Letter of Notification of PPL Electric Utilities Corporation for Approval to Construct the Susquehanna - Harwood 230 kV Transmission Line Taps Located in Luzerne County, Pennsylvania In-Person Evidentiary Hearing	Docket No.: A-2025-3059443

Pages 565 - 775

Hearing Room 4, Plaza Level

Commonwealth Keystone Building

400 North Street

Harrisburg, PA

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Docket No. A-2025-3059443

Hearing Date: September 18, 2026

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania	:	Docket No. A-2025-3059443

OCA HEARING EXHIBIT NO. 1

LIST OF EVIDENCE TO BE MOVED INTO THE EVIDENTIARY RECORD BY THE OFFICE OF CONSUMER ADVOCATE

The Office of Consumer Advocate (OCA) intends to submit the following evidence into the evidentiary record in the above captioned proceedings at the scheduled evidentiary hearings in this proceeding.

DIRECT TESTIMONY

OCA Statement No. 1: Direct Testimony of Frank A. Felder, Ph.D. consisting of written testimony with signed verification of Frank A. Felder, Ph.D., Principal, Independent Electricity Consultants LLC, and the following:

- Exhibit FF-1
- Verification of Frank A. Felder, Ph.D.

OCA Statement No. 2: Direct Testimony of Rao Konidena consisting of written testimony with signed verification of Rao Konidena, President, Rakon Energy LLC, and the following:

- Exhibit RA-1
- Verification of Rao Konidena

CONFIDENTIAL

OCA Statement No. 2: CONFIDENTIAL Direct Testimony of Rao Konidena consisting of written testimony with signed verification of Rao Konidena, President, Rakon Energy LLC, and the following:

- Exhibit RA-1
- Verification of Rao Konidena

HIGHLY CONFIDENTIAL

OCA Statement No. 2: HIGHLY CONFIDENTIAL Direct Testimony of Rao Konidena consisting of written testimony with signed verification of Rao Konidena, President, Rakon Energy LLC, and the following:

- Exhibit RA-1
- Verification of Rao Konidena

SUPPLEMENTAL DIRECT TESTIMONY

OCA Statement No. 3: Supplemental Direct Testimony of Zachary F. Teti, M.S. consisting of written testimony with signed verification of Zachary F. Teti, M.S., Senior Regulatory Analyst, Pennsylvania Office of Consumer Advocate, and the following:

- Verification of Zachary F. Teti, M.S.

SURREBUTTAL TESTIMONY

OCA Statement No. 1SR: Surrebuttal Testimony of Frank A. Felder, Ph.D. consisting of written testimony with signed verification of Frank A. Felder, Ph.D., Principal, Independent Electricity Consultants LLC, and the following:

- Verification of Frank A. Felder, Ph.D.

OCA Statement No. 2SR: Surrebuttal Testimony of Rao Konidena consisting of written testimony with signed verification of Rao Konidena, President, Rakon Energy LLC, and the following:

- Verification of Rao Konidena

ADDITIONAL EXHIBITS

OCA Hearing Exhibit No. 1:	List of Evidence to be Moved into the Evidentiary Record by the Office of Consumer Advocate (OCA)
OCA Cross Examination Exhibit No. _____:	PPL Response to OCA Interrogatory II-7
OCA Cross Examination Exhibit No. _____:	PPL Response to OCA Interrogatory II-8
OCA Cross Examination Exhibit No. _____:	PPL Response to OCA Interrogatory II-9
OCA Cross Examination Exhibit No. _____:	PPL Response to OCA Interrogatory VIII-1
OCA Cross Examination Exhibit No. _____:	PPL Response to OCA Interrogatory II-14
OCA Cross Examination Exhibit No. _____:	PPL Response to OCA Interrogatory II-23
OCA Cross Examination Exhibit No. _____:	PPL Response to OCA Interrogatory X-1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania	:	Docket No. A-2025-3059443

WRITTEN STATEMENT OF OCA WITNESS RAO KONIDENA

In accordance with PPL's and Presiding Officers' requests for a written statement from Mr. Konidena accompanied by signed verification, Mr. Konidena provides the following responses to PPL's questions:

a. A full and complete list of all non-public materials that were disclosed to Claude and the date upon which the disclosure(s) occurred.

