Evolving Cost Structures, Wholesale Prices, and Retail Rate Design for a Deeply Decarbonized Grid

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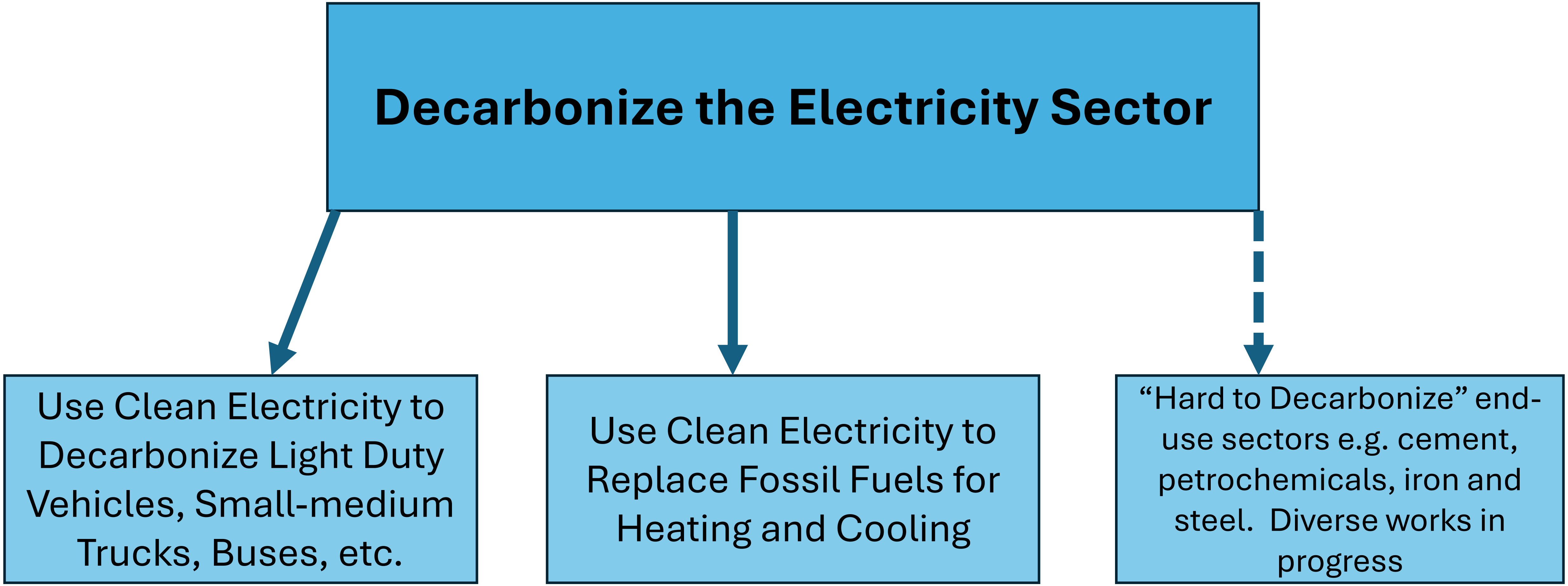
Electricity to Lead Decarbonization of the Economy

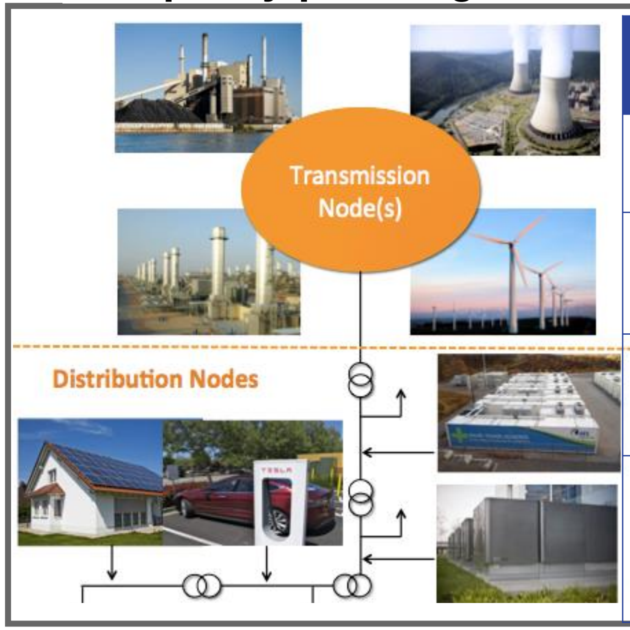


Outline

- Optimal Generation and Storage Portfolios to Meet various Decarbonization Constraints (2050)
  - Northeast
  - Southeast
  - Texas
- Wholesale Price (marginal generation cost) Distributions for these Generation Portfolios (2050)
- Retail Rate Design For Energy Consumption
- Retail Rate Design for Distribution Network Utilization

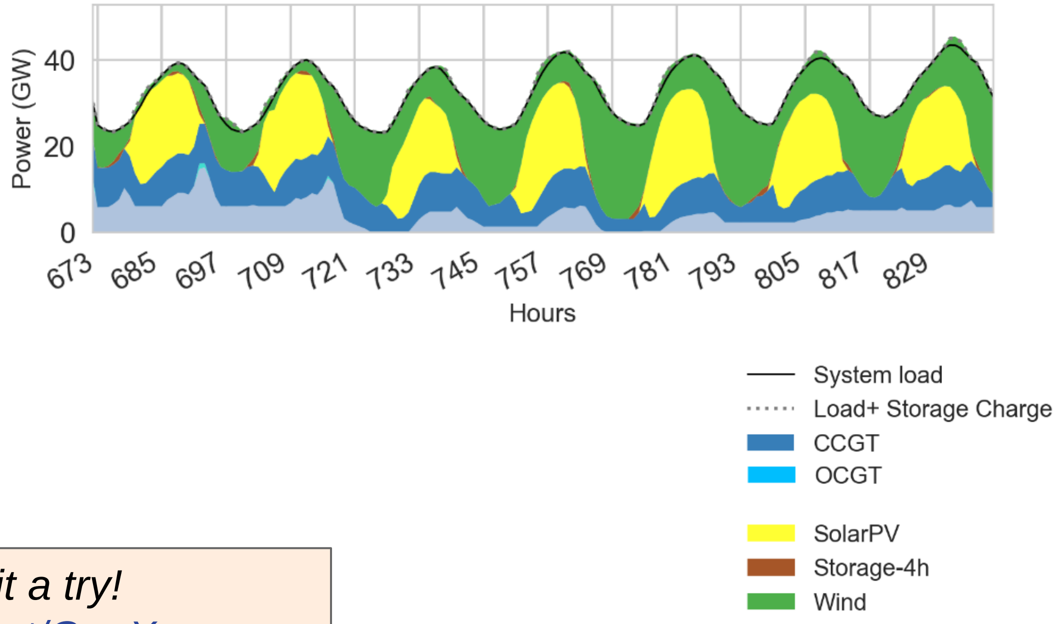
Systems analysis is based on the GenX model, an integrated electricity system planning model with adjustable temporal, spatial and technological resolution

Capacity planning for the bulk power system (GenX)



Unique features
Operational detail
Temporal resolution (hourly)
Demand and supply side resources
Configurable network & market representation (energy, operating reserves)

Illustration of operational and temporal detail in GenX model



GenX is open-source, give it a try!
https://github.com/GenXProject/GenX

Powered by: julia + JUMP

Table 6.9 Modeled emissions reduction results for different decarbonization targets summarized using alternative metrics commonly used in policy discourse

	gCO_2/kWh	NL	50	10	5	0
Relative to 2018 levels						
Northeast	249	-2%	80%	96%	98%	100%
Southeast	387	59%	87%	97%	99%	100%
Texas	418	78%	88%	98%	99%	100%
Relative to No Limit levels						
Northeast	253	0%	80%	96%	98%	100%
Southeast	158	0%	68%	94%	97%	100%
Texas	92	0%	46%	89%	95%	100%
Carbon-free generation						
Northeast	—	26%	85%	86%	90%	100%
Southeast	—	54%	85%	91%	93%	100%
Texas	—	74%	85%	91%	92%	100%

