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Energy Affordability in the DMV

COG Built Environment and Energy Advisory Committee Meeting 04/16/2026

Romita Biswas - Technical Lead & Advisor

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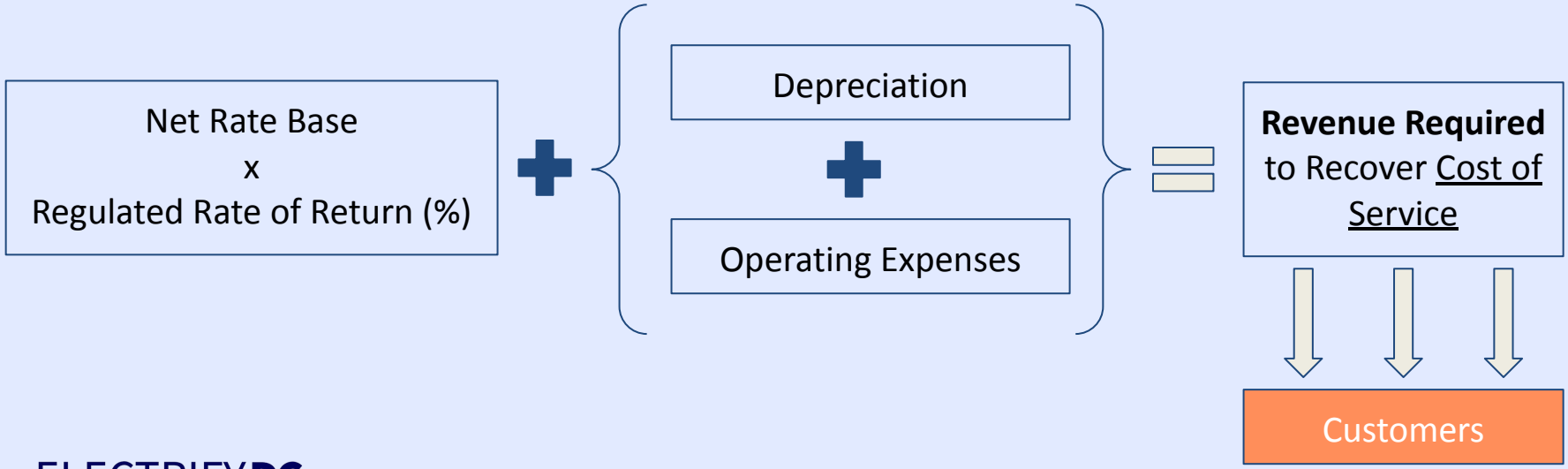
DISTRICT SUSTAINABILITY AWARD WINNER Electrify DC 2025

Utility Revenue Certainty

- Cost of Service Recovery (**COSR**) Model - fundamental for utilities
  - Recover asset investments to provide service to customers and achieve fair return on investments



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Utility Revenue Certainty

- Net Rate Base x Rate of Return → directly regulated
  - CAPEX - Capital Expenditures allowed to receive Rate of Return or Equity (ROE)
  - Long term investments depreciate with time
    - Example: Poles, Wires, Transformers, Software Solutions (if multi-year system)
- Operational Expenses (OPEX) → pass-through costs to customer
  - Procuring energy in real time
  - Deviations in expected costs
  - Maintenance and operations

Costs to Customers

- Customers Bills **tend** to made up of three components:
  - Fixed Charge - “subscription fee” to connect to the grid
    - Can rise with “peak power” needed
    - CAPEX
  - Volumetric Charge - varies with usage
    - Cost utility incurs to procure bulk power for their customers
    - OPEX
  - Taxes, fees, surcharges
- Benefits from “network effect” - more people, less burden per person

Costs to Customers

Current Electric Charges and Credits	
Residential (Schedule 1)	***02/12-03/12***
Distribution Service Charges	**21.41**
Electricity Supply Service (ESS)	
Generation	20.94
Transmission	6.75
Fuel	9.32
Electricity Supply Charges	**37.01**
Deferred Fuel Cost Charge	0.91
Sales and Use Surcharge	0.29
State/Local Consumption Tax	0.49
Arlington County Utility Tax	3.00
Taxes, Fees and Charges	**4.69**
Current Electric Charges	**63.11**
Account Balance	**63.11**

CAPEX - utility assets cost of service

OPEX - procuring bulk power

Figure: Dominion Romita Customer Bill

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CAPEX vs OPEX

- CAPEX or “regulated” portion of bills tend to be smaller
  - Benefit from “network effect” - more customers means less burden per customer
    - Ex: $3 million / x customers → $ unit cost / customer
- OPEX or “partially unregulated” portion of bills are higher
  - Geographically tied
    - Rising with:
      - Energy Market Prices - Real time Locational Marginal Prices (LMP)
      - Capacity Market Prices - Long term cost of capacity in Locational Deliverability Area (LDA)
        - Contribution to 5 coincident peak events (5CP)
    - Stabilized with managed hedge portfolio and power purchase agreements (regulated)

