

Disclaimer

S&P Global Energy ("SPGE") is a business division of S&P Global Inc. The reports, data, and information referenced in this document ("Deliverables") are the copyrighted property of SPGE and represent data, research, opinions, or viewpoints of SPGE. SPGE prepared the Deliverables using reasonable skill and care in accordance with normal industry practice. The Deliverables speak to the original publication date of the Deliverables. The information and opinions expressed in the Deliverables are subject to change without notice and SPGE has no duty or responsibility to update the Deliverables (unless SPGE has expressly agreed to update the Deliverables). Forecasts are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen including the actions of government, individuals, third parties and competitors. The Deliverables are from sources considered by SPGE (in its professional opinion) to be reliable, but SPGEI does not assume responsibility for the accuracy or completeness thereof, nor is their accuracy or completeness or the opinions and analyses based upon them warranted.

To the extent permitted by law, SPGE shall not be liable for any errors or omissions or any loss, damage, or expense incurred by reliance on the Deliverables or any statement contained therein, or resulting from any omission. THE DELIVERABLES ARE PROVIDED "AS IS" AND TO THE MAXIMUM EXTENT ALLOWED BY LAW, NEITHER SPGE, ITS AFFILIATES NOR ANY THIRD-PARTY PROVIDERS MAKES ANY REPRESENTATION, WARRANTY, CONDITION, OR UNDERTAKING, WHETHER EXPRESS, IMPLIED, STATUTORY OR OTHERWISE, RELATING TO THE DELIVERABLES OR THE RESULTS OBTAINED IN USING THEM; INCLUDING: A) THEIR MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE; OR B) THEIR CONTINUITY, ACCURACY, TIMELINESS OR COMPLETENESS. The Deliverables are supplied without obligation and on the understanding that any recipient who acts upon the Deliverables or otherwise changes its position in reliance thereon does so entirely at its own risk.

The Deliverables should not be construed as financial, investment, legal, or tax advice or any advice regarding any recipient's corporate or legal structure, assets or liabilities, financial capital or debt structure, current or potential credit rating or advice directed at improving any recipient's creditworthiness nor should they be regarded as an offer, recommendation, or as a solicitation of an offer to buy, sell or otherwise deal in any investment or securities or make any other investment decisions. The Deliverables should not be relied on by Client in making any investment or other decision and should not in any way serve as a substitute for other enquiries or procedures which may be appropriate. The Deliverables should not be used as the basis of or input for any ESG rating, score, opinion, or evaluation. The Deliverables should not be reproduced or made available to any other person without SPGE's prior written consent. Client may not use the Deliverables to transmit, undertake or encourage any unauthorised investment advice or financial promotions, or to generate any advice, recommendations, guidance, publications or alerts made available to its own customers or any other third-parties. Nothing in the Deliverables constitutes a solicitation by SPGE or its Affiliates of the purchase or sale of any loans, securities or investments. SPGE Personnel are not providing legal advice or acting in the capacity of lawyers under any jurisdiction in the performance of Services or delivery of Deliverables. SPGE is not a registered lobbyist and cannot advocate on anyone's behalf to government officials regarding specific policies. The Deliverables contain the results of SPGE's independent research and analysis and are intended for general informational purposes only. The Deliverables are not intended, and may not be used, to promote, directly or indirectly, the supply or use of any product or business interest, including, but not limited to, the benefits of any product, business, or business activity for protecting or restoring the environment or mitigating the causes or effects of climate change. No data or opinions contained in the Deliverables constitute a representation to the public with respect to the benefits of any product, business or business activity, and should not be relied on as a recommendation for any specific action to be taken.

S&P Global Inc. also has the following divisions: S&P Dow Jones Indices, S&P Global Market Intelligence, S&P Global Mobility, and S&P Global Ratings, each of which provides different products and services. S&P Global keeps the activities of its business divisions separate from each other in order to preserve the independence and objectivity of their activities. SPGE publishes commodity information, including price assessments and indices and maintains clear structural and operational separation between SPGE's price assessment activities and the other activities carried out by SPGE and the other business divisions of S&P Global Inc. to safeguard the quality, independence and integrity of its price assessments and indices and ensure they are free from any actual or perceived conflicts of interest. The Deliverables should not be construed or regarded as a recommendation of any specific price assessment or benchmark.

Unless SPGE has expressly agreed otherwise, the Deliverables are not works-made-for-hire and SPGE shall own all right, title, and interest in and to the Deliverables, including all intellectual property rights which subsist in the Deliverables. Use of the Deliverables is subject to any licence terms and restrictions agreed between SPGE and the commissioning Client. The SPGE name(s) and logo(s) and their related trademarks appearing in the Deliverables are the property of S&P Global Inc., or their respective owners.

Christopher Wilfong
Director, Power Market Consulting

Christopher.Wilfong@spglobal.com

Ivonne Pena Cabra
Consulting Manager

ivonne.pena.cabra@spglobal.com

S&P Global Energy



Load Analysis Subcommittee

Updated: 9.22.2026

AEP Appalachian Transmission Company, Inc.(TO) Affiliate of:Appalachian Power Company			
Dan White Managing Director of Economics and Forecasting dmwhite@aep.com 6147162843 Primary	Mark Harris mharris@aep.com 918-599-2174 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Alternate
AEP Energy Partners, Inc.(TO) Affiliate of:Appalachian Power Company			
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Mark Harris mharris@aep.com 918-599-2174 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate
AEP Energy, Inc.(TO) Affiliate of:Appalachian Power Company			
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate
AEP Indiana Michigan Transmission Company, Inc.(TO) Affiliate of:Appalachian Power Company			
Dan White Managing Director of Economics and Forecasting dmwhite@aep.com 6147162843 Primary	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate
AEP Kentucky Transmission Company, Inc.(TO) Affiliate of:Appalachian Power Company			
Dan White Managing Director of Economics and Forecasting dmwhite@aep.com 6147162843 Primary	Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate



Load Analysis Subcommittee

Updated: 9.22.2026

AEP Ohio Transmission Company, Inc.(TO) Affiliate of:Appalachian Power Company			
Dan White Managing Director of Economics and Forecasting dmwhite@aep.com 6147162843 Primary	Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate
AEP Retail Energy Partners, LLC(TO) Affiliate of:Appalachian Power Company			
Takis Laios Managing Director of Economics and Forecasting tlaios@aep.com (614) 716-3462 Primary	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate
AEP West Virginia Transmission Company, Inc.(TO) Affiliate of:Appalachian Power Company			
Dan White Managing Director of Economics and Forecasting dmwhite@aep.com 6147162843 Primary	Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate
AES ES Holdings, LLC(GO) Affiliate of:Dayton Power & Light Company (The)			
John Horstmann Director, RTO Affairs john.horstmann@aes.com (610) 933-3170 Primary	Elizabeth Savage Manager Regulatory Affairs elizabeth.savage@aes.com 703-505-3283 Alternate	Roster Open	Roster Open
AES Energy Storage, LLC(GO) Affiliate of:Dayton Power & Light Company (The)			
John Horstmann Director, RTO Affairs john.horstmann@aes.com (610) 933-3170 Primary	Elizabeth Savage Manager Regulatory Affairs elizabeth.savage@aes.com 703-505-3283 Alternate	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

AES Integrated Energy, LLC(OS) Affiliate of:Dayton Power & Light Company (The)			
John Horstmann Director, RTO Affairs john.horstmann@aes.com (610) 933-3170 Primary	Elizabeth Savage Manager Regulatory Affairs elizabeth.savage@aes.com 703-505-3283 Alternate	Roster Open	Roster Open
AES Laurel Mountain, LLC(GO) Affiliate of:Dayton Power & Light Company (The)			
John Horstmann Director, RTO Affairs john.horstmann@aes.com (610) 933-3170 Primary	Elizabeth Savage Manager Regulatory Affairs elizabeth.savage@aes.com 703-505-3283 Alternate	Roster Open	Roster Open
AES Ohio Generation, LLC(GO) Affiliate of:Dayton Power & Light Company (The)			
John Horstmann Director, RTO Affairs john.horstmann@aes.com (610) 933-3170 Primary	Elizabeth Savage Manager Regulatory Affairs elizabeth.savage@aes.com 703-505-3283 Alternate	Roster Open	Roster Open
AES Solutions Management, LLC(OS) Affiliate of:Dayton Power & Light Company (The)			
John Horstmann Director, RTO Affairs john.horstmann@aes.com (610) 933-3170 Primary	Elizabeth Savage Manager Regulatory Affairs elizabeth.savage@aes.com 703-505-3283 Alternate	Roster Open	Roster Open
AMP Transmission, LLC(TO) Affiliate of:American Municipal Power, Inc.			
Bartley Taberner Senior Director, Transmission Planning & Development btaber@amppartners.org 614-3985982 Primary	Chris Norton Director of Regulatory Market Affairs cnorton@amppartners.org 614-540-1111 Alternate	Kevin Foust Senior Transmission Planning Engineer kfoust@amppartners.org 614-395-4018 Alternate	Frank Favella Senior Transmission Planning Engineer ffavella@amppartners.org 614-395-4018 Alternate
AXPO U.S. LLC(OS) Voting Member			
Joseph Cattano Director, Head of Operations joseph.cattano@axpo.us 2128471237 Primary	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Allegheny Electric Cooperative, Inc.(ED) Voting Member			
Jamie Lejar Power Supply Analyst jamie_lejar@aces-energy.com 717-901-4469 Primary	Carl Johnson Senior Consultant cjohnson@aces-llc.com 518-605-6041 Alternate	Roster Open	Roster Open
Allegheny Energy Supply Company, L.L.C.(GO) Affiliate of: Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (517) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingsmithl@firstenergycorp.com 330-715-5759 Alternate	Roster Open	Roster Open
American Municipal Power, Inc.(ED) Affiliate of: American Municipal Power, Inc.			
Carl Johnson Senior Consultant cjohnson@aces-llc.com 518-605-6041 Alternate	Chris Norton Director of Regulatory Market Affairs cnorton@amppartners.org 614-540-1111 Alternate	Roster Open	Roster Open
American Transmission Systems, Inc.(TO) Affiliate of: Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (517) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingsmithl@firstenergycorp.com 330-715-5759 Alternate	Phil Bowers Manager, Compliance, Data, and Models pbowers@firstenergycorp.com 330-697-6286 Alternate	Roster Open
Apogee Energy Trading LLC(OS) Voting Member			
Teoman Guler Chief Investment Officer tguler@roscommonanalytics.com 212 850 8868 Primary	Roster Open	Roster Open	Roster Open
Appalachian Power Company(TO) Affiliate of: Appalachian Power Company			
Takis Laos Manager: Transmission Asset Strategy tlaos@aep.com (614) 716-3462 Primary	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate



Load Analysis Subcommittee

Updated: 9.22.2026

Aquenergy Systems, LLC(GO) Affiliate of: West Deptford Energy, LLC			
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Alternate	Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-584-4380 Alternate	Roster Open	Roster Open
Armenia Mountain Wind, LLC(GO) Affiliate of: Armenia Mountain Wind, LLC			
Michael Hurd michael.hurd@aes.com (937) 259-7372 Alternate	Roster Open	Roster Open	Roster Open
Aspen Gen Funding, LLC(OS) Affiliate of: NRG Business Marketing LLC			
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Alternate	Roster Open	Roster Open	Roster Open
Aspen Generating, LLC(GO) Affiliate of: West Deptford Energy, LLC			
Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-584-4380 Alternate	Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Alternate	Roster Open	Roster Open
Atlantic City Electric Company(ED) Affiliate of: Exelon Business Services Company, LLC			
Alexander Stern Director RTO Relations & Strategy alexander.stern@exeloncorp.com 201-401-8079 Primary	David Apostol Load Forecasting Analysis Mgr David.Apostol@exeloncorp.com 6302347030 Alternate	David Vermeire david.vermeire@exeloncorp.com 302.454.4538 Alternate	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Avangrid Power, LLC(GO) Affiliate of:Avangrid Power, LLC		
Kevin Kilgallen Director Market Structure & Policy kevin.kilgallen@avangrid.com 610-425-0824 Primary	Roster Open	Roster Open
BP Energy Company(OS) Affiliate of:BP Energy Company		
Raj Chintapalli ISO Coordinator raj.chintapalli@bp.com 646-971-3539 Primary	Roster Open	Roster Open
Baltimore Gas and Electric Company(TO) Affiliate of:Exelon Business Services Company, LLC		
Alexander Stern Director RTO Relations & Strategy alexander.stern@exeloncorp.com 201-401-8079 Primary	David Apostol Load Forecasting Analysis Mgr David.Apostol@exeloncorp.com 6302347030 Alternate	David Vermeire david.vermeire@exeloncorp.com 302.454.4538 Alternate
Baltimore Power Company LLC(OS) Voting Member		
Karl Malloy Karl.Malloy@baltimorepower.com 8886682435 Alternate	Roster Open	Roster Open
Bath County Energy, LLC(GO) Affiliate of:West Deptford Energy, LLC		
Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-594-4380 Alternate	Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@lspower.com 7328592439 Alternate	Roster Open
Beech Ridge Energy LLC(GO) Affiliate of:Invenergy Energy Management LLC		
Justin Radl Sr. Director, Regulatory jradl@invenergy.com 6087970249 Primary	Reid Wagner Manager, Regulatory Affairs rwagner@invenergy.com 7165812251 Alternate	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenergy.com 7738082135 Alternate



Load Analysis Subcommittee

Updated: 9.22.2026

Beech Ridge Energy Storage LLC(GO) Affiliate of: Invenery Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenery.com 6087970249 Primary	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Roster Open
Big Sandy Peaker Plant, LLC(GO) Affiliate of: Big Sandy Peaker Plant, LLC			
Sophia Dossin Manager of Eastern Market and Regulatory Affairs sdossin@mrpgenco.com 541-359-7408 Primary	Brant Yung Director byung@mrpgenco.com 312-766-8514 Alternate	Roster Open	Roster Open
Blue Ridge Power Agency, Inc.(ED) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-llc.com 518-605-6041 Primary	Roster Open	Roster Open	Roster Open
Borough of Chambersburg(ED) Voting Member			
Steven Lieberman AVP Transmission & PJM Affairs slieberman@amppartners.org 614-519-9168 Alternate	Jeff Heverley Assistant Electric Superintendent jheverley@chambersburgpa.gov 717-261-3236 Alternate	Roster Open	Roster Open
Borough of Lavallette, New Jersey(ED) Voting Member			
Brian Vayda Executive Director bvayda@ppanj.net 570-401-4255 Primary	Roster Open	Roster Open	Roster Open
Borough of Mont Alto, Pennsylvania(ED) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-llc.com 518-605-6041 Alternate	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Brandon Shores LLC(GO) Affiliate of: Talen Energy Marketing, LLC			
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenenergy.com 610-601-0171 Alternate	Roster Open	Roster Open	Roster Open
Brunner Island, LLC(GO) Affiliate of: Talen Energy Marketing, LLC			
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenenergy.com 610-601-0171 Alternate	Roster Open	Roster Open	Roster Open
Buckeye Power, Inc.(ED) Voting Member			
Craig Grooms Director, Resource Scheduling cgrooms@ohioec.org (614) 430-7863 Primary	Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Alternate	Kara Smith ksmith@ohioec.org 614-430-7812 Alternate	Roster Open
CPV Power Holdings, LP(GO) Affiliate of: CPV Power Holdings, LP			
Matt Litchfield Director mlitchfield@cpv.com 781-817-8964 Alternate	Roster Open	Roster Open	Roster Open
Cadence Solar Energy LLC(GO) Affiliate of: Invenery Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenery.com 6087970249 Primary	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Roster Open
Calpine Bethlehem, LLC(GO) Voting Member			
Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Primary	Jung Suh Manager, ISO Analytics jung.suh@calpinesolutions.com 610-717-6472 Alternate	Frederick Heinle erik.heinle@constellation.com 202 510 7208 Alternate	Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Alternate



Load Analysis Subcommittee

Updated: 9.22.2026

Calpine Energy Services, L.P.(GO) Affiliate of: Constellation Energy Generation, LLC				
Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Primary	Clint Sandidge clint.sandidge@calpinesolutions.com (713) 361-7717 Alternate	Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Alternate	Frederick Heinle erik.heinle@constellation.com 202 510 7208 Alternate	Frederick Heinle erik.heinle@constellation.com 202 510 7208 Alternate
Calpine Energy Solutions, LLC(OS) Affiliate of: Constellation Energy Generation, LLC				
Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Primary	Frederick Heinle erik.heinle@constellation.com 202 510 7208 Alternate	Jung Suh Manager, ISO Analytics jung.suh@calpinesolutions.com 610-717-6472 Alternate	Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Alternate	
Calpine Mid Atlantic Marketing, LLC(GO) Affiliate of: Constellation Energy Generation, LLC				
Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Primary	Frederick Heinle erik.heinle@constellation.com 202 510 7208 Alternate	Jung Suh Manager, ISO Analytics jung.suh@calpinesolutions.com 610-717-6472 Alternate	Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Alternate	
Calvert Cliffs Nuclear Power Plant, LLC(GO) Affiliate of: Constellation Energy Generation, LLC				
Adrien Ford Wholesale Market Development adrien.ford@constellation.com 215-251-2427 Primary	Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Alternate	Juliet Anderson Wholesale Market Development Manager juliet.anderson@constellation.com 5404670833 Alternate	Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Alternate	
Carroll County Energy LLC(GO) Affiliate of: Carroll County Energy LLC				
Thomas Hyzinski twhyzinski@gtpowergroup.com 484-523-0480 Alternate	Roster Open	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Central Transmission, LLC(OS) Affiliate of: West Deptford Energy, LLC		
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Alternate	Roster Open	Roster Open
Central Virginia Electric Cooperative(ED) Voting Member		
Carl Johnson Senior Consultant cjohnson@ces-llc.com 518-605-6041 Primary	Roster Open	Roster Open
Champion Energy Marketing LLC(OS) Affiliate of: Constellation Energy Generation, LLC		
Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Primary	Jung Suh Manager, ISO Analytics jung.suh@calpinesolutions.com 610-717-6472 Alternate	Frederick Heinle erik.heinle@constellation.com 202 510 7208 Alternate
Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Alternate		
Champion Energy Services, LLC(OS) Affiliate of: Constellation Energy Generation, LLC		
Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Primary	Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Alternate	Jung Suh Manager, ISO Analytics jung.suh@calpinesolutions.com 610-717-6472 Alternate
Frederick Heinle erik.heinle@constellation.com 202 510 7208 Alternate		
Champion Energy, LLC(OS) Affiliate of: Constellation Energy Generation, LLC		
Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Primary	Jung Suh Manager, ISO Analytics jung.suh@calpinesolutions.com 610-717-6472 Alternate	Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Alternate
Frederick Heinle erik.heinle@constellation.com 202 510 7208 Alternate		
Chief Conemaugh Power II, LLC(GO) Affiliate of: Parkway Generation Operating LLC		
Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-584-4380 Primary	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Chief Keystone Power II, LLC(GO) Affiliate of: Parkway Generation Operating LLC			
Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-584-4380 Primary	Roster Open	Roster Open	Roster Open
Citadel FNGE Ltd.(OS) Affiliate of: Citadel FNGE Ltd.			
Tyler Kuhn tyler.kuhn@citadel.com 203-900-6146 Primary	Ike Gibbs Chief Compliance Officer ike.gibbs@citadel.com 203-900-6055 Alternate	Roster Open	Roster Open
City of Dover, Delaware(ED) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-llc.com 518-605-6041 Primary	Roster Open	Roster Open	Roster Open
Clearlight Energy Services LLC(GO) Affiliate of: West Deptford Energy, LLC			
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Primary	Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-584-4380 Alternate	Roster Open	Roster Open
Cleveland Electric Illuminating Company(ED) Affiliate of: Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (517) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingensmithl@firstenergycorp.com 330-715-5759 Alternate	Roster Open	Roster Open
Commonwealth Edison Company(TO) Affiliate of: Exelon Business Services Company, LLC			
Alexander Stern Director RTO Relations & Strategy alexander.stern@exeloncorp.com 201-401-8079 Primary	David Apostol Load Forecasting Analysis Mgr David.Apostol@exeloncorp.com 6302347030 Alternate	David Vermeire david.vermeire@exeloncorp.com 302.454.4538 Alternate	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Consolidated Edison Company of New York, Inc.(OS) Affiliate of:Rockland Electric Company			
Dave Buchner Senior Planning Analyst BuchnerD@coned.com (212) 460-3046 Primary	Roster Open	Roster Open	Roster Open
Constellation Energy Generation, LLC(GO) Affiliate of:Constellation Energy Generation, LLC			
Adrien Ford Wholesale Market Development adrien.ford@constellation.com 215-251-2427 Primary	Juliet Anderson Wholesale Market Development Manager juliet.anderson@constellation.com 5404670833 Alternate	Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Alternate	Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Alternate
Constellation NewEnergy, Inc.(OS) Affiliate of:Constellation Energy Generation, LLC			
Adrien Ford Wholesale Market Development adrien.ford@constellation.com 215-251-2427 Primary	Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Alternate	Juliet Anderson Wholesale Market Development Manager juliet.anderson@constellation.com 5404670833 Alternate	Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Alternate
Consumer Protection and Advocate Division of the Tennessee Attorney General(EUC) Voting Member			
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Roster Open	Roster Open	Roster Open
Cornerstone Gas, L.L.C.(GO) Affiliate of:Cornerstone Gas, L.L.C.			
Meg Tubridy Director, PJM Market and Regulatory Affairs meg.tubridy@jeraamericas.com 2818489876 Primary	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

DTE Atlantic, LLC(OS) Affiliate of:DTE Energy Trading, Inc.			
Greg Pakela Manager, Transmission Market Development gregory.pakela@dteenergy.com (734) 887-2119 Primary	Roster Open	Roster Open	Roster Open
DTE Energy Trading, Inc.(OS) Affiliate of:DTE Energy Trading, Inc.			
Greg Pakela Manager, Transmission Market Development gregory.pakela@dteenergy.com (734) 887-2119 Primary	Roster Open	Roster Open	Roster Open
Darby Power, LLC(GO) Affiliate of:Talen Energy Marketing, LLC			
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenenergy.com 610-601-0171 Primary	Roster Open	Roster Open	Roster Open
Dayton Power & Light Company (The)(TO) Affiliate of:Dayton Power & Light Company (The)			
sharon schroder Managing Director, Reg & RTO Affairs sharon.schroder@aes.com 19374758592 Primary	John Horstmann Director, RTO Affairs john.horstmann@aes.com (610) 933-3170 Alternate	Roster Open	Roster Open
Delaware Division of the Public Advocate(EUC) Voting Member			
Andrea Maucher Utility Analyst andrea.maucher@delaware.gov 302-241-2545 Alternate	Greg Poulos poulos@pjm-advocates.org 614-507-7377 Alternate	Anna Bautista Public Utility Analyst anna.bautista@delaware.gov 3022412545 Alternate	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Delaware Municipal Electric Corporation, Inc.(ED) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Primary	Roster Open	Roster Open	Roster Open
Delmarva Power & Light Company(ED) Affiliate of:Exelon Business Services Company, LLC			
Alexander Stern Director RTO Relations & Strategy alexander.stern@exeloncorp.com 201-401-8079 Primary	David Apostol Load Forecasting Analysis Mgr David.Apostol@exeloncorp.com 6302347030 Alternate	David Vermeire david.vermeire@exeloncorp.com 302.454.4538 Alternate	Roster Open
Dominion Energy Generation Marketing, Inc.(GO) Affiliate of:Virginia Electric & Power Company			
Joseph Bocanegra SENIOR ENERGY MARKET ANALYST joseph.i.bocanegra@dominionenergy.com 540-598-7674 Primary	Keith Graham Manager Electric Transmission Planning Keith.L.Graham@dominionenergy.com 804-836-6236 Alternate	Praveen Dhanasekar praveen.dhanasekar@dominionenergy.com 8324193069 Alternate	James Davis REGULATORY MARKET POLICY STRATEGIC ADV james.g.davis@dominionenergy.com 804-393-3271 Alternate
Dominion Energy South Carolina, Inc.(OS) Affiliate of:Virginia Electric & Power Company			
Joseph Bocanegra SENIOR ENERGY MARKET ANALYST joseph.i.bocanegra@dominionenergy.com 540-598-7674 Primary	Keith Graham Manager Electric Transmission Planning Keith.L.Graham@dominionenergy.com 804-836-6236 Alternate	Praveen Dhanasekar praveen.dhanasekar@dominionenergy.com 8324193069 Alternate	James Davis REGULATORY MARKET POLICY STRATEGIC ADV james.g.davis@dominionenergy.com 804-393-3271 Alternate
Doswell, LLC(GO) Affiliate of:NRG Business Marketing LLC			
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Alternate	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Duke Energy Business Services LLC(TO) Affiliate of: Duke Energy Business Services LLC			
Bryan Garnett Manager Bryan.Garnett@duke-energy.com 980-373-7536 Primary	Roster Open	Roster Open	Roster Open
Duquesne Light Company(TO) Affiliate of: Duquesne Light Company			
John Peoples Manager, Energy Procurement & Settlement jpeoples@duqlight.com 412-393-6385 Primary	Brandon Bergstrom Lead Forecast Analyst, Energy Supply, Procurement & Settlement bbergstrom@duqlight.com 412-393-6052 Alternate	Roster Open	Roster Open
East Coast Power Linden Holding, L.L.C.(GO) Affiliate of: Cornerstone Gas, L.L.C.			
Roy Shanker PH.D. droys Shanker@comcast.net 301-332-0486 Primary	Meg Tubridy Director, PJM Market and Regulatory Affairs meg.tubridy@jeraamericas.com 2818489876 Alternate	Roster Open	Roster Open
East Kentucky Power Cooperative, Inc.(TO) Voting Member			
Fernie Williams Planning Analyst ferniewilliams@ekpc.coop 859-745-9429 Primary	Danielle Houston Load Forecasting Analyst danielle.houston@ekpc.coop 865-567-6357 Alternate	Mark Mefford Senior Load Forecasting Analyst mark.mefford@ekpc.coop 8597459663 Alternate	Roster Open
Eastern Shore Solar LLC(GO) Affiliate of: Virginia Electric & Power Company			
Joseph Bocanegra SENIOR ENERGY MARKET ANALYST joseph.i.bocanegra@dominionenergy.com 540-598-7674 Primary	James Davis REGULATORY MARKET POLICY STRATEGIC ADV james.g.davis@dominionenergy.com 804-393-3271 Alternate	Praveen Dhanasekar praveen.dhanasekar@dominionenergy.com 8324193069 Alternate	Keith Graham Manager Electric Transmission Planning Keith.L.Graham@dominionenergy.com 804-836-6236 Alternate



Load Analysis Subcommittee

Updated: 9.22.2026

Easton Utilities Commission(ED) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-ld.com 518-605-6041 Primary	Roster Open	Roster Open	Roster Open
Edgecombe Solar LLC(OS) Affiliate of: Invenegy Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenegy.com 6087970249 Primary	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenegy.com 7738082135 Alternate	Reid Wagner Manager, Regulatory Affairs rwagner@invenegy.com 7165812251 Alternate	Roster Open
Electranet REP I, LLC(OS) Voting Member			
James Huang Director Wholesale Markets jhuang@erock.com 832-627-6830 Primary	Roster Open	Roster Open	Roster Open
Elkhart County Solar Project, LLC(GO) Affiliate of: Shell Energy North America (US), L.P.			
Sean Chang Director, Regulatory Affairs sean.chang@shell.com 713-230-3340 Primary	Sumra Pouallion Regulatory Affairs Analyst sumra.chaudhry@shell.com 8583974922 Alternate	Roster Open	Roster Open
Elliott Bay Energy Trading, LLC(OS) Voting Member			
Mark Hurwich Principal mhurwich@elliottbayenergy.com (206) 282-2160 Primary	Roster Open	Roster Open	Roster Open
Enel Green Power Hilltopper Wind, LLC(GO) Affiliate of: Enel X North America, Inc.			
Juan Diaz Regulatory and IA Director juan.diaz9@enel.com 978-808-2136 Primary	Pasquale Roselli pasquale.roselli@enel.com 9788028135 Alternate	Tracie Brennan Manager, Portfolio Management, Energy Management Tracie.Brennan@enel.com 9782966834 Alternate	John Branch john.branch@enel.com 3512281012 Alternate



Load Analysis Subcommittee

Updated: 9.22.2026

Enel Trading North America, LLC(OS) Affiliate of: Enel X North America, Inc.			
Juan Diaz Regulatory and IA Director juan.diaz9@enel.com 978-808-2136 Primary	Pasquale Roselli pasquale.roselli@enel.com 978-808-2136 Alternate	John Branch john.branch@enel.com 3512281012 Alternate	Tracie Brennan Manager, Portfolio Management, Energy Management Tracie.Brennan@enel.com 978-2966834 Alternate
Enel X North America, Inc.(OS) Affiliate of: Enel X North America, Inc.			
Mona Tierney-Lloyd Head of Institutional Affairs mona.tierney-lloyd@enel.com 415 238 3788 Primary	Juan Diaz Regulatory and IA Director juan.diaz9@enel.com 978-808-2136 Alternate	Roster Open	Roster Open
Energy Cooperative Association of Pennsylvania (The)(OS) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Primary	Roster Open	Roster Open	Roster Open
Enerwise Global Technologies, LLC(OS) Affiliate of: NRG Business Marketing LLC			
Bruce Campbell Consultant Bruce@CampbellEA.com 301-957-0643 Primary	Dann Price Executive Director dann.price@cpowerenergymanagement.com 610-813-6376 Alternate	Roster Open	Roster Open
Energy Kansas Central, Inc.(OS) Affiliate of: Energy Metro, Inc.			
William Birnel william.birnel@westarenergy.com 785-575-6454 Primary	Cliff Franklin Senior Regulatory Specialist Clifford.Franklin@westarenergy.com (785) 575-1878 Alternate	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Exelon Business Services Company, LLC(TO) Affiliate of Exelon Business Services Company, LLC			
Alexander Stern Director RTO Relations & Strategy alexander.stern@exeloncorp.com 201-401-8079 Primary	David Apostol Load Forecasting Analysis Mgr David.Apostol@exeloncorp.com 6302347030 Alternate	David Vermeire david.vermeire@exeloncorp.com 302.454.4538 Alternate	Roster Open
FirstEnergy Pennsylvania Electric Company(ED) Affiliate of Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (517) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingsmithl@firstenergycorp.com 330-715-5759 Alternate	Yvonne Hartman Senior Engineer, EDPP Models yhartman@firstenergycorp.com (610) 921-6726 Alternate	Roster Open
Forest Investment Group, LLC(OS) Voting Member			
Michael Chu Managing Member michael.chu@forestinvestmentgroup.com (203) 918-2722 Primary	Roster Open	Roster Open	Roster Open
Fowler Ridge Wind Farm LLC(GO) Affiliate of West Deptford Energy, LLC			
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Primary	Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-584-4380 Alternate	Roster Open	Roster Open
GSG 6, LLC(GO) Affiliate of West Deptford Energy, LLC			
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Primary	Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-584-4380 Alternate	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Galt Power, Inc.(OS) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-llc.com 518-605-6041 Alternate	Roster Open	Roster Open	Roster Open
Geenex Solar LLC(OS) Voting Member			
Kenneth Foladare Director - Regulatory Affairs ken.foladare@langibinc.com 484-241-1751 Primary	Roster Open	Roster Open	Roster Open
Gen IV Investment Opportunities, LLC(OS) Affiliate of: West Deptford Energy, LLC			
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Alternate	Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-584-4380 Alternate	Roster Open	Roster Open
GenOn Energy Management, LLC(GO) Affiliate of: GenOn Energy Management, LLC			
Thomas Hyzinski twhyzinski@gtpowergroup.com 484-523-0480 Alternate	Roster Open	Roster Open	Roster Open
Geronimo Power Marketing, LLC(OS) Affiliate of: Green River Holdings, LLC			
Ava Duane Regulatory Policy Manager aduanne@geronimopower.com 4844310697 Primary	Roster Open	Roster Open	Roster Open
Grand Ridge Energy II LLC(GO) Affiliate of: Invenegy Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenegy.com 6087970249 Primary	Reid Wagner Manager, Regulatory Affairs rwagner@invenegy.com 7165812251 Alternate	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenegy.com 7738082135 Alternate	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Grand Ridge Energy III LLC(GO) Affiliate of: Invenery Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenery.com 6087970249 Primary	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Roster Open
Grand Ridge Energy IV, LLC(GO) Affiliate of: Invenery Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenery.com 6087970249 Primary	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Roster Open
Grand Ridge Energy Storage, LLC(GO) Affiliate of: Invenery Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenery.com 6087970249 Primary	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Roster Open
Grand Ridge Energy, LLC(GO) Affiliate of: Invenery Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenery.com 6087970249 Primary	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Roster Open
Great Cove Solar II LLC(GO) Affiliate of: Dayton Power & Light Company (The)			
John Horstmann Director, RTO Affairs john.horstmann@aes.com (610) 933-3170 Primary	Elizabeth Savage Manager Regulatory Affairs elizabeth.savage@aes.com 703-505-3283 Alternate	Roster Open	Roster Open
Great Cove Solar LLC(GO) Affiliate of: Dayton Power & Light Company (The)			
John Horstmann Director, RTO Affairs john.horstmann@aes.com (610) 933-3170 Primary	Elizabeth Savage Manager Regulatory Affairs elizabeth.savage@aes.com 703-505-3283 Alternate	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Green River Holdings, LLC(GO) Affiliate of: Green River Holdings, LLC			Roster Open	Roster Open
Ava Duane Regulatory Policy Manager aduane@geronimopower.com 4844310697 Primary				Roster Open
Greensville County Solar Project, LLC(GO) Affiliate of: Virginia Electric & Power Company				
Joseph Bocanegra SENIOR ENERGY MARKET ANALYST joseph.i.bocanegra@dominionenergy.com 540-598-7674 Primary	James Davis REGULATORY MARKET POLICY STRATEGIC ADV james.g.davis@dominionenergy.com 804-393-3271 Alternate	Praveen Dhanasekar praveen.dhanasekar@dominionenergy.com 8324193069 Alternate	Keith Graham Manager Electric Transmission Planning Keith.L.Graham@dominionenergy.com 804-836-6236 Alternate	
Guernsey Power Station LLC(GO) Affiliate of: Talen Energy Marketing, LLC				
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenenergy.com 610-601-0171 Primary			Roster Open	Roster Open
H.A. Wagner LLC(GO) Affiliate of: Talen Energy Marketing, LLC				
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenenergy.com 610-601-0171 Alternate			Roster Open	Roster Open
Hagerstown Light Department(ED) Voting Member				
Carl Johnson Senior Consultant cjohnson@ces-td.com 518-605-6041 Primary			Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Handsomen Lake Energy, LLC(GO) Affiliate of: Constellation Energy Generation, LLC			
Adrien Ford Wholesale Market Development adrien.ford@constellation.com 215-251-2427 Primary	Juliet Anderson Wholesale Market Development Manager juliet.anderson@constellation.com 5404670833 Alternate	Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Alternate	Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Alternate
Hardin Solar Energy II LLC(GO) Affiliate of: Invenery Energy Management LLC			
Justin Radi Sr. Director, Regulatory jradi@invenery.com 6087970249 Primary	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Roster Open
Hardin Solar Energy LLC(GO) Affiliate of: Virginia Electric & Power Company			
Joseph Bocanegra SENIOR ENERGY MARKET ANALYST joseph.i.bocanegra@dominionenergy.com 540-598-7674 Primary	James Davis REGULATORY MARKET POLICY STRATEGIC ADV james.g.davis@dominionenergy.com 804-393-3271 Alternate	Praveen Dhanasekar praveen.dhanasekar@dominionenergy.com 8324193069 Alternate	Keith Graham Manager Electric Transmission Planning Keith.L.Graham@dominionenergy.com 804-836-6236 Alternate
Helix Ironwood, LLC(GO) Affiliate of: NRG Business Marketing LLC			
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Alternate	Roster Open	Roster Open	Roster Open
Hunterstown Generation, LLC(GO) Affiliate of: West Deptford Energy, LLC			
Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-584-4380 Alternate	Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Alternate	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

IR Energy Management LLC(OS) Affiliate of: Invenery Energy Management LLC			
Justin Radi Sr. Director, Regulatory jradi@invenery.com 6087970249 Primary	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Roster Open
Illinois Citizens Utility Board(EUC) Voting Member			
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Roster Open	Roster Open	Roster Open
Illinois Municipal Electric Agency(ED) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-llc.com 518-605-6041 Primary	Charlie Robling Manager of Energy Markets & Settlements crobbling@imea.org 217-789-4632 Alternate	Roster Open	Roster Open
Indiana Michigan Power Company(TO) Affiliate of: Appalachian Power Company			
Takis Laos Manager: Transmission Asset Strategy tlaos@aep.com (614) 716-3462 Primary	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate
Indiana Municipal Power Agency(ED) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-llc.com 518-605-6041 Primary	Roster Open	Roster Open	Roster Open
Indiana Office of Utility Consumer Counselor (IN OUCC)(EUC) Voting Member			
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Inspire Energy Holdings, LLC(OS) Affiliate of: Rhythm Ops, LLC			
Sean Chang Director, Regulatory Affairs sean.chang@shell.com 713-230-3340 Primary	Roster Open	Roster Open	Roster Open
Interstate Gas Supply, LLC(OS) Affiliate of: Interstate Gas Supply, LLC			
Michael Swary Power Supply Lead michael.swary@igs.com 614-659-5714 Primary	Roster Open	Roster Open	Roster Open
Invenergy Energy Management LLC(GO) Affiliate of: Invenergy Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenergy.com 6087970249 Primary	Reid Wagner Manager, Regulatory Affairs rwagner@invenergy.com 7165812251 Alternate	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenergy.com 7738082135 Alternate	Roster Open
Invenergy Nelson Expansion LLC(GO) Affiliate of: Invenergy Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenergy.com 6087970249 Primary	Reid Wagner Manager, Regulatory Affairs rwagner@invenergy.com 7165812251 Alternate	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenergy.com 7738082135 Alternate	Roster Open
Invenergy Nelson, LLC(GO) Affiliate of: Invenergy Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenergy.com 6087970249 Primary	Reid Wagner Manager, Regulatory Affairs rwagner@invenergy.com 7738082135 Alternate	Reid Wagner Manager, Regulatory Affairs rwagner@invenergy.com 7165812251 Alternate	Roster Open
Jersey Central Power & Light Company(TO) Affiliate of: Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (617) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingensmith@firstenergycorp.com 330-715-5759 Alternate		Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Kentucky Power Company(TO) Affiliate of:Appalachian Power Company			
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate
Keystone Appalachian Transmission Company(TO) Affiliate of:Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (517) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingensmithl@firstenergycorp.com 330-715-5759 Alternate	Roster Open	Roster Open
Kingsport Power Company(TO) Affiliate of:Appalachian Power Company			
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate
Lackawanna Energy Center LLC(GO) Affiliate of:Invenery Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenery.com 6087970249 Primary	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Roster Open
Lawrenceburg Power, LLC(GO) Affiliate of:Talen Energy Marketing, LLC			
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenergy.com 610-601-0171 Primary	Roster Open	Roster Open	Roster Open
MC Squared Energy Services, LLC(OS) Affiliate of:Interstate Gas Supply, LLC			
Michael Hurd michael.hurd@aes.com (937) 259-7372 Alternate	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

MP2 Energy LLC(OS) Affiliate of: Shell Energy North America (US), L.P.			
Sean Chang Director, Regulatory Affairs sean.chang@shell.com 713-230-3340 Primary	Sumra Poualion Regulatory Affairs Analyst sumra.chaudhry@shell.com 8583974922 Alternate	Roster Open	Roster Open
MP2 Energy NE LLC dba Shell Energy Solutions(OS) Affiliate of: Shell Energy North America (US), L.P.			
Sean Chang Director, Regulatory Affairs sean.chang@shell.com 713-230-3340 Primary	Sumra Poualion Regulatory Affairs Analyst sumra.chaudhry@shell.com 8583974922 Alternate	Roster Open	Roster Open
MRP ELGIN LLC(GO) Affiliate of: Big Sandy Peaker Plant, LLC			
Sophia Dossin Manager of Eastern Market and Regulatory Affairs sdossin@mrpgenco.com 541-359-7408 Primary	Brant Yung Director byung@mrpgenco.com 312-766-8514 Alternate	Roster Open	Roster Open
MRP ROCKY ROAD LLC(GO) Affiliate of: Big Sandy Peaker Plant, LLC			
Sophia Dossin Manager of Eastern Market and Regulatory Affairs sdossin@mrpgenco.com 541-359-7408 Primary	Brant Yung Director byung@mrpgenco.com 312-766-8514 Alternate	Roster Open	Roster Open
Macquarie Energy LLC(OS) Affiliate of: Wheelabrator Falls Inc.			
Charlie Fenner charles.fenner@macquarie.com (713) 275-8823 Alternate	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Madison Fields Solar Project, LLC(GO) Affiliate of: Shell Energy North America (US), L.P.			
Sean Chang Director, Regulatory Affairs sean.chang@shell.com 713-230-3340 Primary	Sumra Poulalion Regulatory Affairs Analyst sumra.chaudhry@shell.com 8583974922 Alternate	Roster Open	Roster Open
Marion County Solar Project, LLC(GO) Affiliate of: Shell Energy North America (US), L.P.			
Sean Chang Director, Regulatory Affairs sean.chang@shell.com 713-230-3340 Primary	Sumra Poulalion Regulatory Affairs Analyst sumra.chaudhry@shell.com 8583974922 Alternate	Roster Open	Roster Open
Martin County Solar Project, LLC(GO) Affiliate of: Shell Energy North America (US), L.P.			
Sean Chang Director, Regulatory Affairs sean.chang@shell.com 713-230-3340 Primary	Sumra Poulalion Regulatory Affairs Analyst sumra.chaudhry@shell.com 8583974922 Alternate	Roster Open	Roster Open
Maryland Office of People's Counsel(EUC) Voting Member			
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Roster Open	Roster Open	Roster Open
Mehoopany Wind Energy LLC(GO) Affiliate of: West Deptford Energy, LLC			
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Primary	Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-584-4380 Alternate	Roster Open	Roster Open
Merrill Lynch Commodities, Inc.(OS) Voting Member			
Kojo Ofori-Atta Kojo_ofori-Atta@ml.com (713) 544-5499 Alternate	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Miami Valley Lighting, LLC(EUC) Affiliate of:Dayton Power & Light Company (The)			
John Horstmann Director, RTO Affairs john.horstmann@aes.com (610) 933-3170 Primary	Elizabeth Savage Manager Regulatory Affairs elizabeth.savage@aes.com 703-505-3283 Alternate	Roster Open	Roster Open
Mianus River Energy, L.P.(OS) Affiliate of:Mianus River Energy, L.P.			
Mike Liao Managing Partner mliao@greenwichcm.com 203-340-0386 Primary	Roster Open	Roster Open	Roster Open
Mid-Atlantic Interstate Transmission, LLC(TO) Affiliate of:Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (517) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingensmithl@firstenergycorp.com 330-715-5759 Alternate	Roster Open	Roster Open
Monongahela Power Company(TO) Affiliate of:Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (517) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingensmithl@firstenergycorp.com 330-715-5759 Alternate	Roster Open	Roster Open
Montour, LLC(GO) Affiliate of:Talen Energy Marketing, LLC			
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenergy.com 610-601-0171 Alternate	Roster Open	Roster Open	Roster Open
Moxie Freedom LLC(GO) Affiliate of:Talen Energy Marketing, LLC			
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenergy.com 610-601-0171 Primary	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

NGV US TRANSMISSION INC.(OS) Voting Member			
Michael Leff michael.leff@nationalgrid.com 7326686738 Primary	Varun Saluja varun.saluja@nationalgrid.com 5087403281 Alternate	Eric Steltzer eric.steltzer@nationalgrid.com 781-264-3662 Alternate	Roster Open
NRG Curtailment Solutions, Inc.(OS) Affiliate of:NRG Business Marketing LLC			
Malcolm Ainspan malcolm.ainspan@nrg.com 877-711-5453 Primary	Roster Open	Roster Open	Roster Open
New Jersey Division of Rate Counsel(EUC) Voting Member			
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Roster Open	Roster Open	Roster Open
New York State Electric & Gas Corporation(OS) Affiliate of:Avangrid Power, LLC			
Carl Johnson Senior Consultant cjohnson@ces-ld.com 518-605-6041 Alternate	Roster Open	Roster Open	Roster Open
NextEra Energy Transmission MidAtlantic, Inc.(TO) Affiliate of:NextEra Energy Marketing, LLC			
Kaley Bangston Senior Director kaley.bangston@nexteraenergy.com 339-221-8929 Primary	Roster Open	Roster Open	Roster Open
NextEra Energy Transmission, LLC(OS) Affiliate of:NextEra Energy Marketing, LLC			
Kaley Bangston Senior Director kaley.bangston@nexteraenergy.com 339-221-8929 Primary	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