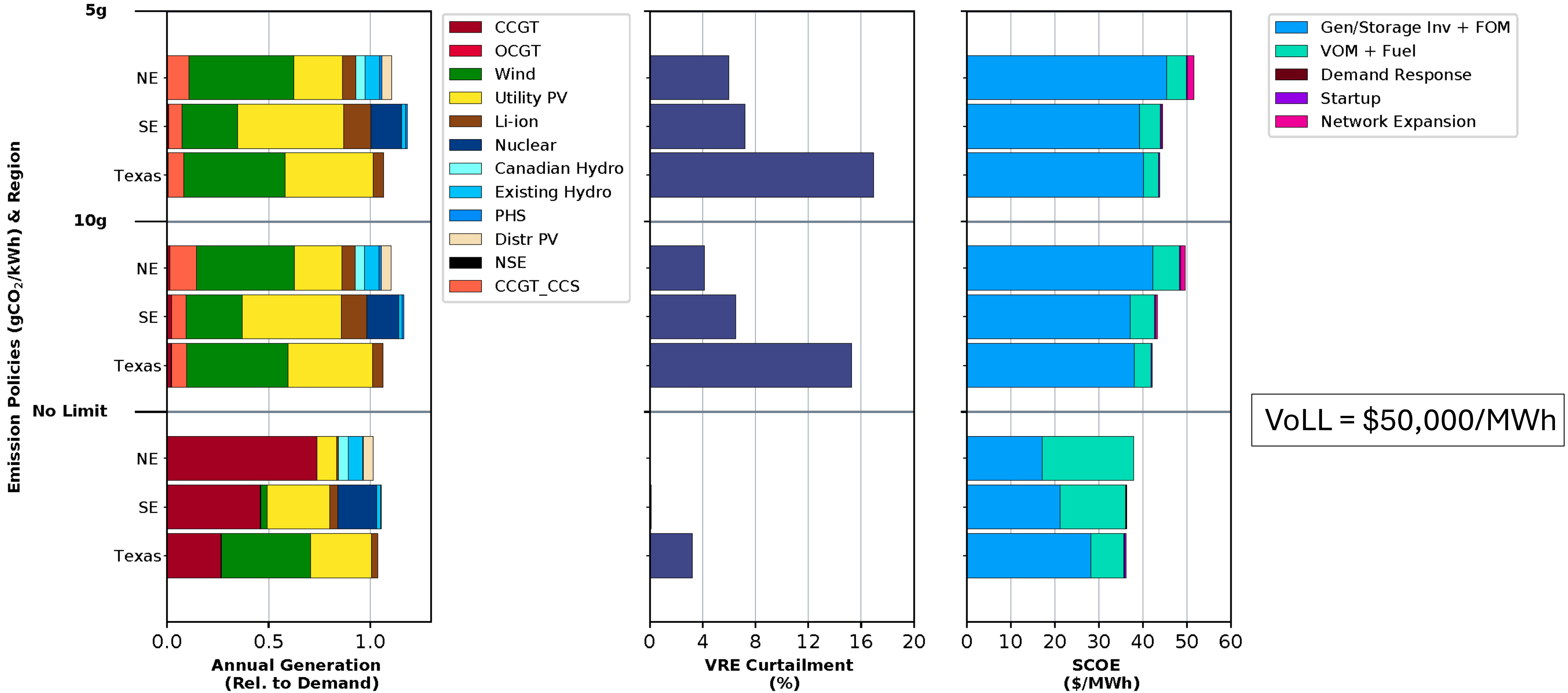


Figure 1. ***Annual generation, VRE curtailment, and system average costs of electricity (SCOE) in the Northeast (NE), Southeast (SE), and Texas (TX) under tightening CO_2 emissions constraints.*** *Modeling results are shown for a scenario with no limit on emissions (bottom row) and for two alternative carbon emissions limits scenario with an emissions intensity limit of 10 (middle row) and 5 gCO2/kWh (top row). SCOE includes total annualized investment, fixed O&M, operational costs of generation, storage, and transmission, and any non-served energy penalty. Emissions intensity under the “No Limit” policy case for each region is as follows: NE: 253 gCO2/kWh, SE: 158 gCO2/kWh, Texas: 92 gCO2/kWh. For the Northeast case, “Wind” represents the sum of onshore and offshore generation. Installed power and energy capacity results for these cases are shown in Figure S 3 in the SI, along with methodological assumptions about the modeling noted in section S1. For comparison purposes, annual generation is normalized to the annual electricity demand in each region.*

2050 Wholesale Market Price Distributions for Texas

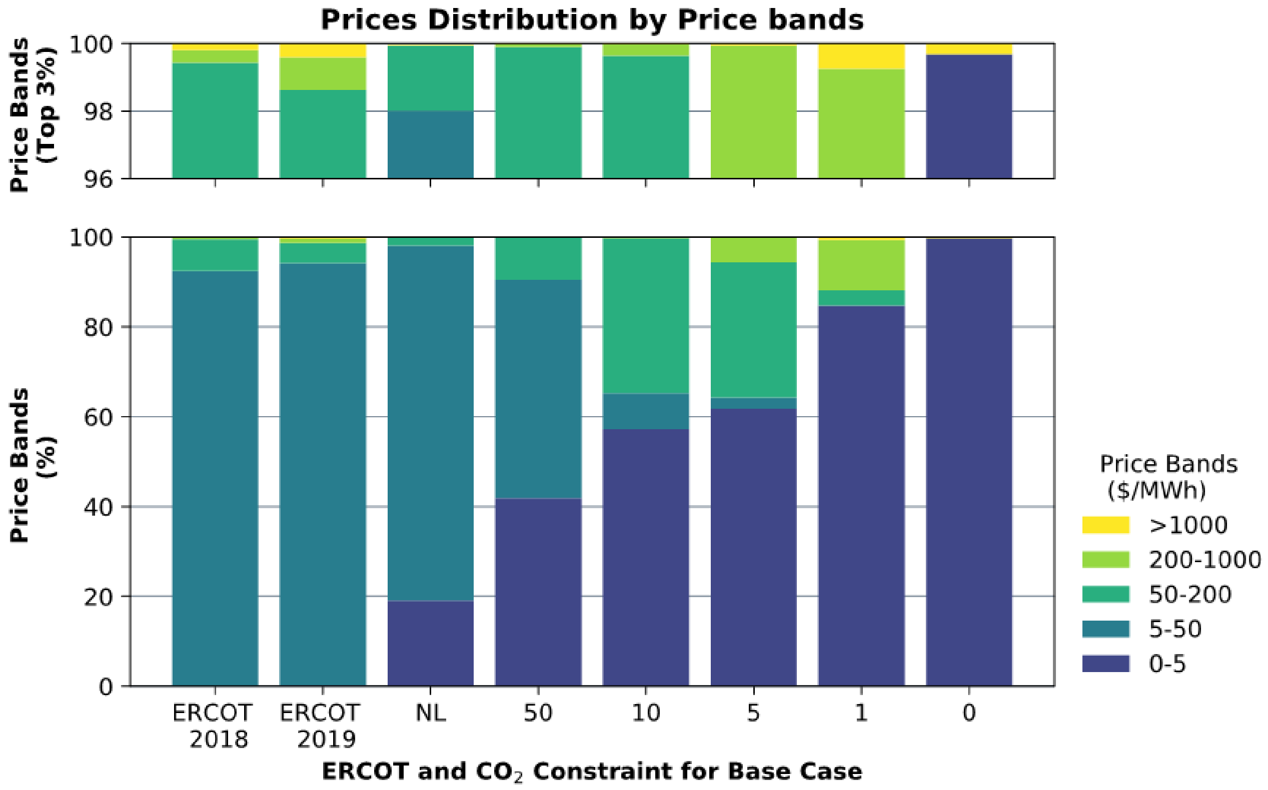


Figure 2: Marginal value of energy under base case assumptions (Li-ion battery storage only) for Texas. *The price bands are based on the known marginal cost of various generation technologies; we zoom in on the top 3% to show the price distributions at that extreme. Results for the Northeast and Southeast are presented in Appendix D. ERCOT historical prices are from ERCOT (2021).*

