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E-FILE

April 30, 2026

Matthew Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, Pennsylvania 17120

Re: PPL Electric Utilities Corporation
2025 Annual Reliability Report
Docket No. M-2023-3039027

Dear Secretary Homsher:

Enclosed for filing on behalf of PPL Electric Utilities Corporation ("PPL Electric") is PPL Electric's 2025 Annual Reliability Report to the Pennsylvania Public Utility Commission. This report is being filed pursuant to the Commission's regulations at 52 Pa. Code § 57.195(a).

As required by the Commission's regulations, copies of the enclosed report have been served upon the Office of Consumer Advocate ("OCA") and the Office of Small Business Advocate ("OSBA").

Pursuant to 52 Pa. Code § 1.11, the enclosed document is to be deemed filed on April 30, 2026, which is the date it was filed electronically with the Commission's E-Filing System.

If you have any questions regarding the enclosed report, please call me or Beth Johnson, PPL Electric's Senior Director - Regulatory, at (610) 774-7011.

Respectfully submitted,

Kimberly A. Klock

Enclosures

cc via email: Darryl Lawrence, Esquire
NazAarah Sabree
John Van Zant

PPL Electric Utilities Corporation
2025 Annual Reliability Report
to the
Pennsylvania Public Utility Commission

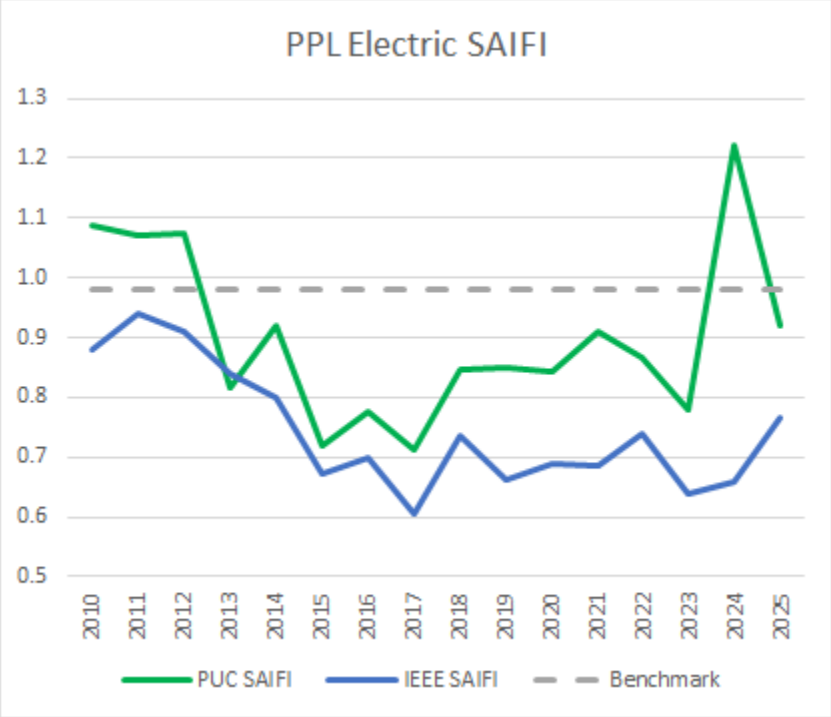
April 30, 2026

1) An overall current assessment of the state of the system reliability in the EDC's service territory including a discussion of the EDC's current programs and procedures for providing reliable electric service.

SAIFI Performance

In 2025, PPL Electric saw 25% improvement in System Average Interruption Frequency Index (SAIFI) compared to 2024, and a return to within-benchmark performance with a SAIFI of 0.919. This was accomplished during a challenging storm year. 2025 saw a record 53 storm events, including 14 Public Utility Commission (PUC) Reportable storms. Four storms incurred 800 cases or higher. It is notable that PUC Reporting thresholds have not changed since they were established during the benchmark period from 1994-1998, PPL Electric experienced an average of only 4.2 PUC Reportable storms per year. Over the last 5 years, PPL Electric has averaged 13.8 PUC Reportable storms per year, a 229% increase, despite having avoided over 3.3 million customer interruptions since the inception of the company's Fault Location Isolation and System Restoration (FLISR) system.

PPL Electric's ongoing focus on preventing customer interruptions through system automation, vegetation management and asset performance continues to directly support historically strong reliability results, which have seen the company achieve benchmark SAIFI in 12 of the last 13 years, and first quartile Institute Electrical and Electronics Engineers (IEEE) SAIFI (weather normalized) since 2014.



PPL Electric continues to drive high levels of reliability performance through:

- Commitment to providing safe, reliable, affordable service to PPL Electric customers.
- A focus on storm hardening.
- Strategic vegetation management.
- Implementation of proactive fault sensing.
- Continued strategic investment in distribution automation technology such as:
  - Multi and single-phase Smart Grid Initiative.
  - Increased leverage of PPL Electric's Automated Distribution Management System (ADMS).
  - Full implementation of Fault Isolation and System Restoration (FISR) technology automatically restoring more than 3.3 million customers since 2015.
- Strategic data-driven reliability investments that include asset replacement, and system improvements that include storm hardening standards.
- An increased focus on remediating momentary outages before they become permanent outages.
- Continued focus on outage response improvements.
- Moving to data driven condition-based maintenance programs.

The data table below shows the impact of storms in 2025.

Year	Non Reportable Storms	PUC Major Events	PUC Storms	Total Storms	PUC Storm Cases (MEDs excluded)	PUC Storm CI (MEDs excluded)	PUC Storm CMI (MEDs excluded)	
1991	unknown	0	2					
1992	unknown	1	3					
1993	unknown	1	3					
1994	unknown	1	2					
1995	unknown	0	5					
1996	unknown	0	4					
1997	unknown	0	6					
1998	unknown	1	4					
1999	unknown	1	4					
2000	unknown	0	5					
2001	13	0	2	15				
2002	12	1	7	20	3,787	448,916	99,462,247	
2003	8	4	1	13	998	82,650	14,689,512	
2004	14	0	4	18	2,882	302,418	97,539,670	
2005	9	1	4	14	2,088	203,184	41,309,452	
2006	19	0	9	28	5,067	546,292	148,343,084	
2007	22	1	5	28	3,973	427,012	98,060,819	
2008	20	0	7	27	3,952	443,305	137,727,147	
2009	16	0	4	20	2,692	257,598	52,777,061	
2010	19	0	10	29	4,235	408,459	102,001,866	
2011	24	3	6	33	3,327	382,914	111,501,018	
2012	16	1	7	24	2,690	365,386	113,548,058	
2013	13	0	3	16	1,112	127,021	26,326,830	
2014	11	0	5	16	3,247	296,380	132,323,895	
2015	19	0	1	20	1,015	167,931	28,418,978	
2016	20	0	4	24	2,695	264,998	54,593,236	
2017	16	0	10	26	3,000	258,504	71,286,608	
2018	17	1	5	23	3,952	305,482	110,654,537	
2019	16	0	10	26	5,339	409,578	131,734,085	
2020	19	0	8	27	6,446	460,738	98,791,154	
2021	27	0	15	42	10,228	615,674	177,415,466	
2022	27	0	9	36	7,861	514,833	127,957,386	
2023	31	0	14	45	8,698	526,451	146,614,799	
2024	20	0	17	37	16,663	1,096,312	581,974,917	
2025	39	0	14	53	11,042	699,698	203,595,957	

PUC BENCHMARK PERIOD

PPL Electric's recent storm experience correlates with data from the National Oceanic and Atmospheric Administration (NOAA) illustrating an increase in severe storms (defined as storms exceed $1B in damages, adjusted for inflation).

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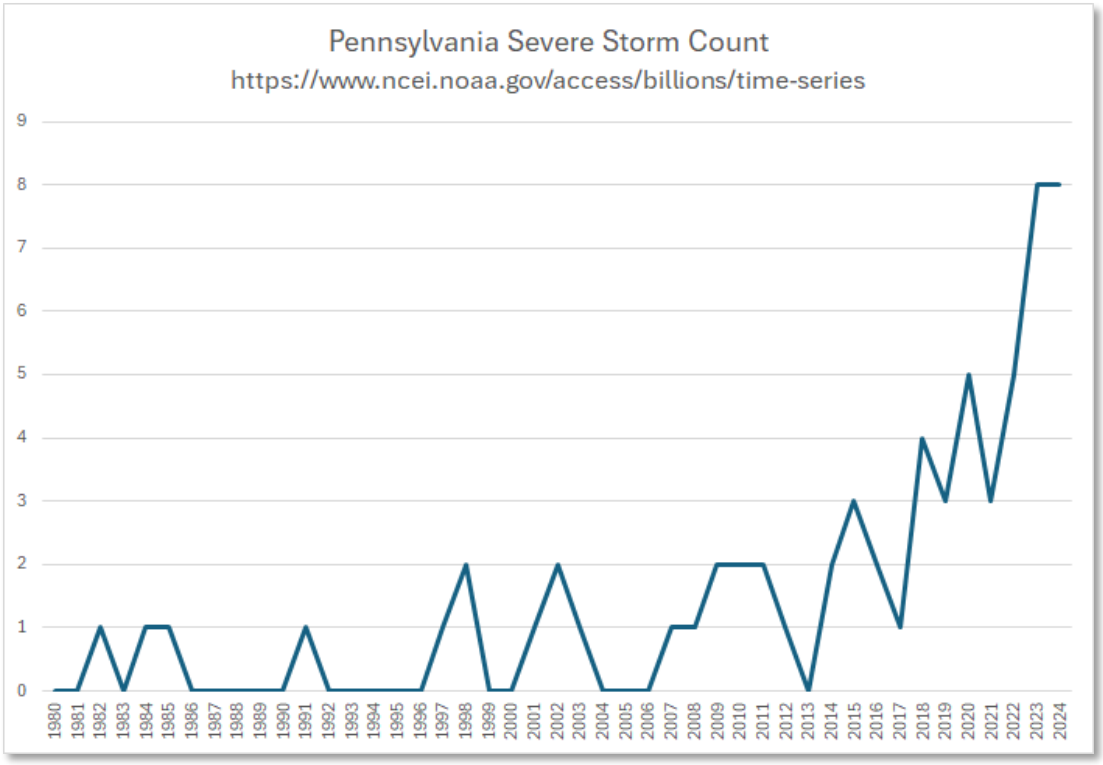
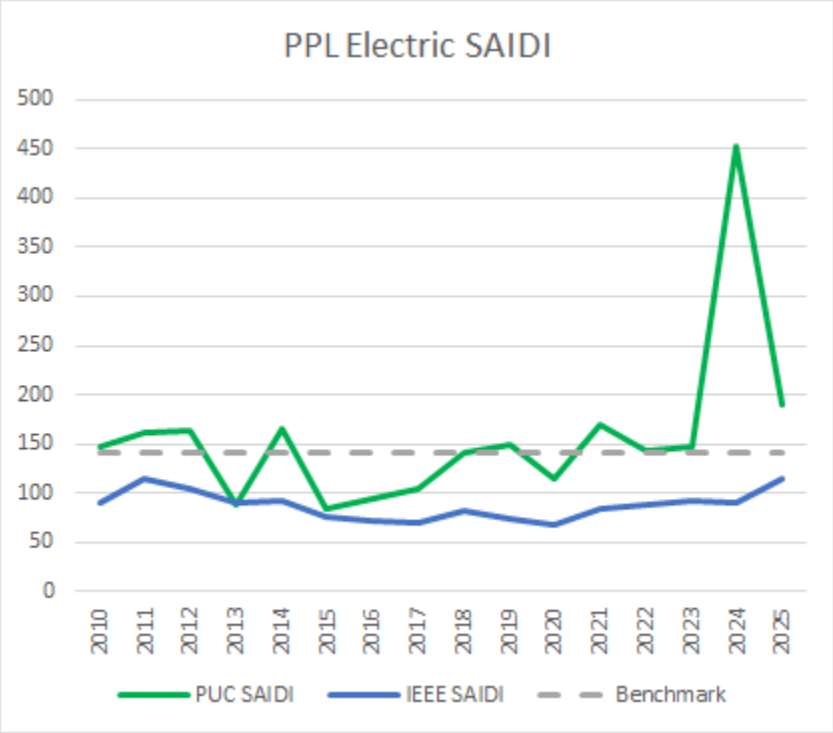


SAIDI Performance

2025 PUC System Average Interruption Disruption Index (SAIDI) was heavily impacted by storm Customer Minutes Interrupted (CMI) which was the second highest on record but was improved by 58% over 2024 SAIDI. Once again, weather normalized SAIDI performed well.