North American Power and Gas, LLC(OS) Affiliate of Constellation Energy Generation, LLC				
Abhishek Ghosh Senior Manager Josh.Ghosh@constellation.com 612-419-9201 Primary	Imran Lalani Market Development Manager Imran.Lalani@Constellation.com 571 269 7653 Alternate	Jung Suh Manager, ISO Analytics jung.suh@calpinasolutions.com 610-717-6472 Alternate	Frederick Heinle erik.heinle@constellation.com 202 510 7208 Alternate	
North Carolina Electric Membership Corporation(ED) Voting Member				
James Manning Sr Engineer, Transmission Resources james.manning@ncemcs.com (919) 645-2415 Primary	Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Alternate	Roster Open	Roster Open	
North Carolina Municipal Power Agency Number 1(OS) Voting Member				
Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Alternate	Roster Open	Roster Open	Roster Open	
Northeastern REMC(ED) Voting Member				
Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Primary	Roster Open	Roster Open	Roster Open	
Northern Virginia Electric Cooperative (NOVEC)(ED) Voting Member				
Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Primary	Rory Sweeney rsweeney@novrec.com 571-866-1563 Alternate	Roster Open	Roster Open	
Office of the Attorney General, Kentucky(EUC) Voting Member				
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Roster Open	Roster Open	Roster Open	



Load Analysis Subcommittee

Updated: 9.22.2026

Office of the People's Counsel for the District of Columbia(EUC) Voting Member			
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Roster Open	Roster Open	Roster Open
Ohio Consumers' Counsel(EUC) Voting Member			
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Roster Open	Roster Open	Roster Open
Ohio Edison Company(ED) Affiliate of: Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (517) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingensmithl@firstenergycorp.com 330-715-5759 Alternate	Roster Open	Roster Open
Ohio Power Company(TO) Affiliate of: Appalachian Power Company			
Takis Lalos Manager: Transmission Asset Strategy tlalos@aep.com (614) 716-3462 Primary	Mark Harris mharris@aep.com 918-599-2174 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate
Ohio Valley Electric Corporation(TO) Affiliate of: Appalachian Power Company			
Chad Burnett Director Economic Forecasting cbburnett@aep.com 918-599-2169 Primary	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate
Old Dominion Electric Cooperative(ED) Affiliate of: Old Dominion Electric Cooperative			
Michael Jesensky Project Director Mike.Jesensky@dominionenergy.com 804-819-2071 Primary	William Pezalla Vice President of Regulatory Affairs bpezalla@odec.com 804-290-2193 Alternate	Michael Cocco Senior Director of RTO and Regulatory Affairs mcocco@odec.com 804-968-4025 Alternate	Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Alternate



Load Analysis Subcommittee

Updated: 9.22.2026

Orsted Onshore North America, LLC(GO) Voting Member			
Lopa Parikh Head of Electricity Policy lpari@orsted.com +18572916592 Primary	Eric Wilkinson Analyst erwil@orsted.com 413-387-7197 Alternate	Azade Brahman Lead Grid Connection Manager AZBRA@orsted.com 857-310-2466 Alternate	Roster Open
PECO Energy Company(TO) Affiliate of:Exelon Business Services Company, LLC			
Alexander Stern Director RTO Relations & Strategy alexander.stern@exeloncorp.com 201-401-8079 Primary	David Apostol Load Forecasting Analysis Mgr David.Apostol@exeloncorp.com 6302347030 Alternate	David Vermeire david.vermeire@exeloncorp.com 302.454.4538 Alternate	Roster Open
PPL Electric Utilities Corporation d/b/a PPL Utilities(TO) Affiliate of:PPL Electric Utilities Corporation d/b/a PPL Utilities			
Gary Hartman Supv Load, Sched & Settlement GMHartman@pplweb.com 6107746058 Primary	Arun Nava Data Specialist ANava@pplweb.com 6107742909 Alternate	Roster Open	Roster Open
PSEG Energy Resources & Trade LLC(OS) Affiliate of:Public Service Electric and Gas Company			
James Hough Sr. Energy Trader James.hough@pseg.com 973-430-6948 Primary	Roster Open	Roster Open	Roster Open
PSEG Energy Solutions LLC(OS) Affiliate of:Public Service Electric and Gas Company			
James Hough Sr. Energy Trader James.hough@pseg.com 973-430-6948 Alternate	Roster Open	Roster Open	Roster Open
PSEG Nuclear LLC(GO) Affiliate of:Public Service Electric and Gas Company			
James Hough Sr. Energy Trader James.hough@pseg.com 973-430-6948 Alternate	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Parkway Generation Operating LLC(GO) Affiliate of:Parkway Generation Operating LLC			
Jeffrey Whitehead Consultant jeff@wenergysolutions.com 484-584-4380 Primary	Roster Open	Roster Open	Roster Open
Pennsylvania Office of Consumer Advocate(EUC) Voting Member			
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Joe Harmar Assistant Consumer Advocate JHarmar@paoca.org 7177804527 Alternate	Melanie El Atieh Deputy Consumer Advocate melatieh@paoca.org 7177804531 Alternate	Zach Teti Senior Regulatory Analyst zteti@paoca.org 7177804514 Alternate
Pleasant Prairie Solar Energy LLC(OS) Affiliate of:Invenery Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenery.com 6087970249 Primary	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Roster Open
Potomac Electric Power Company(ED) Affiliate of:Exelon Business Services Company, LLC			
Alexander Stern Director RTO Relations & Strategy alexander.stern@exeloncorp.com 201-401-8079 Primary	David Vermeire david.vermeire@exeloncorp.com 302.454.4538 Alternate	David Apostol Load Forecasting Analysis Mgr David.Apostol@exeloncorp.com 6302347030 Alternate	Roster Open
Providence Heights Wind, LLC(GO) Affiliate of:Avangrid Power, LLC			
Kevin Kilgallen Director Market Structure & Policy kevin.kilgallen@avangrid.com 610-425-0824 Primary	Roster Open	Roster Open	Roster Open
Public Service Electric and Gas Company(TO) Affiliate of:Public Service Electric and Gas Company			
Glenn Catenacci Transmission Engineer glenn.catenacci@pseg.com (973) 430-7821 Primary	Stephen Wreschnig Manager-Electric and Gas Sales and Revenue stephen.wreschnig@pseg.com (973) 430-5934 Alternate	Heather Svenson RTO Strategy Manager heather.svenson@pseg.com 973-430-6625 Alternate	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Public Staff - North Carolina Utilities Commission(EUC) Voting Member			
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Roster Open	Roster Open	Roster Open
RPA Energy, Inc.(OS) Voting Member			
Brian Trombino President & CEO btrombino@rpaenergy.com 516-858-3352 Alternate	Roster Open	Roster Open	Roster Open
RWE Americas, LLC(GO) Affiliate of:RWE Americas, LLC			
Eric Stephens Sr. Director Regulatory Affairs Wholesale Markets Eric.Stephens@RWE.com 614-506-2374 Primary	Roster Open	Roster Open	Roster Open
RWE CLEAN ENERGY WHOLESALE SERVICES, INC.(OS) Affiliate of:RWE Americas, LLC			
Rehan Gilani gilani@coneddev.com 914-329 4619 Primary	Roster Open	Roster Open	Roster Open
Richfield Solar Energy LLC(GO) Affiliate of:Invenery Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenery.com 6087970249 Primary	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Seneca Generation, LLC(GO) Affiliate of: West Deptford Energy, LLC		
Jeffrey Whitehead Consultant jeff@wenergysolutions.com 484-584-4380 Alternate	Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@lspower.com 7328592439 Alternate	Roster Open
Shell Energy North America (US), L.P.(OS) Affiliate of: Shell Energy North America (US), L.P.		
Sean Chang Director, Regulatory Affairs sean.chang@shell.com 713-230-3340 Primary	Sumra Pouillon Regulatory Affairs Analyst sumra.chaudhry@shell.com 8583974922 Alternate	Roster Open
Silver Run Electric, LLC(TO) Affiliate of: West Deptford Energy, LLC		
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@lspower.com 7328592439 Alternate	Roster Open	Roster Open
Southampton Solar LLC(GO) Affiliate of: Virginia Electric & Power Company		
Joseph Bocanegra SENIOR ENERGY MARKET ANALYST joseph.l.bocanegra@dominionenergy.com 540-598-7674 Primary	Keith Graham Manager Electric Transmission Planning Keith.L.Graham@dominionenergy.com 804-836-6236 Alternate	Praveen Dhanasekar praveen.dhanasekar@dominionenergy.com 8324193069 Alternate
Southern Maryland Electric Cooperative, Inc.(ED) Voting Member		
John Rohrbach ED Regulatory Strategy jrohrbach@acespower.com (317) 344-7216 Primary	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Star Jasmine Houston LLC(OS) Voting Member		
Yan Chen Chairman starjasminehouston@gmail.com 917-558-5196 Primary	Roster Open	Roster Open
Summit Farms Solar, LLC(GO) Affiliate of: Virginia Electric & Power Company		
Joseph Bocanegra SENIOR ENERGY MARKET ANALYST joseph.j.bocanegra@dominionenergy.com 540-598-7674 Primary	Praveen Dhanasekar praveen.dhanasekar@dominionenergy.com 8324193069 Alternate	Keith Graham Manager Electric Transmission Planning Keith.L.Graham@dominionenergy.com 804-836-6236 Alternate
James Davis REGULATORY MARKET POLICY STRATEGIC ADV James.g.davis@dominionenergy.com 804-393-3271 Alternate		
Susquehanna Nuclear, LLC(GO) Affiliate of: Talen Energy Marketing, LLC		
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenenergy.com 610-601-0171 Alternate	Roster Open	Roster Open
Syncarpha Solar, LLC(GO) Voting Member		
Steve Shparber Out of House Counsel steven.shparber@nelsonmullins.com 202-689-2994 Primary	Roster Open	Roster Open
TEC Trading, Inc.(OS) Affiliate of: Old Dominion Electric Cooperative		
William Pezalla Vice President of Regulatory Affairs bpezalla@odec.com 804-290-2193 Primary	Michael Cocco Senior Director of RTO and Regulatory Affairs mcocco@odec.com 804-968-4025 Alternate	Roster Open
Roster Open		



Load Analysis Subcommittee

Updated: 9.22.2026

TWE Myrtle Solar Project, LLC(GO) Affiliate of: Virginia Electric & Power Company			
Joseph Bocanegra SENIOR ENERGY MARKET ANALYST joseph.l.bocanegra@dominionenergy.com 540-598-7674 Primary	Keith Graham Manager Electric Transmission Planning Keith.L.Graham@dominionenergy.com 804-836-6236 Alternate	Praveen Dhanasekar praveen.dhanasekar@dominionenergy.com 8324193069 Alternate	James Davis REGULATORY MARKET POLICY STRATEGIC ADV james.g.davis@dominionenergy.com 804-393-3271 Alternate
Talen CG Holdings, LLC(OS) Affiliate of: Talen Energy Marketing, LLC			
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenenergy.com 610-601-0171 Primary	Roster Open	Roster Open	Roster Open
Talen Energy Marketing, LLC(GO) Affiliate of: Talen Energy Marketing, LLC			
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenenergy.com 610-601-0171 Alternate	Roster Open	Roster Open	Roster Open
Texas Retail Energy, LLC(OS) Voting Member			
Tim Keaten Director, Energy Operations tim.keaten@texasretailenergy.com (479) 204-0338 Primary	Roster Open	Roster Open	Roster Open
The Potomac Edison Company(TO) Affiliate of: Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (517) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingensmithl@firstenergycorp.com 330-715-5759 Alternate	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Todd Solar LLC(GO) Affiliate of: Invenery Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenery.com 6087970249 Primary	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Roster Open
Toledo Edison Company(ED) Affiliate of: Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (517) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingensmithl@firstenergycorp.com 330-715-5759 Alternate	Roster Open	Roster Open
TotalEnergies Gas & Power North America, Inc.(OS) Affiliate of: Mount Storm Wind LLC			
Glenn Kinser Trading Regulatory Advisor glenn.kinser@totalenergies.com 713-647-5070 Primary	Roster Open	Roster Open	Roster Open
Town of Thurmont(ED) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Alternate	Roster Open	Roster Open	Roster Open
Town of Williamsport (The)(ED) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Primary	Roster Open	Roster Open	Roster Open
Trade Post Solar LLC(OS) Affiliate of: Invenery Energy Management LLC			
Justin Radl Sr. Director, Regulatory jradl@invenery.com 6087970249 Primary	Rob Stupar Senior Manager, Regulatory Affairs rstupar@invenery.com 7738082135 Alternate	Reid Wagner Manager, Regulatory Affairs rwagner@invenery.com 7165812251 Alternate	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Trans-Allegheny Interstate Line Company(TO) Affiliate of: Monongahela Power Company			
Shawn Hurd shurd@firstenergycorp.com (517) 515-2005 Primary	Laurel Klingensmith Manager, Market Policy klingensmithl@firstenergycorp.com 330-715-5759 Alternate	Roster Open	Roster Open
Transource Energy, LLC(TO) Affiliate of: Appalachian Power Company			
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate
Transource Maryland, LLC(TO) Affiliate of: Appalachian Power Company			
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Mark Harris mharris@aep.com 918-599-2174 Alternate	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate
Transource Pennsylvania, LLC(TO) Affiliate of: Appalachian Power Company			
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate
Transource West Virginia, LLC(TO) Affiliate of: Appalachian Power Company			
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate	Randy E. Holliday Staff Economist reholliday@aep.com (614) 716-2337 Alternate	Mark Harris mharris@aep.com 918-599-2174 Alternate
UGI Utilities, Inc.(TO) Affiliate of: UGI Energy Services, LLC			
Ayana Wood Power Supply and Rates Analyst awood@ugi.com (610) 796-3562 Primary	Kyle Stair Business Support Engineer kstair@ugi.com 5707091829 Alternate	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Union Electric Company d/b/a Ameren Missouri(OS) Voting Member			
Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Alternate	Roster Open	Roster Open	Roster Open
University Park Energy, LLC(GO) Affiliate of:NRG Business Marketing LLC			
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Alternate	Roster Open	Roster Open	Roster Open
Urban Grid Solar Projects, LLC(GO) Affiliate of:Brookfield Renewable Trading and Marketing LP			
Jeff Hudson Director - Interconnection jeff.hudson@urbangridco.com (704) 709-0341 Primary	Roster Open	Roster Open	Roster Open
Valley Link Transmission Maryland, LLC(TO) Affiliate of:Appalachian Power Company			
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Roster Open	Roster Open	Roster Open
Valley Link Transmission Virginia, LLC(TO) Affiliate of:Appalachian Power Company			
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Roster Open	Roster Open	Roster Open
Valley Link Transmission West Virginia, LLC(TO) Affiliate of:Appalachian Power Company			
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Roster Open	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

Virginia Division of Consumer Counsel(EUC) Voting Member			
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Roster Open	Roster Open	Roster Open
Virginia Electric & Power Company(TO) Affiliate of: Virginia Electric & Power Company			
Joseph Bocanegra SENIOR ENERGY MARKET ANALYST joseph.l.bocanegra@dominionenergy.com 540-598-7674 Primary	James Davis REGULATORY MARKET POLICY STRATEGIC ADV james.g.davis@dominionenergy.com 804-393-3271 Alternate	Jacob Midkiff Manager, ET Planning & Strategic Initiatives jacob.a.midkiff@dominionenergy.com 804-389-9836 Alternate	Praveen Dhanasekar praveen.dhanasekar@dominionenergy.com 8324193069 Alternate
Virginia Solar 2017 Projects LLC(GO) Affiliate of: Virginia Electric & Power Company			
Joseph Bocanegra SENIOR ENERGY MARKET ANALYST joseph.l.bocanegra@dominionenergy.com 540-598-7674 Primary	Praveen Dhanasekar praveen.dhanasekar@dominionenergy.com 8324193069 Alternate	James Davis REGULATORY MARKET POLICY STRATEGIC ADV james.g.davis@dominionenergy.com 804-393-3271 Alternate	Keith Graham Manager Electric Transmission Planning Keith.L.Graham@dominionenergy.com 804-836-6236 Alternate
Vitol Inc.(OS) Voting Member			
Jason Barker VP Regulatory Affairs bjb@vcrenewables.com 443-613-3634 Alternate	Roster Open	Roster Open	Roster Open
WGL Energy Services, Inc.(OS) Voting Member			
Emily Wise Director - Electricity Supply & Trading emily.wise@wglenergy.com 703-287-9546 Primary	Todd Sandford VP - Commercial Operations todd.sandford@wglenergy.com 412-235-8707 Alternate	Roster Open	Roster Open



Load Analysis Subcommittee

Updated: 9.22.2026

WPPI Energy(OS) Voting Member		
Carl Johnson Senior Consultant cjohnson@ces-ltd.com 518-605-6041 Primary	Roster Open	Roster Open
Waileye Power, LLC(GO) Affiliate of:Parkway Generation Operating LLC		
Jeffrey Whitehead Consultant jeff@jwenergysolutions.com 484-584-4380 Primary	Roster Open	Roster Open
Waterford Power, LLC(GO) Affiliate of:Talen Energy Marketing, LLC		
Jennifer Hohenshilt Director - Market & Regulatory Policy jennifer.hohenshilt@talenergy.com 610-601-0171 Primary	Roster Open	Roster Open
West Deptford Energy, LLC(GO) Affiliate of:West Deptford Energy, LLC		
Daniel Pierpont Vice President, Wholesale Market Policy dpierpont@ispower.com 7328592439 Alternate	Roster Open	Roster Open
West Virginia Consumer Advocate Division(EUC) Voting Member		
Greg Poulos poulos@pjm-advocates.org 614-507-7377 Primary	Roster Open	Roster Open
Wheeling Power Company(TO) Affiliate of:Appalachian Power Company		
Takis Laios Manager: Transmission Asset Strategy tlaios@aep.com (614) 716-3462 Primary	Mark Harris mharris@aep.com 918-599-2174 Alternate	Jack Keegan Director, RTO Strategy jkeegan@aep.com 614-377-8144 Alternate



Load Analysis Subcommittee

Updated: 9.22.2026

Whitney Hill Wind Power, LLC(GO) Affiliate of: Enel X North America, Inc.			
John Branch john.branch@enel.com 3512281012 Alternate	Roster Open	Roster Open	Roster Open
Wilkinson Solar LLC(GO) Affiliate of: Virginia Electric & Power Company			
Joseph Bocanegra SENIOR ENERGY MARKET ANALYST joseph.l.bocanegra@dominionenergy.com 540-598-7674 Primary	Praveen Dhanasekar praveen.dhanasekar@dominionenergy.com 8324193069 Alternate	James Davis REGULATORY MARKET POLICY STRATEGIC ADV james.g.davis@dominionenergy.com 804-393-3271 Alternate	Keith Graham Manager Electric Transmission Planning Keith.L.Graham@dominionenergy.com 804-836-6236 Alternate
Wolf Hills Energy, LLC(GO) Affiliate of: Big Sandy Peaker Plant, LLC			
Sophia Dossin Manager of Eastern Market and Regulatory Affairs sdossin@mrpgenco.com 541-359-7408 Primary	Brant Yung Director byung@mrpgenco.com 312-766-8514 Alternate	Roster Open	Roster Open
Wolverine Power Supply Cooperative, Inc.(ED) Voting Member			
Ryan Wernette rwernette@wpsci.com 2317793336 Primary	Roster Open	Roster Open	Roster Open
sPower Energy Marketing, LLC(GO) Affiliate of: Dayton Power & Light Company (The)			
John Horstmann Director, RTO Affairs john.horstmann@aes.com (610) 933-3170 Primary	Elizabeth Savage Manager Regulatory Affairs elizabeth.savage@aes.com 703-505-3283 Alternate	Roster Open	Roster Open

2025

PJM Long-Term Load Forecast Report

Posted Date: January 24, 2025

Prepared by PJM Resource Adequacy Planning Department



For Public Use

Contents

TO Zones and Subzones.....	1
Glossary	3
Executive Summary	4
<i>Energy Information Administration & Vendor Data</i>	<i>5</i>
<i>Load Adjustments.....</i>	<i>5</i>
<i>Summer & Winter Summary.....</i>	<i>6</i>
PJM Map.....	7
PJM RTO, LDA, and Zonal Dashboards	8

TO Zones and Subzones

Abbreviation	Zone Name	Date Incorporated
AE	Atlantic Electric zone	
AEP	American Electric Power zone	Oct. 1, 2004
APP	Appalachian Power, sub-zone of AEP	
APS	Allegheny Power zone	April 1, 2002
ATSI	American Transmission Systems, Inc. zone	June 1, 2011
BGE	Baltimore Gas & Electric zone	
CEI	Cleveland Electric Illuminating, sub-zone of ATSI	
COMED	Commonwealth Edison zone	May 1, 2004
CSP	Columbus Southern Power, sub-zone of AEP	
DAY	Dayton Power & Light zone	Oct. 1, 2004
DEOK	Duke Energy Ohio/Kentucky zone	January 1, 2012
DLCO	Duquesne Lighting Company zone	January 1, 2005
DOM	Dominion Virginia Power zone	May 1, 2005
DPL	Delmarva Power & Light zone	
EKPC	East Kentucky Power Cooperative zone	June 1, 2013
FE-East	The combination of FirstEnergy's Jersey Central Power & Light, Metropolitan Edison, and Pennsylvania Electric zones (formerly GPU)	
INM	Indiana Michigan Power, sub-zone of AEP	
JCP&L	Jersey Central Power & Light zone	
KP	Kentucky Power, sub-zone of AEP	

Abbreviation	Zone Name	Date Incorporated
METED	Metropolitan Edison zone	
MP	Monongahela Power, sub-zone of APS	
OEP	Ohio Edison, sub-zone of ATSI	
OP	Ohio Power, sub-zone of AEP	
OVEC	Ohio Valley Electric Corporation zone	December 1, 2018
PECO	PECO Energy zone	
PED	Potomac Edison, sub-zone of APS	
PEPCO	Potomac Electric Power zone	
PL	PPL Electric Utilities, sub-zone of PLGroup	
PLGroup/PLGRP	Pennsylvania Power & Light zone	
PENLC	Pennsylvania Electric zone	
PP	Pennsylvania Power, sub-zone of ATSI	
PS	Public Service Electric & Gas zone	March 1, 2002
RECO	Rockland Electric (East) zone	
TOL	Toledo Edison, sub-zone of ATSI	
UGI	UGI Utilities, sub-zone of PLGroup	
WP	West Penn Power, sub-zone of APS	

Glossary

Term / Abbreviation	Definition
Battery Storage	Devices that enable generated energy to be stored and then released at a later time. (Also Battery Energy Storage System – BESS)
Contractually Interruptible	Load Management from customers responding to direction from a control center
Cooling Load	The weather-sensitive portion of summer peak load
Direct Control	Load Management achieved directly by a signal from a control center
Heating Load	The weather-sensitive portion of winter peak load
Net Energy	Net Energy for Load, measured as net generation of main generating units plus energy receipts minus energy deliveries
PRD	Price Responsive Demand
Unrestricted Peak	Peak load prior to any reduction for load management or voltage reduction.
Zone	Areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement

Executive Summary

This report presents an independent load forecast prepared by PJM staff.

- The report includes a 20 year long-term forecasts of peak loads, net energy, load management, distributed solar generation, plug-in electric vehicles, and battery storage for each PJM zone, region, locational deliverability area (LDA), and the total RTO.
- New to the report this year is a table for the total load associated with adjustments to summer peak loads (Table B-9b available on the [PJM Website](#)). All tables are now provided in excel format for ease of use.
- Residential, Commercial, and Industrial sector models were estimated with data from 2014 through 2023. Hourly models were estimated with data from 2015 to August 2024. Weather scenarios were simulated with data from years 1993 through 2023, generating 403 scenarios.
- The economic forecast used was Moody's Analytics' September 2024 release.

Energy Information Administration & Vendor Data

The Energy Information Administration (EIA) did not publish an Annual Energy Outlook (AEO) update in 2024 as they revamp models and make improvements to capture emerging technologies. Therefore, the 2023 update of Itron's end-use data provides the basis for appliance saturation rates, efficiency, and intensity and is consistent with the EIA's 2023 AEO. PJM obtained additional information from certain zones on Residential saturation rates based on their own load research. Details on zones providing information are presented in the supplement.

Consultant forecasts for behind the meter solar/battery and electric vehicles including light, medium & heavy duty were provided by S&P Global.

- The behind the meter solar/battery values were derived by PJM from a forecast obtained from [SPGCI](#)
- The electric vehicle values were derived by PJM from a forecast obtained from [SPGCI](#)

Load Adjustments

The forecasts of the following zones have been adjusted to account for large, unanticipated load changes, market adjustments, and peak shaving adjustments (see [Tables B-9](#) and [B-9b](#) and the supplement for details available on the [PJM Website](#)):

Zones	Adjusted to account for:
AEP	growth in data center load and a chip processing plant
APS, ATSI, BGE, DAYTON, PECO, and PL	growth in data center load
COMED	growth in data center load and an electric vehicle battery plant
DEOK	adjusted to account for growth in a steel facility
DOM	growth in data center load and a voltage optimization program
PS	growth in data center load and port electrification
EKPC	a peak shaving program that commenced in the 2023 DY
ATSI and DOM	Non-Retail Behind-the-Meter Generation (NRBTMG) transitioning to participation as Demand Response in the Reliability Pricing Model

Compared to the 2024 Load Report,
the 2025 PJM RTO summer peak forecast
shows the following changes for three years
of interest:

Next Year:		
Delivery	RPM Auction	RTEP Study
2025	2026	2030
+651 MW (0.4%)	+2,134 MW (1.4%)	+16,010MW (9.5%)

Summer & Winter Summary

Summer peak load growth for the PJM RTO

- Projected to average 3.1% per year over the next 10-year period and 2.0% over the next 20 years.
- Summer peak is forecasted to be 209,923 MW in 2035, a 10-year increase of 55,779 MW, and reaches 228,544 MW in 2045, a 20-year increase of 74,400 MW.
- Annualized 10-year growth rates for individual zones range from 0.1% to 6.3%; median of 0.7%.

Winter Peak Load Growth – PJM RTO

- Projected to average 3.8% per year over the next 10-year period, and 2.4% over the next 20 years.
- The PJM RTO winter peak load in 2034/35 is forecasted to be 198,175 MW, a 10-year increase of 62,048 MW, and reaches 218,760 MW in 2044/45, a 20-year increase of 82,633 MW.
- Annualized 10-year growth rates for individual zones range from 0.1% to 6.0%; median of 1.6%.

Net Energy Load Growth – PJM RTO

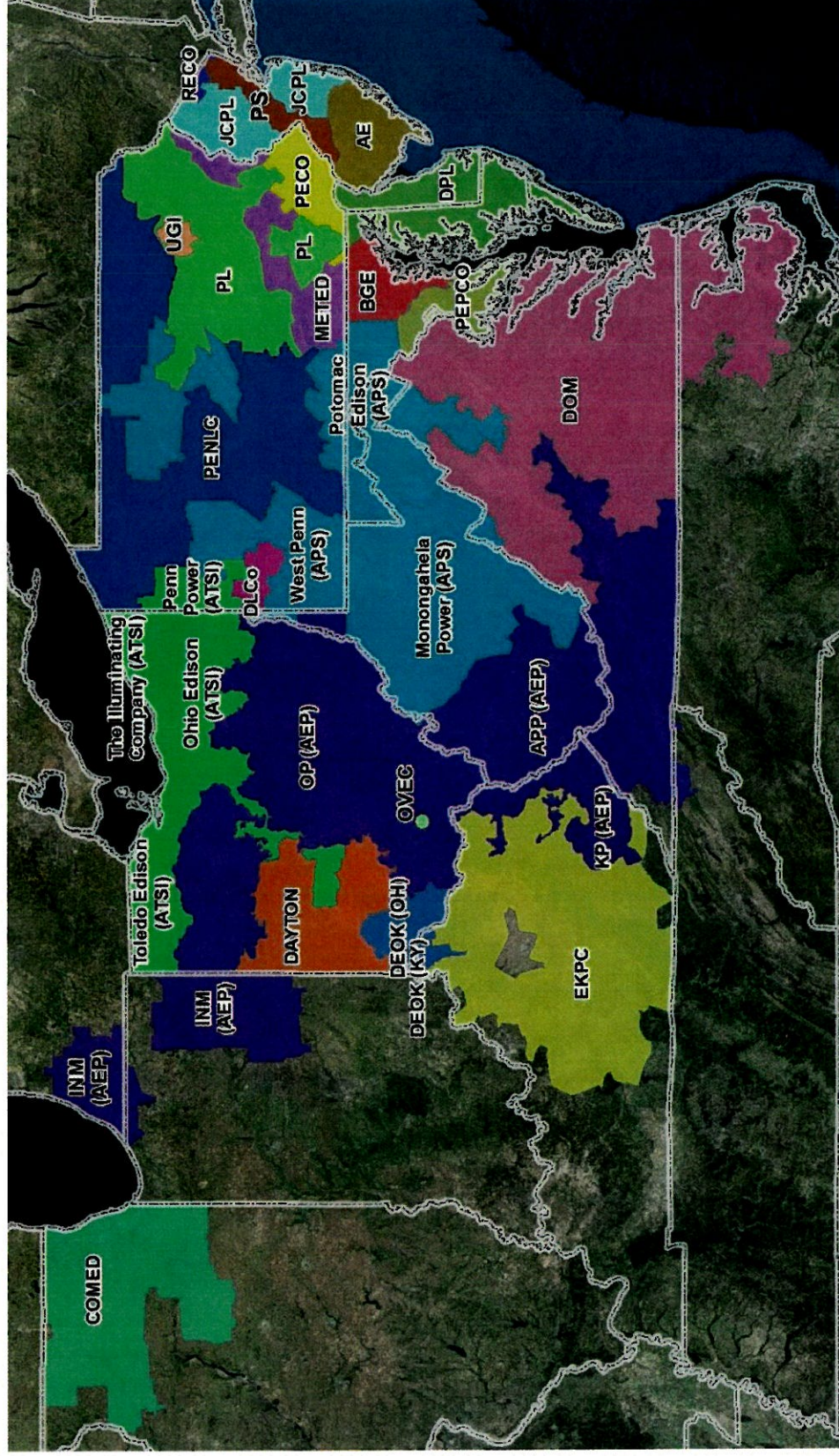
- Projected to average 4.8% per year over the next 10-year period, and 2.9% over the next 20-years.
- Total PJM RTO energy is forecasted to be 1,328,045 GWh in 2035, a 10-year increase of 495,264 GWh, and reaches 1,482,068 GWh in 2045, a 20-year increase of 649,287 GWh.
- Annualized 10-year growth rates for individual zones range from 0.2% to 8.4%; median of 1.6%.

NOTE:

Unless noted otherwise, all peak and energy values are non-coincident, unrestricted peaks, which represent the peak load or net energy after reductions for distributed solar generation and battery storage (in summer peak), additions for plug-in electric vehicles, and prior to reductions for load management impacts.

All compound growth rates are calculated from the first year of the forecast.

PJM Map



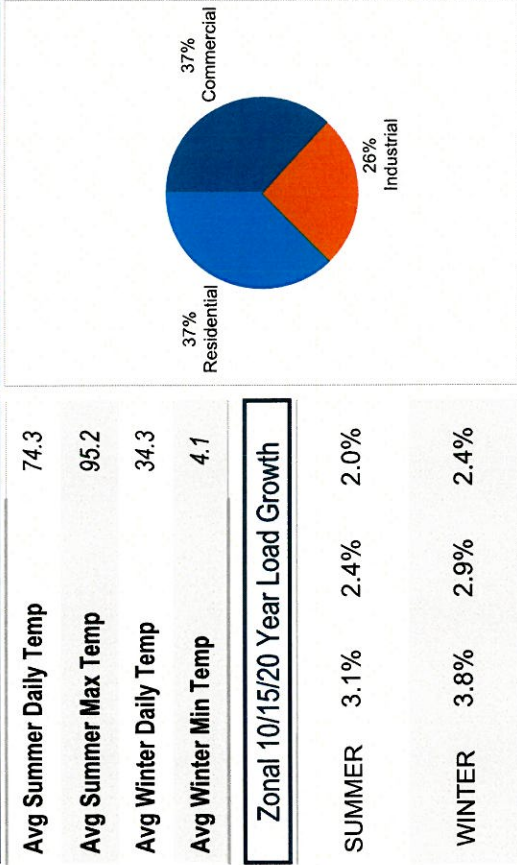
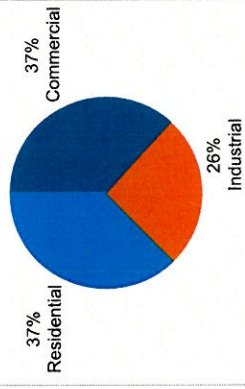
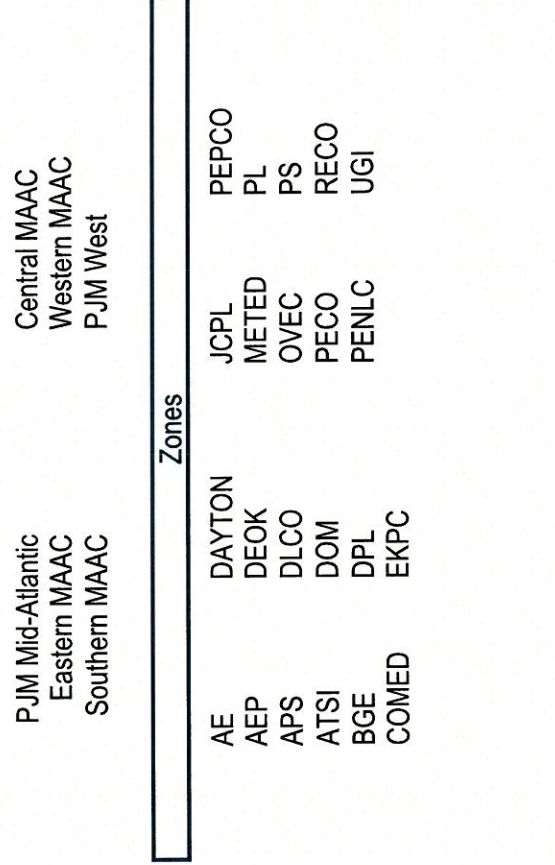


PJM RTO, LDA, and Zonal Dashboards

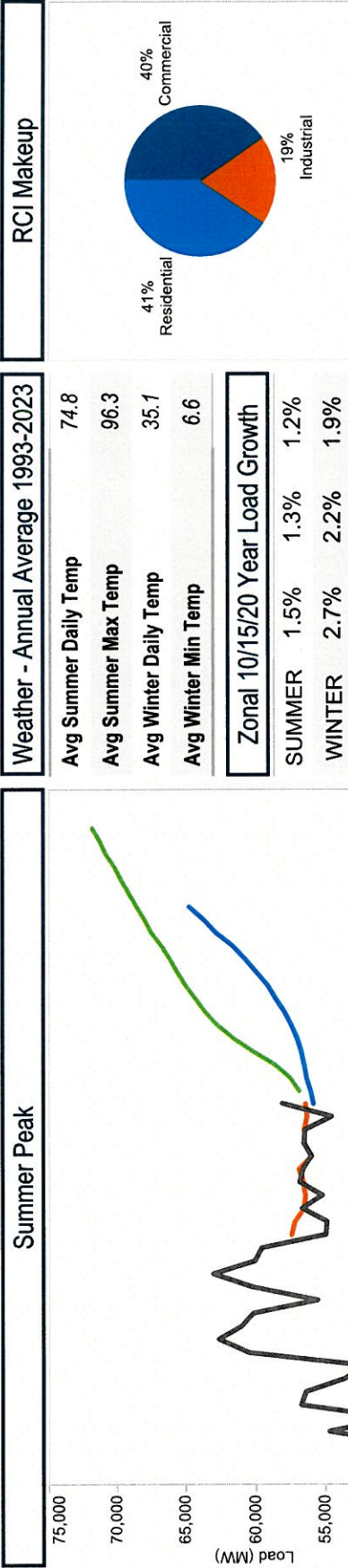
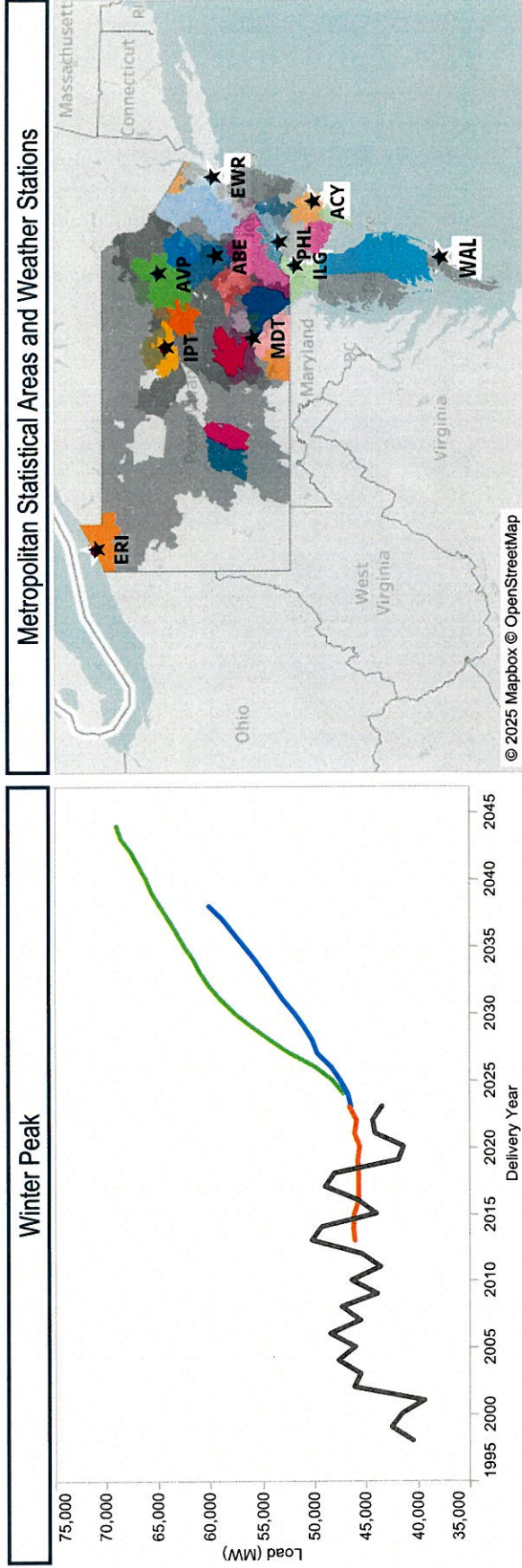
[Click below to jump to an LDA or PJM Zone's data page](#)

PJM RTO	MAAC	E-MAAC	S-MAAC	PJM Western
AE	BGE	DPL	JCPL	METED
PECO	PENLC	PEPCO	PL	PS
RECO	UGI	AEP	APS	ATSI
COMED	DAYTON	DEOK	DLCO	EKPC
DOM				

PJM RTO

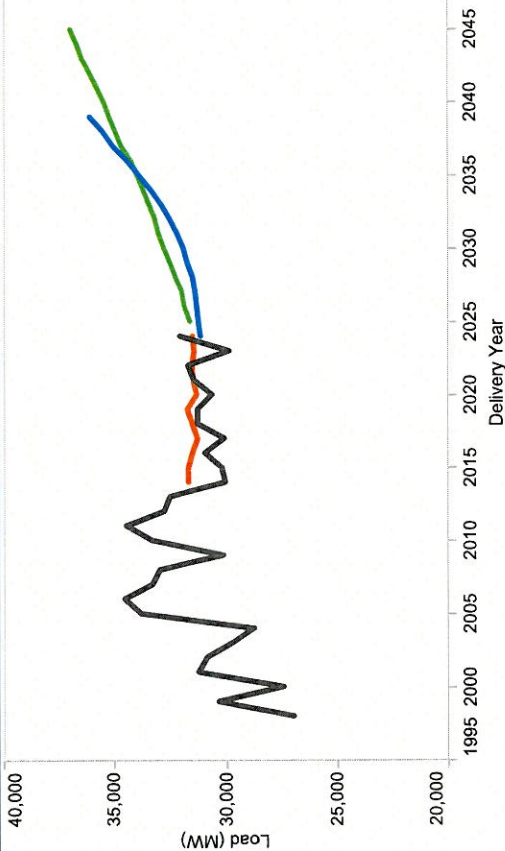


PJM Mid-Atlantic (MAAC)

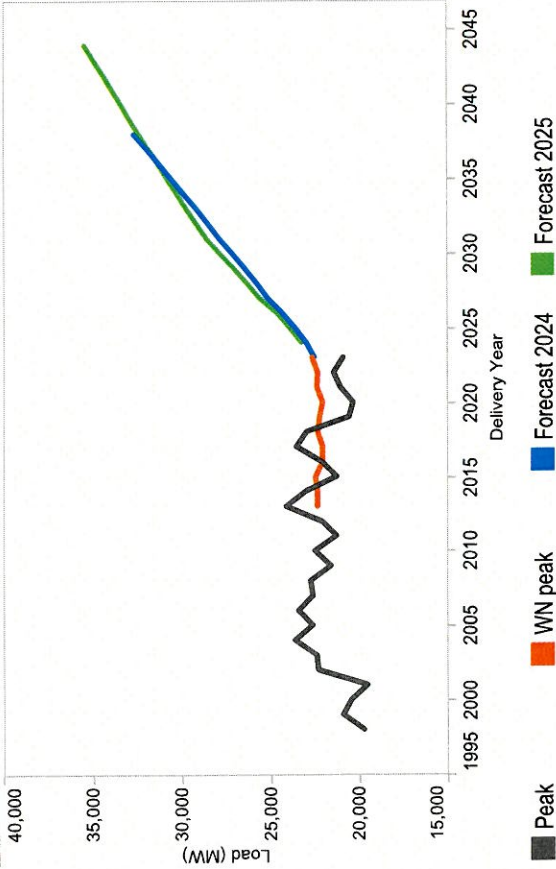


PJM Eastern Mid-Atlantic (E-MAAC)

Summer Peak



Winter Peak



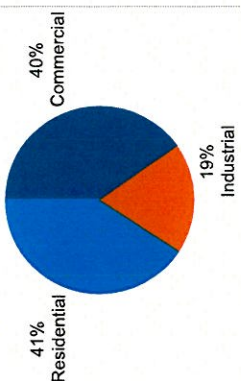
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	75.7
Avg Summer Max Temp	97.5
Avg Winter Daily Temp	36.4
Avg Winter Min Temp	7.9

Zonal 10/15/20 Year Load Growth

SUMMER	0.7%	0.8%	0.8%
WINTER	2.7%	2.3%	2.1%

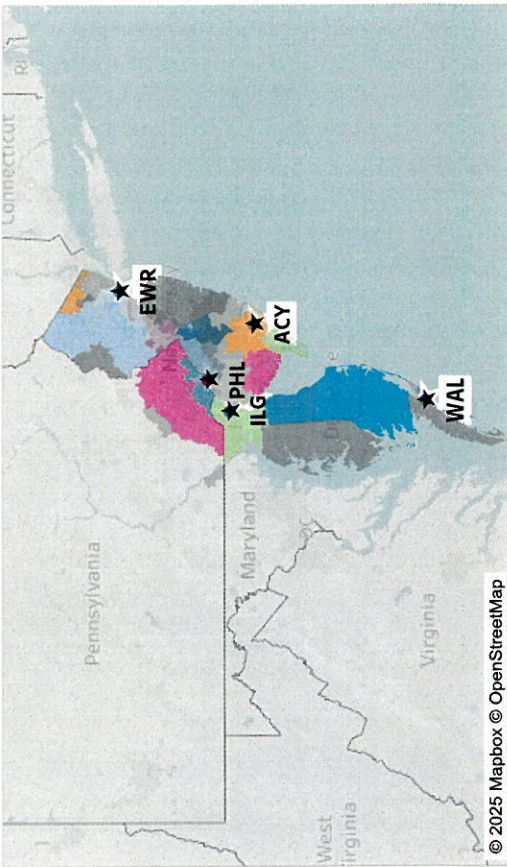
RCI Makeup



Zones

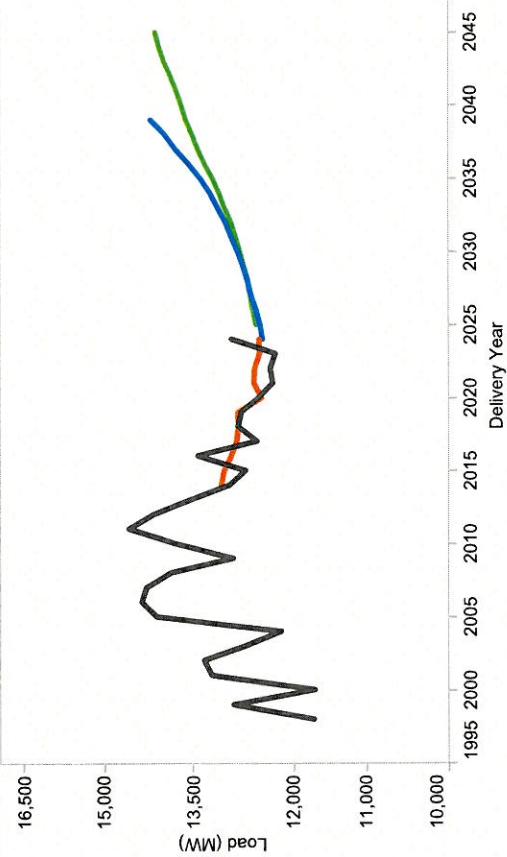
AE	DPL	JCPL	PECO	PS	RECO
----	-----	------	------	----	------