OPEX - Energy Markets

- The price or LMP nodes across a region - vary with time (determined every 5 minutes - settled every 1 hour)
  - Supply and demand at each node
  - Generators get paid out LMP
- Load Serving Entities (LSEs) are subject to the temporal and geographical differences in procuring energy.
  - Serve energy across LMP nodes
  - Buy energy across LMP nodes and over a region larger than the one they serve
- Customers (unless exposed) do not experience the variances at each price node because of the aggregation across a region

OPEX - Energy LMPs

- Pricing at each node is determine by:
  - Congestion
    - More congestion → more demand → higher price
  - Transmission
    - Energy from further away costs more → delivery fee
      - (Market mechanism). No way to track electrons.
  - Marginal Price of Energy
    - Cost of the amount of power needed to meet the last amount of demand

- **If more fuel intensive electricity is procured from further away during high periods of demand, the price of electricity will be higher.**

OPEX - Capacity Market

- PJM wide capacity market used for long term pricing to pay generators to show up on peak demand days
- Market rule changes to measure effective capacity and reliability - Effective Load Carrying Capacity (ELCC)
- LDA specific clearing price - pocket of grid where enough capacity must be located locally because of grid constraints
  - Physical import limits into highly congested areas
- Cost of asking generators to show up passed down

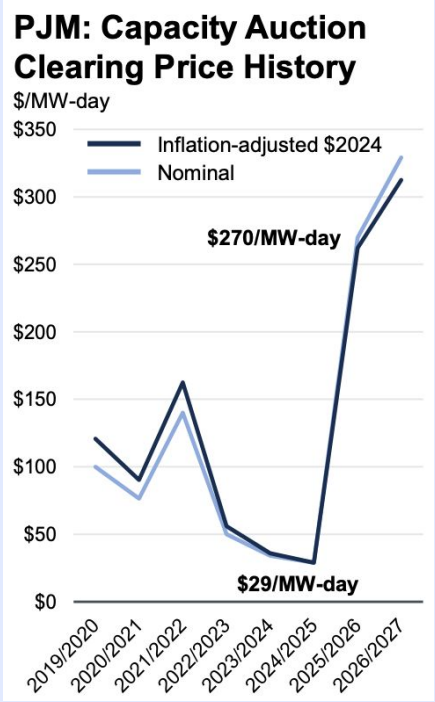

Figure: LBL Retail Price Drivers

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OPEX - Capacity Changes

- Capacity clearing price jumped due to **power plant retirements**, **large load growth**, and **modification** to Effective Load Carrying Capability (**ELCC**) rules
- Updated ELCC rules from averaging to marginal (all hours), devaluing existing assets resulting in sharp supply shortage
- Triggered Reliability Must Run (RMR) settlement agreements to facilitate retirement of old power plants
  - **Paid** through customer rates **outside** of **capacity markets** to continue operating past planned retirement

BGE LDA Costs	Annual Costs to BGE Customers
RMR Costs	$159 million
Capacity Market Costs *(Incremental)*	$504 million
Total Incremental Costs	$663 million

Figure: OPC Maryland RMR Impact

ELCC Rating 2024/2025→26

ELCC Class	2024/2025
Onshore Wind	21%
Offshore Wind	47%
Solar Fixed Panel	33%
Solar Tracking Panel	50%
4-hr Storage	92%
6-hr Storage	100%
8-hr Storage	100%
10-hr Storage	100%
Solar Hybrid Open Loop - Storage Component	75%
Solar Hybrid Closed Loop - Storage Component	68%
Hydro Intermittent	36%
Landfill Gas Intermittent	61%
Hydro with Non-Pumped Storage*	95%

Figure: ELCC 2024/2025

	2025/2026 BRA ELCC Class Ratings
Onshore Wind	35%
Offshore Wind	60%
Fixed-Tilt Solar	9%
Tracking Solar	14%
Landfill Intermittent	54%
Hydro Intermittent	37%
4-hr Storage	59%
6-hr Storage	67%
8-hr Storage	68%
10-hr Storage	78%
Demand Resource	76%
Nuclear	95%
Coal	84%
Gas Combined Cycle	79%
Gas Combustion Turbine	62%
Gas Combustion Turbine Dual Fuel	79%
Diesel Utility	92%
Steam	75%

Figure: ELCC 2025/2026

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ELCC Rating 2026/2027

- Further reduction in effective capacity expected
- Updated ratings are consistent with a greater share of winter risk
- ELCC ratings for 2026/2027 are lower for all sources except:
  - Onshore wind
  - Offshore wind
  - Hydro Intermittent
  - Nuclear

ELCC Class	2025/26 3IA Rating	2026/27 BRA Rating	Change (%)
Onshore Wind	38%	41%	+3
Offshore Wind	62%	69%	+7
Fixed-Tilt Solar	10%	8%	-2
Tracking Solar	14%	11%	-3
Intermittent Landfill Gas	51%	50%	-1
Intermittent Hydropower	37%	38%	+1
Capacity Storage Resource (4-Hour Duration)	55%	50%	-5
Capacity Storage Resource (6-Hour Duration)	65%	58%	-7
Capacity Storage Resource (8-Hour Duration)	68%	62%	-6
Capacity Storage Resource (10-Hour Duration)	77%	72%	-5
Demand Resource	77%	69%	-8
Nuclear	95%	95%	-
Coal	83%	83%	-
Gas Combined Cycle	78%	74%	-4
Gas Combustion Turbine	63%	60%	-3
Gas Combustion Turbine Dual Fuel	79%	78%	-1
Diesel Utility	92%	91%	-1
Steam	74%	73%	-1