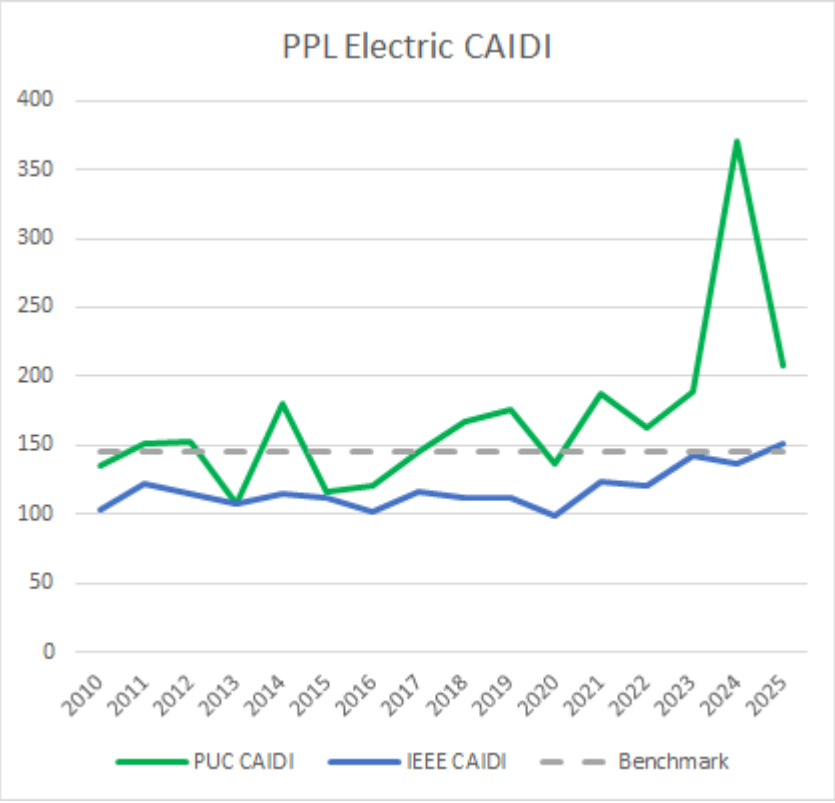


CAIDI Performance

Similarly, 2025 PUC Customer Average Interruption Duration Index (CAIDI) was heavily impacted by storms.

Given 2025 storm severity, along with automated systems preventing and converting outages to momentary interruptions, higher CAIDI values are not unexpected. However, several initiatives continue to be evaluated to improve CAIDI performance. Some of these strategic areas include:

- Optimize resource planning and scheduling.
- Setting Restore vs. Repair strategy early on in storm response.
- Resource Strategy/Optimization.
- Resource scheduling and prearranging resource availability.
- Leveraging data technology to isolate impact and dispatching resources needed to address outages.



IEEE Metrics

Because weather has a significant impact on volatility in reliability metrics, PPL Electric's IEEE Metrics are shown below. The IEEE 1366 Standard is a widely used methodology that allows for weather normalized performance evaluation that better reflects system performance during non-major storm events. The table below lists PPL Electric's IEEE performance metrics compared to the 2024 performance quartiles for large utilities nationally, as issued by the IEEE Annual Reliability Survey. This survey comprises 74 utilities serving 73 million customers across the country. PPL Electric has been a top quartile IEEE SAIFI performer since 2014.

PPL Electric's continued focus on improving system reliability is directly related to its strong IEEE SAIFI and SAIDI performance. As a company on the forefront of automation, PPL Electric's CAIDI is predictably a second or third quartile performer.

	IEEE CAIDI	IEEE SAIFI	IEEE SAIDI
2021	124	0.68	84
2022	121	0.74	89
2023	143	0.64	92
2024	137	0.66	90
Rolling 4Q ending 12/31/2025	152	0.76	116
IEEE First Quartile Ceiling	108	0.86	95
IEEE Second Quartile Ceiling	124	1.06	137
IEEE Third Quartile Ceiling	149	1.51	215

Reliability Programs

It is PPL Electric's continuing goal to achieve and maintain best in class levels of electric delivery service to its customers in a cost-effective manner. Maintenance programs are one of the key elements that focus on maintaining system and circuit reliability, equipment performance, and interruption prevention. The scope of these maintenance programs, procedures, and activities covers all areas of the electrical infrastructure.

These programs include:

Transmission
Transmission inspection programs include aerial patrols conducted via helicopter or Unmanned Aerial Vehicle (UAV). These patrols focus on comprehensive inspections and routine "stop and go" inspections for identification of maintenance work. Inspections focus on all transmission line equipment, including poles, arms, line switches, interrupters, arresters, grounding, guying, anchors, and other key components. Proactive replacement programs are in place to target specific risk areas (e.g. cellon treated wood poles, upswept wood arms, CORTEN lattice towers, wood crossarms, copper conductor, vintage switches, etc.) and to apply data-driven approaches to mitigate known reliability risks (e.g. avian interference, lightning performance, etc.).

Substation
Substation maintenance programs include inspections and overhauls of equipment, such as breakers, disconnects, power cables, and security equipment. Some equipment is maintained on a time basis; other equipment is condition-monitored. These two methods help ensure that maintenance work is performed in a cost-effective manner and keep rates low for PPL Electric customers. Besides time and condition-based maintenance, thermographic inspections help ensure that substation equipment does not operate at elevated temperature levels for an extended period, which helps prevent equipment failure.

Distribution
Distribution programs encompass many maintenance aspects similar to transmission and substations and also include load surveys that help engineers determine peak load requirements, circuit analyses for the identification of lines requiring maintenance work, voltage relief, or other capital improvements. Overhead line inspections identify damaged or deteriorated equipment that is repaired or replaced proactively. In addition, distribution maintenance includes inspections of poles, voltage regulators, line switches, capacitors, and other key distribution equipment. PPL Electric also tests underground cable to determine if the cable needs to be replaced, repaired or cured to prevent future failures.

Vegetation
The vegetation on PPL Electric's transmission and distribution rights-of-way (ROW) is maintained utilizing a combination of several management techniques. These include tree pruning, tree removal, and incompatible brush management. Lines are surveyed on a routine basis through a combination of remote-sensing technology and field observations. The work is scheduled and budgeted based on the conditions observed and past performance. Outside of the ROW, hazard trees with the potential to contact PPL Electric facilities are evaluated for removal when possible.

Each of these programs is more fully described in Appendices A through D.

2) A description of each major event that occurred during the year being reported on, including the time and duration of the event, the number of customers affected, the cause of the event and any modified procedures adopted to avoid or minimize the impact of similar events in the future..

No major events occurred during 2025.

3) A table showing the actual values of each of the reliability indices (SAIFI, CAIDI, SAIDI, and if available, MAIFI) for the EDC's service territory for each of the preceding 3 calendar years. The report shall include the data used in calculating the indices, namely the average number of customers served, the number of sustained customer interruptions, the number of customers affected, and the customer minutes of interruption. If MAIFI values are provided, the number of customer momentary interruptions shall also be reported.

Year		**2023**	**2024**	**2025**[1]	**3 Yr. Avg.**
SAIFI	BM 0.98	0.78	1.22	0.92	0.97
	STD 1.18	0.78	1.22	0.92	0.97
CAIDI	BM 145	189	371	208	256
	STD 174	189	371	208	256
SAIDI	BM 142	147	451	191	263
	STD 205	147	451	191	263
MAIFI[2]		0.3	9.7	11.7	7.2
Customers Served[3]		1,456,541	1,470,254	1,477,678	1,468,158
Number of Sustained Customer Interruptions (Trouble Cases)		23,088	32,294	26,185	27,189
Number of Customers Affected		1,136,056	1,791,362	1,358,109	1,428,509
Customer Minutes of Interruptions (CMI)		214,414,610	663,783,475	282,306,130	386,834,738
Number of Customer Momentary Interruptions		470,327	14,308,908	17,288,955	10,689,397

[1] Any slight variations from data provided previously are the result of error corrections.

[2] MAIFI calculations moved to meter based data in 2024. This has been noted in quarterly reports since 2023.

[3] PPL Electric calculates the annual indices using customers served at the end of the period. This is consistent with the method used to calculate PPL Electric's benchmarks.

4) A breakdown and analysis of outage causes during the year being reported on, including the number and percentage of service outages, the number of customers interrupted, and customer interruption minutes categorized by outage cause such as equipment failure, animal contact, tree related, and so forth. Proposed solutions to identified service problems shall be reported.

The table shows a breakdown of service outage causes for 2025. Service interruption definitions are provided in Appendix E. PPL Electric has maintenance programs to address controllable service outages. Those programs are detailed in Appendices A through D.

Cause Description	Trouble Cases	Percent of Trouble Cases	Customer Interruptions	Percent of Customer Interruptions	Customer Minutes	Percent of Customer Minutes
Animals	4,098	15.7%	53,010	3.9%	4,366,952	1.5%
Contact / Dig-In	164	0.6%	9,661	0.7%	1,399,532	0.5%
Directed by Non-PPL Authority	76	0.3%	4,930	0.4%	481,312	0.2%
Equipment Failures	5,619	21.5%	310,733	22.9%	44,960,374	15.9%
Improper Design	4	0.0%	612	0.0%	102,107	0.0%
Improper Installation	6	0.0%	3,066	0.2%	351,886	0.1%
Improper Operation	10	0.0%	4,933	0.4%	115,194	0.0%
Nothing Found	1,256	4.8%	80,861	6.0%	9,256,089	3.3%
Other Controllable	80	0.3%	9,532	0.7%	1,471,074	0.5%
Other Non-Control	393	1.5%	24,720	1.8%	3,150,098	1.1%
Other Public	45	0.2%	12,683	0.9%	634,586	0.2%
Tree Related	13,608	52.0%	723,932	53.3%	201,240,202	71.3%
Unknown	2	0.0%	4	0.0%	1,910	0.0%
Vehicles	824	3.1%	119,432	8.8%	14,774,814	5.2%
Total	26,185	100.0%	1,358,109	100.0%	282,306,130	100.0%

Analysis of causes contributing to the majority of service interruptions:

Weather Conditions: PPL Electric records weather conditions, such as wind or lightning, as contributing factors to service interruptions, but does not code them as direct interruption causes. Therefore, some fluctuations in cause categories, especially tree and equipment related causes, are attributable to weather variations. For the current reporting period, weather was considered a significant contributing cause in 55% of cases, 64% of customer interruptions, and 81% of CMI.

Tree Related: Vegetation is one of the largest single contributors to the number of cases of trouble, customer interruptions, and customer minutes. For the current reporting period, approximately 82% of the cases of trouble, 84% of the customer interruptions and 91% of the customer minutes attributed to tree related outages were weather-related.

Animals: Animals accounted for approximately 16% of PPL Electric's cases of trouble. Although this represents a significant number of cases, the effect on SAIFI and CAIDI is small because approximately 73% of the number of cases of trouble were associated with individual distribution transformers. PPL Electric has distribution and substation animal guarding programs to systematically protect existing facilities most at risk of incurring animal-caused interruptions. All PPL Electric substations are animal guarded.

Vehicles: Although vehicles cause a small percentage of the number of cases of trouble, they can account for a larger percentage of customer interruptions and customer minutes, because main distribution lines generally are located along major thoroughfares with higher traffic densities. In addition, vehicle-related cases often result in extended repair times to replace broken poles. PPL Electric has a program to identify and relocate poles that are subject to multiple vehicle hits.

Equipment Failure: Equipment failure is one of the largest single contributors to the number of cases of trouble, customer interruptions, and customer minutes. However, approximately 37% of the cases of trouble, 49% of the customer interruptions and 64% of the customer minutes attributed to equipment failure were weather-related and, as such, are not considered to be strong indicators of equipment condition or performance.

Nothing Found: This description is recorded when the responding crew can find no cause for the interruption. That is, when there is no evidence of equipment failure, damage, or contact after a line patrol is completed. For example, during heavy thunderstorms, when a line fuse blows and, when closed for test, the fuse holds, and a patrol reveals nothing.

5) A list of the major remedial efforts taken to date and planned for circuits that have been on the worst performing 5% of circuits list for a year or more.

PPL Electric uses a weighted circuit SAIDI and circuit SAIFI contribution over the previous three years to define the worst performing circuits on its system. IEEE Major Event days, transmission outages, and scheduled outages are excluded. By this methodology, all circuits remain on the list for the entire calendar year. This ranking system was put in place as of the first quarter of 2025.

01 Circuit 14009 -- SELLERSVILLE 40-09

Remedial Actions

Year	Remediation	Complete
2025	Install fusing	Y
2026	Reconductor and reconfigure single phase	N
2026	Construct tie line between 14008 and 14009	N
2026	Reconductor single phase	N

02 Circuit 12402 -- MILFORD 24-02

Remedial Actions

Year	Remediation	Complete
2024	Perform full circuit trimming	Y
2024	Replace reclosers	Y
2025	Install fusing	Y
2026	Reconductor and install Smart Grid device	N
2026	Reconductor, relocate conductor, install fusing	N
2026	Reconductor, underground line, install fusing	N
2026	Upgrade devices, upgrade single-phase to three-phase	N
2026	Reconductor segment	N
2026	Install new device and tie, relocate spans, reconductor	N
2026	Remove inaccessible, UG primary, reconductor	N
2026	Reconductor segment	N
2026	Reconductor, install fusing	N
2026	Install Smart Grid device, upgrade single-phase to three-phase, install tie line	N

03 Circuit 40601 -- PINE GROVE 06-01

Remedial Actions

Year	Remediation	Complete
2024	Perform hot spot tree trimming	Y
2024	Replace poles	Y
2025	Replace poles	Y
2025	Install fusing	Y
2025	Evaluate storm hardening	Y
2026	Install fusing	N
2026	Install proactive fault sensors	N
2026	Install Smart Grid devices	N
2026	Reconductor sections of line	N

04 Circuit 42101 -- FRAILEY 69/23 KV LINE 21-01

Remedial Actions

Year	Remediation	Complete
2025	Rebuild substation	Y
2025	Install new conductor	Y
2025	Install poles	Y
2025	Relocate conductor	Y
2025	Replace Smart Grid devices	Y
2025	Construct tie lines	Y
2025	Convert circuit to 12kV to improve tie capability	Y

05 Circuit 28602 -- BLYTHEBURN 86-02

Remedial Actions

Year	Remediation	Complete
2024	Install sectionalizing devices	Y
2024	Perform hot spot tree trimming	Y
2024	Perform full circuit trimming	Y
2025	Review and optimize coordination and protection	Y
2025	Install fusing	Y
2026	Construct three-phase tie line	N
2026	Evaluate storm hardening	N