Metropolitan Statistical Areas and Weather Stations

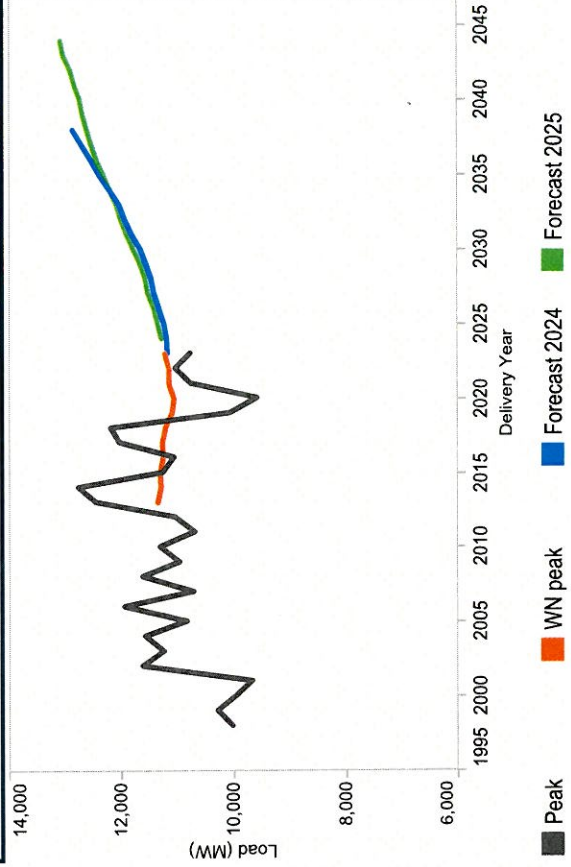


PJM Southern Mid-Atlantic (S-MAAC)

Summer Peak



Winter Peak



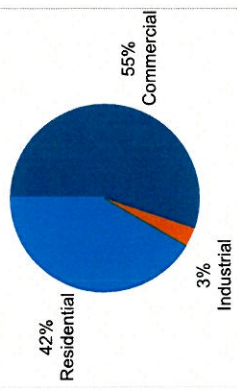
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	77.1
Avg Summer Max Temp	98.0
Avg Winter Daily Temp	38.1
Avg Winter Min Temp	10.4

Zonal 10/15/20 Year Load Growth

SUMMER	0.5%	0.6%	0.6%
WINTER	0.8%	0.8%	0.7%

RCI Makeup

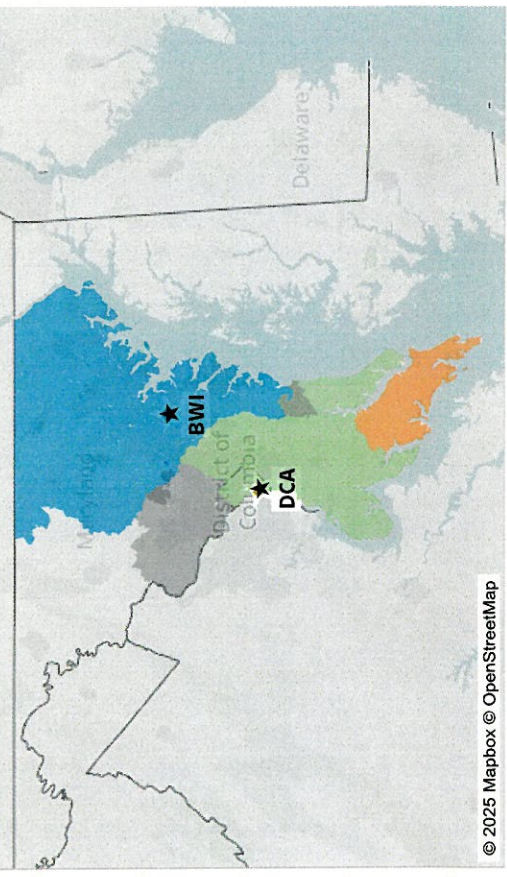


Zones

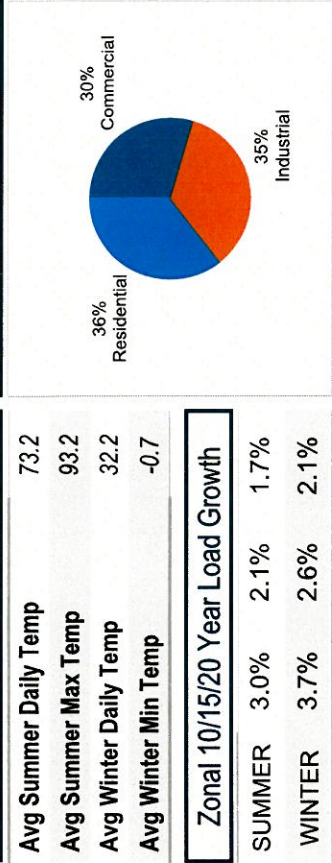
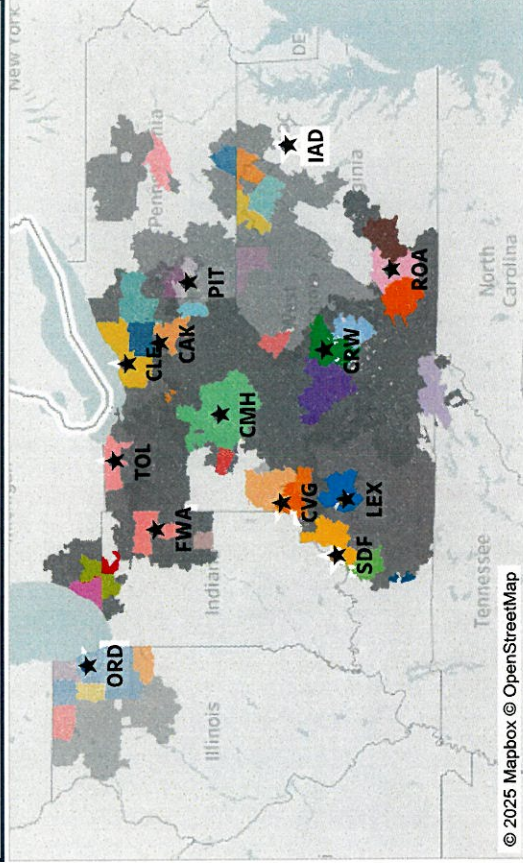
BGE

PEPCO

Metropolitan Statistical Areas and Weather Stations



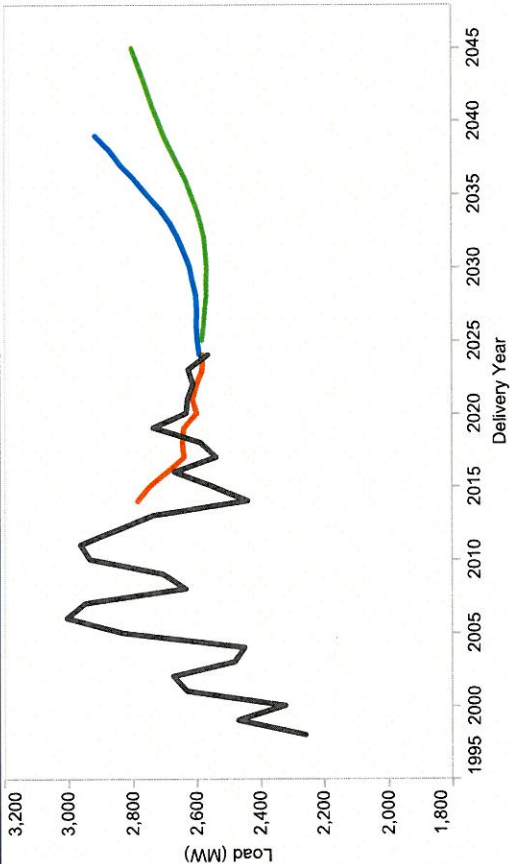
PJM Western



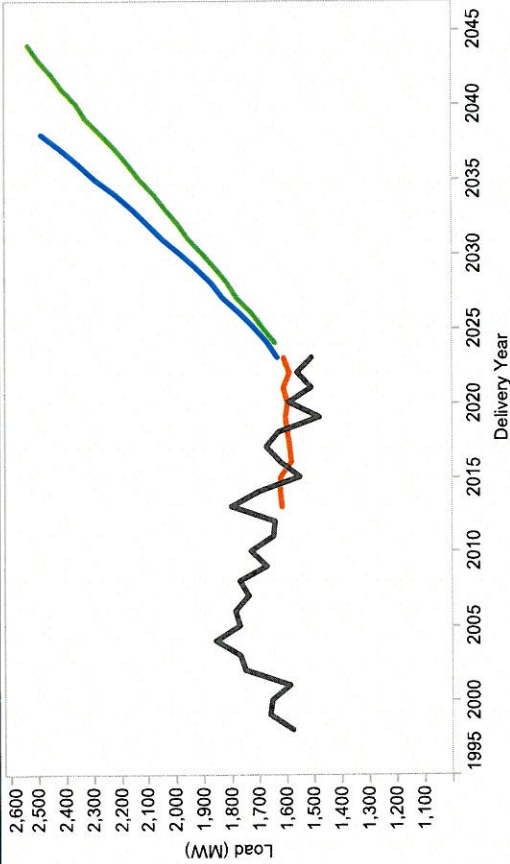
Back to Top 13 | Page

Atlantic Electric (AE)

Summer Peak



Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

Weather - Annual Average 1993-2023

Avg Summer Daily Temp	74.3
Avg Summer Max Temp	97.0
Avg Winter Daily Temp	36.8
Avg Winter Min Temp	6.1

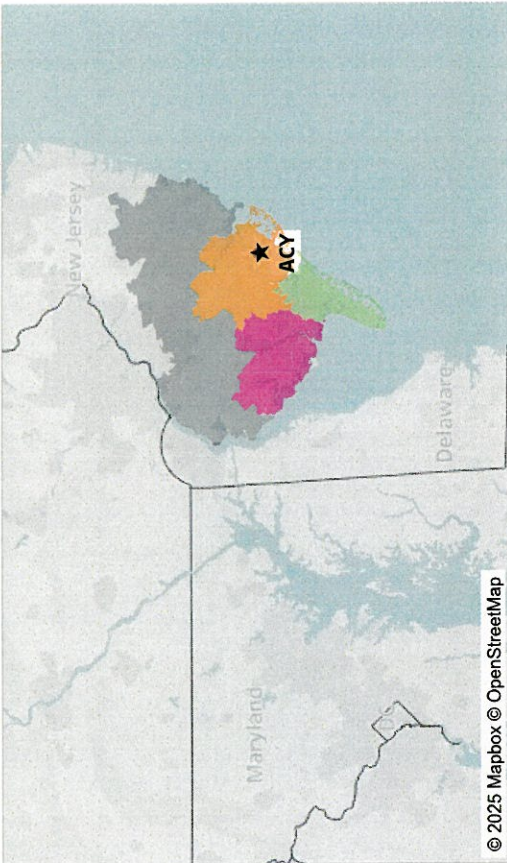
Zonal 10/15/20 Year Load Growth

SUMMER	0.1%	0.3%	0.4%
WINTER	2.4%	2.3%	2.2%

LDAS

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Metropolitan Statistical Areas and Weather Stations



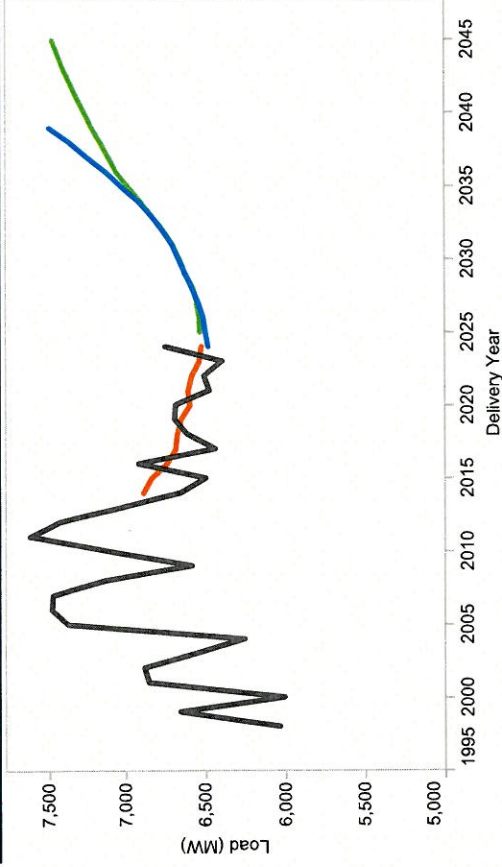
MSA

■ AE - Non-Metro
■ Atlantic City-Hammon, NJ

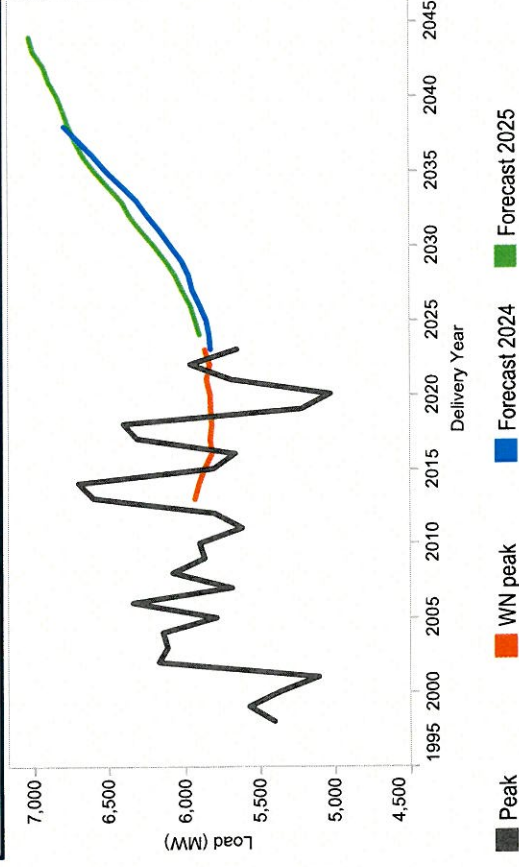
■ Ocean City, NJ
■ Vineland-Bridgeton, NJ

Baltimore Gas & Electric (BGE)

Summer Peak



Winter Peak



■ Peak
 ■ WN peak
 ■ Forecast 2024
 ■ Forecast 2025

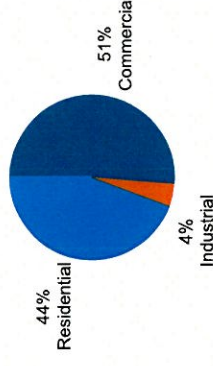
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	76.1
Avg Summer Max Temp	98.0
Avg Winter Daily Temp	36.9
Avg Winter Min Temp	8.0
Zonal 10/15/20 Year Load Growth	
SUMMER	0.7%
WINTER	1.0%

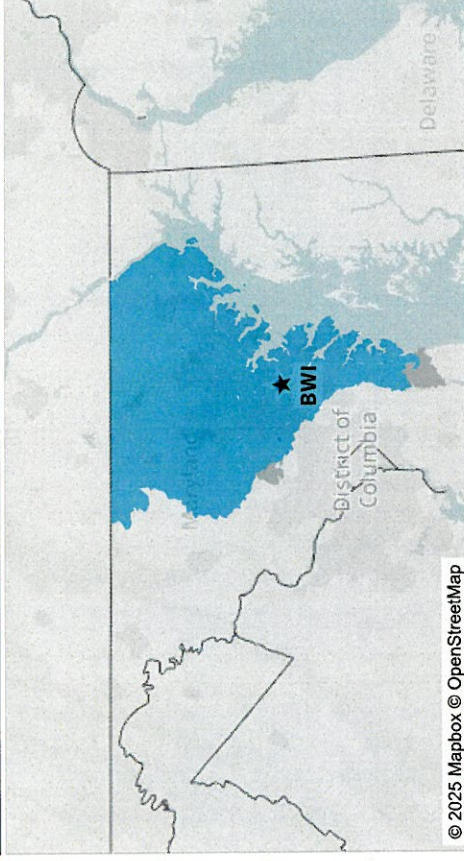
LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

RCI Makeup



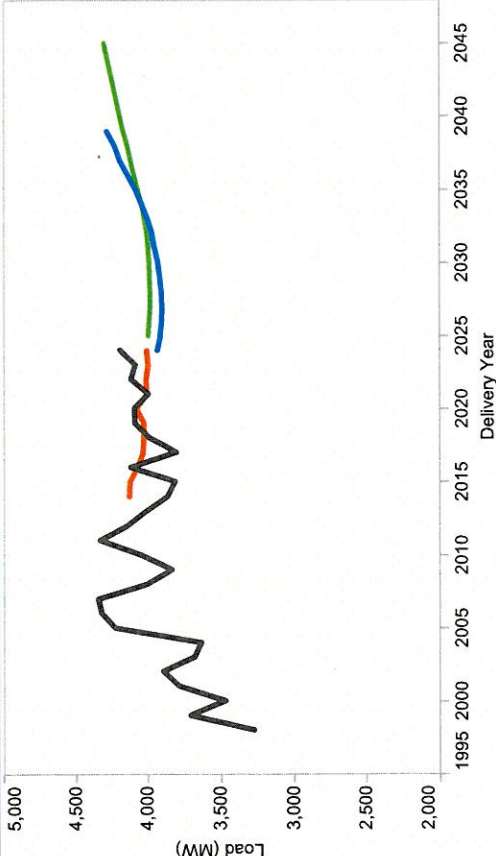
Metropolitan Statistical Areas and Weather Stations



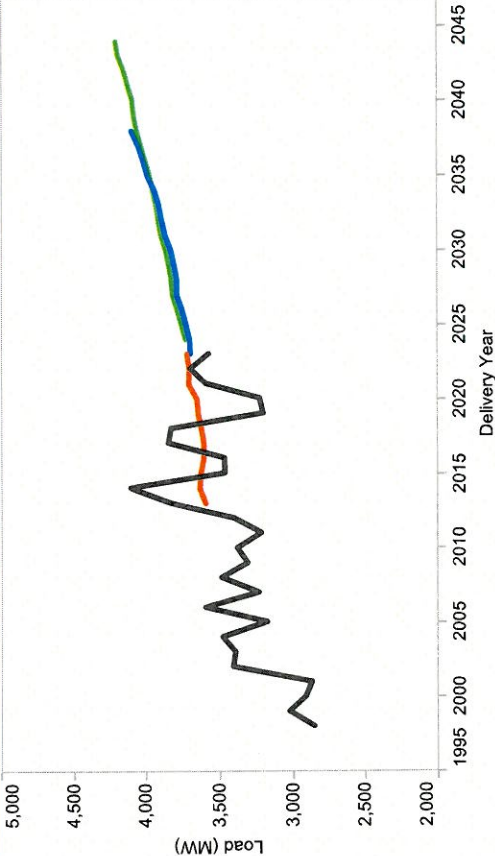
MSA
■ Baltimore-Columbia-Towson, MD
■ BGE - Non-Metro

Delmarva Power and Light (DPL)

Summer Peak



Winter Peak



Weather - Annual Average 1993-2023

Avg Summer Daily Temp	75.5
Avg Summer Max Temp	95.1
Avg Winter Daily Temp	37.2
Avg Winter Min Temp	9.7

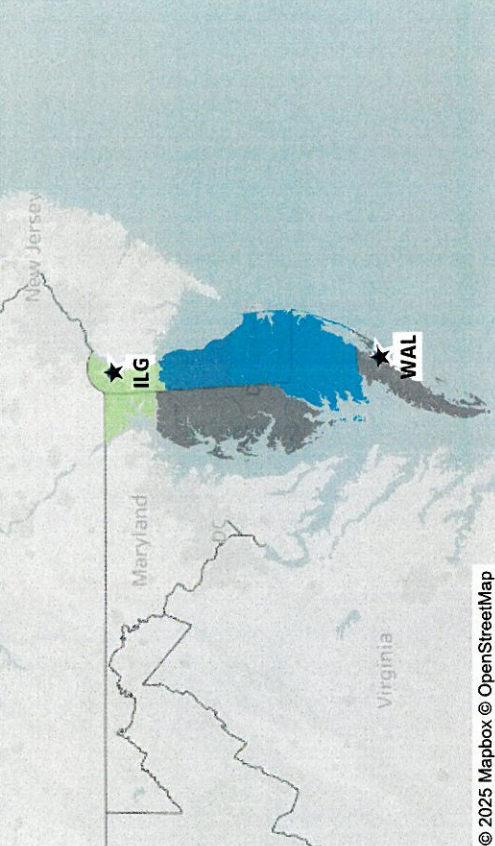
Zonal 10/15/20 Year Load Growth

SUMMER	0.2%	0.3%	0.4%
WINTER	0.6%	0.6%	0.6%

LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

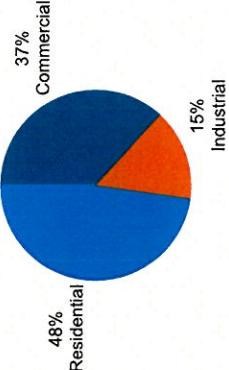
Metropolitan Statistical Areas and Weather Stations



MSA
Dover, DE
DPL - Non-Metro

Salisbury, MD-DE
Wilmington, DE-MD-NJ

RCI Makeup

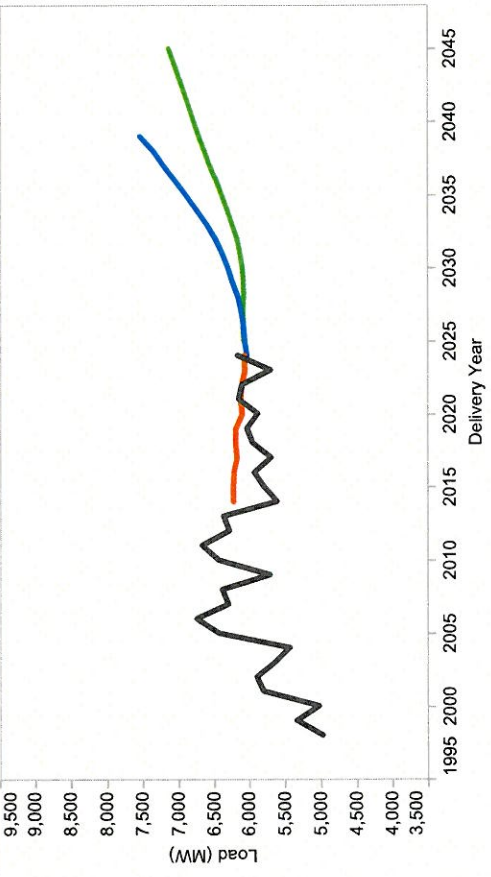
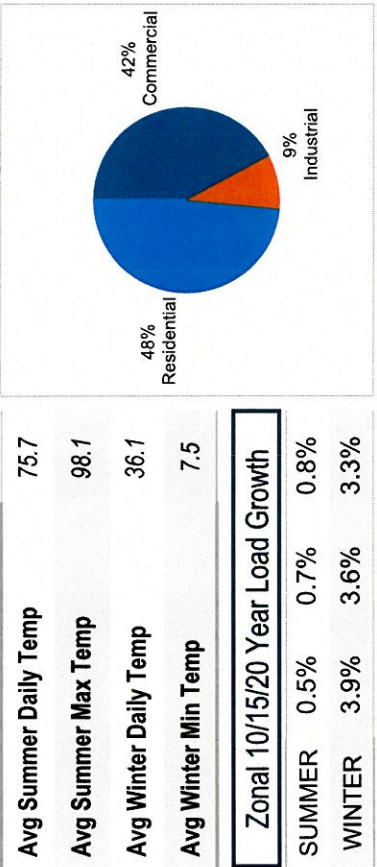


Jersey Central Power and Light (JCPL)

Summer Peak

Weather - Annual Average 1993-2023

RCI Makeup

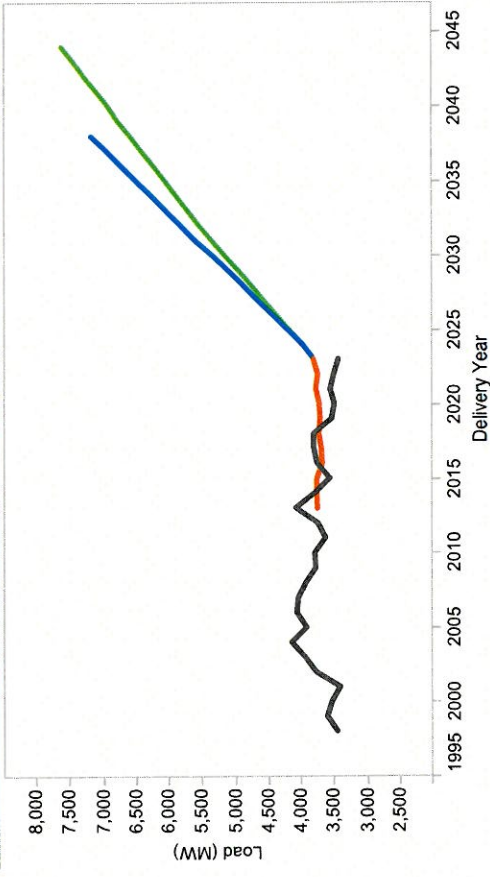


Zonal 10/15/20 Year Load Growth				
SUMMER	0.5%	0.7%	0.8%	
WINTER	3.9%	3.6%	3.3%	

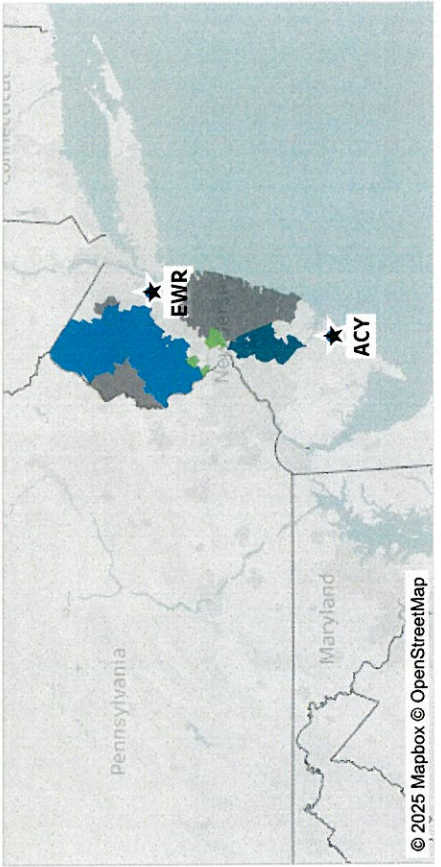
LDAs

EASTERN MID-ATLANTIC GPU PJM MID-ATLANTIC PJM RTO

Winter Peak



Metropolitan Statistical Areas and Weather Stations



Metropolitan Edison (METED)

Summer Peak

Weather - Annual Average 1993-2023

Avg Summer Daily Temp	74.7
Avg Summer Max Temp	95.8
Avg Winter Daily Temp	34.6
Avg Winter Min Temp	6.7

Zonal 10/15/20 Year Load Growth

SUMMER	1.4%	1.8%	1.9%
WINTER	1.6%	2.0%	2.1%

RCI Makeup

Residential	42%
Commercial	15%
Industrial	42%

LDAs

CENTRAL MID-ATLANTIC GPU PJM MID-ATLANTIC PJM RTO

WESTERN MID-ATLANTIC

Metropolitan Statistical Areas and Weather Stations

Winter Peak

MSA

- METED - Non-Metro
- Allentown-Bethlehem-Easton, PA-NJ
- East Stroudsburg, PA
- Gettysburg, PA
- Lebanon, PA
- Reading, PA
- York-Hanover, PA

Forecast 2024

Forecast 2025

Peak

WN peak

Peak

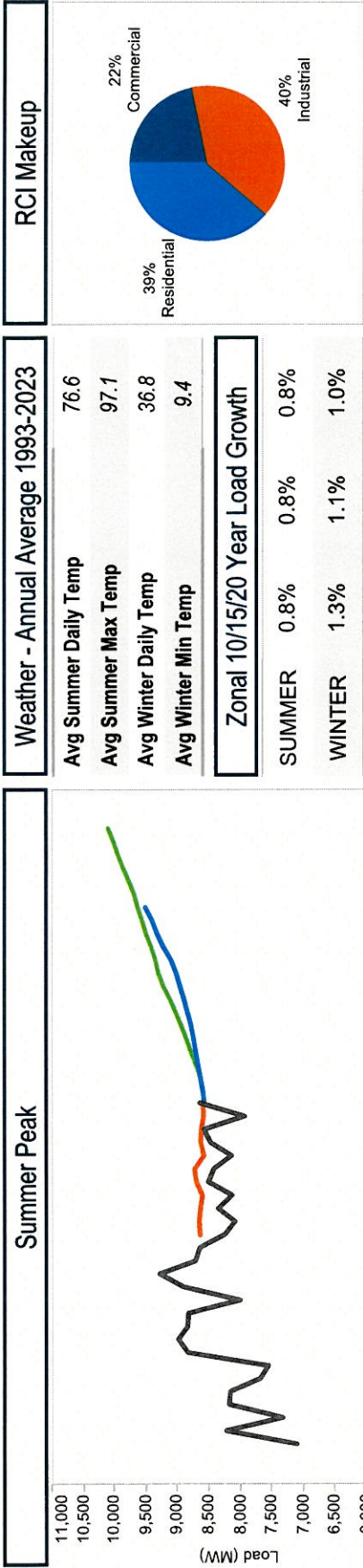
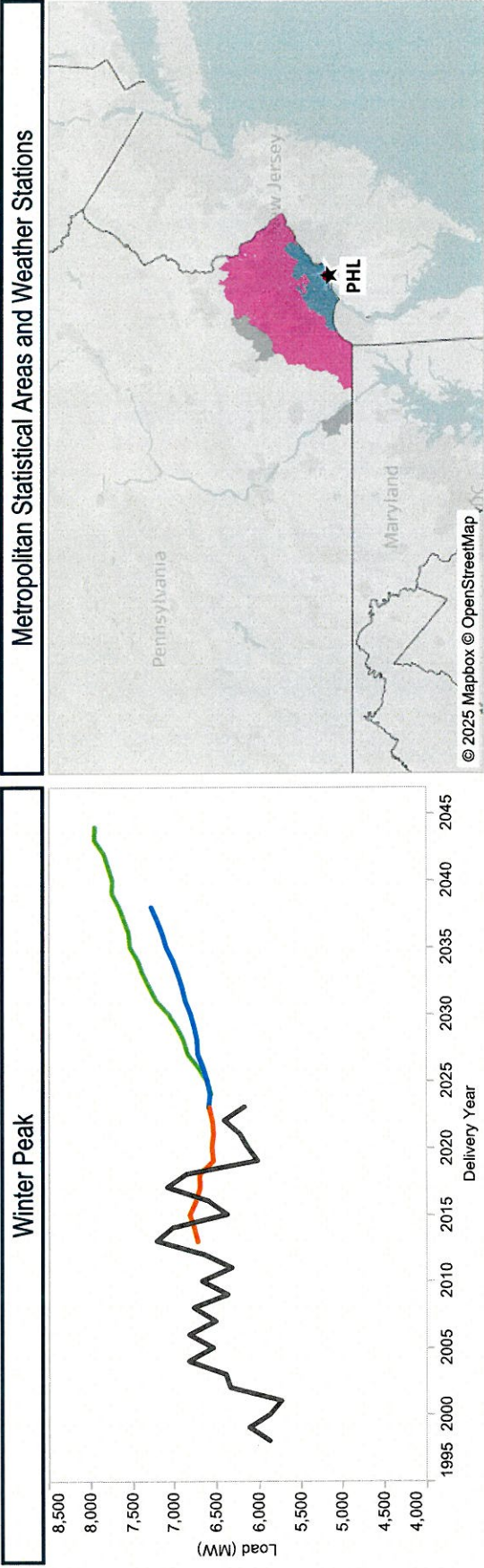
PJM © 2025

[www.pjm.com](#) | For Public Use

[Back to Top](#)

18 | Page

PECO Energy (PECO)

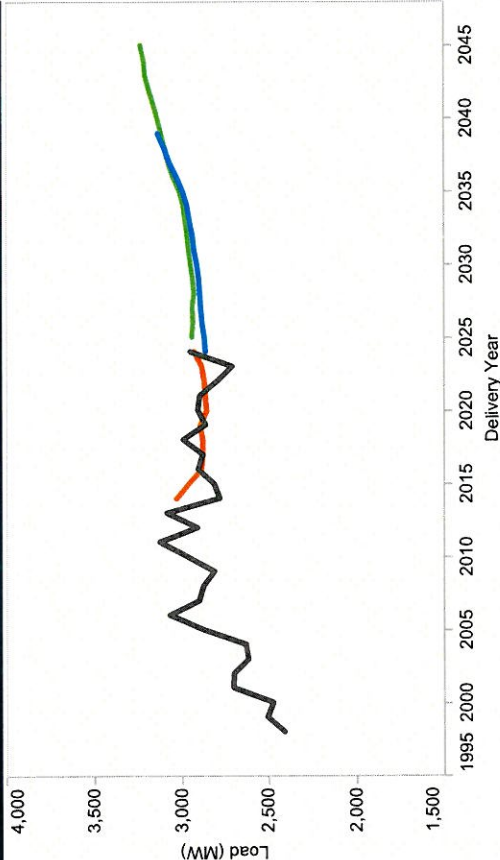


MSA

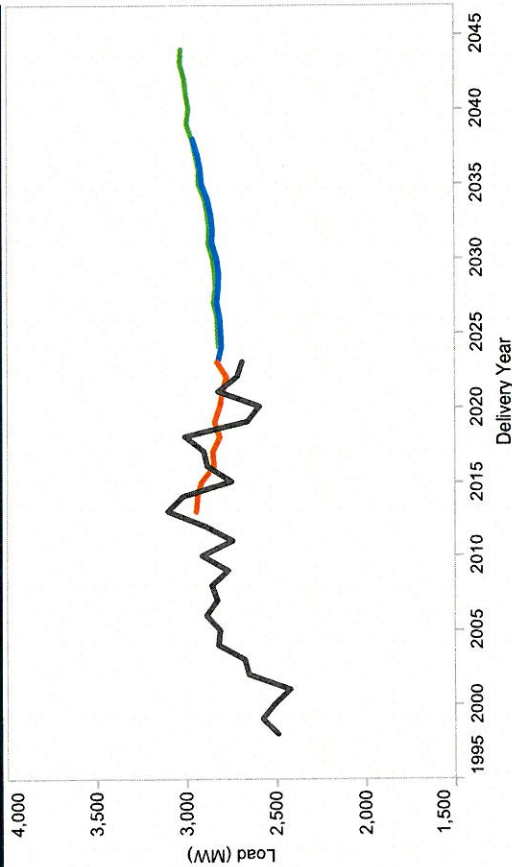
- Montgomery County-Bucks County-Chester County, PA
- PECO - Non-Metro
- Philadelphia, PA

Pennsylvania Electric Company (PENLC)

Summer Peak



Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

Weather - Annual Average 1993-2023

Avg Summer Daily Temp	71.1
Avg Summer Max Temp	91.7
Avg Winter Daily Temp	30.5
Avg Winter Min Temp	2.1

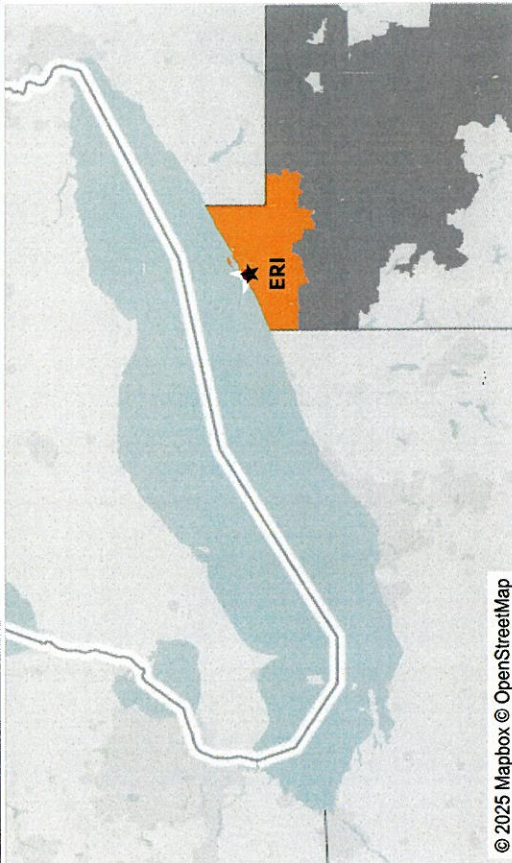
Zonal 10/15/20 Year Load Growth

SUMMER	0.2%	0.4%	0.5%
WINTER	0.3%	0.4%	0.4%

LDAs

GPU PJM MID-ATLANTIC PJM RTO WESTERN MID-ATLANTIC

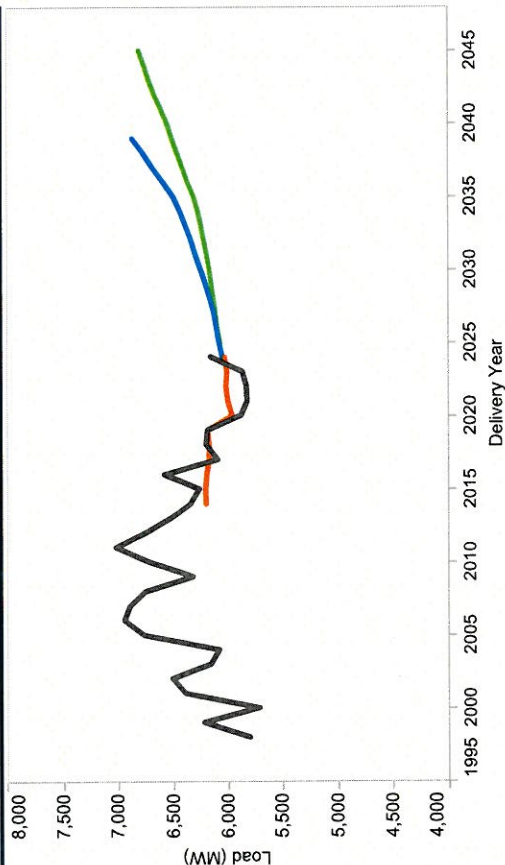
Metropolitan Statistical Areas and Weather Stations



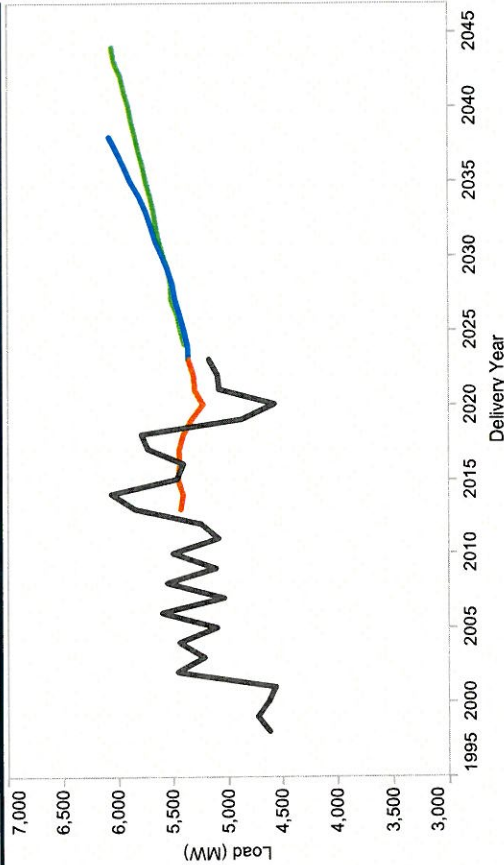
■ Johnstown, PA
■ PENLC - Non-Metro

Potomac Electric Power (PEPCO)

Summer Peak



Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

Weather - Annual Average 1993-2023

Avg Summer Daily Temp	78.1
Avg Summer Max Temp	98.0
Avg Winter Daily Temp	39.2
Avg Winter Min Temp	12.8

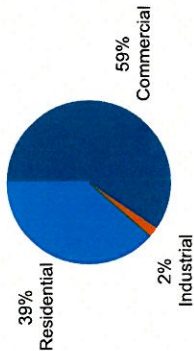
Zonal 10/15/20 Year Load Growth

SUMMER	0.4%	0.5%	0.6%
WINTER	0.6%	0.6%	0.6%

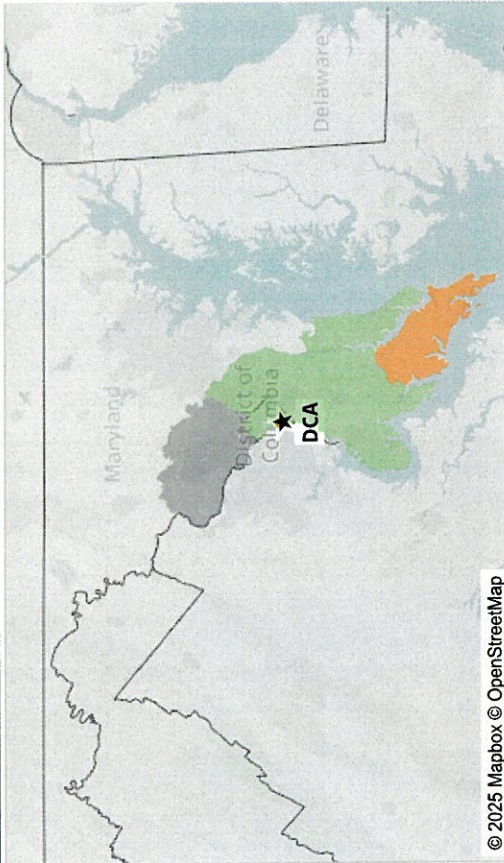
LDAS

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
SOUTHERN MID-ATLANTIC

RCI Makeup



Metropolitan Statistical Areas and Weather Stations

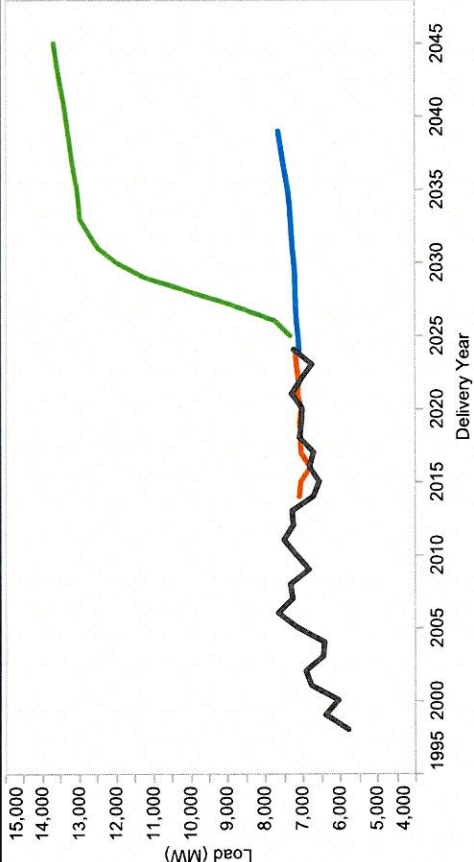


MSA

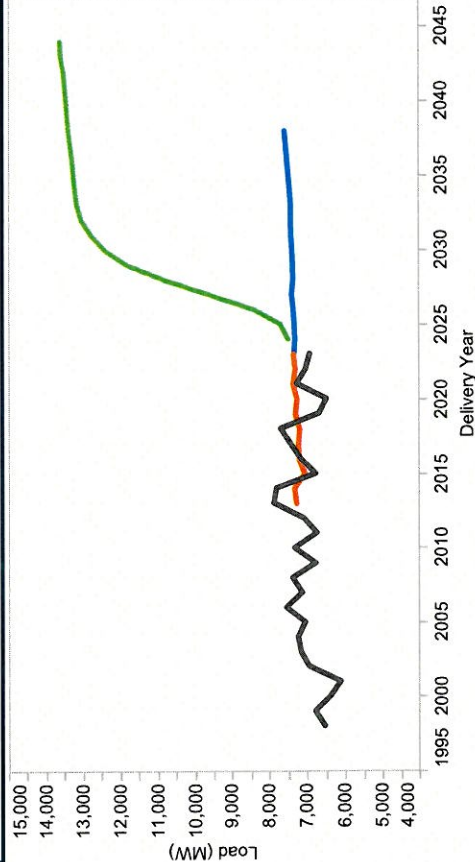
■ Washington-Arlington-Alexandria, DC-VA..
■ California-Lexington Park, MD
■ PEPCO - Non-Metro

PPL Electric Utilities (PL)

Summer Peak



Winter Peak



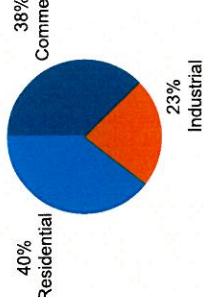
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	72.4
Avg Summer Max Temp	94.2
Avg Winter Daily Temp	31.7
Avg Winter Min Temp	2.9