Figure: ELCC Class Ratings Shift Towards More Winter Risk

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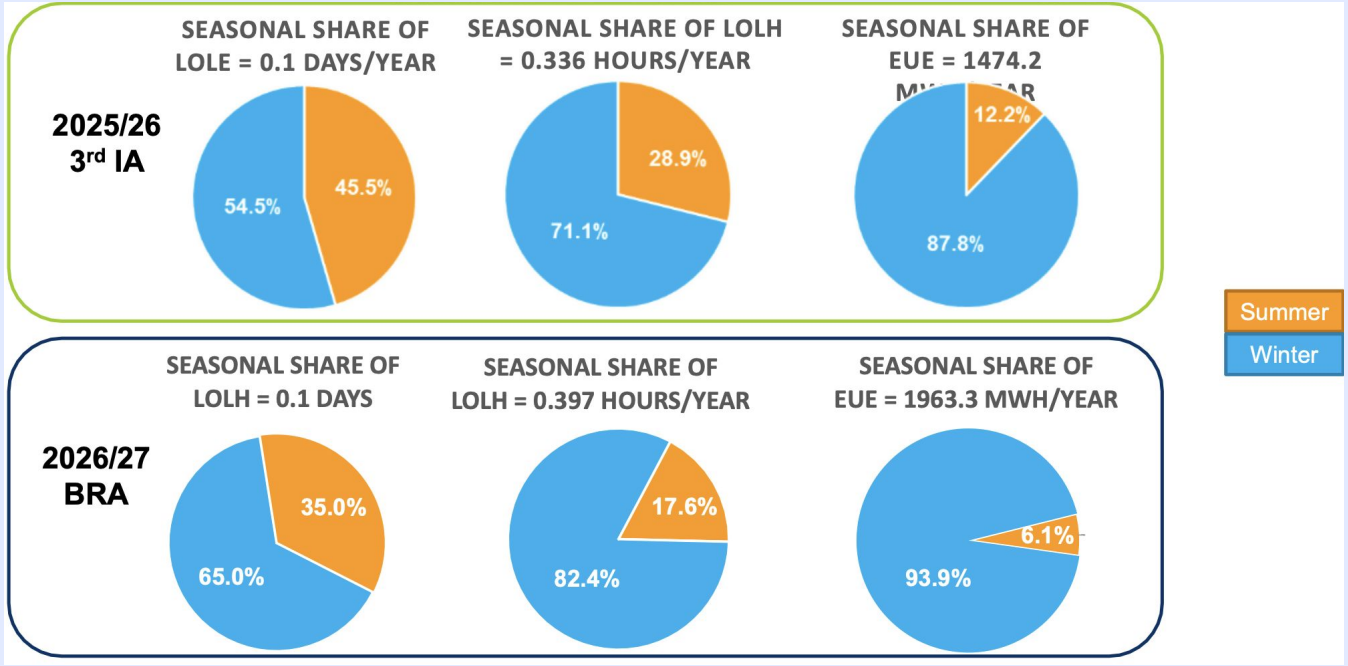
Seasonal Changes → ELCC Update



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2026/27 Capacity Auction hit Max

- New Price Limits Approved by FERC:
  - $329.17/MW-day (ceiling)
  - $177.24/MW-day (floor)

- PJM's forecasted peak load increased year over year by more than 5,400 MW, driven largely by **data center expansion**, electrification and economic growth.

- Some LDAs like DOM this is lower than 2025/26 ($432.48/MW-day)

Zone	Base Zonal UCAP Obligation	Preliminary Zonal Net Load Price	Final Zonal UCAP Obligation	Final Zonal Net Load Price
AE	2,160.0	$329.43	2,176.4	$329.08
AEP	12,278.4	$329.43	12,291.5	$329.08
APS	8,007.8	$329.43	8,030.0	$329.08
ATSI	11,437.6	$329.43	11,380.0	$329.08
BGE	5,784.6	$329.43	5,767.4	$329.08
COMED	17,602.8	$329.43	17,799.0	$329.08
DAYTON	2,888.2	$329.43	2,927.3	$329.08
DEOK	3,918.1	$329.43	3,919.3	$329.08
DLCO	2,399.7	$329.43	2,404.5	$329.08
DOM	22,133.2	$329.43	22,773.9	$329.08
DPL	3,437.1	$329.43	3,508.4	$329.08
EKPC	2,178.6	$329.43	2,210.1	$329.08
JCPL	5,257.7	$329.43	5,303.9	$329.08
METED	2,752.8	$329.43	2,687.2	$329.08
OVEC	54.9	$329.43	55.6	$329.08
PECO	7,482.6	$329.43	7,495.2	$329.08
PENLC	2,557.9	$329.43	2,485.1	$329.08
PEPCO	5,369.3	$329.43	5,355.8	$329.08
PL	7,004.2	$329.43	6,732.3	$329.08
PS	9,142.2	$329.43	8,831.8	$329.08
RECO	357.7	$329.43	355.9	$329.08

Figure: PJM 2026/27 3IA Report

Capacity Cost Share to Customers

How expensive is reliability and how does that cost get allocated to the customer?

