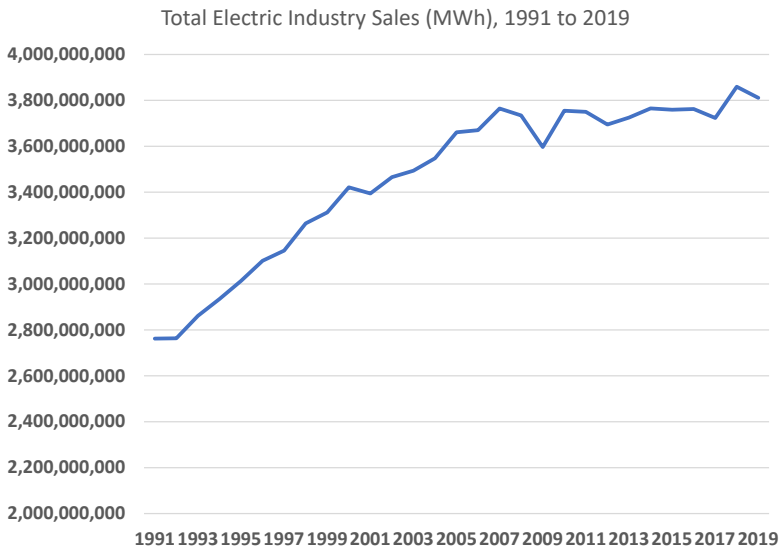
IPU's 66th Annual Regulatory Studies Program

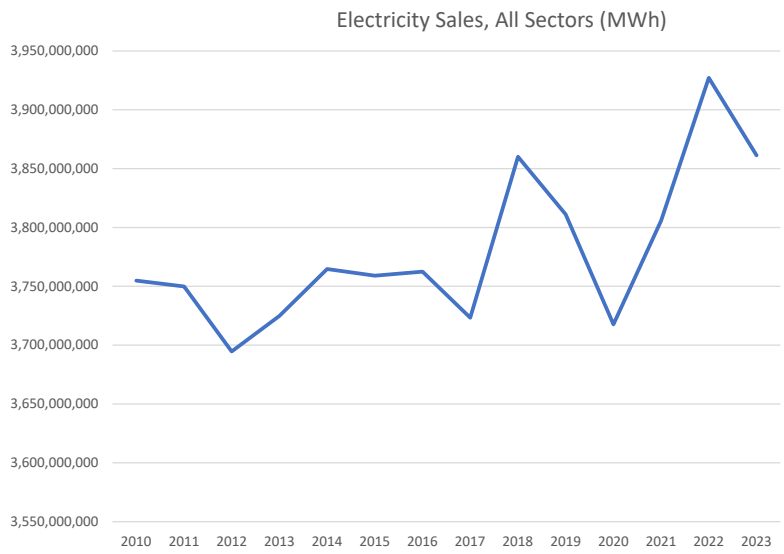
Sector Breakout: Electricity
August 16, 2024

Kenneth Rose
DePaul University and IPU Senior Fellow

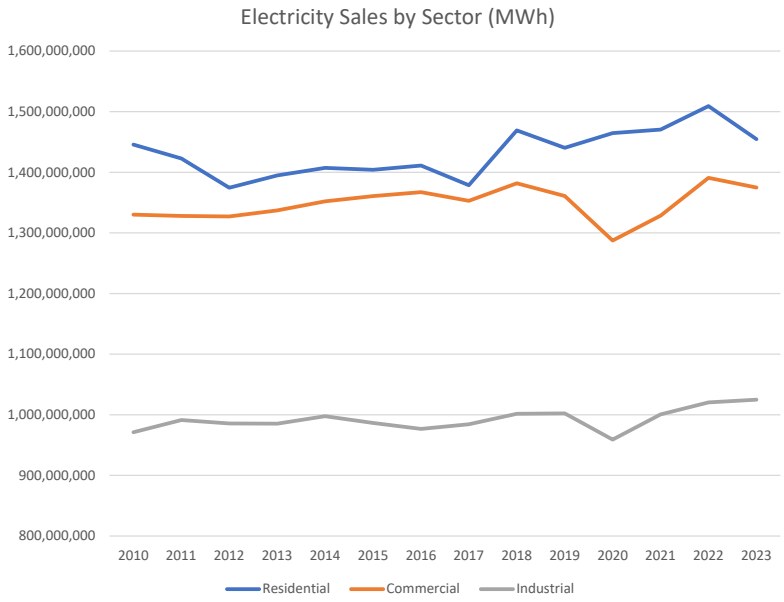
- Electric sales increased by 40% from 1991 to 2018.



- Electric sales increased by 4.6% from 2010 to the current peak in sales in 2022, then decreased in 2023.

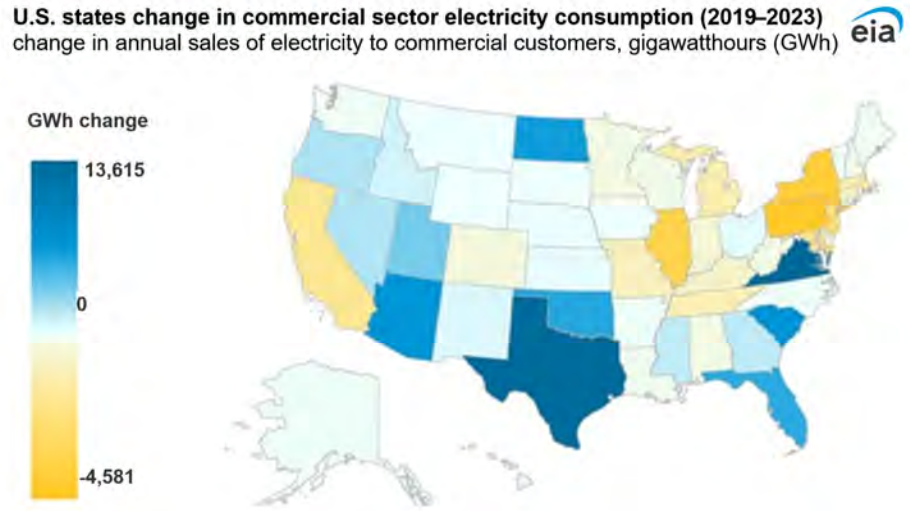


- Residential sales increased 4.4% from 2010 to 2022, while commercial grew by 4.6%, for the same period. Industrial grew by 5.5% from 2010 to 2023.

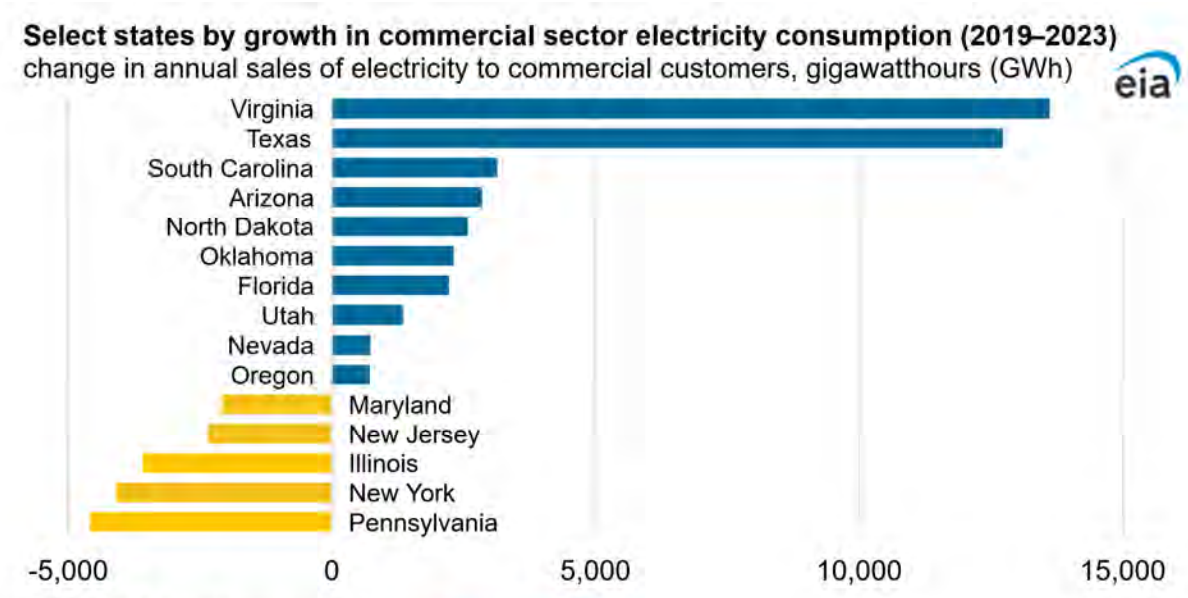


JUNE 28, 2024

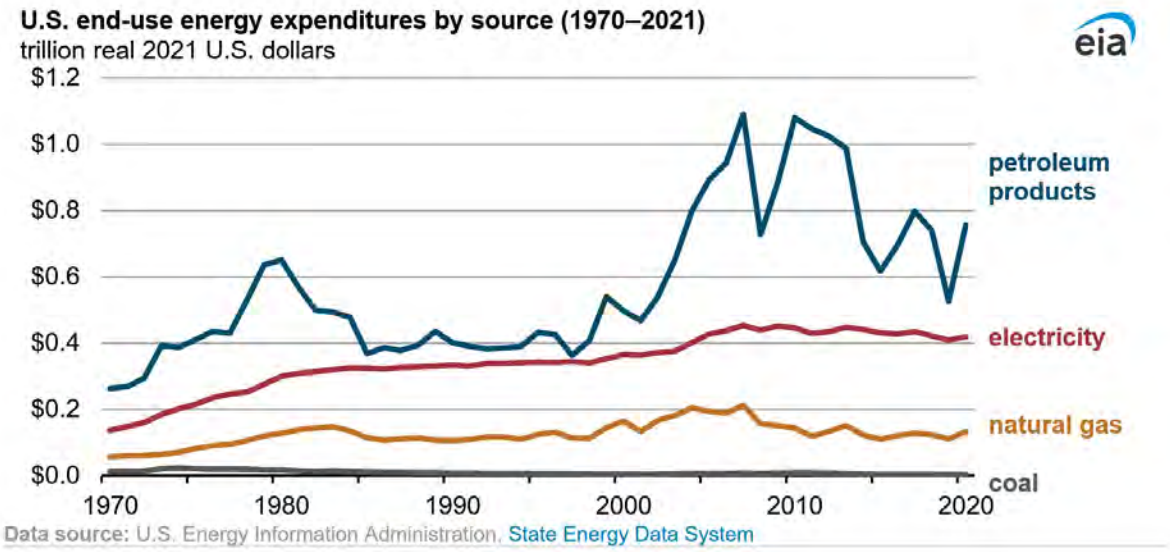
Commercial electricity demand grew fastest in states with rapid computing facility growth



Data source: U.S. Energy Information Administration, *Electricity Data Browser*

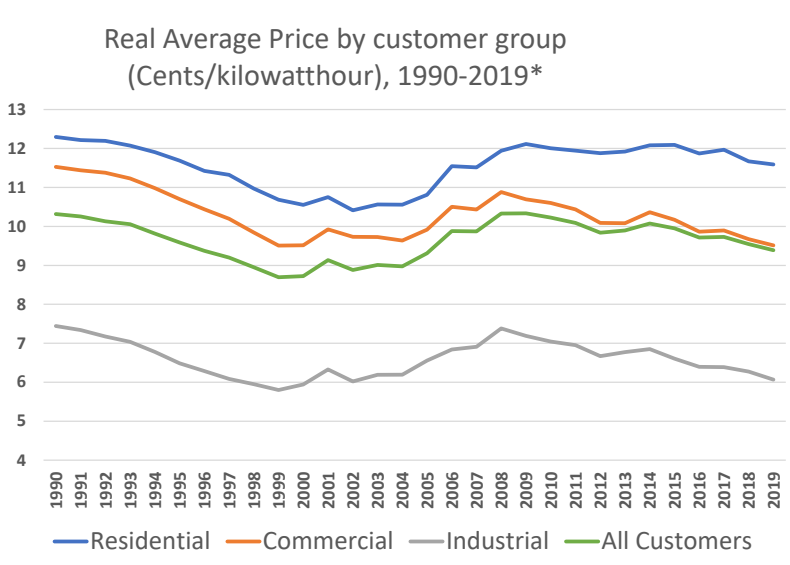


Data source: U.S. Energy Information Administration, *Electricity Data Browser*

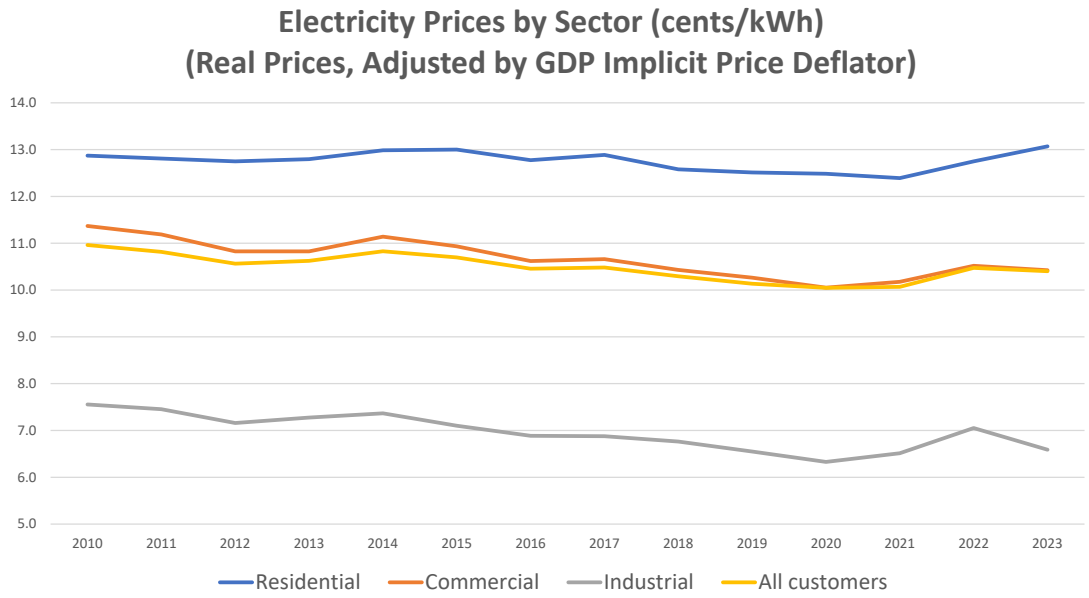


EIA Chart, August 2023

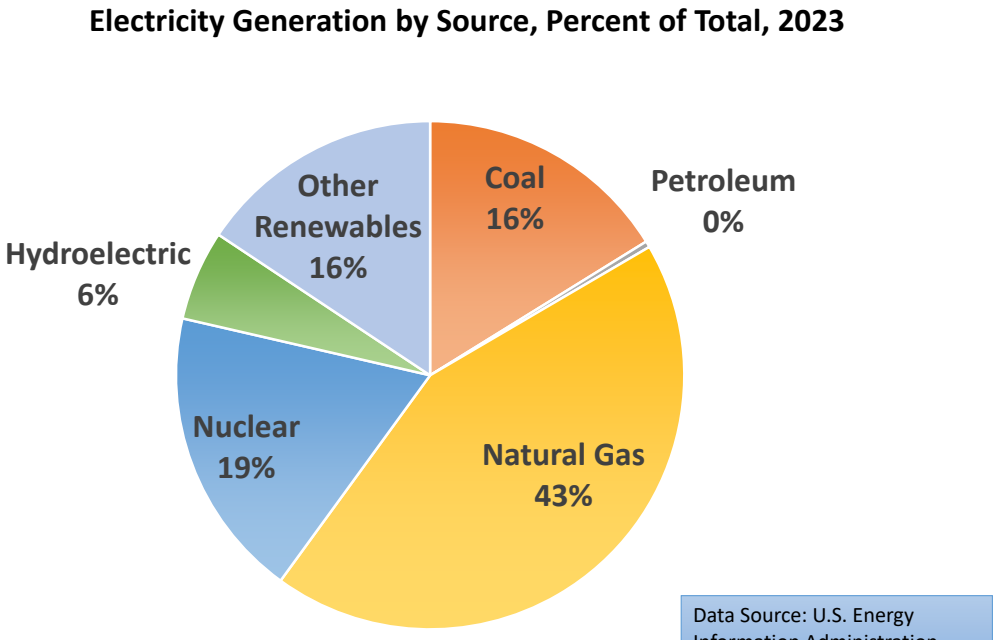
- Inflation adjusted prices of electricity for residential, commercial, industrial, and for all customers have all decreased since 1990.
- Remarkable given all that has occurred over that time, including a 40% increase in sales, the Clean Air Act implementation, wholesale and retail restructuring, and the growth of renewable energy resources, the real price for all customers fell by 9 percent overall.



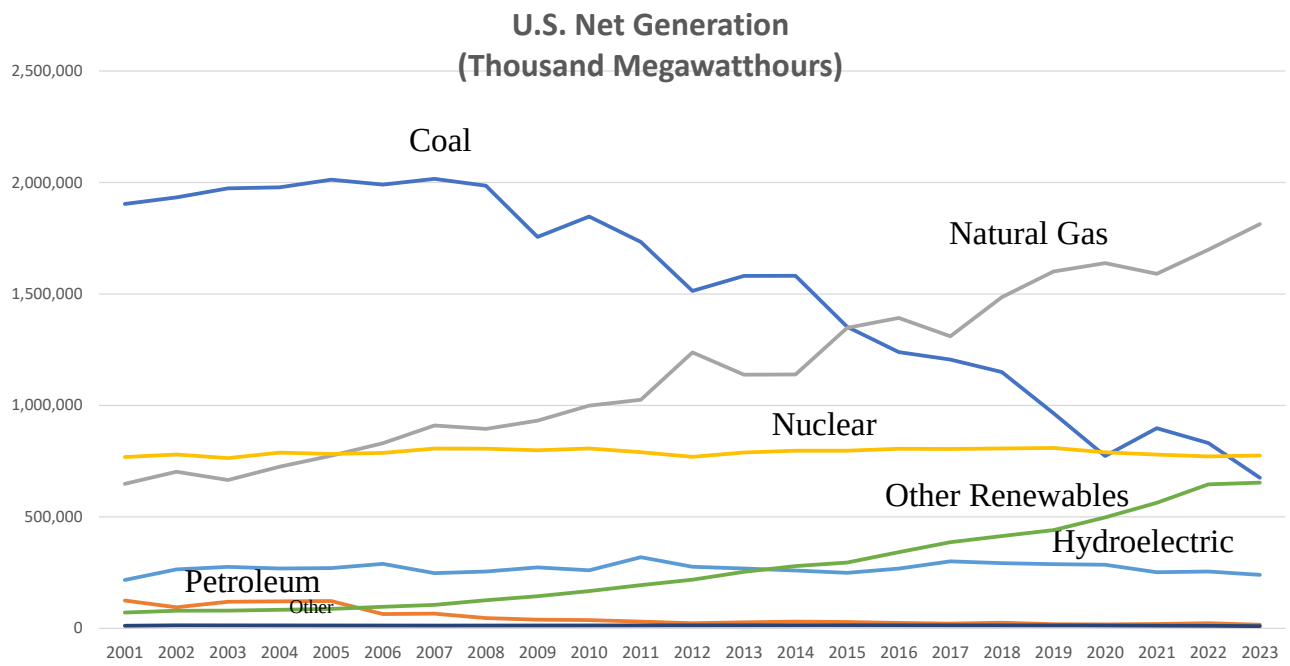
- *EIA price data adjusted with the Gross Domestic Product: Implicit Price Deflator, Index 2012=100 from U.S. Bureau of Economic Analysis, Gross Domestic Product: Implicit Price Deflator [GDPDEF], retrieved from FRED, Federal Reserve Bank of St. Louis.