Zonal 10/15/20 Year Load Growth

SUMMER	5.9%	4.1%	3.2%
WINTER	5.8%	4.0%	3.0%

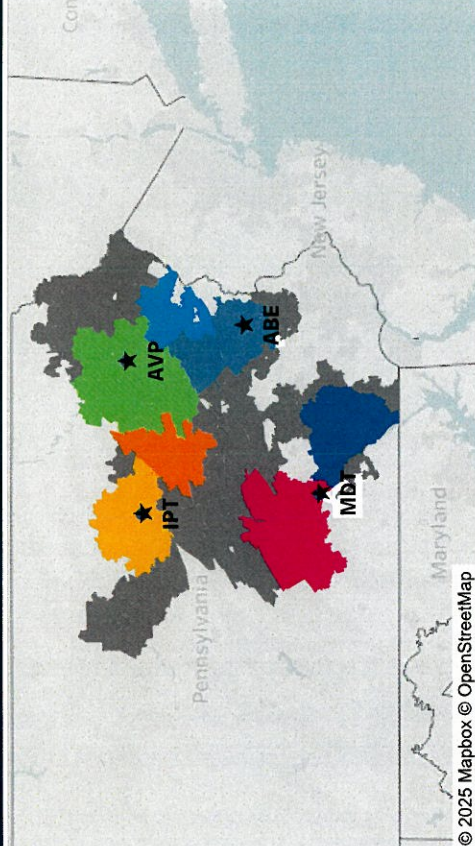
RCI Makeup



LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

Metropolitan Statistical Areas and Weather Stations

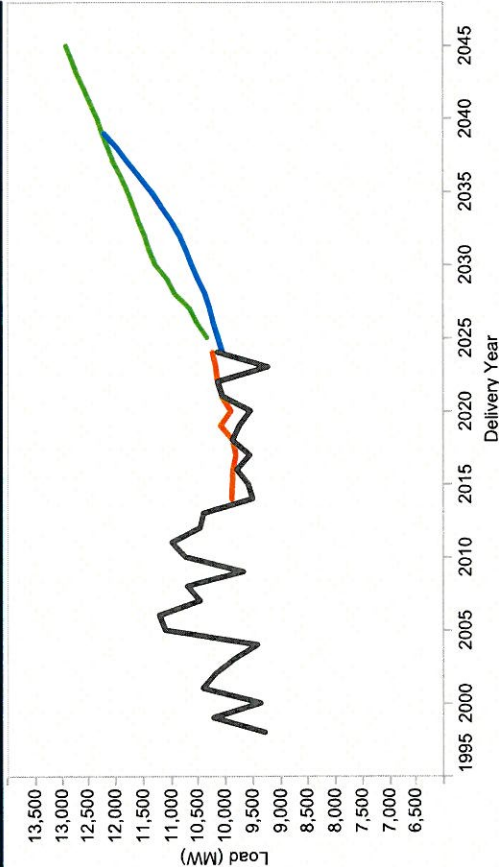


Peak WN peak Forecast 2024 Forecast 2025

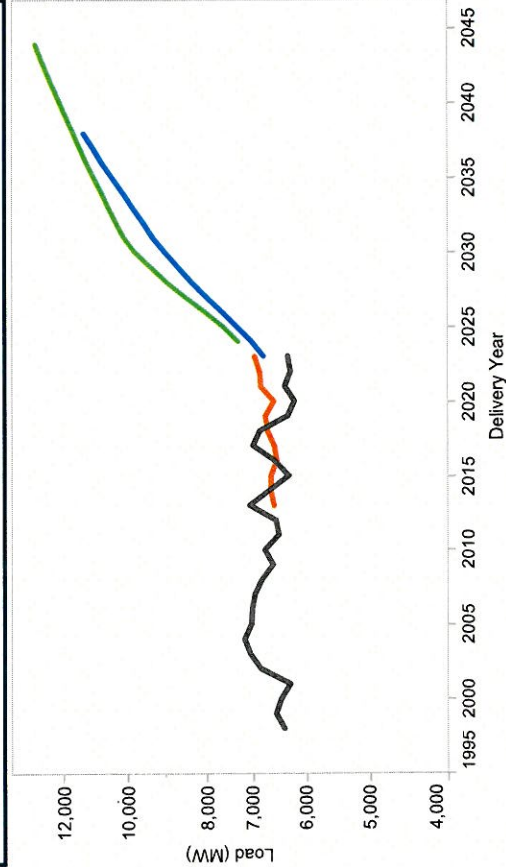
MSA Lancaster, PA Allentown-Bethlehem-Easton, PA-NJ Bloomsburg-Berwick, PA East Stroudsburg, PA Harrisburg-Carlisle, PA PL - Non-Metro Scranton-Wilkes-Barre-Hazleton, PA Williamsport, PA

Public Service Electric & Gas (PS)

Summer Peak



Winter Peak



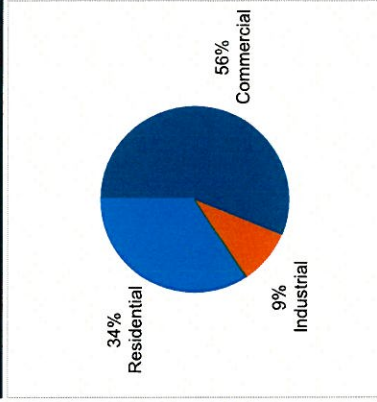
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	76.1
Avg Summer Max Temp	98.9
Avg Winter Daily Temp	35.8
Avg Winter Min Temp	7.4

Zonal 10/15/20 Year Load Growth

SUMMER	1.3%	1.2%	1.1%
WINTER	4.0%	3.3%	2.9%

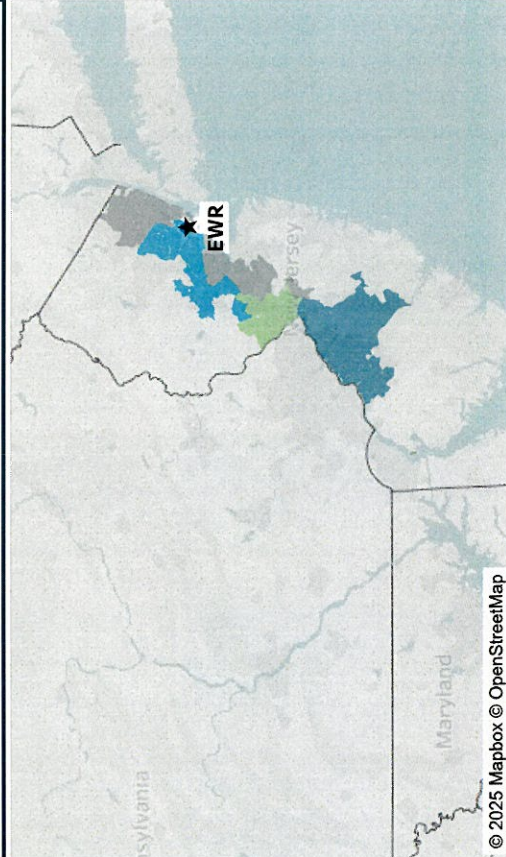
RCI Makeup



LDAs

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Metropolitan Statistical Areas and Weather Stations



Peak WN peak Forecast 2024 Forecast 2025

MSA
Camden, NJ
Newark, NJ-PA
PS - Non-Metro
Trenton, NJ

Rockland Electric Company (RECO)

Summer Peak

Delivery Year

Weather - Annual Average 1993-2023

Avg Summer Daily Temp	76.1
Avg Summer Max Temp	98.9
Avg Winter Daily Temp	35.8
Avg Winter Min Temp	7.4

Zonal 10/15/20 Year Load Growth

SUMMER	0.1%	0.4%	0.5%
WINTER	2.6%	2.5%	2.3%

RCI Makeup

50% Residential
49% Commercial
1% Industrial

LDAS

EASTERN MID-ATLANTIC PJM MID-ATLANTIC PJM RTO

Winter Peak

Delivery Year

Metropolitan Statistical Areas and Weather Stations

© 2025 Mapbox © OpenStreetMap

MSA

- New York-Jersey City-White Plains, NY-NJ
- Newark, NJ-PA

Peak

WN peak

Forecast 2024

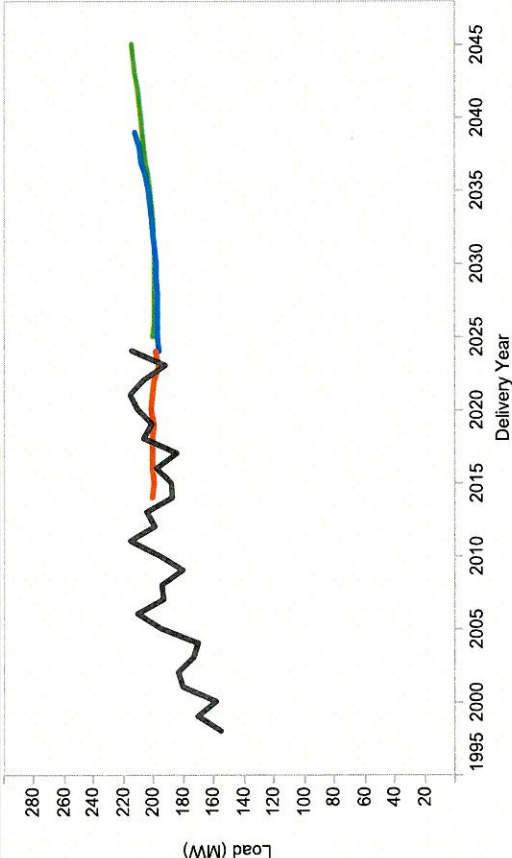
Forecast 2025

PJM © 2025

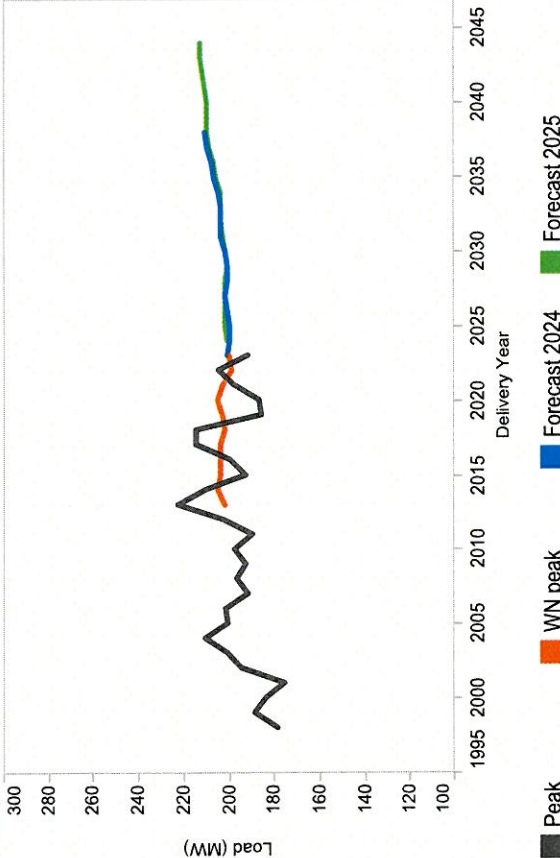
www.pjm.com | For Public Use

UGI Energy Services (UGI)

Summer Peak



Winter Peak



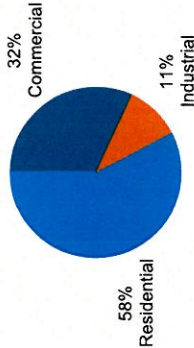
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	70.6
Avg Summer Max Temp	93.2
Avg Winter Daily Temp	30.1
Avg Winter Min Temp	-1.0

Zonal 10/15/20 Year Load Growth

SUMMER	0.1%	0.3%	0.3%
WINTER	0.1%	0.3%	0.3%

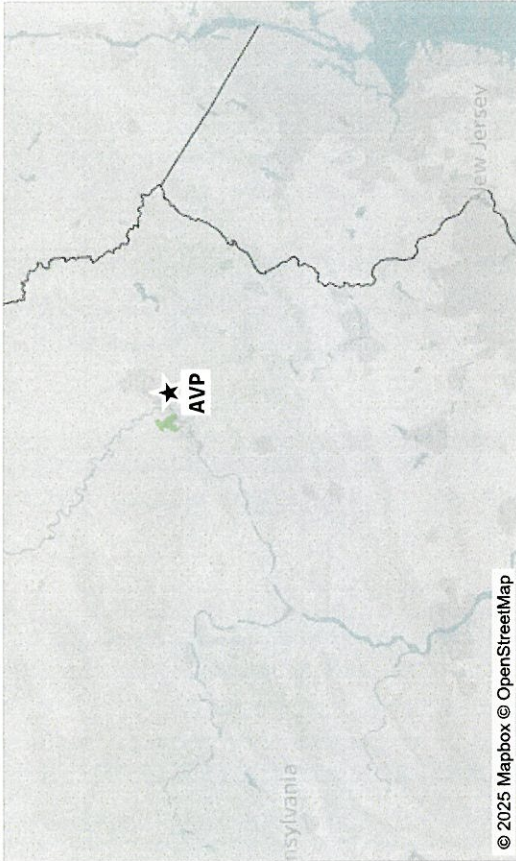
RCI Makeup



LDAs

CENTRAL MID-ATLANTIC PJM MID-ATLANTIC PJM RTO
PLGRP WESTERN MID-ATLANTIC

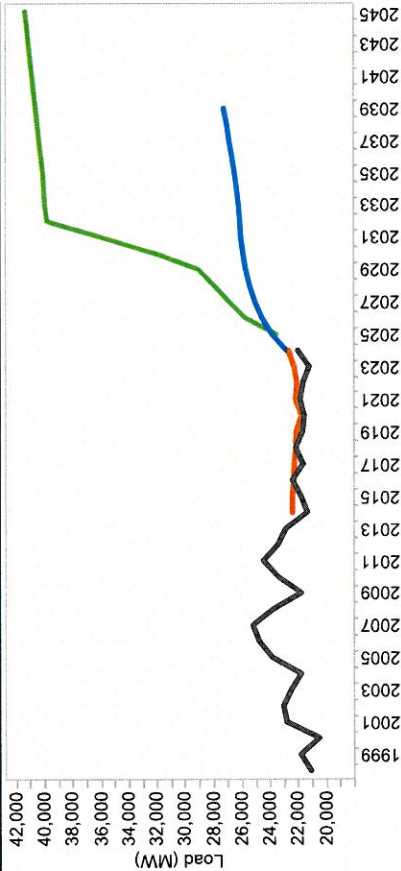
Metropolitan Statistical Areas and Weather Stations



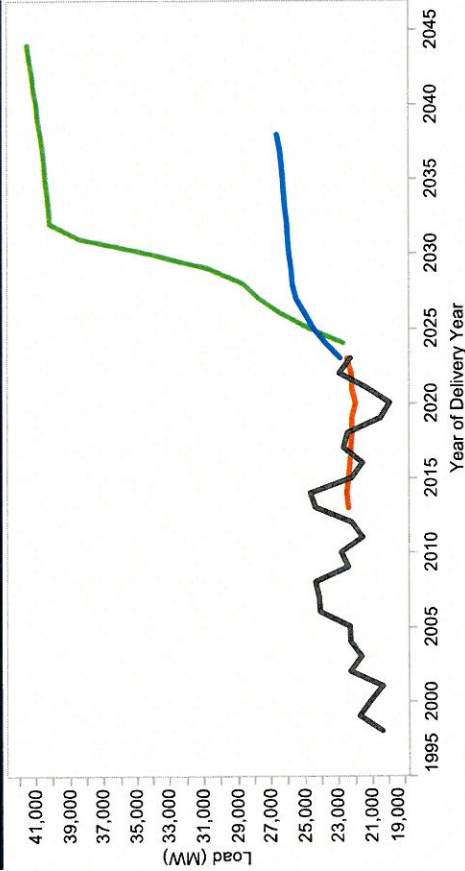
MSA
■ Scranton--Wilkes-Barre--Hazleton, PA

American Electric Power (AEP)

Summer Peak



Winter Peak



Peak
WN peak
Forecast 2024
Forecast 2025

MSA
AEP - Non-Metro
Beckley, WV
Blacksburg-Christiansburg-Radford, VA
Canton-Massillon, OH
Charleston, WV
Columbus, OH

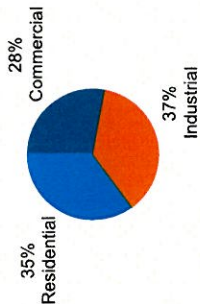
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	73.2
Avg Summer Max Temp	92.3
Avg Winter Daily Temp	33.4
Avg Winter Min Temp	2.9

Zonal 10/15/20 Year Load Growth

SUMMER	5.5%	3.7%	2.9%
WINTER	5.9%	4.0%	3.1%

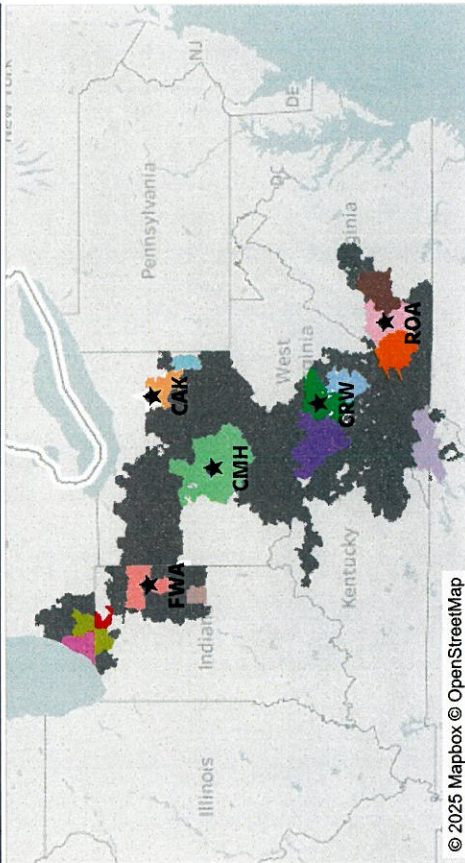
RCI Makeup



LDAS

PJM RTO PJM WESTERN

Metropolitan Statistical Areas and Weather Stations

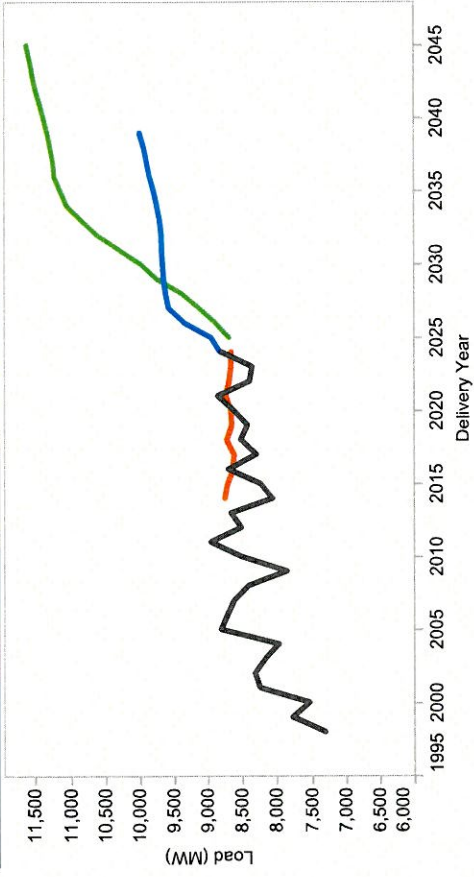


Elkhart-Goshen, IN
Fort Wayne, IN
Huntington-Ashland, WV-KY-OH
Kingsport-Bristol-Bristol, TN-VA
Lynchburg, VA
Muncie, IN

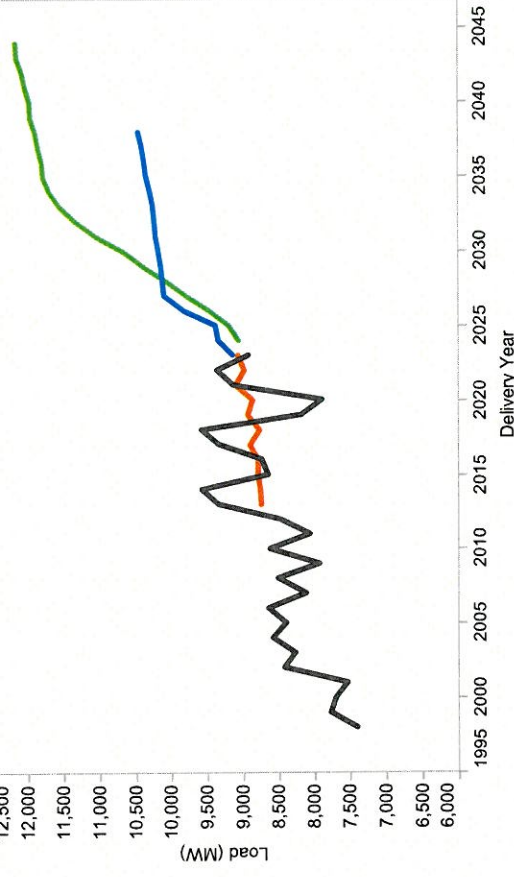
Niles-Benton Harbor, MI
Roanoke, VA
South Bend-Mishawaka, IN-MI
Weirton-Stuebenville, WV-OH

Allegheny Power Systems (APS)

Summer Peak



Winter Peak



■ Peak ■ WN peak ■ Forecast 2024 ■ Forecast 2025

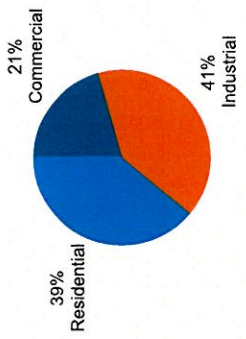
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	72.8
Avg Summer Max Temp	92.6
Avg Winter Daily Temp	33.1
Avg Winter Min Temp	2.4

Zonal 10/15/20 Year Load Growth

SUMMER	2.5%	1.8%	1.5%
WINTER	2.6%	1.9%	1.5%

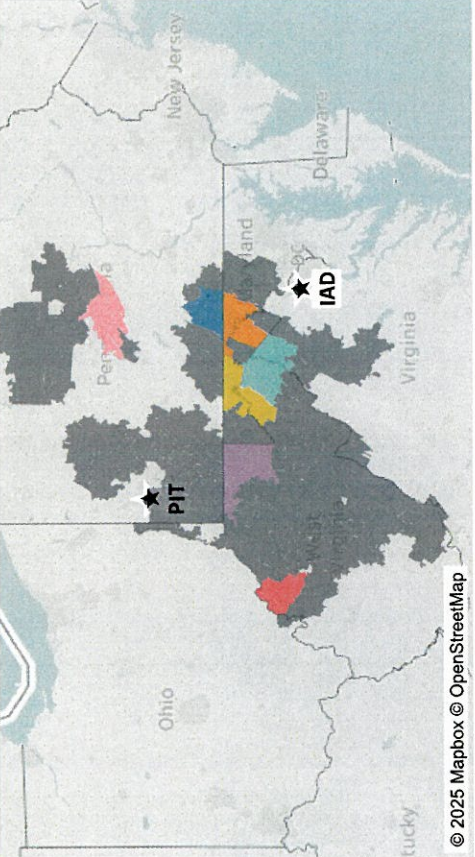
RCI Makeup



LDAs

PJM RTO PJM WESTERN

Metropolitan Statistical Areas and Weather Stations



MSA

- APS - Non-metro
- Chambersburg-Waynesboro, PA
- Cumberland, MD-WV
- Hagerstown-Martinsburg, MD-WV
- Morgantown, WV
- Parkersburg-Vienna, WV
- State College, PA
- Winchester, VA-WV

American Transmission Systems, Inc (ATSI)

Summer Peak

Load (MW)

Delivery Year

Weather - Annual Average 1993-2023

Avg Summer Daily Temp	71.6
Avg Summer Max Temp	91.9
Avg Winter Daily Temp	30.2
Avg Winter Min Temp	-1.0

RCI Makeup

34% Residential

26% Commercial

40% Industrial

Zonal 10/15/20 Year Load Growth

SUMMER	2.3%	1.8%	1.5%
WINTER	2.9%	2.2%	1.8%

LDAs

PJM RTO PJM WESTERN

Winter Peak

Load (MW)

Delivery Year

Metropolitan Statistical Areas and Weather Stations

MSA

- Pittsburgh, PA
- Springfield, OH
- Toledo, OH
- Youngstown-Warren-Boardman, OH-PA

Akron, OH

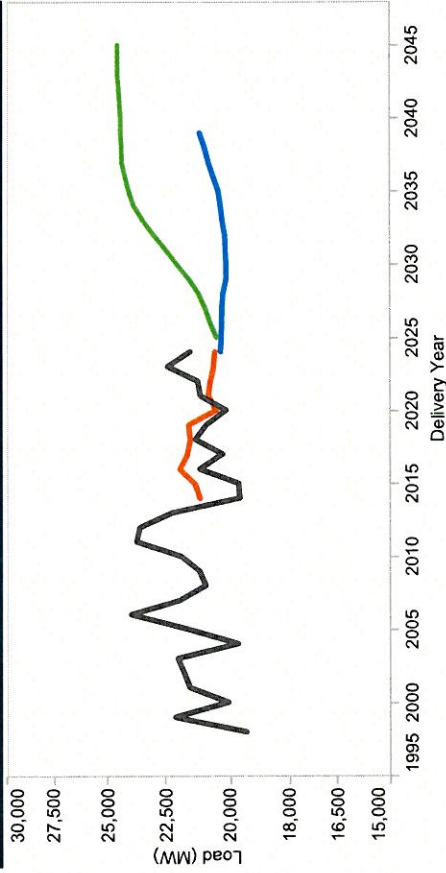
ATSI - Non-Metro

Cleveland-Elyria, OH

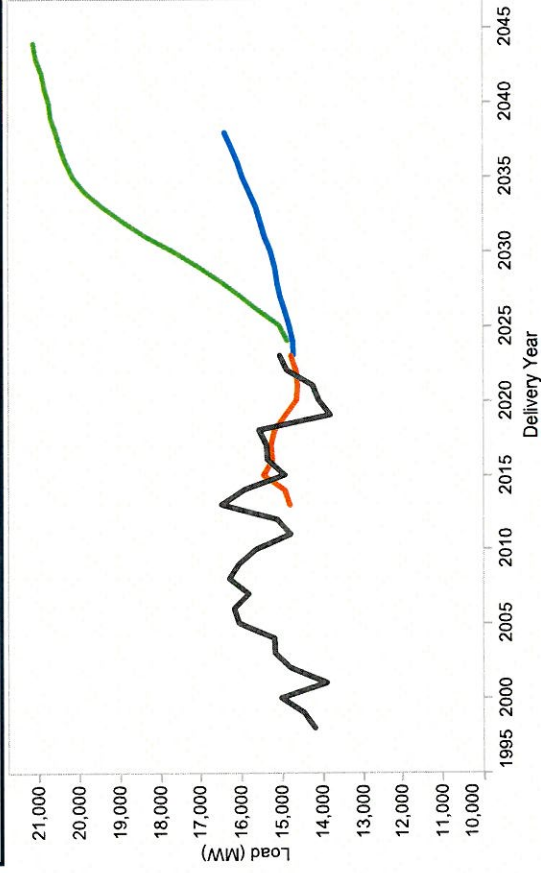
Mansfield, OH

Commonwealth Edison (COMED)

Summer Peak



Winter Peak



■ Peak
 ■ WN peak
 ■ Forecast 2024
 ■ Forecast 2025

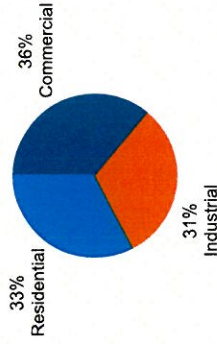
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	73.0
Avg Summer Max Temp	95.5
Avg Winter Daily Temp	27.8
Avg Winter Min Temp	-7.1

Zonal 10/15/20 Year Load Growth

SUMMER	1.6%	1.2%	0.9%
WINTER	2.9%	2.2%	1.8%

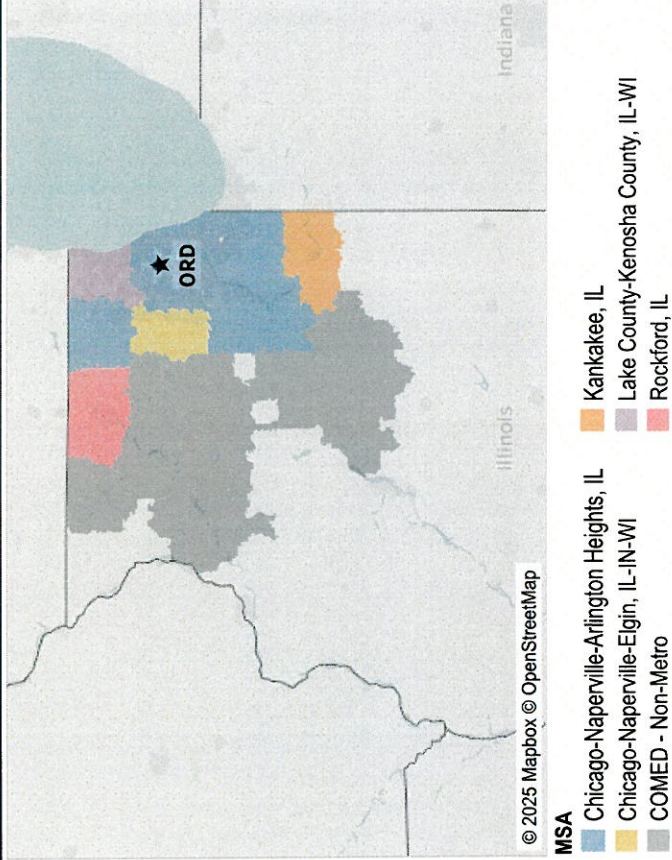
RCI Makeup



LDAS

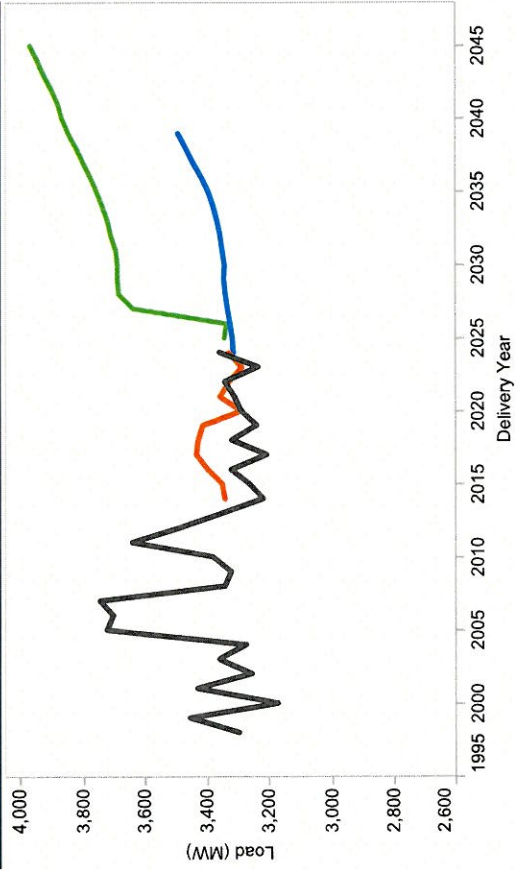
PJM RTO PJM WESTERN

Metropolitan Statistical Areas and Weather Stations

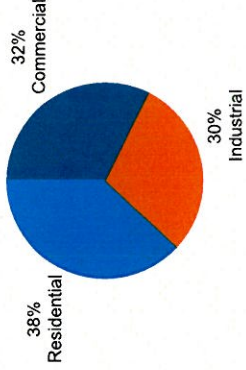


Dayton Power and Light (DAYTON)

Summer Peak	Weather - Annual Average 1993-2023	RCI Makeup
-------------	------------------------------------	------------

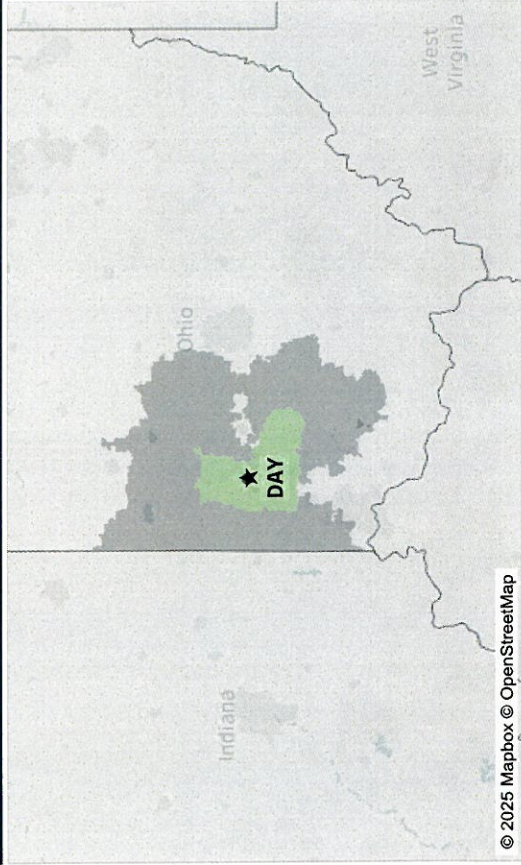
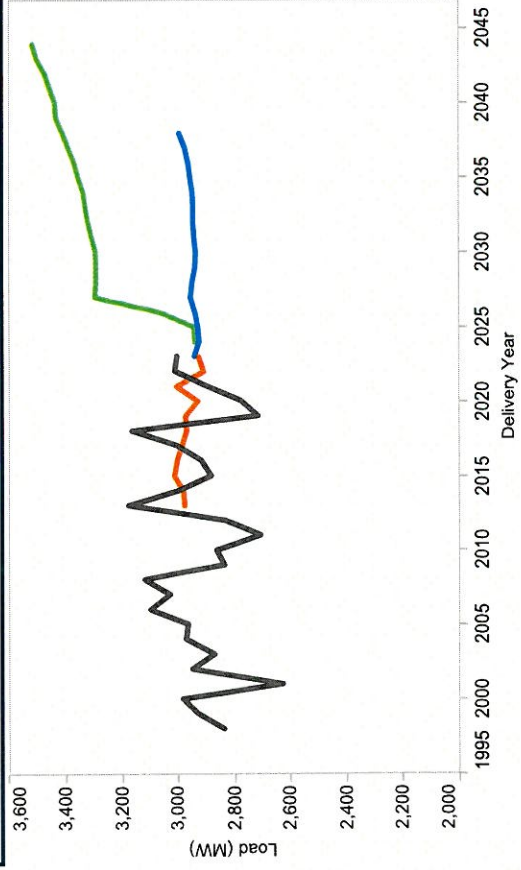


Avg Summer Daily Temp	73.2
Avg Summer Max Temp	93.2
Avg Winter Daily Temp	31.3
Avg Winter Min Temp	-3.0
Zonal 10/15/20 Year Load Growth	
SUMMER	1.2% 1.0% 0.9%
WINTER	1.3% 1.0% 0.9%



LDAs
PJM RTO PJM WESTERN

Metropolitan Statistical Areas and Weather Stations



MSA
■ Peak
■ WN peak
■ Forecast 2024
■ Forecast 2025
■ DAY - Non-Metro
■ Dayton, OH

Duke Energy Ohio and Kentucky (DEOK)

Summer Peak

Load (MW)

Delivery Year

Weather - Annual Average 1993-2023

Avg Summer Daily Temp	74.4
Avg Summer Max Temp	94.2
Avg Winter Daily Temp	34.1
Avg Winter Min Temp	-1.1

Zonal 10/15/20 Year Load Growth

SUMMER	0.7%	0.7%	0.7%
WINTER	0.9%	0.8%	0.8%

RCI Makeup

38% Commercial

37% Residential

25% Industrial

LDAs

PJM RTO PJM WESTERN

Winter Peak

Load (MW)

Delivery Year

Metropolitan Statistical Areas and Weather Stations

MSA

Cincinnati, OH-KY-IN

DEOK - Non-Metro

CVG

© 2025 Mapbox © OpenStreetMap

Duquesne Light Company (DLCO)

Summer Peak

Load (MW)

Delivery Year

Weather - Annual Average 1993-2023

Avg Summer Daily Temp	71.7
Avg Summer Max Temp	91.8
Avg Winter Daily Temp	31.7
Avg Winter Min Temp	-0.8

Zonal 10/15/20 Year Load Growth

SUMMER	0.4%	0.5%	0.6%
WINTER	0.7%	0.8%	0.8%

RCI Makeup

33% Residential

20% Industrial

47% Commercial

LDAs

PJM RTO PJM WESTERN

Winter Peak

Load (MW)

Delivery Year

Metropolitan Statistical Areas and Weather Stations

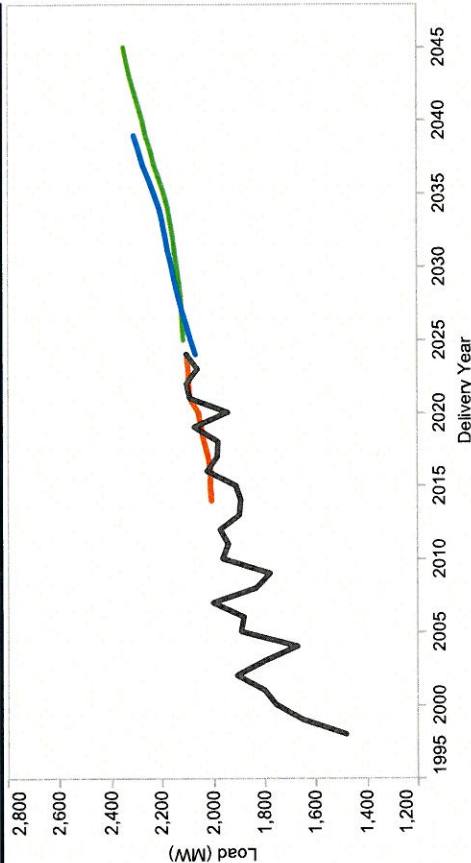
MSA

Pittsburgh, PA

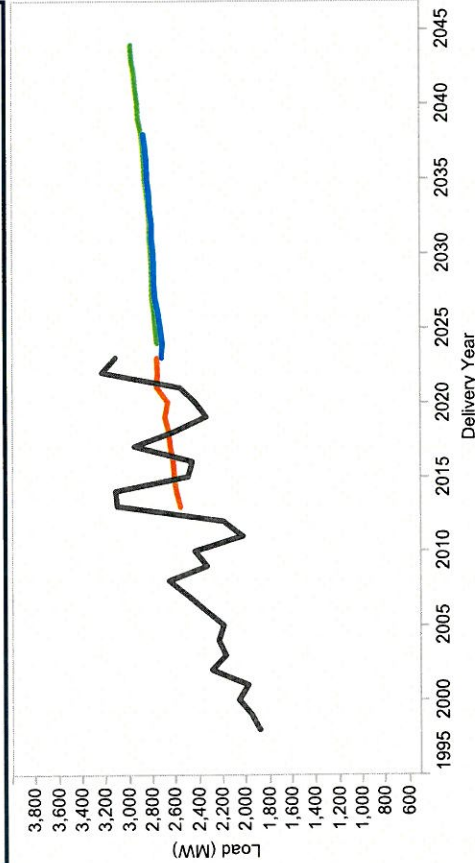
© 2025 Mapbox © OpenStreetMap

East Kentucky Power Cooperative (EKPC)

Summer Peak



Winter Peak



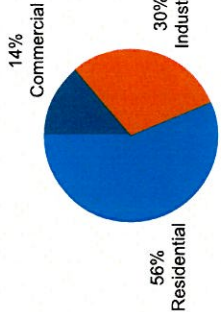
Weather - Annual Average 1993-2023

Avg Summer Daily Temp	75.5
Avg Summer Max Temp	94.4
Avg Winter Daily Temp	36.1
Avg Winter Min Temp	2.4

Zonal 10/15/20 Year Load Growth

SUMMER	0.3%	0.5%	0.5%
WINTER	0.3%	0.4%	0.4%

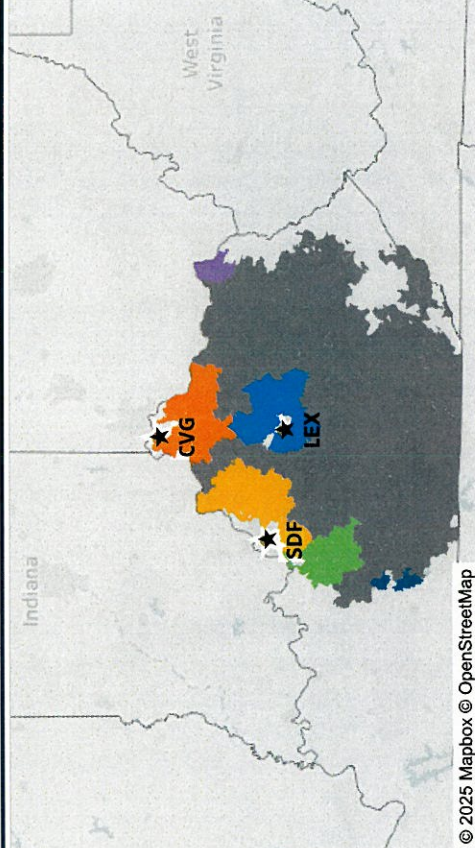
RCI Makeup



LDAS

PJM RTO PJM WESTERN

Metropolitan Statistical Areas and Weather Stations

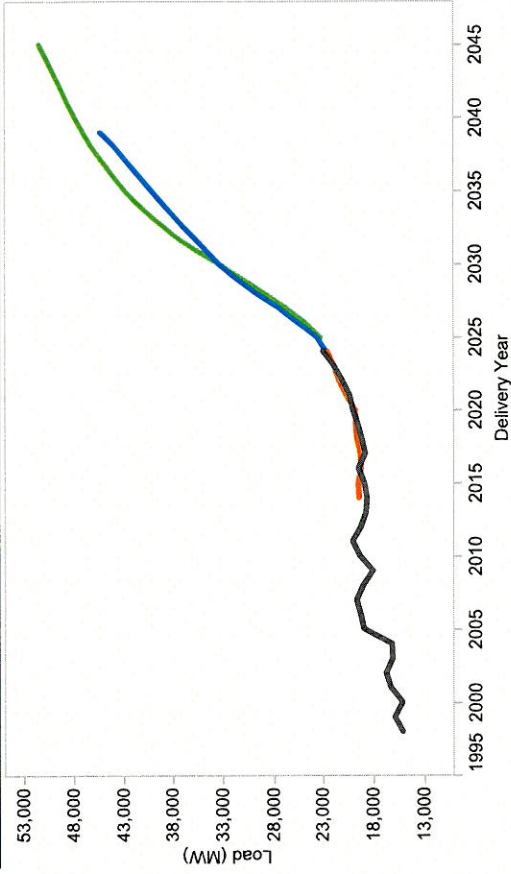


Peak WN peak Forecast 2024 Forecast 2025

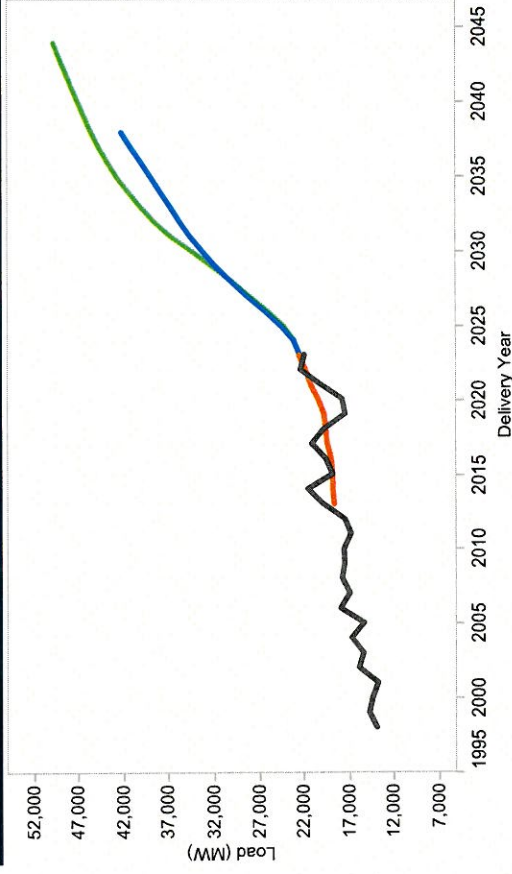
MSA Bowling Green, KY Cincinnati, OH-KY-IN EKPC - Non-Metro Elizabethtown-Fort Knox, KY Huntington-Ashland, WV-KY-OH Lexington-Fayette, KY Louisville/Jefferson County, KY-IN

Dominion (DOM)

Summer Peak



Winter Peak



■ Peak
 ■ WN peak
 ■ Forecast 2024
 ■ Forecast 2025

Weather - Annual Average 1993-2023

Avg Summer Daily Temp	77.0
Avg Summer Max Temp	97.0
Avg Winter Daily Temp	40.5
Avg Winter Min Temp	12.4

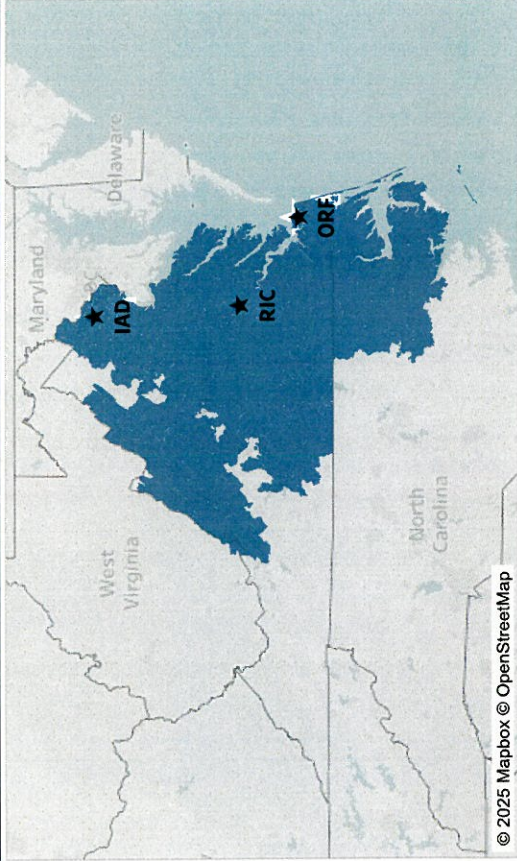
Zonal 10/15/20 Year Load Growth

SUMMER	6.3%	4.9%	4.0%
WINTER	6.0%	4.7%	3.9%

LDAs

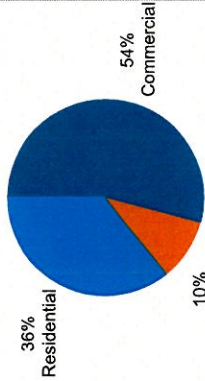
PJM RTO

Metropolitan Statistical Areas and Weather Stations



MSA
■ Virginia Commonwealth Economics

RCI Makeup



WEST VIRGINIA LEGISLATURE

2025 REGULAR SESSION

ENROLLED

Committee Substitute

for

House Bill 2014

BY DELEGATES HANSHAW (MR. SPEAKER), RILEY,
FEHRENBACHER, ANDERSON, ZATEZALO, AKERS AND
HORNBUCKLE

(BY REQUEST OF THE EXECUTIVE)

[Passed April 12, 2025; in effect 90 days from
passage (July 11, 2025)]

1 AN ACT to amend and reenact §5B-2-21, §24-2-1d, §24-2-1q, §24- 2-15, §24-2-19, and §24-2-
2 21a of the Code of West Virginia, 1931, as amended; to amend the code by adding four
3 new sections, designated §5B-2-21a, §5B-2-21b, §5B-2N-2a, and §11B-2- 33, and to
4 amend the code by adding a new article, designated §11-6N-1, §11-6N-2, §11-6N-3, §11-
5 6N-4, and §11-6N-5, all relating to the generation and consumption of electric power;
6 establishing the certified microgrid development program; providing for microgrid
7 certification requirements; providing for microgrid electric service requirements; providing
8 for microgrid customer eligibility; providing for microgrid special contracts; prohibiting
9 microgrids from participating in Pilot and tax increment financing programs; defining
10 microgrid property subject to property tax; providing for microgrid letter of intent, notice
11 period and negotiation; providing for microgrid special contracts; establishing the high
12 impact data center program; providing for notification, certification, and recordkeeping;
13 authorizing certain agencies to assist certified microgrid districts and certified high impact
14 data centers; prohibiting local jurisdiction regulation of microgrid districts and high impact
15 data centers; providing for payment of certain fees and taxes; providing for certain services
16 to microgrid districts and certified high impact data centers; establishing the electric grid
17 stabilization and security fund and its purpose; creating new article relating to special
18 method for valuation of certain high technology property; defining terms; providing for
19 microgrid districts and certified high impact data centers property returns to be filed with
20 Board of Public Works; providing for special rules for tax distribution; establishing certain
21 funds to receive distributions; terminating article; establishing the personal income tax
22 reduction fund and providing for purpose; providing for additional duties of public service
23 commission 2 relating to future electric generating capacity, base fuel coal supply for
24 electric grid resiliency, consumer rate relief bonds, and automatic adjustment clauses,
25 price indexes, or fuel adjustment; providing for rulemaking; and providing that certain
26 funds may not be used by a public utility to close or cease operations at an electric
27 generating plant.