06 Circuit 24602 -- VARDEN 46-02

Remedial Actions

Year	Remediation	Complete
2024	Perform full circuit trimming	Y
2024	Replace underground conductor	Y
2024	Upgrade reclosers to Smart Grid devices	Y
2024	Upgrade Smart Grid devices	Y
2025	Replace poles	Y
2025	Replace single-phase reclosers	Y
2026	Install animal guarding	N
2026	Install proactive fault sensors	N
2026	Replace cross-arms	N
2026	Perform storm hardening	N

07 Circuit 41802 -- GOWEN CITY 18-02

Remedial Actions

Year	Remediation	Complete
2024	Install proactive fault sensors	Y
2024	Replace cross-arms	Y
2024	Replace poles	Y
2025	Reconductor sections of line	Y
2025	Replace cross-arms	Y
2025	Replace poles	Y
2026	Construct three-phase tie line	N
2026	Relocate sections of conductor	N
2026	Replace Smart Grid devices	N
2028	Perform full circuit trimming	N

08 Circuit 13603 -- RICHLAND 36-03

Remedial Actions

Year	Remediation	Complete
2024	Install proactive fault sensors	Y
2024	Perform full circuit trimming	Y
2024	Replace reclosers	Y
2025	Evaluate installing sectionalizing devices	Y
2025	Evaluate reconductoring	Y
2025	Evaluate single-phase reclosers	Y
2025	Evaluate single-phase tie lines	Y
2025	Evaluate three-phase tie line	Y
2025	Evaluate tree-shielding cable	Y
2026	Install fusing	N
2026	Upgrade fuse to recloser	N
2026	Reconductor section of circuit	N
2026	Install single-phase reclosers	N

09 Circuit 18001 -- ZIONSVILLE 80-01

Remedial Actions

Year	Remediation	Complete
2024	Install proactive fault sensors	Y
2024	Perform full circuit trimming	Y
2024	Replace cross-arms	Y
2024	Replace poles	Y
2025	Install reclosers	Y
2026	Evaluate constructing tie line	Y
2026	Evaluate storm hardening	Y
2026	Evaluate tree-shielding cable	Y
2026	Install Smart Grid devices	N
2026	Relocate single-phase conductor	N
2026	Replace poles	N
2026	Underground sections of conductor	N
2026	Install tree-shielding cable	N
2026	Split circuit into two circuits	N
2026	Reconductor three-phase sections with tree shielding cable.	N
2026	Install two tie lines.	N

10 Circuit 43401 -- BENTON 34-01

Remedial Actions

Year	Remediation	Complete
2024	Relocate single-phase conductor	Y
2024	Review and optimize coordination and protection	Y
2025	Evaluate storm hardening	Y
2025	Install Smart Grid Device	Y
2025	Replace reclosers	Y
2026	Install fusing	N
2026	Install sectionalizing devices	N
2026	Perform storm hardening	N
2026	Relocate and reconductor line sections	N
2026	Remove conductor sections	N
2026	Underground three-phase conductor	N

11 Circuit 27102 -- GREENFIELD 71-02

Remedial Actions

Year	Remediation	Complete
2025	Install animal guarding	Y
2025	Replace poles	Y
2026	Recloser device replacement	Y
2026	Install proactive fault sensors	N
2026	Relocate sections of conductor	N
2026	Review and optimize coordination and protection	N
2026	Perform storm hardening	N
2026	Reconductor three-phase	N

12 Circuit 23504 -- GEORGETOWN 35-04

Remedial Actions

Year	Remediation	Complete
2024	Perform infrared scanning	Y
2024	Replace transformers	Y
2024	Replace underground conductor	Y
2024	Re-sag conductor	Y
2026	Perform Proactive Circuit Analysis	N

13 Circuit 25801 -- SULLIVAN TRAIL 58-01

Remedial Actions

Year	Remediation	Complete
2024	Install proactive fault sensors	Y
2024	Perform hazard tree removal	Y
2024	Relocate single-phase conductor	Y
2026	Transfer section of conductor to neighboring circuit	N
2026	Construct three-phase tie line	N
2026	Relocate single-phase conductor	N
2026	Underground single-phase conductor	N
2026	Underground three-phase conductor	N

14 Circuit 20401 -- ASHFIELD 04-01

Remedial Actions

Year	Remediation	Complete
2024	Install fusing	Y
2024	Install proactive fault sensors	Y
2024	Install single-phase reclosers	Y
2024	Install Smart Grid devices	Y
2024	Remove conductor sections	Y
2025	Install Smart Grid devices	Y
2025	Replace Smart Grid devices	Y
2026	Construct three-phase tie line	N
2026	Relocate and reconductor line sections	N
2026	Split and relocate section of conductor	N
2026	Upgrade conductor from single-phase to three-phase	N
2026	Upgrade conductor from two-phase to three-phase	N

15 Circuit 16802 -- WAGNERS 68-02

Remedial Actions

Year	Remediation	Complete
2024	Install sectionalizing devices	Y
2024	Install single-phase reclosers	Y
2024	Replace cross-arms	Y
2024	Replace poles	Y
2025	Install single-phase reclosers	Y
2026	Install animal guarding	N
2026	Replace poles	N
2026	Install proactive fault sensors	N
2026	Install three-phase reclosers	N
2026	Install single-phase reclosers	N
2027	Perform storm hardening	N
2028	Perform full circuit trimming	N

16 Circuit 14008 -- SELLERSVILLE 40-08

Remedial Actions

Year	Remediation	Complete
2024	Install proactive fault sensors	Y
2025	Underground single-phase conductor	Y
2025	Install animal guarding	Y
2025	Install single-phase Recloser and fusing	Y
2025	Reconfiguring single-phase	Y
2025	Refeeding Ridge Valley Road	N
2026	Evaluate three-phase tie lines	N
2026	Evaluate Smart Grid devices	N
2026	Evaluate tree-shielding cable	N
2027	Perform full circuit trimming	N

17 Circuit 13601 -- RICHLAND 36-01

Remedial Actions

Year	Remediation	Complete
2024	Replace reclosers	Y
2025	Replace reclosers	Y
2025	Evaluate storm hardening	Y
2026	Relocations, reconductoring, and undergrounding	N
2026	Reconductoring single-phase and install fusing	N
2026	Reconductoring single-phase and constructing tie	N
2026	Install Smart Grid device	N

18 Circuit 47002 -- HUGHESVILLE 70-02

Remedial Actions

Year	Remediation	Complete
2025	Upgrade Smart Grid devices	Y
2025	Relocate single-phase conductor	Y
2025	Install animal guarding	Y
2025	Upgrade reclosers to Smart Grid devices	Y
2026	Construct three-phase tie line	N
2026	Install Smart Grid devices	N
2026	Perform storm hardening	N
2026	Reconductor single-phase sections	N
2026	Remove conductor sections	N

19 Circuit 43101 -- SOUTH MILTON 31-01

Remedial Actions

Year	Remediation	Complete
2025	Perform Proactive Circuit Analysis	Y
2026	Install single-phase reclosers	N
2026	Relocate sections of conductor	N
2026	Replace poles	N
2026	Relocate Smart Grid device	N
2027	Perform full circuit trimming	N

20 Circuit 28604 -- BLYTHEBURN 86-04

Remedial Actions

Year	Remediation	Complete
2024	Perform full circuit trimming	Y
2025	Install fusing	Y
2025	Replace single-phase reclosers	Y
2025	Transfer section of conductor to neighboring circuit	Y
2026	Install Smart Grid devices	N
2026	Relocate single-phase conductor	N
2026	Relocate three-phase conductor	N
2026	Replace Smart Grid devices	N
2026	Construct three-phase tie line	N

21 Circuit 18501 -- CANADENSIS 85-01

Remedial Actions

Year	Remediation	Complete
2024	Install proactive fault sensors	Y
2024	Perform hot spot tree trimming	Y
2024	Replace cross-arms	Y
2024	Replace poles	Y
2024	Replace Smart Grid devices	Y
2025	Replace poles	Y
2025	Replace reclosers	Y
2025	Replace Smart Grid devices	Y
2025	Upgrade transformers	Y
2026	Install proactive fault sensors	Y
2026	Replace sectionalizer with Smart Grid device	Y
2026	Install single-phase Smart Grid device	Y
2026	Replace Smart Grid devices	Y
2026	Install animal guarding	N
2026	Install tree-shielding cable	N
2026	Perform full circuit trimming	N
2026	Install single-phase reclosers	N
2027	Perform circuit storm hardening	N

22 Circuit 26704 -- HEMLOCK FARMS 67-04

Remedial Actions

Year	Remediation	Complete
2024	Construct three-phase tie line	Y
2024	Remove conductor sections	Y
2024	Replace poles	Y
2024	Replace reclosers	Y
2025	Install fusing	Y
2025	Install Smart Grid devices	Y
2026	Install animal guarding	N
2026	Install proactive fault sensors	N
2026	Replace porcelain cutouts	N

23 Circuit 23510 -- GEORGETOWN 35-10

Remedial Actions

Year	Remediation	Complete
2024	Re-sag conductor	Y
2024	Inspect all underground connections	Y
2025	Transfer section of conductor to neighboring circuit	Y
2026	Install sectionalizing devices	N
2026	Install Smart Grid devices	N

24 Circuit 23401 -- HONESDALE 34-01

Remedial Actions

Year	Remediation	Complete
2024	Reconductor single-phase sections	Y
2024	Perform hot spot tree trimming	Y
2024	Install fusing	Y
2025	Replace poles	Y
2026	Install proactive fault sensors	N
2026	Replace porcelain cutouts	N
2026	Install animal guarding	N
2026	Replace reclosers	N
2026	Perform full circuit trimming	N
2026	Perform storm hardening	N

25 Circuit 59201 -- THOMPSONTOWN 92-01

Remedial Actions

Year	Remediation	Complete
2024	Install proactive fault sensors	Y
2024	Perform full circuit trimming	Y
2025	Install fusing	Y
2025	Evaluate reconductoring	Y
2026	Reconductoring and underground single-phase section	N

26 Circuit 25501 -- MADISONVILLE 55-01

Remedial Actions

Year	Remediation	Complete
2024	Install Smart Grid devices	Y
2024	Replace poles	Y
2024	Replace single-phase reclosers	Y
2025	Install proactive fault sensors	Y
2025	Install animal guarding	N
2025	Reconductor sections of line	N
2025	Upgrade reclosers to Smart Grid devices	N
2026	Perform storm hardening	N
2027	Perform full circuit trimming	N

27 Circuit 53601 -- DALMATIA 36-01

Remedial Actions

Year	Remediation	Complete
2024	Install proactive fault sensors	Y
2024	Install three-phase reclosers	Y
2025	Install fusing	Y
2025	Evaluate reconductoring	Y
2025	Evaluate reinforcement of three-phase tie line	Y
2025	Evaluate relocation of single-phase conductor	Y
2025	Evaluate relocation of three-phase conductor	Y
2026	Construct three-phase tie line	N
2026	Reconductor sections of line	N
2026	Reinforce three-phase tie line	N
2026	Relocate single-phase conductor	N
2026	Relocate three-phase conductor	N
2027	Perform full circuit trimming	N

28 Circuit 46302 – ROHRSBURG 63-02

Remedial Actions

Year	Remediation	Complete
2025	Relocate section of single-phase conductor	Y
2026	Extend sections of conductor	N
2026	Install Smart Grid devices	N
2026	Perform storm hardening	N
2026	Reconductor sections of line	N
2026	Relocate sections of conductor	N
2026	Underground section of three-phase conductor	N

29 Circuit 28102 – TWIN LAKES 81-02

Remedial Actions

Year	Remediation	Complete
2024	Install single-phase reclosers	Y
2024	Replace poles	Y
2025	Install proactive fault sensors	Y
2025	Replace lightning arrestor	Y
2026	Perform Proactive Circuit Analysis	N
2026	Install Smart Grid devices	N
2026	Replace porcelain cutouts	N
2026	Install animal guarding	N
2026	Replace cross-arms	N
2026	Replace poles	N
2026	Perform full circuit trimming	N

30 Circuit 26602 – BROOKSIDE 66-02

Remedial Actions

Year	Remediation	Complete
2024	Perform full circuit trimming	Y
2025	Replace poles	Y
2025	Replace transformers	Y
2026	Construct tie line	N
2026	Install proactive fault sensors	N
2026	Optimize recloser settings	N
2026	Review and optimize coordination and protection	N

31 Circuit 16801 – WAGNERS 68-01

Remedial Actions

Year	Remediation	Complete
2024	Replace poles	Y
2024	Replace Smart Grid devices	Y
2026	Install animal guarding	N
2026	Construct single-phase tie line	N
2026	Install single-phase reclosers	N
2026	Install Smart Grid devices	N
2026	Install tree-shielding cable	N
2026	Reconductor single-phase sections	N
2026	Perform storm hardening	N

32 Circuit 16803 – WAGNERS 68-03

Remedial Actions

Year	Remediation	Complete
2024	Install sectionalizing devices	Y
2024	Replace poles	Y
2024	Replace transformers	Y
2025	Install single-phase reclosers	Y
2025	Replace poles	Y
2026	Evaluate tie line	N
2026	Install animal guarding	N
2028	Perform full circuit trimming	N