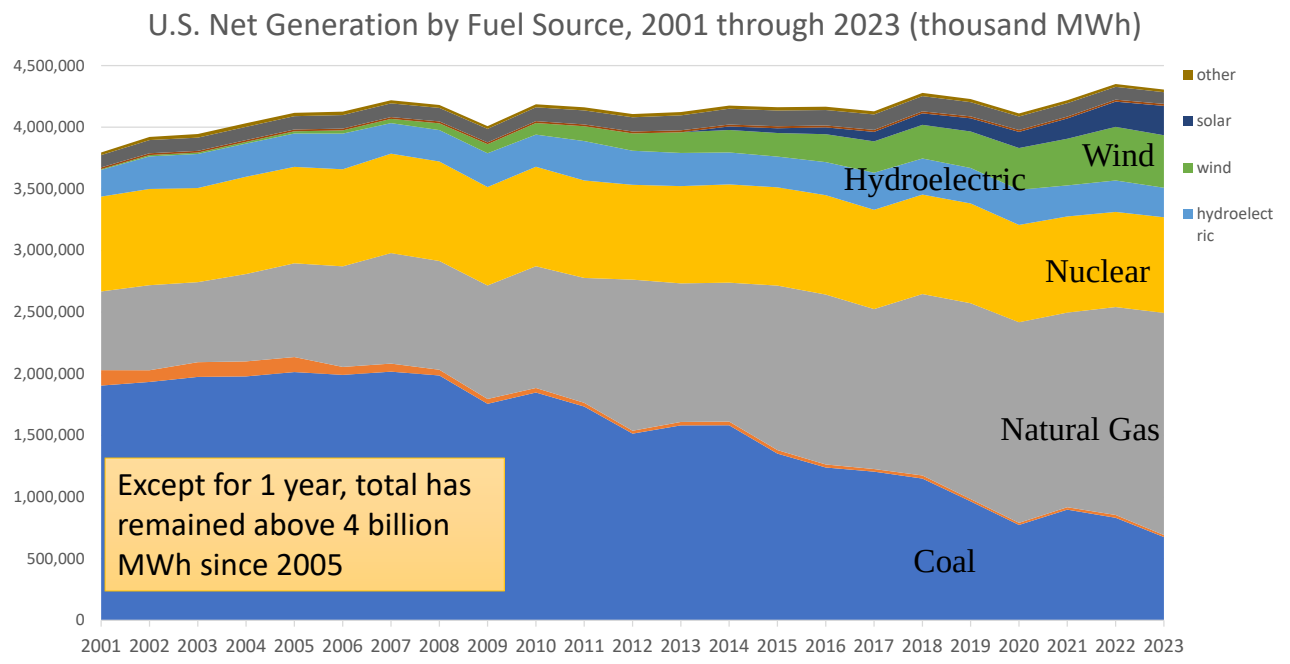
Data Sources: EIA electricity price data adjusted by the Bureau of Economic Analysis Implicit Price Deflators for Gross Domestic Product.



Data Source: U.S. Energy Information Administration.

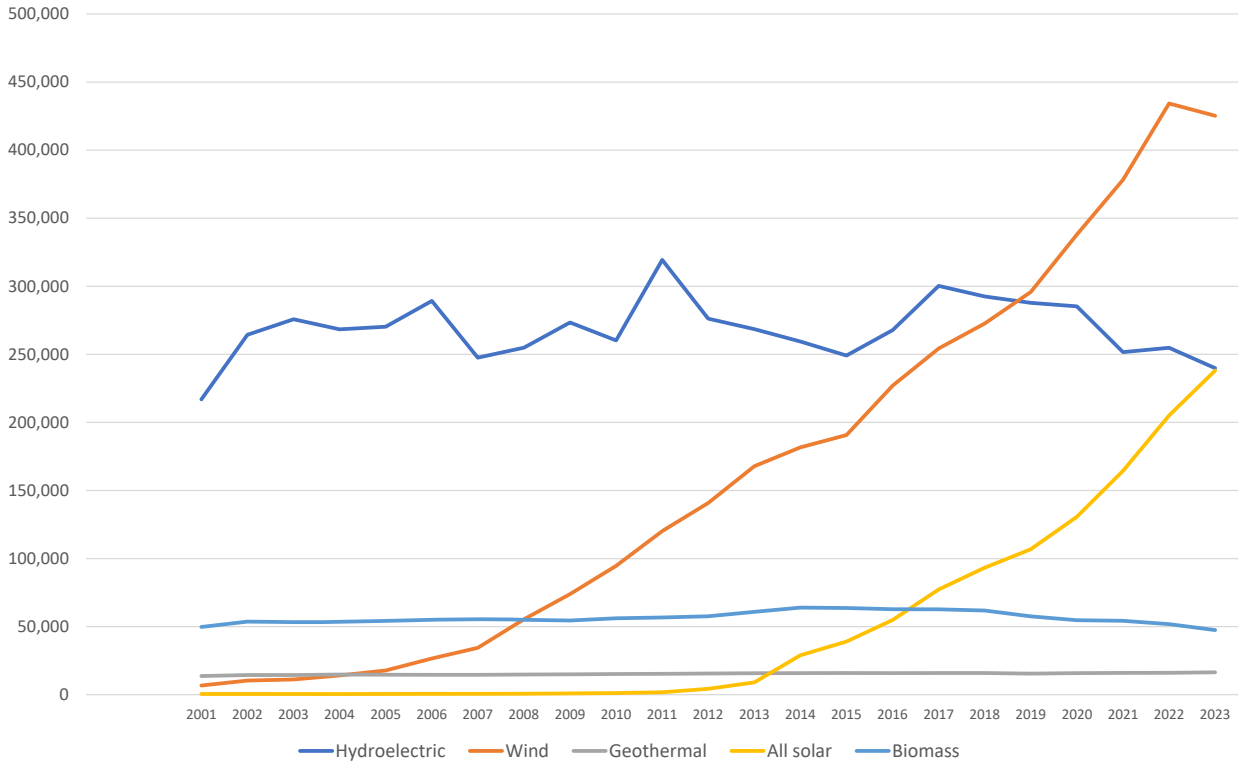


Data Source: U.S. Energy Information Administration.

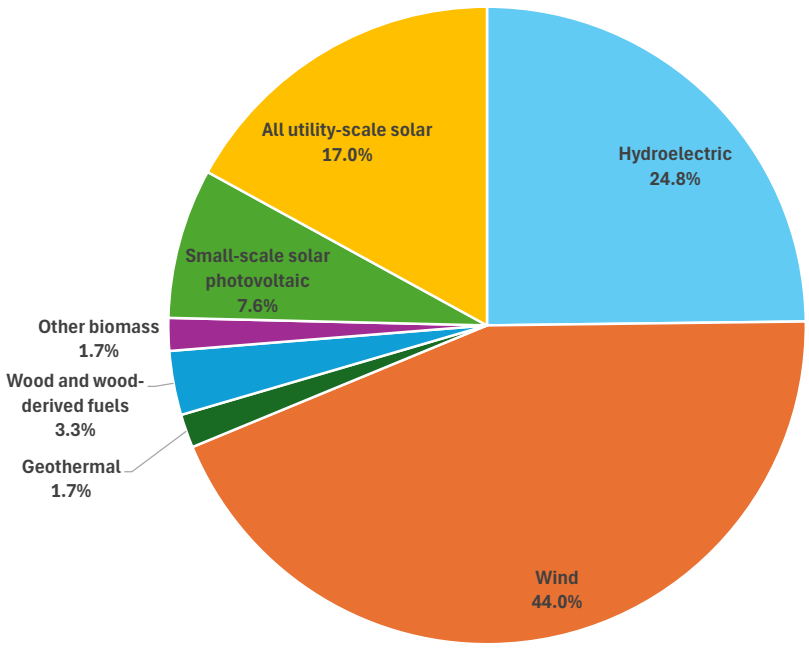


Data Source: U.S. Energy Information Administration.

Net Generation from Renewable Sources, 2001 through 2023 (thousand MWh)

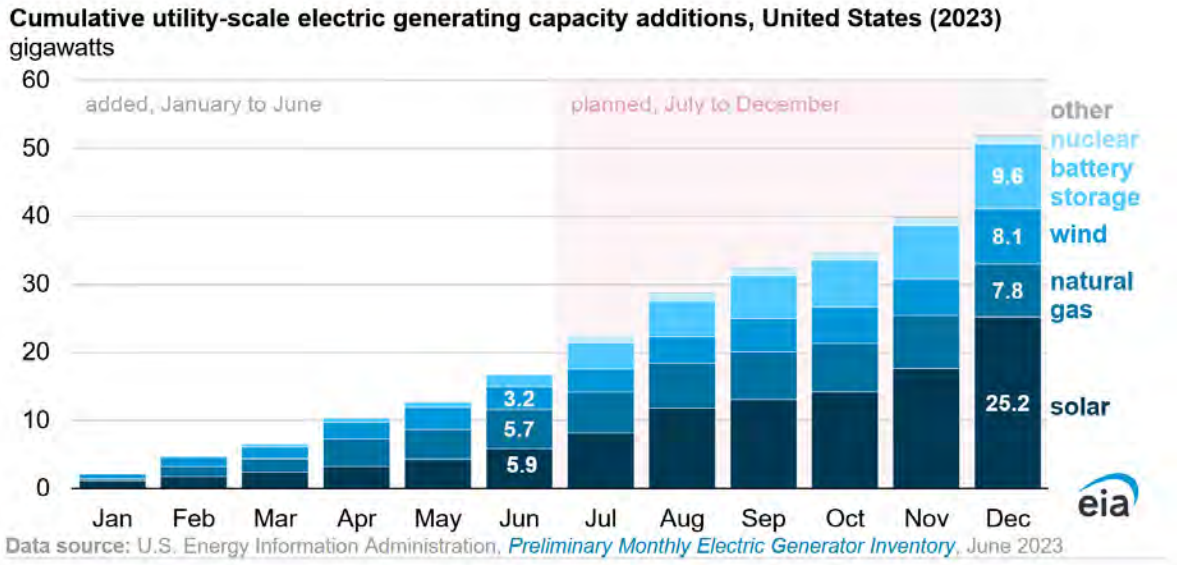


Percent Net Generation from Renewable Sources, 2023

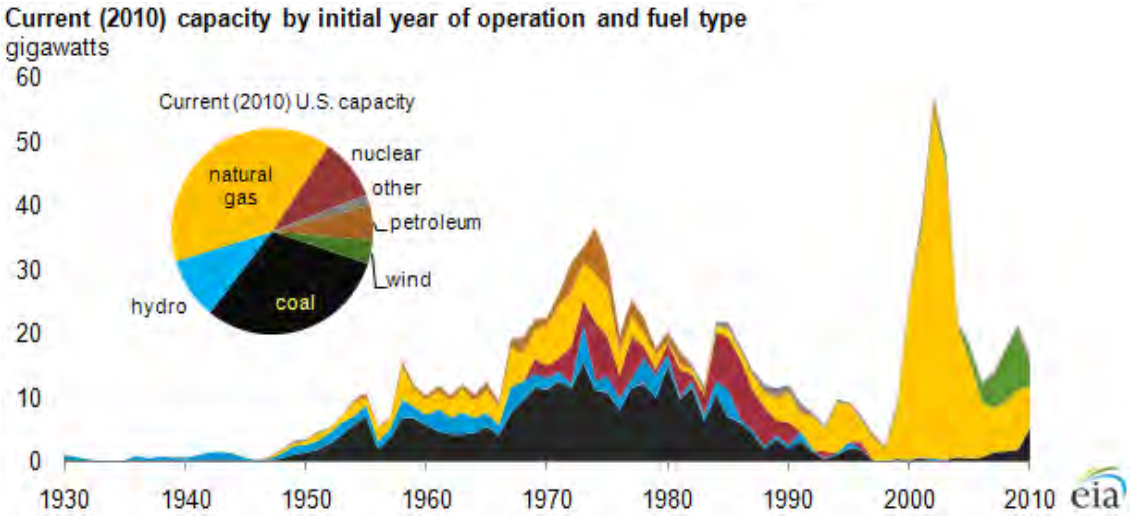


AUGUST 8, 2023

Developers added 16.8 GW of U.S. utility-scale generating capacity in first-half 2023

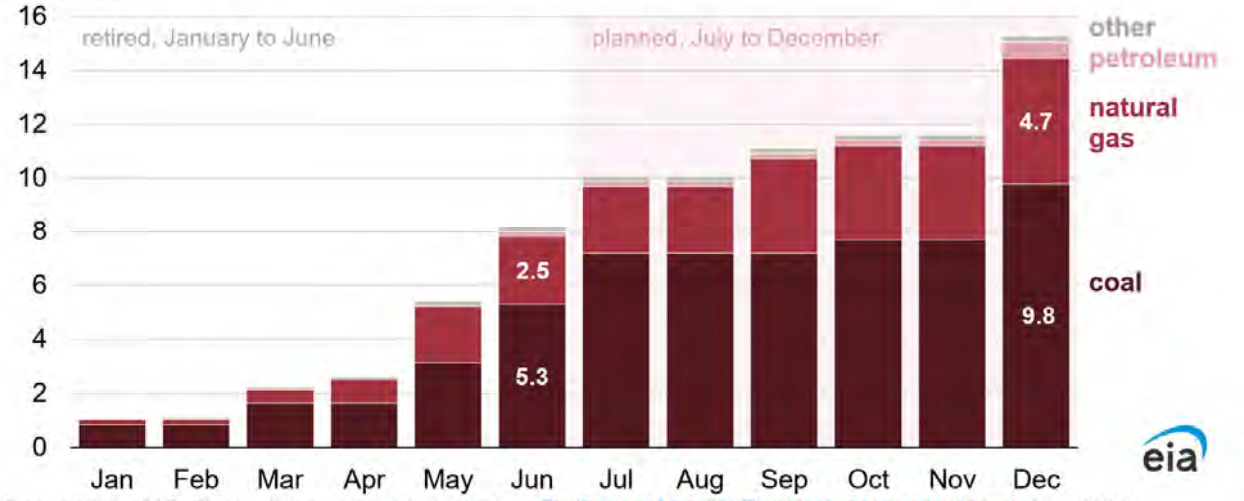


Power Plants are Aging and Mostly Built Natural Gas the Last Decade



Source: http://www.eia.gov

Cumulative utility-scale electric generating capacity retirements, United States (2023)
gigawatts

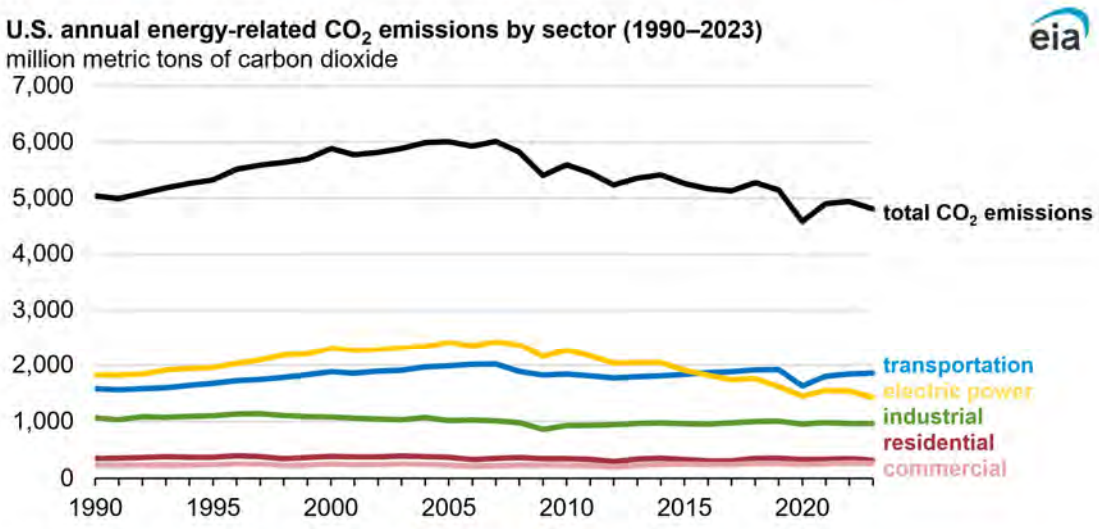


Data source: U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory*, June 2023

APRIL 29, 2024

U.S. energy-related CO_2 emissions decreased by 3% in 2023

U.S. annual energy-related CO_2 emissions by sector (1990–2023)
million metric tons of carbon dioxide