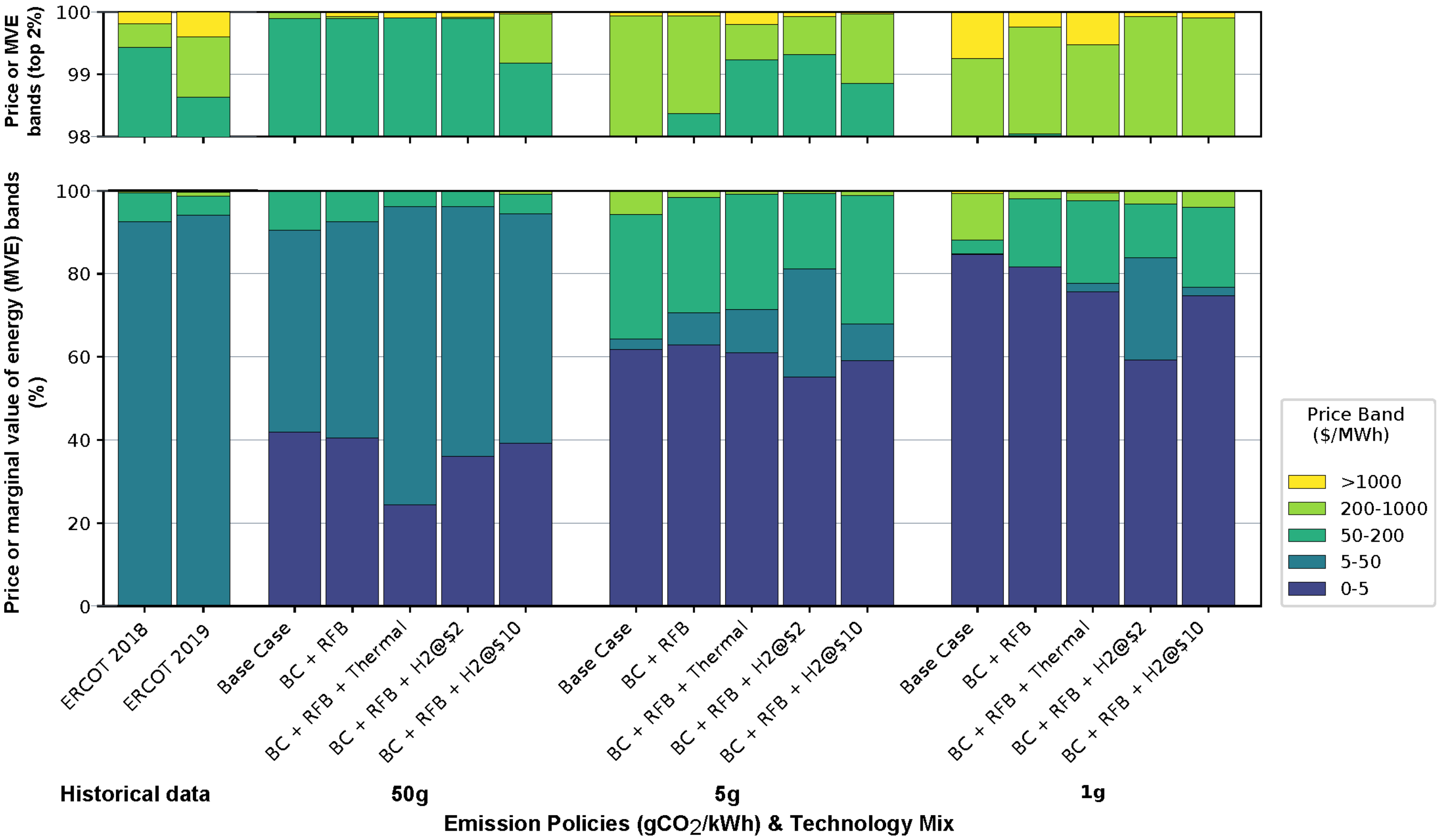


Figure 4. ***Impact of storage technology, external H_2 demand as well as the price of non-power H2 supply on the distribution of Marginal value of Energy (MVE) for various CO2 emissions constraints.*** *For comparison, wholesale energy price distributions from ERCOT in 2018 and 2019 are also shown in the first two columns of the chart [39]. Technology scenarios evaluated here are described in Table 1. Labels for scenarios with H2 "Base Case + RFB + np-H2 @ \$2/kg" has been shortened to read as "BC + RFB + H2@\$2" for brevity. Base case corresponds to Li-ion as the sole energy storage technology and no external H_2 demand. BC = Base Case. RFB = Redox Flow Battery.*

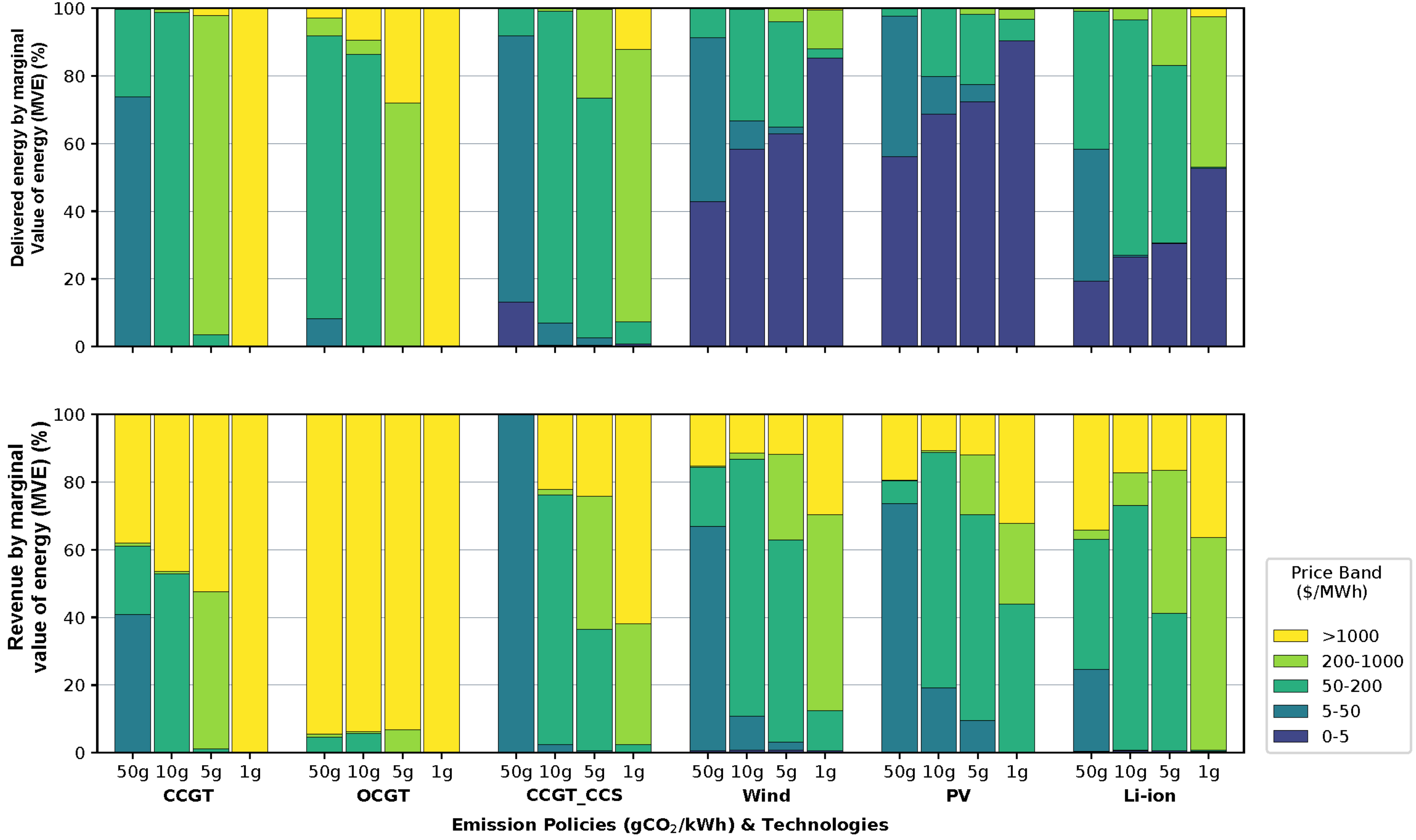
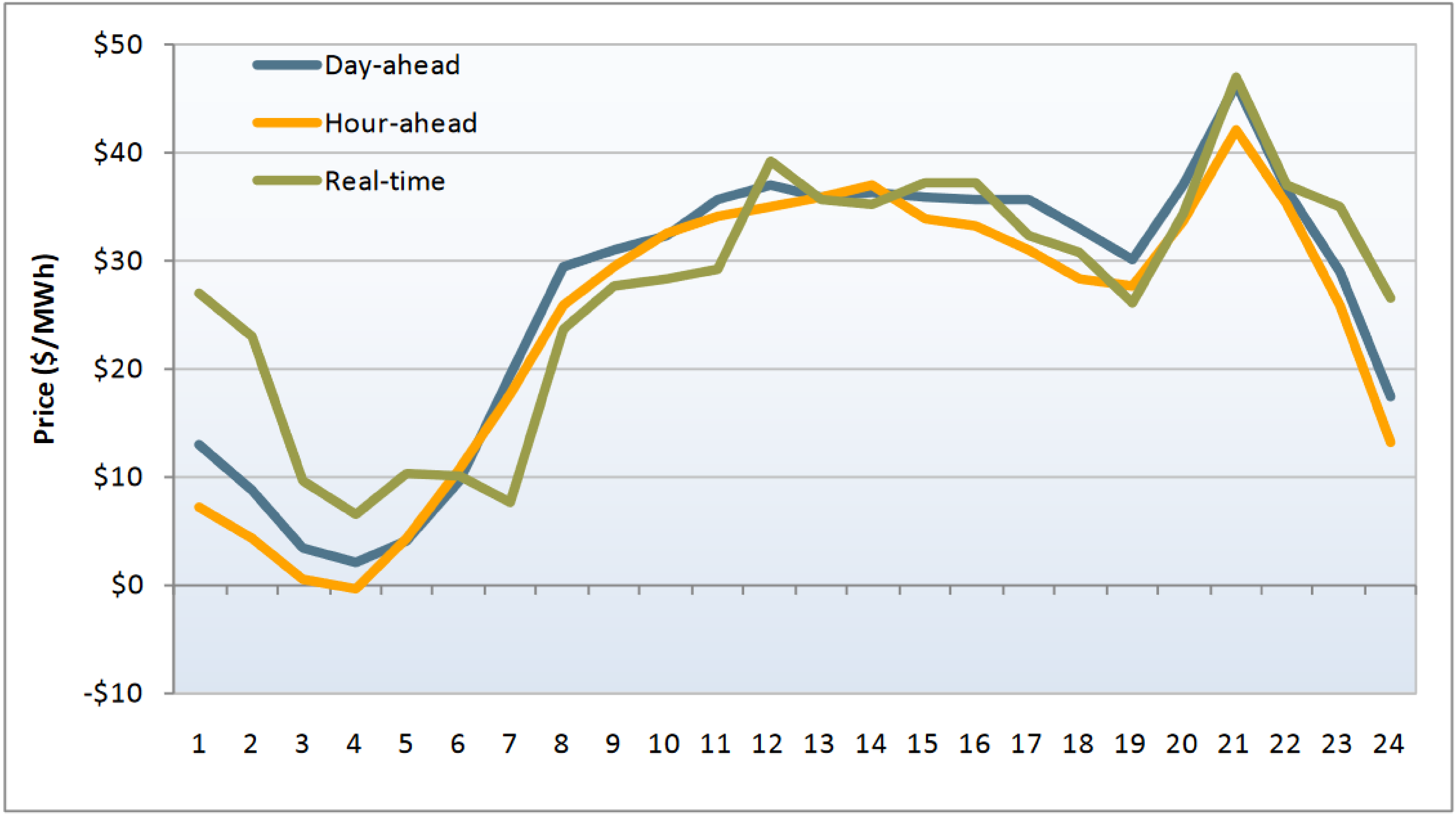