- Capacity markets are focused on reliability and providing power during peak events.
- Each customer is responsible for requiring x amount of power during peak events.
  - Peak Load Contribution (PLC) assigned to each customer
  - Based on 5 coincident peak hours (5CP) of the year
  - Determined retroactively to be applied for current year
- Average share across the 5CPs is applied to the zone's weather-normalized RTO coincident peak to derive PLC
- **Each customer is allocated a portion of the capacity cost based on their usage during peak hours from the year before (depends on jurisdiction)**

Stabilizing Market Dynamics

- **Capacity** requirements of an LSE may be met through capacity actions or self-supply arrangements providing for long-term commitment of resources
  - Self-supply agreements like power purchase agreements are still subject ELCC class ratings from PJM

- Reduce PLC contribution during 5CP to reduce Capacity Clearing Price for LDA

- Financial Transmission Rights (FTR) Hedge Portfolio (regulated by PSC/PUC)
  - FTRs are contracts that hedge against congestion occurring - price difference between two LMP nodes
  - An FTR contract is purchased by a utility, so when LMP price differences arise they are paid out the difference - buffer against congestion

Reducing Customer Bills

- Increasing **supply** and reducing **demand** lowers the LDA capacity clearing price
- **Increasing** supply - shifting right
- **Reducing** demand - shifting left
- Same concept applies to **energy market clearing prices**

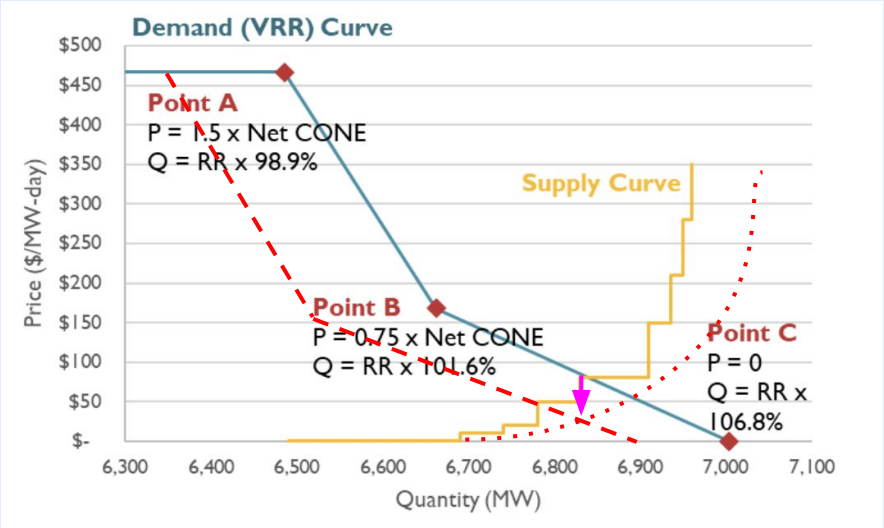

Figure: [Maryland OPC Bill Rate Impact]
Notes: the supply curve is for illustrative purposes only and is not based on real supply offers. VRR curve for Pepco LDA, 2025/2026.

Red lines are "modified" supply and demand curves to show lower clearing price.

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Options to Reduce Bills

- Issue: Increasing the registered or purchased supply within an LDA is resource intensive - time and capital
  - Decreasing ELCC ratings do not help with supply issues
    - Resources above 65% ELCC Rating: Offshore wind, **10 hour Storage, Demand Resource**, Nuclear, Coal, Gas combined cycle, Gas combustion turbine dual fuel, Diesel utility

- One good option is increasing **Demand Resource** or registered Demand Response
  - Not resource intensive - utility programs and curtailment service provider

- Reducing our Peak Load Contribution (PLC) during the Summer Peak Demand Events
  - Reduced load must be targeted at 5 Coincident Peaks (5CP)
    - Peak is determined at the end of the summer (forecasting required)
    - Benefit of “network effect” is felt in the following year

Essentially - Reduce Demand

- How much do we have to reduce demand for it to be meaningful in terms of $$?
- Look to each LDA's Variable Resource Requirement (VRR) Curve → demand curve used in capacity auctions
- Reduce during Peak Load Events in the Summer - demand reduction must be targeted
  - June 1 - Sep 30 (capacity)
  - 12 month period (transmission)

Example: DOM Region (LDA)

- Move down the curve from Point A to B through demand response:
  - 27,150⟶27,398 (≈248 MW)
  - 248/0.69 (ELCC) = 359.42 MW
- Specifically apply demand response during 5CP to prove DOM LDA has enough supply
- Impacts demand curve - proves we don't need as much capacity because our peak demand is lower