Be it enacted by the Legislature of West Virginia:

CHAPTER 5B. ECONOMIC DEVELOPMENT ACT OF 1985.

ARTICLE 2. DEPARTMENT OF ECONOMIC DEVELOPMENT.

§5B-2-21. Certified Microgrid Development Program.

1 (a) *Program established.* — The Certified Microgrid Development Program is hereby
2 created and is to be administered as a program within the Division of Economic Development to
3 encourage the continued development, construction, operation, maintenance, and expansion in
4 West Virginia of high impact plants and facilities, in certain circumstances where the availability
5 of electricity generated is demonstrated to be necessary. In order to effectuate the purposes of
6 this section, the Division of Economic Development, or any agency, division, or subdivision
7 thereof, may propose for promulgation of legislative rules, including emergency rules, in
8 accordance with §29A-3-1 *et seq.* of this code.

9 (b) *District certification.* — The Secretary of the Department of Commerce may identify
10 and certify microgrid districts in this state upon a finding that the following requirements are met:

11 (1) Certification of the microgrid district and location of new or expanded businesses within
12 the microgrid district will have a significant and positive economic impact on the state;

13 (2) Certification of the microgrid district is necessary to attract at least two businesses to
14 locate or expand in this state;

15 (3) The area to be certified as a microgrid district shall be no greater than 2,250 acres and
16 nearly contiguous;

17 (4) The electricity generated within the microgrid district will be used only within the
18 microgrid district or delivered to the wholesale market;

19 (5) The information described in §5B-2-21(h) of this code has been provided to the
20 Department of Commerce;

21 (6) The requirements of §5B-2-21(i) of this code have been satisfied; and

(7) The requirements of §5B-2-21(b)(5) and (6) of this code may not apply to microgrid districts certified on or before January 1, 2024;

(8) The requirements of subsections (d), (e), (g), (h), and (j) of this section enacted during the regular session of the Legislature, 2025, shall not apply to any microgrid district certified on or before January 1, 2024, or any special contract entered into and approved by the Public Service Commission on or before January 1, 2025. No amendments to this section enacted during the regular session of the Legislature, 2025, shall be interpreted to remove an existing microgrid district certification.

The Secretary of the Department of Commerce may not certify more than two microgrid districts: *Provided*, That this limit on certifying microgrid districts shall not apply to any microgrid district wherein greater than 70% of the electricity generated within the microgrid district is consumed by one or more high impact data centers, as defined in §11-6N-2 of this code, or will be consumed by one or more high impact data centers, when such data centers are completed and fully operational. A designation made pursuant to this section by the secretary as to the certification of a microgrid district is final.

(c) *Providing electric service within a certified microgrid district.* — Within a microgrid district, any person, firm, corporation, or entity or their lessees and tenants seeking to provide electric service through the generation or distribution of electricity within the microgrid district to businesses locating within the microgrid district may:

(1) Not be subject to the jurisdiction of the Public Service Commission with respect to rates, obtaining a certificate of convenience and necessity, conditions of service or complaints pursuant to chapter 24 of this code;

(2) Not be subject to the net metering and interconnection standards as set forth in §24-2F-8 of this code;

(3) Elect to qualify as an exempt wholesale generator under federal law for purposes of furnishing electric service through the generation of electricity to a utility or regional transmission

organization without being subject to the Public Service Commission's siting certificate requirements as set forth in §24-2-1(d), §24-2-11c, or §24-2-1o of this code;

(4) Provide any such electric service to businesses making a capital investment in a new or expanded facility located within the certified microgrid district;

(5) Not provide any such electric service for purposes of encouraging businesses already receiving electric service from a regulated utility in this state to relocate to the certified microgrid district; and

(6) Not deliver outside the microgrid district more than 10% of the electricity generated within the certified microgrid district and only delivered to the wholesale market.

(d) *Microgrid customers; eligibility.* — In order to take advantage of the provisions of this section, a plant or facility choosing to locate and operate within a microgrid district must constitute new electric load. Any owner, lessee, or tenant of a plant or facility that has not previously received electric service from a regulated public electric utility located within this state, or who is making a capital investment in a new facility within the microgrid district shall be considered eligible new electric load. Electric service to any such plant or facility shall be considered new electric load so long as any customer making a new capital investment within the microgrid district does not decrease the load of an existing facility outside the microgrid district in this state in conjunction with the new capital investment within the microgrid district, and regardless of whether or not a person or entity previously received service from a public electric utility at or near the same location prior to the certification of the microgrid district.

An eligible plant or facility choosing to locate and operate within a microgrid district is not required to connect with and use any public electric utility: *Provided*, That any connection with and use of a public electric utility for purposes of the initial construction and development within the microgrid district shall not impact a plant or facility's status as new electric load in order to take advantage of the provisions of this section.

73 (e) *Microgrid customers; special contracts and rates.* — After certification of a microgrid
74 district, the Public Service Commission may approve special contracts for a a microgrid customer
75 within the microgrid district. For purposes of this section, a “special contract” is:

76 (1) a written agreement between an electric utility and an eligible retail electric microgrid
77 customer within the microgrid district that is filed with the Public Service Commission and that
78 provides that an eligible retail electric microgrid customer will receive utility service on terms and
79 conditions, including rates, that vary from the utility’s tariff on file with the Public Service
80 Commission, or

81 (2) electric utility service terms and conditions, including rates, ordered by the Public
82 Service Commission that vary from the electric utility’s tariff to be in effect between a utility and
83 an eligible retail electric microgrid customer when the electric utility and the eligible retail electric
84 microgrid customer are unable to negotiate a written agreement.

85 A microgrid customer seeking a special contract shall first enter into negotiations with the
86 utility within whose service territory the microgrid district is located regarding the terms and
87 conditions of a mutually agreeable special contract. If the negotiations result in an agreement
88 between the microgrid customer and the utility within 120 days, the microgrid customer and the
89 utility shall jointly file with the Public Service Commission the special contract. If the negotiations
90 are unsuccessful in the 120-day period, the microgrid customer may file a petition with the Public
91 Service Commission to consider establishing a special contract. The Public Service Commission
92 shall consider all relevant factors in establishing a special contract. Upon the filing of a petition
93 pursuant to this section, the Public Service Commission shall establish a special contract for the
94 provision of requested service, including backup and supplemental service to a microgrid
95 customer within the microgrid district. Microgrid customers’ load within the microgrid district not
96 covered by a contract for back up and supplemental service shall be considered non-firm and
97 interruptible. The Public Service Commission shall establish a special contract upon the filing of
98 a petition pursuant to this section and shall do so within 90 days of filing.

(f) *Electrical infrastructure costs.* — Regulated electric utility customers shall not bear any costs including, but not limited to, construction, operational, ancillary services, grid-related, energy-related, or capacity-related costs, associated with any electricity generation, transmission or distribution facilities that provide electrical service to a microgrid district. Any costs of this nature are to be borne by the generator or electricity consumers situated within the microgrid district.

(g)(1) *Payment In Lieu Of Taxes Electricity Generation and Distribution.* — Notwithstanding the provisions of §5D-1-14, §7-5-13, §7-11B-3(b), §7-11B-8(c)(4), §7-11B-15(a)(7), §7-11B-15(a)(15), §7-11B-18, §8-19-4, §8-29A-7, §8A-12-12, §11-13-2p, §11-13C-5(l)(1)(A), §16-13A-21, §16-15-18(b)(6), §17-16A-16(b), §17-16B-20(b), §18-9A-12(c), § 31-21-5, and §31-21-15 of this code, or any other provision of this code, no payment in lieu of taxes shall be entered into with relation to the property of any electricity generating plant, facility, or generating unit or any property comprising, in whole or in part, any electricity distribution apparatus, equipment, lines or facilities (A) located in the county and (B) directly or indirectly dedicated to providing electric power to any plant, facility or property subject to this subsection. Nor shall any payment in lieu of taxes be entered into with relation to any leasehold interest or any other property interest related thereto.

(2) *Tax Increment Financing.* — Notwithstanding the provisions of §7-11B-1 *et seq.* of this code, or any other provision of this code, no tax increment financing project, plan or arrangement shall be entered into or undertaken with relation to any electricity generation or distribution property subject to this subsection.

(3) For purposes of this subsection, an electricity generating plant, facility, or generating unit or electricity distribution apparatus, equipment, lines, or facilities shall be deemed to be "dedicated" to providing electric power to any plant, facility, or property subject to this subsection if not less than 75% of the output of the electricity generation property or electricity distribution property, measured in kilowatt hours, are used to supply electricity to a facility, project, or series of related or integrated facilities within the county or counties subject to this subsection.

(4) For purposes of this section, property includes all real property, all buildings and structures affixed to land, and all tangible personal property, including, but not limited to equipment, inventories and mobile equipment, and also including property subject to special salvage valuation under §11-6A-1 *et seq.*, §11-6E-1 *et seq.*, §11-6H-1 *et seq.*, §11-6J-1 *et seq.*, §11-6F-1 *et seq.*, and §11-6L-1 *et seq.* of this code, or any other special *ad valorem* property valuation provision of this code; *Provided*, That property subject to special valuation shall be allowed that special valuation as authorized by law, for purposes of calculating and determining the *ad valorem* property tax imposed with relation thereto, notwithstanding being otherwise subject to the provisions of this section.

(h) *Microgrid District Development; Letters of Intent.* — To become a certified microgrid district under this section, the person or entity must present the Secretary of the Department of Commerce with a confidential letter of intent. The letter of intent shall include sufficient economic, financial, and engineering information concerning the proposed project with sufficient detail to adequately inform the department of the size, scope, and nature of the target customers of the project, including, without limitation, the approximate proposed acreage and location, estimated capital investment, evidence of financial capacity, estimated project completion date, major project milestones, estimated generation capacity, estimated power loading internal to the microgrid, estimated power, including backup power, needed from the local distribution electric utility, estimated power supplied to the wholesale market, and the types or sources of each electric power generation unit. The letter of intent and all supplied information shall be held in confidence pursuant to §5B-2-21a(e) of this code by the department.

(i) *Microgrid District Development; Notice Period and Negotiation.* — At least 120 days before submitting a letter of intent and other materials to the department, an applicant seeking a microgrid district certification must make good faith efforts to negotiate for the supply of all or part of its electricity needs for the project from the local distribution electric utility. The letter of intent must also include documentation evidencing the good faith efforts to negotiate. This time-period

150 limitation and negotiation requirement does not apply to microgrid districts proposing to produce
151 300 megawatts or more of electricity or for microgrid districts that are proposing to not be
152 connected in any way to the local distribution electric utility after completion of all construction.

153 (j) *Microgrid District Development; Special Contracts and Power Rates.* — (1) A certified
154 microgrid district seeking a special contract from a local distribution electric utility located in the
155 state shall first enter negotiations for not more than 120 days with the local distribution utility
156 regarding the terms and conditions of a special contract. The microgrid district shall provide
157 reasonable access and terms to the local distribution utility to enable the electric utility's
158 transmission and/or distribution facilities to tie into those of the microgrid district. The 120-day
159 negotiation period required by this section may be satisfied by the precertification negotiation
160 period required by §5B-2-21(i) of this code.

161 (2) If the negotiations result in a mutually agreeable special contract, the contracting
162 parties shall jointly file the special contract pursuant to the rules of the commission.

163 (3) If negotiations for a special contract with the local distribution utility are unsuccessful,
164 a certified microgrid district may file a petition with the commission to establish a special contract.

165 (4) The commission shall establish a special contract upon the filing of a petition pursuant
166 to this section. The Public Service Commission shall consider all relevant factors in establishing
167 special contracts. The Public Service Commission shall establish a special rate for the requested
168 service, including backup and supplemental service to a microgrid district. The microgrid district's
169 load not covered by a contract shall be considered non-firm and interruptible. The commission
170 shall issue a final order determining the terms of a special contract within 90 days of filing of a
171 petition.

§5B-2-21a. Data Centers.

1 (a) *Findings and purpose.* — The Legislature hereby finds and declares the following:

2 (1) Data centers represent a significant and growing sector of the economy, generating
3 substantial economic activity, including jobs, infrastructure investments, and technological
4 innovation.

5 (2) Data centers are critical national infrastructure that require abundant, low-cost energy
6 to protect sensitive data, operate high-level computation assets, and ensure the resilience of the
7 digital economy.

8 (3) The People's Republic of China is positioning itself to be the global leader of data
9 centers and is investing in technology to encourage the flow of data toward China instead of
10 toward the United States.

11 (4) It is in the United States' national security interests to limit the flow of data to China
12 and to protect the flow of data and maximize computational power inside the United States. The
13 President has declared that it is the policy of the United States "to sustain and enhance America's
14 global AI dominance in order to promote human flourishing, economic competitiveness and
15 national security." Removing Barriers to American Leadership in Artificial Intelligence, Executive
16 Order 14179 (Jan 23, 2025).

17 (5) As of early 2025, the highest concentration of high-level computational power and data
18 centers in the world is located in Loudoun County, Virginia. This severe concentration of data
19 centers in one location is a national security vulnerability because it invites the potential for
20 cyberattacks and espionage against the Nation's critical data infrastructure.

21 (6) Data centers have historically obtained their electricity from the electric grid. Some
22 data center developers now seek or require the use of microgrids to provide their primary and
23 backup power.

24 (7) West Virginia is strategically positioned as the best location in the United States to
25 place data centers due to: (A) its close proximity to Washington, D.C., and the federal government;
26 (B) its close proximity to the majority of the Nation's population; (C) its low tax rates; (D) it having
27 the least restrictive regulatory environment in the Nation; (E) its supply of abundant energy and

28 natural resources to power the data centers; (F) its supply of resources, such as coal mine
29 methane blended with natural gas, to assist data centers locating in West Virginia to meet their
30 energy needs and environmental goals; and (G) its skilled and loyal workforce that has some of
31 the lowest turnover rates in the Nation.

32 As such, the state has a significant interest in encouraging the development and
33 expansion of data centers, which can serve as drivers of broader economic growth. The
34 Legislature finds that these externalities transcend local borders, including environmental
35 concerns, energy consumption, and regional economic growth. Additionally, the provisions in this
36 section align with the Legislature's goal of fostering a competitive, forward-thinking economy that
37 benefits all residents.

38 (b) *Program established.* — The High Impact Data Center Program is hereby created and
39 is to be administered as a program within the Division of Economic Development to encourage
40 the continued development, construction, operation, maintenance, and expansion in West
41 Virginia of high impact data centers. In order to effectuate the purposes of this section, the Division
42 of Economic Development, or any agency, division, or subdivision thereof, may promulgate
43 legislative rules, including emergency rules, in accordance with §29A-3-1 *et seq.* of this code.

44 (c) *Notification.* — Any data center shall compare its current or planned operations against
45 the definition of "high impact data center" established in §11-6N-2 of this code and provide
46 notification to the Division of Economic Development when the data center becomes aware that
47 it will satisfy or has satisfied that definition. The notification will include information addressing
48 the elements of that definition, including known or expected power consumption of the data
49 center. This notification shall be made (1) within 30 days after the data center determines that it
50 meets these requirements, or (2) when the data center reasonably anticipates that it will, at some
51 future date, meet these requirements, in which case the data center may provide that anticipated
52 future date in its notification.

53 (d) *Certification.* — The Secretary of the Department of Commerce shall identify and certify
54 high impact data centers in this state upon a finding that a data center satisfies the requirements
55 for the definition of "high impact data center" set forth in §11-6N-2 of this code. The Secretary
56 shall issue confirmation of certification to a high impact data center within 14 days following receipt
57 of the notification from the data center required by this section.

58 (e) *Recordkeeping.* — Any information provided by a data center pursuant to this section
59 that is identified by the data center as confidential business information shall be exempt from the
60 Freedom of Information Act. The Secretary shall take reasonable and appropriate steps to protect
61 this information. Notwithstanding the foregoing, the Secretary shall maintain a complete list of all
62 certified high impact data centers and all relevant information that can be made available to the
63 Governor and Legislature, removing specifically identifying information to ensure confidentiality
64 of any such information as identified by any high impact data center.

**§5B-2-21b. Authority to assist certified microgrid district projects and certified high impact
data center projects; legislative findings.**

1 (a) *Findings and purpose.* — The Legislature hereby finds and declares the following:

2 (1) The findings and purpose set forth in §5B-2-21a(a) (2025), except to the extent
3 expressly modified herein, are hereby incorporated herein by reference with the same force and
4 effect as though fully set forth herein.

5 (2) It is in the best interests of the state to induce and assist in development of these
6 projects, in order to advance the public purposes of relieving unemployment by preserving and
7 creating jobs, and preserving and creating new and greater sources of revenue for the support of
8 public services provided by the state and local government.

9 (3) It is the intent of the Legislature to occupy the whole field of the creation and regulation
10 of certified microgrid districts and certified high impact data centers. The stated purpose of this
11 section is to promote uniform and consistent application of the act within the state.

(b) The Department of Commerce shall assist projects developing or operating a certified microgrid district pursuant to §5B-2-21 of this code or a certified high impact data center pursuant to §5B-2-21a of this code. The Secretary of Commerce shall designate one of their personnel as "Data Economy Liaison" to serve as a single point-of-contact for certified microgrid districts and high impact data centers to assist coordinate and expedite their development and operation, including, but not limited to site selection and permitting. A "certified microgrid district" is a microgrid project, regardless of stage of development or operation, that has been certified by the Secretary of the Department of Commerce as set forth in §5B-2-21 of this code. A "certified high impact data center" is a data center project, regardless of stage of development or operation, that has been certified by the Secretary of the Department of Commerce as set forth in §5B-2-21a of this code.

(c) This section prohibits:

(1) Counties and municipalities, whether by ordinance, resolution, administrative act, or otherwise, from enacting, adopting, implementing, or enforcing ordinances, regulations, or rules which limit, in any way, the creation of, and acquisition, construction, equipping, development, expansion, and operation of any certified microgrid district or certified high impact data center project; and

(2) Counties and municipalities from imposing or enforcing local laws and ordinances concerning the creation or regulation of any certified microgrid district or certified high impact data center therein.

(d) In accordance with §5B-2-21(b) and §5B-2-21(c) of this code, and notwithstanding any provision of this code to the contrary, or any municipality's home rule powers with respect to ordinances and ordinance procedures, including any authority pursuant to the Municipal Home Rule Program under §8-1-5a of this code, certified microgrid districts and certified high impact data centers may not be subject to the following:

(1) County or municipal zoning, horticultural, noise, viewshed, lighting, development, or land use ordinances, restrictions, limitations, or approvals;

(2) County or municipal building permitting, inspection, or code enforcement;

(3) County or municipal license requirements;

(4) The legal jurisdiction of the county or municipality in which the certified microgrid district or certified high impact data center is entirely or partially located, except as specifically provided in this article;

(5) Any requirement under state law for the consent or approval of the municipality in which a certified microgrid district or certified high impact data center is entirely or partially located of any state or county action pursuant to this code, specifically including, but not limited to, §7-11B-1 *et seq.* of this code, for formal consent of the governing body of a municipality for county or state action regarding the establishment of tax increment financing development or redevelopment districts or the approval of tax increment financing development or redevelopment plans.

(e) Notwithstanding the creation of a certified microgrid district or a certified high impact data center, the owner, operator, or manager, as applicable, and all tenants, lessees or licensees thereof, of a certified microgrid district or a certified high impact data center shall:

(1) Pay business and occupation tax, if applicable, pursuant to §8-13-5 of this code, to the municipality in the same manner as any other business or commercial venture located within the municipality;

(2) Collect and remit municipal sales and service tax and municipal use tax, if applicable, pursuant to §8-1-5a, §8-13C-4, and §8-13C-5 of this code, to the municipality in the same manner as any other business or commercial venture located within the municipality;

(3) Pay ad valorem real and personal property tax pursuant to the same millage rates as any other business or commercial venture located within the county and municipality;

(4) Pay all municipal service fees enacted pursuant to §8-13-13 of this code, including, but not limited to, fire, police, sanitation, or city service fees;

(5) Pay all utility rates, fees, and charges for utilities used or consumed during construction and operation of premises within the certified microgrid district or certified high impact data center, including, but not limited to, water, sewer, stormwater, and garbage and recycling collection: *Provided, That* (A) The rates, fees, and charges for such services shall be based on the cost of providing such service and the utility shall enter into a contract under the rules of the Public Service Commission for each such service with the developer and file the special contract with the Public Service Commission; and (B) the developer shall only be required to pay any capacity improvement fee or impact fee to the extent that capital additions, betterments, and improvements must be designed, acquired, constructed, and equipped by the utility to provide such service to the project; Utility customers outside of the microgrid district shall not bear any construction or operational costs associated with any new utility property built solely to provide service within a microgrid district;

(6) Be entitled to municipal police protection and municipal fire protection, if available, in the same manner as any other business or commercial venture located within the municipality; and

(7) Design, acquire, construct, and equip the certified microgrid district or certified data center pursuant to the State Building Code in accordance with §8-12-13 of this code and the corresponding State Rule 87 CSR 4.

(f) The Department of Commerce, Department of Environmental Protection, and Department of Transportation may take actions necessary in support of the development of any certified microgrid district or certified data center, including, but not limited to, the development or improvement of such highways, roads, thoroughfares, and sidewalks within any county or

86 municipality in which the certified microgrid district or certified data center is partially or entirely
87 located.

88 (g) In order to effectuate the purposes of this section, the Department of Commerce, or
89 any agency, division, or subdivision thereof, may promulgate legislative rules, including
90 emergency rules, in accordance with §29A-3-1 *et seq.* of this code.

ARTICLE 2N. GRID STABILIZATION AND SECURITY ACT OF 2023.

§5B-2N-2a. Creating the Electric Grid Stabilization and Security Fund.

1 (a) The Electric Grid Stabilization and Security Fund is hereby created. The fund shall be
2 administered by the Department of Commerce and shall consist of all moneys made available for
3 the purposes and from the sources set forth in this section of the code.

4 (b) The fund consists of moneys received from the following sources:

- 5 (1) All moneys received pursuant to §11-6N-4(b)(4)(C) of this code;
6 (2) All appropriations provided by the Legislature;
7 (3) Any moneys available from external sources; and
8 (4) All interest and other income earned from investment of moneys in the fund.

9 (c) The Department of Commerce shall use moneys in the fund to provide support for
10 electric grid stabilization for regulated utilities and grid security, including development, efficiency,
11 and environmental upgrades, but not decommissioning and replacement of existing facilities;
12 maintenance of utility owned and operated coal and natural gas electric generation, regardless of
13 unit or plant ownership by different regulatory jurisdictions; and transmission resources which
14 solely serve West Virginia rate payers.

15 (d) Any balance, including accrued interest and any other returns, in the Electric Grid
16 Stabilization and Security Fund at the end of each fiscal year may not expire to the General
17 Revenue Fund but remain in the fund and be expended for the purposes provided by this section.

18 (e) Fund balances may be invested with the state's Consolidated Investment Fund.
19 Earnings on the investments shall be used solely for the purposes defined in §5B-2-16(c) of this
20 code.

21 (f) In order to effectuate the purposes of this section, the Department of Commerce may
22 promulgate legislative rules, including emergency rules, in accordance with §29A-3-1 *et seq.* of
23 this code.

CHAPTER 11. TAXATION.

ARTICLE 6N. SPECIAL METHOD FOR VALUATION OF CERTAIN HIGH-TECHNOLOGY PROPERTY.

§11-6N-1. Legislative findings and purpose.

1 The Legislature hereby finds and declares the following:

2 The findings and purpose set forth in §5B-2-21a(a) (2025) (except to the extent expressly
3 modified herein) are hereby incorporated herein by reference with the same force and effect as
4 though fully set forth herein.

§11-6N-2. Definitions.

1 (a) *General* — When used in this article, words defined in §11-6N-2(b) of this code have
2 the meanings ascribed to them in this section, except in those instances where a different
3 meaning is provided in this article or the context in which the word is used clearly indicates that a
4 different meaning is intended by the Legislature.

5 (b) *Definitions* — For purposes of this section, the following terms shall mean:

6 (1) "Affiliated group" means one or more chains of corporations, limited liability entities, or
7 partnerships, or any combination thereof, connected through the ownership of stock or ownership
8 interests with a common parent which is a corporation, limited liability entity, or partnership, but
9 only if the common parent owns directly, or indirectly, a controlling interest in each of the members
10 of the group.

(2) "Base assessed value" means the taxable assessed value of all data center property of a high impact data center as shown upon the landbooks and personal property books of the assessor on July 1 of the calendar year preceding certification as a high impact data center.

(3) "Current assessed value" means the annual taxable assessed value of all data center property of a high impact data center as shown upon the landbook and personal property records of the assessor.

(4) "Critical IT load" means that portion of electric power capacity, expressed in terms of megawatts, which is reserved solely for owners or tenants of a data center to operate their computer server and required supporting equipment.

(5) "Data center property" means property used exclusively at a data center to construct, outfit, operate, support, power, cool, dehumidify, secure, or protect a data center and any contiguous dedicated substations. The term includes, but is not limited to, construction materials, component parts, machinery, equipment, computers, servers, installations, redundancies, and operating or enabling software, including any replacements, updates and new versions, and upgrades to or for such property, regardless of whether the property is a fixture or is otherwise affixed to or incorporated into real property.

(6) "High Impact Data Center" means a facility or group of facilities that:

(A) Consists of one or more parcels in this state, along with the buildings, substations and other infrastructure, fixtures, and personal property located on the parcels;

(B) Is owned, operated, or leased by an entity or affiliated group of entities;

(C) Is used to house and operate equipment that receives, stores, aggregates, manages, processes, transforms, retrieves, researches, or transmits data; or that is necessary for the proper operation of equipment that receives, stores, aggregates, manages, processes, transforms, retrieves, researches, or transmits data;

(D) Has a critical IT load in the aggregate of 90 megawatts total or higher; and

(E) Is placed into service on or after July 1, 2025.

(7) "Incremental value", for any high impact data center, means the difference between the base assessed value and the current assessed value. The incremental value will be positive if the current value exceeds the base value, and the incremental value will be negative if the current value is less than the base assessed value.

(8) "Microgrid power generator" includes any entity supplying power under the rules provided in §5B-2-21 of this code to a high impact data center.

(9) "Microgrid power generator property" means and includes any and all property used by microgrid power generator within a certified microgrid district.

(10) "Situs county" means the county or counties in which any High Impact Data Center property subject to tax is located, in relative proportion to the amount of data center property located therein.

(11) "Tax increment" means the amount of regular levy property taxes attributable to the amount by which the current assessed value of real and tangible personal property that is data center property of a high impact data center exceeds the base assessed value of the property.

§11-6N-3. Returns of property of high impact data centers to Board of Public Works.

(a) On or before May 1 in each year, a return in writing shall be filed with the Board of Public Works: By the owner or operator of any company holding data center property of a high impact data center or a microgrid power generator supplying microgrid power to a high impact data center.

(b) The words "owner or operator," as applied herein to high impact data centers, shall include any owner or operator of a high impact data center or microgrid power generator.

(c) The return shall be signed and sworn to by the owner or operator if a natural person, or, if the owner or operator shall be a corporation, shall be signed and sworn to by its president, vice president, secretary, or principal accounting officer.

(d) The return required by this section of every owner or operator shall cover the year ending on December 31, next preceding, and shall be made on forms prescribed by the Board of

Public Works, which board is hereby invested with full power and authority and it is hereby made its duty to prescribe the forms required from any owner or operator herein mentioned information as in the judgment of the board may be of use to it in determining the true and actual value of the properties of the owners or operators.

(e) Except for the special rules for tax distribution provided in §11-6N-4 of this code, the provisions of this article are subject to the Assessment of Public Service Businesses, set forth in §11-6-1, *et seq.* of this code, as if the provisions thereof were set forth in extenso in this article.

§11-6N-4. Special Rules for Tax Distribution of High Impact Data Centers.

(a) On and after July 1, 2025, any property subject to valuation under §11-6N-3 of this code shall be subject to the rules on tax distribution provided under this section.

(b) The State Auditor shall maintain a separate and discrete accounting of each High Impact Data Center project regarding tax distribution provided in this section and any distribution to which a county is entitled as provided by this section shall be distributed directly to the situs county for each project.

(c) *Ad Valorem* Property Tax Distribution — The provisions of this subsection are applicable to all data center property of a high impact data center upon certification as a high impact data center per §11-6N-2 of this code.

(1) For so long as the high impact data center exists, the State Auditor shall divide the *ad valorem* property tax revenue collected, with respect to taxable data center property of a high impact data center as follows:

(A) The amount of *ad valorem* property tax revenue that should be generated by multiplying the assessed value of the property for the then current tax year by the aggregate of applicable levy rates for the tax year;

16 (B) The amount of *ad valorem* property tax revenue that should be generated by
17 multiplying the base assessed value of the property by the applicable regular ad valorem levy
18 rates for the tax year;

19 (C) The amount of *ad valorem* tax revenue that should be generated by multiplying the
20 base assessed value of the property for the current tax year by the applicable levy rates for
21 general obligation bond debt service for the tax year;

22 (D) The amount of *ad valorem* property tax revenue that should be generated by
23 multiplying the current assessed value of the property for the current tax year by the applicable
24 excess levy rates for the tax year; and

25 (E) The amount of *ad valorem* property tax revenue that should be generated by
26 multiplying the incremental value by the applicable regular levy rates for the tax year.

27 (2) The State Auditor shall determine from the calculations set forth in subdivision (1) of
28 this subsection the percentage share of total *ad valorem* revenue for each levying body according
29 to paragraphs (B) through (D), inclusive, of said subdivision by dividing each of such amounts by
30 the total *ad valorem* revenue figure determined by the calculation in paragraph (A) of said
31 subdivision; and

32 (3) On each date on which *ad valorem* tax revenue is to be distributed to the levying
33 bodies, such revenue shall be distributed by:

34 (A) Applying the percentage share determined according to paragraph (B), subdivision (1)
35 of this subsection to the revenues received and distributing such share to the levying bodies
36 entitled to such distribution pursuant to current law;

37 (B) Applying the percentage share determined according to paragraph (C), subdivision (1)
38 of this subsection to the revenues received and distributing such share to the levying bodies
39 entitled to such distribution by reason of having general obligation bonds outstanding;

(C) Applying the percentage share determined according to paragraph (D), subdivision (1) of this subsection to the revenues received and distributing such share to the levying bodies entitled to such distribution by reason of having excess levies in effect for the tax year; and

(D) Applying the percentage share determined according to paragraph (E), subdivision (1) of this subsection to the revenues received and distributing such share to a fund dedicated at the time of construction of a high impact data center.

(4) In each year for which there is a positive tax increment, the State Auditor shall remit that portion of the *ad valorem* property taxes collected that consists of the tax increment and shall be distributed as follows:

(A) 50 percent of the increment shall be placed in the Personal Income Tax Reduction Fund provided in §11B-2-33 of this code;

(B) 30 percent of the increment to the situs county as defined in this article;

(C) 10 percent of the increment to all counties on a per capita basis according to the most recent census;

(D) 5 percent of the increment shall be placed Economic Enhancement Grant Fund administered by the Water Development Authority provided in §22C-1-6a; and

(E) 5 percent of the increment shall be placed in the Electric Grid Stabilization and Security Fund provided in §5B-2N-2a.

(5) (A) *Payment In Lieu Of Taxes, Increment Property* — Notwithstanding the provisions of §5D-1-14, §7-5-13, §7-11B-3(b), §7-11B-8(c)(4), §7-11B-15(a)(7), §7-11B-15(a)(15), §7-11B-18, §8-19-4, §8-29A-7, §8A-12-12, §11-13-2p, §11-13C-5(l)(1)(A), §16-13A-21, §16-15-18(b)(6), §17-16A-16(b), §17-16B-20(b), §18-9A-12(c), §31-21-5, and §31-21-15 of this code, or any other provision of this code, no payment in lieu of taxes shall be entered into with relation to any property subject to this section or any leasehold interest related thereto, or any other property interest related thereto.

(B) *Tax Increment Financing, Increment Property* — Notwithstanding the provisions of §7-11B-1 *et seq.* of this code, or any other provision of this code, no tax increment financing project,

67 plan or arrangement shall be entered into or undertaken with relation to any property subject to
68 this section.

§11-6N-5. Termination.

1 The provisions of this article shall sunset, expire, and be of no force and effect on or after
2 December 31, 2055.

CHAPTER 11B. DEPARTMENT OF REVENUE

ARTICLE 2. STATE BUDGET OFFICE.

§11B-2-33. Personal Income Tax Reduction Fund.

1 (a) The personal income tax reduction fund is hereby established. The personal income
2 tax reduction fund shall be funded continuously and on a revolving basis in accordance with this
3 section, with all interest or other earnings on the moneys therein credited to the fund. The personal
4 income tax reduction fund shall be funded as provided in §11-6N-4(b)(4) of this code. Moneys in
5 the personal income tax reduction fund may be expended solely for the purposes set forth in this
6 section.

7 (b) Notwithstanding any other provision of this code to the contrary, on or before the last
8 day of any fiscal year, the net proceeds of the personal income tax reduction fund will be certified
9 and included as a portion of adjusted general revenue fund collections under the provisions of
10 §11-21-4h of this code for that fiscal year.

11 (c) Not later than 60 days following the certification, the Secretary of Revenue shall
12 transfer the certified amount determined in subsection (b) of this section to the general revenue
13 fund. The amounts transferred will not be included as a portion of adjusted general revenue fund
14 collections under the provisions of §11-21-4h of this code for the fiscal year in which the money
15 is transferred.

16 (d) The moneys in the income tax reduction fund shall be made available to the West
17 Virginia Board of Treasury Investments and to the West Virginia Investment Management Board
18 for management and investment of the moneys in accordance with the provisions of §12-6C-1 *et*
19 *seq.* of this code in such amounts as may be directed in the discretion of the Secretary of

Revenue. Any balance of the income tax reduction fund, including accrued interest and other return earned thereon at the end of any fiscal year, shall not revert to the General Fund but shall remain in the income tax reduction fund for the purposes set forth in this section.

(e) Termination – Upon the certification of a reduction in the personal income tax under the provisions of §11-21-4h of this code that results in the elimination of the personal income tax, or if the personal income tax provided for under §11-21-1 *et seq.* is eliminated by separate enactment of the Legislature, this fund will be thereby eliminated and any monies dedicated thereto shall be dedicated to the general revenue of the state.

CHAPTER 24. PUBLIC SERVICE COMMISSION.

ARTICLE 2. POWERS AND DUTIES OF PUBLIC SERVICE COMMISSION.

§24-2-1d. Future electric generating capacity requirements.

(a) In order to maximize the use of electricity generated within the state by using coal or natural gas produced within the state, the Public Service Commission shall by order, no later than December 31, 1989, establish the schedule and amount of future electric generating capacity additions required by each West Virginia electric utility, for the next ten years, taking into account: (i) Projected load growth; (ii) existing generating capacity; (iii) existing contractual commitments to sell or purchase capacity; (iv) planned retirement and life extensions of existing capacity; (v) planned construction of capacity; (vi) availability of capacity from generating units of affiliated companies; (vii) capacity factors for existing generation; and (viii) such other reasonable factors as the commission may deem relevant and appropriate to consider. For purposes of this section, "capacity factor" shall mean the ratio of the actual energy produced by a power plant over a specific period to the maximum possible energy it could have produced if running at full capacity during that same period.

(b) If the commission determines after considering all such named and other relevant and appropriate factors that a utility will be required to purchase electric generating capacity beyond those agreements approved by the Federal Energy Regulatory Commission or the West Virginia Public Service Commission in order to serve its West Virginia customers, the amount of such

17 required additional purchased capacity so identified by the commission will for purposes of this
18 section be referred to as the utility's "projected deficient capacity": *Provided*, That this subsection
19 shall not include power generating facilities whose total production of electricity is sold outside
20 the State of West Virginia.

21 (c) In the interests of: Keeping utility rates of residential customers as low as possible;
22 keeping utility rates for commercial and industrial customers competitive with those of other
23 states; attracting new industry for which electric power costs are a major factor in location
24 determinations; and of not placing any greater cost burden on government than is absolutely
25 necessary for its electric power needs, each utility shall acquire, if reasonable, its projected
26 deficient capacity from electric generation situated in West Virginia which burns coal or gas
27 produced in West Virginia and which will provide the most reliable supply of capacity and energy
28 at the least cost to those customers of the utility who will be served by such electric generation:
29 *Provided*, That all power purchase contracts executed prior to the effective date of this section
30 which satisfy the following requirements, regardless of location, shall be considered, for the
31 purposes of this subsection, as electric generation situated in West Virginia: (1) Said contracts
32 were negotiated in accordance with procedures and priced according to methodologies of other
33 contracts which the commission has ordered approved; (2) said contracts either guarantee or are
34 substantially amended to guarantee for the life of the contract the use of an amount of West
35 Virginia fuel which equals or exceeds the amount which would be required, on a percentage of
36 output basis, to produce the amount of electric power to be consumed in West Virginia; and (3)
37 said contracts meet the requirements for a qualifying facility established by the Federal Energy
38 Regulatory Commission pursuant to the Public Utility Regulatory Policies Act of 1978.

39 (d) The commission shall evaluate each capacity auction conducted by PJM
40 Interconnection, LLC, or its successor and, to the maximum extent permitted by law, encourage
41 the coordination of the voluntary participation of every electric generating unit in the state in each
42 capacity auction for the benefit of ratepayers in the state.

43 (e) In order to ensure the state's existing generating units can continue to meet future
44 generation needs, the commission shall conduct a review of each generating unit's current
45 consumer economic dispatch. Factors to be considered by the commission in reviewing consumer
46 economic dispatch shall include, but not be limited to: (1) current capacity factors; (2)
47 management of fuel supplies and contracts; (3) overall plant operation and maintenance; (4)
48 placement of bids in the PJM Interconnection, LLC, or its successor's day-ahead and real-time
49 energy markets; (5) utilization of the PJM Interconnection, LLC, or its successor's Reliability
50 Pricing Model (RPM) or Fixed Resource Requirement (FRR); and (6) the utilization of automatic
51 adjustment clauses, price indexes, or fuel adjustment clauses by the utilities. For purposes of
52 this section, "consumer economic dispatch" shall mean the process of operating generation
53 facilities to produce electricity at the lowest cost while reliably meeting consumer demand,
54 considering the operational limits of generation and transmission facilities.

55 (f) Electric utilities shall be prepared to maximize the production of electricity from their
56 generating units when such self-generation will result in reduced energy costs for West Virginia
57 ratepayers. The commission shall require the utilities to maintain their thermal baseload
58 generating units in a manner to allow them to be able to self-generate and achieve at least a sixty-
59 nine percent capacity factor. Nothing herein shall require a utility to operate a generating unit at
60 a sixty-nine percent capacity if doing so will cause an increase in the charge or charges for electric
61 energy over and above the established and published tariff, rate, joint rate, charge, toll or
62 schedule. The commission shall propose rules for legislative approval in accordance with the
63 provisions of §29A-3-1 *et seq.* of this code to carry out its duties and obligations as set forth
64 herein.

§24-2-1q. Base fuel coal supply requirements for electric grid resiliency.

1 Recognizing that coal inventories at coal-fired power plants may increase and decrease
2 over time, in order to ensure grid resiliency and homeland security, each generating public utility
3 shall plan incoming and outgoing coal so as to maintain an average annual minimum 30-day
4 aggregate coal supply on site at each coal-fired power plant. The commission may propose rules

for legislative approval in accordance with the provisions of §29A-3-1 *et seq.* of this code to carry out its duties and obligations as set forth herein.

§24-2-15. Certain Automatic adjustment clauses, price indexes or fuel adjustment.

The commission shall not enforce, originate, continue, establish, change or otherwise authorize or permit an increase in the charge or charges for electric energy over and above the established and published tariff, rate, joint rate, charge, toll or schedule as the result of any automatic adjustment clause, fuel supply price index, or fuel adjustment clause. Automatic adjustment clauses, fuel supply contract price indexes, or fuel adjustment clauses that do not create a net increase in the charge or charges for electric energy over and above the established and published tariff, rate, joint rate, charge, toll, or schedule shall be permitted by the commission. For purposes of this section, a "net increase" in the charge or charges for electric service shall mean that for the calendar year in which the automatic adjustment clause, fuel supply contract price index, or fuel adjustment clause is utilized, the average charge or charges for electric energy are higher than they would have been if the adjustment clause, fuel supply contract price index, or fuel adjustment clause were not utilized. The commission shall encourage the use of permitted automatic adjustment clauses, fuel supply contract price indexes, or fuel adjustment clauses as a means of increasing the generation of coal-fired power plants within the state. The Commission shall promulgate procedural rules governing the utilization of automatic adjustment clauses, fuel supply contract price indexes, and fuel adjustment clauses.

§24-2-19. Integrated Resource Planning Required.

(a) Not later than March 31, 2015, the Public Service Commission shall issue an order directing any electric utility that does not have an existing requirement approved by the Public Service Commission that provides for the future review of both supply side and demand side resources to develop an initial integrated resource plan to be filed not later than January 1, 2016, in conjunction with other similar deadlines required by other states or entities of the electric utilities. This order may include guidelines for developing an integrated resource plan.

7 (b)(1) Any electric utility that has an existing requirement approved by the Public Service
8 Commission that provides for the future review of both supply side and demand side resources is
9 exempt from this initial integrated resource plan filing until such time as that existing requirement
10 has been satisfied. Thereafter, such electric utility is required to file an integrated resource plan
11 pursuant to §24-2-19(a) of this code.

12 (2) Each electric utility that has filed the initial integrated resource plan shall file an updated
13 plan at least every five years after the initial integrated resource plan has been filed. Any electric
14 utility that was exempt from filing an initial integrated resource plan shall file an integrated
15 resource plan within five years of satisfying any existing requirement and at least every five years
16 thereafter. All integrated resource plans shall comply with the provisions of any relevant order of
17 the Public Service Commission establishing guidelines for the format and contents of updated
18 and revised integrated resource plans.

19 (c) The Public Service Commission shall analyze and review an integrated resource plan.
20 The Public Service Commission may request further information from the utility, as necessary.
21 Nothing in this section affects the obligations of utilities to obtain otherwise applicable commission
22 approvals.