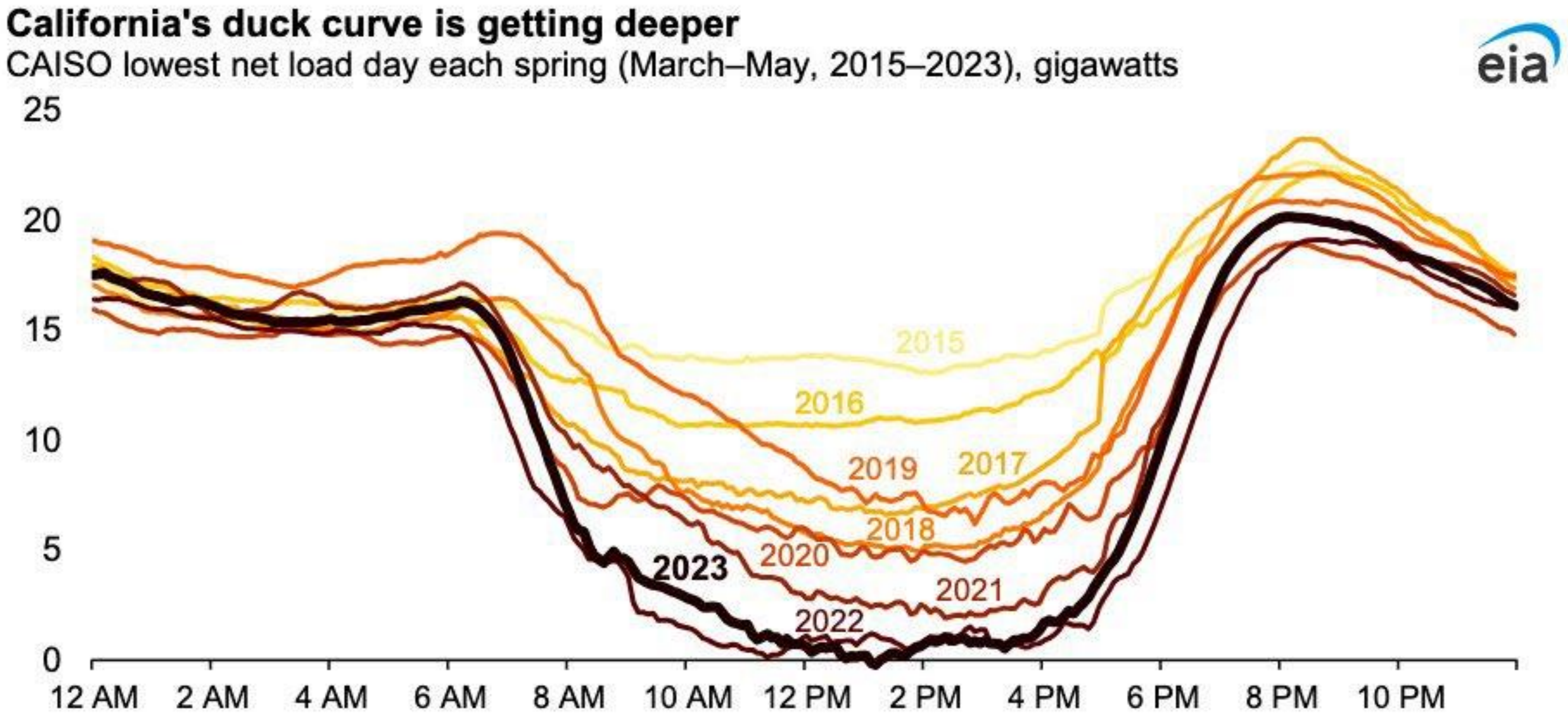
Figure 6. ***Technology operation and revenue by marginal value of energy (MVE) band for various resources under the Base Case defined in Table 1.*** *The upper panel shows the distribution of delivered energy by price band for different technologies and emission constraints. The lower panel shows the revenue distribution by price band.*

Figure 1.3 Hourly comparison of PG&E load aggregation point prices – Q2 2011



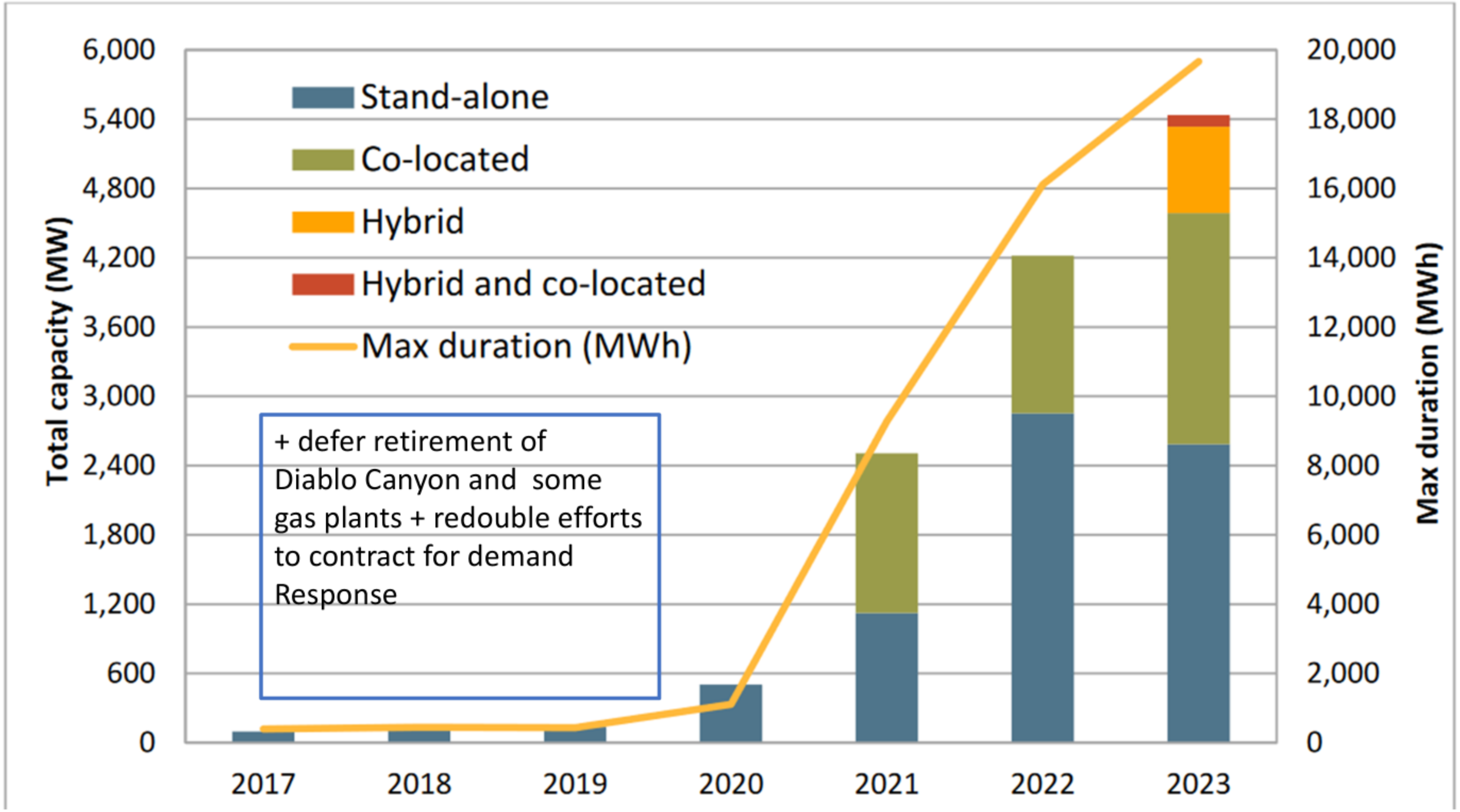
JUNE 21, 2023

As solar capacity grows, duck curves are getting deeper in California



Data source: California Independent System Operator (CAISO)