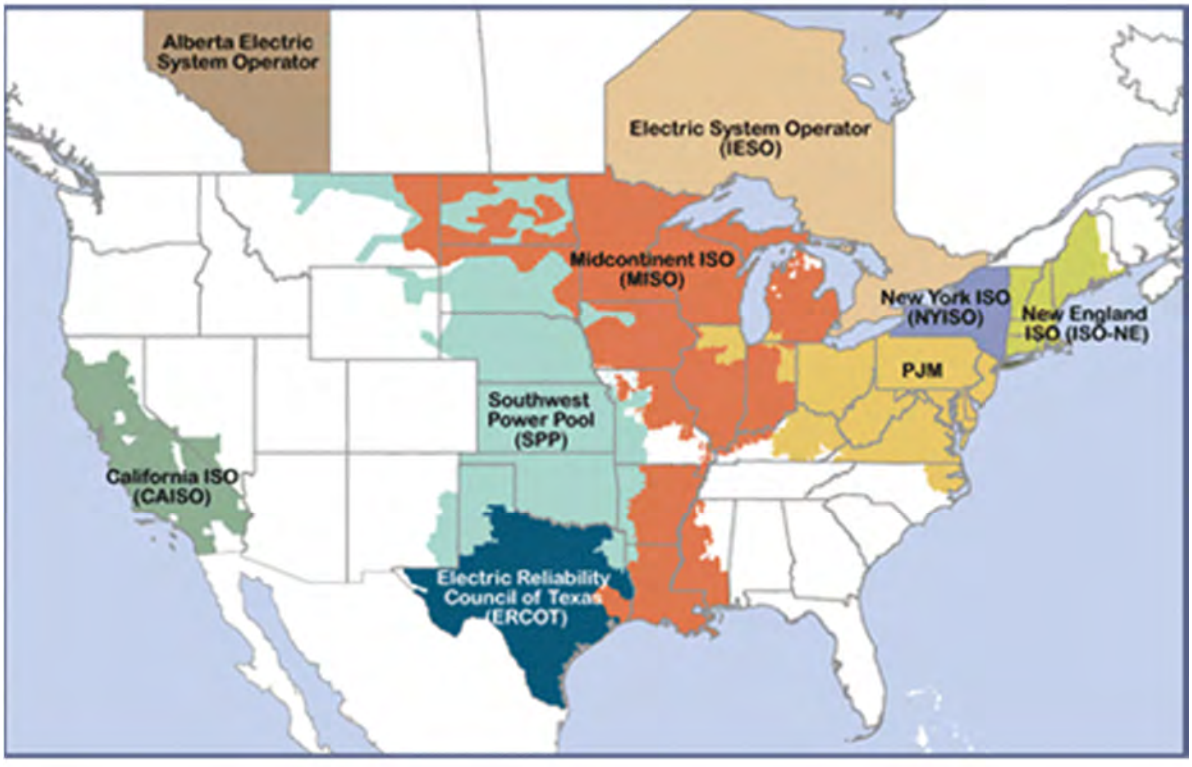


Data source: U.S. Energy Information Administration, *Monthly Energy Review*, March 2024

Wholesale Electricity Market Introduction

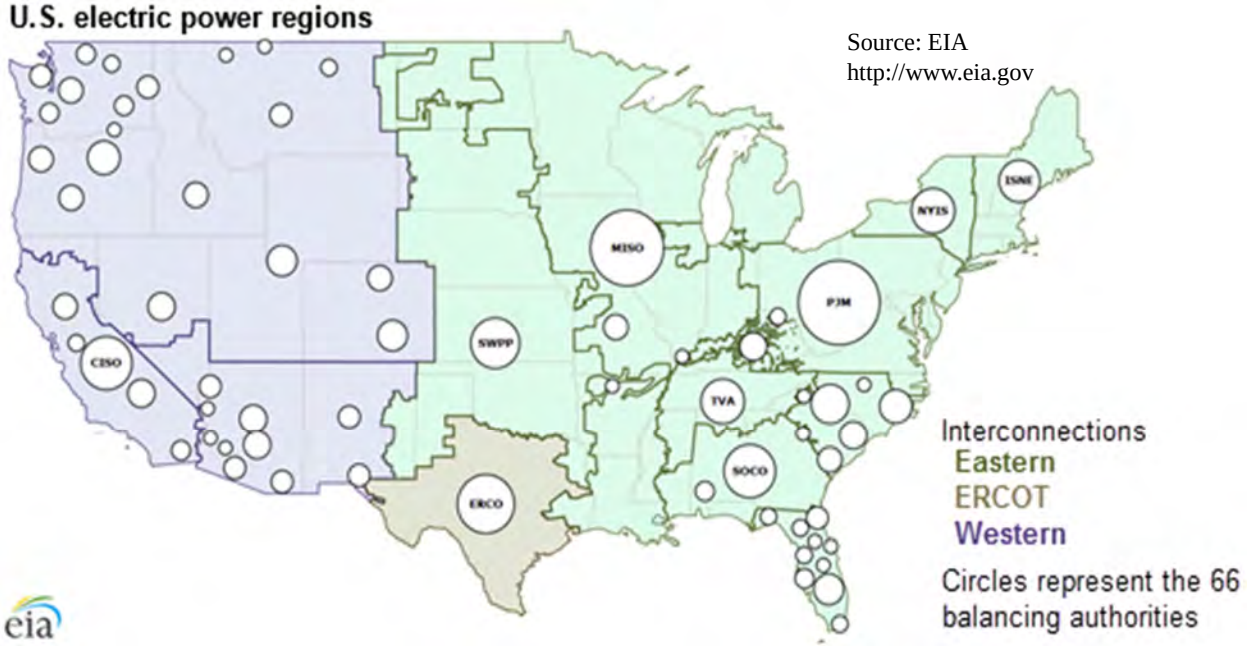
- We have developed a mix of complex wholesale market mechanisms designed to simulate the operations of competitive markets (energy, ancillary services, and transmission congestion-based transmission rights
- In many regions, these market mechanisms operate within a complex framework of RTO operating rules overseen by FERC

Regional Transmission Organizations and Independent System Operators



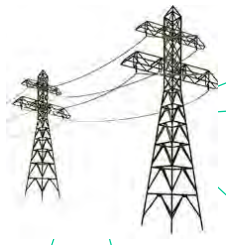
U.S. electric power regions

Source: EIA
http://www.eia.gov



- The Eastern Interconnection encompasses the area east of the Rocky Mountains and a portion of northern Texas. The Eastern Interconnection consists of 36 balancing authorities: 31 in the United States and 5 in Canada.
- The Western Interconnection encompasses the area from the Rockies west and consists of 37 balancing authorities: 34 in the United States, 2 in Canada, and 1 in Mexico.
- The Electric Reliability Council of Texas (ERCOT) covers most, but not all, of Texas and consists of a single balancing authority.

Summary of Unbundled RTO Wholesale Structure



energy

capacity

transmission service

ancillary services

RTO/ISO administrative fees

- FERC charge
- regional state committee charge
- market monitoring fund
- NERC charge
- NERC region charge
- RTO/ISO administrative services charge

Pricing Arrangement

- Real-time
- Day-ahead
- Forward Capacity/Reliability Pricing Model
- Point-to-Point Transmission Service
- Network Transmission Service
- 1) Scheduling, system control & dispatch
- 2) reactive supply & voltage control from generation sources
- - Black start service
- 3) regulation & frequency response service
- 4) energy imbalance service
- 5) operating reserve – spinning (synchronized) reserve
- 6) operating reserve – supplemental reserve

Scarcity Pricing

Locational Marginal Pricing

generation offers, demand bids and scheduled bilateral transactions

congestion management

Financial Transmission Rights (FTRs) - bilateral trading, and monthly, annual and long term FTR auctions

Cost-based pricing

Market-based pricing

load-serving entities (LSEs) meet their capacity obligations by self-supply, bilateral contracts, and capacity auctions

Transmission Expansion Planning

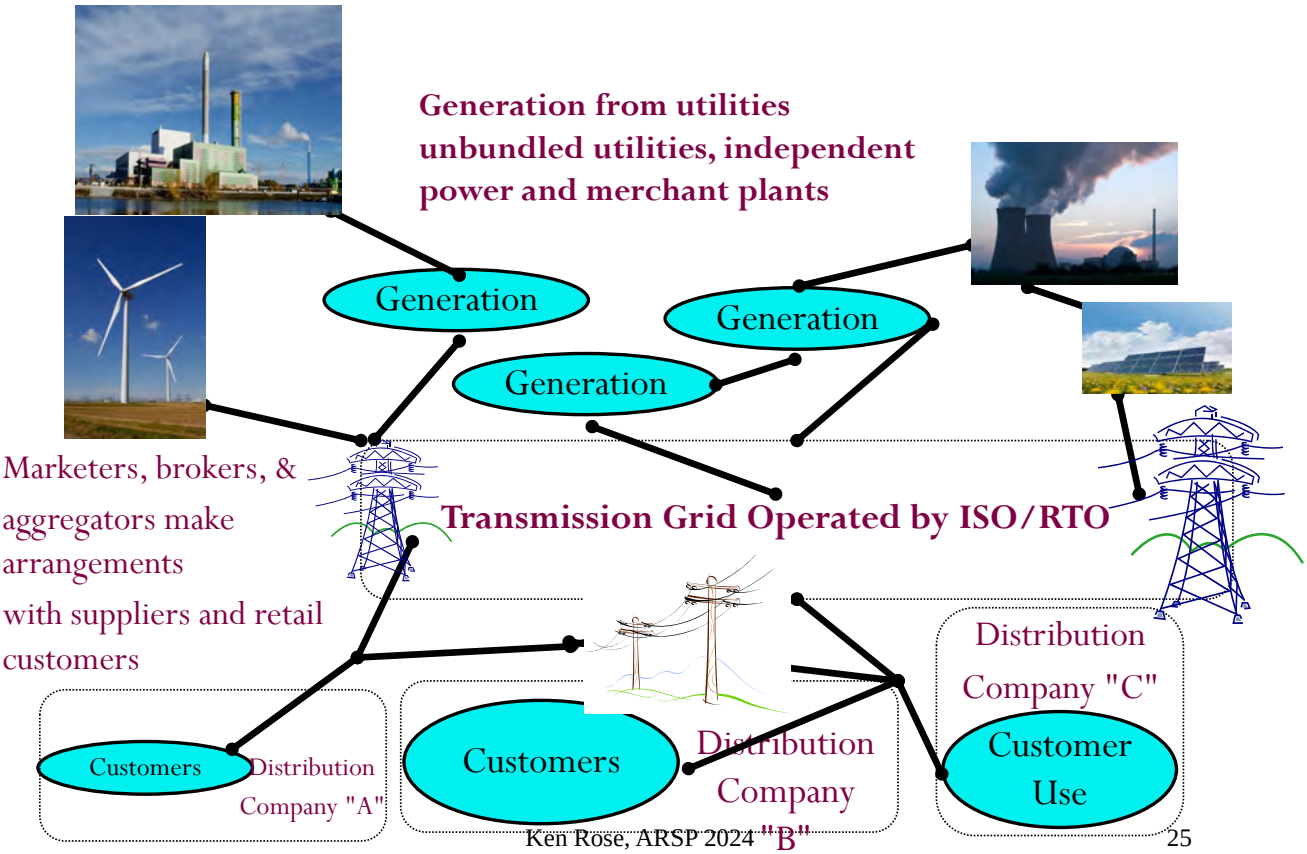
How did things get so complicated?

- Unbundling was done to facilitate wholesale competition by providing open, non-discriminatory access to transmission
- This developed into subdividing electricity into component parts with some being competitive and some remaining regulated
- RTO unbundling has provided the platform to divide and subdivide power components that has resulted in today's complex mechanism

Grid Policy Context Overview – *Restructuring*

- "Restructuring" refers to the policy and regulatory changes in the electric utility industry that increased or introduced competition in the wholesale and (in some states) retail portions of the industry
- This includes:
  - open and nondiscriminatory transmission access
  - creation of Independent System Operators (ISO) and Regional Transmission Operators (RTO)
  - creation of ISO/RTO markets, such as energy and capacity markets
  - "choice" or access to alternative power suppliers for retail customers

Restructured Electric Supply Industry



History and Development of Regional Transmission Organizations

- Utility coordination through power pools began in the 1920s
- In 1968 NERC and regional reliability areas were established for coordination purposes to increase reliability -- the adequacy and stability of the electric systems
- "Voluntary" transmission open access beginning in the 1980s
  - transmission owners could (and did) deny access to their transmission system
  - limited opportunities for "wheeling in" or "wheeling through" utility systems

History and Development *(continued)*

- The Energy Policy Act of 1992
  - required open transmission access to facilitate broader wholesale markets
  - also created the exempt wholesale generator (EWG) -- wholesale generators exempt from PUHCA
- FERC Order 888 (1996) required all transmission owning utilities to provide open access and comparable transmission interconnection and service to other generators and market participants
  - participation in an independent transmission organizations was voluntary

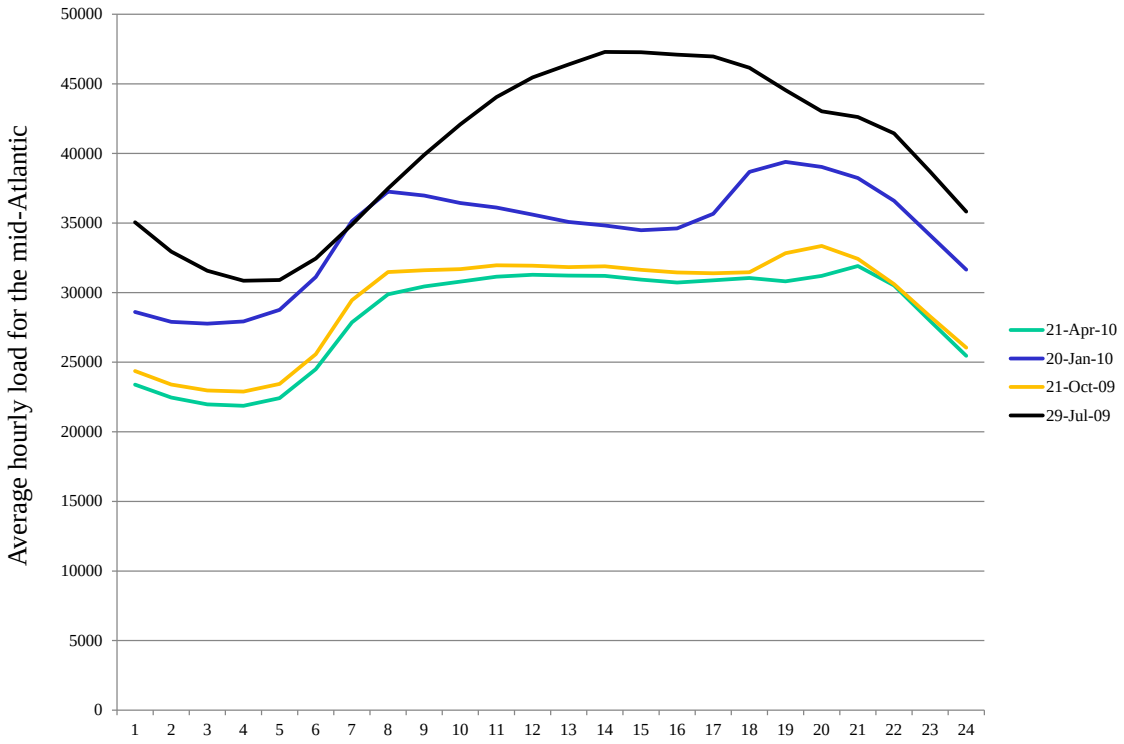
History and Development *(continued)*

- FERC Order 2000 "Regional Transmission Organizations" Issued December 20, 1999
- Order 2000's "minimum characteristics and functions that an RTO must satisfy"
  - Minimum Characteristics:
    1) Independence
    2) Scope and Regional Configuration
    3) Operational Authority
    4) Short-term Reliability

History and Development *(continued)*

- Minimum Functions:
  1. Tariff Administration and Design
  2. Congestion Management
  3. Parallel Path Flow
  4. Ancillary Services
  5. OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)
  6. Market Monitoring
  7. Planning and Expansion
  8. Interregional Coordination

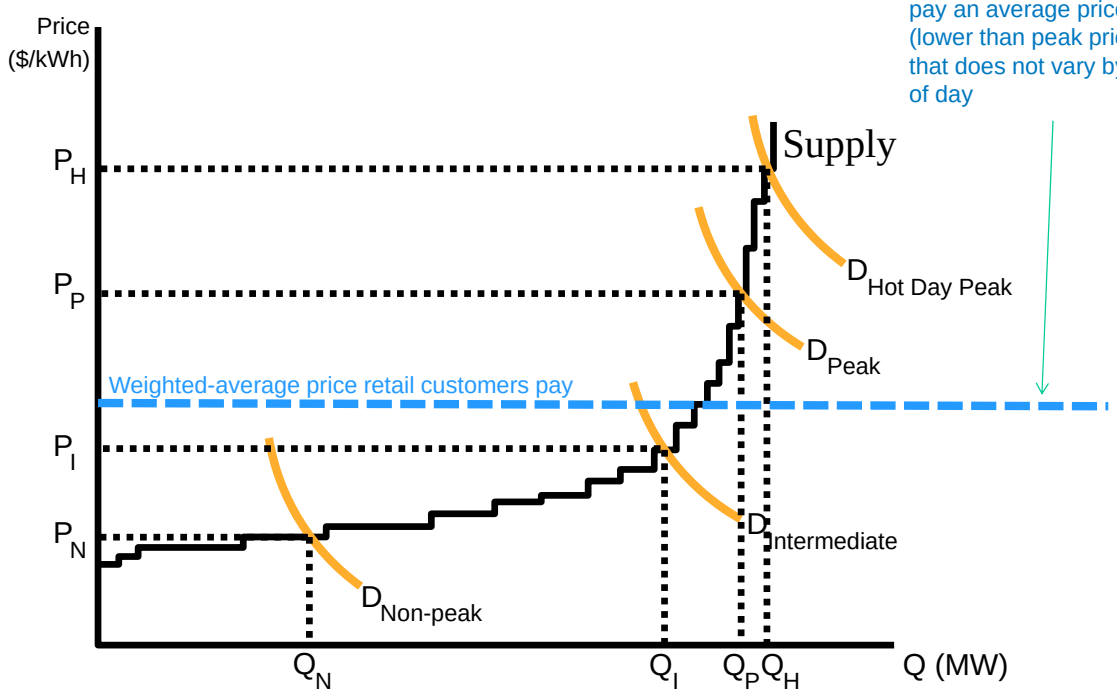
Customer load varies by time of day and season