33 Circuit 10601 – BLOOMING GLEN 06-01

Remedial Actions

Year	Remediation	Complete
2025	Relocate sections of conductor	Y
2025	Install fusing	Y
2026	Reconductor single-phase tap	N
2026	Reconductor three-phase section	N
2026	Reconductor single-phase tap	N
2026	Underground tap and install reclosers	N
2026	Underground single-phase taps	N
2026	Construct tie line	N
2026	Reconductor section and install single-phase recloser	N
2026	Underground and reconductor segments	N
2026	Replace recloser with Smart Grid device	N
2026	Relocate overhead primary to underground	N
2026	Reconductor three-phase	N
2026	Underground tap	N

34 Circuit 11003 – EAST GREENVILLE 10-03

Remedial Actions

Year	Remediation	Complete
2025	Transfer section of conductor to neighboring circuit	Y
2026	Evaluate constructing three-phase tie line	N
2026	Evaluate installing Smart Grid devices	N
2026	Evaluate reconductoring	N
2026	Evaluate tree-shielding cable	N
2026	Evaluating installing Fusing on Single-phase	N
2026	Install proactive fault sensors	N
2027	Perform full circuit trimming	N

35 Circuit 58301 – NOTTINGHAM 83-01

Remedial Actions

Year	Remediation	Complete
2025	Evaluate fusing	Y
2025	Install fusing	Y
2025	Install single-phase reclosers	Y

36 Circuit 45002 – LIMESTONE 50-02

Remedial Actions

Year	Remediation	Complete
2024	Install fusing	Y
2025	Install Smart Grid device	Y
2026	Evaluate hot spot tree trimming	N
2026	Install Smart Grid devices	N
2026	Evaluate storm hardening	N
2026	Upgrade substation transformer	N
2027	Construct three-phase tie line	N
2027	Perform full circuit trimming	N

37 Circuit 54201 – PENNSBORO 42-01

Remedial Actions

Year	Remediation	Complete
2024	Perform full circuit trimming	Y
2025	Install fusing	Y
2026	Install animal guarding	N
2026	Install fusing	N
2026	Install proactive fault sensors	N

38 Circuit 15704 – TANNERSVILLE 57-04

Remedial Actions

Year	Remediation	Complete
2024	Replace poles	Y
2024	Replace Smart Grid devices	Y
2025	Install single-phase reclosers	Y
2025	Replace transformers	Y
2026	Install animal guarding	N
2026	Install Smart Grid devices	N
2026	Install voltage regulator	N
2026	Perform full circuit trimming	N
2026	Relocate single-phase conductor	N
2026	Replace poles	N
2026	Install single-phase reclosers	N

39 Circuit 63403 – HONEYBROOK 34-03

Remedial Actions

Year	Remediation	Complete
2024	Install fusing	Y
2024	Perform hot spot tree trimming	Y
2025	Replace cross-arms	Y
2025	Replace poles	Y
2025	Install fusing	Y
2026	Install proactive fault sensors	N
2026	Install three-phase recloser	N
2026	Storm hardening analysis will be performed on circuit	N
2026	Install fusing	N
2027	Reconductor single-phase section	N
2027	Transfer of section to neighboring circuit	N
2027	Reconductor single-phase section	N
2027	Perform full circuit trimming	N

40 Circuit 10904 – COOPERSBURG 09-04

Remedial Actions

Year	Remediation	Complete
2025	Install fusing	Y
2026	Construct tie lines	N
2026	Evaluate three-phase reconductor	N
2026	Evaluate three-phase ties	N
2026	Evaluate single-phase reconductor	N
2026	Reconductor single-phase sections	N
2026	Reconfigure single-phase sections	N
2026	Upgrade poles	N
2026	Upgrade reclosers to Smart Grid devices	N
2026	Perform full circuit trimming	N
2026	Upgrade substation	N

41 Circuit 53803 – MILLERSBURG 38-03

Remedial Actions

Year	Remediation	Complete
2025	Install fusing	Y
2025	Evaluate fusing	Y
2025	Evaluate reconductoring single-phase sections	Y
2025	Install fusing	Y
2025	Evaluate relocating three-phase conductor	Y
2026	Install proactive fault sensors	N
2026	Refeed customers in high outage section	N
2026	Refeed single phase section	N

42 Circuit 26001 -- WEST DAMASCUS 60-01

Remedial Actions

Year	Remediation	Complete
2024	Install animal guarding	Y
2024	Replace cross-arms	Y
2024	Replace reclosers	Y
2025	Upgrade Smart Grid devices	Y
2026	Evaluate storm hardening	Y
2026	Perform storm hardening	Y
2026	Install proactive fault sensors	N
2026	Install single-phase reclosers	N
2026	Replace poles	N
2026	Replace porcelain cutouts	N
2026	Replace reclosers	N
2026	Replace transformers	N
2029	Perform full circuit trimming	N

43 Circuit 54101 -- S SHERMANSDALE 41-01

Remedial Actions

Year	Remediation	Complete
2023	Install proactive fault sensors	Y
2024	Install fusing	Y
2024	Perform full circuit trimming	Y
2025	Evaluate constructing three-phase tie line	Y
2025	Evaluate converting recloser to remote operability	Y
2025	Evaluate re-sourcing single-phase section	Y
2025	Evaluate single-phase reconductoring	Y
2025	Evaluate single-phase relocations	Y
2025	Evaluate three-phase reclosers	Y
2025	Evaluate single-phase tie line	Y
2025	Install fusing	Y
2025	Install single-phase reclosers	Y
2026	Convert recloser to remote operability	N
2026	Construct three-phase tie line	N
2026	Convert recloser to remote operability	N
2026	Re-sourcing single-phase section	N
2026	Reconductor single-phase section	N
2026	Relocate single-phase sections	N
2026	Install three-phase reclosers	N

44 Circuit 46701 -- RENOVO 67-01

Remedial Actions

Year	Remediation	Complete
2024	Install animal guarding	Y
2024	Install proactive fault sensors	Y
2024	Upgrade reclosers to Smart Grid devices	Y
2025	Replace poles	Y
2025	Replace reclosers	Y
2026	Relocation and reconductoring of substation getaway	N
2026	Install tree wire and/or UG on two 1ph taps	N
2026	Install sectionalizing devices	N

45 Circuit 24603 -- VARDEN 46-03

Remedial Actions

Year	Remediation	Complete
2024	Remove conductor sections	Y
2024	Replace reclosers	Y
2024	Replace poles	Y
2025	Evaluate recloser replacement	Y
2026	Install proactive fault sensors	N
2026	Install single-phase reclosers	N
2026	Perform full circuit trimming	N
2026	Replace porcelain cutouts	N
2026	Replace reclosers	N
2026	Replace poles	N

46 Circuit 26603 -- BROOKSIDE 66-03

Remedial Actions

Year	Remediation	Complete
2025	Replace poles	Y
2025	Replace reclosers	Y
2025	Perform full circuit trimming	Y
2026	Construct tie line	N
2026	Install proactive fault sensors	N
2026	Install tree-shielding cable	N
2026	Perform storm hardening	N
2026	Reconductor sections of line	N
2026	Relocate sections of conductor	N
2026	Underground single-phase conductor	N

47 Circuit 58402 -- MOUNT ROCK 84-02

Remedial Actions

Year	Remediation	Complete
2023	Perform full circuit trimming	Y
2024	Install fusing	Y
2025	Construct tie line	Y
2025	Evaluate converting tie line to remote operability	Y
2025	Evaluate re-sourcing single-phase section	Y
2025	Evaluate fusing	Y
2026	Install proactive fault sensors	N
2026	Install single-phase reclosers	N
2026	Install three-phase sectionalizing devices	N
2026	Reconductor single-phase sections	N
2026	Convert tie line to remote operability	N

48 Circuit 49804 -- UNIVERSITY 98-04

Remedial Actions

Year	Remediation	Complete
2024	Construct three-phase tie line	Y
2024	Install fusing	Y
2024	Perform Proactive Circuit Analysis	Y
2024	Review and optimize coordination and protection	Y
2025	Underground three-phase conductor	Y
2025	Install single-phase reclosers	Y
2025	Evaluate storm hardening	Y
2026	Evaluate conductor relocation	N
2026	Perform full circuit trimming	N
2026	Reframe lines outside of substation	N
2026	Underground single-phase conductor	N
2026	Perform storm hardening	N
2026	Reconductor single-phase sections	N
2026	Reconductor three-phase section	N
2026	Refeed section of conductor	N
2026	Relocate sections of conductor	N

49 Circuit 64802 -- MOUNT NEBO 48-02

Remedial Actions

Year	Remediation	Complete
2024	Install proactive fault sensors	Y
2024	Upgrade reclosers to Smart Grid devices	Y
2025	Perform hot spot tree trimming	Y
2025	Additional fusing to be installed	Y
2025	Install Smart Grid devices	Y
2026	Reconductoring	N
2026	Perform full circuit trimming	N
2027	Evaluate relocations	N

50 Circuit 45101 -- CASS 69/23 KV LINE 51-01

Remedial Actions

Year	Remediation	Complete
2025	Relocate sections of conductor	Y
2025	Construct tie lines	Y
2025	Convert circuit to 12kV to improve tie capability	Y
2026	Install poles	N
2026	Rebuild substation	N
2026	Replace poles	N
2026	Perform full circuit trimming	N

51 Circuit 22601 -- KIMBLES 26-01

Remedial Actions

Year	Remediation	Complete
2025	Install animal guarding	Y
2026	Install single-phase reclosers	N
2026	Replace reclosers	N
2026	Replace poles	N
2027	Perform full circuit trimming	N

52 Circuit 24401 -- TINKER 44-01

Remedial Actions

Year	Remediation	Complete
2024	Replace voltage regulators	Y
2025	Replace poles	Y
2025	Replace reclosers	Y
2026	Install proactive fault sensors	N
2026	Install single-phase reclosers	N
2026	Relocate sections of conductor	N
2026	Replace porcelain cutouts	N
2026	Perform full circuit trimming	N
2026	Replace reclosers	N

53 Circuit 10401 -- LITTLE GAP 04-01

Remedial Actions

Year	Remediation	Complete
2025	Evaluate upgrade to covered conductor or tree-shielding cable	Y
2025	Evaluate undergrounding	Y
2026	Install Smart Grid devices	N
2027	Perform full circuit trimming	N

54 Circuit 59202 -- THOMPSONTOWN 92-02

Remedial Actions

Year	Remediation	Complete
2024	Install proactive fault sensors	Y
2024	Repair section of conductor	Y
2025	Replace switch(es)	Y
2025	Evaluate conductor relocations	Y
2025	Evaluate reconductoring single-phase sections	Y
2025	Evaluate reconductoring three-phase sections	Y
2025	Evaluate re-sourcing sections	Y
2025	Evaluate single-phase reclosers	Y
2025	Evaluate three-phase reclosers	Y
2025	Evaluate undergrounding	Y
2025	Install single-phase reclosers	Y
2025	Replace reclosers	Y
2025	Evaluate three-phase tie	Y
2025	Upgrade remote tie	Y
2026	Underground sections	N
2026	Install three-phase tie	N
2026	Relocate conductor	N
2026	Reconductor single-phase sections	N
2026	Reconductor three-phase sections	N
2026	Re-source sections	N
2026	Install three-phase reclosers	N

55 Circuit 20601 -- GREENWOOD 06-01

Remedial Actions

Year	Remediation	Complete
2024	Replace single-phase conductor	Y
2025	Replace Smart Grid devices	Y
2026	Construct three-phase tie line	N
2026	Convert existing sectionalizers to Smart Grid devices	N
2026	Install Smart Grid devices	N
2026	Relocate and upgrade conductor	N
2026	Relocate conductor	N
2027	Perform full circuit trimming	N

56 Circuit 15701 -- TANNERSVILLE 57-01

Remedial Actions

Year	Remediation	Complete
2025	Install fusing	Y
2025	Replace poles	Y
2025	Replace reclosers	Y
2025	Upgrade reclosers to Smart Grid devices	Y
2025	Install single-phase reclosers	Y
2025	Install Smart Grid devices	Y
2026	Extend section of conductor	N
2026	Install animal guarding	N
2026	Install proactive fault sensors	N
2026	Relocate section of conductor	N

57 Circuit 46004 -- BERWICK 60-04

Remedial Actions

Year	Remediation	Complete
2024	Perform full circuit trimming	Y
2024	Review and optimize coordination and protection	Y
2025	Evaluate three-phase tie line	Y
2026	Perform Proactive Circuit Analysis	N
2026	Perform storm hardening	N
2026	Relocate sections of conductor	N
2026	Underground single-phase conductor	N

58 Circuit 24203 -- PROVIDENCE 42-03

Remedial Actions

Year	Remediation	Complete
2025	Replace poles	Y
2025	Perform full circuit trimming	Y
2025	Replace cross-arms	Y

59 Circuit 21203 -- EAST CARBONDALE 12-03

Remedial Actions

Year	Remediation	Complete
2025	Install animal guarding	Y
2025	Perform hot spot tree trimming	Y
2025	Replace reclosers	Y
2026	Install proactive fault sensors	N
2026	Perform full circuit trimming	N
2026	Replace reclosers	N

60 Circuit 13703 -- SCHNECKSVILLE 37-03

Remedial Actions

Year	Remediation	Complete
2026	Evaluate loop for underground section	N
2026	Evaluate replacing underground cable	N
2026	Perform full circuit trimming	N

