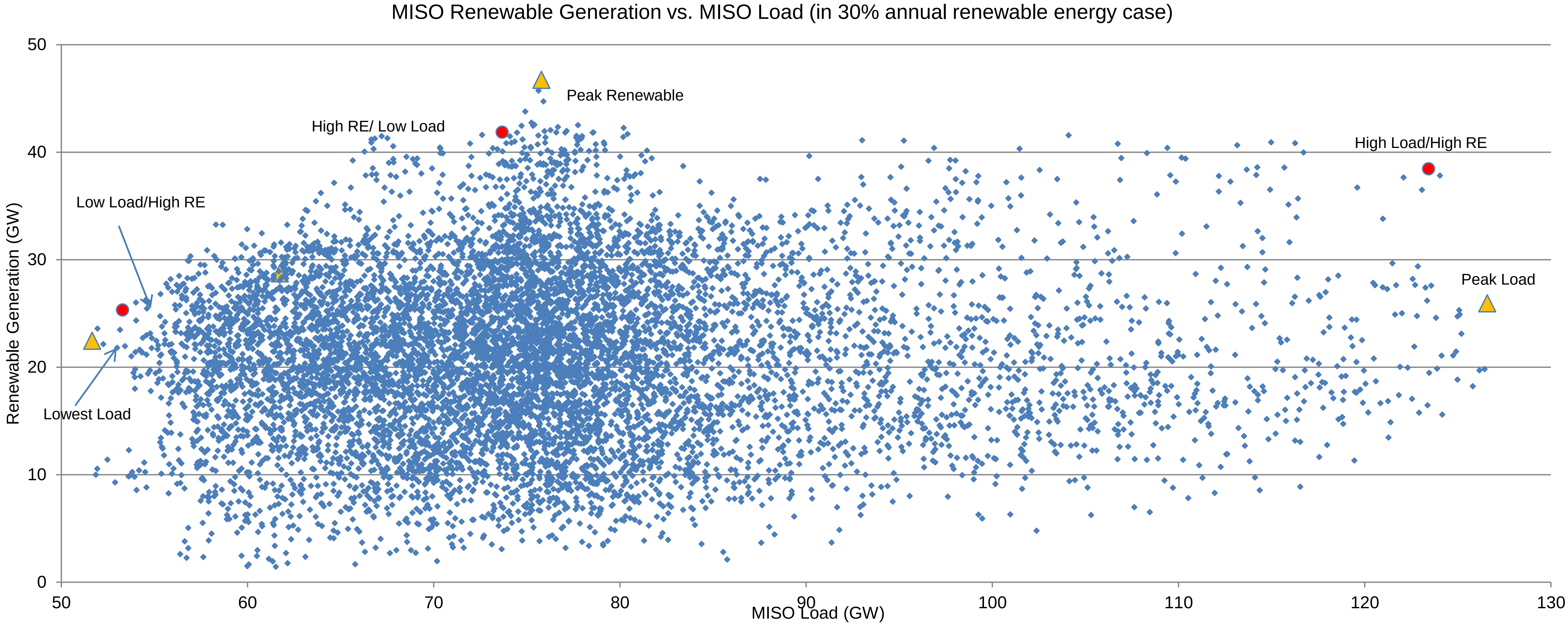
- Reduced flexibility and potential shortages of currently free ancillaries (e.g., voltage, frequency)
- Market design must incentivize availability of all needed essential reliability services

Improved load modeling and DER forecasting is needed to inform the right solution

- Our planning environment is changing:
  - Some customers are actively managing their energy usage
  - Some customers have preferences on fuel supply source
  - Sustained lower natural gas prices & improved economics and tax credits around renewable resources accelerated generation resource evolution
  - Greater granularity and deeper understanding of each component of the energy demand is needed

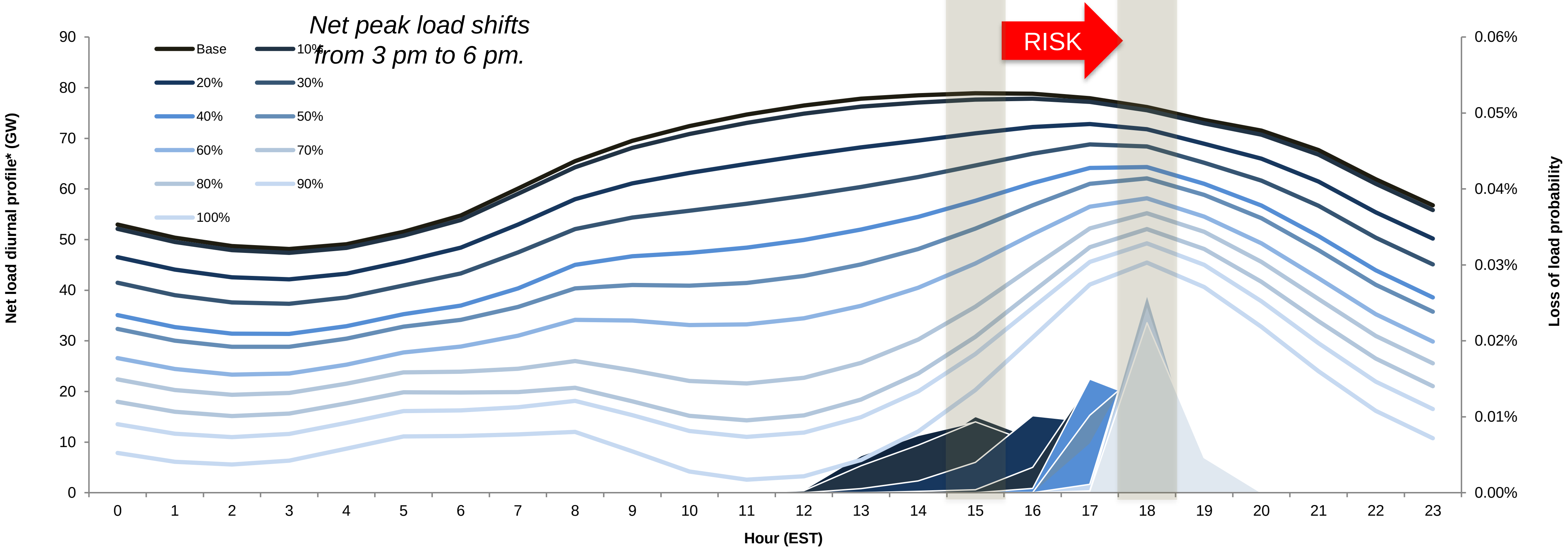
- The changing resource mix and its interaction with demand and energy become more prominent inputs driving transmission planning outcomes

Traditional points of transmission stress are changing as renewable penetration grows* - **All Hours Matter**



*As seen in MISO's Renewable Integration Impact Assessment (RIIA)

As renewable penetration increases, the risk of losing load shifts and compresses to a smaller number of hours



- Probability of losing load is targeted at one day in ten years over all penetration levels.
- While aggregate risk remains constant, the risk in specific hours increases.

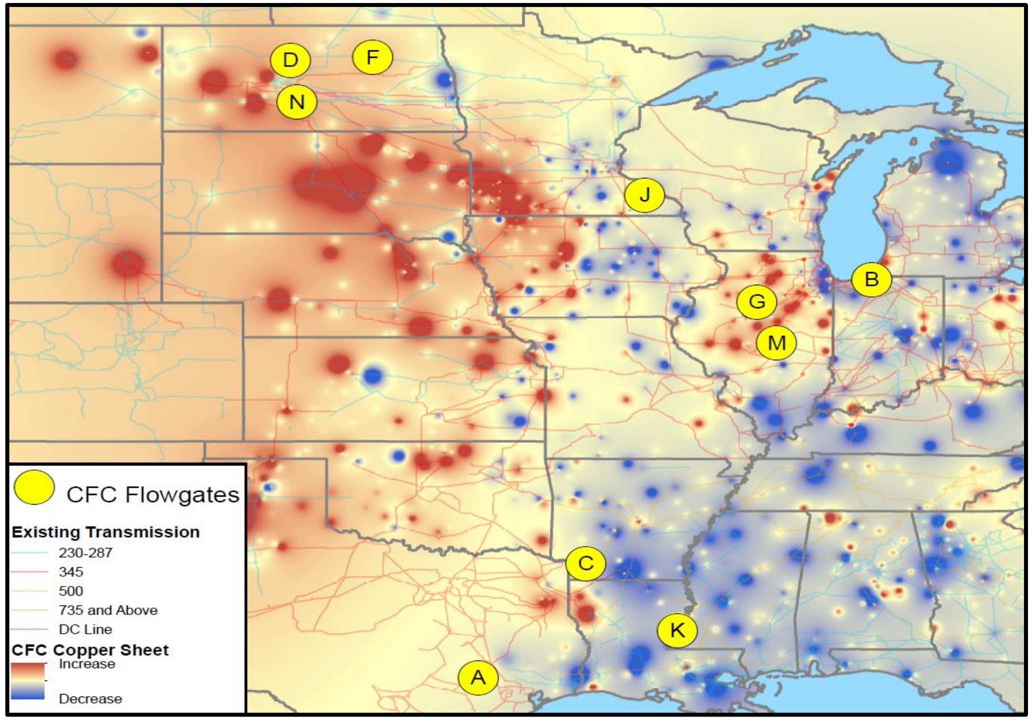
Profile shapes represent hourly averages across all days of the 6 study years.

*Source: Renewable Integration Impact Assessment (RIIA)

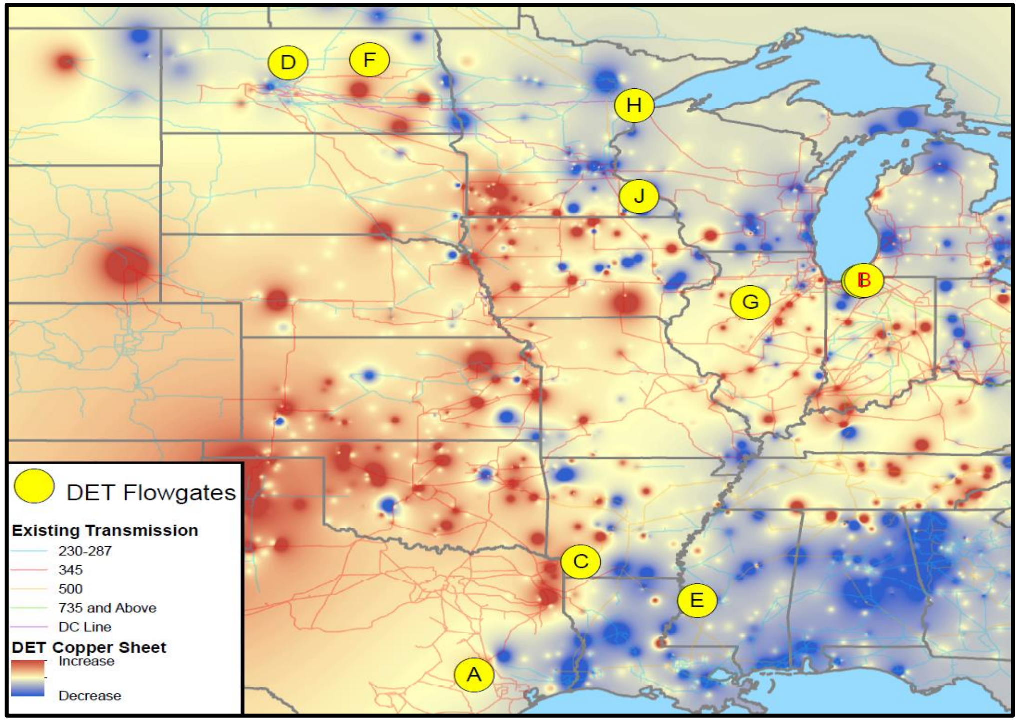
Hourly gross load forecast helps provide foresight into the risks & planning for appropriate mitigation

Regional congestion and transmission needs vary based on shifting energy requirements

Transmission copper sheet in CFC Future



Transmission copper sheet in DET Future



Red denotes sources for economic generation; blue denotes lack of economic generation resources

MI POWER GRID
MPSC

Objective is to develop MISO region's long-term system forecast

Componentized Demand & Energy Forecast	Gross Demand & Energy	DR/EE (incl. non-market)	DER, storage, & BTMG (incl. non-market)	Electric Vehicle Penetrations
Temporal & Granularity	20-year horizon	Monthly granularity	Base hourly load shape	
Consistency	Consistent drivers	Common set of assumptions	Participation	

The load shape observed from operations is comprised of many components

Gross demand & energy forecast

+ Energy Efficiency

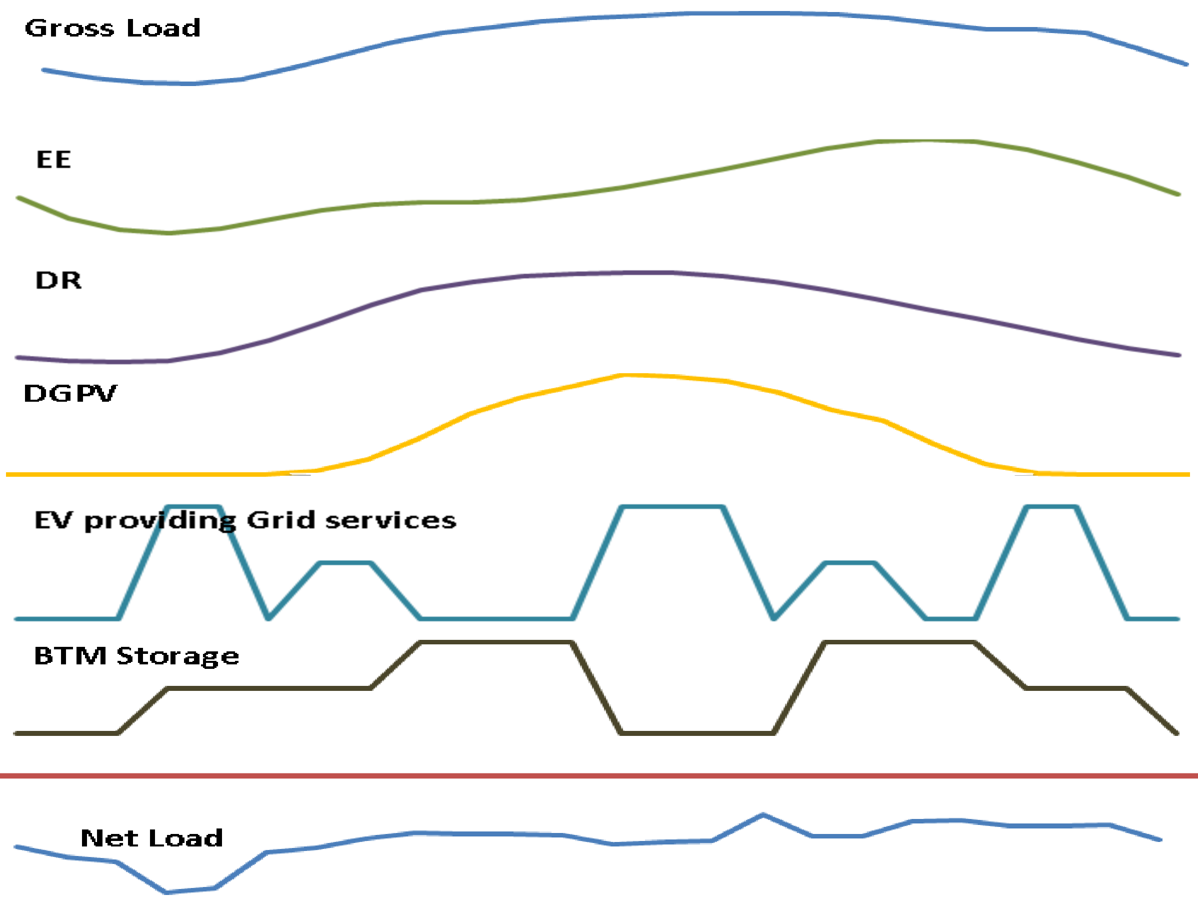
+ Demand Response

+ BTM Distributed Energy Resources

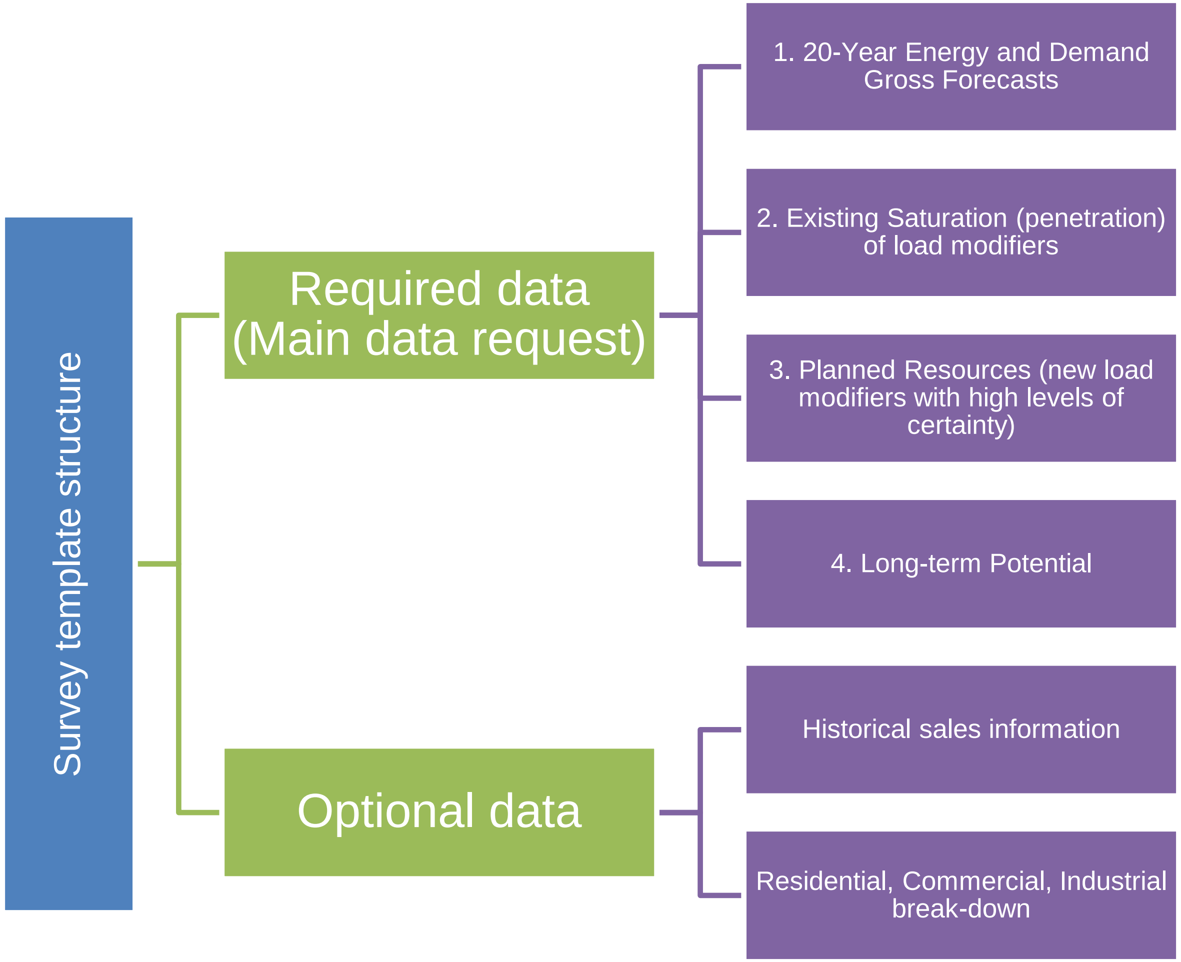
+ Electric Vehicles and Electrification

+ BTM Storage

= Observable Net Load Shape



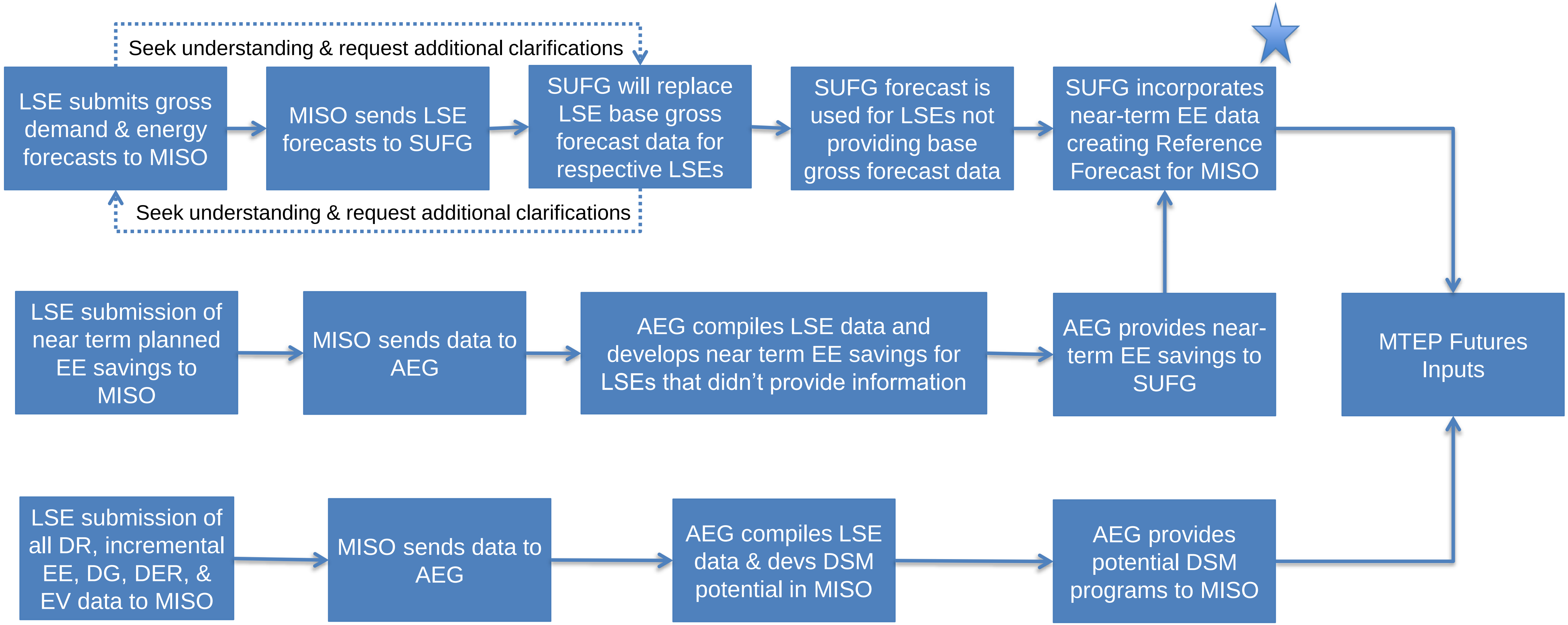
The development of a regional forecast starts with a survey of all utilities in the MISO footprint



Utilities use a range of methods to produce a load forecast:

- Top-down
  - trend analysis
  - econometric
- Bottom-up
  - survey-based
  - end-use
- Hybrid
  - statistically-adjusted end-use

Futures assumptions are incorporated into the gross reference forecast to develop demand and energy forecast, by future



- LSE(Load Serving Entity)
- AEG(Applied Energy Group) – Emerging Technologies Forecasting vendor
- SUFG(State Utility Forecasting Group) – Load Forecasting vendor

Questions?