Data Source: PJM

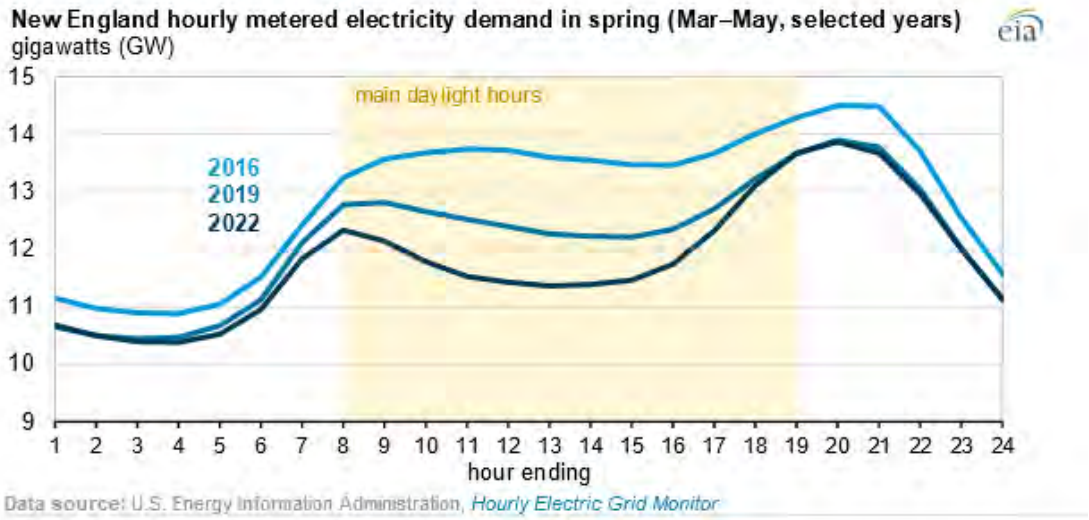
Retail customer demand changes by season and time-of-day

- many (often most) residential retail customers pay an average price (lower than peak prices) that does not vary by time of day



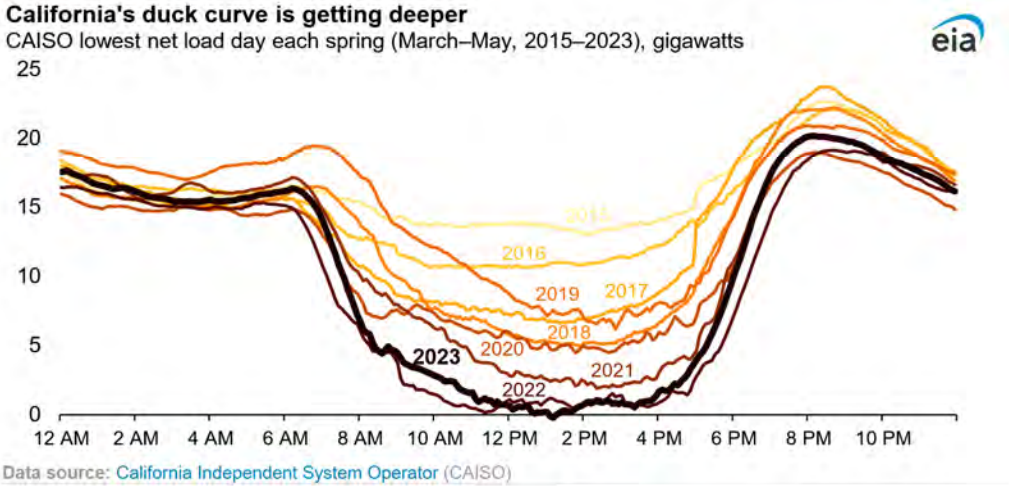
JULY 29, 2022

Small-scale solar is changing hourly utility electricity demand in New England



JUNE 21, 2023

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



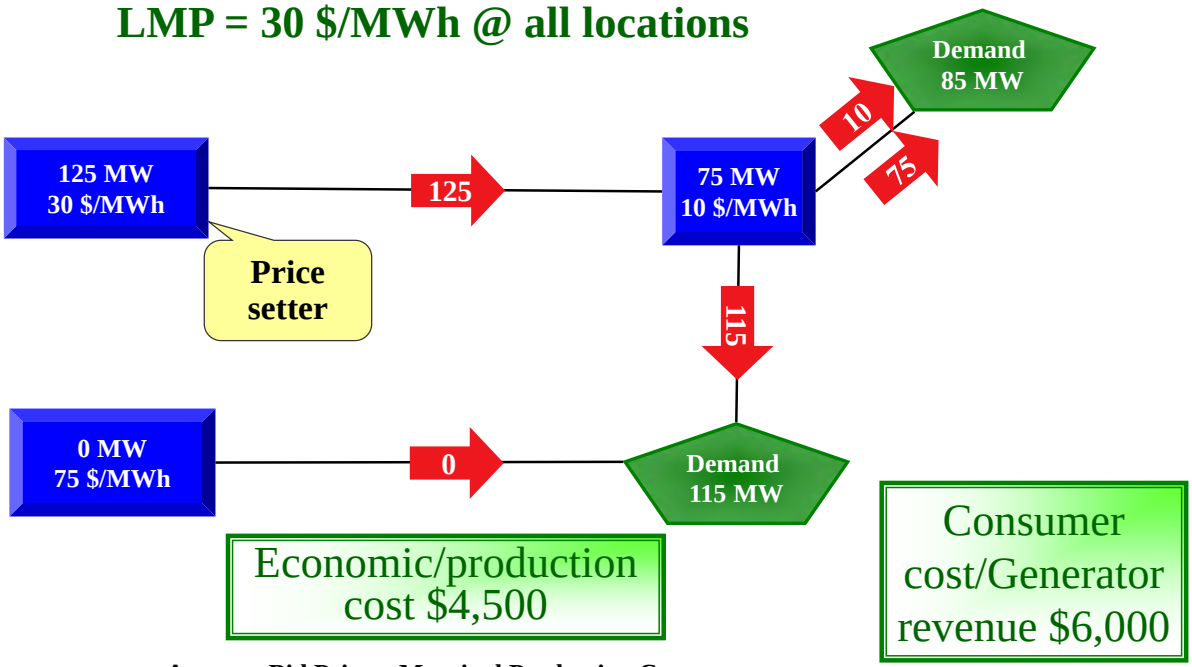
Non-Market Congestion Management

- Transactions are curtailed using transmission loading relief (TLR) mechanisms, non-price allocation of transmission use
- "Socialization" of congestion management costs across all customers in a region
- Problems - as seen by some include:
  - prevents price signals to indicate where new generation, demand response, or transmission is needed
  - transmission capacity is not consistently allocated to market participants that value transmission the most

Congestion Pricing

- Locational Marginal Pricing (LMP)
  - *Without* congestion on the transmission system, the price for power is equal to the price of supplying the next increment of power to meet demand
  - *With* transmission congestion, available lower cost power in one area cannot be delivered, so must be replaced with available higher cost generation from a non-congested area to meet demand
  - The difference between these prices is the opportunity cost of the transmission congestion-- "congestion rental" or "congestion charge"

Dispatch with Loads of 200 MW *without* Congestion Radial Network

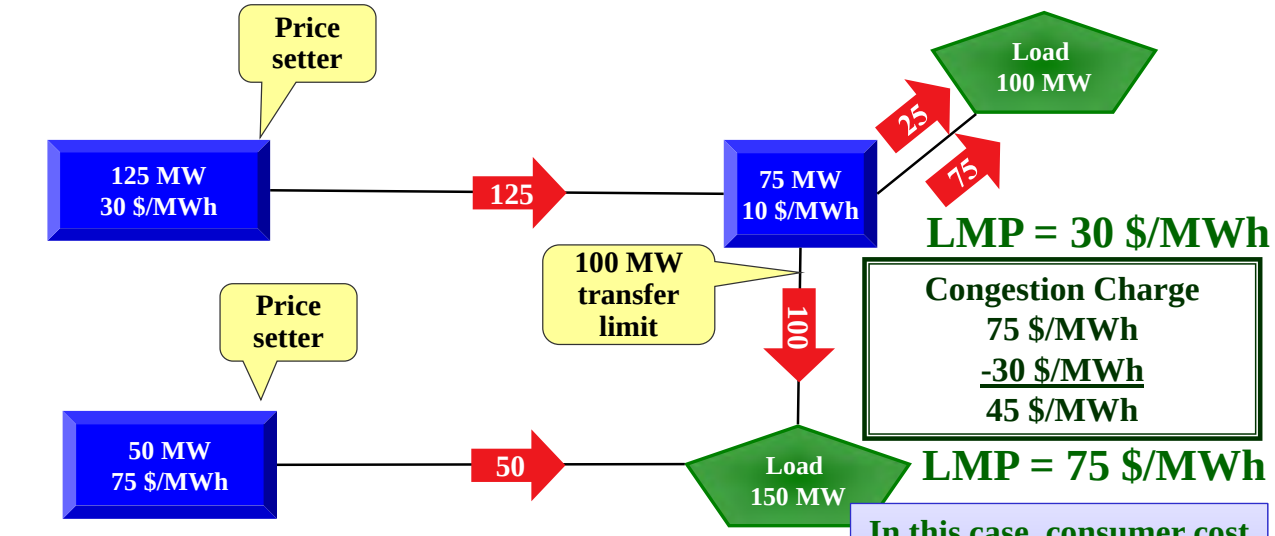


Assumes Bid Price = Marginal Production Cost

Note: Above example assumes that production and load levels are constant over a one-hour time period

Adapted from Tom Veselka, Argonne Nat'l Lab.

Dispatch with Loads of 250 MW *with* Congestion Radial Network



Economic/production cost was $4,500 w/congestion and greater load $8,250

Consumer cost was $6,000

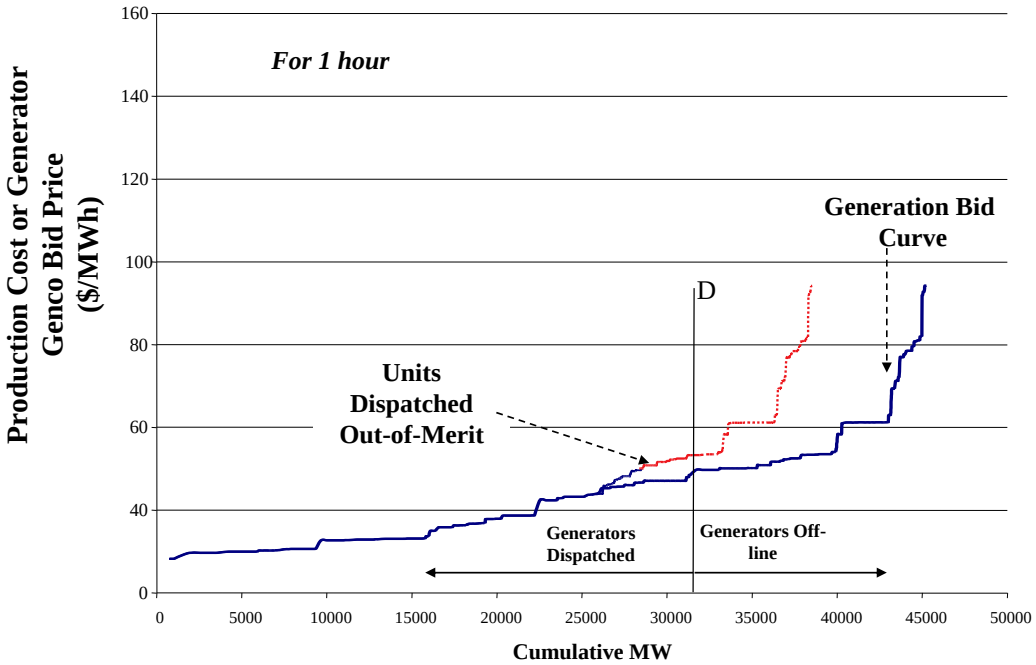
w/cong $14,250

In this case, consumer cost is $8,250 more with congestion and greater load ($3,750 from higher production cost and $4,500 from congestion cost

Assumes Bid Price = Marginal Production Cost

More Expensive Bids Are Dispatched Because of Transmission Congestion

Source: Tom Veselka, Argonne Nat'l Lab



Transmission Congestion Affect the Choice of Generators to Dispatch

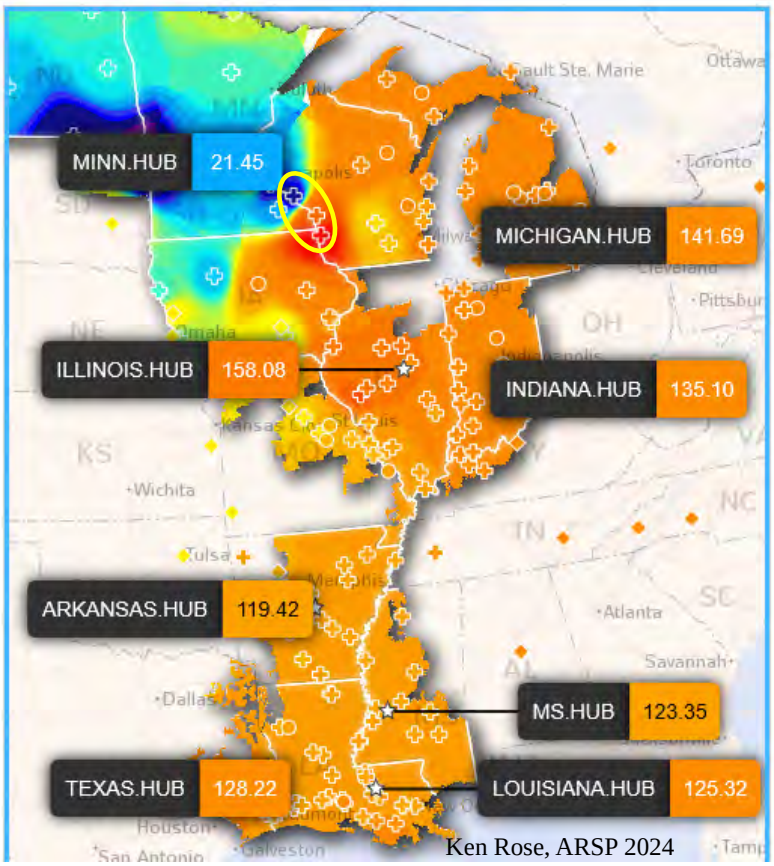
Congestion Pricing

- Locational marginal pricing positive aspects:
  - it is economically efficient since it is based on supply and demand for power, not curtailment to relieve congestion
  - consistent with spot and bilateral markets
  - encourages generators to locate where power is most valued
  - encourages new transmission to relieve congestion
- Better to use market mechanisms to manage congestion rather than physical interruptions or curtailments

Congestion Pricing *(continued)*

- Locational marginal pricing downsides
  - provides weak incentives for transmission investment when the same company owns both generation and transmission (which is common)
  - does not convey any additional information beyond what was already known -- especially for "load pockets" -- just raises the price
  - LMP does not prevent generation market power when it exists and may make it worse
  - since dispatch is based on *bid prices* not marginal operating cost, any market power would raise the price above marginal cost

24-Jun-2022 - 14:20 EST



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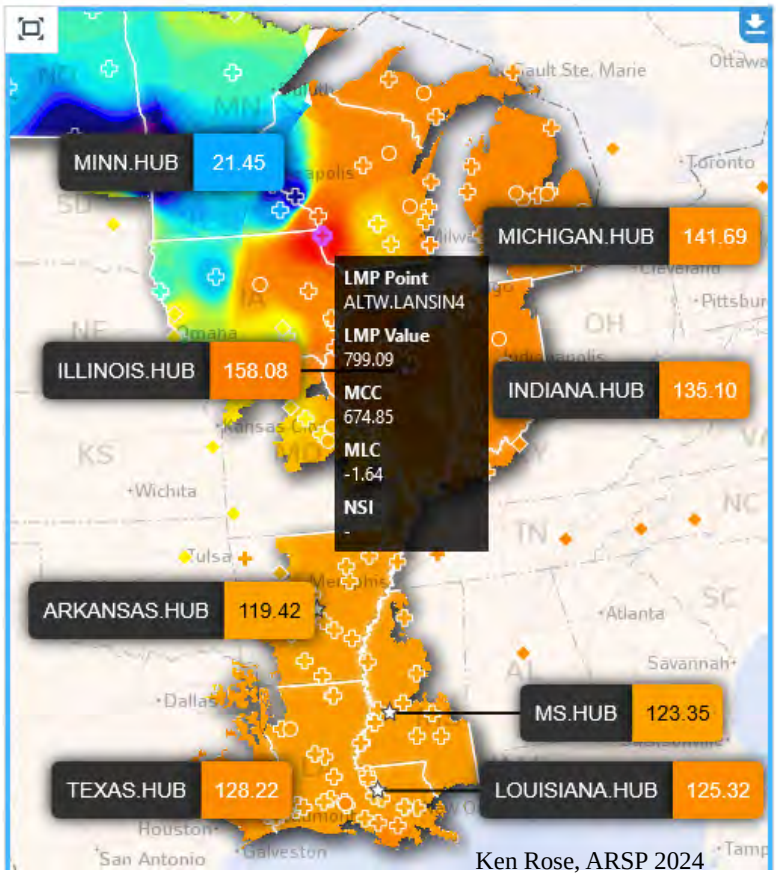
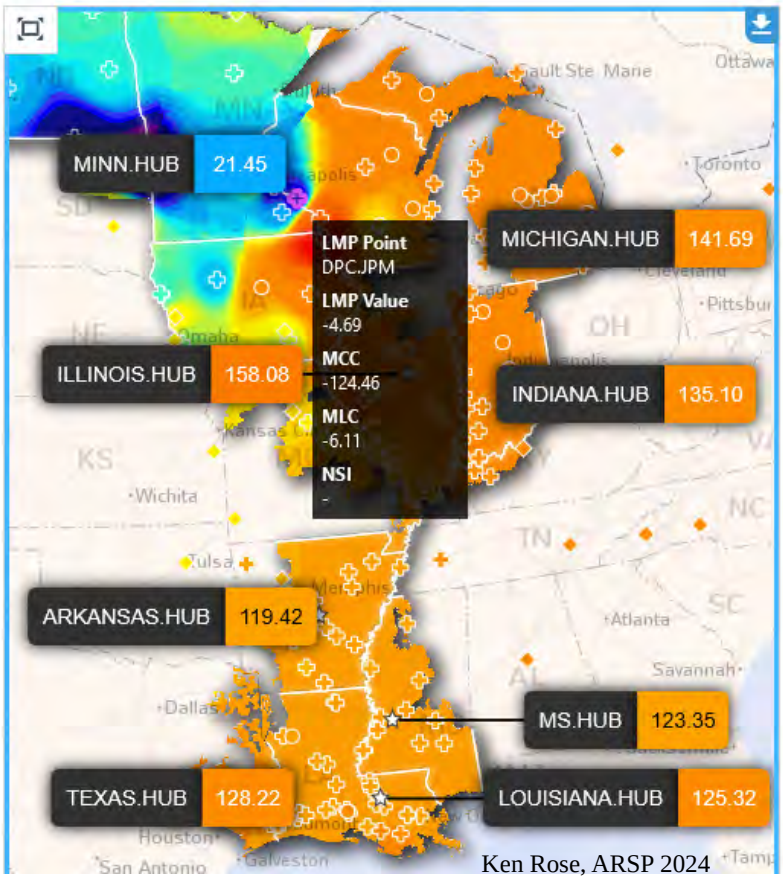