61 Circuit 16101 -- BINGEN 61-01

Remedial Actions

Year	Remediation	Complete
2025	Install animal guarding	Y
2025	Install lightning arrestors	Y
2025	Install single-phase switches	Y
2025	Perform hot spot tree trimming	Y
2025	Reconfigure single-phase sections	Y
2025	Replace poles	Y
2026	Construct tie lines	N
2026	Reconductor single-phase sections	N
2026	Underground single-phase conductor	N
2026	Upgrade poles	N
2026	Upgrade single-phase reclosers	N
2027	Perform full circuit trimming	N

62 Circuit 42401 -- GIRARD MANOR 24-01

Remedial Actions

Year	Remediation	Complete
2024	Review and optimize coordination and protection	Y
2024	Replace Smart Grid devices	Y
2025	Install fusing	Y
2025	Replace poles	Y
2026	Reconductor three-phase sections	N
2026	Relocate sections of conductor	N
2026	Install Smart Grid devices	N
2026	Replace cross-arms	N
2026	Install fusing	N
2026	Replace poles	N
2027	Perform full circuit trimming	N

63 Circuit 25402 -- LAKE HARMONY 54-02

Remedial Actions

Year	Remediation	Complete
2025	Refeed section of conductor	Y
2025	Install Smart Grid devices	Y
2025	Install fusing	Y
2025	Perform full circuit trimming	Y
2027	Perform storm hardening	N

64 Circuit 55002 -- NEWPORT 50-02

Remedial Actions

Year	Remediation	Complete
2024	Install fusing	Y
2024	Install proactive fault sensors	Y
2025	Evaluate relocating single-phase sections	Y
2025	Evaluate constructing three-phase tie line	Y
2025	Perform full circuit trimming	Y
2026	Construct three-phase tie line	N
2026	Reconductor single-phase sections	N
2026	Reconductor and underground single-phase section	N

6) ***A comparison of established transmission and distribution inspection and maintenance goals/objectives versus actual results achieved during the year being reported on. Explanations of any variances shall be included.***

	2025 BUDGET	2025 ACTUAL	DELTA
Transmission			
Transmission C-tag poles (# of poles)	50	50	0%
Transmission arm replacements	15	15	0%
Transmission air break switch inspections (# of inspections)	2	2	0%
Transmission surge arrester installations (# of installations)	17	17	0%
Transmission structure inspections	4,218	4,218	0%
Transmission tree side trim-Bulk Power (linear feet)	NA	21,714	NA
Transmission herbicide-Bulk Power	NA	1,803	NA
Transmission reclearing (# of miles) BES Only	712	708	-1%
Transmission reclearing (# of miles) 69 kV	1557	1547	-1%
Transmission reclearing (# of miles) 138 kV	204	202	-1%
Transmission danger tree removals-Bulk Power (# of trees)	NA	NA	NA
Substation			
Substation batteries (# of activities)	0	175	100%
Circuit breakers (# of activities)	0	5	100%
Substation inspections (# of activities)	1,460	1,203	-18%
Transformer maintenance (# of activities)	632	536	-15%
Distribution			
Distribution C-tag poles replaced (# of poles)	2,500	4,216	69%
C-truss distribution poles (# of poles)	270	270	0%
Capacitor (MVAR added)	NA	13.9	NA
OCR Replacements (# of)	200-230	228	0%
Distribution pole inspections (# of poles)	67,286	67,286	0%
Distribution line inspections (miles)	4,700	4,700	0%
Group re-lamping (# of lamps)	0	0	0%
Test sections of underground distribution cable	NA	438	NA
Distribution tree trimming (# of miles)	3,000	3,037	1%
Distribution herbicide (# of acres)	NA	1296	NA
Distribution >18" removals within R/W (# of trees)	NA	NA	NA
Distribution hazard tree removals outside R/W (# of trees)	NA	8,859	NA
LTN manhole inspections	0	0	0%
LTN vault inspections	0	0	0%
LTN network protector overhauls	0	1	100%
LTN reverse power trip testing	0	0	0%

Explanation of variances greater than 10%:

Substation batteries (# of activities) – Completion of legacy work orders from previous years.

Circuit breakers (# of activities) - Completion of legacy work orders from previous years.

Substation inspections (# of activities) – Attributable to substation inspections bundled under the same work order as transformer maintenance.

Transformer maintenance (# of activities) – Some work deferred to 2026.

Distribution C-tag poles replaced (# of poles) - Completed pole replacements came in above the forecast due to significant storm impacts causing the reprioritization of reliability driven work.

LTN network protector overhauls – Number shown as reported (1). This was a reporting error, no LTN network protector overhauls were performed in 2025.

7) ***A comparison of budgeted versus actual transmission and distribution operation and maintenance expenses for the year being reported on in total and detailed by the EDC's own functional account code or FERC account code as available. Explanations of any variances 10% or greater shall be included.***

The following table provides operation and maintenance expenses for PPL Electric, and includes the work identified in the response to Item (6).

	2025 BUDGET	2025 ACTUAL	DELTA
O&M			
Provide Electric Service	7,012	7,367	5%
Vegetation Management	33,351	33,460	0%
Customer Response	60,298	72,911	21%
Reliability Maintenance	16,964	25,882	53%
System Upgrade	92	456	396%
Customer Service/Accounts	187,078	171,190	-8%
Others	48,886	30,926	-37%

Explanation of variances of 10% or greater:

Customer Response: Higher than projected driven by the actual number of storms greater than the budgeted number of storms.

Reliability Maintenance: Higher than projected driven by increased pole inspections.

System Upgrade: Higher than projected driven by Upgrade System Facilities (Substations).

Other: Higher than projected driven by facilities expenses.

Note: Any differences in O&M or Capital on this document compared to the 2025 4th Quarter Reliability report are the result of a third quarter reporting error, which has been corrected here.

8) A comparison of budgeted versus actual transmission and distribution capital expenditures for the year being reported on in total and detailed by the EDC's own functional account code or FERC account code as available. Explanations of any variances 10% or greater shall be included.

The following table provides capital expenditures for PPL Electric which includes transmission and distribution activities.

	2025 BUDGET	2025 ACTUAL	DELTA
Capital			
New Service/Revenue	138,754	237,754	71%
System Upgrade	400,888	399,630	0%
Reliability & Maintenance	657,009	715,427	9%
Customer Response	76,364	105,334	38%
Other	27,106	33,556	24%

Explanation of variances of 10% or greater:

New Service/Revenue: Higher than projected driven by higher-than-expected customer work

Customer Response: Higher than projected driven by the actual number of storms greater than the budgeted number of storms.

Other: Higher than projected driven by higher vehicle deliveries than budgeted.

9) Quantified transmission and distribution inspection and maintenance goals/objectives for the current year detailed by system area (that is, transmission, substation and distribution).

Inspection & Maintenance Goals/Objectives	2026 Budget
Transmission	
Transmission C-tag poles (# of poles)	65
Transmission arm replacements (# of sets)	6
Transmission air break switch inspections (# of switches)	4
Transmission surge arrester installations (# of sets)	17
Transmission structure inspections (# of activities)	12,419
Transmission tree side trim-Bulk Power (linear feet)	NA
Transmission herbicide-Bulk Power (# of acres)	NA
Transmission reclearing (# of miles) BES Only	805
Transmission reclearing (# of miles) 69 kV	1,790
Transmission reclearing (# of miles) 138 kV	88
Transmission danger tree removals-Bulk Power (# of trees)	NA
Substation	
Substation batteries (# of activities)	0
Circuit breakers (# of activities)	0
Substation visual inspections (# of activities)	1,460
Substation IR inspections	1,460
Substation drone inspections (# of activities)	0
Transformer maintenance (# of activities)	632

Inspection & Maintenance Goals/Objectives	2026 Budget
Distribution	
Distribution C-tag poles replaced (# of poles)	1,559
Distribution OH Transformer Inspections (# of inspections)	84,497
Distribution Pad Mount Transformer Inspections (# of inspections)	22,962
C-truss distribution poles (# of poles)	33
Capacitor (MVAR added)	NA
OCR Replacements (# of)	155-171
Distribution pole inspections (# of poles)	105,859
Distribution infrared line inspections (miles)	4,457
Group re-lamping (# of lamps)	NA
Test sections of underground distribution cable	NA
Distribution tree trimming (# of miles)	4,817
Distribution herbicide (# of acres)	NA
Distribution >18” removals within R/W (# of trees)	NA
Distribution hazard tree removals outside R/W (# of trees)	NA
LTN manhole inspections (# of)	0
LTN vault inspections (# of)	0
LTN network protector overhauls (# of)	0
LTN reverse power trip testing (# of)	0

10) Budgeted transmission and distribution operation and maintenance expenses for the current year in total and detailed by the EDC's own functional account code or FERC account code as available.

The following table provides budgeted operation and maintenance expenses for PPL Electric and includes the work identified in the response to Item (9).

Activity	2026 Budget ($000)
Provide Electric Service	7,076
Vegetation Management	52,499
Customer Response	54,498
Reliability Maintenance	28,079
System Upgrade	-
Customer Service/Accounts	197,654
Others	53,314
Total O&M Expenses	393,120

11) Budgeted transmission and distribution capital expenditures for the current year in total and detailed by the EDC's own functional account code or FERC account code as available.

The following table provides budgeted capital expenditures for PPL Electric and includes transmission and distribution activities.

Activity	2026 Budget ($000)
New Service/Revenue	210,470
System Upgrade	437,440
Reliability & Maintenance	1,003,120
Customer Response	88,213
Other	36,226
Total	1,775,469

12) Significant changes, if any, to the transmission and distribution inspection and maintenance programs previously submitted to the Commission.

No significant changes were requested.

PPL Electric Utilities Corporation
Transmission Programs & Procedures

Program	Activity
Helicopter Inspections – Routine	Aerial linemen perform annual routine transmission line patrols from a helicopter. They identify damaged or deteriorated equipment. Engineers review the findings and develop plans for repair or replacement.
Helicopter Inspections – Comprehensive	Aerial linemen perform an overhead comprehensive inspection of transmission line facilities on a risk-based time cycle. Detailed condition reports with close up digital photos are prepared for each specific component problem found along the transmission line and right of way. Engineers review the findings and schedule corrective maintenance as needed.
Helicopter Inspections – Emergency	Aerial linemen perform patrols of transmission lines that operate abnormally. This inspection focuses on identifying damage that may have been caused by lightning, inclement weather, equipment failure or vandalism. Because of the nature of this work, corrective actions are usually expedited.
Field Inspections – Emergency	Line personnel perform emergency foot patrols to inspect transmission lines that operated abnormally. This inspection focuses on identifying damage that may have been caused by lightning, inclement weather, equipment failure or vandalism. Due to the nature of this damage, corrective actions are generally expedited.
Steel Structure Inspection/Repair	Personnel inspect steel structures at the ground line for corrosion, mechanical damage and foundation degradation. Structural components are coated, and repairs are made based on the findings of the inspections as necessary.
Equipment Maintenance	During helicopter and foot patrols, equipment and facilities are identified that require repairs. Based on need and criticality, repairs are either scheduled or completed as soon as possible.
Planned Reliability Programs	Lightning arresters and avian guards are installed on targeted 69kV and 138kV facilities based on a data-driven risk analysis to improve reliability of worst performing circuits.
Line Switches – Maintenance & Inspection	Line personnel inspect, maintain, and perform operational tests on 138kV and 69kV transmission line switches to assure proper operation.

Appendix A

Program	Activity
Line Switch Upgrades	Transmission line switches are being programmatically upgraded to include motor operators to allow for remote sectionalizing that substantially improves switching times during outages.
Conductor Inspections	Line personnel collect data on overhead facilities using a nondestructive evaluation (NDE) device to identify damage and deterioration not visible through other inspection methods. Engineers review the findings and develop plans for repair or replacement.
Circuit Analysis	Engineers analyze circuit loading and performance to identify areas needing increased line capacity or improved line reliability. Circuits are also reviewed based on operational performance and ranked yearly in a WPC list, with appropriate circuits identified for targeted reliability improvements.

Appendix B

PPL Electric Utilities Corporation
Substation Programs & Procedures

Program	Activity
Load Survey	Automatic monitoring devices such as Supervisory Control and Data Acquisition (SCADA) provide continuous, real-time loading information. Engineers review equipment loading and identify facilities and transfer capabilities approaching capacity limits. A portion of the load may be supplied from a different source, the existing facilities may be upgraded, new lines and equipment may be added, or a new substation may be built to address capacity deficiencies.
Substation Inspection/Repair	Electricians inspect substations for security and equipment reliability on a time based maintenance cycle. They attempt to identify and correct potential equipment problems before a failure or interruption of service occurs.
Equipment Service	Electricians perform operational tests on power transformers, load tap changers (LTC), voltage regulators, circuit breakers, circuit switchers, vacuum switches, air break switches and transformer protective switches on a time-based maintenance cycle to assure that equipment is operating within established parameters. Equipment serviced includes batteries, battery chargers, protective relays, HV fuses and high-speed automatic grounding switches. Depending on the type of equipment, "service" can include actions other than operational testing.
Inspection & Overhaul	Electricians inspect and overhaul circuit breakers, wave traps, ground switches, stick-operated disconnects, gang-operated disconnects and motor-operated disconnects on a time based maintenance cycle to assure proper operation.
Insulation Testing	Technicians perform power factor testing on power transformers, potential transformers, lightning arresters, current transformers, select circuit breakers and power cables on a time-based maintenance cycle. Testing also includes other instrument transformers (capacitance coupled voltage transformer, coupling capacitors, potential devices, etc.). They also perform high-potential testing on12kV oil, air and vacuum circuit breakers to assure proper operation.