23 (d) The Commission may consider both supply-side and demand-side resources when
24 developing the requirements for the integrated resource plans. The plan shall compare projected
25 peak demands with current and planned capacity resources in order to develop a portfolio of
26 resources that represents a reasonable balance of cost and risk for the utility and its customers
27 in meeting future demand for the provision of adequate and reliable service to its electric
28 customers as specified by the Public Service Commission.

29 (e) The commission shall by order, entered no later than July 1, 2025, require all electric
30 utilities operating in the state to supplement their existing integrated resource plans to include a
31 detailed plant upgrade and maintenance plan, improvement compliance schedule, and cost
32 estimate for ensuring the operation of each generating unit through their planned retirement date.
33 The supplemental integrated resource plan shall also include an analysis of the action necessary

34 to extend the life of each generating unit beyond their planned retirement date. Subject to notice
35 and comment from interested parties, the commission may approve the supplemental integrated
36 resource plan without modification or require modification of the supplemental plan before it is
37 approved. The commission shall promulgate rules requiring the supplementation of integrated
38 resource plans as required by this provision. The rules shall also provide a procedure for utilities
39 to submit an independent evaluation of any modification required by the commission hereunder
40 or to challenge such required modification.

**§24-2-21a. Commission authority required when closing an electric generating plant and
circumstances of closure in another jurisdiction.**

41 (a) A public electric utility may not retire, abandon, close, or otherwise permanently render
42 incapable of operating, any electric generating plant or unit without the prior consent and approval
43 of the commission. No funds obtained from (1) the Grid Stabilization and Security Fund set forth
44 in 5B-2N-2a, (2) an environmental control bond issued pursuant to 24-2-4e, (3) a consumer rate
45 relief bond issued pursuant to 24-2-4f, (4) or a utility consumer rate relief bond issued pursuant
46 to 24-2-4h shall be used by a public utility to retire, abandon, close, or otherwise permanently
47 render incapable of operating, any electric generating plant or unit.

48 (b) If an electric utility serving customers in both West Virginia and in an area not subject
49 to the jurisdiction of the commission is ordered to cease operations of a generating plant or unit
50 by the regulating authority of the other jurisdiction and the costs of the plant or unit had been
51 shared through an allocation process for rate making purposes and after a commission
52 proceeding and determination that a generating plant or unit should continue to operate, then the
53 utility shall recover all of the capital, operating and maintenance costs of the electric generation
54 plant or unit from its West Virginia customers to the extent that such costs are no longer allocable
55 to the other jurisdiction, and all of the associated capacity, energy, and environmental attributes
56 shall be assigned to its customers and operations in West Virginia.

The Clerk of the House of Delegates and the Clerk of the Senate hereby
certify that the foregoing bill is correctly enrolled.

.....
Clerk of the House of Delegates

.....
Clerk of the Senate

Originated in the House of Delegates.

In effect 90 days from passage.

.....
Speaker of the House of Delegates

.....
President of the Senate

The within is this the.....
Day of, 2025.

.....
Governor

**PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON**

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA in the City of Charleston on the 19th day of August 2026.

CASE NO. 26-0633-E-GI

General Investigation into Adopting and
Implementing Rules Governing Electric
Generating Capacity Regulations.

COMMISSION ORDER

The Commission schedules a public comment hearing on September 28, 2026, beginning at 9:30 a.m., in the Howard M. Cunningham Hearing Room, Commission Headquarters, 201 Brooks Street, Charleston, West Virginia.

BACKGROUND AND DISCUSSION

On April 12, 2025, the West Virginia Legislature passed Enrolled Committee Substitute for House Bill 2014 (HB 2014), the Power Generation and Consumption Act, effective ninety days from passage, July 11, 2025, and required the Commission to propose rules for legislative approval in accordance with the provisions of W. Va. Code § 29A-3-1, *et seq.*, to carry out its duties and obligations contained in the newly enacted W. Va. Code § 24-2-1d.

On July 20, 2026, the Commission initiated a general investigation to receive comments and recommendations regarding proposed rules governing the regulation of electric generating capacity requirements subject to the jurisdiction provided to the Commission pursuant to W. Va. Code § 24-2-1d.

The Commission established a comment period requiring that written comments and recommendations be filed with the Public Service Commission on or before August 10, 2026, and reply comments be filed on or before August 20, 2026. All comments and recommendations filed in this general investigation shall be submitted to the Commission's Executive Secretary, P.O. Box 812, Charleston, WV 25323.

In addition to the above comment period, the Commission will schedule a public comment hearing on September 28, 2026, beginning at 9:30 a.m., in the Howard M. Cunningham Hearing Room, Commission Headquarters, 201 Brooks Street, Charleston, West Virginia. Members of the public that wish to participate in the hearing through oral argument, witness testimony, or audiovisual presentation must notify the Commission by September 18, 2026. Participants

may submit additional comments, testimony, or written materials for presentation at the hearing. All additional comments, testimony, or written materials must be submitted to the Commission and filed in this case by September 23, 2026.

FINDING OF FACT

Given the comments already received in this matter, the Commission is interested in scheduling a public comment hearing to receive further comments and recommendations regarding the proposed rules governing the regulation of electric generating capacity requirements subject to the jurisdiction provided to the Commission pursuant to W. Va. Code § 24-2-1d.

CONCLUSION OF LAW

1. The Commission should schedule a public comment hearing in this matter.

ORDER

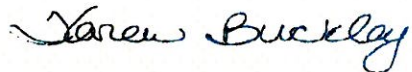
IT IS THEREFORE ORDERED that a public comment hearing will be held in this matter on September 28, 2026, beginning at 9:30 a.m., in the Howard M. Cunningham Hearing Room, Commission Headquarters, 201 Brooks Street, Charleston, West Virginia.

IT IS FURTHER ORDERED that members of the public who wish to participate in the hearing through comment or presentation, witness testimony, or audiovisual presentation must notify the Commission no later than September 18, 2026. Participants may submit additional comments, testimony, or written materials for presentation at the hearing. All additional comments, testimony or written materials must be submitted to the Commission and filed in this case by September 23, 2026.

IT IS FURTHER ORDERED that the Executive Secretary shall immediately publish a copy of this Order once in a daily newspaper of general circulation statewide and file proof of that publication upon receipt.

IT IS FURTHER ORDERED that the Commission Executive Secretary shall serve a copy of this Order and its attachments on all electric utilities in this State and the Consumer Advocate Division by electronic service if e-service agreements are on file, or by United States First Class Mail, and on Staff by hand delivery.

A True Copy, Teste,

A handwritten signature in blue ink that reads "Karen Buckley". The signature is written in a cursive, flowing style.

Karen Buckley, Executive Secretary

JAF/lch
260633ca

Public Service Commission of West Virginia

201 Brooks Street, P.O. Box 812
Charleston, West Virginia 25323

Phone: (304) 340-0300
Fax: (304) 340-0325



August 19, 2026

All Electric Utilities Operating in West Virginia

James M. Bailey, Esq.
Counsel, WVEUG
Spilman Thomas & Battle PLLC
300 Kanawha Boulevard, East
Charleston, WV 25301

James Kotcon
Conservation Chair
WV Chapter of The Sierra Club
PO Box 4142
Morgantown, WV 36504

Kevin Fagan, Esq.
Counsel, UMWA
18354 Quanitco Gateway Drive
Suite 200
Triangle, VA 22172

Betty Rivard
1532 Lee St. E
Charleston WV 25311

Lori Sundstrom
164 Beautiful Ct.
Martinsburg WV 25404-0395

Luanne McGovern
858 Alta Rd.
Charleston WV 25314-1810

Carolyn Rodis
41 Sage Pl.
Shepherdstown WV 25443-1640

Matthew Lebo
1628 6th Ave. Apt 3
Huntington WV 25703-1439

Elaine Matheny
11948 Longdale Rd.
Letart WV 25253-9759

Heather Ransom
14724 Edray Rd.
Cass WV 24927-9263

Brenda Ellid
1132 Hickory Rd.
Charleston WV 25314-1231

Sally Roberts Wilson
54 Cheat Canyon Park Dr.
Morgantown WV 26508-0008

Diane Wooten
1309 55th St.
Vienna WV 26105-3271

Angela Roton
2085 Coopers Creek Rd.
Charleston, WV 25312-8029

Kristi Corbin
1460 Graces Cabin Rd.
Springfield, WV 26763-8803

Cindy Lewellen
546 Westwood Ave.
Morgantown, WV 26505-2115

Amber Boggs
1958 Keeler Ln
Williamstown, WV 26187-8298

Jeff Myers
723 Price Run Rd
Caldwell, WV 24925-951

Derek Adkins
944 Norway Ave.
Huntington, WV 25705-3948

Dustin Adkins
3408 Bloomington Dr.
Huntington, WV 25526-1359

Marsha Wells
110 Twyford Ave.
Sistersville, WV 26175-8888

Tom Carpenter
317 7th St.
Moundsville, WV 26401-2124

Susan Wade
39 Girard Dr.
Cross Lanes, WV 25313-2170

Ivan Frishberg
2099 Baker Mountain Dr.
Yellow Spring, WV 26865

Kitty Keefer
521 Jacob St.
Charleston, WV 25301-1900

Rev. Ray Stonestreet
113 Bias Ln.
Charleston, WV 25312-6619

Dana Adkins
2009 Route 75
Kenova, WV 25530-9732

Julie Wingard
402 W. Maple Ave.
Fayetteville, WV 25840-1418

Dan Faugl
1507 Oakhurst Ave.
Parkersburg, WV 26101-4907

Richard Stonestreet
106 White St. Apt E.
Charleston, WV 25302-4941

Richard Kinder
132 Kinder Ln.
Danese, WV 25831-1100

F. Bean
525 Depot St.
Romney, WV 26757-1300

Cynthia Anderson
191 Firefly Ln
Martinsburg, WV 25403-1071

Bonnie Allen
451 Camellia Dr.
Bluefield, WV 24701-9085

Rev. Ralph Dunkin
27 Finch Ave.
Wheeling, WV 26003-2657

Mary Alice Milnes
107 Earle St.
Elkins, WV 26241-3909

Michael Chelnov
1000 Purusha Pl. Apt 123
Romney, WV 26757-5016

Kemmeth Rivers
3513 Carpenter Ave.
Hurricane, WV 25526-1360

Larry Adkins
1522 Clearview Hts
Charleston, WV 25312-5948

Regan Quinn
1113 Highland Rd.
Charleston, WV 25302-3007

Warren Neal
165 Scaggs Run Rd.
Bluefield, WV 24701-5082

Steve Silverberg
907 Lost World Rd.
Lewisburg, WV 24901-5250

Joe Stanley
1367 Martha Rd.
Barboursville, WV 25504-7436

Alan and Carol Kuhlman
4 Grandview Dr.
Elkview, WV 25071-9350

Anne Chopyak
89 Pocahontas St.
Buckhannon, WV 26201-2528

Catherine Grant
2001 WV Highway 5 E
Glenville, WV 26351-7614

RE: Case No. 26-633-E-GI
General Investigation into Adopting and Implementing Rules Governing
Electric Generating Capacity Regulations.

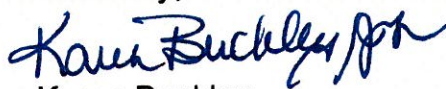
Ladies and Gentlemen:

Enclosed is a copy of a Commission order issued today in the above-styled proceeding.
All other parties of record have signed an email agreement.

Documents submitted to the Public Service Commission of West Virginia may be 1) uploaded to its public website, 2) subject to public disclosure under the West Virginia Freedom of Information Act, and/or 3) subject to disclosure under the West Virginia Open Governmental Proceedings Act. Do not submit personal information with your filings. The Commission is not responsible for confidential or personal information included with your submission. A list of personal information is available here: http://www.psc.state.wv.us/Privacy_Policy/WhatisPII.htm

If you have provided an email address you will automatically receive notifications as documents are filed in this proceeding. The email notifications allow recipients to view a document within an hour from the time the filing is processed. If you have not provided your email address, please send an email to caseinfo@psc.state.wv.us and state the case number in the email subject field. **You are encouraged to file an Electronic Mail Agreement which allows the commission to serve all orders issued in this matter via electronic notification.**

Sincerely,



Karen Buckley
Executive Secretary

KB/jn
Enc.

IN THE SUPREME COURT OF APPEALS OF WEST VIRGINIA

September 2024 Term

No. 24-75

FILED

November 13, 2024

released at 3:00 p.m.
C. CASEY FORBES, CLERK
SUPREME COURT OF APPEALS
OF WEST VIRGINIA

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY,
Petitioners,

v.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA,
Respondent.

Appeal from the Public Service Commission of West Virginia
Case Nos. 21-0339-E-ENEC, 22-0393-E-ENEC, and 23-0377-E-ENEC
AFFIRMED, in part; REVERSED, in part; and REMANDED

Submitted: September 4, 2024
Filed: November 13, 2024

William C. Porth, Esq.
Anne C. Blankenship, Esq.
Robinson & McElwee PLLC
Charleston, West Virginia

Keith D. Fisher, Esq.
American Electric Power
Service Corporation
Charleston, West Virginia

Elbert Lin, Esq.
Hunton Andrews Kurth LLP
Richmond, Virginia
Counsel for Petitioners

Jessica M. Lane, Esq.
Susan M. Stewart, Esq.
Public Service Commission
of West Virginia
Charleston, West Virginia
Counsel for Respondent

Robert F. Williams, Esq.
Heather B. Osborn, Esq.
Charleston, West Virginia
Counsel for Amicus Curiae
The Consumer Advocate Division of the
Public Service Commission of West
Virginia

Barry A. Naum, Esq.
Steven W. Lee, Esq.
Spilman Thomas & Battle, PLLC
Mechanicsburg, Pennsylvania

Susan J. Riggs, Esq.
Spilman Thomas & Battle, PLLC
Charleston, West Virginia
Counsel for Amicus Curiae
West Virginia Energy Users Group

H. Brann Altmeyer, Esq.
Jacob C. Altmeyer, Esq.
Phillips, Gardill, Kaiser,
& Altmeyer, PLLC
Wheeling, West Virginia
Counsel for Amicus Curiae
The West Virginia Coal
Association, Inc.

JUSTICE HUTCHISON delivered the Opinion of the Court.

SYLLABUS BY THE COURT

1. ““The principle is well established by the decisions of this Court that an order of the public service commission based upon its finding of facts will not be disturbed unless such finding is contrary to the evidence, or is without evidence to support it, or is arbitrary, or results from a misapplication of legal principles.” *United Fuel Gas Company v. Public Service Commission*, 143 W.Va. 33, (99 S.E.2d 1).’ Syl. Pt. 5, *Boggs v. Pub. Serv. Comm’n*, 154 W.Va. 146, 174 S.E.2d 331 (1970).” Syl. Pt. 1, *Sierra Club v. Pub. Serv. Comm’n of W. Va.*, 241 W. Va. 600, 827 S.E.2d 224 (2019).

2. ““The detailed standard for our review of an order of the Public Service Commission contained in Syllabus Point 2 of *Monongahela Power Co. v. Public Service Commission*, 166 W.Va. 423, 276 S.E.2d 179 (1981), may be summarized as follows: (1) whether the Commission exceeded its statutory jurisdiction and powers; (2) whether there is adequate evidence to support the Commission’s findings; and, (3) whether the substantive result of the Commission’s order is proper.’ Syl. Pt. 1, *Cent. W.Va. Refuse, Inc. v. Pub. Serv. Comm’n of W.Va.*, 190 W.Va. 416, 438 S.E.2d 596 (1993).” Syl. Pt. 2, *Sierra Club v. Pub. Serv. Comm’n of W. Va.*, 241 W. Va. 600, 827 S.E.2d 224 (2019).

HUTCHISON, Justice:

In Expanded Net Energy Cost (“ENEC”) proceedings before the Public Service Commission of West Virginia (“Commission”), Appalachian Power Company (“APCo”) and Wheeling Power Company (“WPCo”) (collectively “petitioners”), public utilities providing electric service to West Virginia customers, sought to recover approximately \$552.9 million in an accumulated monthly under-recovery balance for the period March 1, 2021, through February 28, 2023. In its January 9, 2024, order, the Commission disallowed recovery of approximately \$231.8 million of the requested amount because the Commission concluded it was incurred as the result of imprudent and unreasonable decisions by petitioners relating to their inadequate stockpiling of coal necessary to fuel their respective coal-fired electric generating facilities. The lack of adequate fuel, the Commission found, caused petitioners to restrict self-generation during periods when self-generation would have been less expensive than purchasing energy which, in turn, required petitioners to rely on more expensive alternative purchased power. The Commission ordered that the remaining balance of the requested under-recovery (approximately \$321.1 million) be assessed to consumers through an ENEC rate increment over a ten-year period, including a 4% carrying charge, to begin September 1, 2024.

Upon our review of petitioners’ appeal of the Commission’s order, we affirm the order to the extent the Commission determined that petitioners failed to manage their power plant operations in a reasonable, prudent, and efficient manner during the period under review resulting in their failure to maintain adequate fuel supplies—specifically, as

they relate to the Commission's ruling that petitioners acted imprudently and unreasonably, we affirm the order's findings of fact, conclusions of law, and the Commission's reasons therefor as stated in its order, and we adopt and incorporate by reference the order to that limited extent. However, we reverse the Commission's order insofar as it disallowed \$231.8 million of the requested under-recovery balance because the Commission's calculation was based upon certain extra-record evidence of which petitioners were not afforded notice or an opportunity to be heard, in violation of their constitutional right to due process of law. Accordingly, we remand the matter for further proceedings for the specific and sole purpose of affording petitioners the opportunity to address that evidence in connection with the quantification of ENEC costs that were incurred as the result of petitioners' imprudent decisions during the time period under review.¹

I. Factual and Procedural Background

Introduction

The John Amos and Mountaineer Plants, owned and operated by APCo, and the Mitchell Plant, in which WPCo owns a 50% undivided interest, are coal-fired electric generating facilities.

¹ The Consumer Advocate Division of the Public Service Commission of West Virginia, the West Virginia Energy Users Group, and the West Virginia Coal Association, Inc., as amici curiae, submitted briefs in this appeal and the Court has considered them in conjunction with the parties' arguments.

ENEC cases are filed annually with the Commission to enable petitioners “to adjust rates for fuel related generation costs and certain purchased power and transmission related costs[;]” they are “specialized and limited rate proceeding[s]” that allow petitioners “to avoid filing a full base rate case to reflect changes in those cost components.”²

ENEC rates are “based on projections of future ENEC cost elements. An important element of the ENEC procedure [is] an over[-] or under-recovery mechanism whereby companies using the ENEC procedure would defer costs that exceeded or were less than their ENEC revenues and request recovery of under-recoveries or rate crediting of over-recoveries (true-up mechanism).”³ Normally, the Commission reviews over- or under-recovery balances and builds them into rates annually so that accumulated balances even out from year to year. However, this “true-up mechanism” “is subject to Commission review of the incurred costs and determination that the costs resulted from prudent actions on the part of the utility and were reasonable. Absent such a finding, there [is] no guarantee that under-recoveries [will] be passed on to customers.”⁴

Indeed, the present matter involves petitioners’ effort to recover ENEC costs of \$552.9 million, which reflect accumulated monthly net under-recoveries from March 1, 2021, through February 28, 2023. Following the completion of a Commission-ordered

² May 13, 2022, Commission Order, Case No. 21-0339-E-ENEC *3.

³ *Id.*

⁴ *Id.*

review of whether petitioners acted reasonably and prudently in incurring the requested ENEC costs and the holding of an evidentiary hearing, the Commission determined that petitioners did not act prudently and reasonably and so it disallowed the recovery of \$231.8 million of the \$552.9 million under-recovery balance that petitioners requested. The Commission authorized a prospective recovery of the remaining \$321.1 million requested in under-recoveries amortized over ten years beginning September 1, 2024, with a carrying charge of 4%.

In disallowing the recovery of \$231.8 million, the Commission determined that petitioners “failed to manage their fuel supplies and power plant operations in a reasonable, prudent, and efficient manner” during the relevant time period and that, had they acted prudently, they “would not have experienced the unreasonably low inventory levels [of coal] that they now use to excuse their inability to maximize the use of their coal-fired power plants.” Instead of generating energy at their own plants, petitioners purchased excessive “amounts of power from the PJM market⁵ at prices that were at the highest level

⁵ PJM Interconnection, LLC “operates a competitive wholesale electricity market and manages the reliability of its transmission grid. . . . In managing the grid, PJM centrally dispatches generation and coordinates the movement of wholesale electricity in all or part of” West Virginia, twelve other states, and the District of Columbia. Petitioners purchase energy from PJM. According to petitioners, APCo also owns and operates its own gas-fired electric generating facilities and hydroelectric facilities, but they also purchase power from various facilities (hydroelectric, wind, solar and coal-fired) under “purchased power agreements.”

in PJM History.”⁶ The Commission deemed this conduct “unreasonable and the result of imprudent decisions regarding coal inventories, coal procurement, bidding into the PJM energy market, and minimization of out-of-service time.” If petitioners had planned and operated their plants prudently, the Commission found, they could have reduced their ENEC costs in West Virginia by at least \$231.8 million during the relevant time period.

Understanding petitioners’ challenge to the Commission’s decision requires understanding that the 2023 ENEC filing is heavily intertwined with petitioners’ previous two ENEC filings (the 2021 and 2022 cases). Therefore, we generally recount below, in simplest terms, the Commission’s orders entered in those cases because they document the

⁶ APCo and WPCo are vertically integrated load-serving utilities with their own power supply. As explained in the order, in ENEC proceedings, there are references to “sales to” and “purchases from” PJM. For vertically integrated load-serving utilities with their own power supply such as petitioners,

the term “sale” refers to self-generated power that is delivered from the power plants into the transmission system and is accounted-for as a “sale” into PJM. The term “purchase” refers to the load of the utility which is taken from the transmission system and is accounted-for as a “purchase.” In effect, the total net transaction of a load serving vertically integrated utility . . . is self-generation to serve load with an accounting performed by PJM. For example, if the load is 10 million Megawatt Hour (MWh) and the self-generation is 10 million MWh during a period when the PJM locational marginal price (LMP) is \$40 per MWh, although the accounting may be referred to as a \$400 million sale to PJM and a \$400 million purchase from PJM, the net purchase from PJM would be zero and the only ENEC cost remaining to be paid by load would be the cost of the self-generation.

record and explain the Commission's decision to order a review of the under-recoveries that were incurred for reasonableness and whether petitioners prudently managed their fuel supply and purchased power decisions.

Case No. 21-0339-E-ENEC

The Commission became concerned as to the cause of petitioners' growing ENEC under-recovery beginning with their 2021 ENEC filing (Case No. 21-0339-E-ENEC), which revealed petitioners were planning to purchase large amounts of more expensive energy from PJM rather than maximizing generation from their own plants at a lower cost. Petitioners proposed to increase ENEC rates to produce an additional \$73 million in annual ENEC revenues. Of that amount, \$55.4 million was for under-recovery of fuel costs, including \$32 million in deferred under-recovery collection from 2020,⁷ and \$17.6 million in projected costs for the forecast period (September 1, 2021, through August 31, 2022). The Commission conducted an evidentiary hearing.

In its order entered September 2, 2021, the Commission observed that petitioners' "projected ENEC costs include significant amounts of purchased power which

⁷ In Case No. 20-0262-E-ENEC (the 2020 ENEC case), petitioners requested an additional \$82 million in annual ENEC revenues. An ENEC rate increase of approximately \$50.1 million beginning September 1, 2020, was agreed to in recognition of the health and economic hardships caused by the COVID-19 pandemic. The remaining \$32 million petitioners originally requested in that case was deferred until the 2021 ENEC case.

could be prudent if it is clear that purchased power costs will be less expensive when compared to generation at the West Virginia power plants.” The Commission determined that petitioners projected ENEC costs that included utilizing their power plants at capacity factors⁸ well below that which should be the basis for such costs but that the evidence, as described more fully in its September 2, 2021, order, dictated that the public interest would be better served by petitioners maximizing generation from their own power plants. At a minimum, the Commission found, petitioners should be using a capacity factor of 69% for their projected ENEC costs. The Commission thus adjusted (i.e., reduced) petitioners’ projected costs to reflect less purchased power and more self-generation and approved ENEC rates using a capacity factor of 69%. To aid the Commission in monitoring petitioners’ “success at increasing generation at its power plants,” it ordered petitioners to file monthly reports as closed entries in the case.⁹

On September 13, 2021, petitioners filed a petition for reconsideration or clarification of the September 2, 2021, Commission Order. The Commission granted the petition to the extent it corrected a miscalculation in its prior order resulting in an increase

⁸ “Capacity factor” refers to the net generation over a period compared to the maximum possible generation over that period.

⁹ The Commission ordered that the reports show net generation from all APCo and WPCo power plants by month; retail and wholesale energy load by month; purchased power energy purchases by month and supplier; and purchased power demand and energy costs by month and supplier.

in petitioners' ENEC rates by \$31.4 million.¹⁰ The Commission also reopened the case for petitioners to explain the significant growth in the under-recovery of ENEC costs as reported by petitioners to the Commission and, as explained in its March 2, 2022, order, "to determine what is currently happening in the PJM markets and what is happening with the ability of [petitioners] to utilize their coal-fired power plants." The Commission

reviewed with alarm the monthly filings submitted by [petitioners] as closed entries in this case. Those filings indicate that there may have been significant deflections from the projections regarding purchased power volumes and purchased power costs and a failure to use lower cost generation in lieu of more expensive purchased power. As a result, the under-recoveries booked by [petitioners] is now reported to be at an alarming level.¹¹

The Commission's decision to reopen the 2021 ENEC proceeding was supported by, among other things, specific data provided by petitioners in their closed entry reports, including evidence that, despite the set target of a minimum 69% capacity factor from their West Virginia plants, "which appear to be able to produce power at costs that are well below the cost of purchased power, the capacity factors have not approached that level in September, October, and November 2021." Petitioners submitted additional evidence and an evidentiary hearing was conducted to address the growing under-recovery.

¹⁰ The Commission declined to address petitioners' request for clarification concerning the requirement that petitioners operate their coal-fired power plants at a 69% capacity factor.

¹¹ Petitioners reported that the actual under-recovery balance had grown to \$176.1 million as of November 30, 2021.

In a Commission Order entered on May 13, 2022, Commission Staff was directed to conduct an in-depth prudency review of the energy costs incurred by petitioners.

In the order, the Commission reiterated its concern

that [petitioners] have been over-relying on PJM energy market purchases in lieu of planning for maximum self-generation through utilization of the capacity they own, and which customers are paying for, at the John Amos, Mountaineer and Mitchell power plants. [Petitioners] claim that they plan on running their plants when it is economical to do so. However, for a variety of reasons including fuel shortages they did not do that at the worst possible time as the PJM energy market prices grew to unprecedented levels beginning in the fall of 2021 and continued at unprecedented levels through the winter of 2021/2022. [Petitioners] claim that when the PJM market prices exploded, they attempted to obtain more fuel for their plant, but to no avail. However, part of the fuel problem faced by [petitioners] was the result of their decision to allow fuel inventories to decline to levels which were unreasonably low.

It is clear that reliance on the PJM energy markets is producing unreasonable cost levels and ENEC under-recoveries that [petitioners] now ask West Virginia customers to pay. The Commission recognized the excessive cost of relying on the PJM energy market in September 2021 when we ordered [petitioners] to increase self-generation in lieu of the PJM market and high cost purchased power contracts. If [petitioners] had been able to increase self-generation and foregone reliance on PJM energy, then the recent spate of under-recoveries would have been greatly reduced or eliminated. Instead, we now learn that utilization of their power plants was limited by unreasonably low fuel supplies and an inability to acquire fuel supplies to accommodate the maximum possible capacity utilization of their power plants.

We were not told by [petitioners] at the initial stage of this proceeding that they were scraping the bottom of their coal inventory which would make it difficult for them to use their power plants at maximum levels no matter how much could be saved by self-generation. It is clear that [petitioners'] fuel

supply planning and overreliance on market purchases are self-inflicted wounds.

....

It is not clear to us how [petitioners] were not more concerned in late 2020 and 2021 that rising gas prices and other modifications that have been driven by PJM policy changes in recent years would make the benefits of low PJM market prices a distant memory. Instead of allowing coal inventories to decline precipitously, [petitioners] should have been doing everything possible to use their plants more and increase fuel inventories at the same time.

For these reasons, and other reasons reflected in its May 13, 2022, order, the Commission directed Commission Staff to conduct an in-depth review of the reasonableness of petitioners' net ENEC costs and petitioners' "policies and procedures for maximizing and maintaining adequate fuel inventory levels [and] bidding their plants into the PJM market to maximize economical self-generation[.]" The Commission further "require[d] evidence of proper and prudent plant maintenance and availability so that the benefits of self-generation can be realized when the opportunities arise."

The Commission deferred consideration of the reported under-recovery balance for rate-making purposes pending receipt of the prudency review; however, it granted petitioners recovery of an additional \$93 million for projected increased costs "to prevent future possible rate shock to the customers" and noted that the recovered costs "will be subject to future review and may be subject to disallowance if the Commission determines that they are unreasonable and the result of imprudent management of generation assets, generation costs and purchased power expenses" by petitioners.

Case No. 22-0393-E-ENEC

On April 19, 2022, petitioners filed Case No. 22-0393-E-ENEC (“2022 ENEC case”) requesting \$297 million in ENEC revenues over and above the amount the Commission approved in the reopened 2021 ENEC case. By order entered February 3, 2023, the Commission determined that reasonableness of the costs and revenues requested in the 2022 ENEC case “will depend on the prudence of [petitioners’] management of fuel supplies and purchased power decisions.” The Commission reiterated its concern relating to petitioners’ “historical and projected fuel and purchased power costs and continuing under-recoveries” and its belief that “self-generated power has been shown to be more economical than reliance on more expensive and less reliable purchased power.” The Commission also noted that it “based the projected costs underlying the current ENEC rates on maximizing self-generated power at [petitioners’] power plants which we determined should be capable of operating at a minimum 69 percent capacity factor.” As explained more fully in its February 3, 2023, order, the Commission stated that petitioners could most easily satisfy their burden of proving that they acted prudently and reasonably if they achieve the 69% annual capacity factor. However, the Commission cautioned that, if petitioners fail to achieve that minimum, then to demonstrate prudence, they would need to show that they (1) “maintain[ed] adequate economical fuel supplies, (2) ke[pt] plants available for generat[ing] the maximum amount of time, (3) maxim[ed] reduction . . . of outage times, and (4) effectively bid[] to clear the PJM energy market” Noting that it had recently granted a \$93 million revenue increase, “which also [was] still subject

to a final determination based on the reasonableness of the underlying costs[,]" the Commission deferred a decision on the requested increase until the completion of the prudency review by Commission Staff.

Case No. 23-0377-E-ENEC

Petitioners filed Case No. 23-0377- E-ENEC ("2023 ENEC case") on April 28, 2023, requesting the recovery of approximately \$641.7 million, including \$552.9 million in an under-recovery balance accumulated from March 1, 2021, through February 28, 2023, (i.e., the months encompassed by the 2021, 2022, and 2023 ENEC cases) and a projected increase of ENEC costs in the amount of \$88.8 million for the forecasted period of September 1, 2023, through August 31, 2024.¹²

Also on April 28, 2023, Commission Staff filed its prudency review, entitled "Independent Technical Prudency Review of the Actions Affecting the Operations of Amos, Mountaineer, and Mitchell Coal Plants Case Nos. 22-0393-E-ENEC and 21-0339-E-ENEC" ("prudency report"), that was prepared by the firm Critical Technology Consulting ("CTC"). The Commission subsequently entered an order reopening the 2021 and 2022 ENEC cases to hear evidence on the prudency report. The parties pre-filed

¹² By order entered September 13, 2023, the Commission granted the requested \$88.8 million in forecasted costs because no party challenged the methodology or reasonableness of the estimates and projections supporting it.

testimony and exhibits and a hearing was conducted over three days (September 5-7, 2023).¹³

In its highly detailed, thorough, and well-reasoned order, the Commission again observed that it was tasked with

determin[ing] if [petitioners] prudently, efficiently, and reasonably used economic self-generation from their own power plants in lieu of higher cost net PJM power. In order to determine if excessive costs were incurred because of [petitioners'] decisions and actions that left them with insufficient supplies of coal for economical self-generation, it is also critical for the Commission to consider whether [petitioners] used the minimum amount of high-priced PJM energy market electricity over the period of review or whether the net power supplied through PJM transactions in lieu of self-generation was excessive.

The Commission found that, despite petitioners' past assurances that "their coal-fired plants are valuable assets that provide a physical hedge against high and volatile PJM energy prices," petitioners, nonetheless, failed to "prudently maintain adequate fuel supplies and manage operations of their . . . plants" to provide that physical hedge. Noting "a clear decline in coal stockpiles from the end of 2020 to mid-2021" and specific increases in the PJM market prices over that same period, the Commission determined that petitioners "did not react prudently to the warning signals they were receiving." As noted by the Commission, the prudency report found that petitioners'

plants were dispatched by PJM at an aggregate 32.5 percent per year. CTC found that [petitioners'] coal plants are in good

¹³ The hearing on the prudency report was conducted immediately prior to the evidentiary hearing on the 2023 ENEC case.

condition and capable of dispatch. CTC found, however, that over the ten-year period prior to the report being filed with the Commission, [petitioners] placed an overreliance on net power supply from the PJM market and significantly reduced self-generation. Further [petitioners] did not appear to take seriously the Commission decision in the 2021 ENEC and 2022 ENEC that directed [them] to self-generate more of their required power.

As discussed in the Prudency Report and testimony, [petitioners] built up larger than normal coal stockpiles through 2020. However, by May 2021, [petitioners] should have been concerned by the diminishing stockpiles of coal in inventory. [Petitioners] should have realized in May 2021, but no later than July 2021, that the coal shortages at their plants would prevent them from self-generating at a meaningful level to offset rising PJM Energy market prices. In July 2021, the stockpiles were critically short, yet no action was taken until September 20, 2021, when [petitioners] issued a coal supply Request for Purchase (RFP). By this point, it was already too late to replenish the stockpiles. Only one coal supplier responded in the affirmative to the RFP and even that offer was rescinded.

The Commission further noted CTC's concern that petitioners failed "to take seriously the Commission directive to increase the plant capacity factors to 69 percent." *Id.* Specifically, petitioners failed to

make changes in the fuel procurement process or bidding their energy into PJM to allow them to provide more self-generation and increase the capacity factor of their plants. [Petitioners] failed to tell a key employee, Mr. Dial, who was in charge of fuel procurement, of the 69 percent capacity factor target set forth in the September 2, 2021 Commission Order. Eighteen days later, Mr. Dial issued an RFP for more coal, unaware, pursuant to his testimony, of a need to not only replenish the stockpiles, but also to be able to meet the 69 percent average generating rate target that had been established by the Commission.

Though petitioners had presented testimony during the hearing on the petition for reconsideration in the 2021 ENEC case that they issued the September 2021 RFP as a result of the September 2, 2021, Commission Order, the evidence revealed that, even after entry of the March 2, 2022, Commission Order on the petition for reconsideration, petitioners had yet to inform Mr. Dial “to procure sufficient coal that would allow [petitioners] to achieve the 69 percent capacity factor target if PJM energy prices continued to increase above earlier projected prices and far above the low levels of PJM market prices in 2020.” Indeed, the Commission determined that the evidence showed that petitioners failed to procure enough coal to generate at a 69% annual capacity factor.

As stated in the order, the Commission considered petitioners’ position “regarding the unexpectedness and exigency of the situation they found themselves in when market prices skyrocketed, and [that] they were caught with insufficient coal supply to maximize their use of their lower cost generation.” However, the Commission “[could] not agree that [petitioners] are blameless and without fault in building up an ENEC under-recovery of over \$550 million.” The Commission determined that

having insufficient supplies of coal in inventory and scheduled for delivery into [petitioners’] plants led to the lowest level of generation in the last twenty years during a period when the PJM LMP spiked to the highest levels experienced in the last twenty years. This “perfect storm” led to an inability to maximize economic generation while using excessive amounts of PJM power. The burden of a significant portion of the resulting excessive costs must fall on [petitioners] because their fuel supply failures and related market offer strategies that lead to rejection of their power plants for dispatch by PJM directly caused the excessive ENEC costs.

(Footnotes omitted). The Commission found that “ENEC under-recoveries were climbing dramatically due to over-reliance on third-party power supplies at rising cost levels that could have been offset by self-generation if [petitioners] had acted reasonably and prudently in a timely manner[,]” and that petitioners “demonstrated an imprudent lack of ongoing attention to assure that they had a continuous supply of coal to maintain adequate stockpiles of coal to maximize generation when it was cheaper than PJM energy prices.” Indeed, the Commission determined that the evidence showed that petitioners failed in “their responsibility to structure their coal supply contracts in a manner that would allow them to respond to rising PJM LMPs by increasing the utilization of their power plants without running out of coal” by entering into “a mix of long-term, medium-term, and short-term contracts and spot purchases when necessary.”

Concluding that petitioners’ imprudent management resulted in their incursion of “excessive net ENEC costs that should not be shouldered entirely by customers,” the Commission disallowed \$231.8 million of the requested ENEC under-recoveries. The Commission authorized a prospective recovery of the remaining \$321.1 million in under-recoveries over ten years beginning September 1, 2024, with a carrying charge of 4%.

It is from this order that petitioners now appeal.

II. Standard of Review

This Court has previously recognized the highly specialized knowledge and expertise of the Commission in considering complex cases such as this:

This Court's standard of reviewing the Commission's order in this case is highly deferential given that this case involves complex issues and arcane concepts that fall within the special competence of the Commission and are governed by Commission precedent. This Court previously has recognized that "[a] public utility commission has broad powers in supervising and regulating the actions of utilities within its jurisdiction in the respects provided for in the statutory or constitutional provisions by which its authority is conferred." *United Fuel Gas Co. v. PSC*, 154 W.Va. 221, 241, 174 S.E.2d 304, 316 (1969) (citation omitted). Further, this Court has recognized that "on questions of expediency, or as to what would be best in the interest of the petitioner, or the public served . . . the Legislature intended that the judgment of the [Public Service] Commission should prevail." *United Fuel Gas Co. v. PSC*, 73 W.Va. 571, 591, 80 S.E. 931, 939 (1914).

W. Va. Citizen Action Grp. v. Pub. Serv. Comm'n of W. Va., 233 W. Va. 327, 331–32, 758 S.E.2d 254, 258–59 (2014). (Emphasis added). Further,

"The principle is well established by the decisions of this Court that an order of the public service commission based upon its finding of facts will not be disturbed unless such finding is contrary to the evidence, or is without evidence to support it, or is arbitrary, or results from a misapplication of legal principles." *United Fuel Gas Company v. Public Service Commission*, 143 W.Va. 33, (99 S.E.2d 1)." Syl. Pt. 5, *Boggs v. Pub. Serv. Comm'n*, 154 W.Va. 146, 174 S.E.2d 331 (1970).

"The detailed standard for our review of an order of the Public Service Commission contained in Syllabus Point 2 of *Monongahela Power Co. v. Public Service Commission*, 166 W.Va. 423, 276 S.E.2d 179 (1981), may be summarized as follows: (1) whether the Commission exceeded its statutory jurisdiction and powers; (2) whether there is adequate evidence to support the Commission's findings; and, (3) whether the substantive result of the Commission's order is proper." Syl. Pt. 1, *Cent. W.Va. Refuse, Inc. v. Pub. Serv. Comm'n of W.Va.*, 190 W.Va. 416, 438 S.E.2d 596 (1993).

Syl. pts. 1 and 2, *Sierra Club v. Pub. Serv. Comm'n of W. Va.*, 241 W. Va. 600, 827 S.E.2d 224 (2019). *See Monongahela Power Co.*, 166 W.Va. at 425, 276 S.E.2d at 181 (“[B]ecause the Commission is experienced with the intricacies of the rate-making process we will ordinarily not substitute our judgment for that of the Commission on controverted evidence.”). With these standards to guide us, we now consider petitioners’ appeal.

II. Discussion

A.

Petitioners’ first two assignments of error are related and will be addressed together. Petitioners argue that the Commission used an incorrect legal standard when assessing whether the accumulated under-recovery balance for the period March 1, 2021, through February 28, 2023, was the result of unreasonable and imprudent decision-making by petitioners and that the Commission further erred in concluding that petitioners acted imprudently and unreasonably.

In determining that petitioners failed to prove that they managed their fuel supplies and power plant operations (including purchased power costs) in a reasonable, prudent, and efficient manner, the Commission noted that it considered petitioners’ “contemporary action[s] . . . based on what [was] known or reasonably knowable at the time the action[s] [were] taken” as well as “a continuum of actions leading up to a decision point.” The parties agree that the well-settled legal standard requires the Commission to examine petitioners’ decisions leading up to and resulting in the ENEC costs they seek to

recover from ratepayers based upon facts and information available at the time such decisions were made. In past Commission proceedings, the Commission has stated:

To find that a utility has acted imprudently, the Commission must have evidence before it to show that the utility's decisions were unreasonable based on actual data that was available at the time the utility was making its decisions. Another way of saying this is that the Commission would have to determine that an alternative utility action was reasonable and should have been made based upon facts available at the time the decision was made. The Commission may not find imprudence based on outcomes or new facts that the utility cannot have reasonably been expected to know, or assume.¹⁴

Petitioners argue that by also considering “a continuum of actions leading up to a decision point,” the Commission impermissibly deviated from the appropriate standard by effectively evaluating petitioners’ decision-making relating to their coal procurement efforts (or lack thereof) and consequent inability to economically operate their coal-fired power plants resulting in their purchasing of expensive energy from the PJM market “on the basis of ultimate outcomes considered with 20/20 hindsight.” According to petitioners, the Commission ignored evidence that petitioners’ coal procurement practices comported with industry standards and adapted to changing circumstances and that, not unlike coal-fired electric utilities located outside of West Virginia, petitioners were faced with what they characterize as unforeseeable and challenging circumstances over which they had no control, including that, beginning in the later months of 2021, natural gas and coal prices were increasing unexpectedly and coal was unavailable to purchase. Petitioners also point

¹⁴ *In re Hope Gas, Inc.*, 2006 WL 2134651 *12 (W. Va. P.S.C. April 3, 2006).

to evidence that large quantities of coal that they previously contracted to purchase were not delivered. Simply put, petitioners argue that they did not act imprudently based upon information that was known and knowable to them at the time and the fact that, during the time period at issue, they had insufficient supplies of coal to generate their plants causing them to purchase large amounts of power at high-cost levels to serve their customers was not their fault.

The Commission counters that there was evidence presented that, beginning in the late spring of 2021, the coal market was tightening and the price of natural gas was increasing; that expert witness testimony presented in July of 2021 expressed concern over a significant amount of petitioners' coal supply being concentrated with only two suppliers; that petitioners did not issue an RFP for coal until September 20, 2021, when petitioners' coal supply was already diminishing; that petitioners failed to inform their fuel procurement officer that petitioners were ordered by the Commission to target a 69% capacity factor and so the RFP did not request sufficient coal supplies to meet that target; that petitioners' mix of coal contracts of varying lengths was not sufficient to ensure an adequate supply of coal; and that petitioners' own projections in the 2021 ENEC case indicated that they were over-relying on purchased power even when cost levels were increasing from 2020 levels and it was more economical to self-generate. Noting that petitioners previously assured the Commission that their coal-fired plants would provide a physical hedge against high and volatile electric market prices, the Commission argues that petitioners failed to provide that physical hedge by imprudently disregarding trends and

market signals affecting their coal procurement practices.¹⁵ The Commission contends that the finding that petitioners were imprudent and unreasonable in their decision-making and that the resulting incursion of excessively high under-recoveries should not be passed on to customers was supported by the evidence and should be affirmed.

Upon our considered review, and ever mindful that the complexity of the issues and subject matter falls within the special competence of the Commission, we afford great deference to the Commission's thorough and well-reasoned conclusion that petitioners failed to manage their power plant operations in a reasonable, prudent, and efficient manner resulting in an inadequate stockpile of coal to fuel their facilities that, in turn, caused petitioners to purchase energy at cost levels that were much higher than what it would have cost them to generate from their own plants.¹⁶ Petitioners have failed to establish that the Commission's decision in this regard was arbitrary, contrary to the evidence, without evidence to support it, or resulted from a misapplication of the law,¹⁷ and so, as they relate to the Commission's determination that petitioners acted imprudently and

¹⁵ *Cf. In re Hope Gas, Inc. dba Dominion Hope*, 2013 WL 2370525 *1 (W. Va. P.S.C. May 10, 2013) (regarding a gas utility's burden of proving reasonable and prudent hedging actions, "the prudence of management decisions will not be evaluated with the benefit of 20/20 hindsight. . . .[H]owever, . . . at the time those hedging decisions are made, they must be based on a continuing and reasonable understanding of market conditions, market trends, and other factors that are shaping current and future gas supply and demand and that will likely impact future gas costs.").

¹⁶ *See W. Va. Citizen Action Grp.*, 233 W. Va. at 331-32, 758 S.E.2d at 258-59.

¹⁷ *See Sierra Club*, 241 W. Va. at 601, 827 S.E.2d at 225, syl. pt. 1.

unreasonably, we affirm the January 9, 2024, order's findings of fact, conclusions of law, and the Commission's stated reasons therefor, and adopt and incorporate them by reference into this opinion. We further find that the Commission's determination that petitioners acted imprudently and unreasonably in their decision-making was made in light of information and circumstances that petitioners knew or should have known at the time their decisions were made, as more fully set forth in the Commission's order.