24-Jun-2022 - 14:20 EST

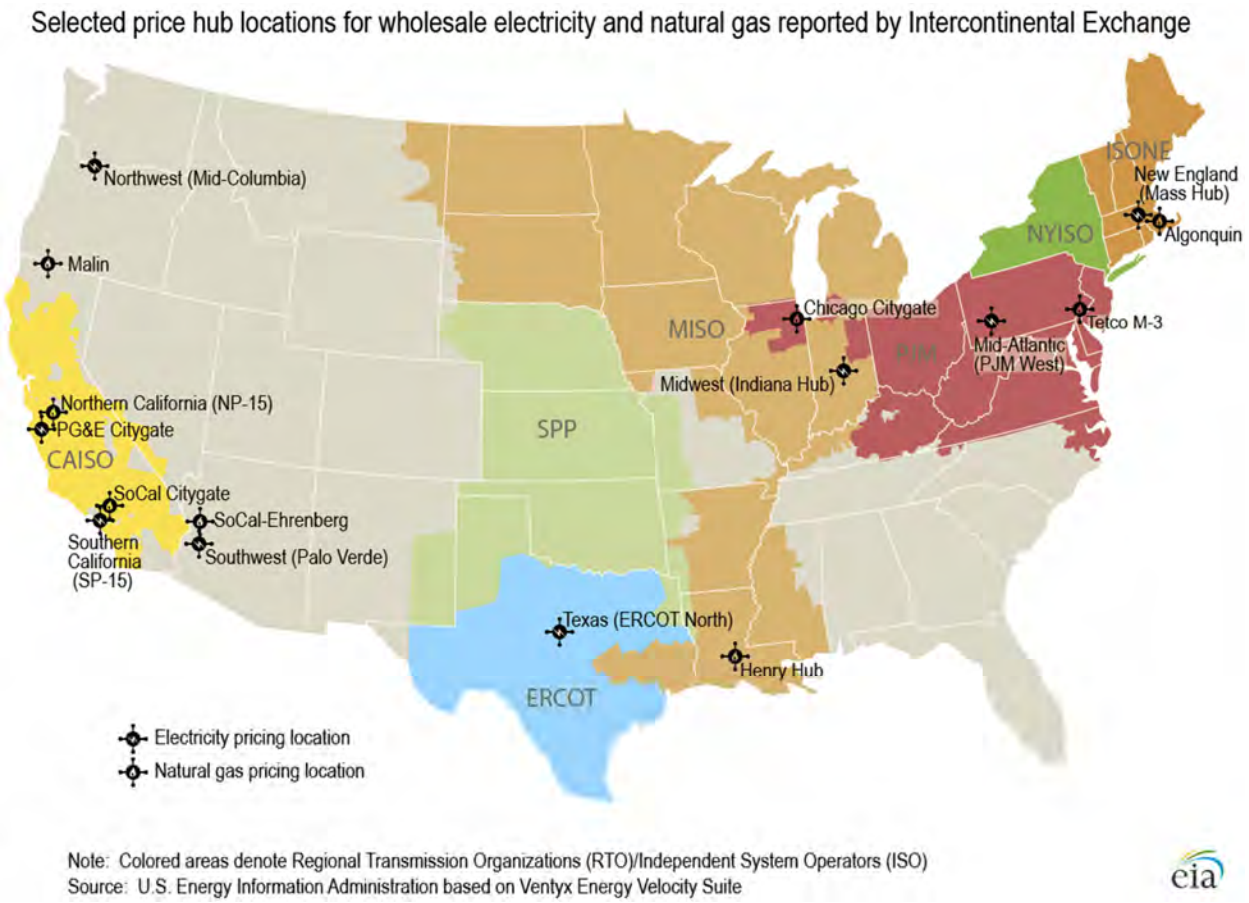


Firm Transmission Rights (FTRs)

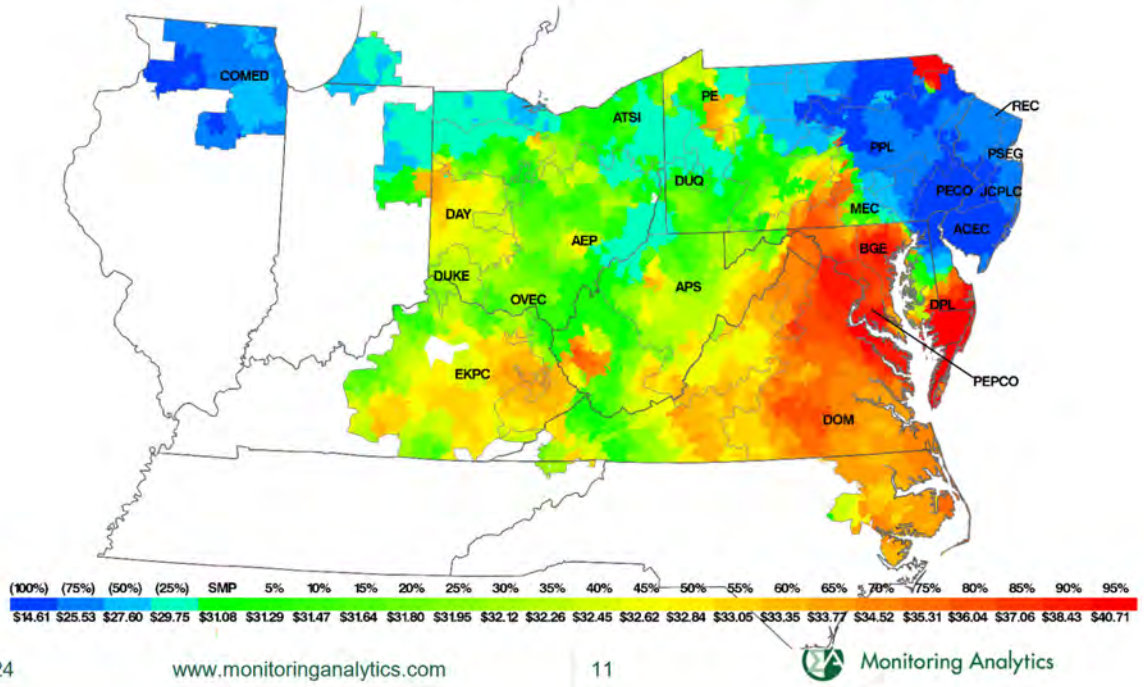
- LMP exposes market participants to price uncertainty
- FTRs are designed to allow customers an opportunity to hedge against the possibility of paying a congestion charge that occurs under LMP
  - provide price certainty to market participants and
  - allow transmission service without congestion charges (most of the time)
- The congestion charges are allocated to the holders of the FTRs (or revenues from an auction)
- They are financial instruments -- not a right for physical delivery of power

Spot markets for real-time energy and ancillary services

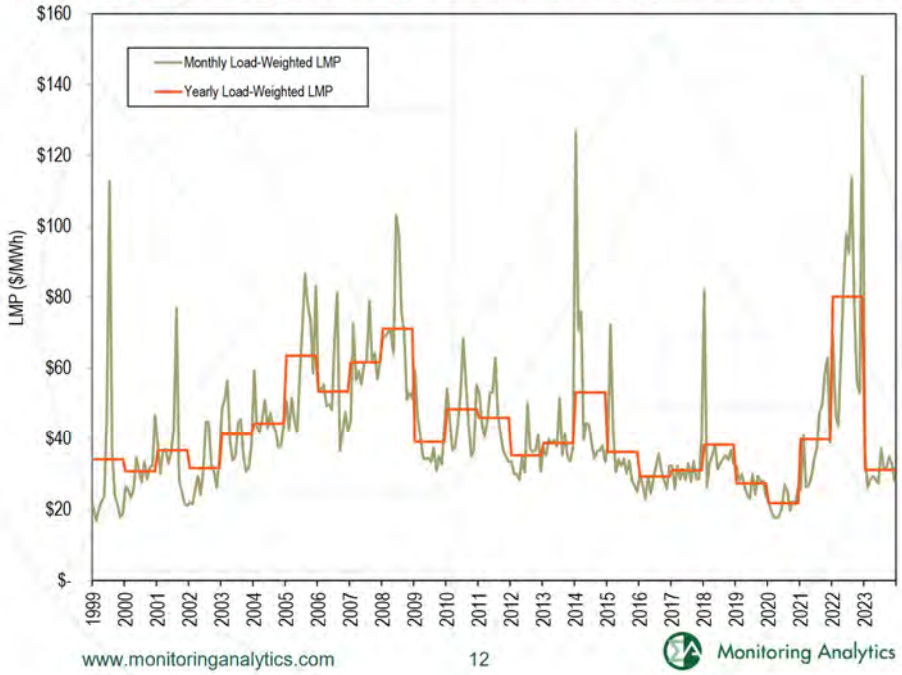
- Most power bought and sold through long-term bilateral contracts between buyers and sellers
- For last-minute sales or purchases for system reliability, ISOs and RTOs use real-time markets to resolve energy imbalances
- They also have day-ahead markets and a market for various ancillary services
- Currently, ISOs/RTOs do one or both



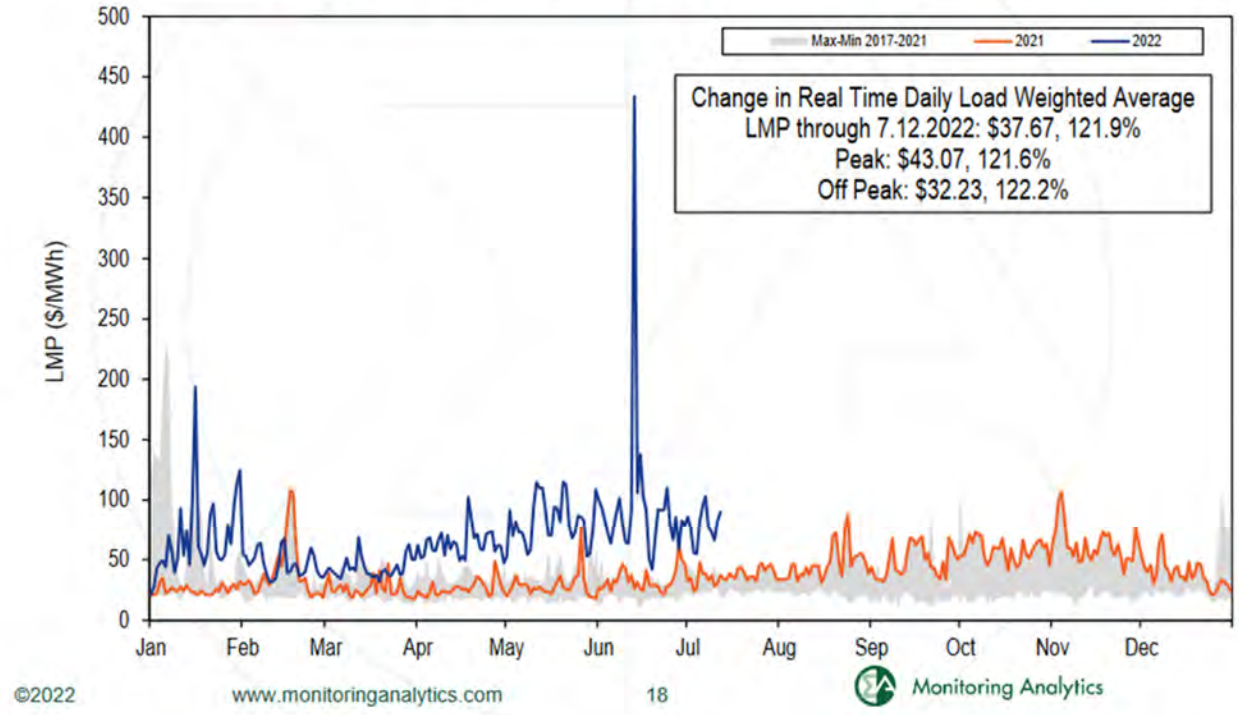
RT load-weighted average LMP

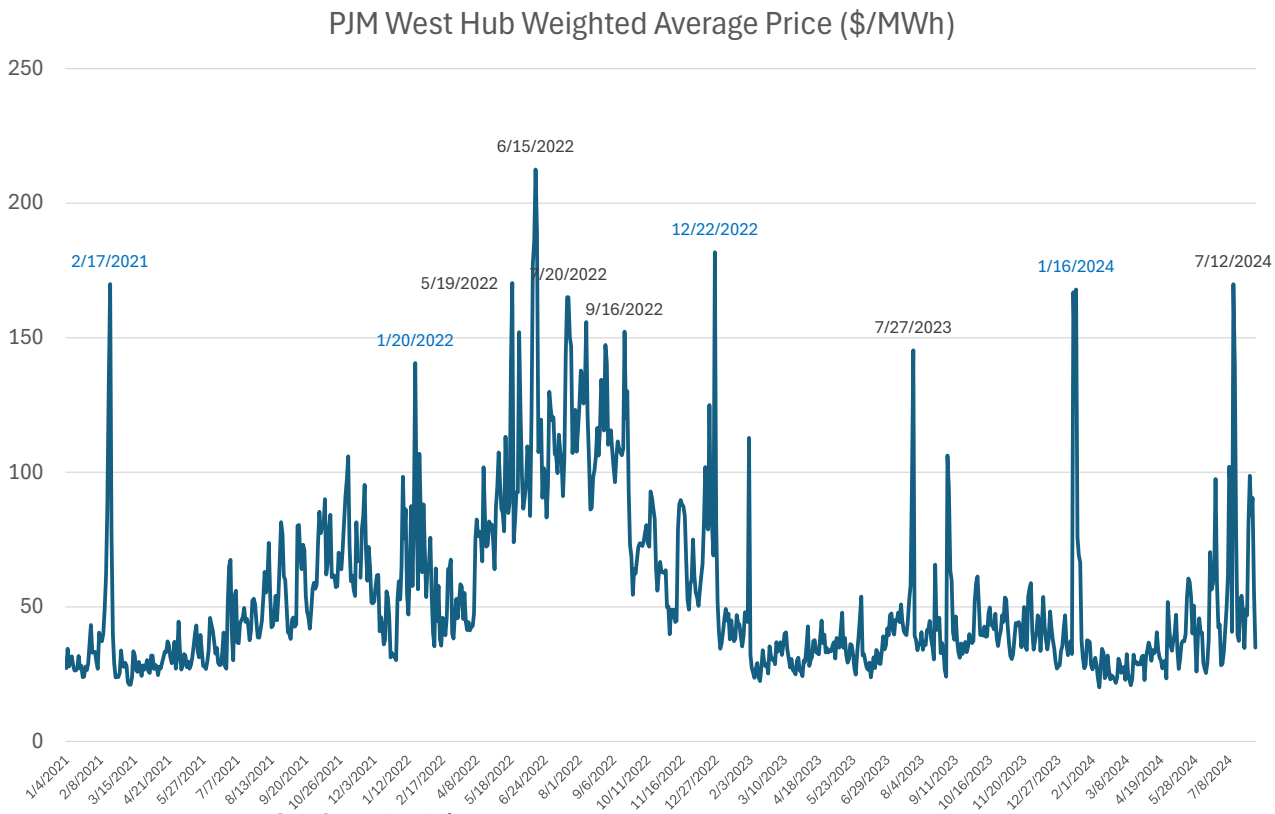


RT monthly and yearly load-weighted average LMP

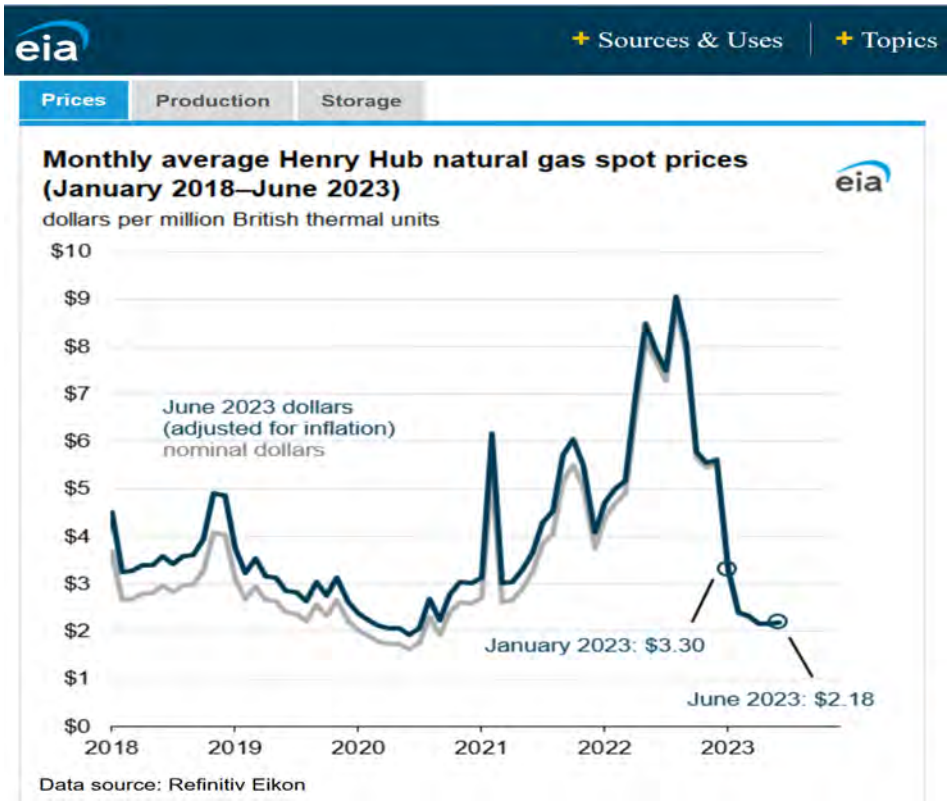


2022 YTD PJM Real-Time LMP





Data Source: Intercontinental Exchange (ICE), from EIA, August 2024.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+ Topics
Prices
Production
Storage
Monthly average Henry Hub natural gas spot prices (January 2018–June 2023)
dollars per million British thermal units
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$9
$8
$7
$6
$5
$4
$3
$2
$1
$0
June 2023 dollars (adjusted for inflation)
nominal dollars
January 2023: $3.30
June 2023: $2.18
2018
2019
2020
2021
2022
2023
Data source: Refinitiv Eikon