RESPONSE: This is the full and complete list of all non-public materials that were disclosed to Claude during the drafting of Mr. Konidena's direct testimony:

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 7, lines 13-16 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA I-1 Attachment 2 and OCA VII-1(a)).
- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 8, lines 1-2 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA VII-1(a)).
- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 11, lines 13-15 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA VII-3(a)).

- OCA Statement No. 2, CONFIDENTIAL information set forth on p. 19, lines 17-18 (citing PPL Responses to OCA VI-1(b) Attachment CONFIDENTIAL).

- OCA Statement No. 2, CONFIDENTIAL information set forth on p. 19, line 20 to p. 20, line 1 (citing PPL Response to OCA VI-1(b) Attachment CONFIDENTIAL).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 63, lines 4 - 8 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA VII-2(b)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 66, lines 5-10 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA XIII-1(a)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 67, line 20 to p. 68, line 1 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA XIII-1(b)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 68, lines 5-10 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA XIII-1(b)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 68, lines 14-16 (citing PPL Reponses to HIGHLY CONFIDENTIAL OCA XIII-1(a), Lines 12-14, Page 7, PPL St. No. 1).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 68, lines 16 (citing PPL Reponses to HIGHLY CONFIDENTIAL OCA XIII-1(b)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 68, lines 18-19 (citing PPL Responses to OCA I-6 Attachment 2 HIGHLY CONFIDENTIAL).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 69, lines 1-2.

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 69, lines 9-10.

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 72, lines 13-15 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA IX-1).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 72, lines 17-18 (citing PPL Response to HIGHLY CONFIDENTIAL OCA XIII-1(a)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 77, lines 4-8 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA IX-1).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 78, lines 10-11 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA IX-1).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 78, lines 13-18 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA XIII-1(a)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 78, lines 20-21 to p. 79, lines 1-4 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA XIII-1(a)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 79, lines 10-11.

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 84, lines 3-5 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA VII-1(d)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 84, lines 7-9 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA VII-2(a)(c)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 84, lines 11-12 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA VII-1(a)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 84, lines 16-17 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA VII-2(d)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 84, lines 19-20 to p. 85, line 1 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA VII-2(d)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 88, lines 18-19 to p. 89, lines 1-2 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA VII-2(d)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 89, lines 8-9 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA VII-2(d)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 97, lines 11-17 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA XIII-1(a)).

- OCA Statement No. 2, HIGHLY CONFIDENTIAL information set forth on p. 104, lines 13-16 (citing PPL Responses to HIGHLY CONFIDENTIAL OCA IX-1).

It is difficult to pinpoint the exact date of disclosure, but, in general, non-public materials were disclosed to Claude during the drafting of Mr. Konidena's direct testimony during May 22-27, 2026 and June 1-3, 2026 and June 14-16, 2026 and June 24, 2026.

b. A full and complete description of the AI service (Claude) used by Mr. Konidena, including but not limited to (i) whether the service is internally housed and segregated by Rakon Energy or if it is open source, (ii) whether the service retains all information provided to it, (iii) whether the service uses such information to train its model for future use, and (iv) whether information provided to the service may be discovered by the general public through their use of the service.

RESPONSE: Mr. Konidena used Claude\Sonnet 5 Medium.

i) This Claude\Sonnet 5 Medium is internally housed and segregated by Rakon Energy. It is not open source.[1] It is "Pro Plan."

ii) No, the service does not retain the information.[2]

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[1] Please see Claude's response when asked "Are you open source?" – response – "No, I'm not open source. Claude is developed by Anthropic, and my underlying model — the weights, training process, and code — isn't publicly released the way an open-source project would be.

A few relevant things, though:

Anthropic does publish research papers, safety findings, and some tools/frameworks related to AI development.
I'm accessible via API and various Anthropic products (claude.ai, Claude Code, etc.), but that's usage access, not access to the underlying model itself.
Anthropic has talked publicly about its general approach to AI safety and alignment, if you're curious about the philosophy behind how I'm built, even though the model itself isn't open.