Aditya Jayam Prabhakar
ajayamprabhakar@misoenergy.org

Distribution Forecasting

Curt Volkmann

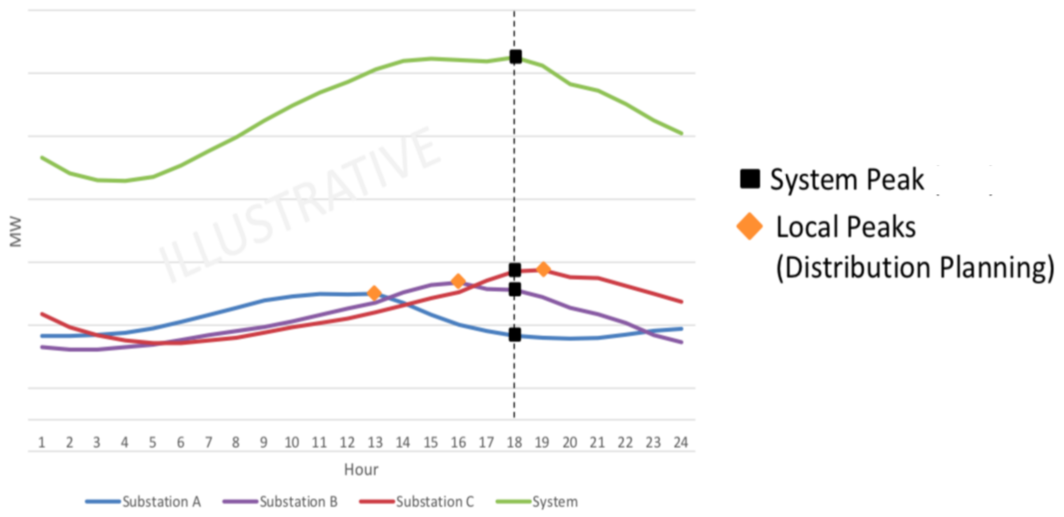
President, New Energy Advisors, LLC

curt@newenergy-advisors.com

www.newenergy-advisors.com

Distribution Forecasting

- Load and DER
- Primary objectives:
  - Identify local distribution equipment that may become overloaded during normal and contingency conditions
  - Identify locations where voltage is unacceptably low or high
  - Identify deficiencies in system protection



Source: https://drpwg.org/wp-content/uploads/2017/04/GSWG_SystemRecap_Final.pdf

Why Distribution Forecasting Matters

- Drives significant distribution capacity capital expenditures in MI from 2018-2022
  - Consumers - $286 million[1]
  - DTE - $831 million[2]
  - I&M - $35 million[3]
- Can determine real and perceived transmission and generation resource requirements
- Determines available circuit hosting capacity and potential need for proactive investment
- Critical for determining feasibility of non-wires alternatives (NWA)

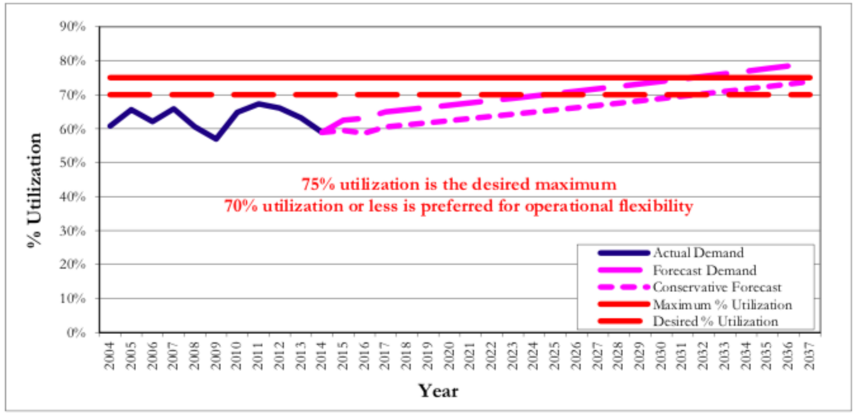
[1] Includes $158 million for LVD lines and substations capacity, $109 million for HVD lines and substations capacity, and $19 million for LVD transformers capacity (from p. 100 of Consumers' 2018 5-year Infrastructure Investment Plan)

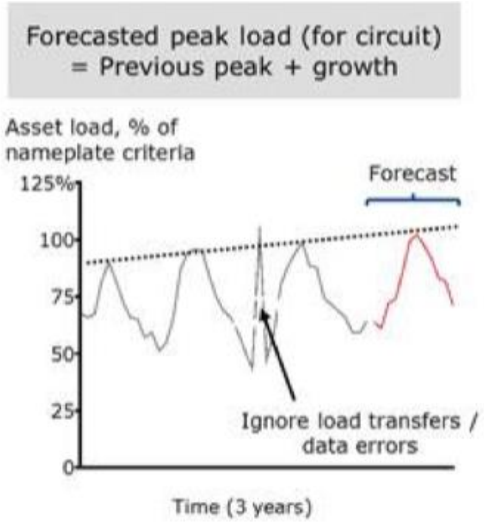
[2] Includes $260 million for Projected Load Relief Capital Spend (from p. 99 of DTEE's 2018 5-year Investment and Maintenance Plan) and $571 million for 4.8kV conversions "driven by strong area load growth and system capacity needs" (pp. 152-153)

[3] Includes 2019-2022 Distribution Asset Management capital expenditures (from p. 37 of I&M's 2019 Five-Year Distribution Plan), excludes capacity-driven Substation Major Projects

Typical Distribution Forecasting

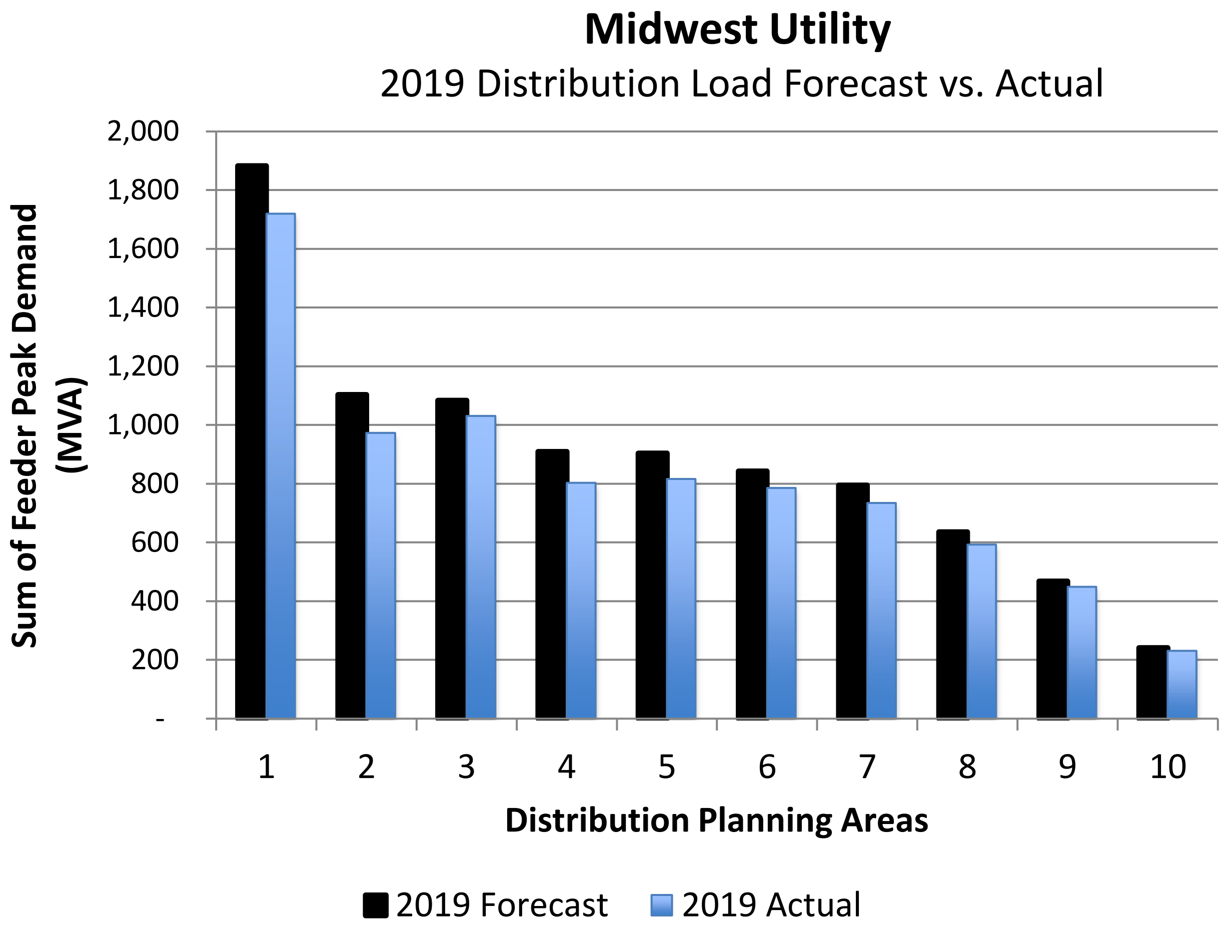
- Annual process focused on substation and circuit peak loads
  - Includes weather adjustments, known new loads, growth projections based on historical trends
- Priority = determine capital projects and budgets
- DER forecast often "top-down"
- DER connectivity often unknown
- Static, opaque, siloed, deterministic, often inaccurate





Source: Consumers Energy 2018-22 Electric Distribution Infrastructure Investment Plan, p. 206, Figure 92

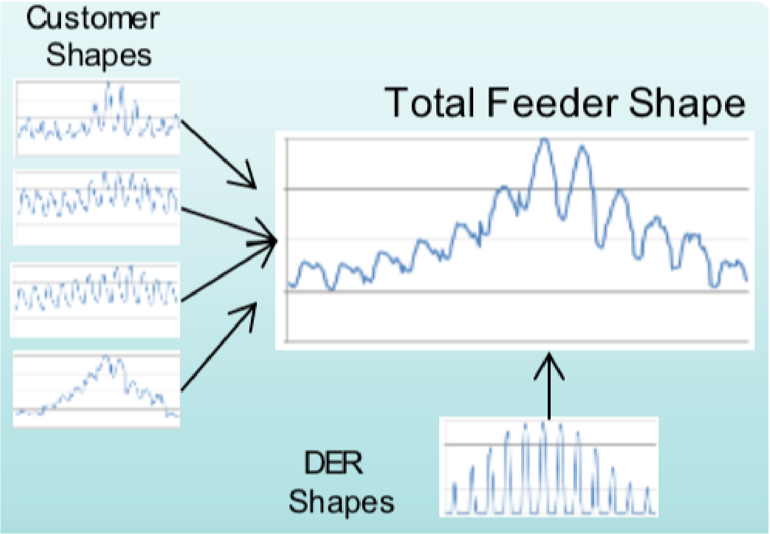
Inaccurate Load Forecasting



- 4-12% over-forecast in every Planning Area
- 730 MVA peak demand over-forecast across the utility's system

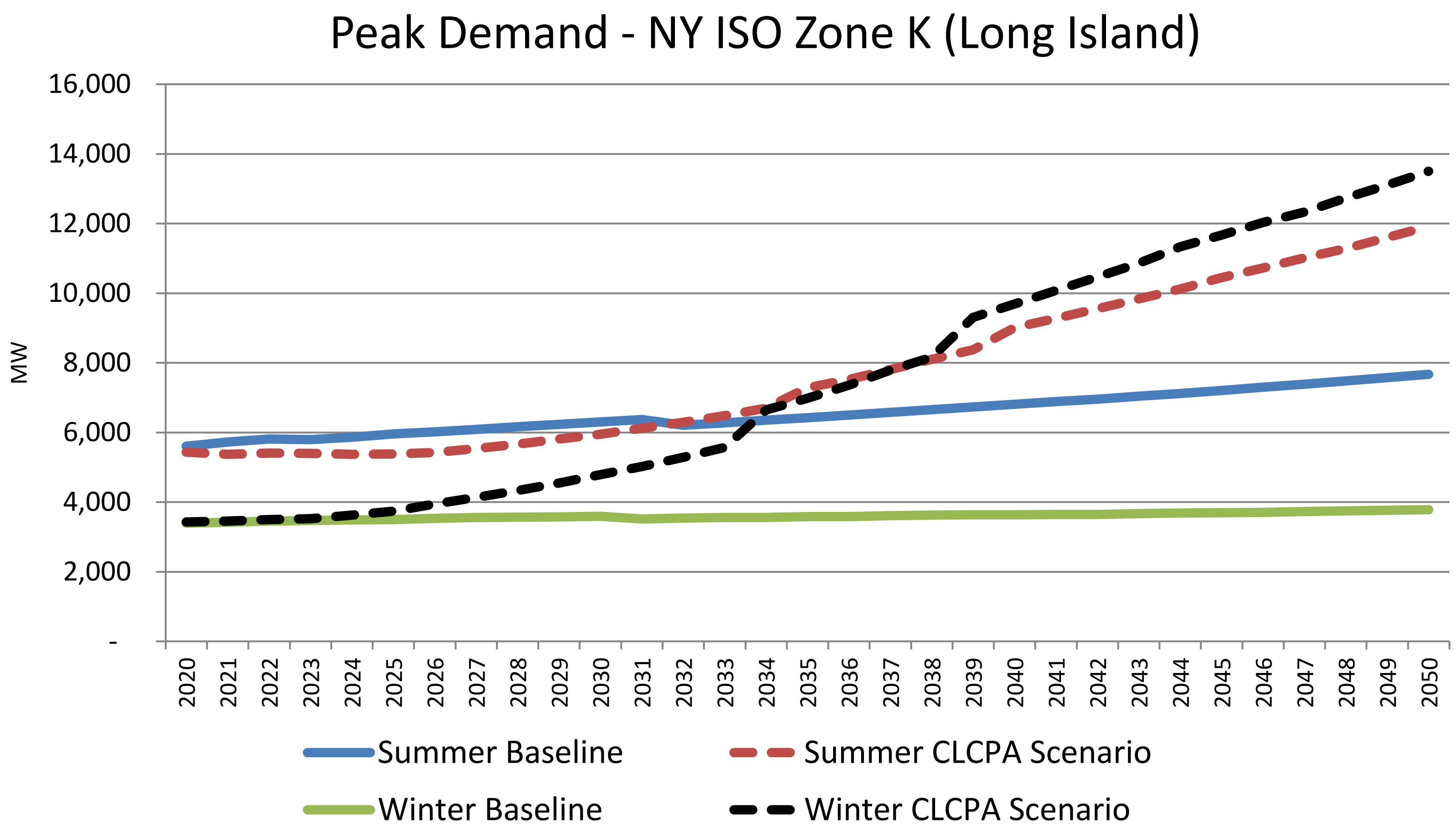
What's Changing?

- New dynamics at the substation/circuit/customer level
  - Deployment of DER and DER combinations
  - Increasing electrification
  - Shifting load patterns from climate change, COVID-19
  - Increased need to understand daytime minimum loads, net and gross loads



Source: https://drpwg.org/wp-content/uploads/2017/04/2-GSWG_Distribution_Planning_Overview.pdf

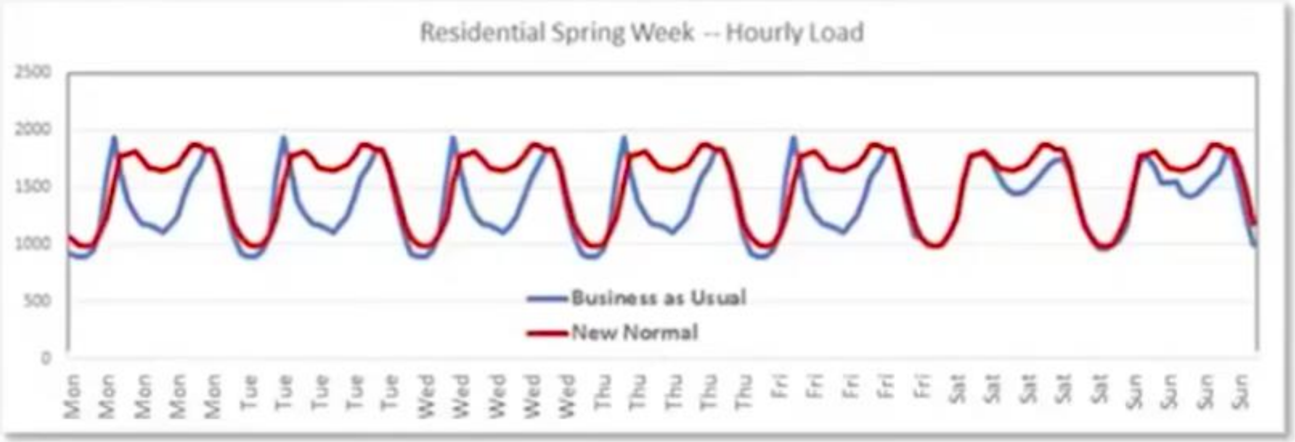
Climate Change Impacts



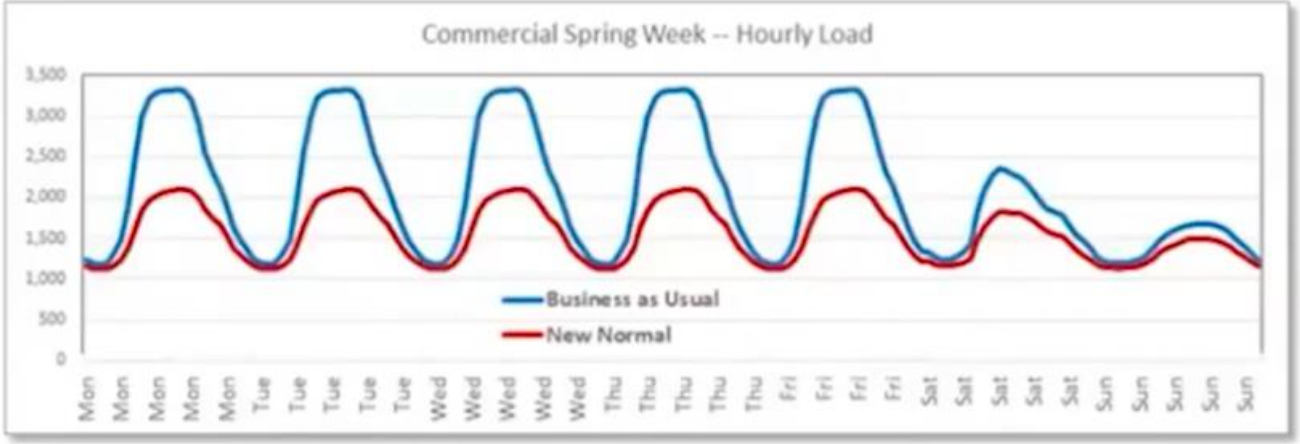
CLCPA = NY Climate Leadership and Community Protection Act, 85% GHG reduction from 1990 levels by 2050

Source: https://www.nyiso.com/documents/20142/10773574/NYISO-Climate-Impact-Study-Phase1-Report.pdf, Tables A-154, A-155

COVID-19 Impacts on Load Shapes



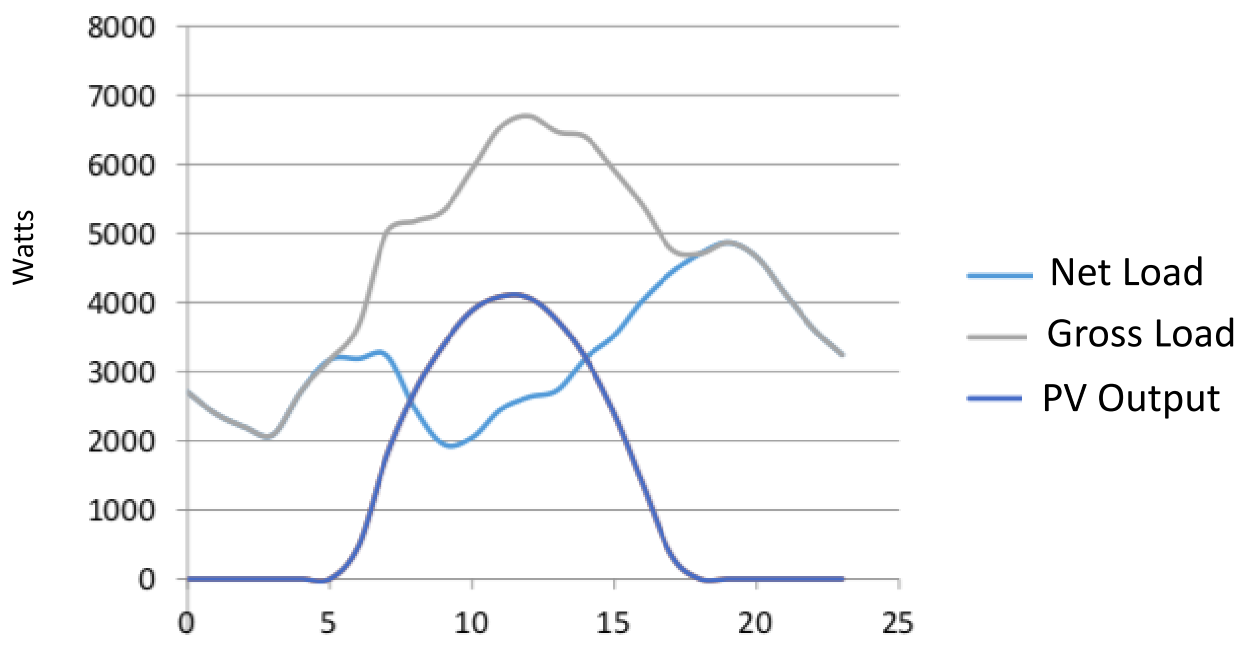
Multiplier	Value
Weekday Impact	1.15
Saturday Impact	1.05
Sunday Impact	1.09
7 Day Impact	1.13



Multiplier	Value
Weekday Impact	0.72
Saturday Impact	0.84
Sunday Impact	0.91
7 Day Impact	0.75

Source: https://www.itron.com/na/solutions/what-we-enable/analytics/forecasting (video)

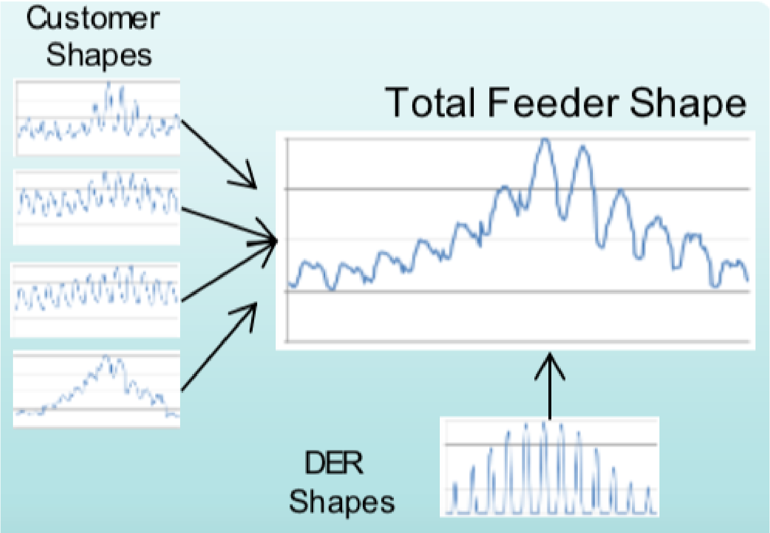
Net and Gross Load



Source: https://www.nrel.gov/docs/fy16osti/63114.pdf

What's Changing?