Program	Activity
Condition Monitoring of Station Equipment	Technicians perform dissolved gas-in-oil, dielectric, oxygen, and oil acidity tests for oil in power transformers and impedance and capacity tests on station batteries to assure equipment is within normal parameters. Periodically, AC power factor tests, hi-potential tests, contact resistance tests and motion tests are performed on circuit breakers. Oil dielectric testing is conducted for oil circuit breakers. Equipment monitors are installed on select assets for near real time health insights allowing for early identification of issues and condition based maintenance
Thermographic Inspections	Technicians perform thermography surveys of substation facilities to identify components operating at elevated temperatures. Based on the findings, engineers develop plans to repair or replace the component(s) prior to failure.
Minor Improvements	Maintenance activities may identify conditions where additions or upgrades are needed to assure reliability. Engineers evaluate the need and develop action plans and schedules to complete the work.
DC Station Service Improvements	Repairmen identify deteriorated station batteries, battery chargers and battery components. Engineers schedule repairs or replacements as necessary.
Capacitor Bank Protection	Engineers monitor the need for synchronous closing schemes on vacuum switches on 69kv capacitor banks. They plan and schedule installations as needed.
Area/Regional Supply	Engineers develop specific projects aimed at improving capacity shortfalls or replacing deteriorated or substandard station equipment.
SCADA Replacement	Engineers identify deteriorating substation SCADA equipment and develop plans to repair or replace it.

Appendix C

PPL Electric Utilities Corporation
Distribution Programs & Procedures

Program	Activity
Load Survey – of equipment that is not continuously monitored	Line personnel measure the loading of facilities during peak periods. Engineers use this data for system studies.
Load Survey – by automatic monitoring devices	Automatic monitoring devices such as SCADA provide continuous, real-time loading information. Operators use this data to assure that loads do not exceed design limits. Engineers use this data for system studies.
Circuit Analysis	Engineers analyze circuit voltage profiles to balance loads and to identify areas requiring voltage support to maintain required voltage at the customer facility.
Voltage Regulator – Inspection & Maintenance	Inspectors examine existing equipment for potential failure, and inspect and maintain controls and tap changers to assure proper operation. Line personnel repair or replace any defective equipment.
Overhead Line Switch – Inspection & Maintenance	Inspectors examine switch installations to identify cracked or broken insulators / bushings, stuck or misaligned blades, insulation or gasket deterioration or other operational problems. Line personnel repair or replace any defective equipment.
Transformer Maintenance	Engineers analyze customer usage data to identify overloaded transformers. Transformers that are heavily loaded are replaced with higher capacity units or part of the load is transferred to other nearby transformers.
Wood Pole – Inspection, Maintenance, Replacement, Trussing, Fiber Wrap (reinforcement)	Inspectors examine wood poles for deterioration and measure the degree of rot. Based on the results, the pole is either scheduled for a future inspection, reinforcement for extended life or replacement.
Overhead Line Inspection	Inspectors examine overhead facilities to identify damaged, deteriorated or substandard equipment. Line personnel repair or replace any defective equipment. Includes visual and thermo-graphic inspections.
Circuit Performance Review	Engineers use PPL Electric's WPC score to ascertain the need for additional circuit reviews or inspections. The improved index looks at a circuit's overall impact to system SAIFI and circuit SAIDI. Actual service interruption history is analyzed to identify causal or geographic patterns.

Program	Activity
Underground Primary Cable – Testing, Maintenance, Replacement, Curing	Inspectors perform insulation and neutral tests on cable in residential developments with potential problems to identify deteriorated cable. Based on the results, the cable is placed back in service, repaired or replaced.
LTN Maintenance	Electricians will inspect, service, maintain and overhaul LTN vaults, manholes, cables, transformers, low voltage network protectors and primary transformer disconnect switches. Based on results, defective equipment is either repaired or replaced.
Public Damaged Facilities Review	A program aimed at identifying the locations of facilities that have been damaged by public contact more than once. Technicians evaluate those installations and, if relocation is possible, schedule work to move the facilities.
Underground Service Cable	Engineers resolve customer service problems that are due to deteriorated service conductors.
Oil Circuit Reclosers	Line personnel replace in-service oil circuit reclosers conditionally.
Line Protection Equipment	Line personnel replace in-service three phase oil circuit reclosers with communicating vacuum devices conditionally.
Capacitor Installation	Engineers perform voltage profiles to determine the need, location and size of any new voltage support equipment required to maintain adequate service voltage levels at customer facilities and provide needed reactive support for system stability. Line personnel install the required equipment.
Upgrade System Facilities	Engineers determine the need for additional capacity and design new and upgraded facilities to assure system reinforcements are constructed by the time they are needed.

Appendix D

PPL Electric Utilities Corporation
Vegetation Programs & Procedures

Program	Activity
Tree Pruning	Tree pruning is scheduled based on field conditions observed and/or a system prioritization process. All pruning is done in accordance with American National Standard for Tree Care Operations-Tree, Shrub and Other Woody Plant Maintenance – Standard Practices (ANSI A300).
Hazard Tree Removal	Trees located both within the right-of-way corridor and outside the right-of-way that may be a threat to line performance/ safety are removed when it is feasible to do so.
Herbicide Application	Tall-growing, undesirable vegetation present within the right-of-way corridor is selectively treated with herbicides. Low-growing vegetation that does not represent a hazard to the safe, reliable operation of PPL Electric's facilities is preserved wherever possible.
Reclearing	Tall-growing, undesirable vegetation growing within the rights-of-way corridors is selectively managed in those situations where herbicides can't be utilized. Low-growing vegetation that does not represent a hazard to the safe, reliable operation of PPL Electric's facilities is preserved wherever possible.

Appendix E

PPL Electric Utilities Corporation
Service Interruption Definitions

Trouble Definitions: After field investigations and repairs are complete, PPL Electric linemen report the cause of each case of trouble. The definitions of the cause codes appear below. Note that while internal codes allow vegetation caused outages to be separated into trimming related and not trimming related, these categories are generally merged for internal reporting purposes, and consistent with the response to question 4.

Improper Design	Controllable	• When an employee or agent of PPL Electric is responsible for an error of commission or omission in the engineering or design of the distribution system.
Improper Installation	Controllable	• When an employee or agent of PPL Electric is responsible for an error of commission or omission in the construction or installation of the distribution system.
Improper Operation	Controllable	• When an employee or agent of PPL Electric is responsible for an error of commission or omission in the operation or maintenance of the distribution system.
Trees –Trimming Related	Controllable	• Outages resulting from conductors contacted by tree growth within the clearance zone defined by the current trimming specification (within the Right-of-Way).
Trees – Not Trimming Related	Non-Controllable	• Outages due to trees but not related to lack of proper tree trimming maintenance. This includes danger trees falling into PPL Electric facilities, and trees or limbs felled by the public.
Animals	Controllable	• Any outage caused by an animal directly or indirectly coming in contact with PPL Electric facilities. This includes birds, squirrels, raccoons, snakes, cows, etc.
Vehicles	Public	• When cars, trucks or other types of vehicles or their cargoes strike facilities causing a problem.
Contact/Dig-in	Public	• When work in the vicinity of energized overhead facilities results in interruptions due to accidental contact by cranes, shovels, TV antennas, construction equipment (lumber, siding, ladders, scaffolding, roofing, etc.). • When contact is made by a non-employee with an underground facility causing interruption.

Equipment Failure	Controllable	• Outages resulting from equipment failures caused by corrosion or contamination from build-up of materials, such as cement dust or other pollutants. • Outages resulting from a component wearing out due to age or exposure, including fuse tearing or breaking. • Outages resulting from a component or substance comprising a piece of equipment failing to perform its intended function. • Outages resulting from a failure that appears to be the result of a manufacturer's defect or cannot be described by any other code indicating the specific type of failure.
Directed by Non-PPL Authority	Non-Controllable	• Interruptions under the control of a PPL Electric switchman or direction of a PPL Electric System Operator for the purpose of dropping load or isolating facilities upon request during emergency situations. • Interruptions which cannot be postponed or scheduled for a later time, and include situations like load curtailment during system emergencies, and requests of civil authorities such as fire departments, police departments, civil defense, etc. for interruption of PPL Electric facilities.
Other – Controllable (Lineman provides explanation)	Controllable	• Interruptions caused by phase to phase or phase to neutral contacts, resulting from sleet or ice dropping off conductors, galloping conductors, or any other phase to phase or phase to neutral contact where weather is a factor. • Interruptions resulting from excessive load that cause that facility to fail. • When restoration of service to a facility, which had been interrupted for repairs or other reasons, causes an additional interruption to another facility which had not been involved in the initial interruptions. • Controllable interruptions or Power Service Problems whose cause is not described by one of the previous controllable cause codes.
Nothing Found	Non-Controllable	• When no cause for the interruption can be found. • When there is no evidence of equipment failure, damage or contact after line patrol is completed. This could be the case during a period of heavy thunder and lightning, when a line fuse blows or a single phase OCR locks open. • When closed for test, the fuse holds or the OCR remains closed. A patrol of the tap reveals nothing.

Other Public (Lineman provides explanation)	Public	• All outages resulting from gunfire, civil disorder, objects thrown, or any other act intentionally committed for the purpose of disrupting service or damaging company facilities.
Other – Non-Controllable (Lineman provides explanation)	Non-Controllable	• Any outage occurring because of a fire, flood or a situation that develops as a result of a fire or flood. Do not use when facilities are de-energized at the request of civil authorities. • When an interruption is caused by objects other than trees, such as kites, balls, model airplanes, roofing material, or fences, being accidentally blown or thrown into overhead facilities. • All problems caused by contact of energized equipment with facilities of other attached companies or by trouble on customer owned equipment. • Interruptions or Power Service Problems whose cause is not described by one of the previous non-controllable cause codes, but is not affected by a PPL Electric employee's decisions.

TABLE OF CONTENTS

1. PURPOSE / SCOPE

1.1. This procedure documents PPL Electric Utilities' (PPL EU) process for addressing the various types of emergencies which may be encountered on the Bulk Electric System (BES) and provide guidance as to how PPL EU would respond in coordination with PJM per:

1.1.1. PJM Manual 13 – Emergency Operations

1.1.2. EOP-011 – Emergency Operations

2. ROLES AND RESPONSIBILITIES

2.1. PJM, as the Reliability Coordinator (RC), Balancing Authority (BA), and Transmission Operator (TOP) for the PPL EU service territory, has the authority to direct PPL EU to take actions to preserve the integrity of the BES. PJM's Manual 13: Emergency Operations documents how PJM and the PJM Members (PPL EU) are expected to respond to emergency conditions and is referenced throughout this procedure. PPL EU is a PJM Member and a registered Transmission Owner (TO) with the North American Reliability Corporation (NERC).

2.2. PPL EU's Transmission System Operators (TSOs) are expected to comply with PJM directives, unless completing the specified direction will violate safety, equipment, regulatory or statutory requirements, or would otherwise jeopardize the safe, stable operation of the BES. In this event, the TSO shall immediately inform PJM of their inability to perform the directive, so that PJM may implement alternate remedial actions, per requirements set by NERC.

2.3. Based on certain operating conditions and triggers, PPL EU will perform the directed PJM Member Actions assigned to TOs per PJM's Manual 13 as outlined in this procedure.

3. APPLICABILITY

3.1. This document applies to all PPL employees and contractors performing tasks directly for, or in support of, PPL EU.

4. TERMS AND DEFINITIONS

4.1. Refer to NERC Glossary of Terms

4.2. Refer to PPL EU program EU-NERC-PGM-DEFINITIONS

5. MAIN BODY

5.1. PPL EU utilizes this procedure to define processes for compliance for NERC Reliability Standards & Requirements and PJM Manual. This procedure defines PPL EU's approach for **EOP-011** as a NERC registered Transmission Owner (TO) and a Distribution Provider (DP).

5.1.1. Per the PJM TO/TOP Matrix of Shared or Assigned Tasks, PJM is responsible for maintaining and implementing PJM M-13 as the PJM Operating Plan to mitigate operating Emergencies in the PJM footprint. As a Member TO, PPL EU will perform the PJM Member Actions captured in PJM's Manual 13 for each applicable part of the plan. This procedure works in conjunction with PJM's Manual 13 and together forms the Emergency Operating Plan for PPL EU. **(EOP-011, R1)**

5.1.2. In addition to the guidance provided in PJM's Manual 13, roles and responsibilities for this procedure are defined in Section 2. Specifically, the TSOs on shift have the responsibility to follow the direction from PJM who is responsible for issuing an Emergency, and for directing operations of the PJM members as necessary to manage, alleviate, or end an Emergency. **(EOP-011, R1.1)**

5.1.3. As outlined throughout this procedure, PPL EU will perform the PJM Member Actions captured in PJM's Manual 13 for each applicable part of the plan. The review and determination of any maintenance or testing, scheduled or being performed, on any monitoring, control, or transmission equipment can be deferred or cancelled is a specified action for PJM Members in PJM's Manual 13. **(EOP-011, R1.2.2)**

5.1.4. As outlined throughout this procedure, PPL EU will perform the PJM Member Actions captured in PJM's Manual 13 for each applicable part of the plan. The reconfiguration of the transmission system is a specified action for PJM Members in PJM's Manual 13. **(EOP-011, R1.2.3)**

5.1.5. Per the PJM TO/TOP Matrix of Shared or Assigned Tasks, PJM is responsible for maintaining PJM M13 that describes PJM's Emergency and Load shed plan.