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BUSINESS
INVESTING
TECH
POLITICS
CNBC TV
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Natural Gas (Sep'24)
@NG.1:New York Mercantile Exchange
*Data is delayed | Exchange | USD
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WATCHLIST +
LIVE
FAST MONEY HALFTIME REPORT
Last | 12:36 PM EDT
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1M
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YTD
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5Y
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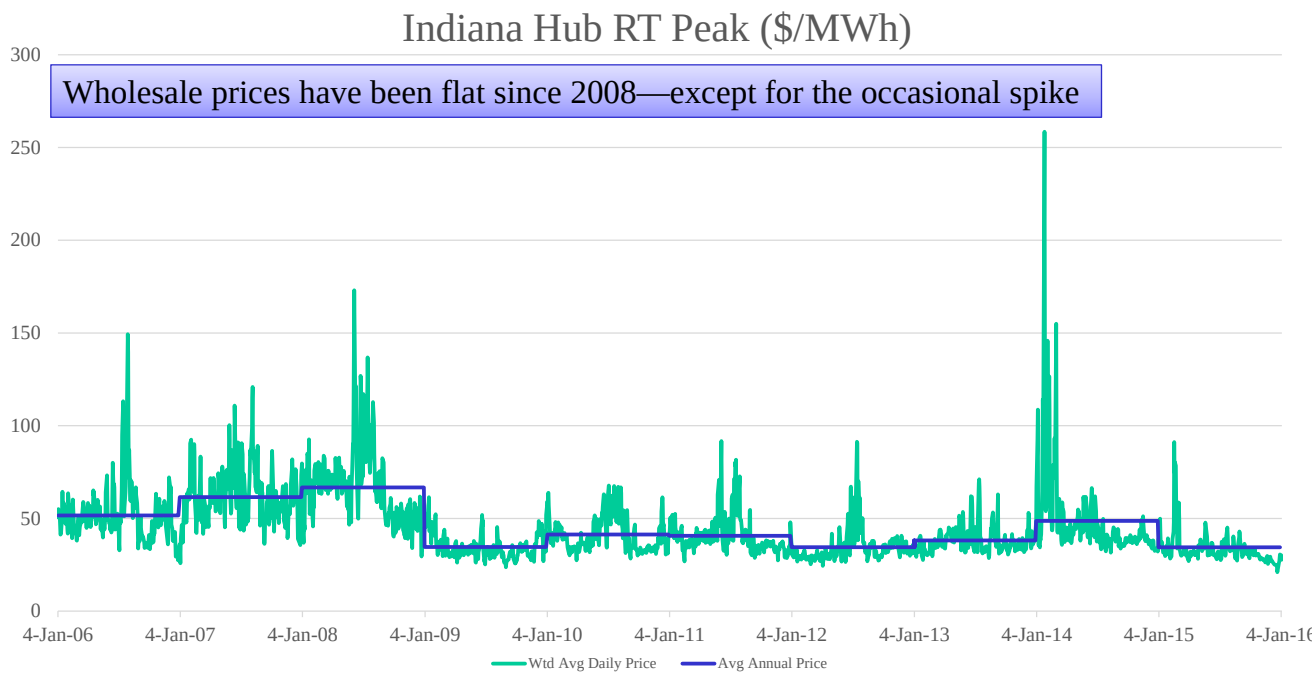
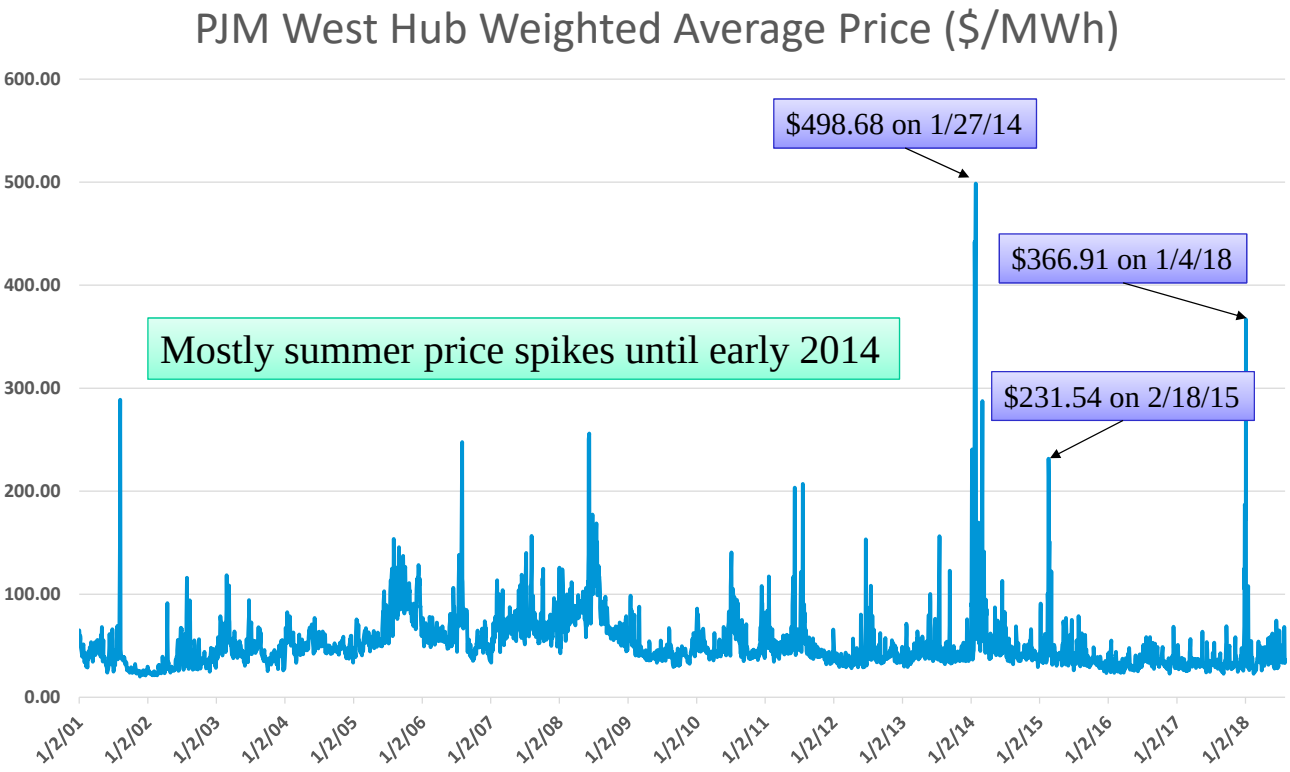
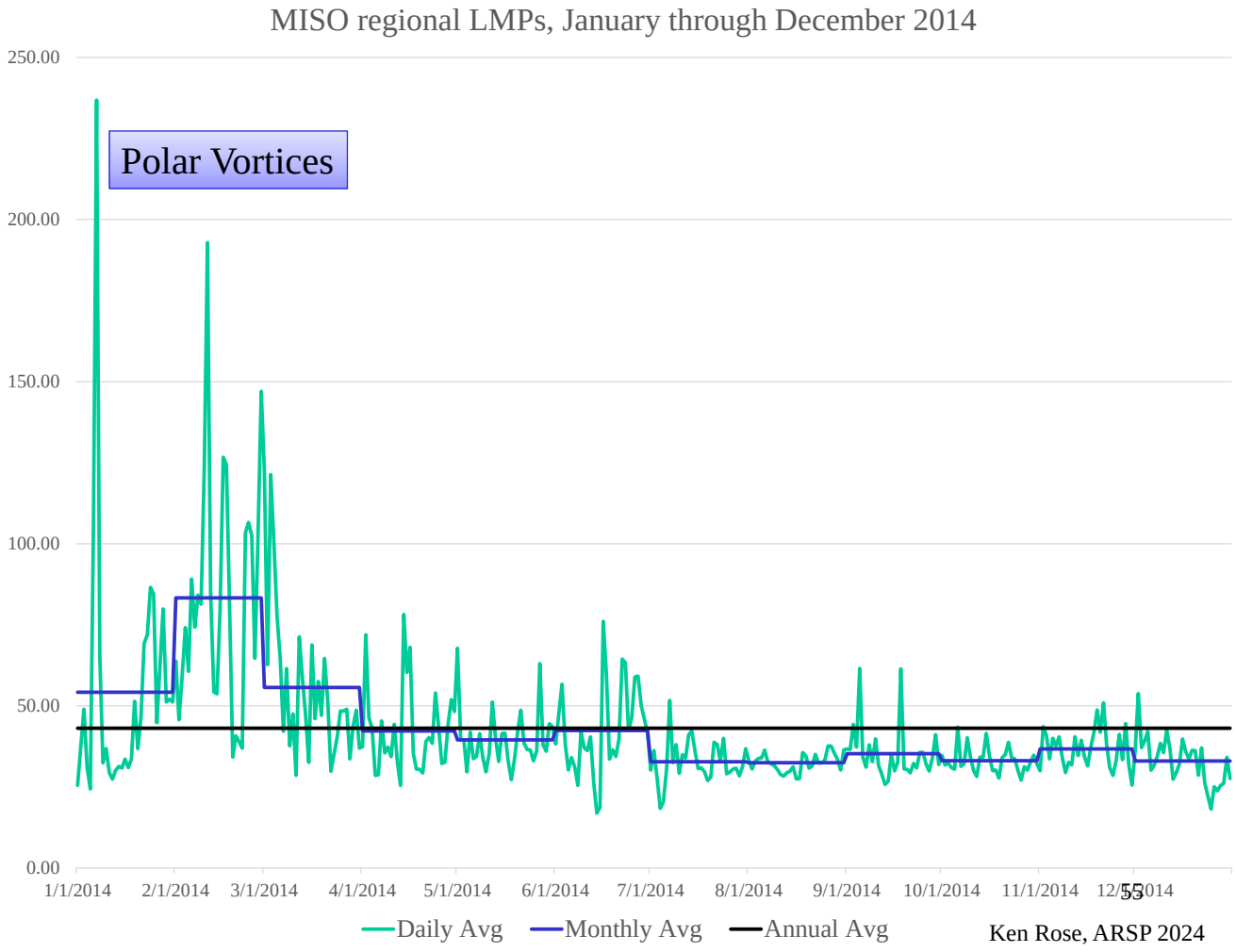
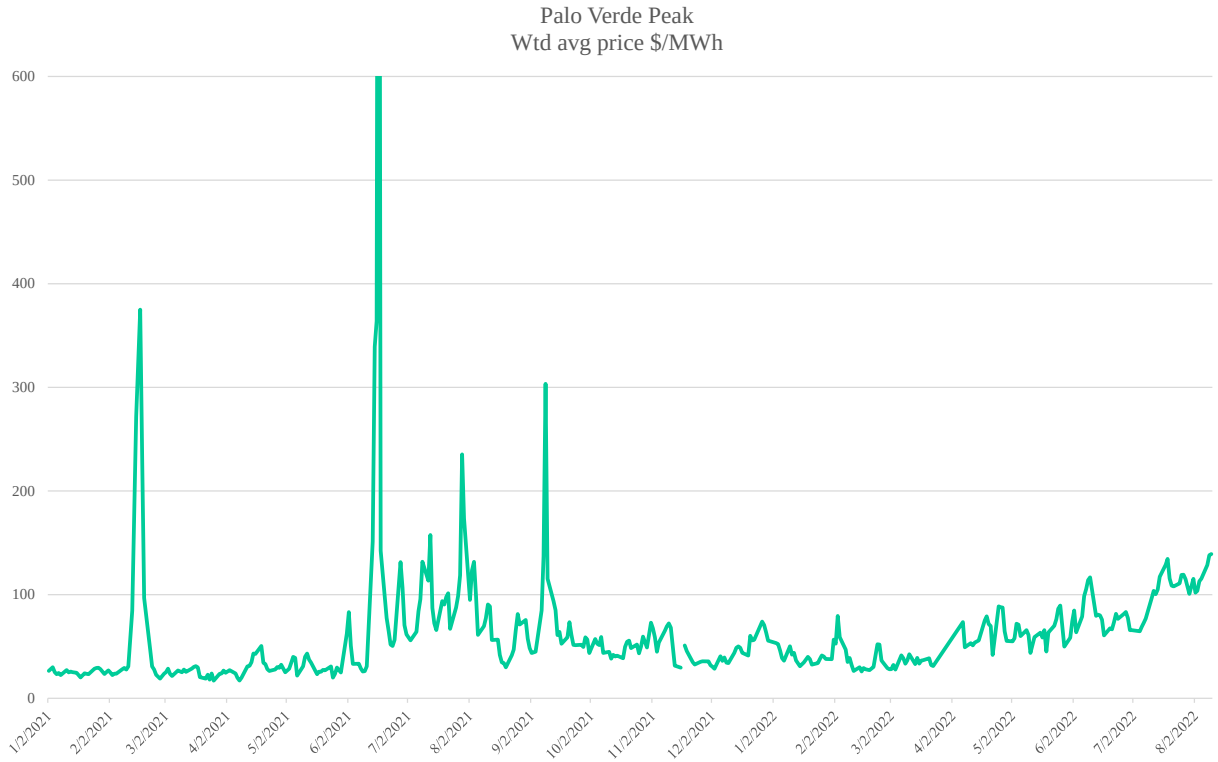


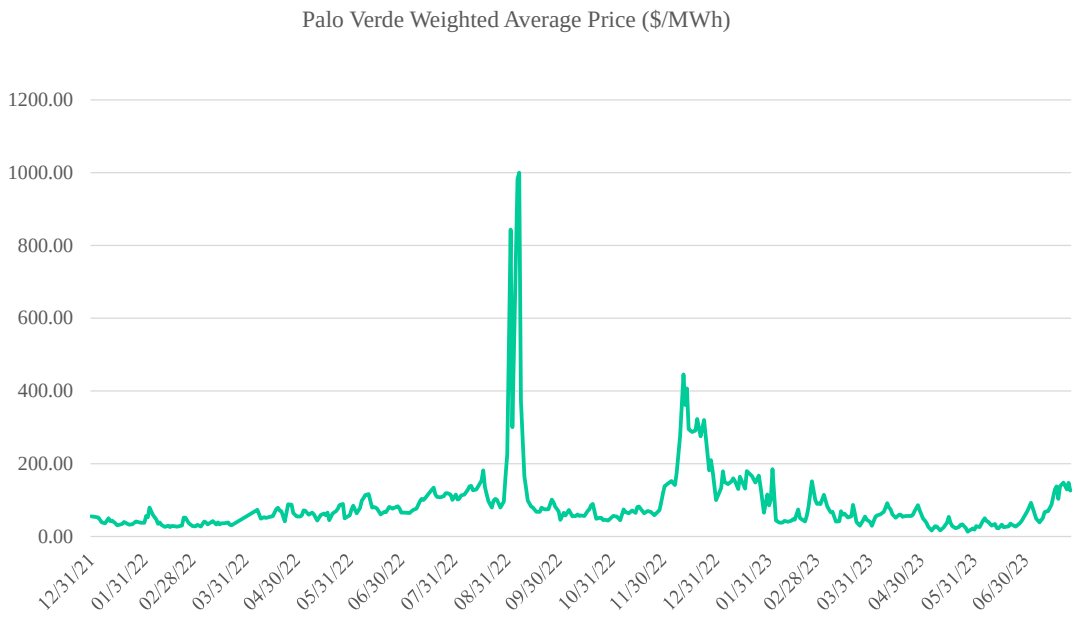
Data Source: Intercontinental Exchange (ICE), from EIA, Feb. 2016.