- New dynamics at the substation/circuit/customer level
  - Deployment of DER and DER combinations
  - Increasing electrification
  - Shifting load patterns from climate change, COVID-19
  - Increased need to understand daytime minimum loads, net and gross loads



Source: https://drpwg.org/wp-content/uploads/2017/04/2-GSWG_Distribution_Planning_Overview.pdf

- Regulatory momentum for increased transparency
- IRP resources increasingly reliant on the distribution system
- New opportunities to incorporate non-traditional solutions (NWA) to reduce costs
- New analytical tools

A Successful NWA Solicitation

DER Attribute Requirements: Elizabeth Lake 66/16 kV Project #1 - Elizabeth Lake 66/16 kV

Year	Capacity (MW)	Energy Need (MWH)	Season	Monthly Frequency	Yearly Frequency
2019	0.00	0.00	Summer	0	0
2020	0.00	0.00	Summer	0	0
2021	0.00	0.00	Summer	0	0
2022	0.00	0.00	Summer	0	0
2023	0.22	0.22	Summer	5	15
2024	3.88	8.04	Summer	6	15
2025	5.48	13.21	Summer	6	15
2026	6.80	18.35	Summer	6	15
2027	4.07	8.60	Summer	6	15
2028	5.78	14.38	Summer	6	15

	Peak Hourly Need (MW)																							
Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	3.9	1.7	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	4.0	5.5	3.3	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	5.3	6.8	4.5	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	4.1	1.9	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	4.4	5.8	3.5	0.0	0.0	0.0	0.0	0.0	0.0

Source: https://library.sce.com/content/dam/sce-doclib/public/regulatory/filings/pending/electric/ELECTRIC_4108-E.pdf

New Analytical Tools (not exhaustive)

LoadSEER™

dGen

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

ProsumerGrid™

MetrixIDR™

GridOS®

WattPlan®

GridUnity

New Approaches to Load and DER Forecasting

- Increased spatial and temporal granularity
- Multiple scenarios to address uncertainty
- Propensity and customer adoption modeling for DER

Source: https://www.integralanalytics.com/wp-content/uploads/2020/06/LoadSEER_4.0_Brief.pdf

DER Disaggregation Methods in CA (2018)

Methods	PG&E	SOUTHERN CALIFORNIA EDISON An EDISON INTERNATIONAL® Company	SDGE A Sempra Energy utility
Proportional Allocation	EE, ES, DR	EE, ES	EE, ES, DR
Propensity Models	EV	EV, DR	EV
Adoption Models	PV, EV	PV	PV

Source: https://drpwg.org/wp-content/uploads/2018/07/R1408013-et-al-SCE-DFWG-Progress-Report.pdf

EE = Energy efficiency
ES = Energy storage
EV = Electric vehicles
DR = Demand response
PV = Behind-the-meter photovoltaic solar

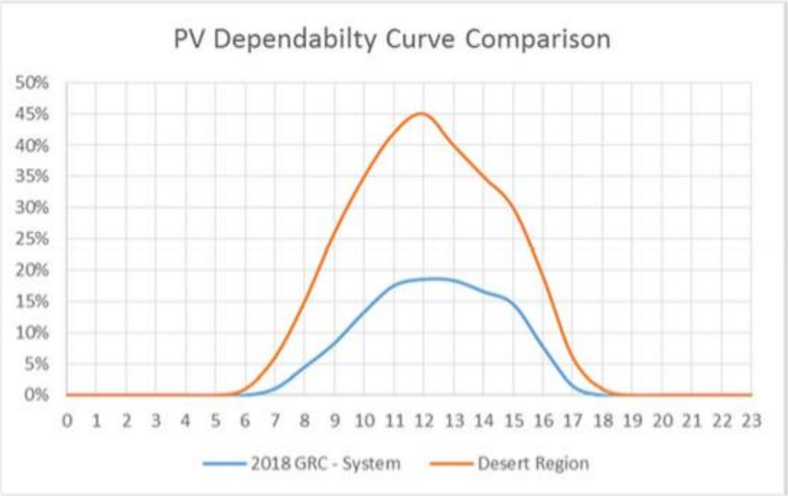
See https://drpwg.org/growth-scenarios/ for more information

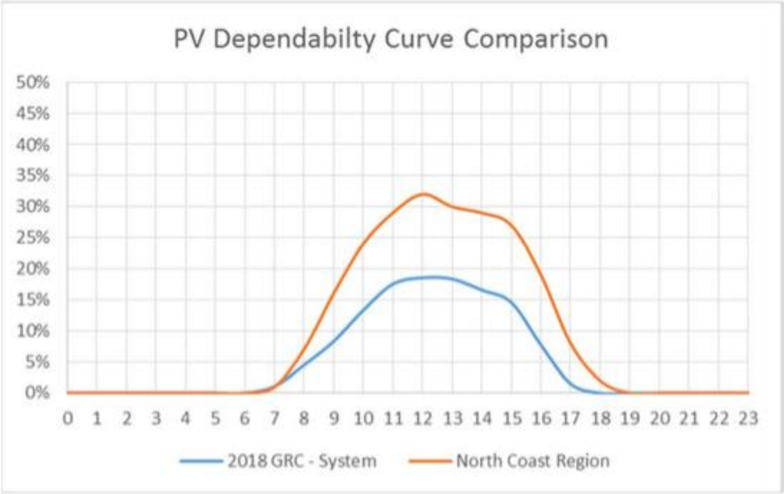
New Approaches to Load and DER Forecasting

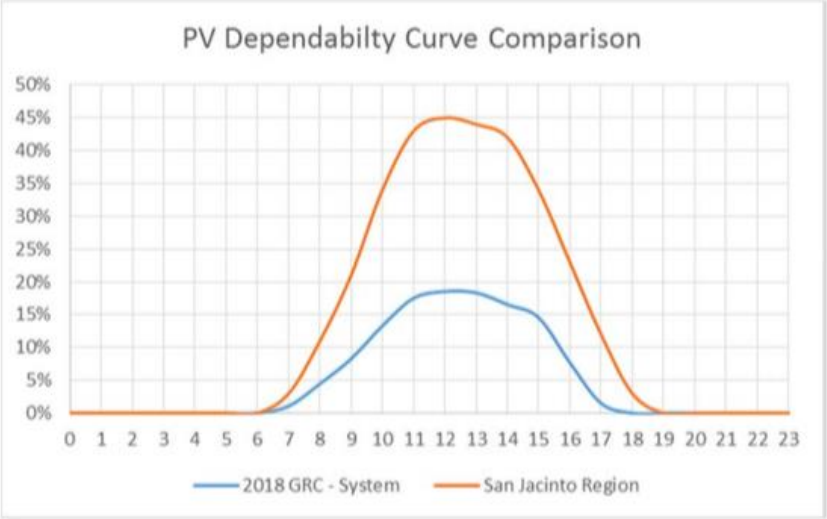
- Increased spatial and temporal granularity
- Multiple scenarios to address uncertainty
- Propensity and customer adoption modeling for DER
- Consideration of third-party DER forecasts
- Stakeholder engagement
- PV Dependability modeling

Source: https://www.integralanalytics.com/wp-content/uploads/2020/06/LoadSEER_4.0_Brief.pdf

PV Dependability Modeling







Source: Southern California Edison 2021 General Rate Case, Application 19-08-013, Exhibit No. SCE-02 Vol.04 Pt 02 Ch II Bk A

Distribution Planning and Forecasting in MI

	Consumers Energy	DTE	Indiana Michigan Power
Time horizon (years)	?	5	10
Loading criteria (% of normal rating)	125%	110%	?
Spatial granularity	Circuit	Circuit	Circuit
Temporal granularity	Annual peak	Annual peak	Annual peak
DER included in forecast:			
DG (solar and wind)	Y	N	Y
Distributed Storage	N	N	N
EE	Y	N	Y
DR	Y	N	Y
EV	Y	N	N
Primary planning tool	CYME	?	CYME
AMI data used in forecast?	Yes	No	No

MPSC Guidance

"The Commission seeks to avoid prescribing specific (forecasting) methods or approaches in the next round of distribution plans but acknowledges that the Staff's recommended dynamic approach to load forecasting with scenario analysis could help better understand and accommodate uncertainty associated with DERs, PEV charging, and other factors."[1]

"The Commission finds it important to run sensitivities in load forecasts for distribution planning and to start modeling locational impacts from customer behavior (whether through plug-in electric vehicles, EWR, storage, solar DG, DR, etc.)"[2]

[1]Case No. U-20147, 11/21/18 Order, p. 32

[2]Case No. U-20147, 8/20/20 Order, p. 49

Information in next 5-year Distribution Plans?

Forecast Accuracy
- Circuit and planning area forecast vs. actual 2016-2020?
- Actions to improve accuracy?

Load Forecasting
- Current and planned spatial/temporal granularity?
- Scenarios?
- Loading criteria?
- Current tools, planned investment in new tools?
- Minimum loads known?
- COVID-19 impacts?
- Electrification impacts?
- Ex post assessments?
- Alignment with IRP?
- Stakeholder engagement?

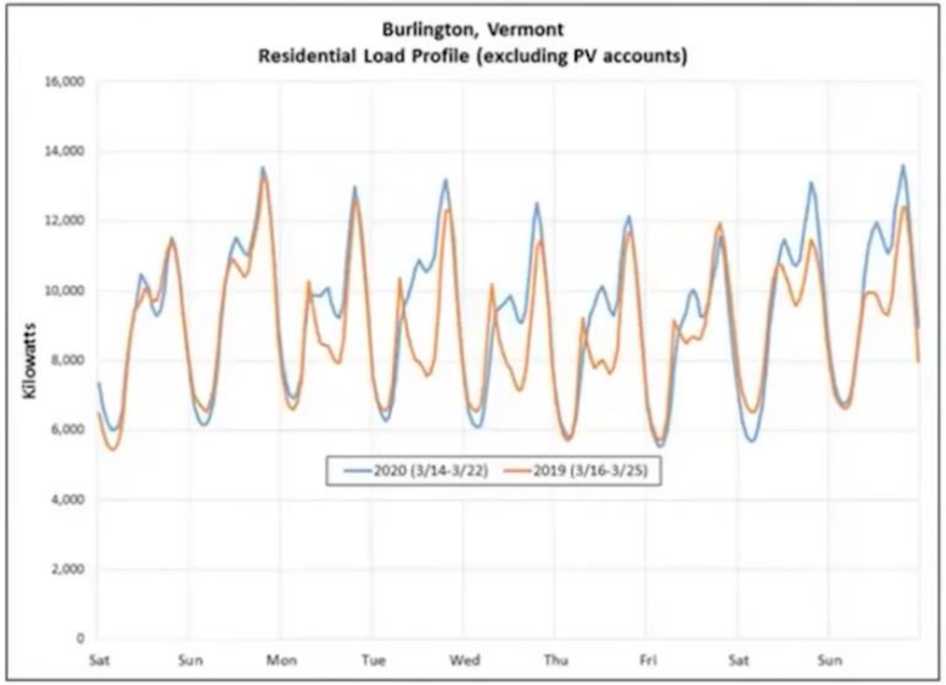
DER Forecasting
- Methodologies?
- Scenarios?
- Compared with third-party forecasts?
- Incorporated in load forecasts?
- DER connectivity known?
- Alignment with IRP?
- Stakeholder engagement?

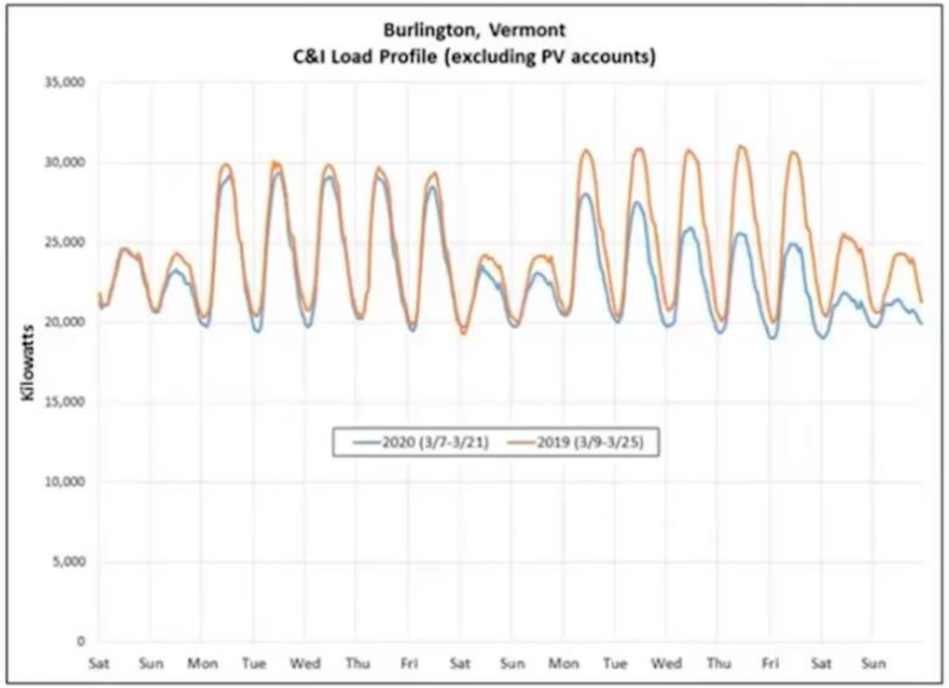
Thank you!

Curt Volkmann
President, New Energy Advisors, LLC
curt@newenergy-advisors.com
www.newenergy-advisors.com

Supplemental Slides

COVID-19 Impacts on Load Shapes





Source: https://www.itron.com/na/solutions/what-we-enable/analytics/forecasting (video)

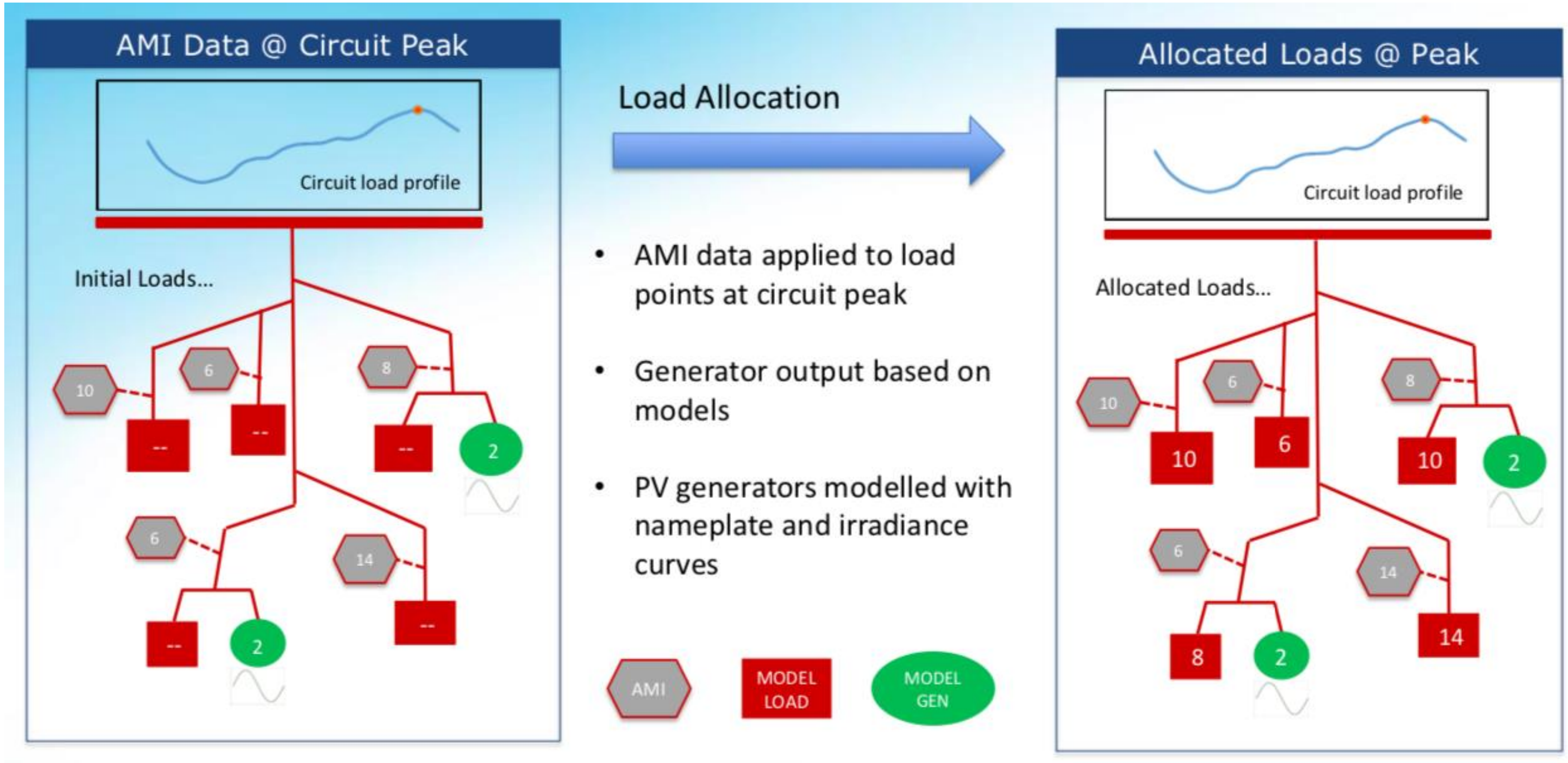
COVID-19 Impacts on System Load

Estimated North American Load Impact by ISO Control Region and Time-of-Use Period

	Total	NYISO	MISO	SPP	CAISO	ISONE	IESO	ERCOT	AESO	PJM
Daily Average										
March	-3.4%	-2.6%	-4.0%	-5.5%	1.0%	-1.9%	-2.2%	-1.8%	0.9%	-4.9%
April	-7.2%	-4.4%	-11.3%	-7.6%	-2.0%	-0.5%	-3.4%	-5.6%	-3.5%	-8.0%
May	-7.5%	-8.2%	-2.9%	-14.4%	-2.5%	-7.3%	-4.1%	-6.4%	-7.9%	-10.9%
June	-4.5%	-4.6%	-5.3%	-2.9%	-3.9%	-1.8%	-1.4%	-5.6%	-7.1%	-4.7%
July	1.1%	3.0%	0.2%	-2.1%	-4.9%	8.1%	7.9%	-4.3%	-6.8%	5.2%
August	-0.6%	1.0%	-3.0%	-1.6%	2.8%	5.3%	-1.3%	-0.2%	-6.8%	0.6%
September	-7.1%	-3.9%	-10.4%	-9.4%	3.9%	-4.9%	-8.7%	-7.1%	-7.6%	-6.5%
October	-5.4%	-4.7%	-8.3%	-5.4%	4.5%	-2.3%	-5.7%	-2.5%	-2.9%	-7.2%
Night Average										
March	-4.2%	-4.0%	-4.8%	-7.1%	0.5%	-2.3%	-2.5%	-3.1%	0.6%	-5.6%
April	-5.7%	-2.4%	-10.3%	-7.2%	-2.0%	0.5%	-2.0%	-5.0%	-3.1%	-5.3%
May	-5.9%	-7.3%	-1.3%	-14.3%	-1.9%	-4.6%	-2.7%	-7.8%	-7.4%	-7.4%
June	-5.8%	-4.6%	-7.6%	-5.9%	-2.7%	-2.2%	-1.9%	-7.6%	-6.9%	-5.6%
July	0.5%	5.6%	-1.1%	-2.3%	-3.9%	6.7%	6.5%	-4.4%	-6.9%	4.6%
August	-1.3%	0.5%	-4.0%	-3.1%	2.2%	4.5%	-2.6%	-2.1%	-7.7%	0.8%
September	-6.7%	-6.2%	-10.2%	-10.3%	2.6%	-4.4%	-7.0%	-6.7%	-8.5%	-5.0%
October	-5.9%	-8.2%	-8.7%	-6.3%	2.9%	-3.0%	-5.2%	-4.4%	-3.5%	-6.9%

Source: https://www.itron.com/na/solutions/what-we-enable/analytics/forecasting/covid (October 2020 Memo)

AMI and Load/DER Forecasting



Source: https://drpwg.org/wp-content/uploads/2018/06/DFWG4_Dispersion_Final.pdf

Making the Most of Michigan's Energy Future

Break

Please mute your microphone and turn off your camera during break.

MI POWER GRID

Making the Most of Michigan's Energy Future

Brady Cowiestoll, National Renewable Energy Laboratory

Advanced Planning Stakeholder Meeting

December 16, 2020

MPSC

Michigan Public Service Commission

Forecasting DER/EVs Techniques & Tools

Brady Cowiestoll
MI PSC
December 16, 2020

People behind the work

dGen

Ben Sigrin

Benjamin.Sigrin@nrel.gov

Tempo

Matteo Muratori

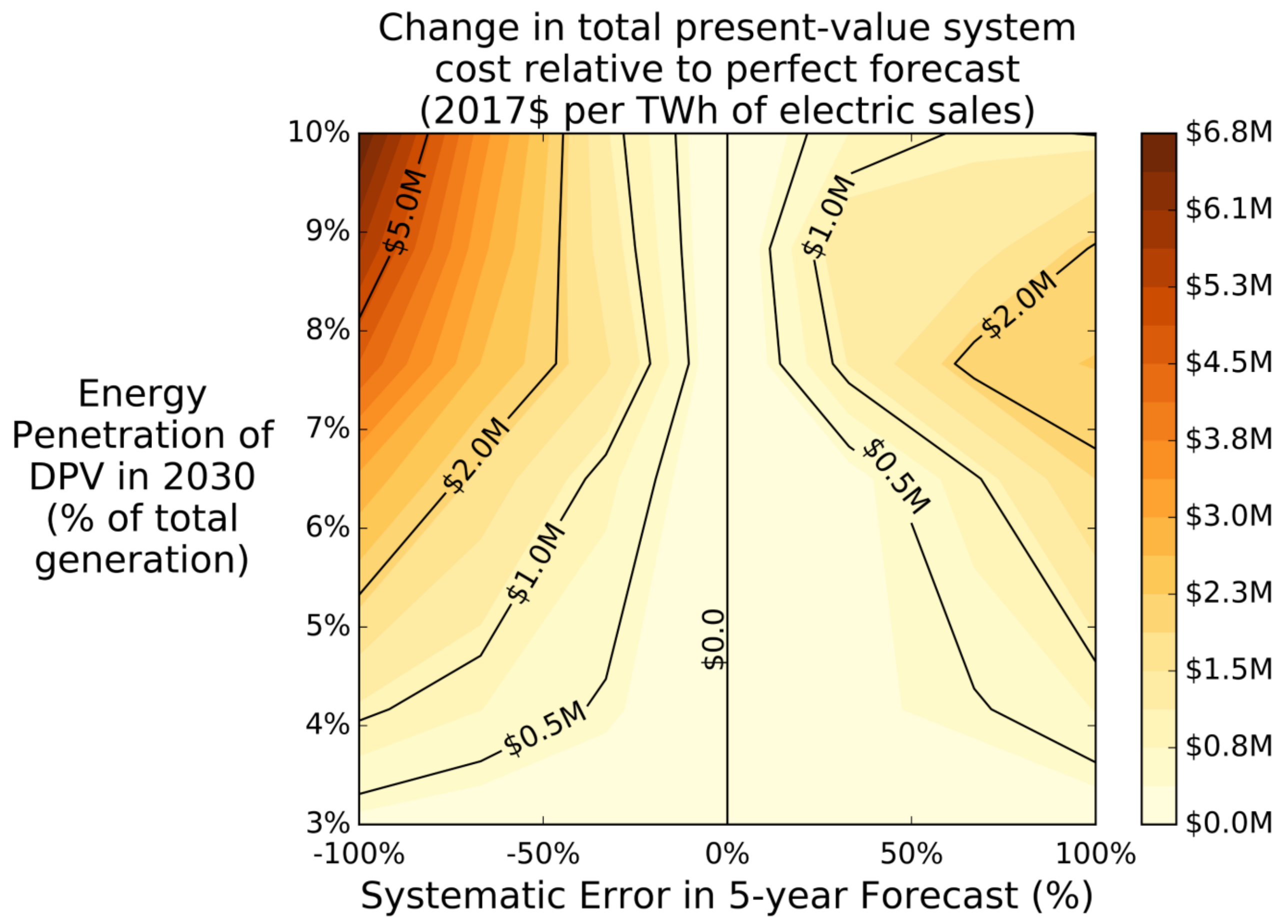
Matteo.Muratori@nrel.gov

Distributed PV (DPV) is growing—

and utilities need to know how to plan for it.


The grid is decentralizing

Mis-forecasting leads to increased costs



Normalized total present-value costs due to systematic DPV misforecasts in the Western Interconnection through 2030

Estimating the Value of Improved Distributed Photovoltaic Adoption Forecasts for Utility Resource Planning, NREL, May 2018 (Gagnon et al. 2018)

Improved DPV capacity forecasting could save ratepayers $400,000/TWh of utility sales

Under-forecasting: An overbuilt system with unused capacity

Over-forecasting: An underbuilt system without sufficient capacity and reliability issues.

Two Types of Forecasting

Transmission-level

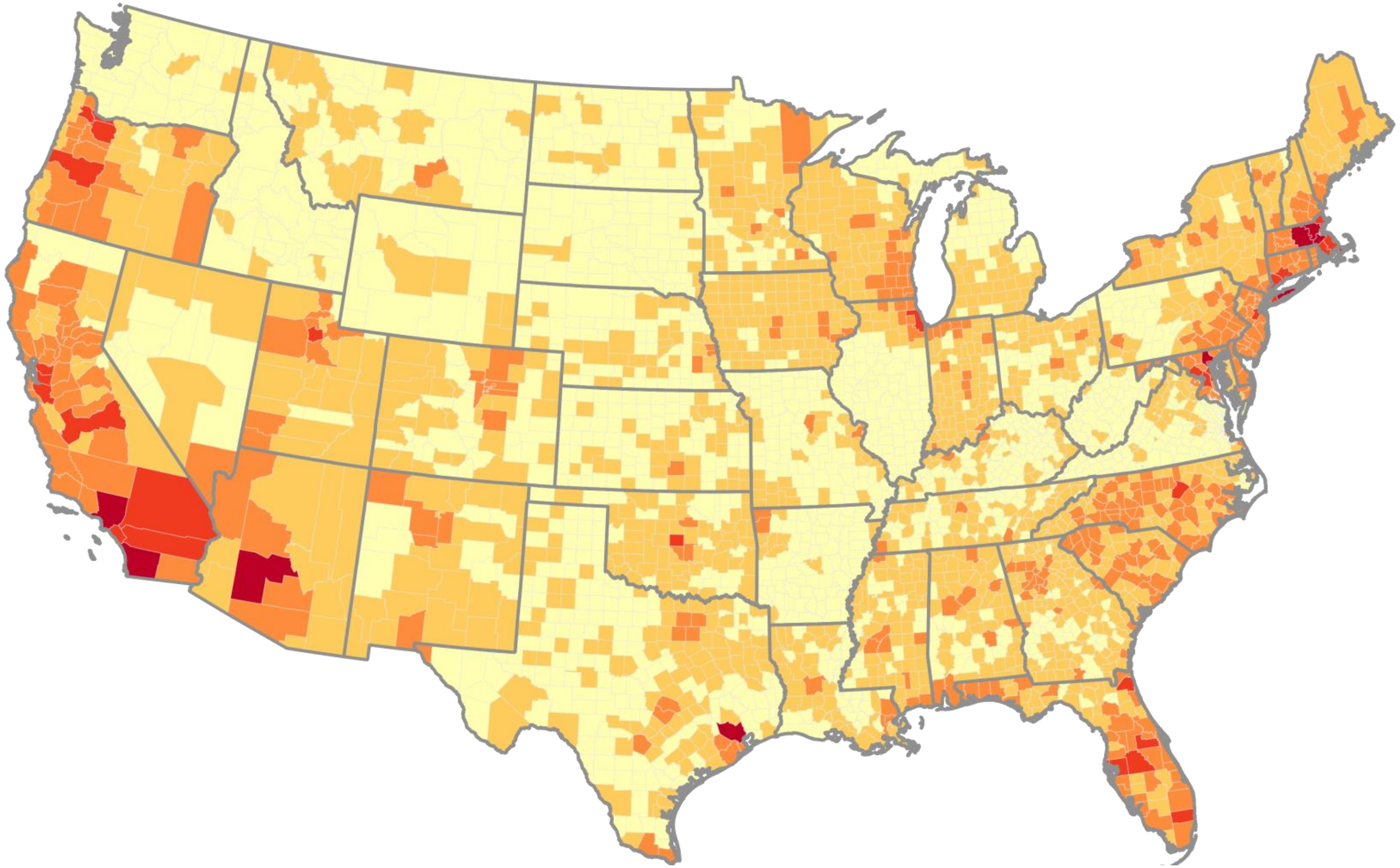
- Focus is on predicting aggregate amount, e.g. state, county, or ISO-level
- Forecasts primarily affect generation and transmission resource plans

Distribution-level

- Focus is on predicting spatial pattern of adoption, e.g. feeder-level or household-level
- Forecasts primarily affect distribution resource plans

Experiences with Transmission-level Planning

How much DPV will be adopted?