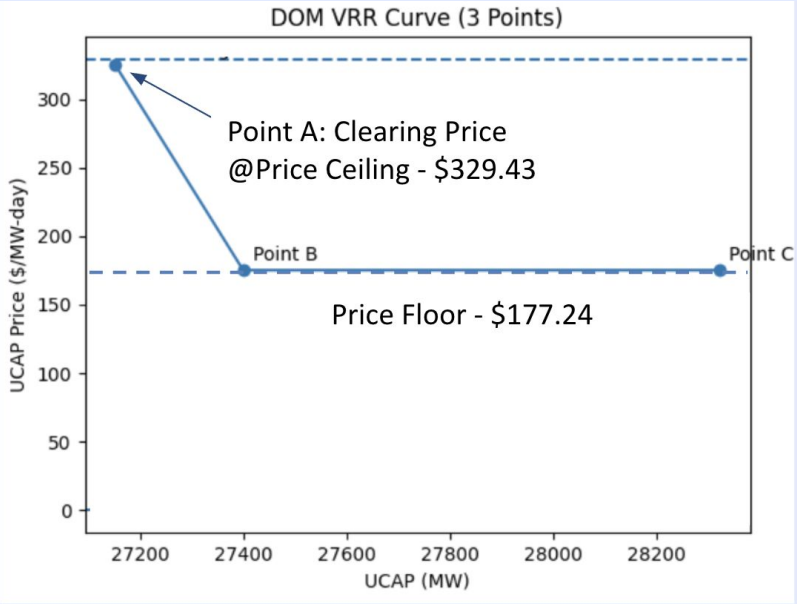

Figure: DOM VRR Curve from PJM 3IA Parameters

- *Supply curve confidential/must be generated through bidding offers of generators*
- *UCAP - Unforced Capacity is generated resources adjusted for forced capacity*

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Demand Response Programs

- Demand Response at the market level is simply reduction in demand through unregistered assets - **DERs on the Grid**
  - Not restricted to utility demand response programs like smart thermostat shifting
  - Battery shifting load - Copper oven, home plug in battery , EV charging
  - Local generation - rooftop solar and balcony solar
  - Any smart appliance that shifts power consumption
  - Ensuring demand response actually happens is KEY → must be financially binding
- Historically 5CP is when the sun is out → 3 pm and 6 pm
  - All DERs mentioned above can work at these times
  - If it's hot enough outside for peak load, sun's likely out - example balcony solar is likely generating

Does it really matter?

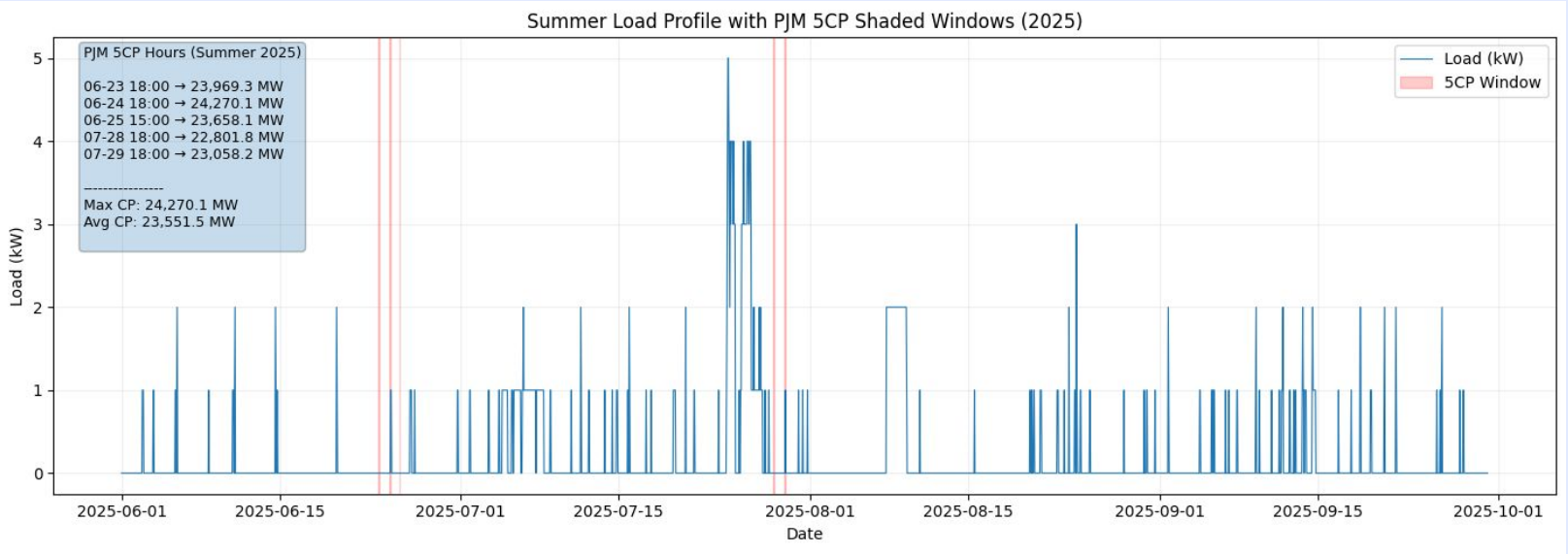
- A supply and demand curve shift will be enough to drive our clearing price down proving to PJM we don't require as much capacity for our LDA.