B.

Petitioners' next assignment of error challenges the Commission's conclusion that \$231.8 million of the \$552.9 million accumulated under-recovery balance requested was the result of petitioners' imprudent and unreasonable decision-making discussed above in Section A. The Commission ordered that this amount be disallowed for recovery in ENEC rates. At issue is whether the Commission violated petitioners' fundamental due process rights by relying on information outside of the evidentiary record in arriving at its disallowance calculation.

Petitioners argue that the Commission improperly used coal reports that petitioners submitted to the Commission on a monthly basis,¹⁸ but that were not made a part of the record in the proceedings below, to unilaterally modify an exhibit that petitioners submitted after the hearing had concluded. Specifically, on the third and final day of the

¹⁸ Electric utilities such as petitioners are required to submit to the Commission, on a monthly basis, certain information relating to their purchases of coal or other fuel. *See* W. Va. Code § 24-2-14 (1975).

proceedings, the Commission requested that petitioners submit evidence of their “market bids and cost-based bids in the PJM market, the corresponding LMP clearing prices, and the resulting market clearing volumes of their self-generation” covering the review period March 1, 2021, through February 28, 2023. Petitioners complied with the Commission’s request and timely submitted the exhibit (“Post-Hearing Exhibit 4”) after the proceedings had concluded. Petitioners argue that the Commission proceeded to calculate the \$231.8 million disallowance by supplanting the cost-based bid prices reflected in petitioners’ exhibit with prices calculated by the Commission using information it obtained from the coal reports that were not presented as evidence during the hearing. Petitioners argue that, critically, exactly how the Commission used the information from the coal reports in its calculation of the disallowance is not apparent from the Commission’s order and so petitioners are unable to verify either the calculation’s accuracy or rebut its legitimacy. According to petitioners, the Commission used prices that were unrealistically low and without any basis in the actual evidentiary record. Petitioners contend that they had no notice that the Commission would be relying on this extra-record evidence and, importantly, were not afforded an opportunity to challenge or otherwise address the manner in which the Commission used it in calculating the extent to which, in the Commission’s view, petitioners acted imprudently and unreasonably. Petitioners argue that the Commission violated their fundamental due process rights.

The Commission responds that the purpose of the proceedings was to ascertain the prudence of petitioners’ coal procurement practices and their “inability to

offset high-priced purchased power. . . with more economic self-generation,” and that petitioners knew that if the Commission determined that petitioners had acted imprudently in incurring excessive ENEC costs, then the next step would be for the Commission to quantify the extent to which those costs were imprudently incurred. Without addressing whether it was a violation of petitioners’ due process rights to inscrutably and significantly modify petitioners’ Post-Hearing Exhibit 4 with extra-record evidence (i.e., the coal reports), the Commission offers a lengthy explanation justifying the reasons why it found it necessary to resort to the use of the reports in calculating the disallowance of \$231.8 million. The Commission argues that petitioners were afforded a fair evidentiary hearing.

It is beyond cavil that a proceeding “‘requiring the taking and weighing of evidence, determinations of fact based upon the consideration of the evidence, and the making of an order supported by such findings, has a quality resembling that of a judicial proceeding.’ . . . A functional analysis of the Commission’s proceedings leads unerringly to the conclusion that they . . . are quasi-judicial proceedings.” *Appalachian Power Co. v. Pub. Serv. Comm’n*, 162 W. Va. 839, 849-50, 253 S.E.2d 377, 384 (1979) (quoting *Morgan v. U.S.*, 298 U.S. 468, 480 (1936)). As such, parties to the Commission’s proceedings are entitled to basic constitutional protections, including due process of law. *See* Syl. Pt. 2, in part, *State ex rel. Ellis v. Kelly*, 145 W. Va. 70, 112 S.E.2d 641 (1960) (“‘Due process of law, within the meaning of the State and Federal constitutional provisions, extends to actions of administrative officers and tribunals. . . .’”). “Procedural due process rights entitle an individual to representation by counsel, notice, an opportunity to be heard, and the right

to present evidence.” *Marcus v. Holley*, 217 W. Va. 508, 527, 618 S.E.2d 517, 536 (2005).

“A due process analysis is founded upon the concept of fundamental fairness.” *Id.*

Ohio Bell Telephone Company v. Public Utilities Commission of Ohio, 301 U.S. 292 (1937), involved administrative proceedings before the Public Utilities Commission of Ohio (“PUCO”) to set rates for Ohio Bell Telephone Company (“Ohio Bell”) customers. PUCO ordered Ohio Bell to file with it a complete inventory of all of its property so that a hearing could be held to determine “the fair value of said property” as of a date certain (June 30, 1925) and “the just and reasonable rates for the service thereby to be furnished” to customers. *Id.* at 295. “A long investigation followed, the evidence being directed in the main to the value of the property on the basis of historical cost and cost of reproduction, and to the deductions chargeable to gross revenues for depreciation reserve and operating expenses generally.” *Id.* at 295-96. Based upon the evidence, PUCO fixed a tentative value as of the date certain but then “[i]t undertook also to fix a valuation for each of the years 1926 to 1933.” *Id.* at 296. In doing so, “it took judicial notice of price trends during those years” based upon property taxes; “building trends” from a recognized engineering construction magazine; labor trends; and court decisions, and “modif[ied] the value which it had found as of the date certain by the percentage of decline or rise applicable to the years thereafter.” *Id.* at 297. Ultimately, PUCO determined that, based upon this evidence, Ohio Bell was in receipt of significant excess earnings and ordered a refund to customers. *Id.* at 298.

Ohio Bell protested, arguing that

the trend percentage accepted in the findings as marking a decline in values did not come from any official sources which [PUCO] had the right to notice judicially; that they had not been introduced in evidence; that the company had not been given an opportunity to explain or rebut them; and that by their use [PUCO] had denied a fair hearing in contravention of the requirements of the Fourteenth Amendment.”

Id. at 298. PUCO reaffirmed its decision and the Supreme Court of Ohio affirmed.

Ohio Bell appealed to the United States Supreme Court, which reversed the decision of the lower court, acknowledging that the lower tribunals took “judicial notice that there has been a depression, and that a decline in the market values is one of its concomitants.” *Id.* at 301. However, the Supreme Court cautioned, “[h]ow great the decline has been for this industry or that, for one material or another, in this year or the next, can be known only to the experts, who may even differ among themselves.” *Id.* Thus, “notice, even when taken, has no other effect than to relieve one of the parties to a controversy of the burden of resorting to the usual forms of evidence. ‘It does not mean that the opponent is prevented from disputing the matter by evidence if he believes it disputable.’” *Id.* at 301-02 (citations omitted). Stated another way, when judicially noticed facts are “put in evidence upon a trial, the party against whom they are offered may see the evidence or hear it and parry its effect.” *Id.* at 302. The Supreme Court instructed that

[t]he fundamentals of a trial were denied to the appellant when rates previously collected were ordered to be refunded upon the strength of evidential facts not spread upon the record. [PUCO] had given notice that the value of the property would be fixed as of a date certain. Evidence directed to the value at that time had been laid before the triers of the facts in thousands of printed pages. To make the picture more complete, evidence had been given as to the value at cost of additions and

retirements. Without warning or even the hint of warning that the case would be considered or determined upon any other basis than the evidence submitted, the Commission cut down the values for the years after the date certain upon the strength of information secretly collected and never yet disclosed. The company protested. It asked disclosure of the documents indicative of price trends, and an opportunity to examine them, to analyze them, to explain and to rebut them. . . . Upon the strength of these unknown documents refunds have been ordered for sums mounting into millions, [PUCO] reporting its conclusion, but not the underlying proofs. The putative debtor does not know the proofs today. This is not the fair hearing essential to due process. It is condemnation without trial.

Id. at 300.¹⁹ This Court has likewise cautioned,

Although we recognize that the Public Service Commission may, in accordance with the well-developed principles governing official notice, occasionally go beyond the confines of the record for information bearing upon its decision, we state unequivocally that we do not favor this procedure except in extremely limited circumstances. The Commission places its decisions and orders in a precarious position when it bases them on extra-record adjudicative facts without advising a party that it intends to do so and without affording the party the opportunity for cross-examination and rebuttal. This is particularly true where there is no cogent or compelling reason for the Commission's failure to offer evidence on the record.

¹⁹ *Accord Union Elec. Co. v. F.E.R.C.*, 890 F.2d 1193, 1202-03 (D.C. Cir. 1989) (provision of the federal Administrative Procedure Act providing that “[w]hen an agency decision rests on official notice of a material fact not appearing in the evidence of record, a party is entitled . . . to an opportunity to show the contrary” that “encompasses a chance not only to dispute the facts noticed but also to ‘parry [their] effect,’ i.e., to offer evidence or analysis contesting the Commission’s inferences.”)

Kanawha Valley Transp. Co. v. Pub. Serv. Comm'n of W. Va., 159 W. Va 88, 98, 219 S.E.2d 332, 339 (1975). *See id.* at 88, 219 S.E.2d at 334, syl. pt. 5 (holding that “[p]arties to a [certificate of convenience and necessity] revocation hearing before the Public Service Commission should be fully informed of the evidence submitted or to be considered and should be given an opportunity to cross-examine witnesses, to inspect documents and offer evidence in rebuttal.”).

We agree with petitioners that it was fundamentally unfair for the Commission to consult and rely on evidence that was neither mentioned nor admitted into the record below to significantly adjust the cost-based bid prices that petitioners submitted in their exhibit to quantify the not insignificant disallowance of \$231.8 million. That the coal reports were submitted to the Commission by petitioners as a matter of course²⁰ is of no moment—even if it were appropriate for the Commission, on its own, to reach into its

²⁰ On March 22, 2024, the Commission filed a motion to supplement the appellate record with the coal reports to which the Commission cited in its January 9, 2024, order. Although the motion states that the coal reports “were used by the Commission in making its decision” in this case and that “the coal reports were inadvertently omitted from the Commission record previously filed with th[is] Court[,]” in connection with the instant appeal, the Commission does not dispute that the coal reports were not actually introduced or otherwise addressed during the course of the proceedings below. Further, despite the Commission’s suggestion during oral argument that the Commission took judicial notice of the reports, *see* W.Va. R. Evid. 201, there is no indication in the Commission’s order that it did so. Regardless, the Commission fails to address petitioners’ argument that they were not afforded notice and an opportunity to be heard as to how the Commission used the reports in quantifying the disallowance. *See Ohio Bell*, 301 U.S. at 301-02. The Commission states simply: “The disingenuous attempt by Petitioners to claim no knowledge of their own reports and to claim that the Commission should not consider information filed by the Petitioners themselves is absurd. Petitioners are most certainly aware of the coal reports that they prepare and file with the Commission.”

records for this factual information, the Commission does not dispute that the manner in which it used the information in the reports to calculate the disallowance was not disclosed to petitioners. Simply put, petitioners had no opportunity to examine, analyze, rebut, or “parry its effect,” *Ohio Bell*, 301 U.S. at 302, and the Commission has offered no cogent or compelling reason for its failure to offer this evidence on the record. *Kanawha Valley Transp.*, 159 W. Va at 98, 219 S.E.2d at 339. Due process “is ultimately measured by the concept of fundamental fairness.” *State ex rel. Blankenship v. Richardson*, 196 W. Va. 726, 739, 474 S.E.2d 906 919 (1996). Because petitioners were entitled to, but not afforded, notice of how the Commission used the information gleaned from the reports and the opportunity to examine, analyze, rebut, and “parry its effect,”²¹ we remand this matter to the Commission for that specific and singular purpose.²²

IV. Conclusion

Based upon all of the foregoing, we affirm the Commission’s order insofar as it concluded that petitioners failed to manage their power plant operations in a reasonable, prudent, and efficient manner, and we adopt and incorporate by reference the

²¹ To be clear, the Court takes no position as to whether the Commission’s use and manner of use of the coal reports were appropriate. Rather, our concern is that basic concepts of fundamental fairness dictate that petitioners should have been given notice and an opportunity to be heard on this evidence.

²² Because we have ordered that this matter be remanded to the Commission, we decline to address petitioners’ remaining assignment of error that the Commission exceeded its authority in ordering that the remaining under-recovery balance be recovered through an ENEC rate increment over a period of ten years, with a 4% carrying charge.

Commission's findings of fact, conclusions of law, and reasons stated therefor in the order to that limited extent. We reverse the order insofar as it disallowed \$231.8 million of the requested under-recoveries and remand this matter to the Commission for the specific and sole purpose of affording petitioners the opportunity to address the coal reports that the Commission relied upon in quantifying the disallowance.

Affirmed, in part; Reversed, in part; and Remanded.

WEST VIRGINIA LEGISLATURE

2025 REGULAR SESSION

ENROLLED

Committee Substitute

for

House Bill 2014

BY DELEGATES HANSHAW (MR. SPEAKER), RILEY,
FEHRENBACHER, ANDERSON, ZATEZALO, AKERS AND
HORNBUCKLE

(BY REQUEST OF THE EXECUTIVE)

[Passed April 12, 2025; in effect 90 days from
passage (July 11, 2025)]

OFFICE OF WEST VIRGINIA
SECRETARY OF STATE

2025 APR 30 P 11:18

FILED

HB2014

WEST VIRGINIA LEGISLATURE

2025 REGULAR SESSION

ENROLLED

Committee Substitute

for

House Bill 2014

BY DELEGATES HANSHAW (MR. SPEAKER), RILEY,
FEHRENBACHER, ANDERSON, ZATEZALO, AKERS AND
HORNBUCKLE

(BY REQUEST OF THE EXECUTIVE)

[Passed April 12, 2025; in effect 90 days from
passage (July 11, 2025)]

OFFICE OF WEST VIRGINIA
SECRETARY OF STATE

2025 APR 30 P 11:18

FILED

1 AN ACT to amend and reenact §5B-2-21, §24-2-1d, §24-2-1q, §24- 2-15, §24-2-19, and §24-2-
2 21a of the Code of West Virginia, 1931, as amended; to amend the code by adding four
3 new sections, designated §5B-2-21a, §5B-2-21b, §5B-2N-2a, and §11B-2- 33, and to
4 amend the code by adding a new article, designated §11-6N-1, §11-6N-2, §11-6N-3, §11-
5 6N-4, and §11-6N-5, all relating to the generation and consumption of electric power;
6 establishing the certified microgrid development program; providing for microgrid
7 certification requirements; providing for microgrid electric service requirements; providing
8 for microgrid customer eligibility; providing for microgrid special contracts; prohibiting
9 microgrids from participating in Pilot and tax increment financing programs; defining
10 microgrid property subject to property tax; providing for microgrid letter of intent, notice
11 period and negotiation; providing for microgrid special contracts; establishing the high
12 impact data center program; providing for notification, certification, and recordkeeping;
13 authorizing certain agencies to assist certified microgrid districts and certified high impact
14 data centers; prohibiting local jurisdiction regulation of microgrid districts and high impact
15 data centers; providing for payment of certain fees and taxes; providing for certain services
16 to microgrid districts and certified high impact data centers; establishing the electric grid
17 stabilization and security fund and its purpose; creating new article relating to special
18 method for valuation of certain high technology property; defining terms; providing for
19 microgrid districts and certified high impact data centers property returns to be filed with
20 Board of Public Works; providing for special rules for tax distribution; establishing certain
21 funds to receive distributions; terminating article; establishing the personal income tax
22 reduction fund and providing for purpose; providing for additional duties of public service
23 commission 2 relating to future electric generating capacity, base fuel coal supply for
24 electric grid resiliency, consumer rate relief bonds, and automatic adjustment clauses,
25 price indexes, or fuel adjustment; providing for rulemaking; and providing that certain
26 funds may not be used by a public utility to close or cease operations at an electric
27 generating plant.

Be it enacted by the Legislature of West Virginia:

CHAPTER 5B. ECONOMIC DEVELOPMENT ACT OF 1985.

ARTICLE 2. DEPARTMENT OF ECONOMIC DEVELOPMENT.

§5B-2-21. Certified Microgrid Development Program.

1 (a) *Program established.* — The Certified Microgrid Development Program is hereby
2 created and is to be administered as a program within the Division of Economic Development to
3 encourage the continued development, construction, operation, maintenance, and expansion in
4 West Virginia of high impact i plants and facilities, in certain circumstances where the availability
5 of electricity generated is demonstrated to be necessary. In order to effectuate the purposes of
6 this section, the Division of Economic Development, or any agency, division, or subdivision
7 thereof, may propose for promulgation of legislative rules, including emergency rules, in
8 accordance with §29A-3-1 *et seq.* of this code.

9 (b) *District certification.* — The Secretary of the Department of Commerce may identify
10 and certify microgrid districts in this state upon a finding that the following requirements are met:

11 (1) Certification of the microgrid district and location of new or expanded businesses within
12 the microgrid district will have a significant and positive economic impact on the state;

13 (2) Certification of the microgrid district is necessary to attract at least two businesses to
14 locate or expand in this state;

15 (3) The area to be certified as a microgrid district shall be no greater than 2,250 acres and
16 nearly contiguous;

17 (4) The electricity generated within the microgrid district will be used only within the
18 microgrid district or delivered to the wholesale market;

19 (5) The information described in §5B-2-21(h) of this code has been provided to the
20 Department of Commerce;

21 (6) The requirements of §5B-2-21(i) of this code have been satisfied; and

(7) The requirements of §5B-2-21(b)(5) and (6) of this code may not apply to microgrid districts certified on or before January 1, 2024;

(8) The requirements of subsections (d), (e), (g), (h), and (j) of this section enacted during the regular session of the Legislature, 2025, shall not apply to any microgrid district certified on or before January 1, 2024, or any special contract entered into and approved by the Public Service Commission on or before January 1, 2025. No amendments to this section enacted during the regular session of the Legislature, 2025, shall be interpreted to remove an existing microgrid district certification.

The Secretary of the Department of Commerce may not certify more than two microgrid districts: *Provided*, That this limit on certifying microgrid districts shall not apply to any microgrid district wherein greater than 70% of the electricity generated within the microgrid district is consumed by one or more high impact data centers, as defined in §11-6N-2 of this code, or will be consumed by one or more high impact data centers, when such data centers are completed and fully operational. A designation made pursuant to this section by the secretary as to the certification of a microgrid district is final.

(c) *Providing electric service within a certified microgrid district.* — Within a microgrid district, any person, firm, corporation, or entity or their lessees and tenants seeking to provide electric service through the generation or distribution of electricity within the microgrid district to businesses locating within the microgrid district may:

(1) Not be subject to the jurisdiction of the Public Service Commission with respect to rates, obtaining a certificate of convenience and necessity, conditions of service or complaints pursuant to chapter 24 of this code;

(2) Not be subject to the net metering and interconnection standards as set forth in §24-2F-8 of this code;

(3) Elect to qualify as an exempt wholesale generator under federal law for purposes of furnishing electric service through the generation of electricity to a utility or regional transmission

organization without being subject to the Public Service Commission's siting certificate requirements as set forth in §24-2-1(d), §24-2-11c, or §24-2-1o of this code;

(4) Provide any such electric service to businesses making a capital investment in a new or expanded facility located within the certified microgrid district;

(5) Not provide any such electric service for purposes of encouraging businesses already receiving electric service from a regulated utility in this state to relocate to the certified microgrid district; and

(6) Not deliver outside the microgrid district more than 10% of the electricity generated within the certified microgrid district and only delivered to the wholesale market.

(d) *Microgrid customers; eligibility.* — In order to take advantage of the provisions of this section, a plant or facility choosing to locate and operate within a microgrid district must constitute new electric load. Any owner, lessee, or tenant of a plant or facility that has not previously received electric service from a regulated public electric utility located within this state, or who is making a capital investment in a new facility within the microgrid district shall be considered eligible new electric load. Electric service to any such plant or facility shall be considered new electric load so long as any customer making a new capital investment within the microgrid district does not decrease the load of an existing facility outside the microgrid district in this state in conjunction with the new capital investment within the microgrid district, and regardless of whether or not a person or entity previously received service from a public electric utility at or near the same location prior to the certification of the microgrid district.

An eligible plant or facility choosing to locate and operate within a microgrid district is not required to connect with and use any public electric utility: *Provided*, That any connection with and use of a public electric utility for purposes of the initial construction and development within the microgrid district shall not impact a plant or facility's status as new electric load in order to take advantage of the provisions of this section.

73 (e) *Microgrid customers; special contracts and rates.* — After certification of a microgrid
74 district, the Public Service Commission may approve special contracts for a a microgrid customer
75 within the microgrid district. For purposes of this section, a "special contract" is:

76 (1) a written agreement between an electric utility and an eligible retail electric microgrid
77 customer within the microgrid district that is filed with the Public Service Commission and that
78 provides that an eligible retail electric microgrid customer will receive utility service on terms and
79 conditions, including rates, that vary from the utility's tariff on file with the Public Service
80 Commission, or

81 (2) electric utility service terms and conditions, including rates, ordered by the Public
82 Service Commission that vary from the electric utility's tariff to be in effect between a utility and
83 an eligible retail electric microgrid customer when the electric utility and the eligible retail electric
84 microgrid customer are unable to negotiate a written agreement.

85 A microgrid customer seeking a special contract shall first enter into negotiations with the
86 utility within whose service territory the microgrid district is located regarding the terms and
87 conditions of a mutually agreeable special contract. If the negotiations result in an agreement
88 between the microgrid customer and the utility within 120 days, the microgrid customer and the
89 utility shall jointly file with the Public Service Commission the special contract. If the negotiations
90 are unsuccessful in the 120-day period, the microgrid customer may file a petition with the Public
91 Service Commission to consider establishing a special contract. The Public Service Commission
92 shall consider all relevant factors in establishing a special contract. Upon the filing of a petition
93 pursuant to this section, the Public Service Commission shall establish a special contract for the
94 provision of requested service, including backup and supplemental service to a microgrid
95 customer within the microgrid district. Microgrid customers' load within the microgrid district not
96 covered by a contract for back up and supplemental service shall be considered non-firm and
97 interruptible. The Public Service Commission shall establish a special contract upon the filing of
98 a petition pursuant to this section and shall do so within 90 days of filing.

99 (f) *Electrical infrastructure costs.* — Regulated electric utility customers shall not bear any
100 costs including, but not limited to, construction, operational, ancillary services, grid-related,
101 energy-related, or capacity-related costs, associated with any electricity generation, transmission
102 or distribution facilities that provide electrical service to a microgrid district. Any costs of this nature
103 are to be borne by the generator or electricity consumers situated within the microgrid district.

104 (g)(1) *Payment In Lieu Of Taxes Electricity Generation and Distribution.* — Notwithstanding
105 the provisions of §5D-1-14, §7-5-13, §7-11B-3(b), §7-11B-8(c)(4), §7-11B-15(a)(7), §7-11B-
106 15(a)(15), §7-11B-18, §8-19-4, §8-29A-7, §8A-12-12, §11-13-2p, §11-13C-5(l)(1)(A), §16-13A-
107 21, §16-15-18(b)(6), §17-16A-16(b), §17-16B-20(b), §18-9A-12(c), §31-21-5, and §31-21-15 of
108 this code, or any other provision of this code, no payment in lieu of taxes shall be entered into
109 with relation to the property of any electricity generating plant, facility, or generating unit or any
110 property comprising, in whole or in part, any electricity distribution apparatus, equipment, lines or
111 facilities (A) located in the county and (B) directly or indirectly dedicated to providing electric power
112 to any plant, facility or property subject to this subsection. Nor shall any payment in lieu of taxes
113 be entered into with relation to any leasehold interest or any other property interest related thereto.

114 (2) *Tax Increment Financing.* — Notwithstanding the provisions of §7-11B-1 *et seq.* of this
115 code, or any other provision of this code, no tax increment financing project, plan or arrangement
116 shall be entered into or undertaken with relation to any electricity generation or distribution
117 property subject to this subsection.

118 (3) For purposes of this subsection, an electricity generating plant, facility, or generating
119 unit or electricity distribution apparatus, equipment, lines, or facilities shall be deemed to be
120 "dedicated" to providing electric power to any plant, facility, or property subject to this subsection
121 if not less than 75% of the output of the electricity generation property or electricity distribution
122 property, measured in kilowatt hours, are used to supply electricity to a facility, project, or series
123 of related or integrated facilities within the county or counties subject to this subsection.

(4) For purposes of this section, property includes all real property, all buildings and structures affixed to land, and all tangible personal property, including, but not limited to equipment, inventories and mobile equipment, and also including property subject to special salvage valuation under §11-6A-1 *et seq.*, §11-6E-1 *et seq.*, §11-6H-1 *et seq.*, §11-6J-1 *et seq.*, §11-6F-1 *et seq.*, and §11-6L-1 *et seq.* of this code, or any other special *ad valorem* property valuation provision of this code; *Provided*, That property subject to special valuation shall be allowed that special valuation as authorized by law, for purposes of calculating and determining the *ad valorem* property tax imposed with relation thereto, notwithstanding being otherwise subject to the provisions of this section.

(h) *Microgrid District Development; Letters of Intent.* — To become a certified microgrid district under this section, the person or entity must present the Secretary of the Department of Commerce with a confidential letter of intent. The letter of intent shall include sufficient economic, financial, and engineering information concerning the proposed project with sufficient detail to adequately inform the department of the size, scope, and nature of the target customers of the project, including, without limitation, the approximate proposed acreage and location, estimated capital investment, evidence of financial capacity, estimated project completion date, major project milestones, estimated generation capacity, estimated power loading internal to the microgrid, estimated power, including backup power, needed from the local distribution electric utility, estimated power supplied to the wholesale market, and the types or sources of each electric power generation unit. The letter of intent and all supplied information shall be held in confidence pursuant to §5B-2-21a(e) of this code by the department.

(i) *Microgrid District Development; Notice Period and Negotiation.* — At least 120 days before submitting a letter of intent and other materials to the department, an applicant seeking a microgrid district certification must make good faith efforts to negotiate for the supply of all or part of its electricity needs for the project from the local distribution electric utility. The letter of intent must also include documentation evidencing the good faith efforts to negotiate. This time-period

150 limitation and negotiation requirement does not apply to microgrid districts proposing to produce
151 300 megawatts or more of electricity or for microgrid districts that are proposing to not be
152 connected in any way to the local distribution electric utility after completion of all construction.

153 (j) *Microgrid District Development; Special Contracts and Power Rates.* — (1) A certified
154 microgrid district seeking a special contract from a local distribution electric utility located in the
155 state shall first enter negotiations for not more than 120 days with the local distribution utility
156 regarding the terms and conditions of a special contract. The microgrid district shall provide
157 reasonable access and terms to the local distribution utility to enable the electric utility's
158 transmission and/or distribution facilities to tie into those of the microgrid district. The 120-day
159 negotiation period required by this section may be satisfied by the precertification negotiation
160 period required by §5B-2-21(i) of this code.

161 (2) If the negotiations result in a mutually agreeable special contract, the contracting
162 parties shall jointly file the special contract pursuant to the rules of the commission.

163 (3) If negotiations for a special contract with the local distribution utility are unsuccessful,
164 a certified microgrid district may file a petition with the commission to establish a special contract.

165 (4) The commission shall establish a special contract upon the filing of a petition pursuant
166 to this section. The Public Service Commission shall consider all relevant factors in establishing
167 special contracts. The Public Service Commission shall establish a special rate for the requested
168 service, including backup and supplemental service to a microgrid district. The microgrid district's
169 load not covered by a contract shall be considered non-firm and interruptible. The commission
170 shall issue a final order determining the terms of a special contract within 90 days of filing of a
171 petition.

§5B-2-21a. Data Centers.

1 (a) *Findings and purpose.* — The Legislature hereby finds and declares the following:

2 (1) Data centers represent a significant and growing sector of the economy, generating
3 substantial economic activity, including jobs, infrastructure investments, and technological
4 innovation.

5 (2) Data centers are critical national infrastructure that require abundant, low-cost energy
6 to protect sensitive data, operate high-level computation assets, and ensure the resilience of the
7 digital economy.

8 (3) The People's Republic of China is positioning itself to be the global leader of data
9 centers and is investing in technology to encourage the flow of data toward China instead of
10 toward the United States.

11 (4) It is in the United States' national security interests to limit the flow of data to China
12 and to protect the flow of data and maximize computational power inside the United States. The
13 President has declared that it is the policy of the United States "to sustain and enhance America's
14 global AI dominance in order to promote human flourishing, economic competitiveness and
15 national security." Removing Barriers to American Leadership in Artificial Intelligence, Executive
16 Order 14179 (Jan 23, 2025).

17 (5) As of early 2025, the highest concentration of high-level computational power and data
18 centers in the world is located in Loudoun County, Virginia. This severe concentration of data
19 centers in one location is a national security vulnerability because it invites the potential for
20 cyberattacks and espionage against the Nation's critical data infrastructure.

21 (6) Data centers have historically obtained their electricity from the electric grid. Some
22 data center developers now seek or require the use of microgrids to provide their primary and
23 backup power.

24 (7) West Virginia is strategically positioned as the best location in the United States to
25 place data centers due to: (A) its close proximity to Washington, D.C., and the federal government;
26 (B) its close proximity to the majority of the Nation's population; (C) its low tax rates; (D) it having
27 the least restrictive regulatory environment in the Nation; (E) its supply of abundant energy and

28 natural resources to power the data centers; (F) its supply of resources, such as coal mine
29 methane blended with natural gas, to assist data centers locating in West Virginia to meet their
30 energy needs and environmental goals; and (G) its skilled and loyal workforce that has some of
31 the lowest turnover rates in the Nation.

32 As such, the state has a significant interest in encouraging the development and
33 expansion of data centers, which can serve as drivers of broader economic growth. The
34 Legislature finds that these externalities transcend local borders, including environmental
35 concerns, energy consumption, and regional economic growth. Additionally, the provisions in this
36 section align with the Legislature's goal of fostering a competitive, forward-thinking economy that
37 benefits all residents.

38 (b) *Program established.* — The High Impact Data Center Program is hereby created and
39 is to be administered as a program within the Division of Economic Development to encourage
40 the continued development, construction, operation, maintenance, and expansion in West
41 Virginia of high impact data centers. In order to effectuate the purposes of this section, the Division
42 of Economic Development, or any agency, division, or subdivision thereof, may promulgate
43 legislative rules, including emergency rules, in accordance with §29A-3-1 *et seq.* of this code.

44 (c) *Notification.* — Any data center shall compare its current or planned operations against
45 the definition of "high impact data center" established in §11-6N-2 of this code and provide
46 notification to the Division of Economic Development when the data center becomes aware that
47 it will satisfy or has satisfied that definition. The notification will include information addressing
48 the elements of that definition, including known or expected power consumption of the data
49 center. This notification shall be made (1) within 30 days after the data center determines that it
50 meets these requirements, or (2) when the data center reasonably anticipates that it will, at some
51 future date, meet these requirements, in which case the data center may provide that anticipated
52 future date in its notification.

53 (d) *Certification.* — The Secretary of the Department of Commerce shall identify and certify
54 high impact data centers in this state upon a finding that a data center satisfies the requirements
55 for the definition of "high impact data center" set forth in §11-6N-2 of this code. The Secretary
56 shall issue confirmation of certification to a high impact data center within 14 days following receipt
57 of the notification from the data center required by this section.

58 (e) *Recordkeeping.* — Any information provided by a data center pursuant to this section
59 that is identified by the data center as confidential business information shall be exempt from the
60 Freedom of Information Act. The Secretary shall take reasonable and appropriate steps to protect
61 this information. Notwithstanding the foregoing, the Secretary shall maintain a complete list of all
62 certified high impact data centers and all relevant information that can be made available to the
63 Governor and Legislature, removing specifically identifying information to ensure confidentiality
64 of any such information as identified by any high impact data center.

**§5B-2-21b. Authority to assist certified microgrid district projects and certified high impact
data center projects; legislative findings.**

1 (a) *Findings and purpose.* — The Legislature hereby finds and declares the following:

2 (1) The findings and purpose set forth in §5B-2-21a(a) (2025), except to the extent
3 expressly modified herein, are hereby incorporated herein by reference with the same force and
4 effect as though fully set forth herein.

5 (2) It is in the best interests of the state to induce and assist in development of these
6 projects, in order to advance the public purposes of relieving unemployment by preserving and
7 creating jobs, and preserving and creating new and greater sources of revenue for the support of
8 public services provided by the state and local government.

9 (3) It is the intent of the Legislature to occupy the whole field of the creation and regulation
10 of certified microgrid districts and certified high impact data centers. The stated purpose of this
11 section is to promote uniform and consistent application of the act within the state.

(b) The Department of Commerce shall assist projects developing or operating a certified microgrid district pursuant to §5B-2-21 of this code or a certified high impact data center pursuant to §5B-2-21a of this code. The Secretary of Commerce shall designate one of their personnel as "Data Economy Liaison" to serve as a single point-of-contact for certified microgrid districts and high impact data centers to assist coordinate and expedite their development and operation, including, but not limited to site selection and permitting. A "certified microgrid district" is a microgrid project, regardless of stage of development or operation, that has been certified by the Secretary of the Department of Commerce as set forth in §5B-2-21 of this code. A "certified high impact data center" is a data center project, regardless of stage of development or operation, that has been certified by the Secretary of the Department of Commerce as set forth in §5B-2-21a of this code.

(c) This section prohibits:

(1) Counties and municipalities, whether by ordinance, resolution, administrative act, or otherwise, from enacting, adopting, implementing, or enforcing ordinances, regulations, or rules which limit, in any way, the creation of, and acquisition, construction, equipping, development, expansion, and operation of any certified microgrid district or certified high impact data center project; and

(2) Counties and municipalities from imposing or enforcing local laws and ordinances concerning the creation or regulation of any certified microgrid district or certified high impact data center therein.

(d) In accordance with §5B-2-21(b) and §5B-2-21(c) of this code, and notwithstanding any provision of this code to the contrary, or any municipality's home rule powers with respect to ordinances and ordinance procedures, including any authority pursuant to the Municipal Home Rule Program under §8-1-5a of this code, certified microgrid districts and certified high impact data centers may not be subject to the following:

(1) County or municipal zoning, horticultural, noise, viewshed, lighting, development, or land use ordinances, restrictions, limitations, or approvals;

(2) County or municipal building permitting, inspection, or code enforcement;

(3) County or municipal license requirements;

(4) The legal jurisdiction of the county or municipality in which the certified microgrid district or certified high impact data center is entirely or partially located, except as specifically provided in this article;

(5) Any requirement under state law for the consent or approval of the municipality in which a certified microgrid district or certified high impact data center is entirely or partially located of any state or county action pursuant to this code, specifically including, but not limited to, §7-11B-1 *et seq.* of this code, for formal consent of the governing body of a municipality for county or state action regarding the establishment of tax increment financing development or redevelopment districts or the approval of tax increment financing development or redevelopment plans.

(e) Notwithstanding the creation of a certified microgrid district or a certified high impact data center, the owner, operator, or manager, as applicable, and all tenants, lessees or licensees thereof, of a certified microgrid district or a certified high impact data center shall:

(1) Pay business and occupation tax, if applicable, pursuant to §8-13-5 of this code, to the municipality in the same manner as any other business or commercial venture located within the municipality;

(2) Collect and remit municipal sales and service tax and municipal use tax, if applicable, pursuant to §8-1-5a, §8-13C-4, and §8-13C-5 of this code, to the municipality in the same manner as any other business or commercial venture located within the municipality;

(3) Pay ad valorem real and personal property tax pursuant to the same millage rates as any other business or commercial venture located within the county and municipality;

62 (4) Pay all municipal service fees enacted pursuant to §8-13-13 of this code, including, but
63 not limited to, fire, police, sanitation, or city service fees;

64 (5) Pay all utility rates, fees, and charges for utilities used or consumed during construction
65 and operation of premises within the certified microgrid district or certified high impact data center,
66 including, but not limited to, water, sewer, stormwater, and garbage and recycling collection:
67 *Provided, That* (A) The rates, fees, and charges for such services shall be based on the cost of
68 providing such service and the utility shall enter into a contract under the rules of the Public
69 Service Commission for each such service with the developer and file the special contract with
70 the Public Service Commission; and (B) the developer shall only be required to pay any capacity
71 improvement fee or impact fee to the extent that capital additions, betterments, and improvements
72 must be designed, acquired, constructed, and equipped by the utility to provide such service to
73 the project; Utility customers outside of the microgrid district shall not bear any construction or
74 operational costs associated with any new utility property built solely to provide service within a
75 microgrid district;

76 (6) Be entitled to municipal police protection and municipal fire protection, if available, in
77 the same manner as any other business or commercial venture located within the municipality;
78 and

79 (7) Design, acquire, construct, and equip the certified microgrid district or certified data
80 center pursuant to the State Building Code in accordance with §8-12-13 of this code and the
81 corresponding State Rule 87 CSR 4.

82 (f) The Department of Commerce, Department of Environmental Protection, and
83 Department of Transportation may take actions necessary in support of the development of any
84 certified microgrid district or certified data center, including, but not limited to, the development or
85 improvement of such highways, roads, thoroughfares, and sidewalks within any county or

86 municipality in which the certified microgrid district or certified data center is partially or entirely
87 located.

88 (g) In order to effectuate the purposes of this section, the Department of Commerce, or
89 any agency, division, or subdivision thereof, may promulgate legislative rules, including
90 emergency rules, in accordance with §29A-3-1 *et seq.* of this code.

ARTICLE 2N. GRID STABILIZATION AND SECURITY ACT OF 2023.

§5B-2N-2a. Creating the Electric Grid Stabilization and Security Fund.

1 (a) The Electric Grid Stabilization and Security Fund is hereby created. The fund shall be
2 administered by the Department of Commerce and shall consist of all moneys made available for
3 the purposes and from the sources set forth in this section of the code.

4 (b) The fund consists of moneys received from the following sources:

5 (1) All moneys received pursuant to §11-6N-4(b)(4)(C) of this code;

6 (2) All appropriations provided by the Legislature;

7 (3) Any moneys available from external sources; and

8 (4) All interest and other income earned from investment of moneys in the fund.

9 (c) The Department of Commerce shall use moneys in the fund to provide support for
10 electric grid stabilization for regulated utilities and grid security, including development, efficiency,
11 and environmental upgrades, but not decommissioning and replacement of existing facilities;
12 maintenance of utility owned and operated coal and natural gas electric generation, regardless of
13 unit or plant ownership by different regulatory jurisdictions; and transmission resources which
14 solely serve West Virginia rate payers.

15 (d) Any balance, including accrued interest and any other returns, in the Electric Grid
16 Stabilization and Security Fund at the end of each fiscal year may not expire to the General
17 Revenue Fund but remain in the fund and be expended for the purposes provided by this section.

18 (e) Fund balances may be invested with the state's Consolidated Investment Fund.
19 Earnings on the investments shall be used solely for the purposes defined in §5B-2-16(c) of this
20 code.

21 (f) In order to effectuate the purposes of this section, the Department of Commerce may
22 promulgate legislative rules, including emergency rules, in accordance with §29A-3-1 *et seq.* of
23 this code.

CHAPTER 11. TAXATION.

ARTICLE 6N. SPECIAL METHOD FOR VALUATION OF CERTAIN HIGH-TECHNOLOGY PROPERTY.

§11-6N-1. Legislative findings and purpose.

1 The Legislature hereby finds and declares the following:

2 The findings and purpose set forth in §5B-2-21a(a) (2025) (except to the extent expressly
3 modified herein) are hereby incorporated herein by reference with the same force and effect as
4 though fully set forth herein.

§11-6N-2. Definitions.

1 (a) *General* — When used in this article, words defined in §11-6N-2(b) of this code have
2 the meanings ascribed to them in this section, except in those instances where a different
3 meaning is provided in this article or the context in which the word is used clearly indicates that a
4 different meaning is intended by the Legislature.

5 (b) *Definitions* — For purposes of this section, the following terms shall mean:

6 (1) "Affiliated group" means one or more chains of corporations, limited liability entities, or
7 partnerships, or any combination thereof, connected through the ownership of stock or ownership
8 interests with a common parent which is a corporation, limited liability entity, or partnership, but
9 only if the common parent owns directly, or indirectly, a controlling interest in each of the members
10 of the group.

11 (2) "Base assessed value" means the taxable assessed value of all data center property
12 of a high impact data center as shown upon the landbooks and personal property books of the
13 assessor on July 1 of the calendar year preceding certification as a high impact data center.

14 (3) "Current assessed value" means the annual taxable assessed value of all data center
15 property of a high impact data center as shown upon the landbook and personal property records
16 of the assessor.

17 (4) "Critical IT load" means that portion of electric power capacity, expressed in terms of
18 megawatts, which is reserved solely for owners or tenants of a data center to operate their
19 computer server and required supporting equipment.

20 (5) "Data center property" means property used exclusively at a data center to construct,
21 outfit, operate, support, power, cool, dehumidify, secure, or protect a data center and any
22 contiguous dedicated substations. The term includes, but is not limited to, construction materials,
23 component parts, machinery, equipment, computers, servers, installations, redundancies, and
24 operating or enabling software, including any replacements, updates and new versions, and
25 upgrades to or for such property, regardless of whether the property is a fixture or is otherwise
26 affixed to or incorporated into real property.

27 (6) "High Impact Data Center" means a facility or group of facilities that:

28 (A) Consists of one or more parcels in this state, along with the buildings, substations
29 and other infrastructure, fixtures, and personal property located on the parcels;

30 (B) Is owned, operated, or leased by an entity or affiliated group of entities;

31 (C) Is used to house and operate equipment that receives, stores, aggregates, manages,
32 processes, transforms, retrieves, researches, or transmits data; or that is necessary for the proper
33 operation of equipment that receives, stores, aggregates, manages, processes, transforms,
34 retrieves, researches, or transmits data;

35 (D) Has a critical IT load in the aggregate of 90 megawatts total or higher; and

36 (E) Is placed into service on or after July 1, 2025.

(7) "Incremental value", for any high impact data center, means the difference between the base assessed value and the current assessed value. The incremental value will be positive if the current value exceeds the base value, and the incremental value will be negative if the current value is less than the base assessed value.

(8) "Microgrid power generator" includes any entity supplying power under the rules provided in §5B-2-21 of this code to a high impact data center.

(9) "Microgrid power generator property" means and includes any and all property used by microgrid power generator within a certified microgrid district.

(10) "Situs county" means the county or counties in which any High Impact Data Center property subject to tax is located, in relative proportion to the amount of data center property located therein.

(11) "Tax increment" means the amount of regular levy property taxes attributable to the amount by which the current assessed value of real and tangible personal property that is data center property of a high impact data center exceeds the base assessed value of the property.

§11-6N-3. Returns of property of high impact data centers to Board of Public Works.

(a) On or before May 1 in each year, a return in writing shall be filed with the Board of Public Works: By the owner or operator of any company holding data center property of a high impact data center or a microgrid power generator supplying microgrid power to a high impact data center.

(b) The words "owner or operator," as applied herein to high impact data centers, shall include any owner or operator of a high impact data center or microgrid power generator.

(c) The return shall be signed and sworn to by the owner or operator if a natural person, or, if the owner or operator shall be a corporation, shall be signed and sworn to by its president, vice president, secretary, or principal accounting officer.

(d) The return required by this section of every owner or operator shall cover the year ending on December 31, next preceding, and shall be made on forms prescribed by the Board of

Public Works, which board is hereby invested with full power and authority and it is hereby made its duty to prescribe the forms required from any owner or operator herein mentioned information as in the judgment of the board may be of use to it in determining the true and actual value of the properties of the owners or operators.

(e) Except for the special rules for tax distribution provided in §11-6N-4 of this code, the provisions of this article are subject to the Assessment of Public Service Businesses, set forth in §11-6-1, *et seq.* of this code, as if the provisions thereof were set forth in extenso in this article.

§11-6N-4. Special Rules for Tax Distribution of High Impact Data Centers.

(a) On and after July 1, 2025, any property subject to valuation under §11-6N-3 of this code shall be subject to the rules on tax distribution provided under this section.

(b) The State Auditor shall maintain a separate and discrete accounting of each High Impact Data Center project regarding tax distribution provided in this section and any distribution to which a county is entitled as provided by this section shall be distributed directly to the situs county for each project.

(c) *Ad Valorem* Property Tax Distribution — The provisions of this subsection are applicable to all data center property of a high impact data center upon certification as a high impact data center per §11-6N-2 of this code.

(1) For so long as the high impact data center exists, the State Auditor shall divide the *ad valorem* property tax revenue collected, with respect to taxable data center property of a high impact data center as follows:

(A) The amount of *ad valorem* property tax revenue that should be generated by multiplying the assessed value of the property for the then current tax year by the aggregate of applicable levy rates for the tax year;

16 (B) The amount of *ad valorem* property tax revenue that should be generated by
17 multiplying the base assessed value of the property by the applicable regular *ad valorem* levy
18 rates for the tax year;

19 (C) The amount of *ad valorem* tax revenue that should be generated by multiplying the
20 base assessed value of the property for the current tax year by the applicable levy rates for
21 general obligation bond debt service for the tax year;

22 (D) The amount of *ad valorem* property tax revenue that should be generated by
23 multiplying the current assessed value of the property for the current tax year by the applicable
24 excess levy rates for the tax year; and

25 (E) The amount of *ad valorem* property tax revenue that should be generated by
26 multiplying the incremental value by the applicable regular levy rates for the tax year.