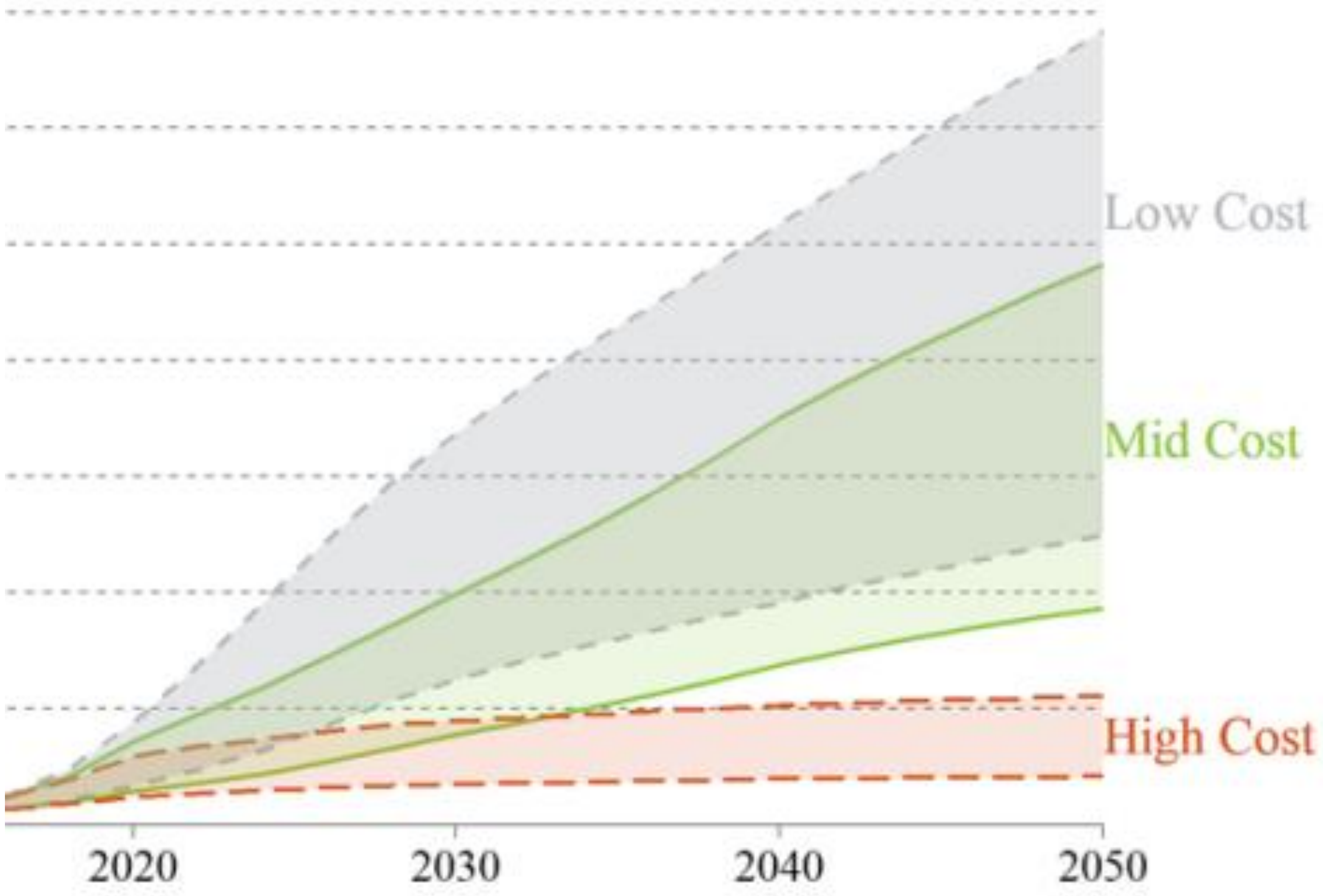
NREL conducts a national DPV adoption forecast annually. This image shows the spatial distribution of the Central scenario for the 2018 study

Transmission-level forecasts are traditionally used in IRPs, load forecasting, and other “big picture” studies

They are often less focused on predictive accuracy and instead on understanding a potential range of outcomes or tipping points.

Often, the projections are highly dependent on policy assumptions

Challenges with Transmission-level Forecasting

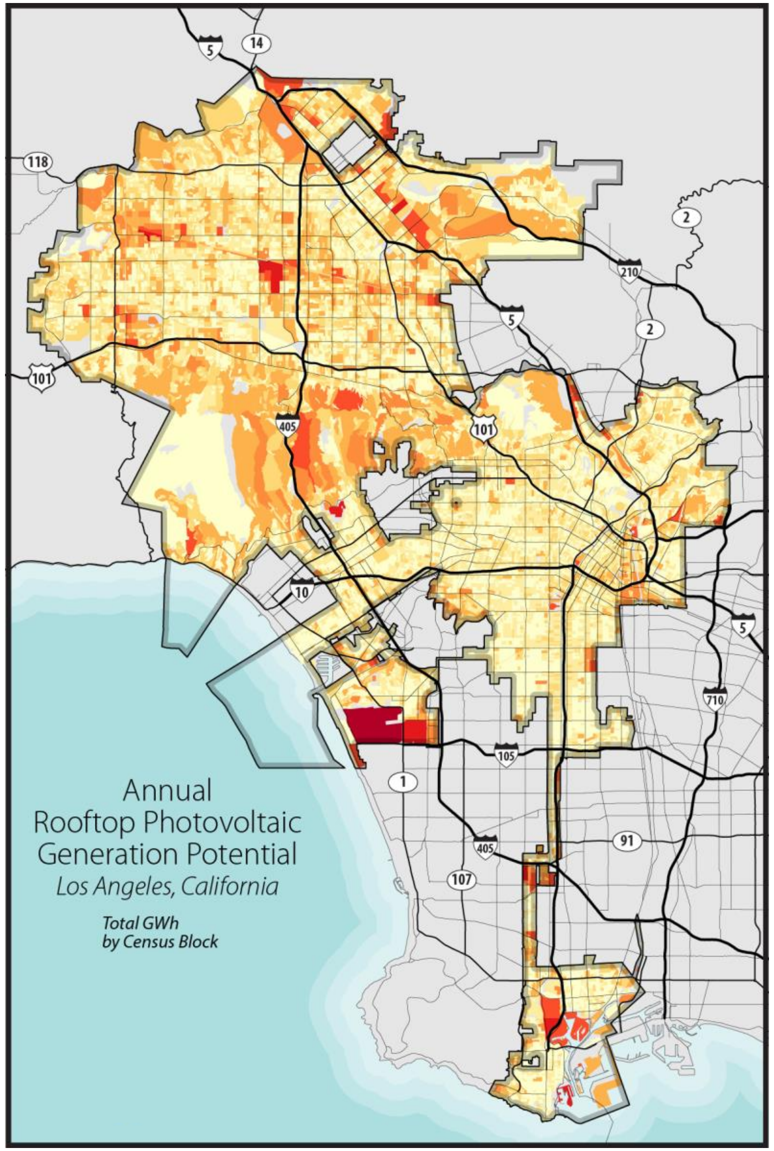


Scenarios show range of cost and DPV future compensation scenarios. Cole et al (2016). *2016 Standard Scenarios Report: A U.S. Electricity Sector Outlook*.

- Projections span a wide range of jurisdictions, making it challenging to reflect current policy and retail electricity parameters
- Wide range of methods to calibrate models, with limited focus historically on validation
- Very few models are publicly accessible or receive stakeholder feedback

Experiences with Distribution-level Planning

Where will DPV be adopted?



Distribution-level DER modeling seeks to understand DER adoption patterns either at the individual or substation-level to inform distribution planning

In ongoing projects with Los Angeles Department of Water and Power (LADWP) and the Orlando Utility Commission (OUC), NREL is developing customer-level probabilities of adoption based on individual-level data

These forecasts are then used to inform, variously, distribution hosting capacity, capacity expansion modeling, and rate design.

Challenges with Distribution-level Modeling

- Highly data and computationally intensive, with varying levels of types of data available
- High risk of overfitting – *when do models add value, vs noise*
- Very few models are publicly accessible or receive stakeholder feedback

Nitty Gritty of Forecasting PV Adoption

Model Structure

- Top-down
- Bottom-up

Model Resolution

- Household
- Zip Code
- Utility Territory

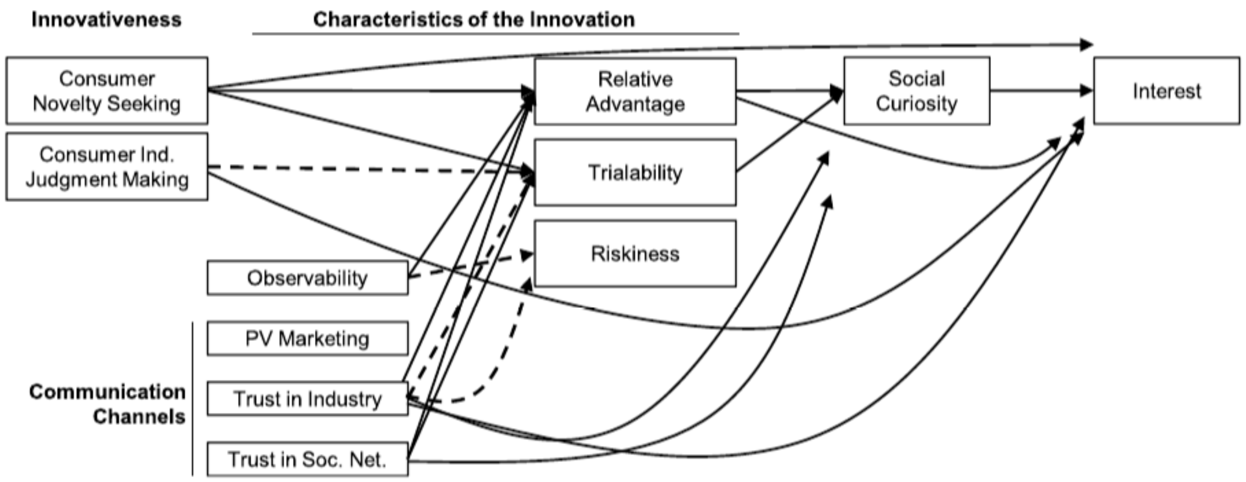
What to model

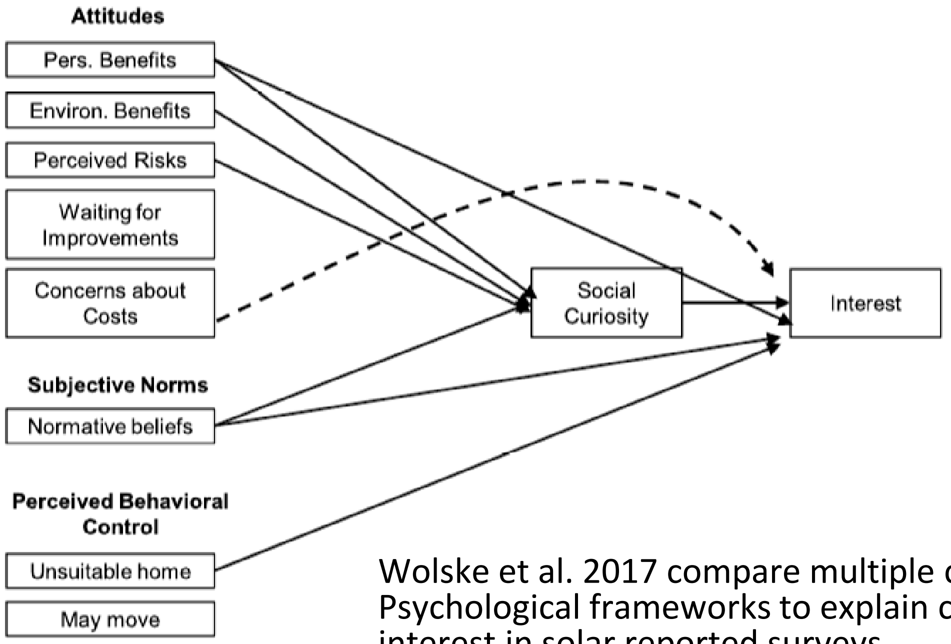
- How much deployment is technically possible?
- How much deployment is economically viable?
- How much deployment will actually occur?

Variables Found to be Predictive of Adoption

Researchers have identified many variables that predict DPV adoption or interest in DPV.

- Williams et al. 2017 found that NPV alone explains most (75%) of inter-national adoption levels.
- Bollinger and Gillingham 2012 found that "peer effects" or spatial proximity to other adopters caused more adoption.
- Wolske et al. 2017 found that level of environmental concern, consumer innovativeness, and perceived social support for solar all predicted interest in solar adoption.
- And many others…

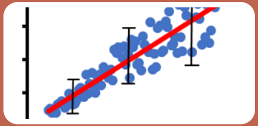




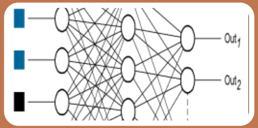
Wolske et al. 2017 compare multiple classical Psychological frameworks to explain consumer interest in solar reported surveys

PV Adoption Forecasting Methods

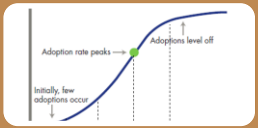
Basic Time Series Models
- Assume an End Point (Policy Based); Trend/Extrapolate



Regression
- Least Squares, Logit, Binomial, etc.

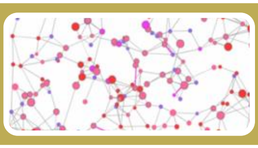


Machine Learning
- Neural network; Decision Trees; etc.

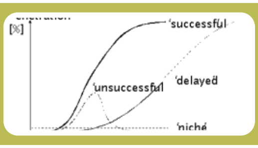


Diffusion
- Bass Diffusion; Threshold Diffusion

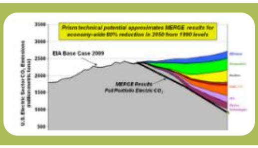
Customer Behavior
- Discrete Choice Experiments; Conjoint Analysis; etc.



Agent Based Models (ABM)
- Machine Learning (Sandia); Decision Formation & Regression (UT Austin)



Combined Market Penetration
- ABM + Bass Diffusion (NREL dSolar; CPUC Public Tool)



Macroeconomic
- EPRI (REGEN); EIA's National Energy Modeling System (NEMS)

Other Considerations
- Technical Potential (LiDAR; Google Sunroof); Spatial Effects; Peer/Network Effects

Example 1: Bass Diffusion Model

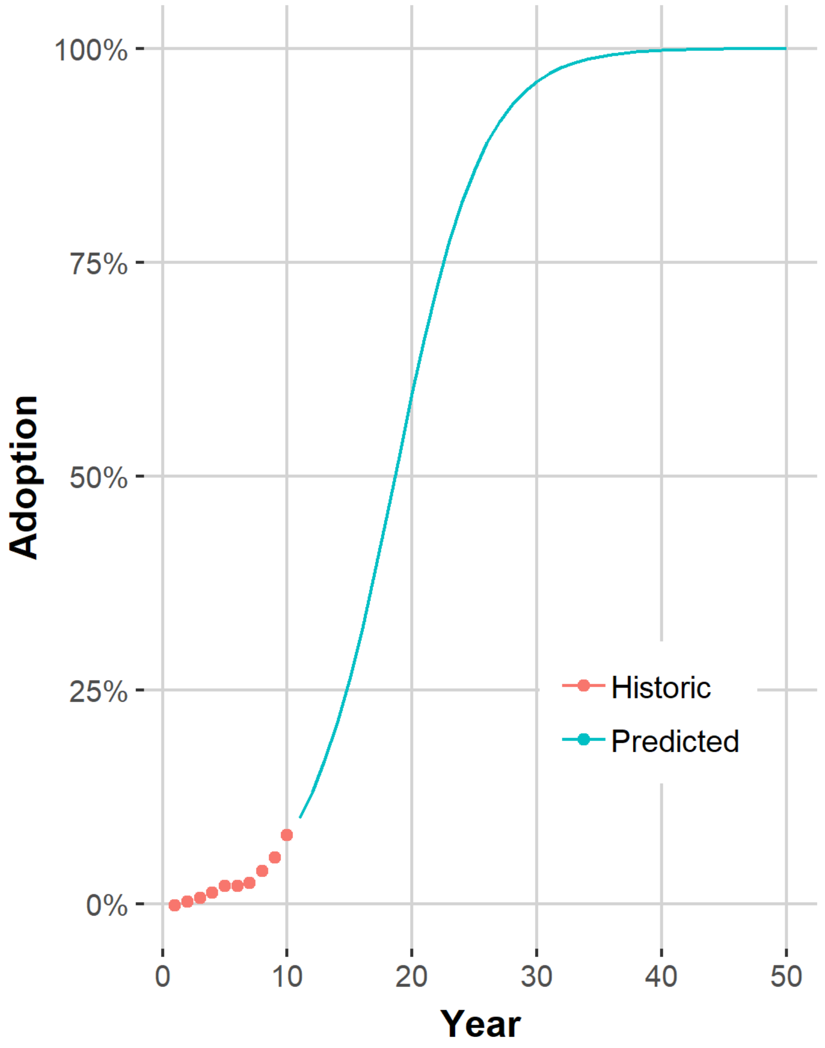
The Bass Diffusion Model is widely used to forecast DPV adoption. It is based on fitting an adoption curve to historic adoption observations

Strengths:

– Widely used by industry and researchers
– Little data needed
– Good prediction for near-term

Weaknesses:

– Sensitive to market fluctuations
– Not spatially disaggregated
– Limited ability to model black swan events



Example 2: Agent-Based Modeling

- **Agent-Based Models (ABM) are an emerging method to forecast DPV adoption. They are based on modeling the individual decision-making of consumers and their surroundings**

- **Strengths:**
  - Simulates individual consumers and their unique characteristics
  - Great for spatial predictions
  - Can be built off existing utility customer records

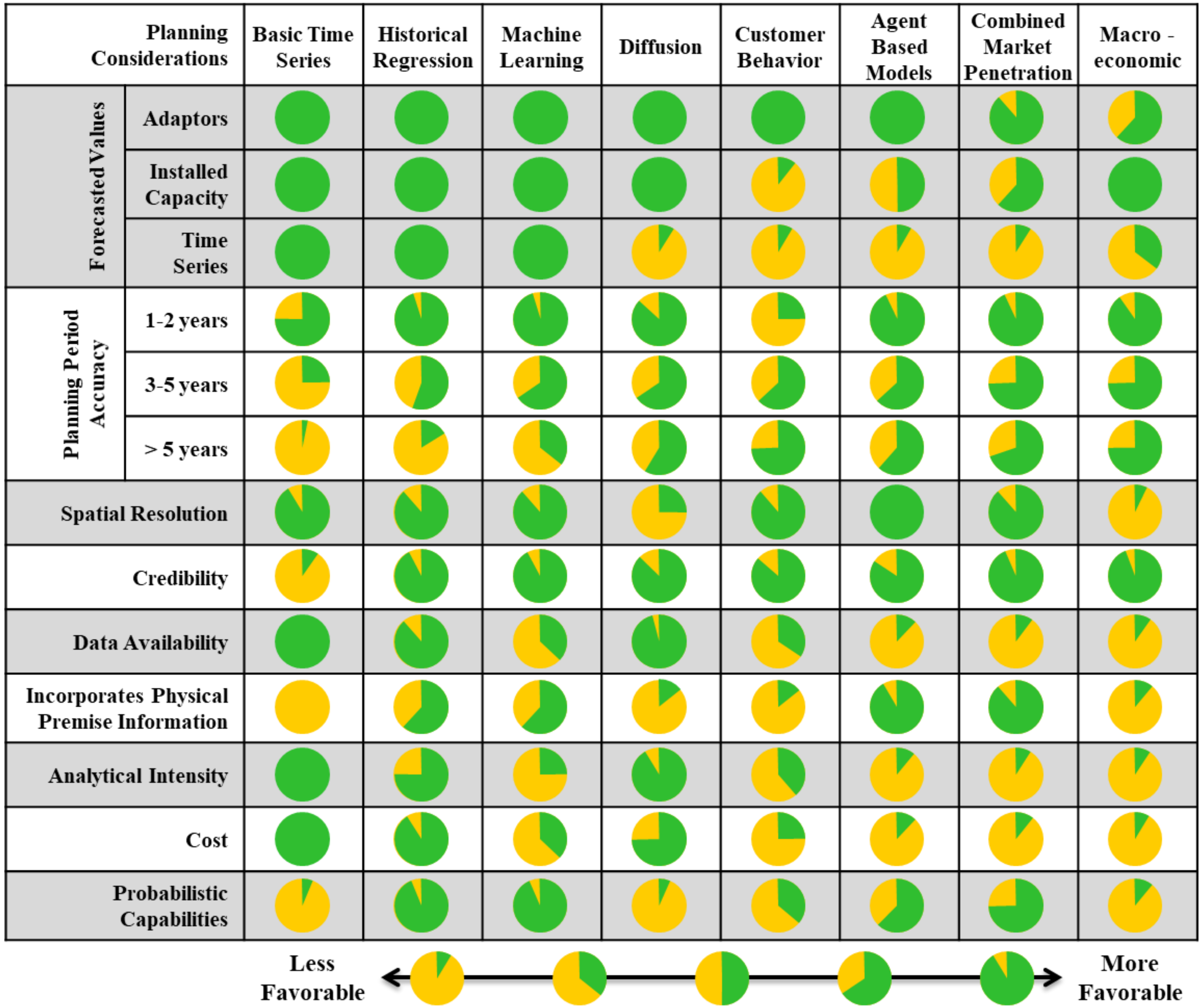
- **Weaknesses:**
  - High data/computational requirements
  - Historically not used for prediction, but this is changing

What Method Should I Use?

Of the 9 methods identified, no single method was found to be superior in all planning dimensions. These include:

- Length of planning horizon
- Spatial resolution
- Understanding new technologies

We developed a scorecard to compare methods and apply it to a few prototypical examples.



Use this method if… Planning Horizon is Primary Concern

Best for near-term forecasts

Best for long-term forecasts

Time Series
Regression
Machine Learning

Customer Behavior
Agent Based Models
Macroeconomic

Combined Market Penetration
Diffusion

Use this method if… Spatial Resolution is Primary Concern

Best for individual-level forecasts

- Agent Based Models
- Machine Learning
- Customer Behavior

Best for aggregate-level forecasts

- Regression
- Macroeconomic
- Time Series
- Combined Market Penetration
- Diffusion

Use this method if… Technology Maturity is Primary Concern

Best for forecasting emergent technologies

Agent Based Models

Customer Behavior

Machine Learning

Time Series

Best for forecasting mature technologies

Regression

Diffusion

Combined Market Penetration

Macroeconomic

Conclusions

- **Is it necessary to use individual-level data?**
  - Forecasters can generally always produce “better” forecasts with more granular data
  - Yet, data may not be available at the individual level

- **Are forecasts accurate enough to make planning decisions?**
  - A forecast is only a means to an end
  - There is insufficient research that has compared predictive accuracy of approaches, or quantifies changes in accuracy at the feeder or household-level

- **No one method to rule them all**
  - No one method was found to be superior in all categories important to planners
  - We recommend different methods for different use cases. Planners should consider building up customer analytics databases over time.