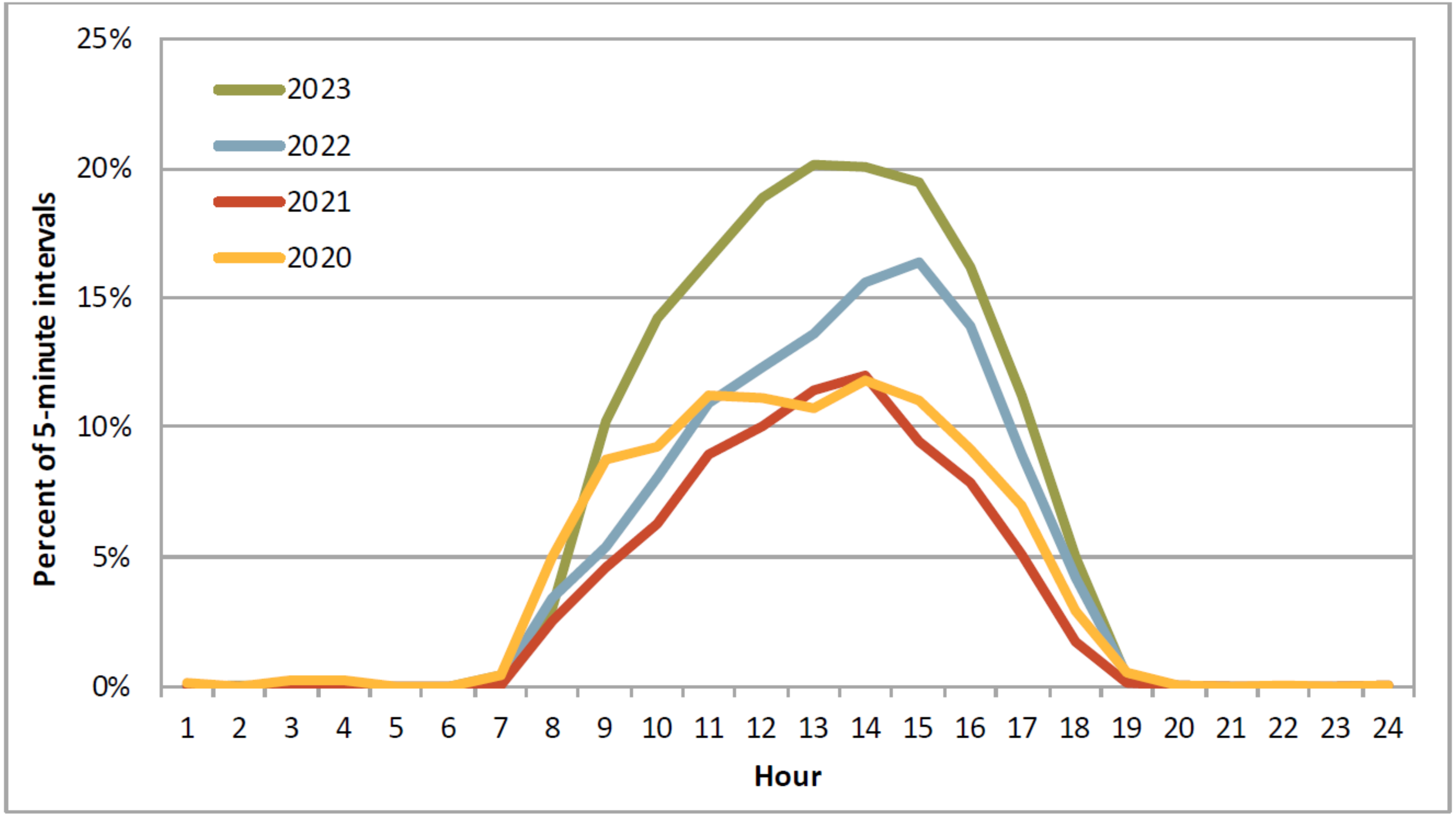
Figure 1.20 Battery capacity (2017–2023)



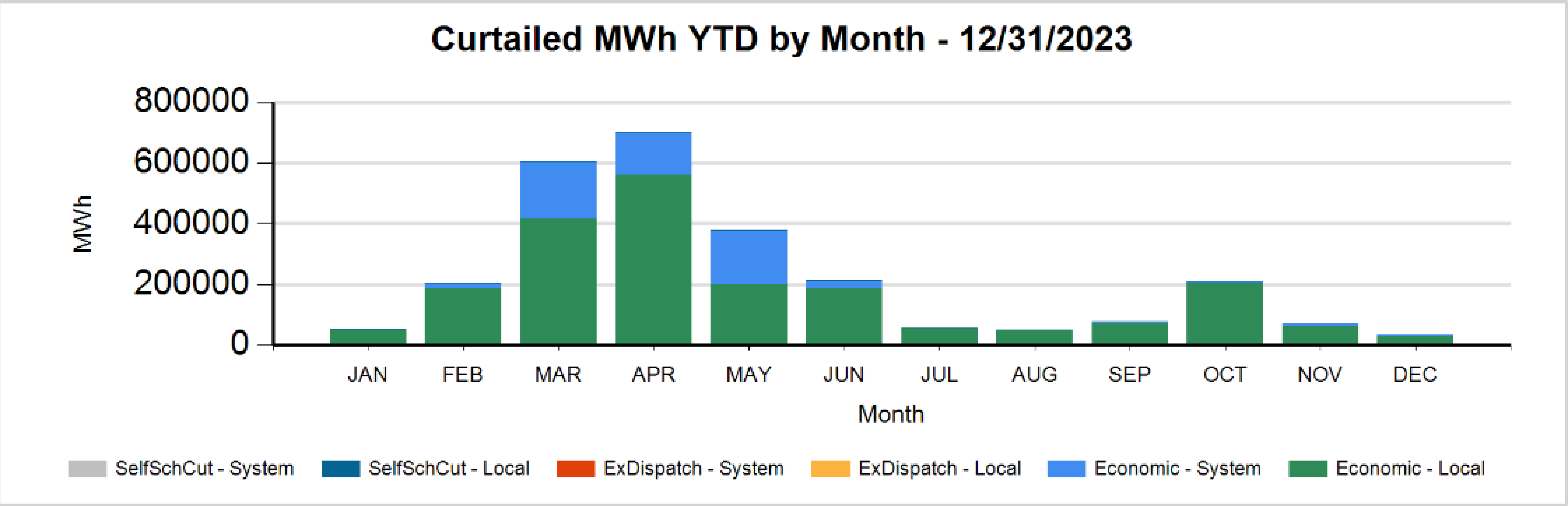
CAISO Annual 2022 (2023)

CAISO, Market Monitoring Report, July 2024

Figure 2.11 Hourly frequency of negative 5-minute prices by year (CAISO LAP areas)



CAISO, Market Monitoring Report, July 2024



Curtailed MWh YTD by Month - 12/31/2023
800000
600000
400000
200000
0
MWh
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Month
SelfSchCut - System
SelfSchCut - Local
ExDispatch - System
ExDispatch - Local
Economic - System
Economic - Local

CAISO

Hybrid Markets

Short-term wholesale markets

- Market-based least-cost economic dispatch
- Market-based management of operating reliability
- Efficient short-term wholesale prices for energy, ancillary services, and reliability given existing capital stock through competitive bidding and co-optimization

Wholesale markets for LT PPAs

- LRP or No LRP
- Support efficient investment in generation and storage through, competitive procurement, and LT CfD/PPA
- Meet decarbonization targets efficiently
- Meet Resource Adequacy(RA)/SoS constraints with supporting investment/resource portfolio over transition period
    - Reliability criteria and capacity market re-design
- Contract design compatible with efficient short-term market operation, pricing, demand response, and incentives for efficient performance

Based on Fabian Roques presentation at Paris-Dauphine

Retail Rate Design Consistent with Evolving Wholesale Market Prices (residential and small C&I)

Retail Rate Design Criteria
Massachusetts DPU 2022

- Efficiency
- Simplicity
- Continuity of rates
- Equity and fairness
- Corporate earnings stability

Two Interrelated Retail Pricing Issues

Argued that current nearly entirely time-invariant, volumetrically based electricity rates will make electrification slower and more expensive than it should be

Issue 1: Energy costs: Time-of-use (TOU) rate designs more attractive than dynamic pricing to risk-averse consumers, TOU rate designs deserve more attention from researchers and regulators (e.g. residential and small commercial customers do not like real time pricing)

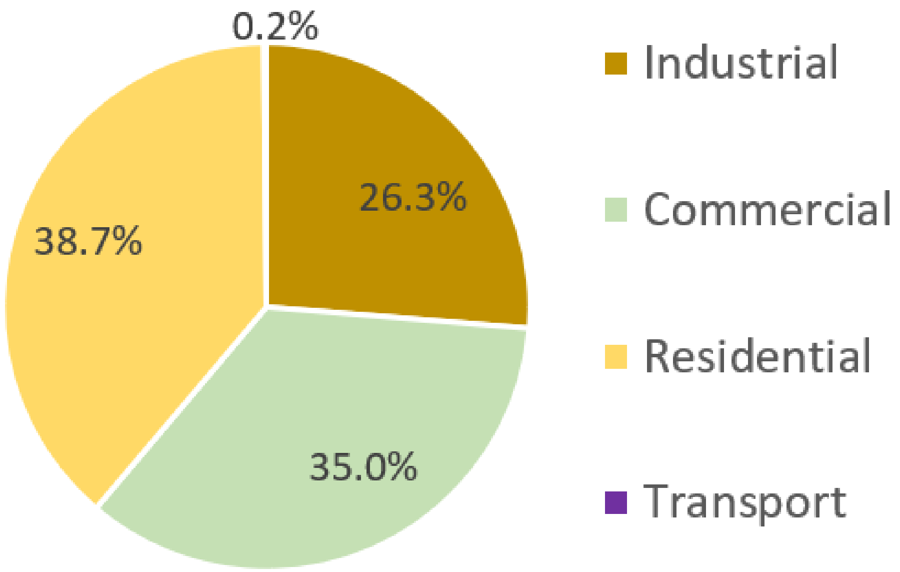
Issue 2: Network costs:

- Instituting capacity charges that reflect future T&D investment costs is increasingly important
- The remaining residual costs should ideally be recovered through fixed customer charges that reflect ability to pay