27 (2) The State Auditor shall determine from the calculations set forth in subdivision (1) of
28 this subsection the percentage share of total *ad valorem* revenue for each levying body according
29 to paragraphs (B) through (D), inclusive, of said subdivision by dividing each of such amounts by
30 the total *ad valorem* revenue figure determined by the calculation in paragraph (A) of said
31 subdivision; and

32 (3) On each date on which *ad valorem* tax revenue is to be distributed to the levying
33 bodies, such revenue shall be distributed by:

34 (A) Applying the percentage share determined according to paragraph (B), subdivision (1)
35 of this subsection to the revenues received and distributing such share to the levying bodies
36 entitled to such distribution pursuant to current law;

37 (B) Applying the percentage share determined according to paragraph (C), subdivision (1)
38 of this subsection to the revenues received and distributing such share to the levying bodies
39 entitled to such distribution by reason of having general obligation bonds outstanding;

(C) Applying the percentage share determined according to paragraph (D), subdivision (1) of this subsection to the revenues received and distributing such share to the levying bodies entitled to such distribution by reason of having excess levies in effect for the tax year; and

(D) Applying the percentage share determined according to paragraph (E), subdivision (1) of this subsection to the revenues received and distributing such share to a fund dedicated at the time of construction of a high impact data center.

(4) In each year for which there is a positive tax increment, the State Auditor shall remit that portion of the *ad valorem* property taxes collected that consists of the tax increment and shall be distributed as follows:

(A) 50 percent of the increment shall be placed in the Personal Income Tax Reduction Fund provided in §11B-2-33 of this code;

(B) 30 percent of the increment to the situs county as defined in this article;

(C) 10 percent of the increment to all counties on a per capita basis according to the most recent census;

(D) 5 percent of the increment shall be placed Economic Enhancement Grant Fund administered by the Water Development Authority provided in §22C-1-6a; and

(E) 5 percent of the increment shall be placed in the Electric Grid Stabilization and Security Fund provided in §5B-2N-2a.

(5) (A) *Payment In Lieu Of Taxes, Increment Property* — Notwithstanding the provisions of §5D-1-14, §7-5-13, §7-11B-3(b), §7-11B-8(c)(4), §7-11B-15(a)(7), §7-11B-15(a)(15), §7-11B-18, §8-19-4, §8-29A-7, §8A-12-12, §11-13-2p, §11-13C-5(l)(1)(A), §16-13A-21, §16-15-18(b)(6), §17-16A-16(b), §17-16B-20(b), §18-9A-12(c), §31-21-5, and §31-21-15 of this code, or any other provision of this code, no payment in lieu of taxes shall be entered into with relation to any property subject to this section or any leasehold interest related thereto, or any other property interest related thereto.

(B) *Tax Increment Financing, Increment Property* — Notwithstanding the provisions of §7-11B-1 *et seq.* of this code, or any other provision of this code, no tax increment financing project,

67 plan or arrangement shall be entered into or undertaken with relation to any property subject to
68 this section.

§11-6N-5. Termination.

1 The provisions of this article shall sunset, expire, and be of no force and effect on or after
2 December 31, 2055.

CHAPTER 11B. DEPARTMENT OF REVENUE

ARTICLE 2. STATE BUDGET OFFICE.

§11B-2-33. Personal Income Tax Reduction Fund.

1 (a) The personal income tax reduction fund is hereby established. The personal income
2 tax reduction fund shall be funded continuously and on a revolving basis in accordance with this
3 section, with all interest or other earnings on the moneys therein credited to the fund. The personal
4 income tax reduction fund shall be funded as provided in §11-6N-4(b)(4) of this code. Moneys in
5 the personal income tax reduction fund may be expended solely for the purposes set forth in this
6 section.

7 (b) Notwithstanding any other provision of this code to the contrary, on or before the last
8 day of any fiscal year, the net proceeds of the personal income tax reduction fund will be certified
9 and included as a portion of adjusted general revenue fund collections under the provisions of
10 §11-21-4h of this code for that fiscal year.

11 (c) Not later than 60 days following the certification, the Secretary of Revenue shall
12 transfer the certified amount determined in subsection (b) of this section to the general revenue
13 fund. The amounts transferred will not be included as a portion of adjusted general revenue fund
14 collections under the provisions of §11-21-4h of this code for the fiscal year in which the money
15 is transferred.

16 (d) The moneys in the income tax reduction fund shall be made available to the West
17 Virginia Board of Treasury Investments and to the West Virginia Investment Management Board
18 for management and investment of the moneys in accordance with the provisions of §12-6C-1 *et*
19 *seq.* of this code in such amounts as may be directed in the discretion of the Secretary of

20 Revenue. Any balance of the income tax reduction fund, including accrued interest and other
21 return earned thereon at the end of any fiscal year, shall not revert to the General Fund but shall
22 remain in the income tax reduction fund for the purposes set forth in this section.

23 (e) Termination – Upon the certification of a reduction in the personal income tax under
24 the provisions of §11-21-4h of this code that results in the elimination of the personal income tax,
25 or if the personal income tax provided for under §11-21-1 *et seq.* is eliminated by separate
26 enactment of the Legislature, this fund will be thereby eliminated and any monies dedicated
27 thereto shall be dedicated to the general revenue of the state.

CHAPTER 24. PUBLIC SERVICE COMMISSION.

ARTICLE 2. POWERS AND DUTIES OF PUBLIC SERVICE COMMISSION.

§24-2-1d. Future electric generating capacity requirements.

1 (a) In order to maximize the use of electricity generated within the state by using coal or
2 natural gas produced within the state, the Public Service Commission shall by order, no later than
3 December 31, 1989, establish the schedule and amount of future electric generating capacity
4 additions required by each West Virginia electric utility, for the next ten years, taking into account:

5 (i) Projected load growth; (ii) existing generating capacity; (iii) existing contractual commitments
6 to sell or purchase capacity; (iv) planned retirement and life extensions of existing capacity; (v)
7 planned construction of capacity; (vi) availability of capacity from generating units of affiliated
8 companies; (vii) capacity factors for existing generation; and (viii) such other reasonable factors
9 as the commission may deem relevant and appropriate to consider. For purposes of this section,
10 "capacity factor" shall mean the ratio of the actual energy produced by a power plant over a
11 specific period to the maximum possible energy it could have produced if running at full capacity
12 during that same period.

13 (b) If the commission determines after considering all such named and other relevant and
14 appropriate factors that a utility will be required to purchase electric generating capacity beyond
15 those agreements approved by the Federal Energy Regulatory Commission or the West Virginia
16 Public Service Commission in order to serve its West Virginia customers, the amount of such

17 required additional purchased capacity so identified by the commission will for purposes of this
18 section be referred to as the utility's "projected deficient capacity": *Provided*, That this subsection
19 shall not include power generating facilities whose total production of electricity is sold outside
20 the State of West Virginia.

21 (c) In the interests of: Keeping utility rates of residential customers as low as possible;
22 keeping utility rates for commercial and industrial customers competitive with those of other
23 states; attracting new industry for which electric power costs are a major factor in location
24 determinations; and of not placing any greater cost burden on government than is absolutely
25 necessary for its electric power needs, each utility shall acquire, if reasonable, its projected
26 deficient capacity from electric generation situated in West Virginia which burns coal or gas
27 produced in West Virginia and which will provide the most reliable supply of capacity and energy
28 at the least cost to those customers of the utility who will be served by such electric generation:
29 *Provided*, That all power purchase contracts executed prior to the effective date of this section
30 which satisfy the following requirements, regardless of location, shall be considered, for the
31 purposes of this subsection, as electric generation situated in West Virginia: (1) Said contracts
32 were negotiated in accordance with procedures and priced according to methodologies of other
33 contracts which the commission has ordered approved; (2) said contracts either guarantee or are
34 substantially amended to guarantee for the life of the contract the use of an amount of West
35 Virginia fuel which equals or exceeds the amount which would be required, on a percentage of
36 output basis, to produce the amount of electric power to be consumed in West Virginia; and (3)
37 said contracts meet the requirements for a qualifying facility established by the Federal Energy
38 Regulatory Commission pursuant to the Public Utility Regulatory Policies Act of 1978.

39 (d) The commission shall evaluate each capacity auction conducted by PJM
40 Interconnection, LLC, or its successor and, to the maximum extent permitted by law, encourage
41 the coordination of the voluntary participation of every electric generating unit in the state in each
42 capacity auction for the benefit of ratepayers in the state.

43 (e) In order to ensure the state's existing generating units can continue to meet future
44 generation needs, the commission shall conduct a review of each generating unit's current
45 consumer economic dispatch. Factors to be considered by the commission in reviewing consumer
46 economic dispatch shall include, but not be limited to: (1) current capacity factors; (2)
47 management of fuel supplies and contracts; (3) overall plant operation and maintenance; (4)
48 placement of bids in the PJM Interconnection, LLC, or its successor's day-ahead and real-time
49 energy markets; (5) utilization of the PJM Interconnection, LLC, or its successor's Reliability
50 Pricing Model (RPM) or Fixed Resource Requirement (FRR); and (6) the utilization of automatic
51 adjustment clauses, price indexes, or fuel adjustment clauses by the utilities. For purposes of
52 this section, "consumer economic dispatch" shall mean the process of operating generation
53 facilities to produce electricity at the lowest cost while reliably meeting consumer demand,
54 considering the operational limits of generation and transmission facilities.

55 (f) Electric utilities shall be prepared to maximize the production of electricity from their
56 generating units when such self-generation will result in reduced energy costs for West Virginia
57 ratepayers. The commission shall require the utilities to maintain their thermal baseload
58 generating units in a manner to allow them to be able to self-generate and achieve at least a sixty-
59 nine percent capacity factor. Nothing herein shall require a utility to operate a generating unit at
60 a sixty-nine percent capacity if doing so will cause an increase in the charge or charges for electric
61 energy over and above the established and published tariff, rate, joint rate, charge, toll or
62 schedule. The commission shall propose rules for legislative approval in accordance with the
63 provisions of §29A-3-1 *et seq.* of this code to carry out its duties and obligations as set forth
64 herein.

§24-2-1q. Base fuel coal supply requirements for electric grid resiliency.

1 Recognizing that coal inventories at coal-fired power plants may increase and decrease
2 over time, in order to ensure grid resiliency and homeland security, each generating public utility
3 shall plan incoming and outgoing coal so as to maintain an average annual minimum 30-day
4 aggregate coal supply on site at each coal-fired power plant. The commission may propose rules

5 for legislative approval in accordance with the provisions of §29A-3-1 *et seq.* of this code to carry
6 out its duties and obligations as set forth herein.

§24-2-15. Certain Automatic adjustment clauses, price indexes or fuel adjustment.

1 The commission shall not enforce, originate, continue, establish, change or otherwise
2 authorize or permit an increase in the charge or charges for electric energy over and above the
3 established and published tariff, rate, joint rate, charge, toll or schedule as the result of any
4 automatic adjustment clause, fuel supply price index, or fuel adjustment clause. Automatic
5 adjustment clauses, fuel supply contract price indexes, or fuel adjustment clauses that do not
6 create a net increase in the charge or charges for electric energy over and above the established
7 and published tariff, rate, joint rate, charge, toll, or schedule shall be permitted by the commission.
8 For purposes of this section, a "net increase" in the charge or charges for electric service shall
9 mean that for the calendar year in which the automatic adjustment clause, fuel supply contract
10 price index, or fuel adjustment clause is utilized, the average charge or charges for electric energy
11 are higher than they would have been if the adjustment clause, fuel supply contract price index,
12 or fuel adjustment clause were not utilized. The commission shall encourage the use of permitted
13 automatic adjustment clauses, fuel supply contract price indexes, or fuel adjustment clauses as
14 a means of increasing the generation of coal-fired power plants within the state. The Commission
15 shall promulgate procedural rules governing the utilization of automatic adjustment clauses, fuel
16 supply contract price indexes, and fuel adjustment clauses.

§24-2-19. Integrated Resource Planning Required.

1 (a) Not later than March 31, 2015, the Public Service Commission shall issue an order
2 directing any electric utility that does not have an existing requirement approved by the Public
3 Service Commission that provides for the future review of both supply side and demand side
4 resources to develop an initial integrated resource plan to be filed not later than January 1, 2016,
5 in conjunction with other similar deadlines required by other states or entities of the electric
6 utilities. This order may include guidelines for developing an integrated resource plan.

7 (b)(1) Any electric utility that has an existing requirement approved by the Public Service
8 Commission that provides for the future review of both supply side and demand side resources is
9 exempt from this initial integrated resource plan filing until such time as that existing requirement
10 has been satisfied. Thereafter, such electric utility is required to file an integrated resource plan
11 pursuant to §24-2-19(a) of this code.

12 (2) Each electric utility that has filed the initial integrated resource plan shall file an updated
13 plan at least every five years after the initial integrated resource plan has been filed. Any electric
14 utility that was exempt from filing an initial integrated resource plan shall file an integrated
15 resource plan within five years of satisfying any existing requirement and at least every five years
16 thereafter. All integrated resource plans shall comply with the provisions of any relevant order of
17 the Public Service Commission establishing guidelines for the format and contents of updated
18 and revised integrated resource plans.

19 (c) The Public Service Commission shall analyze and review an integrated resource plan.
20 The Public Service Commission may request further information from the utility, as necessary.
21 Nothing in this section affects the obligations of utilities to obtain otherwise applicable commission
22 approvals.

23 (d) The Commission may consider both supply-side and demand-side resources when
24 developing the requirements for the integrated resource plans. The plan shall compare projected
25 peak demands with current and planned capacity resources in order to develop a portfolio of
26 resources that represents a reasonable balance of cost and risk for the utility and its customers
27 in meeting future demand for the provision of adequate and reliable service to its electric
28 customers as specified by the Public Service Commission.

29 (e) The commission shall by order, entered no later than July 1, 2025, require all electric
30 utilities operating in the state to supplement their existing integrated resource plans to include a
31 detailed plant upgrade and maintenance plan, improvement compliance schedule, and cost
32 estimate for ensuring the operation of each generating unit through their planned retirement date.
33 The supplemental integrated resource plan shall also include an analysis of the action necessary

34 to extend the life of each generating unit beyond their planned retirement date. Subject to notice
35 and comment from interested parties, the commission may approve the supplemental integrated
36 resource plan without modification or require modification of the supplemental plan before it is
37 approved. The commission shall promulgate rules requiring the supplementation of integrated
38 resource plans as required by this provision. The rules shall also provide a procedure for utilities
39 to submit an independent evaluation of any modification required by the commission hereunder
40 or to challenge such required modification.

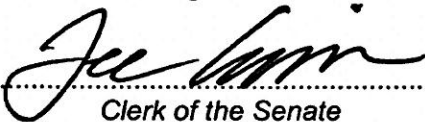
**§24-2-21a. Commission authority required when closing an electric generating plant and
circumstances of closure in another jurisdiction.**

41 (a) A public electric utility may not retire, abandon, close, or otherwise permanently render
42 incapable of operating, any electric generating plant or unit without the prior consent and approval
43 of the commission. No funds obtained from (1) the Grid Stabilization and Security Fund set forth
44 in 5B-2N-2a, (2) an environmental control bond issued pursuant to 24-2-4e, (3) a consumer rate
45 relief bond issued pursuant to 24-2-4f, (4) or a utility consumer rate relief bond issued pursuant
46 to 24-2-4h shall be used by a public utility to retire, abandon, close, or otherwise permanently
47 render incapable of operating, any electric generating plant or unit.

48 (b) If an electric utility serving customers in both West Virginia and in an area not subject
49 to the jurisdiction of the commission is ordered to cease operations of a generating plant or unit
50 by the regulating authority of the other jurisdiction and the costs of the plant or unit had been
51 shared through an allocation process for rate making purposes and after a commission
52 proceeding and determination that a generating plant or unit should continue to operate, then the
53 utility shall recover all of the capital, operating and maintenance costs of the electric generation
54 plant or unit from its West Virginia customers to the extent that such costs are no longer allocable
55 to the other jurisdiction, and all of the associated capacity, energy, and environmental attributes
56 shall be assigned to its customers and operations in West Virginia.

The Clerk of the House of Delegates and the Clerk of the Senate hereby certify that the foregoing bill is correctly enrolled.


.....
Clerk of the House of Delegates


.....
Clerk of the Senate

OFFICE OF WEST VIRGINIA
SECRETARY OF STATE

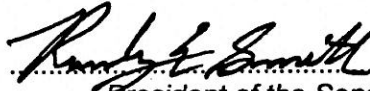
2025 APR 30 P 11:18

FILED

Originated in the House of Delegates.

In effect 90 days from passage.


.....
Speaker of the House of Delegates


.....
President of the Senate

The within isapproved..... this the.....30th.....
Day ofApril....., 2025.


.....
Governor

5. 1. 2. 1994

PRESENTED TO THE GOVERNOR

APR 15 2025

Time 11:37am



January 16, 2026

David Mills
Interim President & CEO

PJM Interconnection
2750 Monroe Blvd.
Audubon, PA 19403

Dear Stakeholders,

Board Decisional Letter on Critical Issue Fast Path - Large Load Additions

At the outset, the PJM Board of Managers (Board) would like to thank you for your participation in the Critical Issue Fast Path (CIFP) accelerated stakeholder process for large load additions. Board members were able to listen in on each step of the CIFP, and the Board appreciated the opportunity to ask questions of presenters during the final stage. After significant deliberation, the Board is issuing this decisional letter that reflects components of the various presentations. Specific elements of presentations are credited in this letter, with the name of the presenter's organization highlighted in bold print.¹

Executive Summary

The Board's decision consists of the following components, some of which will serve as transitional measures while the industry and government collectively work to bring more supply to the system to meet an unprecedented growth in demand. This is a dynamic period in the industry, and as such, the decisions made here can be revisited based on a series of factors, namely whether the region's supply/demand balance and reserve margin are restored to a level that comfortably ensures resource adequacy for existing consumers and large load additions. The primary components of the Board's decision are as follows, with a deeper explanation of each found within the body of this letter.

- Significant Load Forecasting Improvements
- Voluntary Bring Your Own New Generation (BYONG) Paired With Expedited Interconnection Track
- Connect and Manage for New Large Load Additions That Do Not BYONG and Curtailment Prior to Emergency Demand Response in Circumstances Necessitating Load Shed
- Immediate Initiation of Reliability Backstop Procurement
- Holistic Review of Investment Incentives in PJM's Markets in 2026
- Feedback Request on Price Collar for 2028/2029 and 2029/2030 Capacity Auctions

Framing the Board's Review

The Board analyzed the various proposals through a particular frame that we thought would be helpful to explain. That frame begins with the organization's mandate to maintain grid **reliability**. As the results of the 2027/2028 Base Residual Auction (BRA) display, the RTO has cleared short of its reliability requirement for the first time in history. The 2027/2028 BRA cleared 5.6% short of our target reserve margin indicating that the system is at higher risk than

¹ This correspondence satisfies the requirements of Manual 34 Section 8.6.4, and also represents the Board's response to the many thoughtful letters it received during the pendency of the CIFP, a list of which is attached here as Appendix A.

previous years. The Board views this outcome as a clear signal that current trends are not acceptable and warrant corrective action.

Reliability is PJM's primary responsibility, and our Operating Agreement is clear that advancing **competitive markets** is also part of our charge. PJM continues to believe in the benefits of well-functioning competitive markets as these markets have saved consumers billions of dollars pursuant to our value proposition calculations. We will continue to leverage markets to pursue cost-efficient outcomes for consumers.

The Board recognizes the expressed interests at both the federal and state levels in facilitating the timely interconnection of large loads to support continued economic and digital-sector growth. At this time, the Board is not taking action to restrict the interconnection of new load through the creation of a dedicated load interconnection queue or through other limiting measures.

Where PJM can support regional growth while maintaining system reliability and ensuring rates remain just and reasonable, the Board believes it is appropriate to pursue those outcomes. The Board also notes, consistent with the Federal Energy Regulatory Commission's (FERC) recent colocation determination, the significant role of the states and their jurisdiction over the interconnection of retail load.

Further, as a mission-driven organization that fundamentally exists as part of a larger system serving consumers, PJM must be conscious of the **affordability** challenges facing the 67 million consumers in our footprint today. There is much that our states can be doing to contend with higher wholesale costs at the retail level.² At the same time, as the market administrator, PJM should seek to balance the design of its markets to simultaneously set transparent prices that incent the desired behavior from market participants while not being punitive to consumers.

It is with these critical elements in mind that the Board analyzed all proposals set forth during CIFP Stage 4 and hereby directs the staff to advance the following proposals or components of proposals along with other directives.

Board Decision

1. Defining Large Load Additions

For purposes of the proposed Tariff and manual provisions being developed as a result of this CIFP process, the Board proposes to define large load additions as individual additions of load at or above 50 MW at a single Point of Interconnection.³ The Board notes that this level was supported in the CIFP process and is consistent with PJM's definition of large load additions already being utilized in its large load adjustment process.

2. Load Forecasting Improvements

It became clear to the Board during the CIFP that additional improvements should be made to the load forecasting process, building on the progress made by PJM staff and stakeholders through the Load Analysis Subcommittee (LAS). Reforms vetted through the LAS should be implemented. Further, the improvements proposed in the **PJM staff** proposal in the CIFP should also be implemented. These improvements relate to state review of large load additions, addressing duplicative requests, the use of additional third-party review and increased transparency. These represent strong improvements that will continue to both refine the process and

² Op-Ed from SVP Asim Z. Haque, [State Frameworks Are Critical To Addressing PJM Affordability](#)

³ EDC or LSE may request large loads under 50 MW for consideration on a case-by-case basis.

resulting load projections. The Board directs the PJM staff to implement the load forecasting improvements⁴ as set forth in Appendix B. PJM staff will review any specific language changes that are necessary or appropriate with stakeholders prior to their adoption. Load forecasting improvements that have not already been implemented for PJM's 2026 Load Forecast should be in place for PJM's 2027 Load Forecast.

3. Integrating Large Loads

Within the CIFP process, there was significant discussion concerning PJM's obligation to procure capacity to serve large load additions, the curtailment priority for such large load additions and whether capacity obligations should differ where large loads are accompanied by incremental generation to offset their large load additions. The Board appreciates the breadth of stakeholder proposals submitted on these issues and has adopted elements of several proposals with the following goals in mind:

- Provide the appropriate price signals to support the timely development of new capacity resources necessary to serve all load in PJM at the required level of reliability;
- Align curtailment priority and implementation with frameworks established by the relevant states and/or Transmission Owners (TOs) – while PJM will determine the quantity of load requiring curtailment to preserve grid reliability, the states and/or TOs retain responsibility for determining which loads are curtailed when necessary;
- Create incentives for Load Serving Entities (LSEs), large loads and/or states to bring new capacity resources to offset their load additions consistent with cost causation principles; and
- Establish an expedited interconnection pathway for incremental generation advanced by LSEs, large loads and/or states.

For these elements to be successful, the Board expects the data center community and other large loads, along with the LSEs that serve them, to play a constructive role in addressing the reliability and affordability challenges associated with the scale and pace of the forecasted large load additions in the PJM region. The Board is therefore directing management to pursue the following components in accordance with the timelines set forth below.

a. Voluntary Bring Your Own New Generation (BYONG) Commensurate With Large Load Additions and Expedited Interconnection Track

The Board is supportive of frameworks under which LSEs, large loads and states bring their own incremental generation to the system to offset, on an ELCC-measured basis, their load additions. The Board is mindful of the jurisdictional limits of PJM's authority, which apply to PJM's relationship with LSEs rather than individual retail customers. As a result, although the Board is proposing Tariff revisions that focus on aggregate new generation demonstrated by LSEs as available to offset their forecasted large load additions, the states within PJM's footprint retain the authority to determine how such frameworks are applied to individual retail customers, including large loads.

⁴ The primary components of PJM's load forecast proposal and changes made via the LAS affixed here as Appendix B

As has been referenced by many stakeholders, including the Independent Market Monitor (IMM), data centers in particular (which account for a substantial share of forecasted large load additions in the PJM footprint) present characteristics not previously experienced at scale, both in terms of magnitude and speed of deployment. According to McKinsey & Company, PJM is the largest data center market today and is expected to remain so at least until 2030. The Board does not support approaches that seek to limit or eliminate this growth. Rather, the Board views engagement by the data center community as an important component to addressing the reliability and downstream affordability challenges associated with rapid load growth.

Accordingly, the Board encourages voluntary "Bring Your Own New Generation" (BYONG) and directs the **PJM staff** to implement its proposal and associated matrix components related to the **Expedited Interconnection Track**⁵ that will serve as an alternate path for any entity seeking to mitigate curtailment risk by bringing their own new generation to the system on an accelerated basis. PJM staff will review any specific language changes necessary or appropriate with stakeholders prior to adoption or any requisite filing. The Expedited Interconnection Track should be in place by August 2026.

Finally, the Board notes ongoing efforts by several states within the PJM footprint, including initiatives proposed by the **Governors** of Pennsylvania, Virginia, New Jersey and Maryland to facilitate BYONG as reflected in their joint proposal with the Data Center Coalition, Exelon and PPL. While these efforts fall outside the jurisdiction of FERC and are not actions that PJM can implement directly, state-led initiatives to advance new supply – including reforms to support permitting and siting of generation and the transmission necessary to integrate it – will be important to accelerating the addition of needed generation to the system.

b. Connect and Manage

Where an LSE identifies a shortfall between forecasted load additions and the availability of new incremental generation to offset that growth, the Board is directing development of a similar framework articulated by the **PJM Legislators Collaborative/NRDC** and the **Joint Consumer Advocates**. Under this framework, the incremental demand associated with such load growth would be subject to curtailment prior to the deployment of pre-emergency Demand Response. This will help to preserve Demand Response as a valuable reliability tool by not disrupting its business model through a dramatic increase in its use and will provide an incentive for new load to secure capacity or provide flexibility.

Consistent with its operation of the system today, PJM will take all reasonable steps to maintain grid stability and avoid curtailment. However, should system conditions over a given period force PJM to invoke its emergency procedures, the Board finds it reasonable for certain large loads, including data centers, to move to their backup generators, or curtail their demand, for a limited number of hours during the year to prevent a larger scale outage for residential and other consumers. Such curtailment would be expected to occur infrequently, for limited durations, and only when necessary to prevent broader system impacts, consistent with PJM's longstanding operational practice of avoiding curtailment whenever possible.

⁵ Details provided in Appendix C

Ultimately, the determination of which loads are curtailed during emergency conditions rests with TOs, and with LSEs that have direct relationships with their customers. PJM does not have authority to direct individual retail loads to curtail demand. However, PJM will establish an allocation framework whereby TOs and LSEs have advanced notification of the potential magnitude of load reductions that may be required under such conditions. PJM intends to explore how to design curtailment allocations based on the contributions of any shortfall to PJM's required reserve margin.

The Board does not propose that "connect and manage" new large load be removed from the capacity market. Based on current load projections, the system is expected to tighten to a degree that excluding this demand would be unlikely to reduce capacity prices below point "A" on the Variable Resource Requirement (VRR) curve. Removing such load from the market would instead result in large new loads avoiding capacity costs altogether, with those costs shifted to existing consumers.⁶ The capacity market is designed to support system-wide resource adequacy, recognizing that PJM may be required to direct load curtailments to maintain system reliability, with TOs ultimately determining which customers to curtail.

As further detailed below, the Board believes a more comprehensive review of the mechanisms through which PJM's markets produce investment signals is warranted. However, the markets should retain structural integrity during the pendency of this review and beyond.

With respect to this issue and others addressed in this letter, the Board recognizes that a number of future developments will be relevant to the design of longer-term approaches to large load integration. These include, among other factors, the extent to which large loads contract for new generation to offset load additions, potential future actions by federal and state authorities, the resolution of supply chain constraints, success in siting and permitting, and other market and policy developments.

In light of these uncertainties, the Board views the capacity market-related actions outlined in this letter as **interim measures** intended to address near-term reliability risks. These measures may be refined or revisited as additional data becomes available and their impacts can be assessed.

The load shed prioritization and allocation should be completed as soon as practicable. This matter should initially be addressed via the Consensus Based Issue Resolution (CBIR) process, but the Board asks that the stakeholders proceed expeditiously such that changes are in place by the end of 2026 and will monitor the progress to determine whether an accelerated stakeholder process should be initiated.

4. Immediate Initiation of Reliability Backstop Procurement

PJM's primary responsibility is ensuring grid reliability, and an important component of this reliability mandate is resource adequacy. The results of the recent 2027/2028 capacity auction indicate that PJM will fall short of its FERC-required reliability requirement in that delivery year.

The PJM Tariff currently allows PJM to run a backstop capacity procurement if the system clears short of the reliability requirement for three consecutive capacity auctions. In light of the evolving risk profile, the Board

⁶ The Board reserves the right to look at this issue again as part of the design of the reliability backstop procurement described in this letter.

directs PJM staff to develop a proposal to both accelerate and execute this procurement. Accelerating a backstop capacity procurement is especially necessary in light of FERC's recent decision on colocation and its request for more information on utilization of this backstop procurement framework.

During the CIFP process, the coalition comprised of **Constellation, Talen, CPower, Google, Amazon and Microsoft** proposed elements of a framework that the Board believes warrant further consideration by PJM staff and the stakeholders. Any backstop procurement should specify price, term and quantity as core award parameters and be consistent with the Board's direction to procure for the full reliability requirement for the footprint.

The Board directs PJM staff to address cost allocation for any such procurement, including consideration of mechanisms that assign costs to those LSEs that are short as a result of incremental load growth within their service areas. Those LSEs may, in turn, determine how such costs are allocated to incremental loads, consistent with state law.

Over the longer term, the Board does not view it as desirable for PJM to serve as the procuring authority to long-term commitments resulting from backstop procurement. Accordingly, any such procurement should be viewed as a **transitional measure** intended to facilitate the timely integration of new supply, while options for a more durable mechanism are evaluated as part of the broader market review directed below.

The Board recognizes that the existing backstop procurement rules are not sufficiently detailed, and that PJM and the stakeholders will need to discuss the design of the procurement. The Board is directing that immediate attention be provided to this matter with process and deadlines to be discussed at the upcoming January 22 Members Committee meeting.

5. Holistic Review of Investment Incentives in PJM's Markets in 2026

PJM has concluded that the investment environment for new generation has evolved materially in recent years, and in ways that differ significantly from conditions that prevailed at the inception of the Reliability Pricing Model (RPM) capacity market. As it is designed, the three-year forward capacity market was intended to produce a transparent price signal reflecting the value of capacity in a given delivery year and, among other purposes, to inform bilateral contracting between willing buyers and sellers.

The resulting single-year commitment three years forward, however, provides a comparatively short-term signal relative to the long-lived nature of the generation resources that underpin resource adequacy. On its own, this structure may not provide the stable revenue streams needed to justify new investment in today's volatile and uncertain investment environment, particularly when elevated costs are combined with external constraints or intervention.

In addition, a combination of recent factors including heightened price volatility, external headwinds and frequent rule changes has increased investment risk and reduced certainty around long-term procurement decisions. Recent examples of existing resources entering into longer-term bilateral arrangements provide evidence that such contracts are increasingly relied upon to support investment decisions within the independent power producer community.

To date, the current framework of a one-year capacity commitment procured three years forward has not produced a sufficient level of bilateral contracting or price certainty to support the scale of new resource

investment required to maintain resource adequacy. This is evidenced by the large quantity of prospective new resources with signed Generation Interconnection Agreements that are not rapidly moving to construction despite historically high-capacity prices. Accordingly, the Board believes it is appropriate to undertake a focused review of the capacity market to assess whether its design is appropriate for prevailing investment conditions and the incentives needed to attract timely new supply.

The Board also recognizes that PJM's markets must operate in a coordinated manner to deliver clear and transparent price signals regarding the resources needed to maintain grid reliability. In this regard, the Board views the work underway in the Reserve Certainty Senior Task Force as an important foundation and expects that those efforts be advanced in addition to any material changes to the capacity market, so that investment and performance incentives across markets remain cohesive, understandable and actionable.

Accordingly, the Board directs PJM to analyze how the energy, reserve and capacity markets can evolve in a coordinated manner to provide appropriate incentives for both investment and performance. Upon completion of this analysis, PJM should engage stakeholders to discuss a potential enhanced market framework.

The Board's objectives for this work are twofold: (1) to advance necessary changes to the energy and reserve markets that are already underway and that support system operators in managing an increasingly dynamic grid; and (2) to ensure that such changes are aligned with anticipated reforms to support resource adequacy, while continuing to provide a residual mechanism for states with vertically integrated structures.

The Board directs PJM staff to perform this analysis in the first half of 2026. Thereafter, the PJM staff should discuss this analysis with the stakeholders and work with them to formulate a work plan that would serve to implement recommendations made from the analysis. That work plan should be presented to the Board with a recommendation for accelerated stakeholder processes so as to more expeditiously implement the recommendations set forth in the analysis.

6. Price Collar for 2028/2029 and 2029/2030 Capacity Auctions – Feedback Requested

Given the Board and PJM management's acknowledgment of the challenges facing the current capacity market and need for further review, the Board seeks additional stakeholder input as to whether the price collar that was in place for the 2026/2027 and 2027/2028 auctions should be extended. The Board recognizes that there are both advantages and disadvantages associated with such an extension.

On the one hand, a price collar may obscure the market's underlying clearing price and, as a result, could dampen signals needed to support the entry of new supply. On the other hand, as discussed above, there are legitimate questions regarding whether the current capacity market construct, on its own, is sufficient to incentivize new resource development in the absence of the longer-term bilateral arrangements contemplated at the time of the market's design.

Accordingly, the Board seeks additional feedback from stakeholders on this issue and requests that responses address the questions set forth in Appendix D as soon as practicable, but before January 30, 2026. Please send responses to these questions via this [link](#). All feedback will be posted publicly on the CFP LLA webpage. After review of the feedback, the Board will issue an additional letter discussing its decision to make a Federal Power Act (FPA) Section 205 filing related to the price collar, or not, in time for the July auction (2028/2029 Delivery Year).

7. Summary of Actions, Associated Dates and Stakeholder Activity

Action Taken	Associated Dates	Stakeholder Activity
Load Forecasting Improvements	2027 Load Forecast (in place for)	Page Turn of Manuals
Expedited Interconnection Track	August 2026 (in place by)	Page Turn Prior to Requisite Filing
Connect and Manage (Load Shed Prioritization and Allocation)	End of 2026 (in place by)	Consensus Based Issue Resolution Stakeholder Process
Reliability Backstop Procurement	Begin Discussion Immediately	Initial Discussion at Members Committee on January 22, 2026
Market Investment Incentives Review	Analysis Performed in First Half of 2026	Work Plan to Implement Recommendations and Associated Stakeholder Processes Presented to Board
Capacity Auction Price Collar	Written Feedback by January 30, 2026.	Feedback to Board Link here.

The Board thanks the stakeholders for their engagement, and we look forward to continuing to address both the tremendous challenges and opportunities with which we have been presented.

Sincerely and on behalf of my colleagues,

David E. Mills
Chair, PJM Board of Managers
Interim President & CEO, PJM Interconnection, LLC

Appendix A

List of Board Correspondences Regarding CIFP

1. [PJM Board Letter Regarding Implementation of Critical Issue Fast Path Process for Large Load Additions \(PDF\)](#)
2. [Senator Fetterman Letter Regarding the Large Load Addition Critical Issues Fast Path \(CIFP\) Process \(PDF\)](#)
3. [IL Legislative Letter Regarding Critical Issue Fast Path – Large Load Additions \(PDF\)](#)
4. [Congressional Letter Regarding Critical Issue Fast Path – Large Load Additions \(PDF\)](#)
5. [GEO*ESG Solutions Regarding Objection to the Use of CIFP Authority and Request for Clarification on Standby Generation Policy for Data Centers \(PDF\)](#)
6. [Several Environment America Research & Policy Centers Regarding Inclusion of the Expedited Interconnection Track \(EIT\) in PJM's Proposal in the CIFP Process for Large Load Additions \(PDF\)](#)
7. [NJBPU Staff Regarding Critical Issue Fast Path – Large Load Additions \(PDF\)](#)
8. [PJM Legislators' Collaborative Letter Regarding Critical Issue Fast Path – Large Load Additions \(PDF\)](#)
9. [Illinois Governor Pritzker Letter Regarding Critical Issue Fast Path – Large Load Additions \(PDF\)](#)
10. [Apex Letter Regarding Critical Issue Fast Path – Large Load Additions \(PDF\)](#)
11. [Several Governors' Letter Regarding Critical Issue Fast Path – Large Load Additions \(PDF\)](#)
12. [Sierra Club Letter Regarding Critical Issue Fast Path – Large Load Additions \(PDF\)](#)
13. [PJM Ratepayer Comments on the Large Load CIFP \(PDF\)](#)
14. [CAPS Letter Regarding Consumer Advocate Voting on the SMECO Proposal in CIFP-Large Load Addition \(PDF\)](#)

Appendix B

Load Forecasting: PJM Proposal and Load Analysis Subcommittee Work

PJM Staff CIFP Proposal Features:

State Review:

PJM will add a step to the large load adjustment annual submission process that will allow for state commissions to review and provide feedback on the large load adjustments submitted by TOs prior to finalizing and issuing the PJM Load Forecast. The state review would occur, from a timeline perspective, in parallel with the large load addition submission to PJM. Though informal and within the discretion of each state, Electric Distribution Company (EDC)/LSEs would be required to indicate the date the EDC/LSEs shared the large load additions with the Relevant Electric Retail Regulatory authority (RERRA) and provide any feedback received.

Duplicative Requests:

As part of the large load adjustment annual submissions to PJM, TOs shall inquire with their subject customers, and indicate to PJM accordingly, whether any load interconnection requests they've received (that do not have either an Electric Service Obligation [ESO] or Construction Commitment [CC]) are duplicative with other such requests made to interconnect large load either within or outside of the PJM region such that only a subset of such requests are expected to achieve actual commercial operation. If so, the submitters are required to provide the number of sites and amount of megawatts that are duplicative that are included in their submission. If the submitter does not provide the number of sites and megawatts, or further sufficient justification and explanation, then all such requests will be removed from the forecast. This will be added to the annual submission template.

Additional Review:

Provide additional industry-specific review of the PJM load forecast (i.e., cross-check with national-level forecast and equipment projections), which may include a third-party review. This third-party review, initiated by PJM, would weigh both the national level trends as well as the inter-PJM trends that would help inform PJM's load forecast. This review would be presented to stakeholders for opportunity for feedback prior to finalizing for PJM consideration.

Transparency:

To be included in the PJM load forecast, EDC/LSE/TO must ensure customer NDAs include the ability to share all information with PJM related to large loads and such information must be shared.

Load Analysis Subcommittee Enhancements:

- Large load coming online during a delivery year covered by an RPM auction for that forecast cycle with CC or ESO contract of the load within the electric service provider's territory will be considered for inclusion in the PJM forecast plus a meaningful/verifiable financial commitment (such as credit/collateral support, financially significant infrastructure investment, or long-term supply commitment with new or existing resources).
- Large load coming online beyond a delivery year covered by an RMP auction but less than 8 years without construction commitments will be considered for inclusion in the PJM forecast if they have cleared demonstrable project milestones to be considered certain and may be de-rated to reflect its greater uncertainty.

- Requestors should provide a ramp rate with supporting documentation. Absent an EDC/LSE-provided ramp rate, PJM will initially use a default 3-year ramp rate subject to further adjustment based on a comparison of this default value with actual ramp rates of new large loads.
- Utilization factor: PJM uses default historical factor (typically 70%) unless EDC/LSE provides supporting data.

PJM will convene a series of meetings with EDCs and LSEs to improve large load modeling assumptions around ramp rate and utilization. These invite-only meetings would need to maintain strict confidentiality in order to ensure a robust conversation. Any information made public coming out of these meetings would need to be aggregated and anonymized and would be used to help with the formulation of large load additions as well as in PJM's evaluation of large load additions.

- Financial commitment: Document and quantify the customer's financial responsibility. This may align with the rates and agreement provided or be reflected in the capital project plan of the requested EDC/LSE.

Appendix C

Expedited Interconnection Track

PJM Staff CIFP Proposal Features:

New Expedited Interconnection Track (EIT) for sponsored generation with a contractual commitment. This proposal would be standalone outside of the PJM interconnection cycle process and operate in parallel. Expedited timing allows shovel-ready resources to execute Generation Interconnection Agreements (GIAs) sooner and allows an earlier path toward construction and network upgrade certainly.

Contract/No Contract Requirements:

Generation with a contractual agreement: Available to new generation or uprates to existing generation supported by evidence of state commitment to expedite consideration of permitting and siting and a financial commitment with a load that has an executed electric service agreement to interconnect with the TO. The new generation or uprate to existing generation must have an accredited capacity value equal to or greater than the load with which it is contracted.

Generation without a contractual agreement: Available to new generation or uprates to existing generation supported by evidence of state commitment to expedite consideration of permitting and siting. Requires additional financial commitments in the form of higher readiness deposits.

Time Frame:

10 months from application

Generation Eligibility:

All of the following criteria must be met –

- Capacity resource status must be requested with the application along with Capacity Interconnection Rights relevant to the fuel type being interconnected.
- Commercial operations must be achieved within three years of the application submission. Output to the grid may still be limited based on completion of any network upgrades required.
- Point of Interconnection (POI) – must be interconnecting to the transmission system in the relevant state supporting the project
- Megawatt requirements – requests must be for large scale generation greater than 250 MW (UCAP).
- Resource fuel type – all fuel types eligible, including storage

Generation Application:

- Can be submitted to PJM at any time – there are no defined EIT application windows.
- Are prioritized serially, in the order as each application is received by PJM
- Large nonrefundable study deposit (\$500,000) and readiness deposit
 - \$10k/MW for generation paired with load

- \$20k/MW for generation not paired with load
- Applications are capped annually at 10 projects.
- Must provide 3 full years of site control for 100% of generating site and interconnection facilities at time of application.

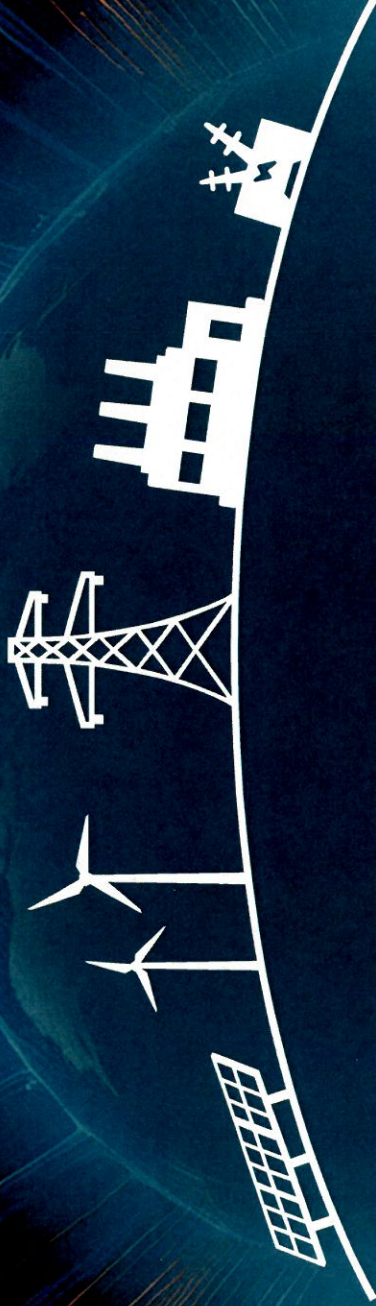
Generation Post-Application, Costs and Agreement Requirements:

- There are no site control changes or other project changes allowed such as fuel type, megawatt size, equipment type, etc. Changes post-GIA execution will follow the existing Necessary Study process.
- Cost allocation – EIT resources are responsible for 100% of all identified required network upgrades. No cost sharing with other EIT projects or Cycle projects.
- Cost estimates – for mitigations will be planning-level estimates only
- Commercial operation no more than 3 years from the date of EIT application. Milestone dates are eligible for extensions according to existing procedures.

Appendix D

Board Questions Regarding Capacity Auction Price Collar

1. The existing price collar includes a price cap of \$325 and a price floor of \$175 adjusted for ELCC changes before each auction. Do you support any extension of the existing price collar? If so, at what level and for what period?
2. If you support an extension of the price collar, please provide the justification that you believe should be presented to FERC that supports your proposed level and time period being just and reasonable.
3. If you do not support any extension of the price collar, please provide the justification that you believe should be presented to FERC to support the argument that a short-term extension of the price collar is not just and reasonable.
4. To the extent you support an extension of the price collar, please explain how you believe such an extension would not adversely impact reliability or investment and when you believe the price collar could be lifted.
5. To the extent you oppose an extension of the price collar as inhibiting needed investment in the short term, please indicate the type of projects you believe could come into service during the delivery years covered by these auctions and the potential impact of a collar extension on those project types.
6. The Quadrennial Review, cosponsored by the Pennsylvania Public Utility Commission, was overwhelmingly approved by the stakeholders. Should the Board consider a transition mechanism to move from the existing collar to Point A on the demand curve? Please provide your views on whether such a transition would be appropriate and the length and stages of such a transition and its consistency with the stakeholder support of the Quadrennial Review.



RTEP 2024

Regional Transmission Expansion Plan

APRIL 17, 2025

How are generation interconnection queue reform initiatives incentivizing new capacity?

What interregional initiatives are supporting PJM's energy transition?

How are the proliferation of data centers and end-user customer electrification impacting PJM load forecasts?

How are data centers, energy transition load growth and generation retirements driving need for new transmission infrastructure to ensure grid reliability?