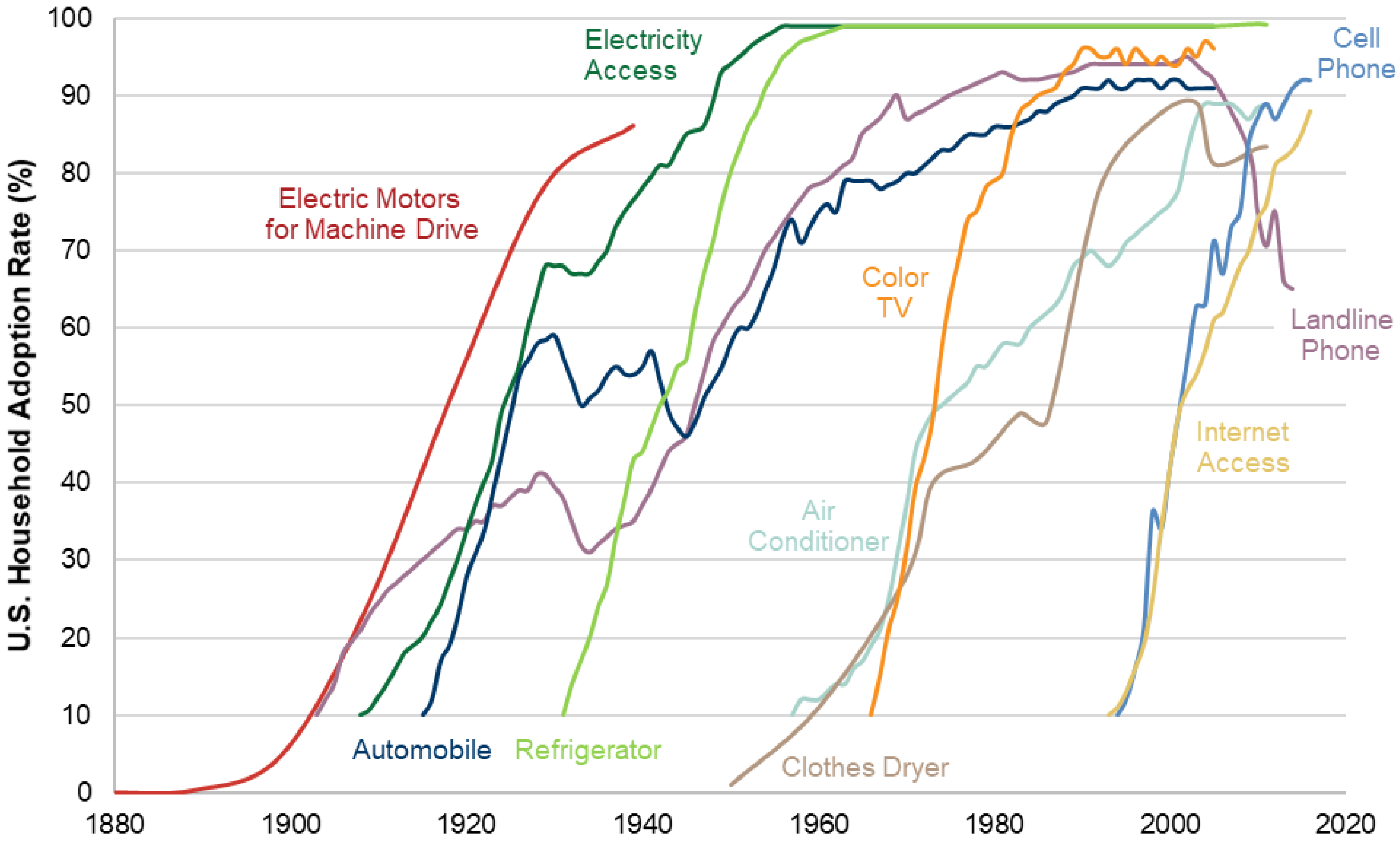
dGen is now open source!

Advancing the state-of-art in long term resource planning

- NREL's **dGen** model, an **agent-based** model for DER customer adoption is now available at https://www.nrel.gov/analysis/dgen/
- Develop **county-level projections** of **distributed solar and storage** deployment for each of the **ISO/RTO participants'** control areas
- **Developed by multidisciplinary team** comprised of members of the NREL dGen modeling team, NREL Commercial and Residential Buildings modeling team, the University of Texas at Austin


Electric Vehicles can be a source of
flexibility – or stress

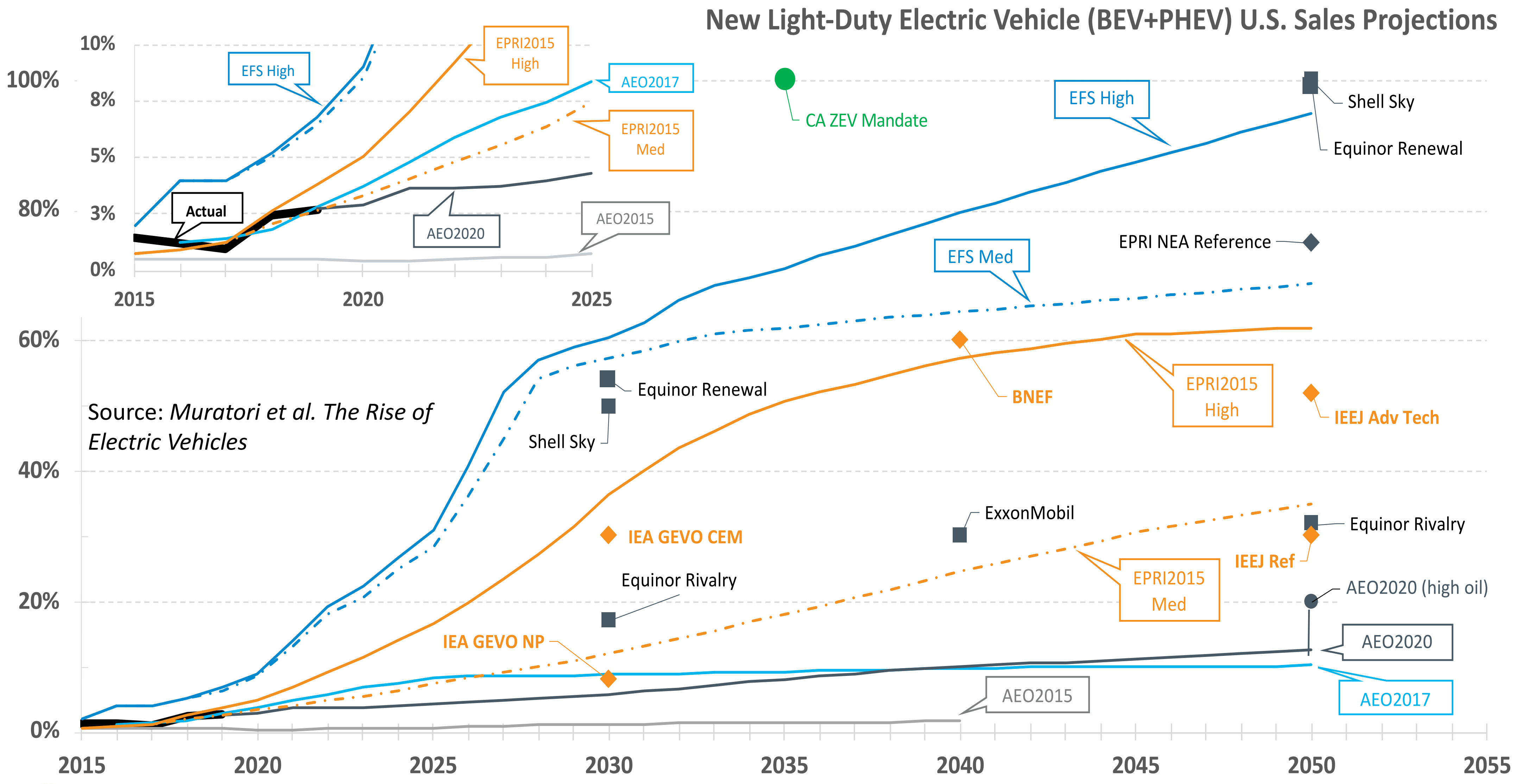
Technology adoption and energy transitions generally follow S-curve shape and are generally underestimated



invention → innovation → niche market → pervasive diffusion → saturation → senescence

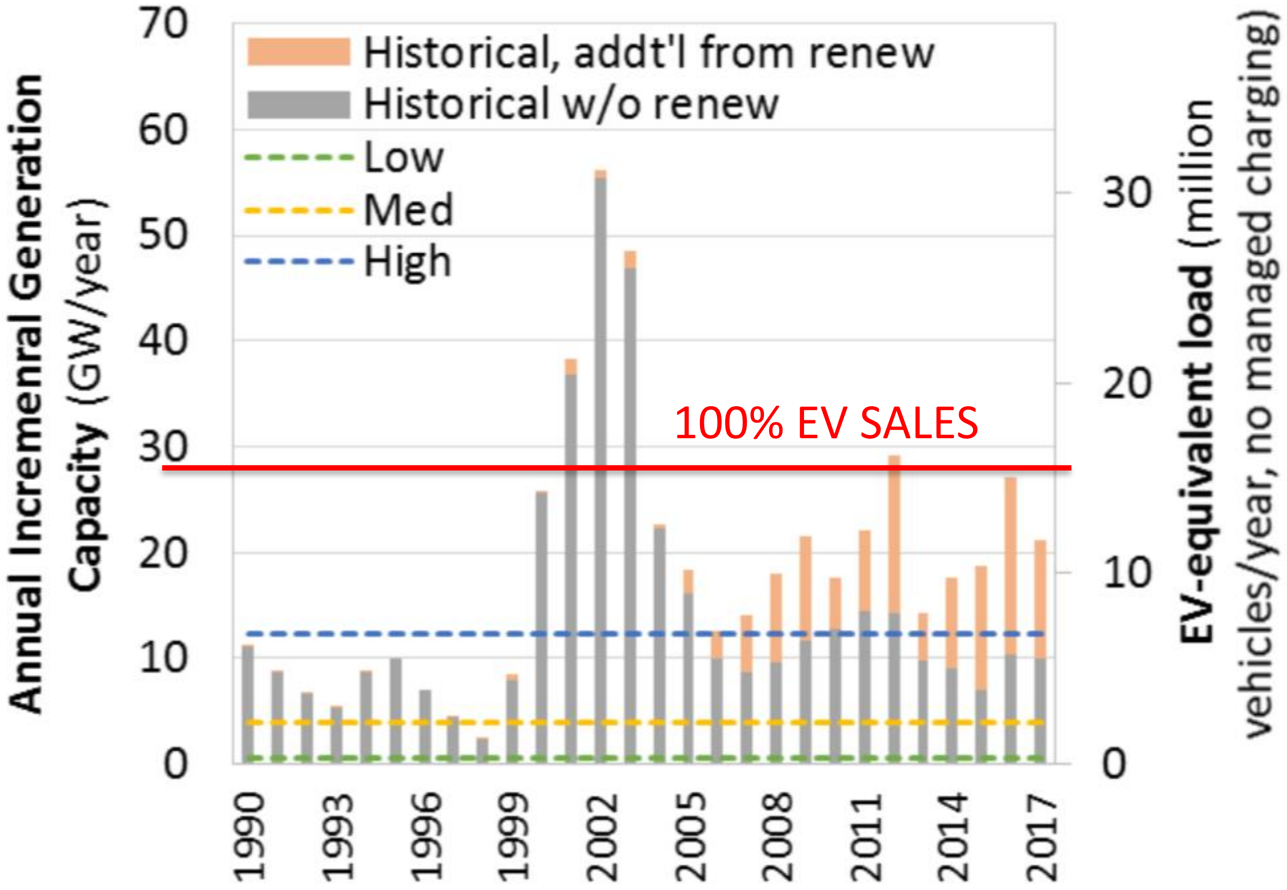
Source: https://www.nrel.gov/analysis/electrification-futures.html

Future expectations: consistently adjusting US LDV EV sales projections upward



Forecasting EVs' impact on the bulk grid

- **~17M light-duty vehicles** are sold each year in the US
- The **grid has evolved** over time to accommodate greater annual load additions
- Based on historical growth rates, sufficient energy generation and generation capacity is expected to be available to **support a growing EV fleet as it evolves over time.**

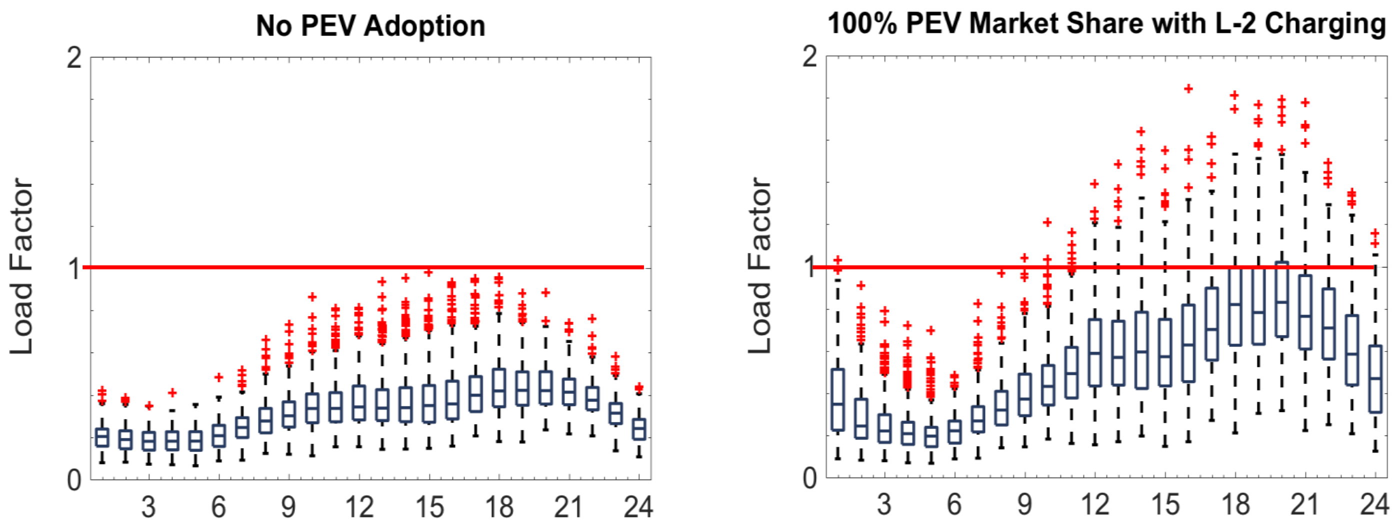


Source: US DRIVE 2019

Forecasting EVs’ impact on the distribution grid

Residential EV charging represents a significant increase in household electricity consumption that can require upgrades of the household electrical system and unless properly managed it may lead to exceeding the maximum power that can be supported by distribution systems, especially for legacy infrastructure and during high demand times.

- **Clustering effects** in EV adoption and **higher power** charging exacerbates these issues
- Effective planning, smart EV charging, and distributed energy storage systems can help to cope with these potential issues.
- Key to **consider EVs in system upgrades**

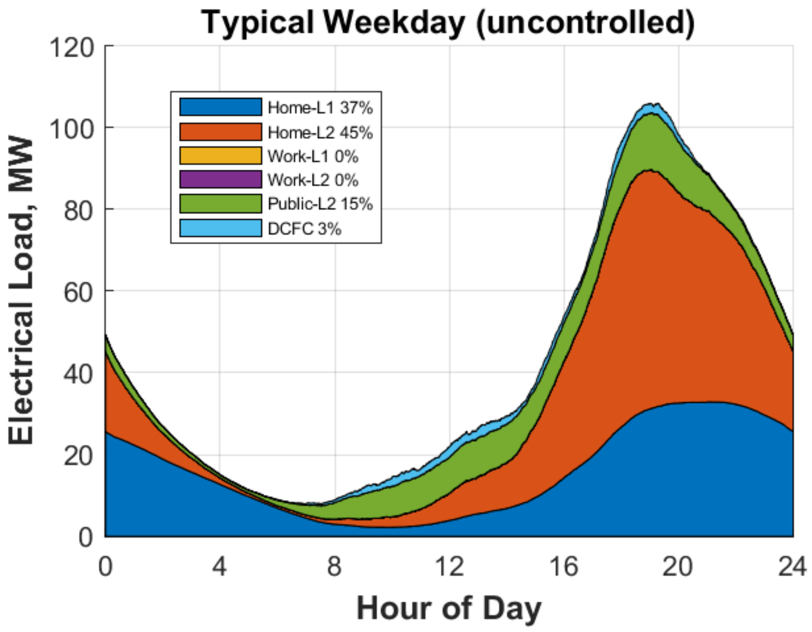


Source: Muratori, M., 2018. Impact of uncoordinated plug-in electric vehicle charging on residential power demand. Nature Energy, 3(3), pp.193-201.

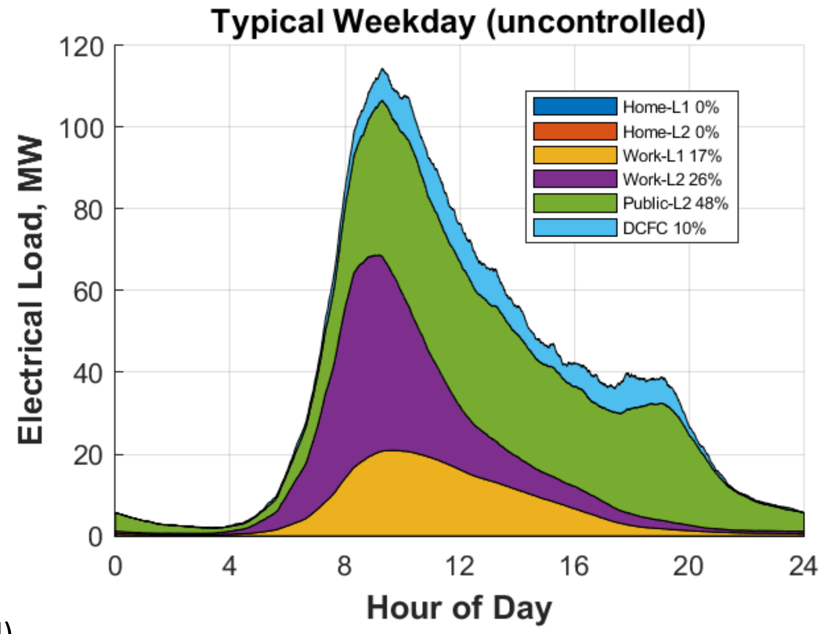
Just as important to forecasting total EV penetration is forecasting charging needs

- **Vehicles are underutilized assets**: parked ~95% of the time. EV charging profiles can look significantly different if vehicles are charged at different locations or times
- **Flexibility is secondary to mobility needs and is enabled by charging infrastructure**

Home-dominant charging



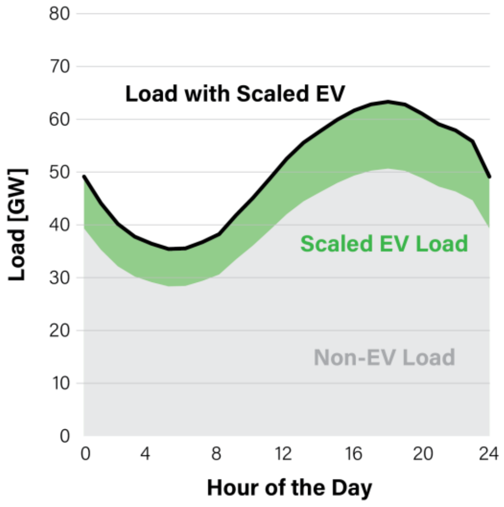
No-home charging

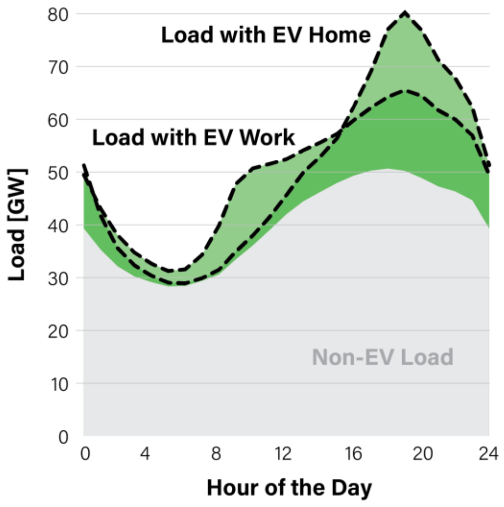


Source: NREL (EVI-Pro Model)

When and *where* EV charging occurs will be as critical as *how much* electricity is needed.

a) ASSUMPTION:
EV charging is often assumed to simply scale up electricity demand.

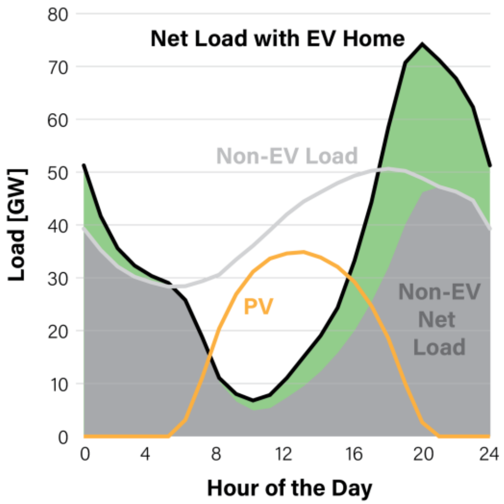


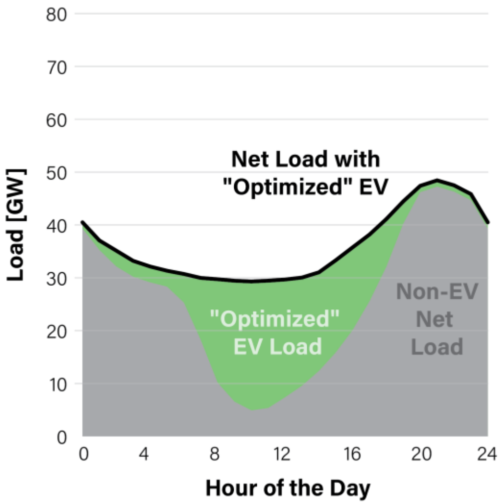


b) COMPLEXITY:
Future EV charging could change the shape of demand, depending on when and where charging occurs.

More nuanced demand-side modeling needed to assess the integration opportunities of EVs on the power system.

c) INTEGRATION:
EV charging can impact power system planning and operations, particularly with high shares of variable renewable energy.





d) FLEXIBILITY:
Optimizing EV charging timing and location could add flexibility to help balance generation and demand.

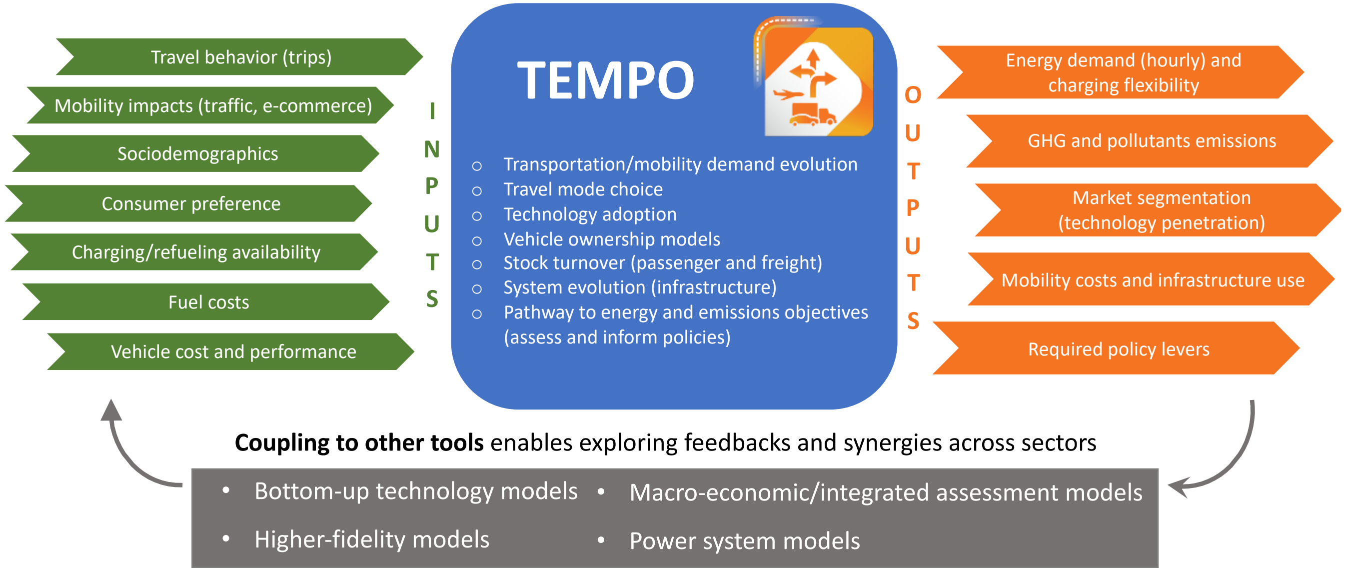
Source: *Muratori and Mai, The Shape of Electrified Transportation*

Projecting disruptive pathways is complex, and requires new “thinking” (modeling)

TEMPO

TEMPO (Transportation Energy & Mobility Pathway Options) is intended to generate future **pathways to achieve system-level goals**, explore the impacts of technological breakthroughs and behavioral changes, estimate energy/emissions implications of different scenarios and decisions, affordability and infrastructure use impacts, and assess **multi-sectoral integration opportunities**.