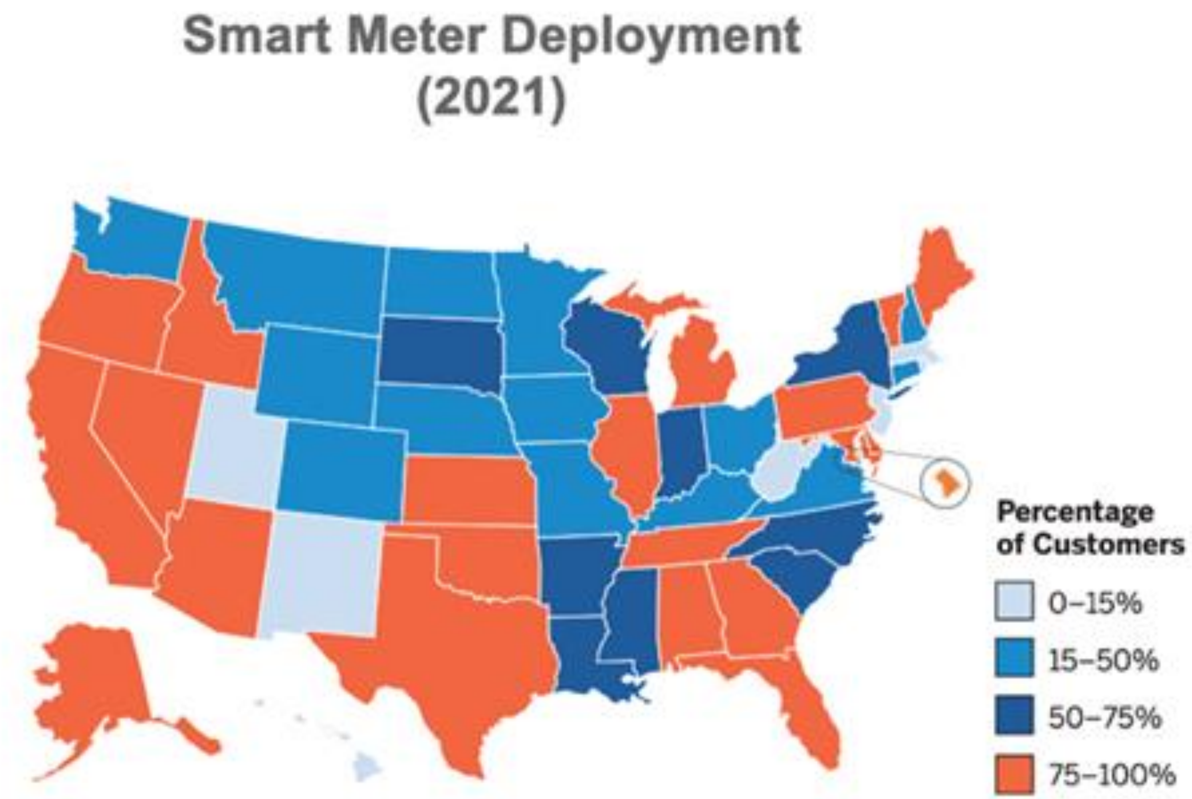
Both energy rates and network tariffs can be complemented with critical peak pricing (CPP), preferably via load control

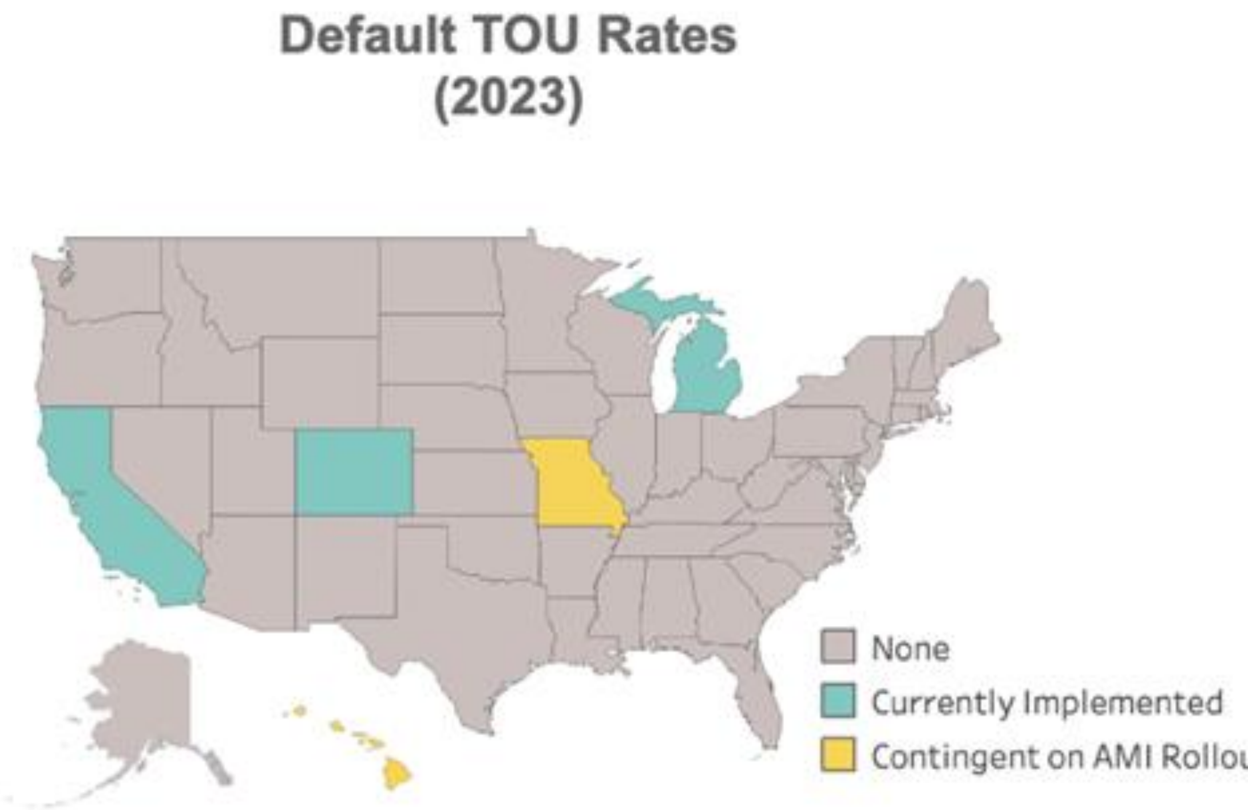
Context: current electricity rates for U.S. residential and small commercial consumers

- For most residential and small C&I consumers electricity is priced as:
  - an almost flat volumetric rate, i.e., a constant $/kWh price, determining most of the bill
  - a small fixed charge ($/connection)
  - No capacity (demand) charge
- The volumetric rate ≈ dividing the total costs a utility must cover in some period by the expected kWh demand in that period
- Only 7.3% of U.S. residential and small commercial consumers are enrolled in alternative rate plans (EIA, 2022)



Statista (2021): Electricity consumption per sector in the U.S.





~ 120 million AMI or ~ 75% 2023

Smart meter deployment among US households (left) and default TOU rate adoption (right). Map at left from (Kavulla, 2023). Default TOU rates shown for each state's largest distribution utility.

Real Time Pricing (RTP) for Residential and Small C&I Customers

- Customers don't like it
- Where it has been made available few customers select it voluntarily (e.g. ComEd)
- Estimated Demand elasticities are very low (-0.0 to -0.075)
- It is not optimal even theoretically if customers are risk-averse, have attention and computational costs, do not optimize every hour, and there are other departures from the EC101 consumer