In addition to M13, this procedure as PPL EU's Emergency Operating Plan includes steps for load shedding below and in Section 5.8. **(EOP-011, R1.2.5)**

5.1.5.1. PPL EU has provisions for manual Load shedding that is capable of being implemented in five (5) minutes. This is accomplished via the Rotating Load Shed (RLS) application within PPL EU's Transmission Management System (TMS). TSOs comply with directives from PJM as outlined in Section 2 of this procedure. **(EOP-011, R1.2.5.1)**

5.1.5.2. PPL EU has provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES. Circuits that serve designated critical loads which are essential to the reliability of the BES are not included in PPL EU's load shed program. See Section 5.8.1.8 which introduces PPL EU's Vital Facility Program (Operating Instruction 2180). **(EOP-011, R1.2.5.2)**

5.1.5.3. PPL EU has provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS. PPL EU does not include circuits that are utilized for UFLS in the manual Load shed tables in the RLS application within the TMS. See Section 5.8 and Action Guide 2. **(EOP-011, R1.2.5.3)**

5.1.5.4. PPL EU has provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions. As outlined in Section 5.8 and Action Guide 2, the tables with the UFLS circuits in the RLS application are not *included* in the list of tables to be shed by the tool by default. These tables could be included should system conditions warrant. **(EOP-011, R1.2.5.4)**

5.1.5.5. PPL EU has provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES. PJM's Manual 13 and PPL EU's OI 2180 outlines these provisions. **(EOP-011, R1.2.5.5)**

5.1.6. In support of the assigned tasks from the PJM TO/TOP Matrix of Shared or Assigned Tasks, PPL EU adheres to all requirements of R8.1 via the sections above in this procedure related to R1.2.5. In support of Requirement 8.2, PPL EU has provisions to provide the load shedding plan to PJM (the TOP) for their review and PPL EU complies with all of PJM's data requests in support of EOP-011. **(EOP-011, R8)**

5.2. The complete list of Advisories, Alerts, Warnings, and Actions that PJM could initiate in support of adverse conditions is available in PJM's Manual 13; each of these will not be repeated in this procedure. As stated above, **PPL EU will perform the PJM Member Actions captured in PJM's Manual 13**. However, not all the member actions are applicable to PPL EU as a member TO. And as situations are unique and ever changing, the way that PPL EU performs the prescribed actions could be different to promote the best outcome in support of the BES.

5.3. This section contains additional guidance on how PPL EU will complete the PJM Member Actions. This information complements the information in PJM's Manual 13 and will be used by PPL EU Transmission Operations when initiated by PJM. **In addition to the guidance below and the member actions in the PJM manual, TSOs should complete the following for any PJM Manual 13 Advisory, Alert, Warning, or Action that is issued:**

5.3.1. **Notify the TCC Lead**

5.3.2. **Complete the corresponding template/log entry in the Transmission Outage Application (TOA)**

5.3.3. **Complete all required notifications per EU-NERC-CIP-060 and Operating Instruction (OI) 3069**

5.3.4. **Update the System Status application on the Emergency Preparedness SharePoint site**

5.3.5. **Consider requesting an IT Change Freeze**

5.4. This section also contains links to **Action Guides** which provide step-by-step instructions for PPL EU TSOs when completing and implementing these actions in PPL EU's tools (namely the Transmission Management System (TMS) and the TOA). These job aids are specific for the PPL EU TSOs and should be utilized as a checklist to ensure the proper steps are taken for each action.

5.5. Extreme Weather Alerts

5.5.1. Background

5.5.1.1. PPL EU takes proactive measures ahead of extreme weather events to promote system readiness and reliability. As part of internal procedures, the PPL EU Emergency Response Organization (ERO) is engaged to facilitate and expedite the preparation for and response to any abnormalities as part of these events.

5.5.2. Implementation

5.5.2.1. **Cold / Hot Weather Alert** - Ensure the TCC Lead is notified and verify that the Extreme Weather Checklist has been initiated with the on-call ERO.

5.6. Curtailment of Non-Essential Building Load

5.6.1. Background

5.6.1.1. The purpose of the Curtailment of Non-Essential Building Load is to provide additional load relief. PPL EU will respond to this request by switching off all nonessential light and power load in the various business offices and administrative offices of the company per the implementation steps below.

5.6.2. Implementation

5.6.2.1. Notify the TCC Lead to engage the Facilities on-call Building Supervisors who will initiate their Nonessential Company Building Load Curtailment Procedure which includes the following steps:

5.6.2.2. Turn off all area and general lighting except where needed to maintain a safe work environment.

5.6.2.3. Raise or lower set points of non-essential space conditioning equipment while maintaining upper and lower limits of ASHRE Standard 55-1981. Air conditioning used to maintain reliable operation of customer communications and power system control computers and equipment is excluded.

5.6.2.4. Where emergency generators are available to carry a portion of the building load, these should be placed in operation. Excluded are emergency lighting generators and those serving critical computer loads (electrical loads needed to maintain customer communications and power system controls) or safety systems.

5.7. Voltage Reduction

5.7.1. Background

5.7.1.1. A voltage reduction on the BES is a controlled decrease in system voltage, typically 5% or less, used to reduce electricity demand during emergency conditions. This action helps preserve system reliability by lowering load without disconnecting customers. It also supports the high-voltage transmission system by relieving stress on critical equipment and maintaining stable operating conditions during periods of system strain.

5.7.1.2. PPL EU performs voltage reductions at the direction of PJM on its sub-transmission (69kV and 138kV) systems. Voltages are lowered by adjusting the transformers' Tap Changers Under Load (TCULs) at the regional transmission substations. These adjustments at the substations reduce the 69kV and 138kV line voltages and the corresponding voltages at the Distribution substations that are sourced from these lines. The adjustments of the TCULs are initiated by Transmission Operations via Supervisory Control and Data Acquisition (SCADA) via the TMS. Voltage Reduction tests are also performed in accordance with PJM and their Manual 13.

5.7.2. Implementation

5.7.2.1. **Voltage Reduction Action –** See PPL EU TCC Action Guide 1 – Implementing a Voltage Reduction (Confidential)

5.7.2.2. For planned tests of the Voltage Reduction Action, see PPL EU TCC Action Guide 5 – Completing a Voltage Reduction Test (Confidential)

5.8. Load Dump

5.8.1. Background

5.8.1.1. Load dump (shed) is a last-resort action used to preserve the reliability of the BES when system conditions threaten stability and all other corrective actions have been exhausted. PJM may direct manual load dump to TOs or Distribution Providers (DPs) to rapidly reduce demand, aiming to minimize overlap with automatic under-frequency load shedding (UFLS). This controlled interruption of customer load helps prevent cascading outages, supports high-voltage system integrity, and maintains system frequency and voltage within safe operating limits.

5.8.1.2. PPL EU is in PJM's **Mid-Atlantic Control Zone**. Per PJM's Manual 13, only Control Zones that are determined to be deficient will be assigned a share of a load shed request initiated due to RTO capacity deficiencies. If the PJM Mid-Atlantic Region is determined to be deficient, its share will be further allocated according to Attachment E: Manual Load Dump Allocation Tables.

5.8.1.3. **Rotating Load Shed (RLS)** - PPL EU performs load dump at the direction of PJM mainly at the Distribution level, but load can be shed at the transmission level if needed. PPL EU performs load dump via the RLS application within its TMS. RLS sheds the directed amount of load by opening distribution circuit breakers (CBs) via SCADA. The application will then rotate the amount of load shed by opening additional CBs and restoring the initial set of CBs. The RLS application will always maintain at a minimum the amount of load shed that was originally directed.

5.8.1.4. Rotating load shedding distributes the impact of service interruptions across different customer groups for short durations, minimizing prolonged outages for any single area. Another advantage to rotating shed load this way is that it reduces the adverse impacts of cold load pickup. PPL EU rotates its shed load at a rotation period set by Transmission Operations per collaboration with Distribution Operations and other key internal stakeholders.

5.8.1.5. **Load Shed Tables –** The RLS application within the PPL EU TMS sheds load via 6 established tables of Distribution 12kV feeder circuits, 1 table for each of PPL EU's 6 geographical regions. These circuits are identified and added into these tables within the RLS application via collaboration of the Transmission and Distribution Operations teams. The targeted amount of load shed is shared amongst these 6 tables.

5.8.1.6. Per NERC EOP-011 and PJM's Manual 13, PPL EU makes provisions to minimize the overlap of circuits that are identified to be shed via these tables for manual load shed, underfrequency load shed outlined below, and vital facilities (i.e. critical load facilities).

5.8.1.7. Through the advanced TMS RLS application including the established load shed tables, PPL EU meets the requirements and considerations for manual load dump in PJM's Manual 13. This includes the ability to implement **load shed within 5 minutes** via an automated program that can rotate load to reduce the impact to end-use customers.

5.8.1.8. **Vital Facilities (VF) –** PPL EU Operating Instruction (OI) 2180 – Vital Facility Program outlines' PPL EU's process for identifying and reviewing facilities that require special consideration during load shedding situations. The OI includes who performs these reviews for special consideration, examples of vital facilities, and how these facilities are removed from the load shed tables previously described.

5.8.1.9. **Underfrequency Load Shed (UFLS)** - In addition to Transmission Operations manually shedding load via its TMS, load can be shed automatically via underfrequency relays. Under some conditions, frequency decay is too rapid for manual load shedding to be effective. In such cases, automatic load shedding devices can help avert a complete system collapse. Underfrequency relays monitor system frequency and automatically disconnect load when frequency drops below predefined thresholds, helping to arrest further decline and stabilize the bulk electric system during severe generation-load imbalances.

5.8.1.10. Underfrequency relays at PPL EU shed load at the Distribution level. Distribution circuits are analyzed and removed from the UFLS program if they carry vital facilities, per PPL EU's OI 2180. Underfrequency relay installations are distributed over the system with reasonable geographic diversity to ensure that load will be shed uniformly throughout the system. PPL EU's UFLS program is defined in EU-NERC-OPS-036 – PPL EU Underfrequency Load Shed Program.

5.8.1.11. Circuits identified for automatic UFLS can also be shed manually. This ability to shed this load manually provides additional operational flexibility; however, these tables are only utilized when warranted by system conditions. These circuits are included in 3 additional tables within the TMS RLS application, 1 table for each of the different UFLS frequency set points. These tables are **not** *included* to be initially shed by the RLS application by default in support of limiting the utilization of these circuits for manual load shed. These tables could be *included* within the RLS application should system conditions warrant this.

5.8.1.12. **Drills –** PPL EU participates in routine manual load dump drills with PJM.

5.8.2. Implementation

5.8.2.1. **Manual Load Dump Action –** See PPL EU TCC Action Guide 2 – Implementing Manual Load Dump (Confidential)

5.8.2.2. *For planned drills of the Manual Load Dump Action, see PPL EU TCC Action Guide 6 – Completing a Manual Load Dump Drill (Confidential)*

5.9. Interconnection Reliability Operating Limits (IROL) Manual Load Dump

5.9.1. Background

5.9.1.1. Per PJM's Manual 13, PJM identifies specific facilities that if loaded above a designated limit could significantly impact system reliability. Such facilities are not localized constraints, rather wide-area limits that are a result of excessive transfers or an indication of wide-area capacity deficiencies. PJM identifies these IROL facilities in their Manual 13.

5.9.1.2. In addition to system-wide load shed, PPL EU supports the mitigation of IROLs. Load dump may be required to provide loading relief on IROL facilities as a last step to prevent exceeding an IROL limit for 30 minutes.

5.9.1.3. When a load dump action is directed for an IROL that PPL EU is a part of, PPL EU will use the multiplier in the IROL Load Dump Table in PJM's Manual 13 and the Load Shed Calculator within the PPL EU TMS to calculate the amount of load to dump.

5.9.2. Implementation

5.9.2.1. **IROL Load Dump Action –** See PPL EU TCC Action Guide 3 – Implementing an IROL Load Dump (Confidential)

5.9.2.2. *For planned drills of the IROL Load Dump Action, see PPL EU TCC Action Guide 7 – Completing an IROL Load Dump Drill (Confidential)*

5.10. Post-Contingency Local Load Relief Warning (PCLLRW)

5.10.1. Background

5.10.1.1. Per PJM's Manual 13, PCLLRWs are issued to provide TOs advanced notice of the potential for load shed in their area. However, **the PCLLRW is not considered a standing Directive to the TO for load shed**. If the contingency for which the PCLLRW was issued occurs, PJM will evaluate the system conditions and then, if needed, issue a Load Shed Directive.

5.10.1.2. When a PCLLRW is issued to PPL EU, the TSOs will work to either develop and potentially implement a switching solution (i.e. radializing or networking load, transferring load, etc.) or work with the PPL EU Distribution System Operators (DSOs) to develop a plan to ensure that sufficient load can be shed to meet the directive should the contingency occur **and** a Load Shed Directive be issued by PJM.

5.10.1.3. **Drills** - PPL EU's TSOs and DSOs perform joint PCLLRW drills routinely.

5.10.2. Implementation

5.10.2.1. **Post Contingency Local Load Relief Warning –** See PPL EU TCC Action Guide 4 – Responding to Post Contingency Local Load Relief Warning (Confidential)

5.10.2.2. For planned drills of Post Contingency Local Load Relief Warnings, see PPL EU TCC Action Guide 8 – Completing a Manual Load Dump Drill (Confidential)

6. REFERENCES

6.1. EU-NERC-CIP-060 – PPL EU NERC Event Response and Reporting

6.2. EU-NERC-OPS-036 – PPL EU Underfrequency Load Shed Program

6.3. Operating Instruction 2180 – Vital Facility Program

6.4. Operating Instruction 3069 – Outline of the Transmission Operations Executive Summary

6.5. PJM Manual 13: Emergency Operations

6.6. System Operating Procedure (SOP)-0018 – Notification Guidelines

7. REGULATORY REQUIREMENTS

7.1. This procedure complies with and supports the PPL EU NERC Compliance Program.

7.2. This procedure is reviewed at least once per calendar year and facilitated by the PPL EU NERC & FERC Compliance Group.