TEMP*O finds pathways* to achieve energy/emissions goals and estimates implications of different scenarios and decisions



Thank you

www.nrel.gov

brady.cowiestoll@nrel.gov

This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the city of Los Angeles. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

NREL Transforming ENERGY

MI POWER GRID

Making the Most of Michigan's Energy Future

Tom Eckman,
Lawrence Berkley National Lab

Advanced Planning Stakeholder Meeting

December 16, 2020

MPSC

Michigan Public Service Commission

Determining Utility System Value of Demand Flexibility From Grid-interactive Efficient Buildings

Tom Eckman

December 16, 2020

Presented to the 5th Michigan Power Grid Advanced Planning Meeting

This presentation was supported by the U.S. Department of Energy's Office of Electricity under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Introduction

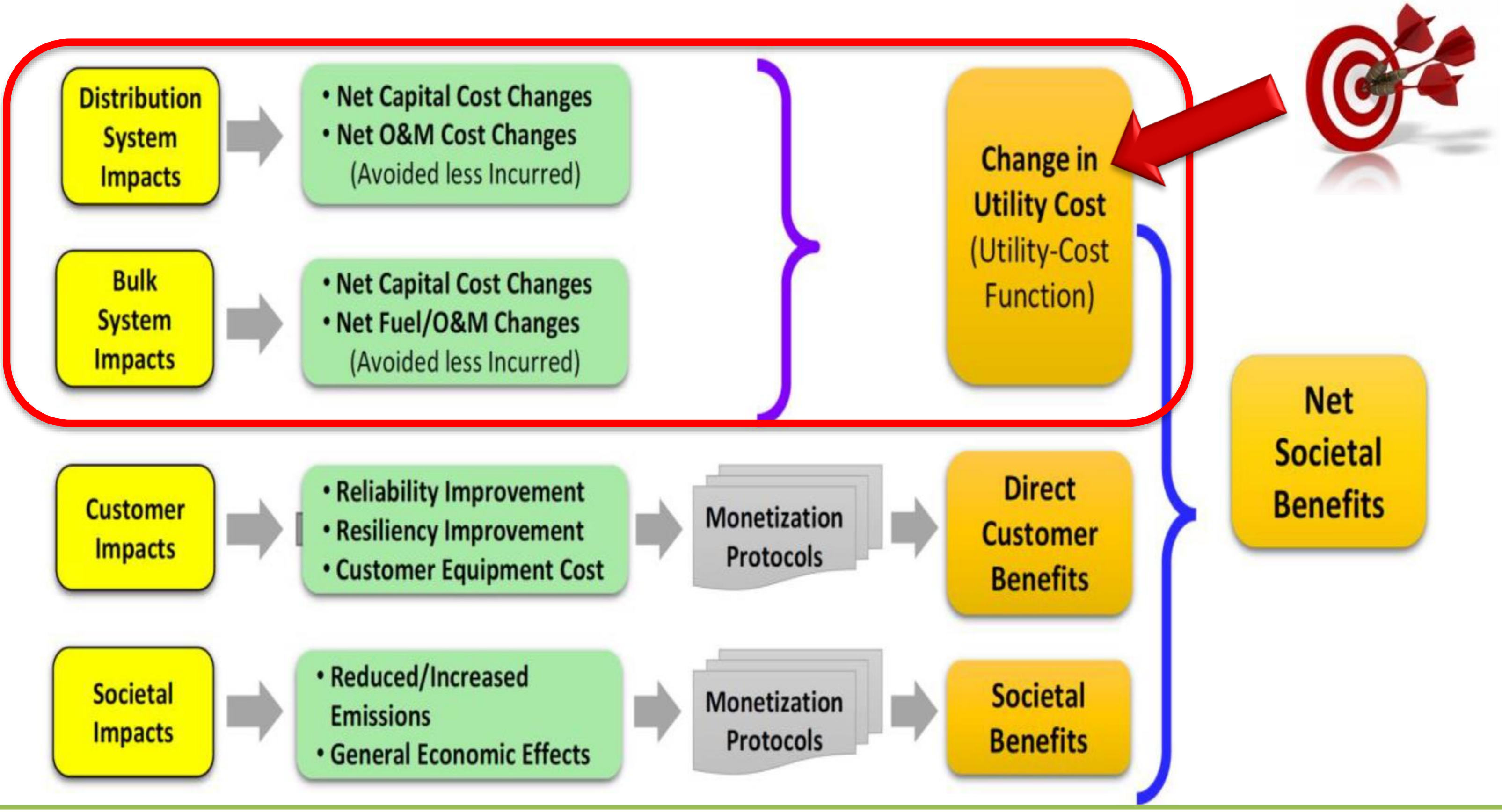
- The State and Local Energy Efficiency Action (SEE Action) Network offers resources, discussion forums, and technical assistance to state and local decision makers as they provide low-cost, reliable energy to their communities through energy efficiency.

- SEE Action reports on Grid-interactive Efficient Buildings
  - **Introduction for State and Local Governments:** Describes grid-interactive efficient buildings in the context of state and local government interests; highlights trends, challenges, and opportunities for demand flexibility; provides an overview of valuation and performance assessments for demand flexibility; and outlines actions that state and local governments can take, in concert with utilities, regional grid operators, and building owners, to advance demand flexibility. (https://emp.lbl.gov/publications/grid-interactive-efficient-buildings)
  - **Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings:** Describes how current methods and practices that establish value to the electric utility system of investments in energy efficiency and other distributed energy resources (DERs) can be enhanced to determine the value of grid services provided by demand flexibility. (https://emp.lbl.gov/publications/determining-utility-system-value)
  - **Issues and Considerations for Advancing Performance Assessments of Demand Flexibility from Grid-interactive Efficient Buildings:** Summarizes current practices and opportunities to encourage robust and cost-effective assessments of demand flexibility performance and improve planning and implementation based on verified performance (https://emp.lbl.gov/publications/performance-assessments-demand)

SEE Action Report on Demand Flexibility Valuation

- Focuses on methods and practices for determining the *economic value* of demand flexibility to *electric utility systems*
  - This value provides the basic information needed to design programs, market rules, and rates that align the economic interest of utility customers with building owners and occupants.
  - Jurisdictions can use utility system benefits and costs as the *foundation* of their economic analysis, but align their primary cost-effectiveness metric with *all applicable policy objectives*, which may include *non-utility system* impacts.
- Provides guidance to state and local policy makers, public utility commissions, state energy offices, utilities, state utility consumer representatives, and other stakeholders on how to improve consistency and robustness of economic valuation of demand flexibility to electric utility systems

Scope of Valuation = Electric Utility System



Grid-interactive efficient buildings with demand flexibility can provide grid services that:

- *reduce generation costs*, and/or
- *reduce delivery (transmission and distribution) costs*

Graphic: EPRI. 2015. *The Integrated Grid: A Benefit-Cost Framework*

Demand Flexibility's Value to Grid Depends on Controls

The list of DERs for which economic value of demand flexibility needs to be established is limited to those that rely on ***controls***.

- Mr. McGuire: I want to say one word to you. Just one word.
- Benjamin: Yes, sir.
- Mr. McGuire: Are you listening?
- Benjamin: Yes, I am.
- Mr. McGuire: ~~***Plastics***~~.

Controls

Planning Challenges (1)

Limited analytical capacity

– Declining costs and increasing levels of storage and other DERs provide opportunities for utilities to incorporate demand flexibility into grid planning, operations, and investment decisions alongside other options for meeting electricity system needs.

– To do so, utilities need to be able to evaluate multiple resource portfolio options in an organized, holistic, and technology-neutral manner and normalize solution evaluation across generation, distribution, and transmission systems.

Planning Challenges (2)

Lack of parity in cost-effectiveness analysis in planning

– For most utilities, economic valuation of DERs as utility system resources generally is not equivalent to such valuation for utility-scale generation resources and traditional transmission and distribution system solutions.

– This lack of parity in cost-effectiveness analysis limits the selection of demand flexibility for achieving state energy goals including reliability, resilience, security, and affordability.

Current Methods and Gaps for Resource Options Analysis and Valuation

Value = Avoided Cost

- Traditionally, the economic value of energy efficiency, demand response, and other DERs has been determined using the “avoided cost” of conventional resources that provide the identical utility system service.

- The underlying economic principle of this approach is that the *value* of a resource can be estimated using the *cost of acquiring the next least expensive alternative resource* that provides comparable services (i.e., the *avoided cost* of that resource).

Primary Valuation Task

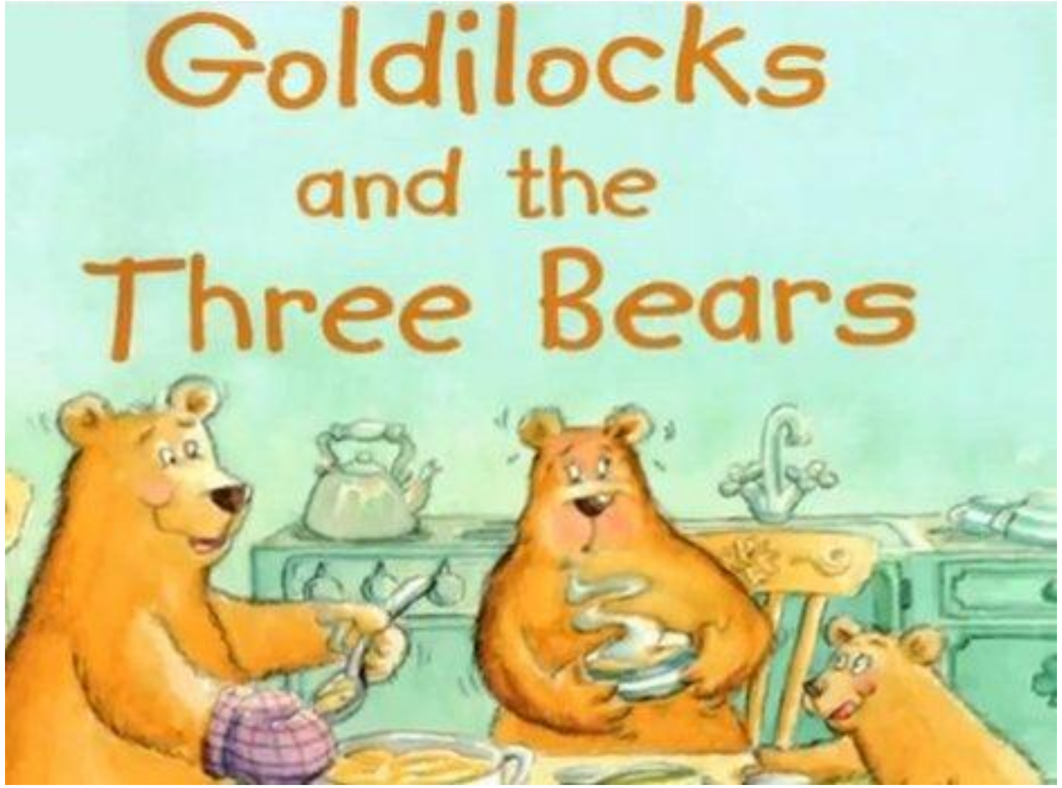
- The primary task required to determine the value of demand flexibility based on avoided cost is to *identify the alternative (i.e., "avoided")* resource and *establish its cost*.

- Methods used to establish avoided cost vary widely across the United States due to differences in:*
  - electricity market structure
  - available resource options and their costs
  - state energy policies and regulatory context

*See "Market Structure Influences Value of Demand Flexibility," "Resource Availability and Cost Vary Across U.S.," and "State Energy Policies and Regulatory Context" in Extra Slides.

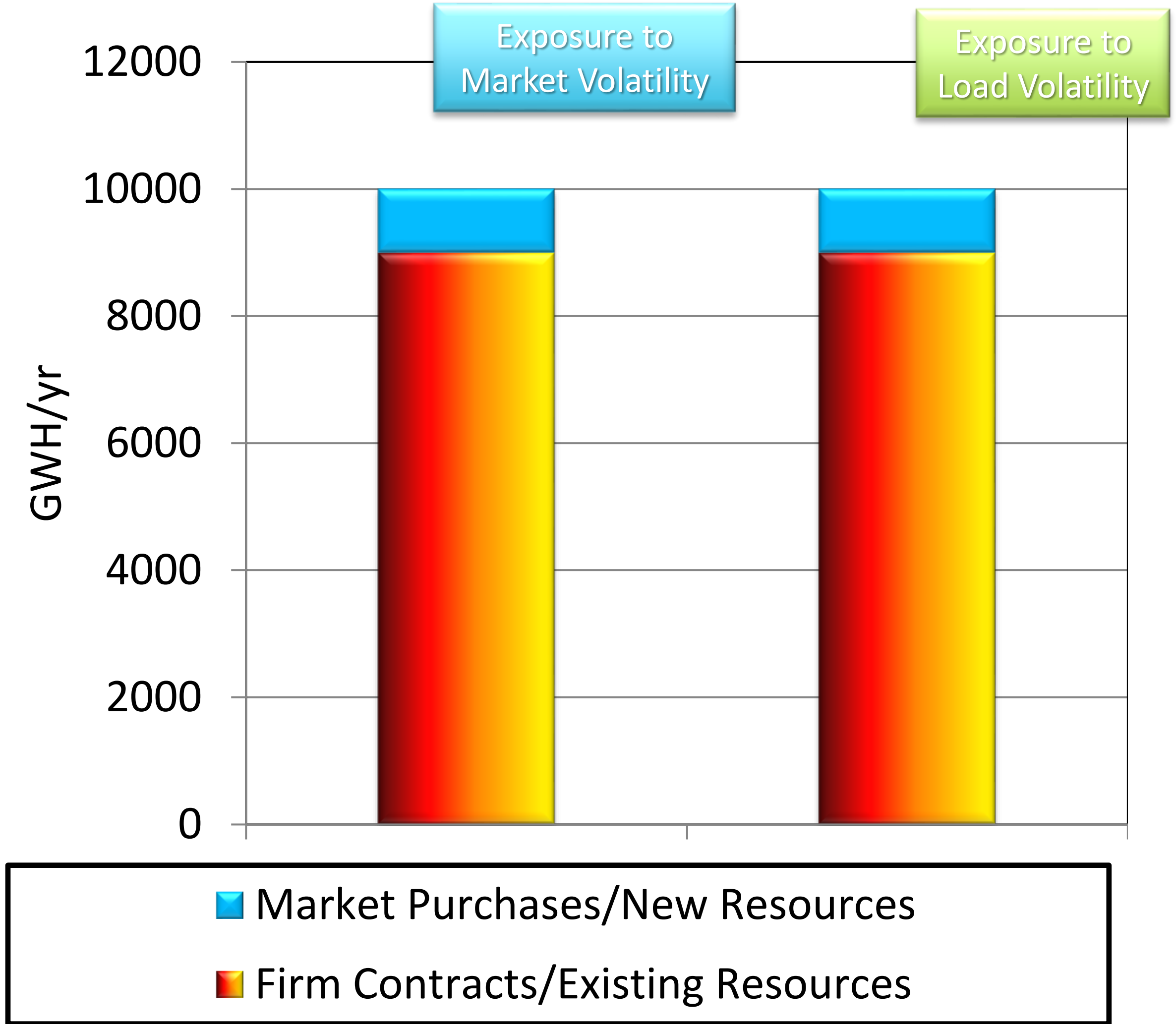
The Resource Options Analysis Problem

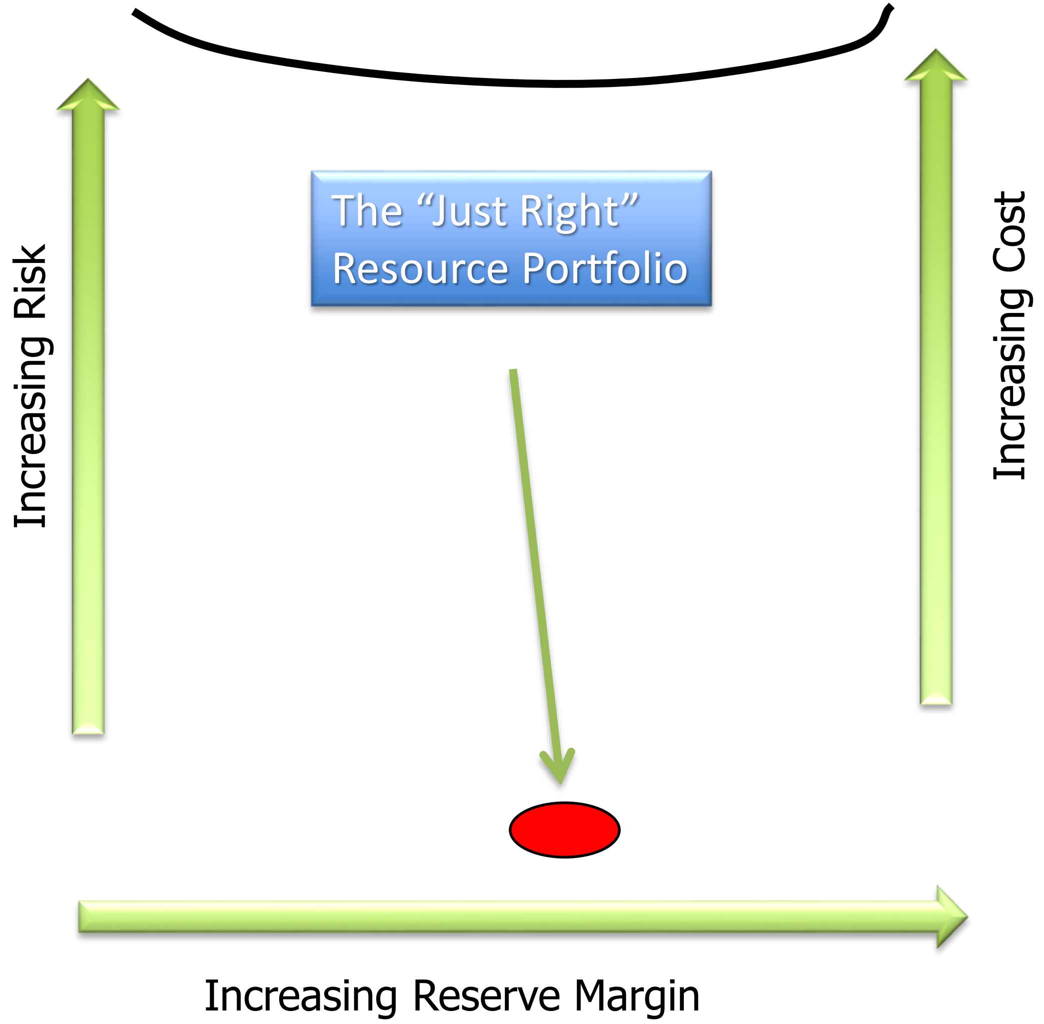
- Don't have too many resources
- Don't have too few resources
- Have "just the right amount" of resources*



**The "right amount" means not only the quantity developed, but the timing of their development and the mix (type) of resources required to provide energy, capacity, flexibility, and other ancillary services for system reliability, including risk management and resilience.*

Solving the "Goldilocks' Problem" Requires Analysis Comparing Cost and Risk of Alternative Resource Options





Primary Methods of Resource Options Analysis for DERs

- **System capacity expansion and market models***
  - *Most prevalent practice* – Reducing the growth rate of energy and/or peak demand in load forecasts input into the model, then let it optimize the type, amount, and schedule of new conventional resources (generation, transmission or distribution)
  - *Less prevalent practice* - Directly competing DERs with conventional resources in the model to determine DERs' impact on existing system loads, load growth, and load shape—and thus dispatch of existing resources—and the type, amount, and timing of conventional resource development
- **Competitive bidding processes/auctions:*** Use "market mechanisms" to select new DERs, currently limited to energy efficiency (EE) and demand response (DR)
- **Proxy resources:** Use the cost of a resource that provides grid services (e.g., a new natural gas-fired simple-cycle combustion turbine to provide peaking capacity) to establish the cost-effectiveness of DERs (i.e., determine the amount to develop) that provide these same grid services
- **Administrative/public policy determinations**: Use legislative or regulatory processes to establish development goals (e.g., Renewable Portfolio Standards and Energy Efficiency Resource Standards)

**Also used for utility scale resource options analysis*

Gaps and Limitations of Current Methods: Restructured Markets

- Not all DERs are eligible to participate in markets.
- Not all utility system DER benefits are reflected in the bulk power system. Not captured:
  - Locational value of avoided/deferred T&D capacity
  - Value of distribution system losses
  - Value of resilience
- “Long-term” resource value is not recognized in some markets.
  - For example, PJM limits compensation for EE and DR to four years, regardless of measure life, assuming that the impact of these resources will be embedded in its econometric forecast after that period.

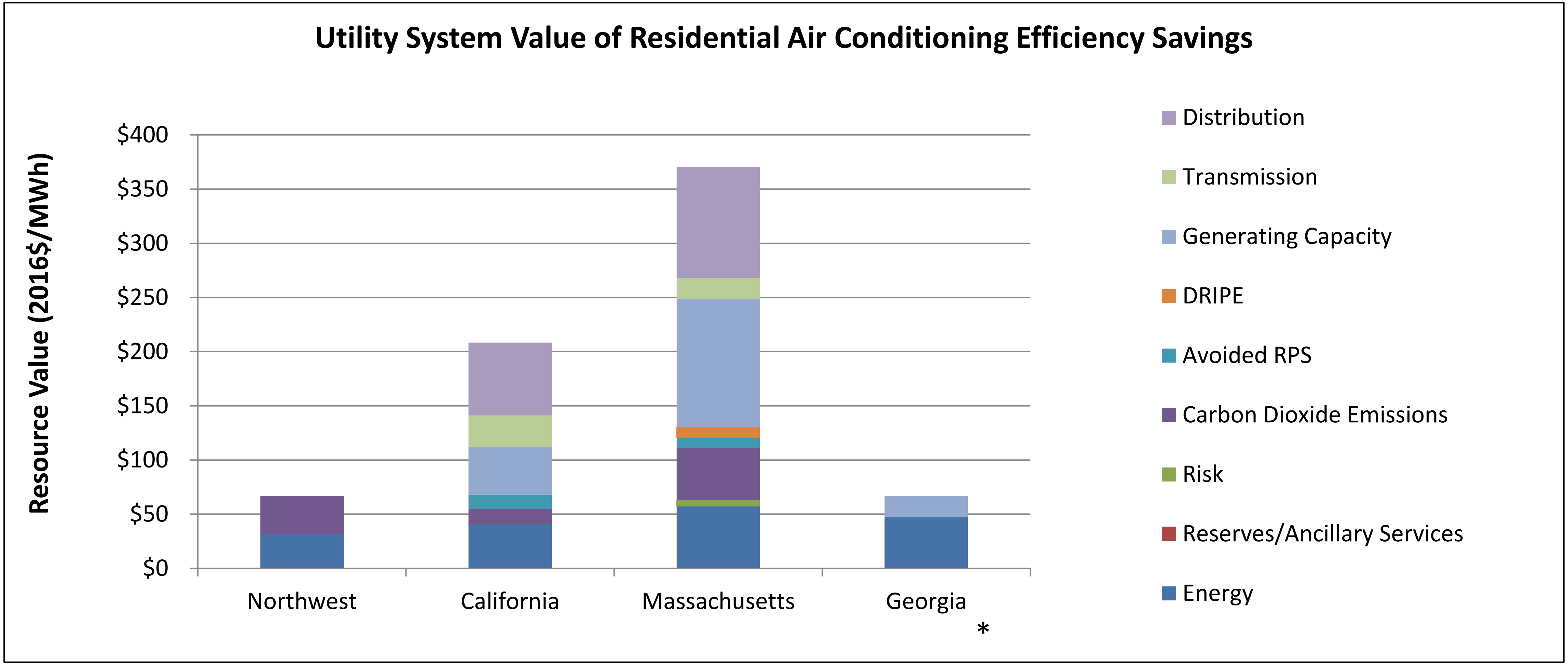
Gaps and Limitations of Current Methods: Utilities in Vertically Integrated States

- Not all utilities (or state requirements) include all system benefits of DERs.
  - e.g., some include time-varying, locational, risk mitigation, and resilience value, while others do not
- Not all utilities (or state requirements) consistently quantify system benefits of DERs.
  - e.g., some use marginal distribution system losses to "gross up" impacts to generation and transmission system, while others use average system losses, and the accuracy of load shape data (if used) varies widely
- Resource options analysis often fails to account for the potential interaction *between* DERs (e.g., impact of EE on DR potential, impact of storage on distributed generation).
- Typical resource optimization modeling embeds DER impacts in the load forecast, so it fails to capture potential DER interactions with existing and future resources.
- Commercially available capacity expansion models have limited capability to model DERs as resource options (except perhaps DR and battery storage).