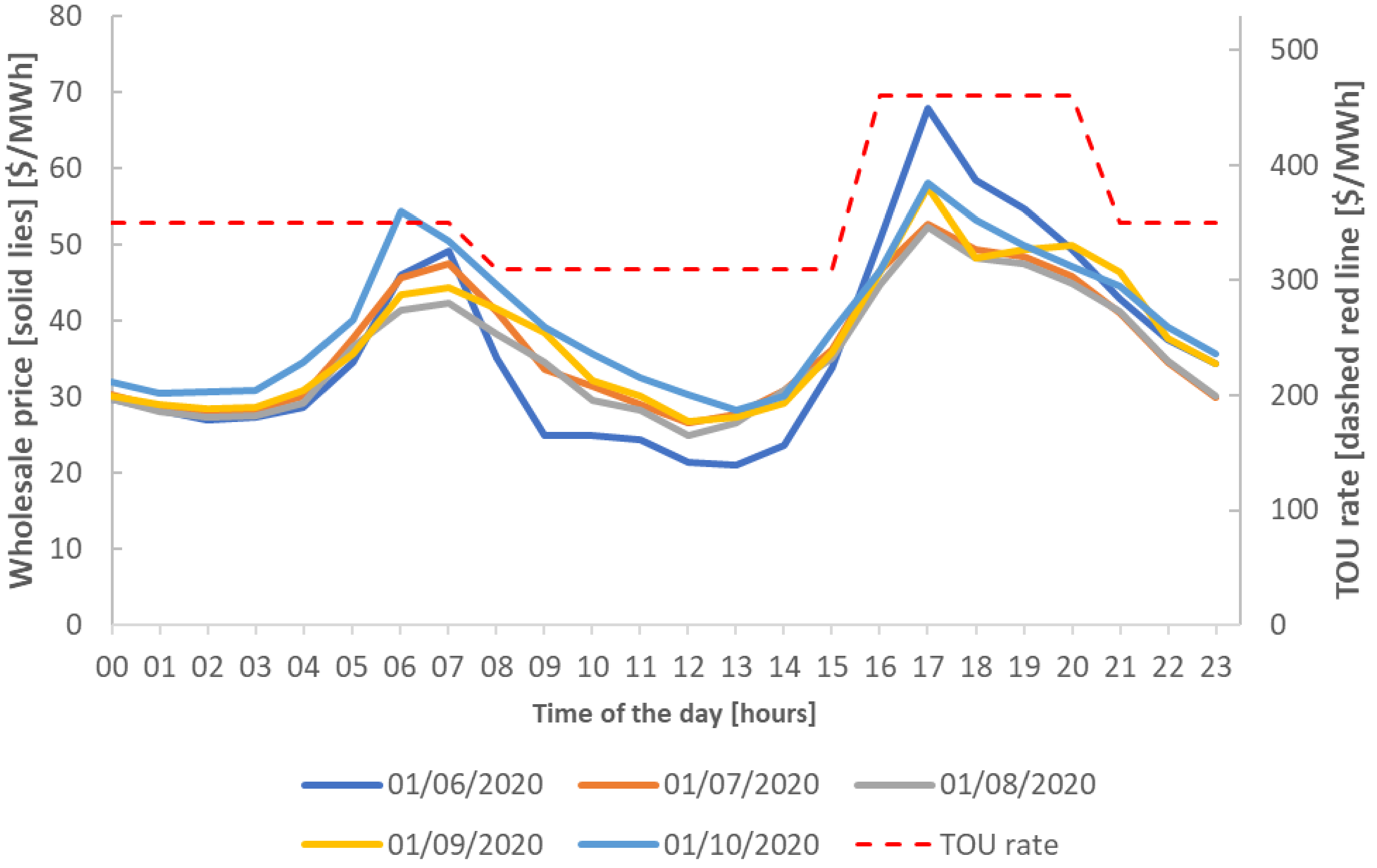
Bill Example

Estimated energy usage of 1,162 kWh from February 1-17, 2021

	Griddy	Just Energy
Total Bill Amount	$3,879.76*	$126.66**
Usability	Micro manage usage real-time to avoid costly bills	Set it and forget it
Charges	Multiple charges per month	One time per month
Price Stability	Unreliable	Reliable & Consistent

https://justenergy.com/griddy/

Research question: Can TOU rates effectively incentivize "desirable" load shifting?



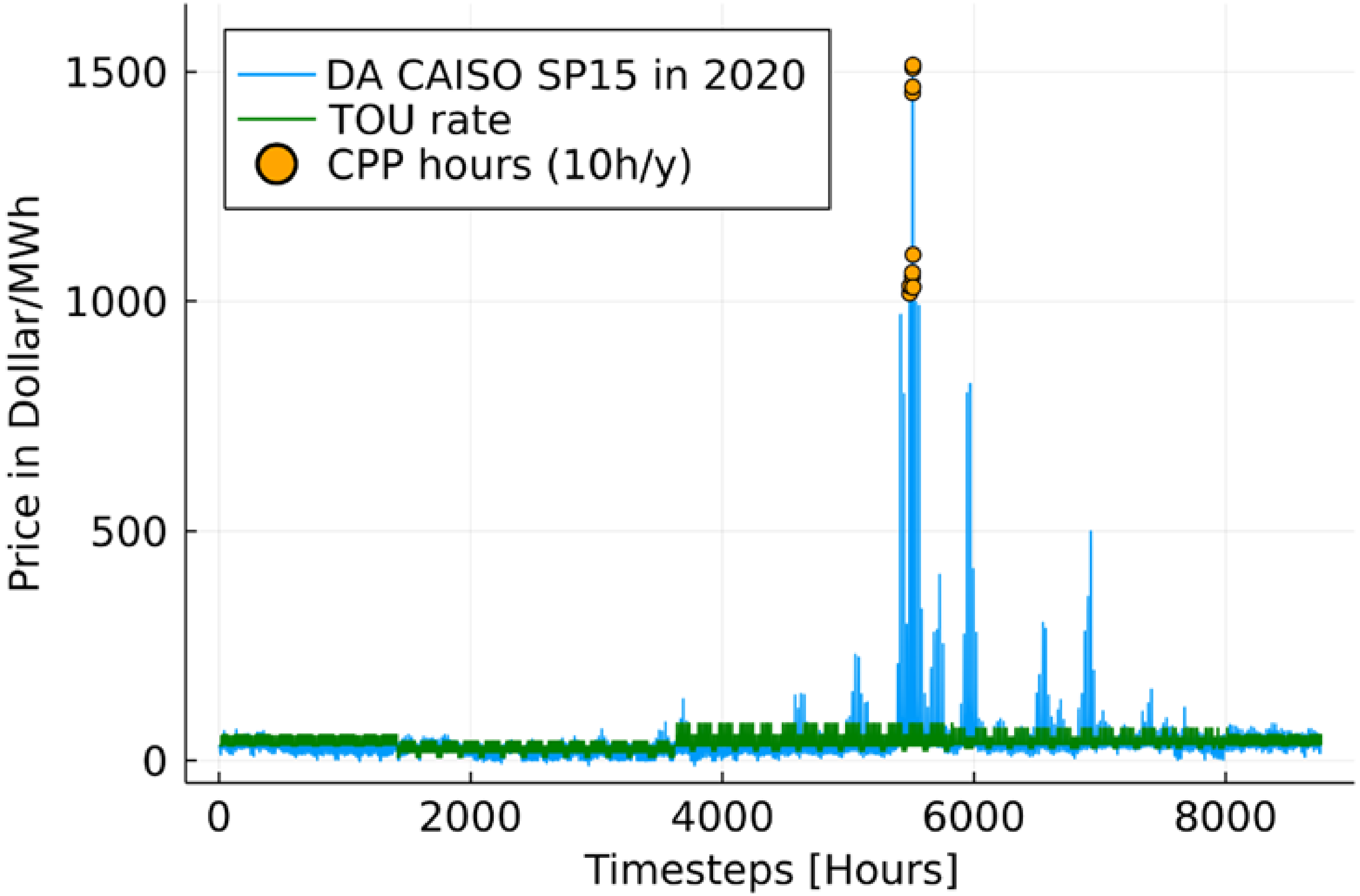


Figure 1: Day-ahead (DA) CAISO SP15 Hub prices in 2020, a calibrated TOU rate based on the preceding 3 years, and a CPP rate passing through the ten highest priced hours of the year.

Tim et. al. EJ

Conclusions

- Previous academic literature argues that TOU alone yields only about 20% of the benefits of RTP
  - Fails to look carefully at emerging intra-day load shifting opportunities
  - Relies in part on simple inter-year correlation coefficients rather than on rank correlation coefficients
  - Ignores consumer risk preferences and “attention” costs
  - Implicitly assumes that marginal cost of distribution is very small (losses) by bundling energy and distribution network pricing together
- TOU (updated) + CPP (load control) yields a large fraction of the benefits of RTP in general
- TOU (updated) alone is especially effective in stimulating load shifting (e.g. EV charging) because relative prices are fairly stable
- But, what about effects of load shifting on distribution network costs?

Retail Pricing for Distribution Network Use

- Growing investment in distribution to meet growing demand from end-use electrification (e.g. EVs, heat pumps) and data center consumption
- Long run marginal cost of expanding distribution system to meet demand is significant and cannot be ignored
- Our case study focuses on impacts of the timing of EV charging and the use of network prices to smooth charging
- Unbundle energy and network prices and analyze interaction between them

PAUL'S BILLS
cents/kWh

Component	October 2006	March 2024	%change	
Customer charge	$6.43	$10.00	56%	regulated
Distribution charge (/kWh)	4.27	9.43	121%	regulated
Transmission charge (/kWh)	1.28	4.05	216%	regulated
Energy Supply (/kWh	11.44	14.78	29%	competitive
CPI			55%	BLS

Charging for electricity distribution networks in scenarios of increased residential end-user electrification