- Reducing targeted demand reduces capacity and transmission costs (long term). Reducing demand in real time reduces energy costs (real time).

- This summer 2026 if we are able to reduce our impact as an **LDA** during forecast peak demand we can have a lower capacity clearing price which can be propagated through lower retail rates (depends on jurisdiction and utility).
    - Goal: Be allocated a lower portion of the cost of capacity for 2027.

Green Button PLC Usage

- %PLC = (average of your load during peak hours) / (average system load during the same peak hours) ⟶ 2025 summer
- Annual Capacity Share = %PLC × Capacity Price ⟶ 2026 bill
- Flat retail rates ⟶ will still have some share for capacity related costs over the LDA



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Solutions

- Demand Response Programs should be **targeted based** on **LDA** not jurisdiction or utility.
  - **Utilities overlap within an LDA**. Coordinated response is difficult without some **cross-collaboration** amongst local governments.

- Demand response program benefits are poorly communicated and incentives are not clear to customers ($25 for a whole year - Dominion)
  - **Real incentive is less capacity costs for the next year**

- Harness "**Network Effect**" of Demand Response - a fundamental aspect of why utilities and COSR models historically work.
  - Targeted "network effect" to reduce capacity costs (LDA), energy costs (LMPs across LSEs) to reduce the clearing prices for multiple markets.

Appendix A

https://www.pjm.com/pjmfiles/directory/etariff/FercOrders/7145/20240130-er24-99-000.pdf

PJM explains that its proposed enhancements adopt a more temporally granular, hourly framework for assessing risk drivers and probabilities of resource and energy inadequacy throughout the year rather than only during periods associated with peak loads, as under PJM's current approach. PJM asserts that this new resource adequacy paradigm will allow PJM to identify the least-cost, efficient portfolio of resources that in aggregate provide resource and energy adequacy in every hour of the year, across all potentially anticipatable scenarios, up to the target reliability metric.

- *Number 16, 17*

FERC reasoning why approved: Specifically, we find that PJM's marginal ELCC framework is just and reasonable because it: (1) incorporates the risk of correlated outages, especially in cold weather conditions, of all supply-side resources, including thermal resources;84 (2) reflects the fact that dual fuel resources are more likely to be available than gas-only resources during certain system conditions; (3) accounts for the fact that highly correlated resources such as solar and short-duration storage resources generally provide less reliability value as more of those resources are added to the system; and (4) accredits all resources within an ELCC class with identical performance characteristics equivalently.

- *Number 42*

Appendix B.1

https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf

The PJM ELCC Model has the following objective – Accredit resources based on the expected performance during expected hours and days of risk during a future Delivery Year
To accomplish that, it is necessary to:

1. Identify the expected hours and days of risk given expected hourly patterns of supply and demand for a delivery year
2. Identify the expected marginal performance of resources during the hours and days identified in #1

Narrowing Gap: For the RTO, the gap between winter and summer peaks is narrowing.
Primary Reasons:

- Delivery Year: Runs from June to May.
- Data Centers: Rapid growth is causing more load in January than the preceding summer. (approximately 60%)
- Rooftop Solar: Growth in rooftop solar reduces summer peaks, but has minimal impact on winter peaks. (approximately 20%)
- Forecasted trends: Effects of electrification of heating on the system (heat pumps). (approximately 20%)