Ken Rose, ARSP 2024




Palo Verde Weighted Average Price ($/MWh)
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1000.00
800.00
600.00
400.00
200.00
0.00
12/31/21
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02/28/22
03/31/22
04/30/22
05/31/22
06/30/22
07/31/22
08/31/22
09/30/22
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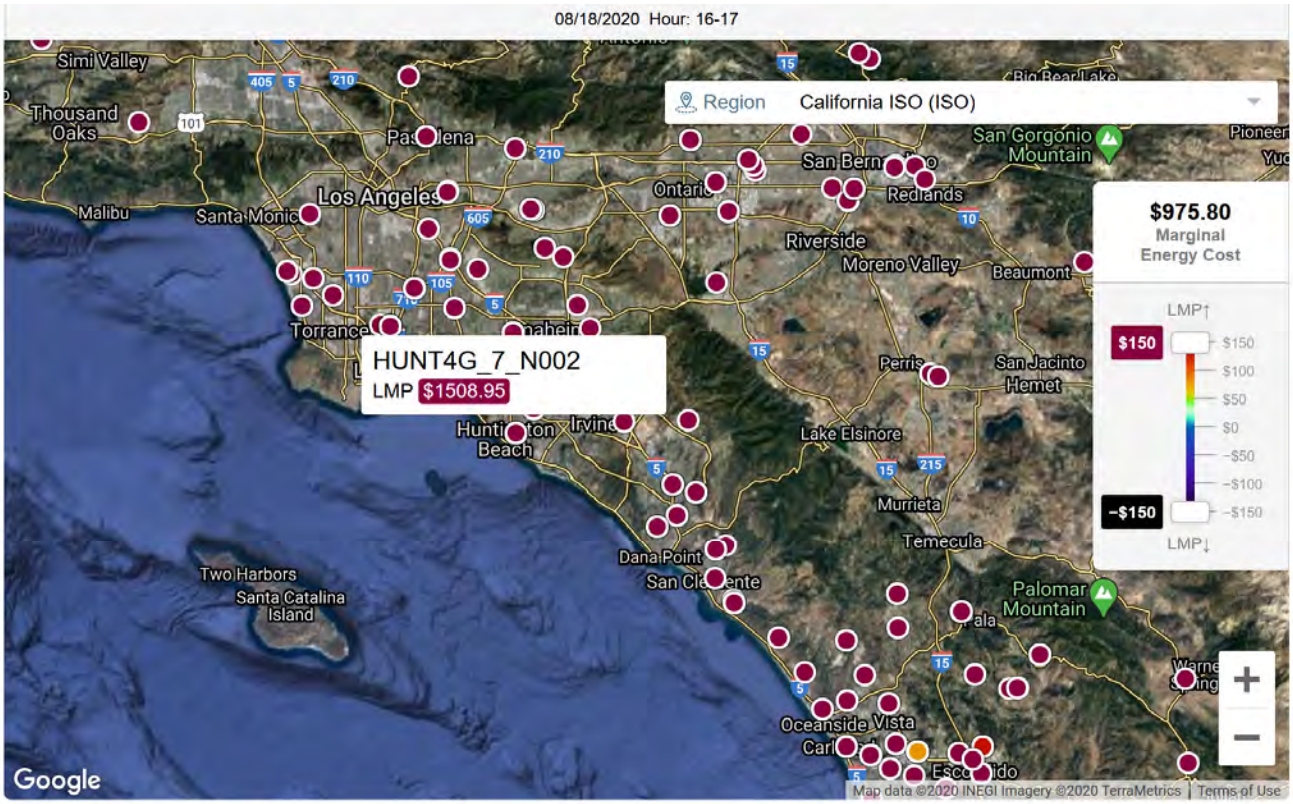
08/18/2020 Hour: 16-17
Region California ISO (ISO)
HUNT4G_7_N002
LMP $1508.95
$975.80
Marginal
Energy Cost
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$100
$50
$0
-$50
-$100
-$150
-$150
LMP↓
Simi Valley
Thousand Oaks
Malibu
Santa Monica
Los Angeles
Pasadena
Ontario
San Bernardino
Redlands
Riverside
Moreno Valley
Beaumont
San Gorgonio Mountain
Torrance
Perris
San Jacinto
Hemet
Lake Elsinore
Murrieta
Temecula
Dana Point
Two Harbors
Santa Catalina Island
Palomar Mountain
Oceanside
Vista
Google
Map data ©2020 INEGI Imagery ©2020 TerraMetrics | Terms of Use

August 2020

RTO capacity markets and reasons given for creating them

- Four RTOs--PJM, ISO New England, New York ISO, Midcontinent ISO (new name, still MISO) have developed "locational" (or sub-regional) capacity markets
- These are intended to encourage building new capacity, retaining existing capacity, and permit other resources, such as demand-response programs, to also participate in the market
- Argument for creating a capacity market is that energy and ancillary services markets do not provide sufficient revenues to recover the power suppliers' fixed costs

Reasons given for creating RTO capacity markets *(continued)*

- For example, a supplier that operates a "peaking" facility that runs only a small percentage of the year may not expect to recover its investment within a reasonable time to make the investment worthwhile
- Capacity markets are intended to provide that revenue by creating an additional market mechanism
- Also, for RTO system reliability sufficient reserve margin is needed beyond what is necessary most hours of the year – same as with utility resource planning, but now with "market based" procurement of capacity

Capacity Market Basic Elements

- RTOs, including New York ISO, ISO New England, and PJM, have developed capacity obligation and resource procuring mechanisms
- They include similar basic elements:

1) an obligation on those responsible for serving end-use customers (load) to have sufficient capacity to reliability serve that load;

2) a methodology to determine a capacity reserve margin and future capacity needs for sub-regions within the RTO and for the entire RTO;

Capacity Market Basic Elements *(continued)*

3) a process for soliciting qualified supply (and demand) resources to meet future capacity needs (for constructing an offer or supply curve);

4) some type of benchmark to judge the cost of new capacity;

5) a methodology or approach for setting a limit on the amount of capacity required or creating a "demand curve"; and

6) a process (such as an auction) to select resources and determine a capacity "price"

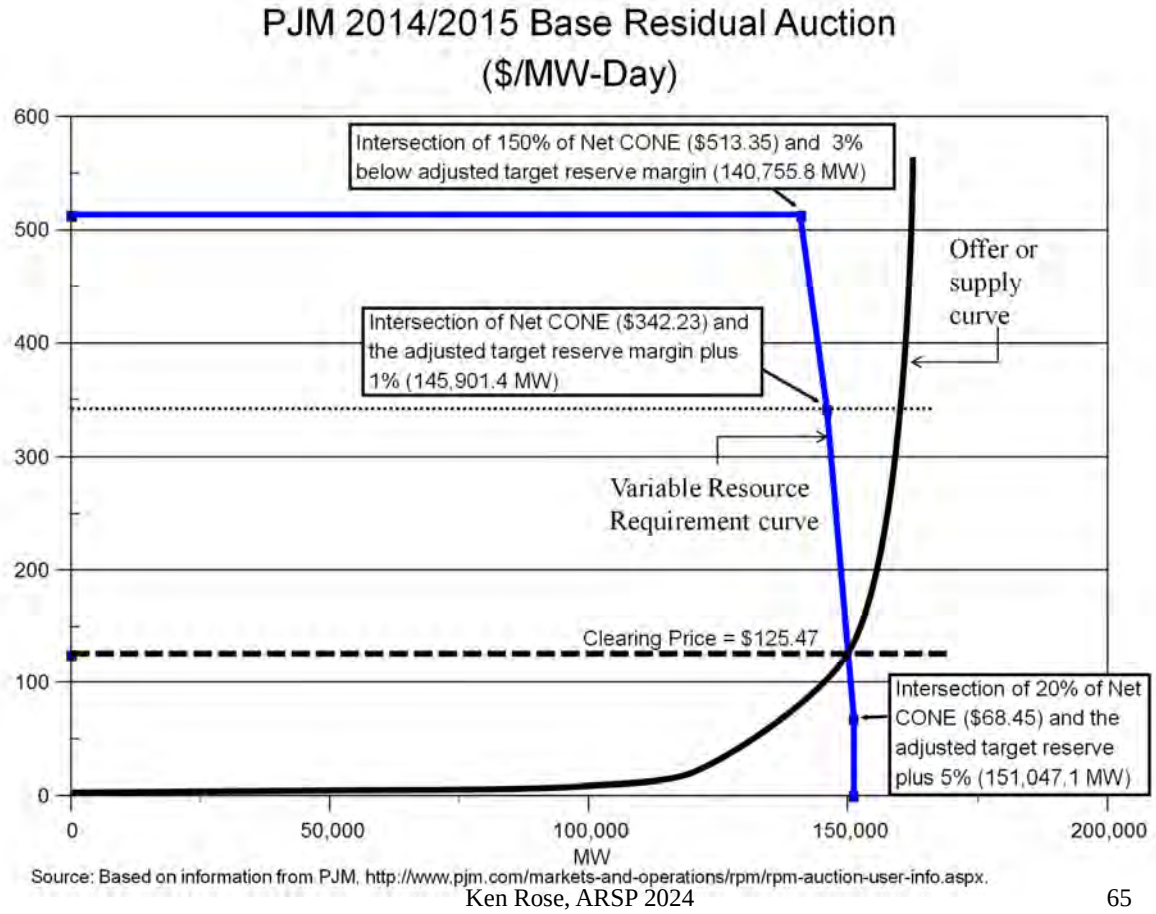
Capacity Market Example

- PJM's Reliability Pricing Model (RPM)
  - replaced the Capacity Credit Market ("CCM")
  - RPM uses locational capacity pricing
  - auctions (began April 2007) where capacity prices are determined with offer-based supply curves cleared against downward-sloping "demand curves"

PJM's RPM*

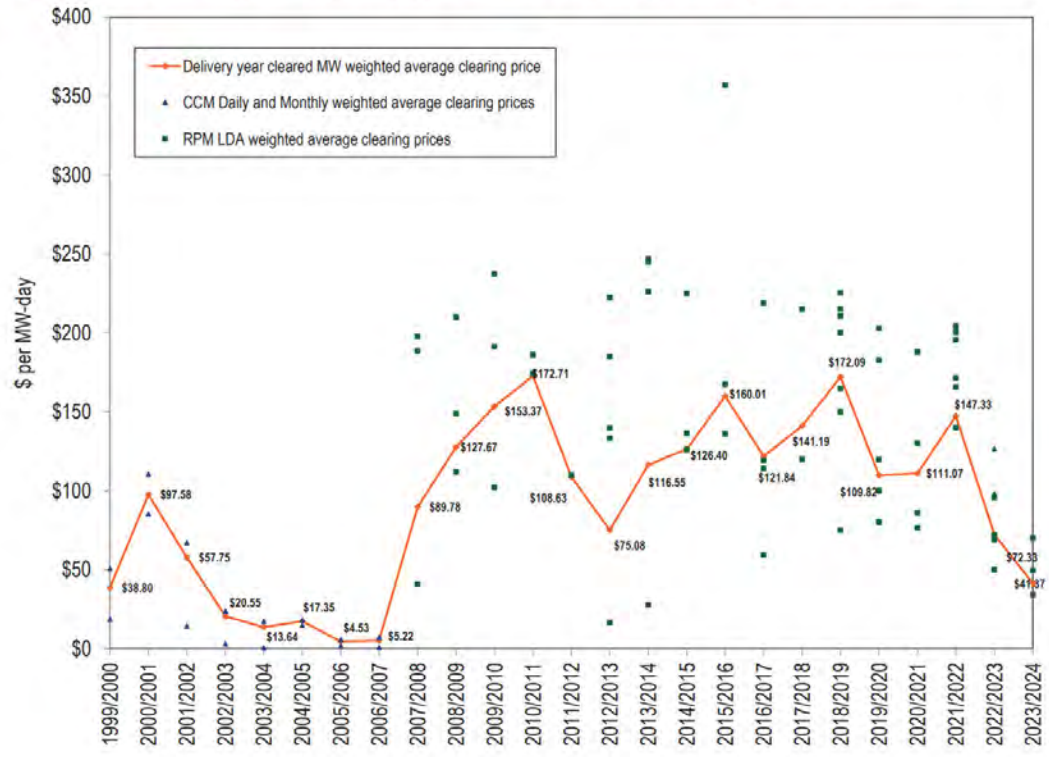
- LSEs can "self-supply" resources to meet their capacity obligations by designating resources they own or purchase bilaterally (must be offered in base auctions)
- "Fixed Resource Requirement" (FRR) allows LSEs to opt out of RPM and meet a fixed capacity obligation
  - LSEs are subject to qualification requirements and face a number of capacity restrictions
- The market clearing price is paid to all capacity committed in an auction
  - these payments can be offset by performance-based penalties

*See details in Brattle Group report on PJM's web site: Pfeifenberger, et al., "Review of PJM's Reliability Pricing Model (RPM)," The Brattle Group, June 30, 2008.



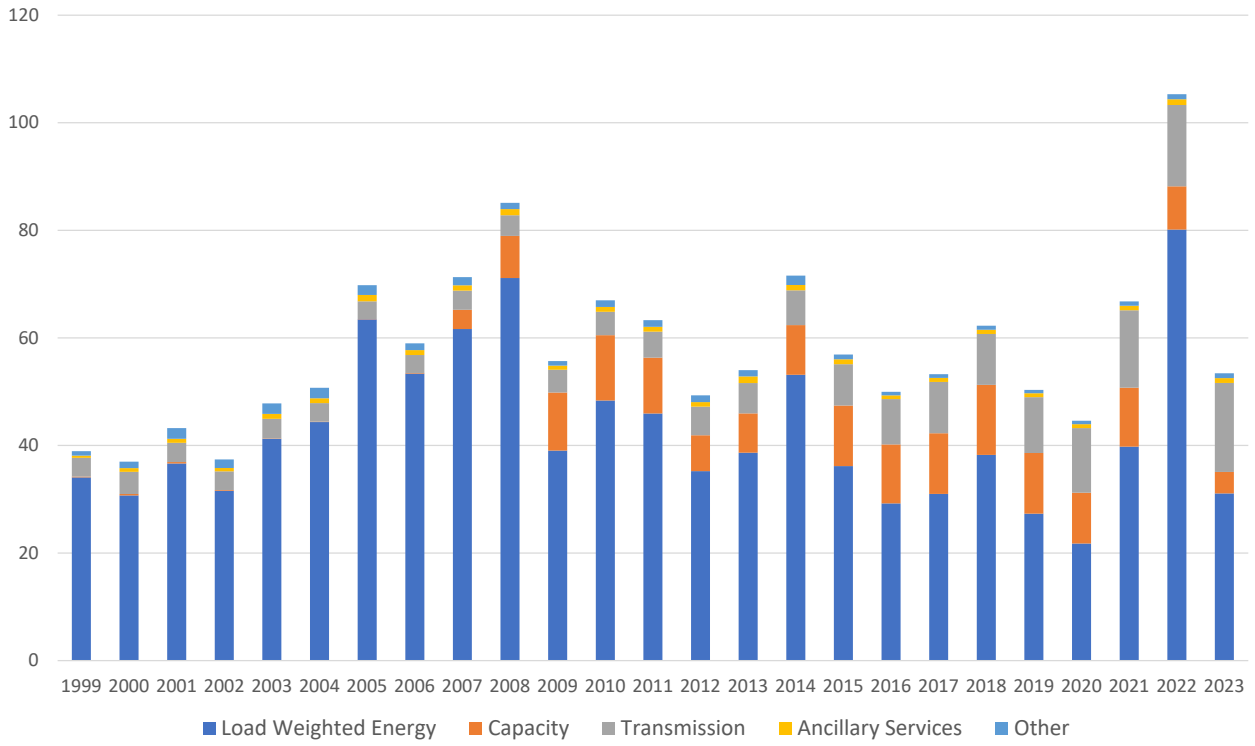
Source: Based on information from PJM, http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx.

Figure 5-5 History of capacity prices: 1999/2000 through 2023/2024[125]



Source: Monitoring Analytics, LLC, 2022, 2022 Quarterly State of the Market Report for PJM: January through June (monitoringanalytics.com)

Total price per MWh by category, 1999 through 2023 ($/MWh)



Data Source: Monitoring Analytics, LLC, 2019 State of the Market Report for PJM.

Table 2. RPM Base Residual Auction Resource Clearing Price Results in the RTO

Delivery Year	Auction Results				
	Resource Clearing Price	Cleared UCAP (MW)	RPM Reserve Margin	Total Reserve Margin[1]	Total Cost to Load ($ billion)
2015/16[2]	$136.00	164,561.2	19.7%	19.3%	$9.7
2016/17[3]	$59.37	169,159.7	20.7%	20.3%	$5.5
2017/18	$120.00	167,003.7	20.1%	19.7%	$7.5
2018/19	$164.77	166,836.9	20.2%	19.8%	$10.9
2019/20	$100.00	167,305.9	22.9%	22.4%	$7.0
2020/21[4]	$76.53	165,109.2	23.9%	23.3%	$7.0
2021/22	$140.00	163,627.3	22.0%	21.5%	$9.3
2022/23	$50.00	144,477.3	21.1%	19.9%	$3.9
2023/24	$34.13	144,870.6	21.6%	20.3%	$2.2
2024/25	$28.92	147,478.9	21.7%	20.4%	$2.2
2025/26[5]	$269.92	135,684.0	18.6%	18.5%	$14.7

[1] Reserve Margin includes FRR+RPM (Total ICAP/Total Peak-1; [2] 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative; [3] 2016/2017 BRA includes EKPC zone;
[4] Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance zone included in RPM

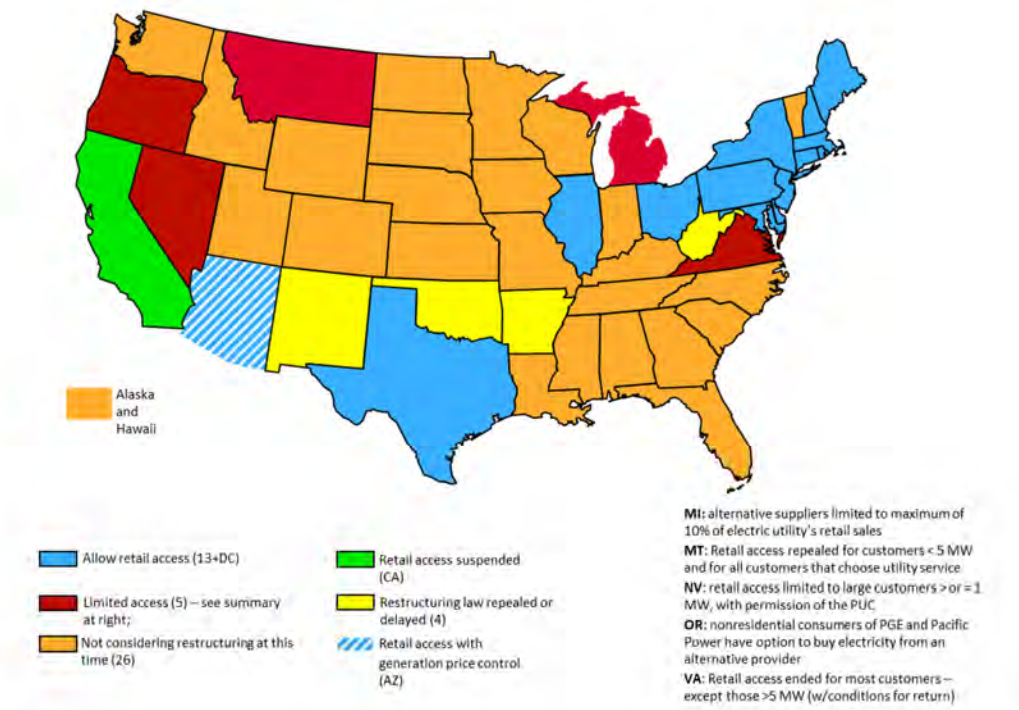
Table 3. Offered and Cleared MWs and Associated Prices by LDA

LDA	MW (UCAP)		System Marginal Price	Locational Price Adder***	RCP for Capacity Performance Resources
	Offered MW*	Cleared MW**			
ATSI	7,791.9	7,764.9	$269.92	$0.00	$269.92
ATSI-CLEVELAND	1,615.5	1,614.0	$269.92	$0.00	$269.92
COMED	22,524.4	21,813.9	$269.92	$0.00	$269.92
DAY	493.1	488.6	$269.92	$0.00	$269.92
DEOK	1,639.5	1,633.8	$269.92	$0.00	$269.92
DOM	20,100.2	20,003.4	$269.92	$174.34	$444.26
MAAC	51,530.7	51,316.9	$269.92	$0.00	$269.92
PPL	8,785.1	8,783.0	$269.92	$0.00	$269.92
EMAAC	24,479.3	24,380.4	$269.92	$0.00	$269.92
DPL-SOUTH	960.4	956.9	$269.92	$0.00	$269.92
PSEG	4,446.7	4,390.3	$269.92	$0.00	$269.92
PS-NORTH	2,536.6	2,507.4	$269.92	$0.00	$269.92
SWMAAC	5,089.1	5,060.8	$269.92	$0.00	$269.92
BGE	612.9	606.9	$269.92	$196.43	$466.35
PEPCO	2,285.5	2,263.2	$269.92	$0.00	$269.92
RTO	**137,153.4**	**135,684.0**	**$269.92**	**$0.00**	**$269.92**

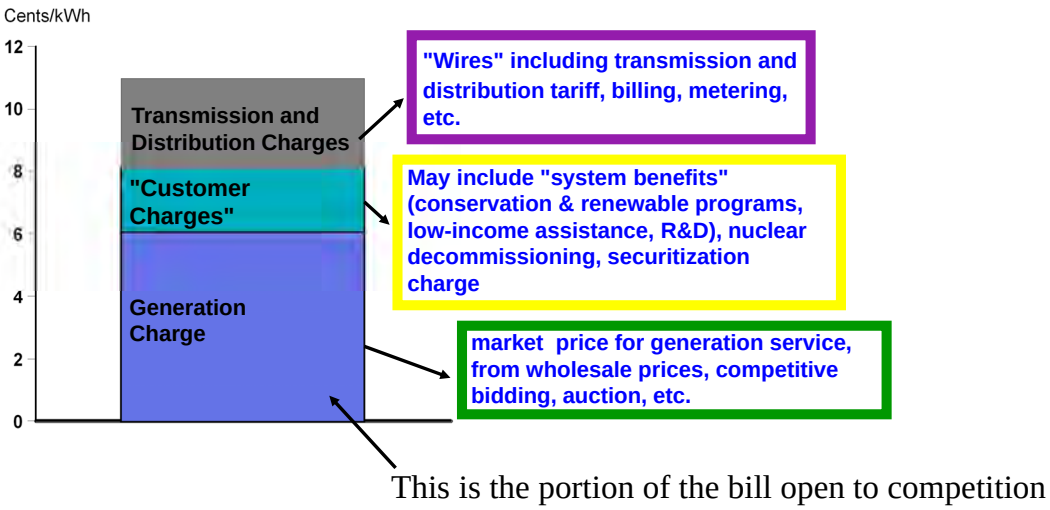
* Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.
** Cleared MW values include Annual and matched Seasonal Capacity Performance sell offers within the LDA.
*** Locational Price Adder is with respect to the immediate parent LDA

Source: PJM, 2025/2026 Base Residual Auction Report, July 30, 2024.