7.3. This procedure is in support of PA PUC Code 57.52.

8. TRAINING

8.1. These procedures are trained during the Initial Training Program (ITP) for Transmission System Operators (TSOs). Drills and tests of these procedures are also performed periodically to ensure readiness and familiarity.

8.2. Procedural updates are shared amongst Transmission Operations personnel, and significant changes are trained on by the TSOs per NERC training requirements.

9. COMPLIANCE AND EXCEPTIONS

9.1. All PPL employees and contractors are expected to fully comply with this procedure.

9.2. Exceptions to this procedure need written approval in advance from the PPL EU VP and COO Transmission & Substations or CIP Senior Manager.

9.3. Report any concerns with adherence to this procedure to the PPL EU NERC Compliance Officer, PPL EU NERC CIP Senior Manager, Mgr. – NERC & FERC Compliance or a member of the NERC & FERC Compliance Group.

10. ATTACHMENTS

All Action Guides are considered confidential.

10.1. PPL EU TCC Action Guide 1 – Implementing a Voltage Reduction
10.2. PPL EU TCC Action Guide 2 – Implementing Manual Load Dump
10.3. PPL EU TCC Action Guide 3 – Implementing IROL Load Dump
10.4. PPL EU TCC Action Guide 4 – Responding to Post Contingency Local Load Relief Warning
10.5. PPL EU TCC Action Guide 5 – Completing a Voltage Reduction Test
10.6. PPL EU TCC Action Guide 6 – Completing a Manual Load Dump Drill
10.7. PPL EU TCC Action Guide 7 – Completing an IROL Load Dump Drill
10.8. PPL EU TCC Action Guide 8 – Completing a Post Contingency Local Load Relief Warning Drill

11. RECORD RETENTION

11.1. Record retention is consistent with the PPL Corporation Records Management Retention Schedule.

11.2. These processes generate the following records of evidence of compliance:

11.2.1. Dated Operating Plan(s) with revision history
11.2.2. Operator Logs from Emergencies
11.2.3. Voice recordings from Emergencies
11.2.4. Dated Load Shed Plan(s) with revision history
11.2.5. Operator logs from Load Shedding
11.2.6. Voice recordings from Load Shedding

11.3. Any records on litigation hold must be retained until instructed otherwise.

12. PROCESS CONTROLS

12.1. Procedural review and approval – Preventative Control.

12.2. Process performed by and reviewed by Subject Matter Experts – Preventative Control.

12.3. Process documentation reviewed annually by PPL NERC & FERC Compliance Group – Preventive Control

13. REVISION HISTORY

Prepared by:	Ryan Rhody Ryan Rhody (Dec 30, 2025 08:59:01 EST)
	Ryan Rhody TCC Supervisor
Reviewed by:	Benjamin Hreha
	Ben Hreha TCC Supervisor
	Michelle Longo (Dec 30, 2025 07:47:59 EST)
	Michelle Longo Manager – NERC & FERC Compliance
Approved by:	Steven Buonomo Steven Buonomo (Dec 29, 2025 15:44:29 EST)
	Steven Buonomo Sr. Mgr. – Transmission Operations

Revision	Date	Revision Comments
1	5/18/2007	1. Changed references from "Spinning Reserve" to "Synchronized Reserve" to reflect changes to PJM Manual 13. 2. Updated contact information for Manager - T&D Operations and Vice President - PPL Electric Utilities. 3. Various minor grammatical and spelling corrections. 4. Added Section 1O detailing revision history.
2	6/1/2007	1. Added Section 1O - Document Review Frequency. 2. Rev History moved to Section 11.

3	8/8/2008	1. Minor grammar corrections throughout document. 2. Changed "Customer Contact Center" to "System Dispatch Group" in Section 8. System Dispatch has primary responsibility for notifying interruptible customers when events are initiated. 3. Revised the internal processes for Interruptible customers based on incident occurring June 10, 2008. Added structure and verification steps to the process and made each potential Interruption event a separate attachment to this procedure. (Removing and revising old attachments as required.) 4. Made TSO and System Dispatch ELCP worksheets each a separate attachment to this procedure to ensure positive control over changes made to those documents.
4	10/17/2008	1. Added additional steps to Attachments "A" and "C" to make it clear that customer calls are required at the end of an Emergency Interruption. 2. Added "Voltage Reduction Warning and Reduction of Non-Critical Plant Load" step back into Attachment "H". It had been inadvertently deleted. 3. Added language to Section 1 A – Objectives to align TSO responsibilities with delegated PJM responsibilities. 4. Minor grammar and spelling corrections.
5	11/3/2008	1. Added wording to direct TSO's to inform PJM in the event directed actions were impossible or inadvisable to take. 2. Added description of required actions for Post-Contingency Local Load Relief Warnings (PCLLRW's) and added worksheet for same to Attachment "H".
6	1/15/2009	1. In Section 1, enumerated all PJM roles (BA, RC and TOP) for which they have authority to direct Company actions. 2. Ensured this manual is in compliance with most recent revision of PJM Manual 13 – Emergency Operations. (Revision 35, effective 11/7/2008)
7	6/1/2009	1. In Section 10, added the requirement to inform affected parties of all revisions to this document via e-mail sent to the ELCP notification distribution list. 2. In Attachment "A", added verbiage "by PJM" to match instructions on System Dispatch checklist for Emergency Interruptions. 3. In Attachment "F", reformatted to link Communication Drills to the PJM ELCP drills. Fleshed out the requirements accordingly. (PJM ELCP drills include Emergency Interruptions of Interruptible customers.) 4. In Attachment "G", added steps to System Dispatch Checklist to reflect linking communication drills to the PJM ELCP drills. 5. In various TSO worksheets, added blocks in the tables to track notifications that were required, but had not been tracked.

		(NUG's, ICS, etc.) 6. Ensured this manual is in compliance with most recent revision of PJM Manual 13 – Emergency Operations. (Revision 36, effective 1/30/2009)
8	8/19/2009	1. In Section 2, Page 8, corrected Heading "J" to read "C1 Message #1 for Cold Weather". 2. Ensured this manual is in compliance with most recent revision of PJM Manual 13 – Emergency Operations. (Revision 37, effective 6/30/2009 – issued 7/30/2009)
9	10/20/2009	1. Added sections for IROL Load Dump Warning and High Voltage / Low Load Action 2. Added TSO worksheets for the above steps and IROL Load Dump Action to Attachment "H". 3. Moved PCLLRW worksheet and descriptions to the "Warnings" section rather than the actions sections. 4. Ensured this Manual is in compliance with most recent revision of PJM Manual 13 – Emergency Operations. (Revision 38, effective 10/05/2009) 5. Added "Document Approvals" Section
10	12/10/2009	1. Removed references to "T&D Operations" and replaced with "Transmission Operations" 2. Changed initiators of Economic Interruptions from "Energy Marketing Center" to "Energy Acquisiton group" throughout the document. 3. Removed all references to "Demand Free Day Cancellations". This program no longer exists as of 1-1-10. Changed Attachment "E" from "Process to implement a Demand Free Day Cancellation" to "Process to implement a PJM ILR test of Interruptible Customers" 4. Changed references from "Emergency Interruption" of Interruptible customers to "PJM ILR" to match changed PJM terminology for this type of interruption 5. Added wording in Attachments "A" through "F" to require completion of Attachment "G" for those procedures. 6. Added references in Attachment "G" back to Attachments "A" through "F"

11	6/1/2010	1. Removed page for "Demand Free Day Cancellations" from Attachment "H". It had inadvertently not been deleted with Revision 10 updates. 2. Ensured this Manual is in compliance with most recent revision of PJM Manual 13 – Emergency Operations. (Revision 39, effective 01/01/2010) 3. Changed formatting of Figures 8.2 and 9.1 to make updates easier, and updated contact process to reflect what is currently done. 4. Removed Tables 6.1 – 6.5. These tables specified the amount of load to be dropped in each region for a loadshedding event. As we added a 6th region (Central) to the loadshed tables, the values changed. Additionally, as more circuits are added annually, the tables would require constant adjustment. A current copy of the schedules can be obtained, if needed, from the TMS system.
12	8/25/2010	1. Ensured this Manual is in compliance with most recent revision of PJM Manual 13 – Emergency Operations. (Revision 40, effective 08/13/2010) 2. Added "Date" space to Main Page of TSO ELCP Worksheets (Attachment "H"). 3. -Added hyperlinks to individual pages for the TSO ELCP Worksheets (Attachment "H").
13	12/2/2010	1. Ensured this Manual is in compliance with most recent revision of PJM Manual 13 – Emergency Operations. (Revision 41, effective 10/01/2010) 2. Added Heavy Load Voltage Schedule Warning (Attachment "H"). 3. Changed "System Development and Technical Support" to "Protection and analysis" 4. Changed "SUPERVISOR- TRANSMISSION NOTIFICATIONS" to include Dave Bonenberger, GM- Transmission Operations and Mike DeCesaris, Mgr-Transmission Operations 5. Changed all references of "Power System Dispatcher" and "PSD" to "TSO" and "TSO"
14	8/10/2011	1. Removed reference to Economic Interruptions including related attachments B, C, and D.
15	10/17/2011	1. Included attachments E and F into attachment A and various spelling corrections.

16	12/17/2012	1. Reformatted document for consistency which updated some section numbers. 2. Revised Service Dependency definitions to reflect addition of Vital Facilities and elimination of Service Dependency Classifications C, D & E. 3. Revised Hot and Cold Weather Alerts to reflect changes to PJM M-13. 4. Removed references to PPL Interruptible Service Rates and inserted PJM Load Management Reductions were applicable. 5. Updated Table 8-1 and added reference to EU-NERC-CIP-060. 6. Added section for records retention. 7. Added header for Attachment B.
17	5/15/2013	1. Annual Review of entire procedure, including consistency with PJM Manual 13 – Emergency Operations, Revision 52 Effective 2/1/2013) 2. Added reference to Vital Facility Program, OI 2180. Changed all references from Service Dependency to Vital Facility. 3. Removed all references and attachments (A, G) concerning Emergency Interruptions directed by PJM as PPL EU no longer has customers under this definition. 4. Updated Attachment B as PPL no longer has any Economic Interruptible customers. Corrected Title of Document Approver.
18	4/16/2014	1. Annual Review of entire procedure, including consistency with PJM Manual 13 – Emergency Operations, Rev 55, Effective 1/1/2014. 2. Section 1.1 - Added summary of actions from manual. 3. Section 1.5 5 – Added note that Corp Communications will notify Trans Operations of Public Appeal decision. 4. Section 3.7 – added new IROL facilities from to match PJM M37, Section 3.1. 5. Corrected reference - Figure 9-1 to 8-1. 6. Section 8.5 – Added note on Corp Communications role. 7. Section 11 – Updated job titles, changed reviewer and approver. 8. Errata changes.
19	10/31/2014	1. Annual Review of entire procedure, including consistency with PJM Manual 13 – Emergency Operations, Rev 56. Moved to Q4 to coincide with PJM M1 Attachment B submittal date. 2. PCLLRW – added DCC notification time and PJM Load Shed Directive time 3. Voltage – Updated notice to PaPUC by DSO and for TSO to follow procedure EU-NERC-CIP-060 for reporting. 4. Changed reference from Webpage ELCP Banner to Desktop ELCP Banner

20	2/27/2015	1. Annual Review of entire procedure, including consistency with PJM Manual 13 – Emergency Operations, Rev 57. Moved back to Q1 to coincide with PJM M1 Attachment B submittal date. 2. Section 3.7 removed Kammer and Belmont transformers. 3. Attachment H-Updated PCLLRW tool to reflect changes to use PJM tool.
21	2/24/2016	1. Annual review of entire procedure. 2. Section 1 1.6 - Removed references to Table 4 & 1.8 All Call communications 3. Section 6.2 & 6.3 - Removed references to table 4. 4. Errata changes throughout the document 5. Section 6.8 & 7.2 removed references to UGI
22	2/28/2017	1. Annual review of entire procedure. 2. Section 1 Removed requirements for UF, customer curtailment & Load Management for T-Ops. 3. Page 13-Changed header for Program Title Chart 4. Section 2 added Advisory to header 5. Section 2.4 Removed SSR and replaced with RRC 6. Removed canned messages for Hot and Cold weather alerts and actions sections 3.9, 3.10, & 4.10. 7. Section 5.1 removed TV and Radio appeals section. 8. Section 7.4 Removed reference to MWF & ICS and replaced Distribution Operations and Customer Service. 9. Remove activation of ECC banner Attachment H for High System Voltage/Low Loads. 10. Removed references/actions to generating stations throughout document.
23	10/30/2025	1. Complete review of entire procedure during PPL Procedure summit. 2. Refreshed entire procedure to better align with the latest version of PJM's Manual 13 and PPL EU's latest tools and procedures. 3. Reformatted procedure to better align with PPL EU NERC Compliance Program. 4. Added PPL EU TCC Action Guides as job aids for PPL EU's TSOs. 5. Errata changes throughout.
24	12/31/2025	1. Added additional details throughout to document PPL EU's Emergency Operating Plan in support of EOP-011. 2. Updated PPL EU TCC Action Guides as job aids for PPL EU's TSOs. 3. Errata changes throughout.