Example Gaps and Limitations

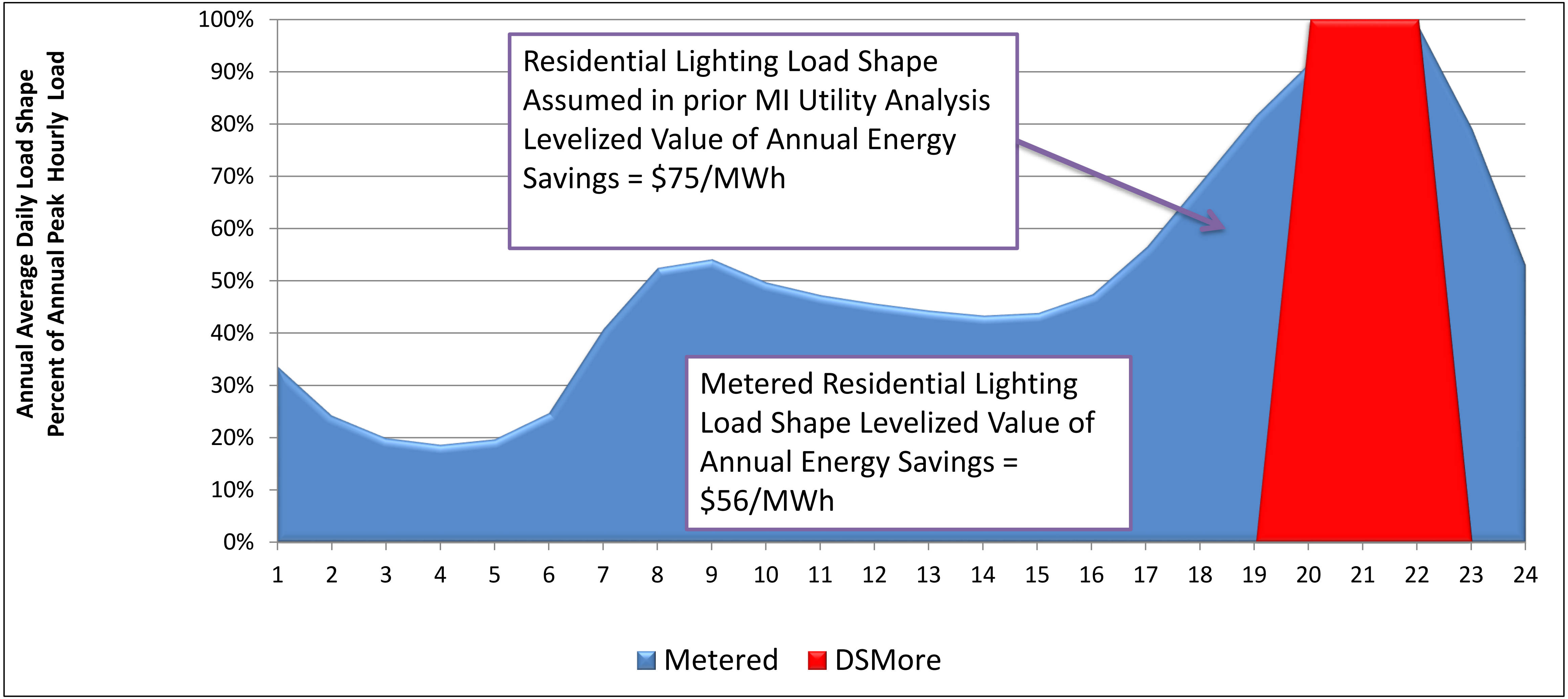
- Not accounting for *all substantial utility system impacts*
- Not using *accurate load shapes* to determine time-varying value
- Not accounting for *distribution and transmission system capacity impacts*
- Not accounting for variations in *interactions between DERs*
- Not accounting for variations in *interactions between DERs and existing and future utility system resources*
- Failing to *quantify risk mitigation and resilience* value of DERs

Not accounting for all substantial utility system impacts undervalues demand flexibility.

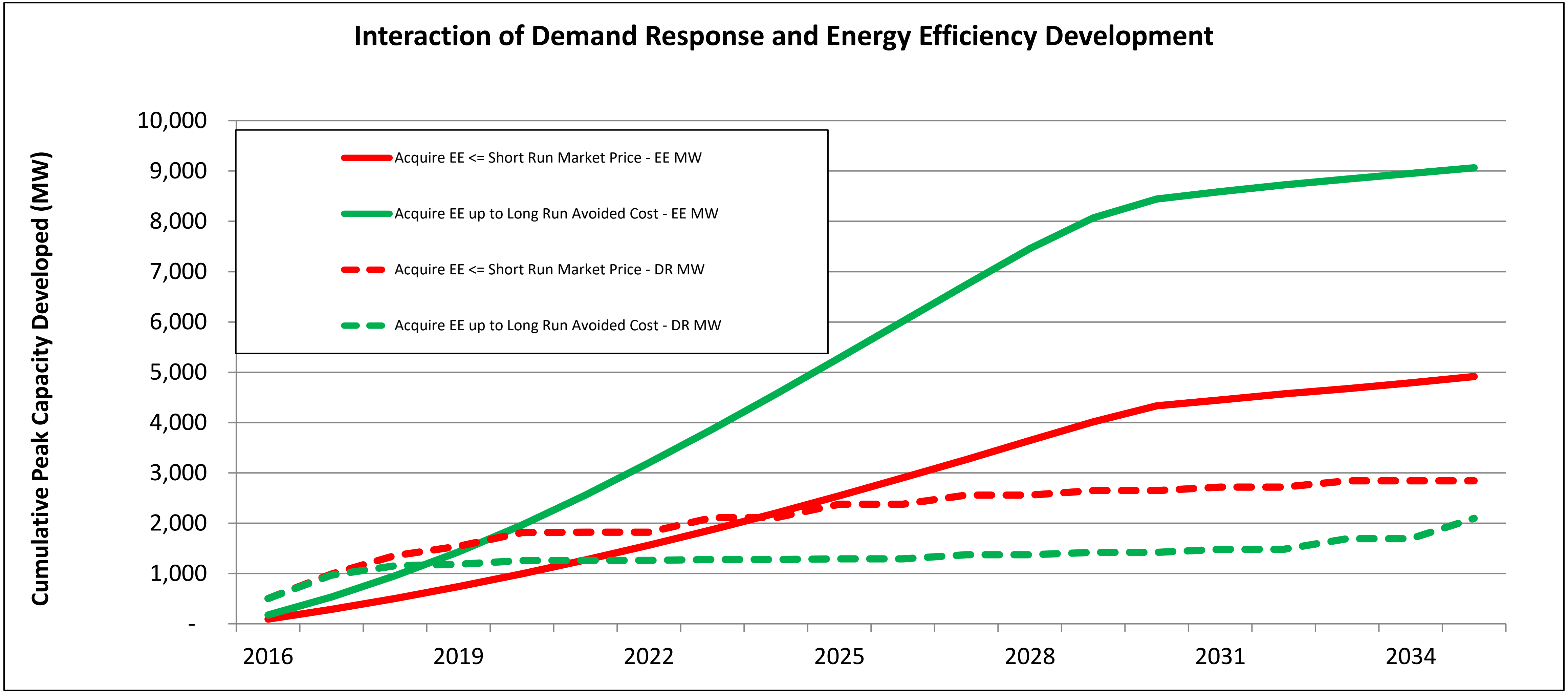


* In Georgia, where publicly available data did not include avoided transmission and distribution system values, the time-varying value of efficiency appears much lower for all measures evaluated. Avoided transmission and distribution costs are included in Georgia Power's energy efficiency evaluations, but are not a part of the publicly available PURPA avoided cost filing.

Using inaccurate load shapes impacts evaluation of DERs as resource options — both energy and peak impacts.

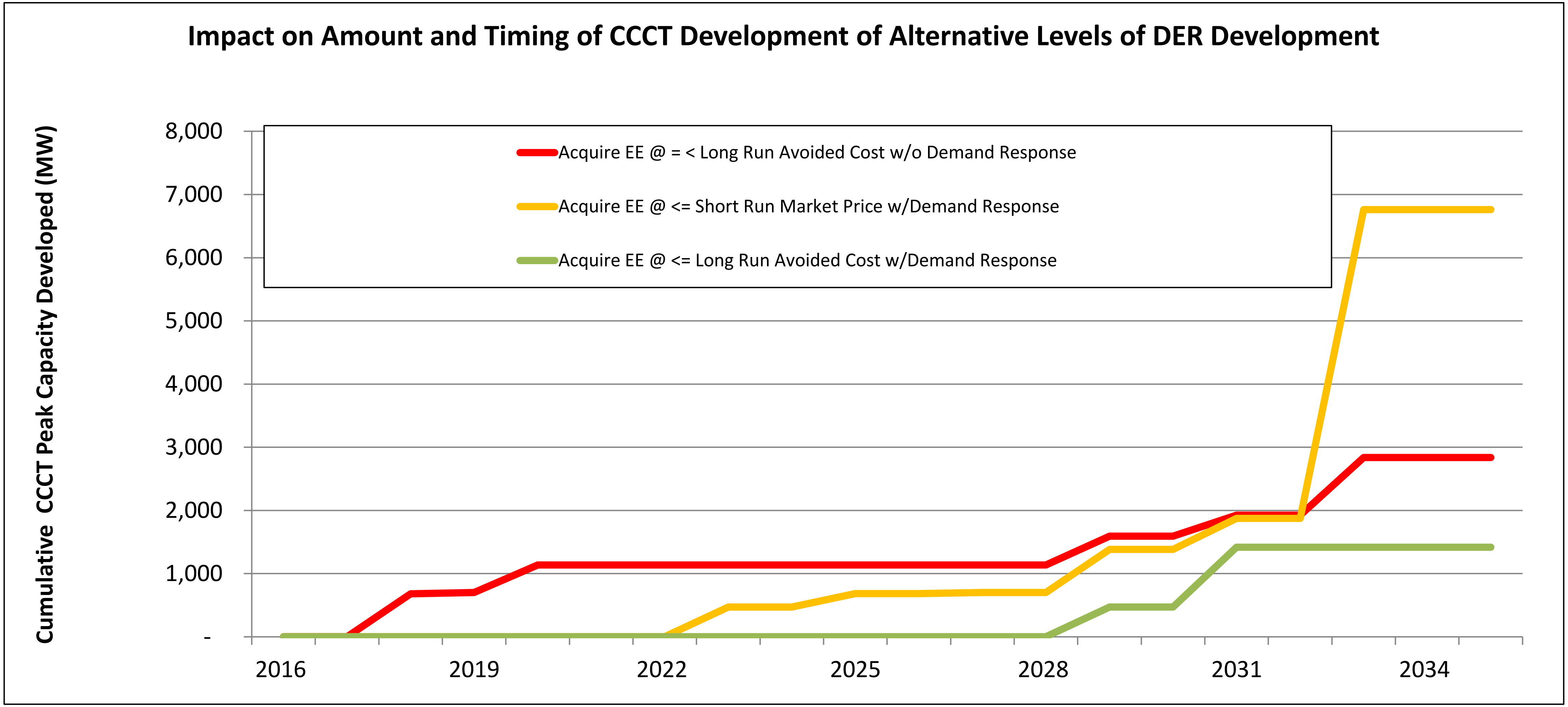


Failing to analyze the potential interactions *between* DERs may result in selection of higher cost resource strategies.



Source: Northwest Power and Conservation Council, 7th Power Plan

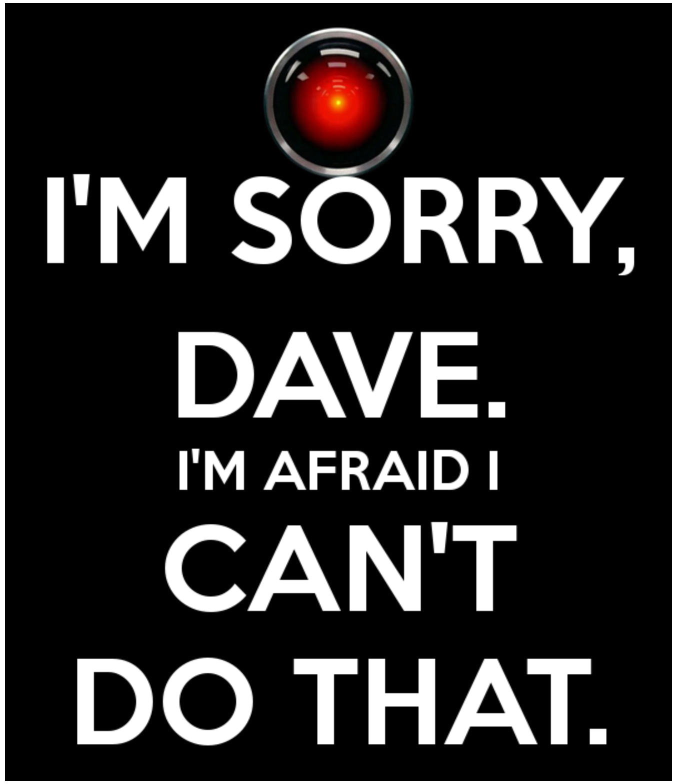
Failing to analyze the potential interaction between DERs and the existing and future utility system may result in less than optimal resource strategies.



Source: Northwest Power and Conservation Council, 7th Power Plan

Most capacity expansion models are not designed to conduct systemic risk analysis

- Market equilibrium models generally optimize capacity expansion for a *single* future.
  - They assume control of not only all “known knowns,” but also the “known unknowns” and the “unknown unknowns.”
- Sensitivity studies are often used to inform risk analysis, but only compare optimizations created for *single* futures.



These models systematically understate risk, and therefore the value of risk mitigation and resilience.

Treating DERs as Resource Options in Capacity Expansion Modeling

It can be done, but it is non-trivial.

– Most commercially available capacity expansion models were not designed to model DERs as *resource options*.
– These models require users to define the specific resource characteristics such as cost, quantity, lead times, and load shapes.
– Treating of DERs as *resource options* in capacity expansion models requires many user-defined inputs, an experienced modeler, potentially multiple model runs, and/or post-processing of model output.

Ways to Improve Valuation of Demand Flexibility That Enhance Its Consideration in Resource Options Analysis and Decision-making

Primary Factors Impacting Value of Demand Flexibility

- There is no single economic value of demand flexibility for utility systems.
- The value of a single “unit” (e.g., kW, kWh) of grid service provided by demand flexibility is a function of:
  - the *timing* of the impact (temporal load profile),
  - the *location* in the interconnected grid,
  - the *grid services* provided,
  - the *expected service life* (persistence) of the impact, and
  - the *avoided cost of the least-expensive resource alternative* providing comparable grid service.
- Demand flexibility valuation methods and practices should account for these variations.

Enhanced Valuation Methods - Seven Considerations*

1. Account for *all electric utility system economic impacts* resulting from demand flexibility
2. Account for variations in value based on *when* demand flexibility occurs
3. Account for the *impact of distribution system* savings on transmission and generation system value
4. Account for variations in value specific *locations* on the grid
5. Account for variations in value due to *interactions between DERs* providing demand flexibility
6. Account for benefits across the *full expected useful lives* (EULs) of the resources
7. Account for variations in value due to *interactions between DERs and other system resources*

*See summary implementation guidance and resources in Extra Slides.

Account for all electric utility system economic impacts resulting from demand flexibility

- The goal is to treat demand flexibility on a par with supply-side options so that *all grid impacts*, *costs, and benefits* to the utility system can be quantified and monetized.

- The objective of this enhancement is to include *all substantive and reasonably quantifiable generation and T&D system impacts.*

Not all utility system benefits provided by demand flexibility are of equal value

T&D Capacity
Resilience
Reserves
Ancillary Services
Losses
Generating Capacity
Energy
Risk
DRIPE
RPS Compliance
Credit Collection
Reliability
Environmental Compliance

So, start with the "Big Ones"

Account for variations in value based on when demand flexibility occurs

- The value of DERs that can adjust load is fundamentally dependent on the timing of their impacts.

- The impact of demand flexibility must be addressed on a more *granular time scale*.
  - The economic value of grid services that demand flexibility provides varies from sub-hourly to daily, monthly, and seasonally as well as across future years and across utility systems.

See "Example: Time-Sensitive Value of Energy Efficiency Measures" in Extra Slides.

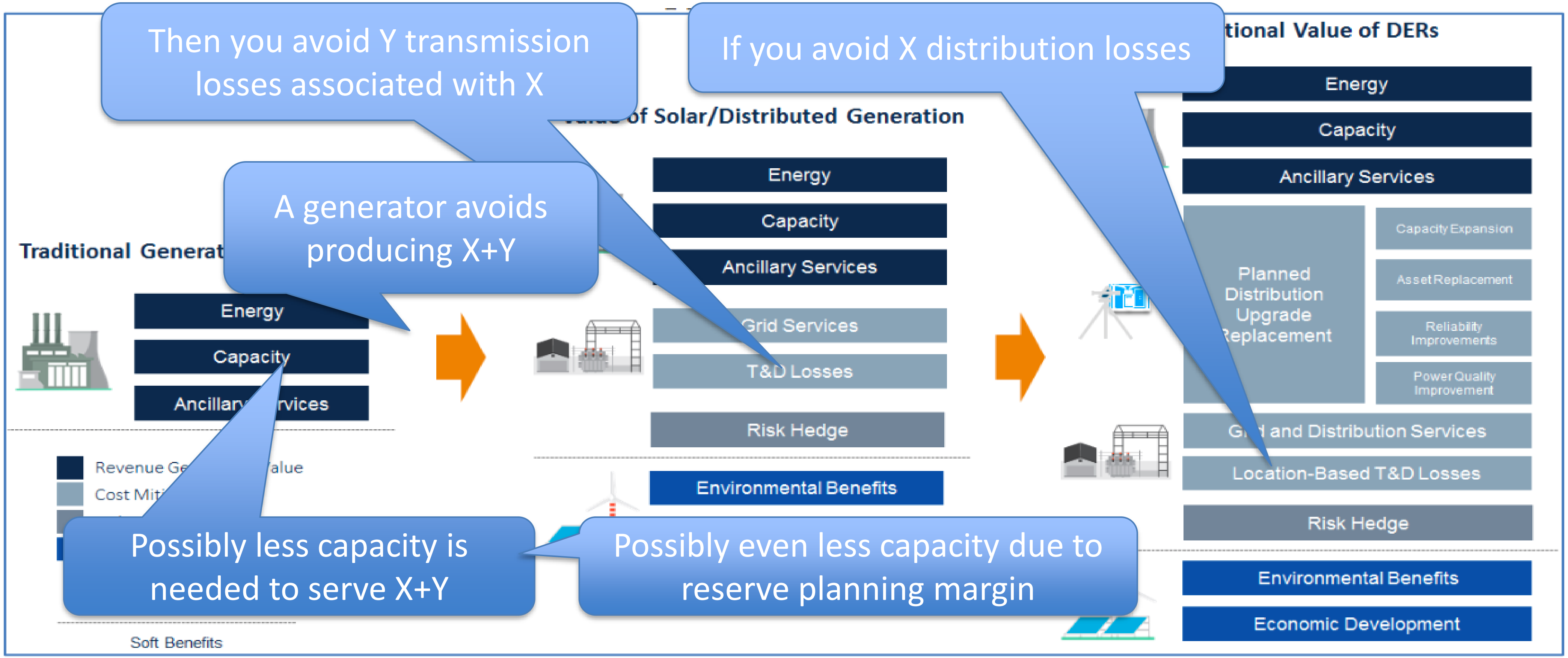
Account for the impact of distribution system savings on transmission and generation system value

- Demand flexibility can be used to avoid *distribution system losses* when they are highest, resulting in reduced transmission system losses and avoided generator capacity needs (including the planning reserve margin).

- *Locational impacts* on the distribution system and their associated economic value should be modeled and *calculated first.* Results can be used to adjust inputs to the analysis of transmission and generation system values.

Ohm's Law:
Volts = I (Amps) x (R)esistance (Ohms)
Power Law:
Watts = Volts x Amps
Therefore:
Watts = Amps x Ohms x Ohms or (I^2R)

DER Value Streams Have Ripple Effects



Ben Kellison, "Unlocking the Locational Value of DER 2016: Technology Strategies, Opportunities, and Markets," January 2016,

Calculate the localized impacts first

See "Three Enhancements to Distribution System Planning" in Extra Slides.

MI POWER GRID

MPSC

Account for variations in value at specific grid locations

- The locational value of demand flexibility is highly dependent on where grid services resulting from demand flexibility occur on the interconnected grid (i.e., T&D systems).
- Particular attention must be given to this issue in regions with centrally-organized organized wholesale markets, where prices for capacity do not reflect distribution system locational benefits.
  - *Using only wholesale energy or capacity market prices to represent the value of demand flexibility undervalues it. These methods do not account for other utility system benefits, particularly those that rely on locational value.*

See "Locational value of demand flexibility may account for significant economic value" and "Account for variations in value due to interactions between DERs providing demand flexibility" in Extra Slides.

Account for variations in value due to interactions between DERs providing demand flexibility

- Analysis should first capture major interactions between pairs of DERs
  - Interactions can be estimated assuming that deployment of DERs does not impact the existing or future electric grid sufficiently to alter avoided cost.
- Higher levels of DERs increases the need to address *interactions of DERs* with one another and with the electric grid. It is unlikely that their collective and cumulative impacts are simply additive, and they *may* alter avoided cost.
  - *Widespread deployment of demand flexibility for grid services will change grid operations and infrastructure development, altering avoided resource costs.*

Account for benefits across full expected useful resources lives

- Expected useful lives (EULs), determined independently of policy or program decisions regarding the length of time compensation is offered for the grid services they provide, should be used in calculating the economic value of DERs providing demand flexibility.
- Demand flexibility that defers or avoids capital expenditures, ongoing fuel costs, or O&M costs throughout their EULs need to be valued (and perhaps compensated) differently than resources that only reduce near-term fuel costs or O&M costs, as well as demand flexibility that is forecast to have variable and uncertain impacts through time.

Program Implications

- Some DERs with demand flexibility *will likely exhibit variation in measure/resource grid impacts* over their lifetimes because:
  - their “dispatch,” while controlled by a grid operator, also will be dictated by the response of building owners and occupants, or
  - by design, the technology they employ is intended to adjust impacts through time (e.g., learning thermostats and similar Artificial Intelligence learning controls)
- Uncertainty regarding EULs for demand flexibility may be best addressed through program designs that rely more on “pay for performance” mechanisms rather than one-time, upfront payments.

Account for variations in value due to interactions between DERs and other system resources

- System expansion models used to estimate avoided costs should include all resources so the model can select them for development when determining impact of widespread deployment of demand flexibility.
- Significant scale is typically necessary to alter the dispatch of existing resources and/or the type, timing, and amount of conventional generating resources sufficiently to materially affect avoided costs.

Applicability of Enhanced Valuation Methods to Distribution, Generation, and Transmission Planning Analyses

Enhanced valuation methods to account for:	Distribution System Planning			Generation Planning		Transmission Planning	
	Hosting Capacity (for distributed generation capacity)	Energy Analysis (loss estimation)	Thermal Capacity (peak capacity)	Capacity Expansion Modeling	Market-Based Mechanisms	Capacity Expansion Modeling	Congestion Pricing Analysis
1. All electric utility system economic impacts resulting from demand flexibility	●	●	●	●	●	●	●
2. Variations in value based on when demand flexibility occurs	●	●	●	●	●	●	●
3. Impact of distribution system savings on transmission and generation system value	◔	●	◑	◑	◑	◑	◑
4. Variations in value at specific locations on the grid	●	●	◔	◔	◔	●	●
5. Variations in value due to interactions between DERs providing demand flexibility	●	◕	●	◕	◕	◕	◕
6. Benefits across the full expected useful lives of the resources	◑	◑	●	◑	◑	●	●
7. Variations in value due to interactions between DERs and other system resources	◕	◑	●	●	●	●	●

● most applicable, ◔ least applicable

Tom Eckman

TEckman49@gmail.com

503-803-5047

Lisa Schwartz

lcschwartz@lbl.gov

510-486-6315

ELECTRICITY MARKETS & POLICY

Follow us on Twitter @BerkeleyLabEMP

Sign up for our mailing list to stay up-to-date on our publications, webinars and other events

EXTRA SLIDES

Grid-interactive Efficient Buildings and Demand Flexibility

Grid-interactive Efficient Building	An energy-efficient building that uses smart technologies and on-site DERs to provide demand flexibility while co-optimizing for energy cost, grid services, and occupant needs and preferences in a continuous and integrated way	Demand Flexibility*	Capability of DERs to adjust a building's load profile across different timescales

DERs – Resources sited close to customers that can provide all or some of their immediate power needs and/or can be used by the utility system to either reduce demand or provide supply to satisfy the energy, capacity, or ancillary service needs of the grid

Smart technologies for energy management - Advanced controls, sensors, models, and analytics used to manage DERs. Grid-interactive efficient buildings are characterized by their use of these technologies.