Status of State Restructuring

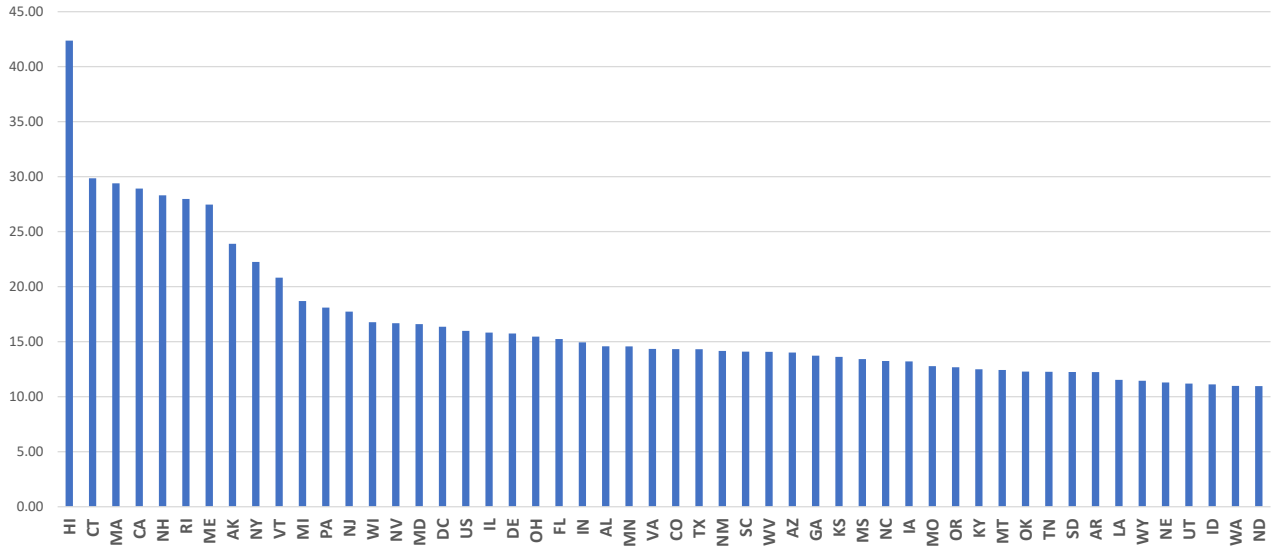


Unbundled Cost Components of a Retail Customer's Price

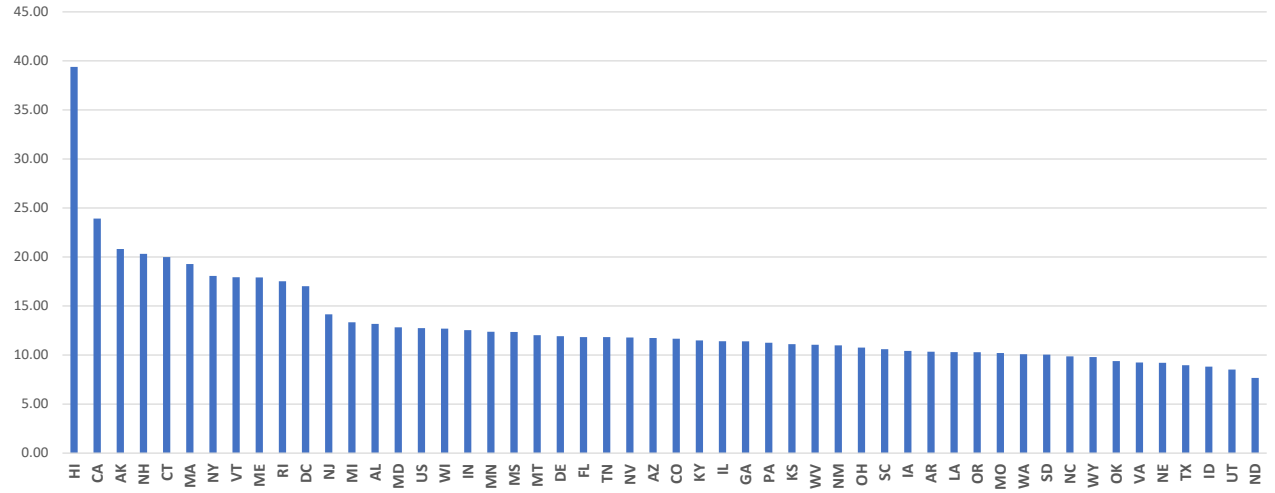


This is the portion of the bill open to competition

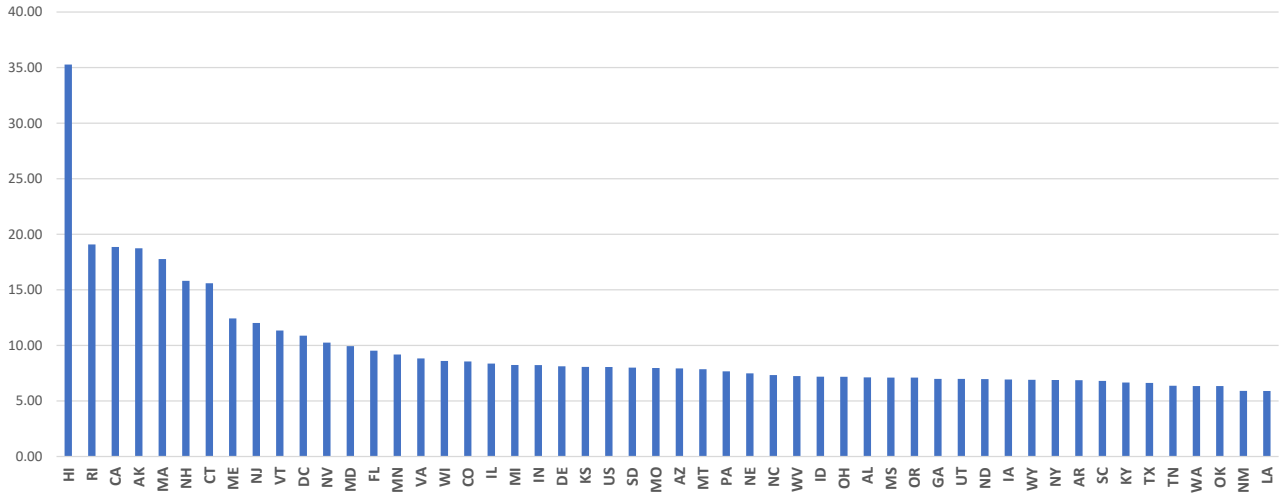
State rank by cents/kWh, 2023
Residential



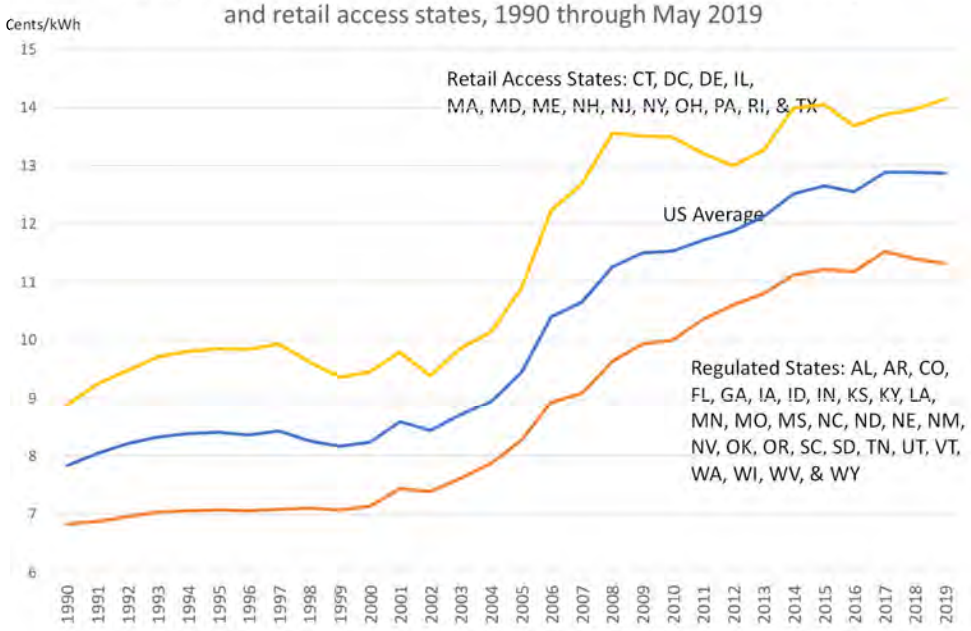
State rank by cents/kWh, 2023
Commercial



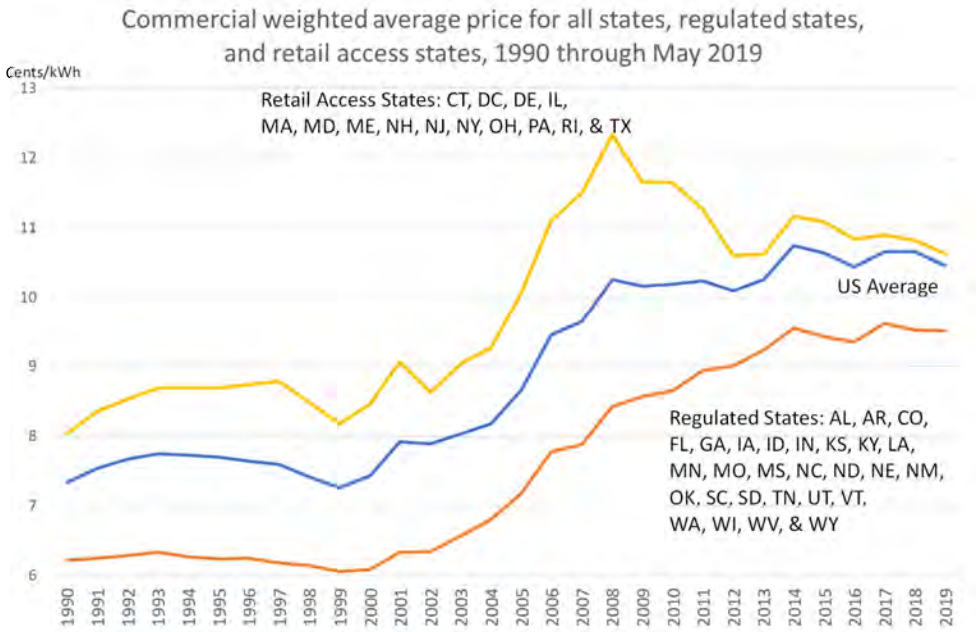
State rank by cents/kWh, 2023
Industrial



Residential weighted average price for all states, regulated states, and retail access states, 1990 through May 2019



Data Source: DOE/EIA.



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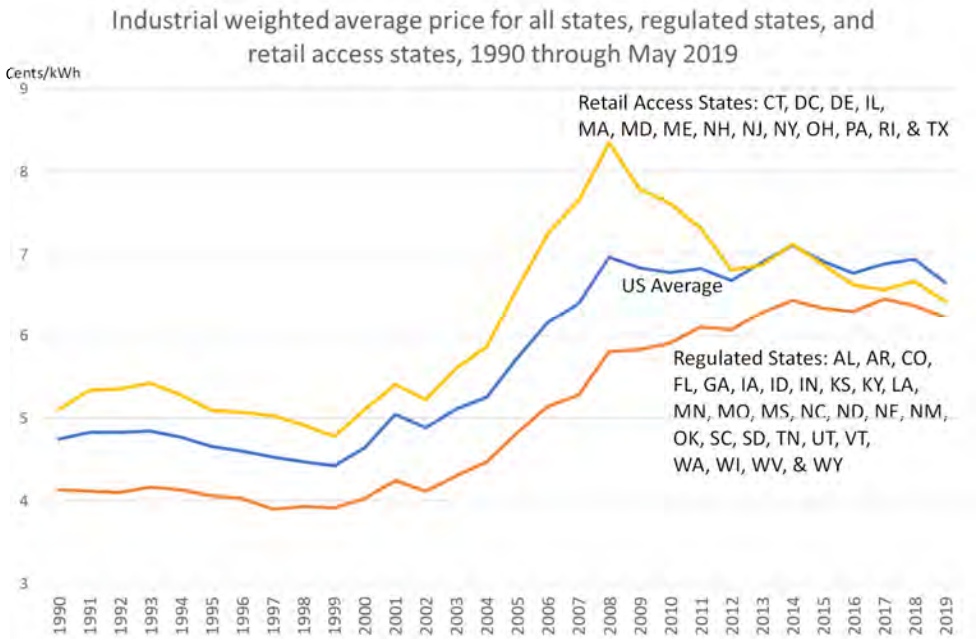

Data Source: DOE/EIA.

Paper on Retail Market Restructuring

"Retail Electricity Market Restructuring and Retail Rates," The Energy Journal, Volume 45, Number 1, ISSN 0195-6574 (Print), ISSN 1944-9089 (Online).

By Kenneth Rose (DePaul University), Brittany Tarufelli (Pacific Northwest National Lab), and Gregory Upton (Louisiana State University)

Link to download the paper:

https://www.iaee.org/energyjournal/article/4100

Working Paper Approach

- From 1996 through 2000, some states passed retail electricity market "restructuring" that, over time, required utilities to separate the generation portion of their operations and allowed customers to purchase power from third party providers. (aka "retail choice," "customer choice," or "retail access")
- Paper examines the effect of restructuring on electricity prices for retail consumers; and test the supposition (or hope) that retail choice would benefit customers
- Used "synthetic control analysis" that compared electricity rates in restructured states relative to non-restructured states with similar economic and political characteristics
- Comparison of these two approaches provides insight into whether non-random policy adoption is important in interpreting results
- Also considered the timing of restructuring, e.g., for each customer class, the date that retail restructuring began, timing of its phase-in, and when full retail market access was available

Restructuring Dates

Table 1: Restructuring Definition

State	Restructuring Transition Begins	Full Retail Market Access Begins
CT	2000	2007
DE	1999	2006
DC	2001	2005
IL	1999	2007
ME	2000	2000
MD	2002	2008
MA	1998	2005
NH	2001	2006
NJ	1999	2004
NY	1998	2011
OH	2001	2011
PA	1999	2012
RI	1997	2008
TX	2002	2007

Notes: The treatment year indicates the date at which a competitive retail market was opened for at least some customers. Full Retail market access begins indicates the year in all customers were subject to market pricing. Our preferred definition excludes reversed restructuring states, including AZ and CA, and hybrid restructuring states, including MI, MT, NV, OR, and VA. For full details on restructuring definitions, see Appendix Table A1.

Data Used in Working Paper

- Data from U.S. Energy Information Administration (EIA)
- Panel of 41 continental states plus Washington, DC from 1990 to 2018
- Variables include state-level average electricity prices by customer type including residential, commercial, and industrial customers
- "Synthetic control groups" are constructed using data on the number of members of state house and senate by political party, the political party of the governor, gross state product, mining and manufacturing gross state product, and the share of industrial and commercial customers
- State-level renewable energy generation and gasoline consumption are used as outcome variables in falsification tests
- State-level population is used to normalize many of these variables for appropriate cross-state comparisons

Some National Price Trends

- Generally, all regions of the country are seeing higher prices since early 2000s (increasing roughly at the rate of inflation since 2000)
- Wholesale prices have fallen since 2008, and been roughly steady since (except a spike now and then, such as 2022)
- Restructured state prices increased rapidly from 2002 until 2008, then leveled off, and increased again for residential customers
- For states that still regulate, prices have leveled off, and are still below states that restructured
- Can discern no clear and consistent pattern of benefit to all consumers from retail access at this time *just looking at the price trends*

Working Paper Results

- The hope, back when original restructuring laws were passed, was that it would reduce rates for retail customers
- However, the analysis found that rates increased in restructured states relative to plausible counterfactuals in the years post-restructuring.
  - But, by twelve years after restructuring, we no longer observe any difference.
- We do not find evidence that restructuring has impacted relative rates between customer classes after full implementation.
- We investigate plausible mechanisms, finding evidence that retail prices became more responsive to natural gas price due to restructuring which timing coincided with increases in natural gas prices nationally.