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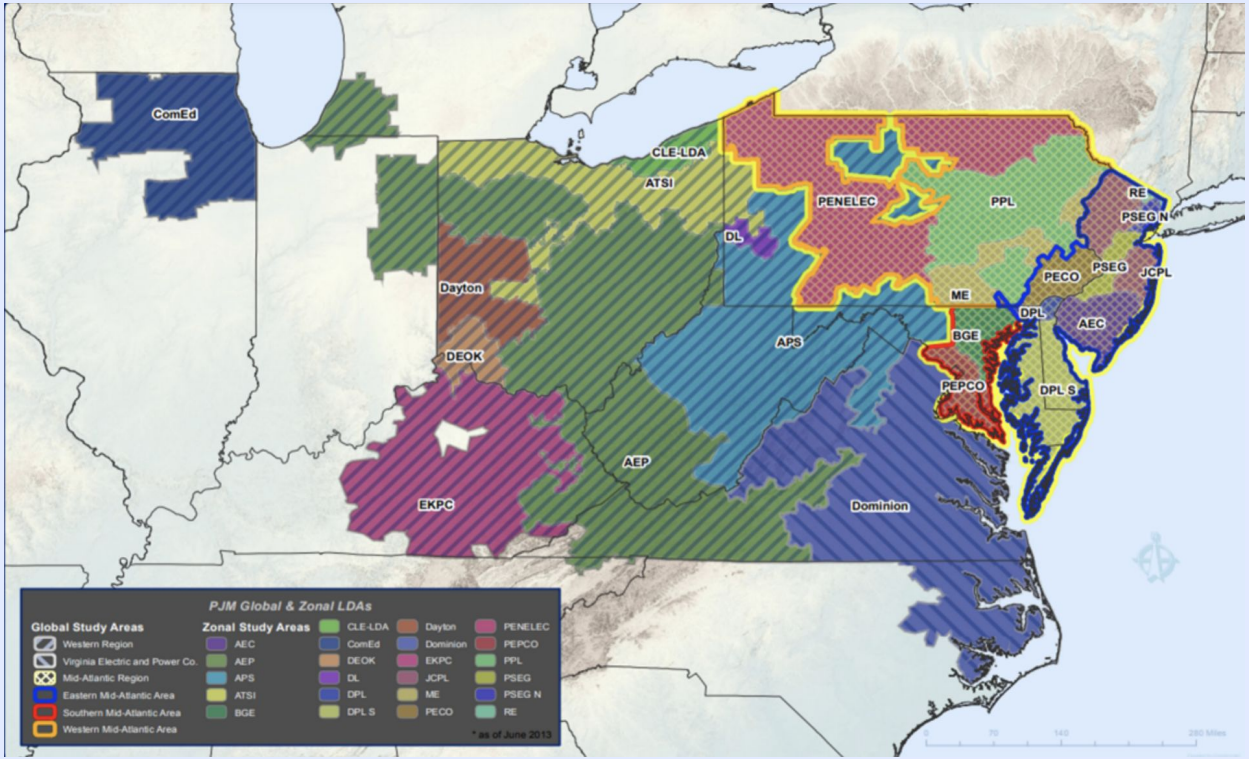
Appendix B.2

LDAs across PJM:

https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250402/20250402-item-09-1---external-resource-capacity-clearing---education.pdf



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Appendix C.1

https://supplier.bge.com/electric/load/plcs.asp

- After the end of a summer period, PJM will identify the five highest weather normalized PJM system coincident load hours that occurred on different days over the period from June 1 through September 30.
- For a given year, an account's daily network transmission service PLC requirement is based on its load at the time of the actual unrestricted peak hours that occurred during the twelve months ending October 31 of the prior calendar year.
- PJM and LSE will identify the five highest unrestricted load hours that occurred on different days during this 12-month period. The LDC will reconcile these five different hours back to the highest unrestricted peak load hour that PJM has determined to be BGE's zonal peak load obligation. The consequent peak load contributions will be calculated as an average over these five hours.
- On a daily basis, BGE calculates and reports to PJM the sum of the PLCs for each account served by the electricity supplier, known as the "Supplier PLC." BGE computes the electricity supplier PLCs after the close of each business day and submits them to PJM using PJM's eRPM system and published submission guidelines.
- The derivation of the peak load contributions consists of four steps:
    - Determine the unreconciled peak loads.
    - Reconcile the peak loads.
    - Derive each account's annual capacity and transmission peak load contribution.

Appendix C.2

https://supplier.bge.com/electric/load/plc-peak-hours.asp

- Capacity Peak Load Contribution from June 1 to September 30
- The local distribution company (LDC)-specific zones will identify the actual zonal loads associated with these five hours. Each LDC-specific zone will reconcile these five different hours back to the one-hour weather normalized, system coincident zonal peak load obligation. The consequent peak load contributions will be calculated as an average over these five hours. Each account's PLC will be updated on a yearly basis in accordance with PJM rules and procedures, with supporting data posted on BGE's Web site. The five days and "hour ending" times in 2024 and 2025 used to calculate the year 2025/2026 & 2026/2027 capacity CPLCs respectively, are as follows:

2024 Dates	Hour	2025 Dates	Hour
June 21	6 PM	June 23	6 PM
July 15	6 PM	June 24	6 PM
July 18	6 PM	June 25	3 PM
August 1	6 PM	July 28	6 PM
August 28	6 PM	July 29	6 PM

Appendix C.3

https://supplier.bge.com/electric/load/plc-peak-hours.asp

- Transmission Peak Load Contribution over 12 month period
- Each local distribution company within PJM has a network transmission service peak load contribution (TPLC) requirement. To allocate fairly the LDC's daily requirement to electricity suppliers, network TPLCs are determined. In accordance with the Open Access Transmission Tariff (OATT) and PJM rules and procedures, BGE will calculate a TPLC "ticket" for each electric account on an annual basis. For a given year, an account's daily network TPLC requirement is based on its load at the time of the actual unrestricted peak hours that occurred during the twelve months ending October 31 of the prior calendar year. At the end of this 12-month period, PJM and BGE will identify the five highest unrestricted load hours that occurred on different days during this 12-month period. The LDC will reconcile these five different hours back to the highest unrestricted peak load hour that PJM has determined to be BGE's zonal peak load obligation. The consequent peak load contributions will be calculated as an average over these five hours. The five days and "hour ending" times in 2025 used to calculate the year 2026 network TPLC respectively, are as follows:

2025 Dates	Hour
Jan 23	8 AM
June 23	7 PM
June 24	7 PM
July 25	6 PM
July 30	6 PM

Appendix C.4

https://supplier.bge.com/electric/load/plcs.asp

Examples of Peak Load Contribution Calculations

NON-INTERVAL CALCULATION									
CUSTOMER	PEAK DATE	PROFILE SEGMENT	PROFILE VALUE (A)	LOSS FACTOR (B)	USAGE FACTOR (C)	UNRECONCILED LOAD (D) (D = A * B * C)	SYSTEM LOAD (E)	SYSTEM SCALING FACTOR (G) (G = E / F)	HOURLY PLC (E) (E = D * G)
A	HOUR 1	R	2.5	1.06665	3.1061	8.283	1400	1.0051	8.325
B	HOUR 1	GL	89.5	1.06665	0.9088	86.759	1400	1.0051	87.202
INTERVAL CALCULATION									
CUSTOMER	PEAK DATE	PROFILE SEGMENT	INTERVAL VALUE (A)	LOSS FACTOR (B)	ALM ADDBACK (C)	UNRECONCILED LOAD (D) (D = [A+C] * C)	SYSTEM LOAD (E)	SYSTEM SCALING FACTOR (D)	HOURLY PLC (E) (E = D * G)
C	HOUR 1	N/A	1250.3	1.02473		1281.219919	1400	1.0051	1287.766
D	HOUR 1	N/A	12.4	1.06665	3.183	16.62160695	1400	1.0051	16.707
SUM UNRECONCILED LOAD (F) 1392.883									

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Appendix C.4

https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2025-peaks-and-5cps.pdf

PJM INTERCONNECTION

Summer 2025 - Coincident Peaks, By Zone (MW)

Date	6/23/2025	6/24/2025	7/29/2025	6/25/2025	7/28/2025
Hour End (EPT)	18:00	18:00	18:00	15:00	18:00
AE	2,527.7	2,624.3	2,598.6	2,394.1	2,439.8
AEP	23,293.9	23,492.1	22,558.0	22,700.9	22,280.2
APS	9,007.7	9,080.9	8,612.9	8,712.8	8,562.3
ATSI	12,631.1	12,819.9	12,114.7	12,262.6	11,702.7
BGE	6,587.7	6,452.6	6,291.4	6,121.2	6,141.6
COMED	20,714.0	18,822.0	19,779.4	16,837.6	19,538.1
DAYTON	3,317.0	3,379.5	3,311.3	3,300.7	3,095.1
DEOK	5,114.2	5,237.8	4,956.2	5,125.6	4,610.5
DLCo	2,694.5	2,737.1	2,573.0	2,645.9	2,607.4
DOM	23,969.3	24,270.1	23,058.2	23,658.1	22,801.8
DPL	4,189.8	4,235.4	4,077.4	4,071.6	3,914.0
EKPC	2,105.9	2,332.8	2,328.6	2,096.9	2,113.8
JCPL	6,093.7	6,285.1	6,083.3	5,760.8	5,702.5
METED	3,021.7	3,034.1	2,964.6	2,877.4	2,880.9
OVEC	57.0	78.0	53.0	62.0	42.0
PECO	8,297.2	8,475.2	8,255.2	8,231.6	7,751.1
PENLC	2,896.4	2,895.2	2,865.6	2,879.1	2,800.1
PEPCO	5,989.0	6,025.9	5,648.8	5,752.5	5,589.1
PL-EU	7,454.3	7,507.9	7,294.3	7,316.3	7,061.8
PS	10,060.9	10,210.6	9,987.3	9,497.5	9,311.3
RECO	415.6	415.1	410.0	393.9	372.6
UGI	210.6	217.1	212.8	204.4	206.0
PJM RTO	160,649.2	160,628.6	156,034.6	152,903.5	151,524.7

Appendix D

https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/gdecs/2025/20250930/20250930-item-03---pjm-market-rules-gdecs-revised-chart.pdf

Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13; provided, however: (i) the Daily Deficiency Rate under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 11A, and Tariff, Attachment DD, section 13 shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions); and (ii) the charges set forth in Tariff, Attachment DD, section 10A shall apply, only to those FRR Entities which opted to be subject to the Non-Performance Charge under section C.1 of this Schedule 8.1. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 7A, Tariff, Attachment DD, section 10A, and Tariff, Attachment DD, section 11A. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

Appendix E

https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-planning-period-parameters-for-base-residual-auction-pdf.pdf

For the 2026/2027 and 2027/2028 BRAs, as approved by FERC in Docket ER25-1357, a price cap and price floor have been established to the normal VRR Curve. For the RTO and each LDA, the cap has been set at $333.44/MW-day (UCAP) and the floor has been set at $179.55/MW-day (UCAP) for the 2027/2028 BRA. For comparison, the cap and floor prices for the 2026/2027 BRA were $329.17/MW-day (UCAP) and $177.24/MW-day (UCAP) respectively. The differences result from the change in the Reference Resource UCAP factor from 78% to 77%. As discussed in the Price Responsive Demand (PRD)section of this report, the VRR curve of the RTO and each affected LDA will be shifted leftward along the horizontal axis to reflect any PRD that has elected to participate in the 2027/2028 Delivery Year BRA.

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