**Also called "energy flexibility" or "load flexibility"*

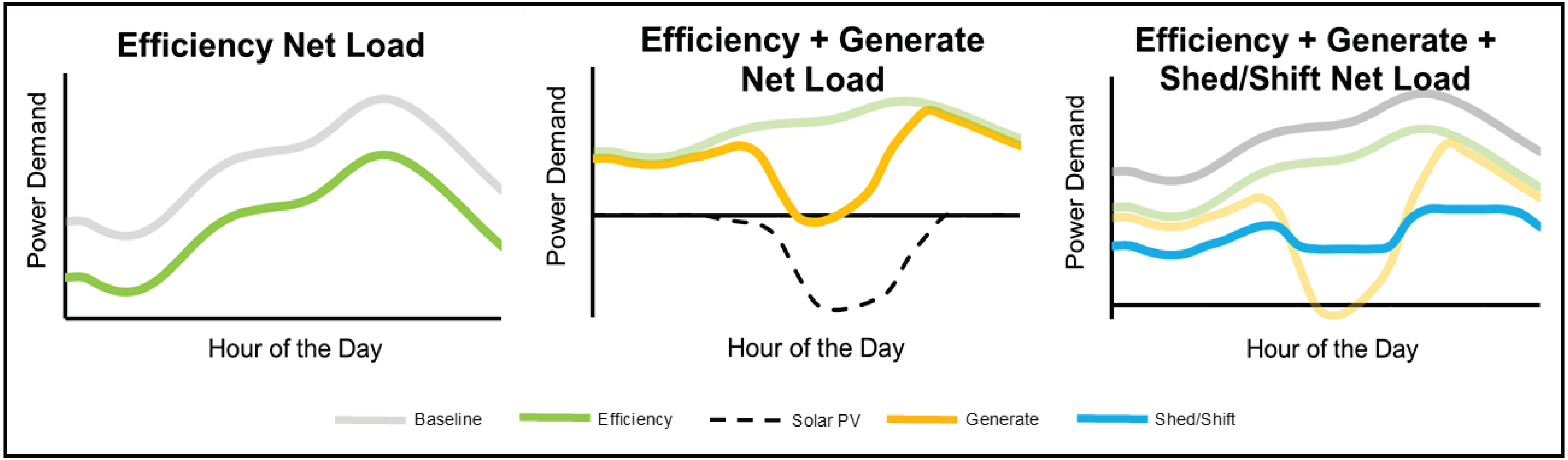
Source: Neukomm et al. 2019. *Grid-interactive Efficient Buildings Technical Report Series: Overview of Research Challenges and Gaps*. Also see example building in Extra Slides. More information here.

Demand-side Management Strategies to Manage Building Loads

- *Energy efficiency:* Ongoing reduction in energy use while providing the same or improved level of building function
- Demand flexibility:
  - *Load shed*: Ability to reduce electricity use for a short time period and typically on short notice.
  - *Load shift*: Ability to change the timing of electricity use. In some situations, a shift may lead to changing the amount of electricity that is consumed.
  - *Modulate*: Ability to balance power supply/demand or reactive power draw/supply autonomously (within seconds to sub seconds) in response to a signal from the grid operator during the dispatch period
  - *Generate*: Ability to generate electricity for onsite consumption and even dispatch electricity to the grid in response to a signal from the grid

Source: Neukomm et al. 2019

Daily Average Load Profiles for Grid-interactive Efficient Building



Source: Neukomm et al. 2019

Left: *Energy efficiency alone pushes down the load curve.*
Middle: *Energy efficiency plus distributed generation (in this case, solar PV) reduce overall energy use, but the building's peak load coincides with utility peaks.*
Right: *Adding load shedding and shifting flattens the building load profile, providing the greatest support to the grid.*

Summary of Valuation Enhancements and Implementation Guidance (1)

Valuation Enhancement	Guidance
1. Account for all electric utility system economic impacts resulting from demand flexibility	Prioritize enhancements for analyses used to derive the value of primary utility system benefits.
2. Account for variations in value based on when demand flexibility occurs	Develop and use hourly forecasts of avoided energy and capacity costs in combination with publicly available load shape data for DERs to value demand flexibility.
3. Account for the impact of distribution system savings on transmission and generation system value	Model and calculate distribution system-level impacts (i.e., locational impacts and associated economic value) first so that results can be used to adjust inputs to analysis of bulk transmission and generation system values.

Summary of Valuation Enhancements and Implementation Guidance (2)

Valuation Enhancement	Guidance
4. Account for variations in value at specific locations on the grid	Initiate a distribution system planning process that includes: (1) hosting capacity analysis to estimate generating DER capacity limits and identifies demand flexibility that can mitigate limits, (2) thermal limit analysis to estimate locational value of non-wires solutions, (3) energy analysis to quantify marginal distribution system losses, and (4) systemwide analysis of the avoided cost of deferred distribution capacity expansion.
5. Account for variations in value due to interactions between DERs providing demand flexibility	Start accounting for interactions between DERs. Basic analysis can assume that deployment of multiple types of DERs does not impact the existing or future electric grid in a way that alters avoided costs. Such basic analysis does not require the use of system capacity expansion models.

Summary of Valuation Enhancements and Implementation Guidance (3)

Valuation Enhancement	Guidance
6. Account for benefits across the full expected lives of the resources	As a first step, use the EUL of DERs providing demand flexibility to calculate their economic value. However, because demand flexibility is largely based on controls, the dispatch of which is determined by the combined impact of grid operators and owner/occupant responses, EULs may be more a function of rate and program design, compared to EULs for traditional energy efficiency measures. Uncertainty regarding EULs for demand flexibility may be best addressed through program design.
7. Account for variations in value due to interactions between DERs and other system resources	Use distribution, transmission and generation capacity expansion modeling, supplemented as necessary with other methods described in section 4 of this report, to determine the impact of widespread deployment of demand flexibility for grid services. Implementing this enhancement will require customization of commercially available capacity expansion models.

Implementation Resources (1)

Valuation Enhancement`	Implementation Resources
1. Account for all electric utility system economic impacts resulting from demand flexibility	• National Efficiency Screening Project, *National Standard Practice Manual* • EPRI, *The Integrated Grid - A Benefit-Cost Framework* • EPA, *Assessing the Multiple Benefits of Clean Energy – Resources for States* (particularly Section 3.2.4)
2. Account for the time-sensitive economic value of demand flexibility	• Berkeley Lab reports discuss data and methods required to capture temporal value of energy efficiency including *Time-Varying Value of Electric Energy Efficiency* and *Time-Varying Value of Energy Efficiency in Michigan*. More resources at https://emp.lbl.gov/projects/time-value-efficiency. • Smart Electric Power Alliance, *Beyond the Meter: Addressing the Locational Valuation Challenge for Distributed Energy Resources*
3**. Account for the impact of distribution system-level savings on transmission and generation system value**	• PNNL, *Electric Distribution System Planning with DERs – Tools and Methods (forthcoming)* • Smart Electric Power Alliance, *Beyond the Meter: Addressing the Locational Valuation Challenge for Distributed Energy Resources*

Implementation Resources (2)

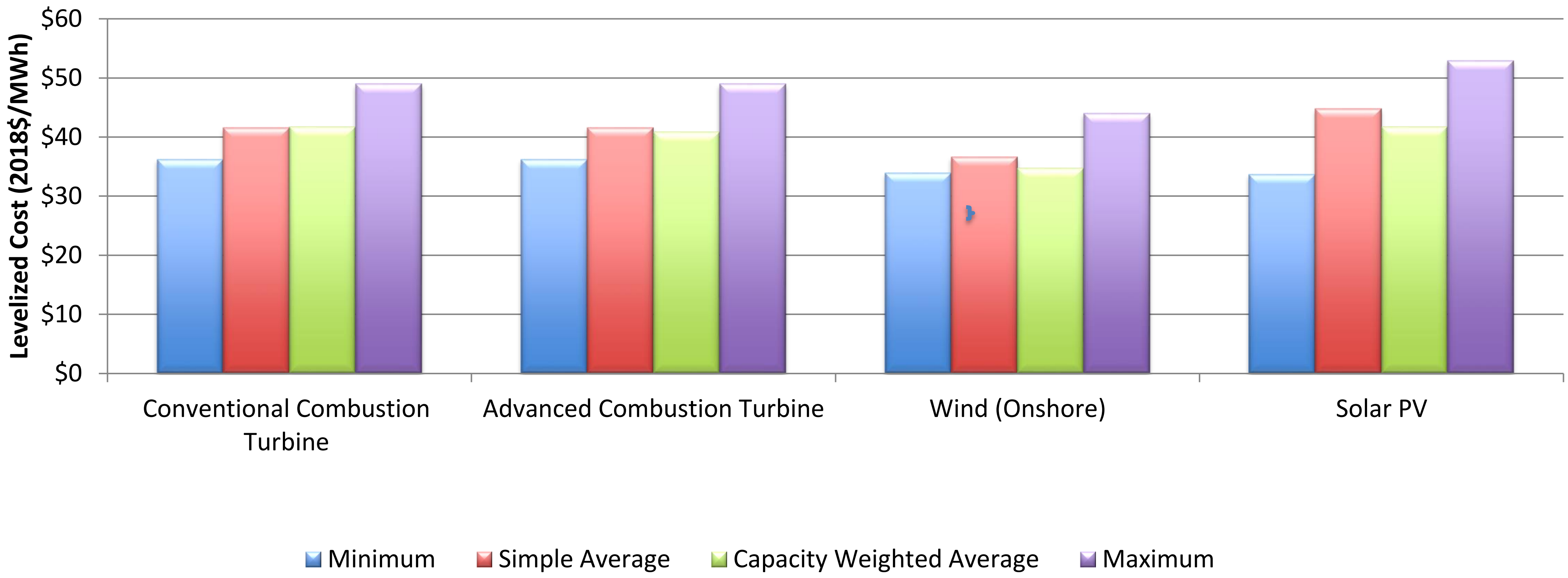
Valuation Enhancement	Implementation Resources
4. Account for the locational economic value of demand flexibility	• Smart Electric Power Alliance, *Beyond the Meter: Addressing the Locational Valuation Challenge for Distributed Energy Resources* • *Benefit-Cost Analysis Handbook* developed for New York's REV process • California's Locational Net Benefits Analysis Tool (and user's guide) • ConEd's *Benefit Cost Analysis Handbook* recognizes DER benefits for avoided distribution capacity infrastructure and provides methods to quantify location-specific marginal costs that the system defers or avoids by opting for non-wires solutions.
5. Account for interactions between DERs providing demand flexibility	• Frick et al., Berkeley Lab, *A Framework for Integrated Analysis of Distributed Energy Resources: Guide for States* EPRI, *The Integrated Grid - A Benefit-Cost Framework*
6. Account for potential variations in the timing and/or amount of the electric grid service provided by demand flexibility over the expected lives of the DERs	• EPRI, *The Integrated Grid - A Benefit-Cost Framework*
7. Account for interactions between DERs providing demand flexibility and existing and potential conventional grid resources supplying comparable services	• Berkeley Lab, *A Framework for Integrated Analysis of Distributed Energy Resources: Guide for States* • EPRI, *The Integrated Grid - A Benefit-Cost Framework*

Market Structure Influences Value of Demand Flexibility

- **Organized Markets**
  - Value established by market
  - Only values "products" traded in market:
    - Capacity
    - Energy
    - Reserves (spinning and balancing)
    - Volt/Var support
  - Gaps/Challenges
    - Locational value of avoided/deferred T&D capacity not captured
    - Value of resilience
    - Value of increased hosting capacity
    - Recognition of "long-term" resource value in some markets

- **"Dis-organized" Markets**
  - Value established through regulatory/planning processes (e.g., PURPA filings, IRPs)
  - Value depends on scope of state "cost-effectiveness" test
  - Gaps/Challenges
    - Not all states include all utility system benefits of demand flexibility or quantify them in a consistent manner (e.g., not all states use time-dependent valuation).
    - Methods to quantify and monetize the locational value of demand flexibility are "under construction."
    - Integrated analysis of the impacts of demand flexibility is complex, and thus rarely done.

Resource Availability and Cost Vary Across U.S.



Regional variation in levelized avoided cost of electricity for new generation resources entering service in 2021.

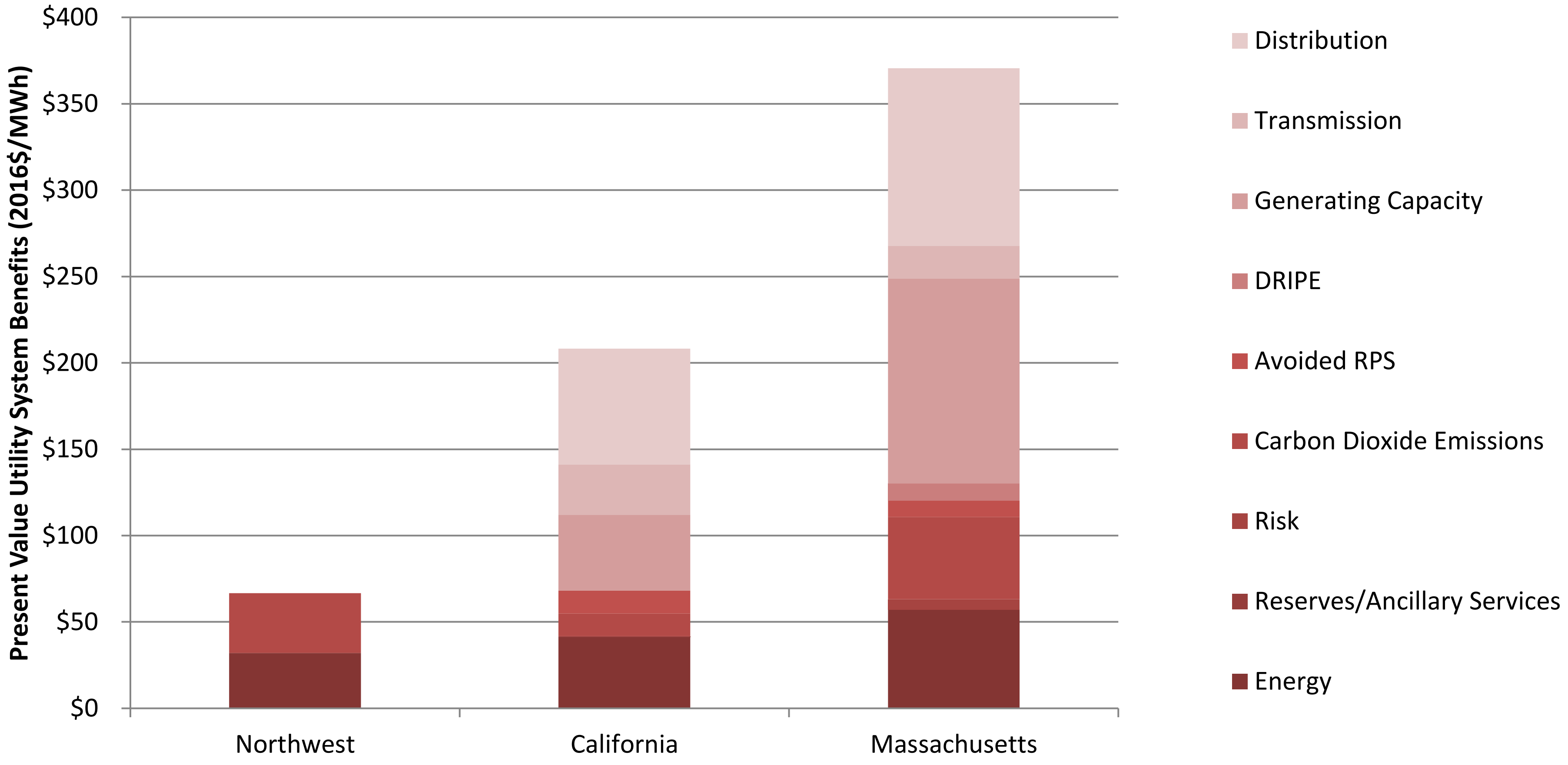
Source: U.S. Energy Information Administration, Annual Energy Outlook 2019

State Energy Policies and Regulatory Context

- State policies directly or indirectly influence which of the utility system benefits of demand flexibility to include in determinations of its economic value by:
  - Establishing costs and benefits to be included in a utility's (or third-party program administrator's) cost-effectiveness tests
  - Prescribing a specific methodology for determining avoided cost

- State resource standards also directly impact avoided costs—for example:
  - Wind resource development to satisfy a state renewable energy standard might *lower the avoided cost of energy* (kWh), but have little impact on the avoided cost of new peaking capacity (KW).
  - Energy efficiency development to satisfy a state's energy efficiency resource standard might *lower the avoided cost of energy (kWh) as well as peaking capacity (kW)* by reducing the near-term need for new generation or transmission peaking capacity.

Example: Time-Sensitive Value of Energy Efficiency Measures for Residential Air-Conditioning by Region/State



Source: Mims et al. 2017. *Time-varying value of electric energy efficiency*

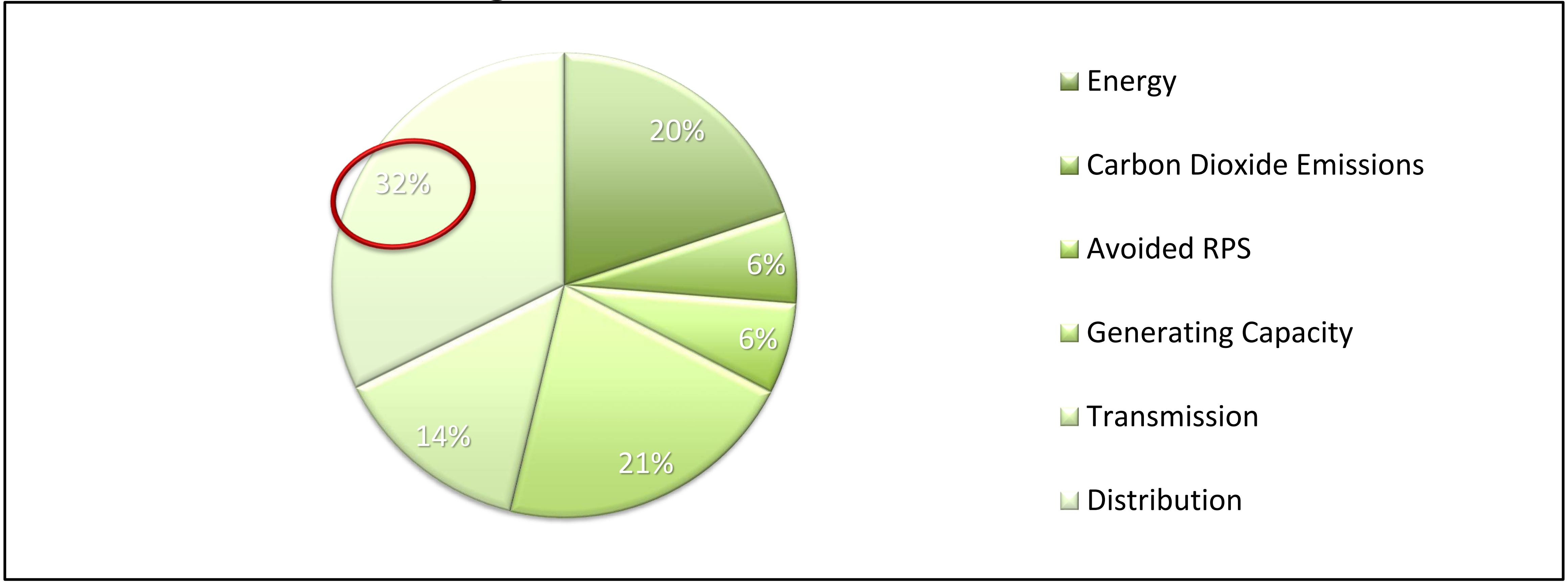
Three Enhancements to Distribution System Planning

- **Hosting capacity analysis** – Estimates maximum generating capacity of DERs that can be accommodated on individual feeders without adversely impacting power quality or reliability or requiring significant distribution system upgrades

- **Energy analysis** - Quantifies the magnitude of marginal distribution system losses (i.e., I^2R)

- **Thermal capacity (limit) analysis** - Identifies potential locational value from deferral of distribution asset investments from demand flexibility deployment

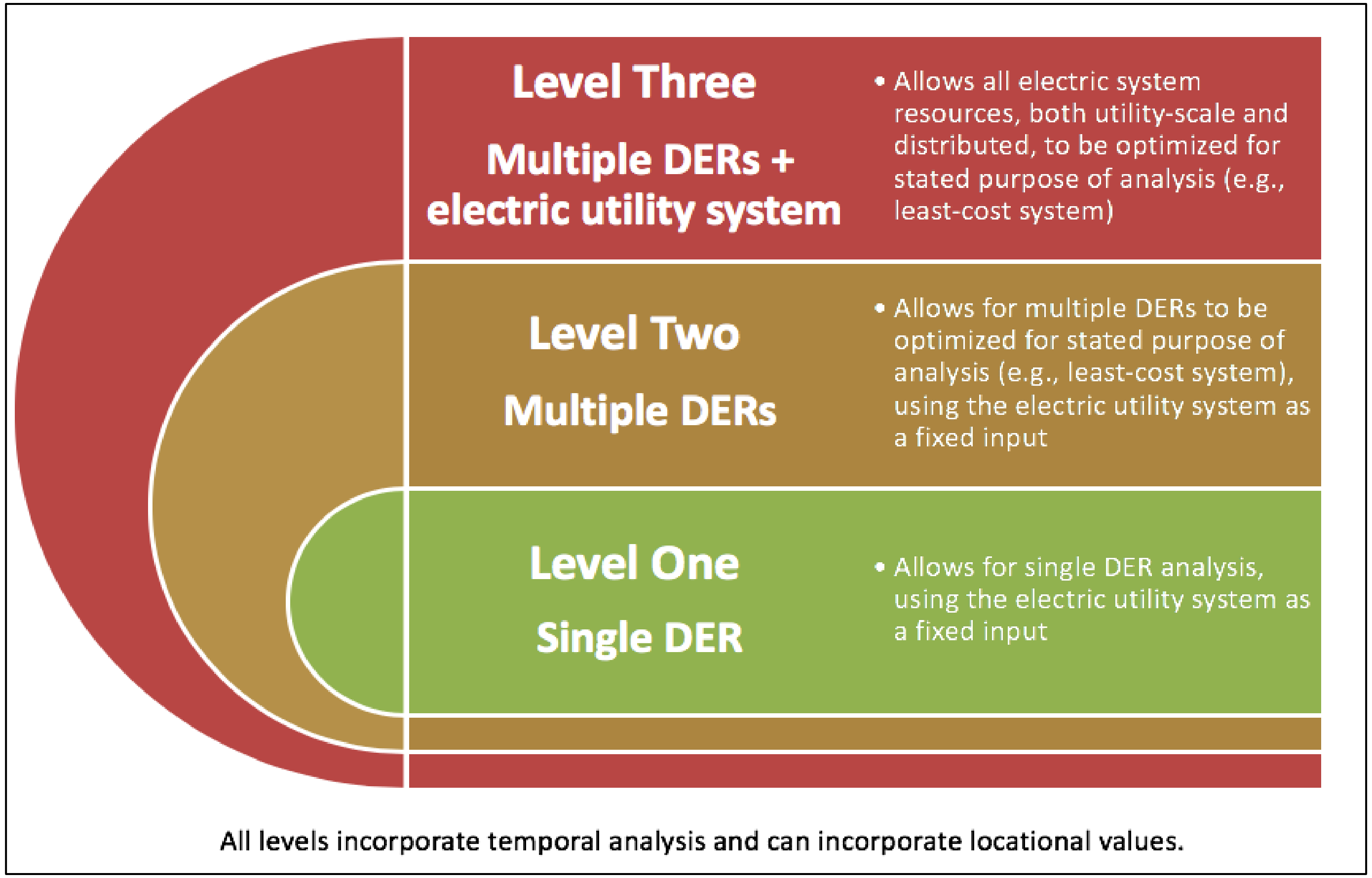
Locational value of demand flexibility may account for significant economic value.



Example - Relative Contribution to Total Utility System Value for Energy and Capacity Savings From Residential Air-Conditioning Efficiency Measures in California

Source: Mims et al. 2017. *Time-varying value of electric energy efficiency*

Framework for Addressing Interactions Between DERs



Source: Mims Frick et al. 2018. *A Framework for Integrated Analysis of Distributed Energy Resources: Guide for States*

Feedback Request

1. Please provide any comments related to today's expert presentations.

2. What is an appropriate growth rate to be used for a high load growth sensitivities? Should there be a different growth rate applied for high load with and without deep electrification? Should the rate be different for the lower peninsula and the upper peninsula? If so, what should they be?

3. What is an appropriate growth rate to be used for low load growth sensitivities? How should the low load growth sensitivity consider customer adoption of distributed energy resources? Should the rate be different for the lower peninsula and the upper peninsula? If so, what should they be?

Feedback Request Cont.

4. Are there publicly available recommended sources that should be used for technology and fuel price forecasts? Are there other collaborative ways to develop technology and fuel price forecasts that could be used by all Michigan utilities filing an IRP?

5. Are there publicly available recommended sources that should be used for capacity and energy price forecasts?

Stakeholder Feedback Requests

Please submit responses to the stakeholder feedback comments received to Danielle Rogers by **January 8, 2021.**

RogersD8@michigan.gov

Making the Most of Michigan's Energy Future

Thank You

Upcoming Advanced Planning Stakeholder Meetings
January 19, 2021