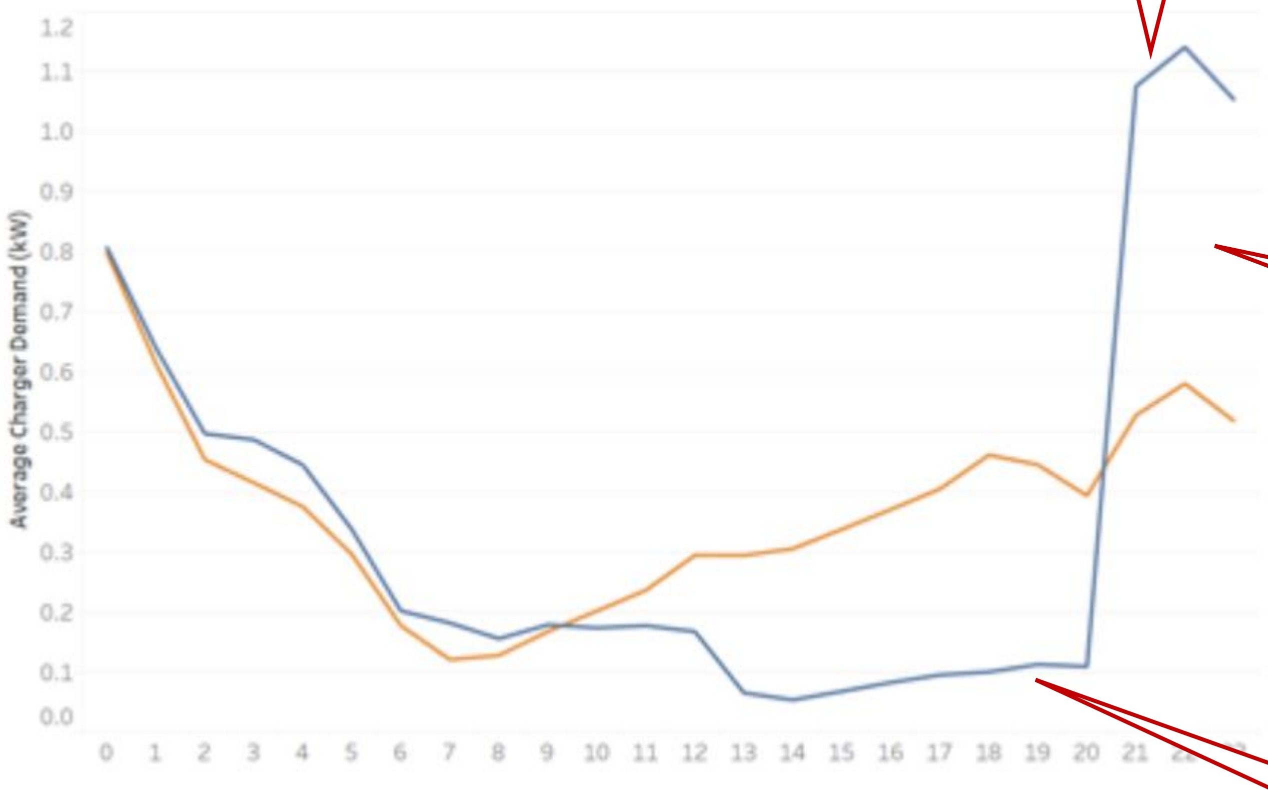
- **The "snapback" problem**
  - Time-of-use energy rates create "snap-back" with EVs

- **Unique load characteristics**
  - Flexible, peaky, significant load (~50% increase in annual household consumption)

- **Attempt to present a real-world case as comprehensible as possible**

However, TOU energy charges can make the "network challenge" harder when not complemented with appropriate network tariffs

Off-peak starts



Programs lead to "snapback" demand from programmable devices responding to price

Peak price period

Green Mountain Power 2021 Integrated Research Plan

Case Study: Overview of methodology

- We model 400 households with unique hourly load profiles for one year
- We assume the **energy prices to be exogeneous and reflected via a simple two-period TOU tariff** (peak: 8am-9pm weekdays, the remainder off-peak), no other distortions
- We vary the rate of electrification over the households; each EV has a unique driving schedule:
  - Each EV has a unique driving schedule that must be respected:
  - EV load responds rationally to price signals (energy charge + network tariff) when plugged-in (perfect foresight) – MILP
- We test **four standard formats network tariff designs**: fixed, volumetric, capacity, and subscription (with and without time differentiation)

Magnitudes under 0% of EV adoption

Tariff Type	Cost
Fixed charge	$1000 per year
Flat volumetric (baseline)	$0.11/kWh all hours
TOU volumetric 2-period	$0.07/kWh off-peak $0.18/kWh peak
Flat capacity/subscription	$158/kW-year
TOU capacity/subscription 3-period	$30/kW-year off-peak $70 /kW-year mid-peak $87/kW-year on-peak

Case Study: Overview of methodology

- We asses the results based on **three metrics**

1. **Annual peak**: highest aggregate demand of all homes across the full year
    - Proportional to revenue requirement: total network cost to be collected through tariff

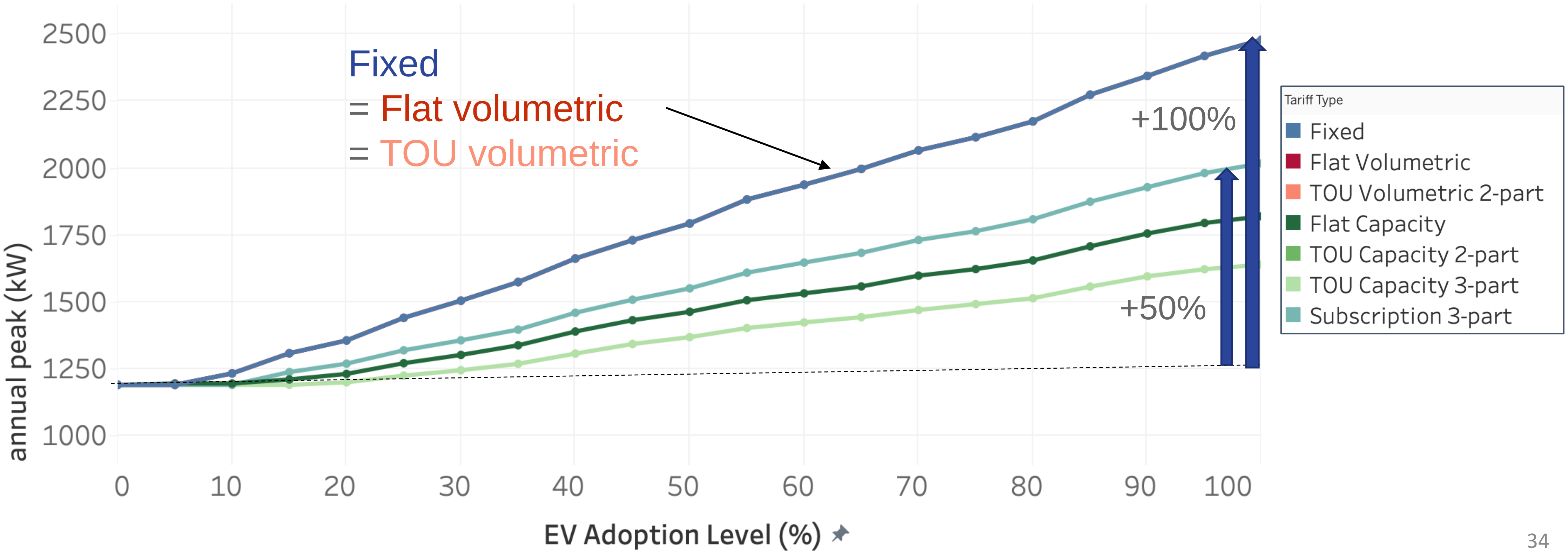
2. **Levelized cost of EV charging**: $/kWh equivalent paid to charge EVs (even more important for heat pump due to cheap natural gas)

3. **Change in network cost for non-EV owners**: Change in network cost for non-EV owners expressed in $/year relative to flat volumetric network tariff at 0% EV adoption

Capacity-based charges are a good idea

Designing distribution networks tariffs for scenarios of increased residential end-user electrification: can the US learn something from Europe?

October 2023- Working paper



Capacity-based charges find a right balance between cost-reflectivity and distributional impacts…

Results for 50% EV adoption among the 400 households

Complexity

Network Tariff	Annual Peak (kW)	Levelized Charging Cost ($/kWh)	Change in Network Cost for non-EV owners (%)
Fixed	1572	$0.07	63%
Status quo	1572	$0.18	-8%
1-part Demand Charge	1326	$0.08	12%
3-part Seasonal Subscription	1283	$0.10	13%
3-part Seasonal Demand Charge	1178	$0.07	8%

The higher the peak, the higher total network costs that need to be recuperated from all consumers

The lower the levelized charging costs, the more EV adoption is stimulated

Low distributional impacts are vital for the acceptability of the tariff

…with subscription charges capturing a large share of the benefits while having lower complexity

Electricité de France 2024
Tarif Blue Tempo Option

Option Tempo (TTC)							
Puissance Souscrite (kVA)	Abonnement mensuel (€ TTC/mois)	Prix du kWh (cts € TTC/kWh)					
		Bleu HC	Bleu HP	Blanc HC	Blanc HP	Rouge HC	Rouge HP
6	12,96	12,96	16,09	14,86	18,94	15,68	75,62
9	16,16	12,96	16,09	14,86	18,94	15,68	75,62
12	19,44	12,96	16,09	14,86	18,94	15,68	75,62
15	22,45	12,96	16,09	14,86	18,94	15,68	75,62
18	25,44	12,96	16,09	14,86	18,94	15,68	75,62
30	38,29	12,96	16,09	14,86	18,94	15,68	75,62
36	44,42	12,96	16,09	14,86	18,94	15,68	75,62

https://particulier.edf.fr/content/dam/2-Actifs/Documents/Offres/Grille_prix_Tarif_Bleu.pdf

EDF Tarif Bleu EJP Option (closed)

EDF	Abonnement annuel (€/an)	Jour Non-EJP	Jour EJP
9 kVA	189.6 €	0.1758 €	1.5197 €
12 kVA	225.12 €	0.1758 €	1.5197 €
15 kVA	261.36 €	0.1758 €	1.5197 €
18 kVA	296.52 €	0.1758 €	1.5197 €
36 kVA	517.56 €	0.1758 €	1.5197 €