Is there something specific you're trying to figure out — like comparing me to open-source models for a project, or wondering about data/privacy implications?".

[2] Please see Claude's response when asked, "Do you retain all the information provided to you?". Claude's response was, "It depends on what you mean by "retain":

Within this conversation: Yes, I have access to everything you've told me in this chat (including your earlier questions about Tomhicken and Sugarloaf) for as long as this conversation continues.

Across conversations: No, not by default. Once this conversation ends, I won't remember it unless you've enabled Claude's memory feature in Settings — and based on your first question, it looks like that's not turned on for you. With memory off, each new conversation starts with a blank slate.

Behind the scenes (data handling): That's a separate question from what I can "recall," and it's really an Anthropic policy matter rather than something about my own memory. Broadly:

Conversations may be used to improve Anthropic's models unless you've opted out, depending on your account type and settings.
Retention periods and data handling differ for consumer accounts vs. API/business usage.
I don't have visibility into backend logging, retention windows, or deletion policies — I only know what I can access in the moment I'm responding to you.

If you want precise, current answers on data retention or training-use policy, I'd point you to Anthropic's actual Privacy Policy and Terms rather than relying on me — I want to be upfront that I could get details wrong or out of date. Want me to search for their current policy?"

iii) No. Under "Settings\Privacy" – "Help Improve our AI models" is disabled.[3]

iv) No, conversations are not shared with general public.[4]

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[3] Please see Claude's response when asked whether it retains information to train models? Claude's response was "I don't have direct visibility into this myself — it's not something I can check or verify from inside a conversation. But here's what's generally true based on Anthropic's public policies:

Consumer accounts (claude.ai Free/Pro/Max): By default, conversations may be used to help train future models, but you can opt out via Settings → Privacy → "Help improve Claude" (or similar wording — it's changed over time).
API, Claude for Work, Team, and Enterprise accounts: Generally not used for training by default, since these have stricter data-use agreements.
Even when data is used, Anthropic has stated it applies safeguards like de-identification for training purposes.

Since policies do get updated, and I can't confirm your specific account settings or the current fine print, I'd trust Anthropic's actual Privacy Policy over my summary here. Want me to search for the current version so you get the exact, up-to-date wording?"

[4] Please see Claude's response when asked whether past, present or future conversations are shared with general public? – Claude's response was, "Good question, and an important one. Let me be careful and precise here rather than guessing.

Short answer: Not by default, but there are some caveats worth knowing.

Your conversations aren't public. Claude conversations are private to your account — they're not searchable or viewable by other users, and they don't appear on the open web.
Anthropic employees/systems may access data in limited circumstances — e.g., for abuse monitoring, safety review, or (if you haven't opted out) model training — but that's internal access, not public discoverability.
Shared links are the exception. If you or Anthropic (via a feature like "share this conversation") generate a public link to a chat, that specific conversation becomes accessible to anyone with the link. That's opt-in, not automatic.
Legal process (subpoenas, court orders) could in theory compel disclosure of data, as with most tech companies — this isn't "public" but it's a form of external access.
Security incidents (breaches) are always a theoretical risk with any online service, though not something specific to how Claude works.

Since data handling and privacy policy specifics are exactly the kind of thing that can change and where I don't want to give you stale or approximate info, let me pull the current, official policy so you have precise wording rather than my paraphrase.

I found some useful context — let me pull directly from Anthropic's official privacy page to give you the accurate current picture rather than relying on third-party summaries.

Here's the accurate, current picture based on Anthropic's official Privacy Center:

Your conversations are not made publicly discoverable in the normal course of things. There's no mechanism by which random people can search or browse other users' Claude chats. But here's what actually happens to your data:

Training (consumer accounts — Free/Pro/Max):

Since September 2025, Anthropic uses an opt-in model: you choose in Settings → Privacy whether your conversations can be used to improve Claude.
If you opt in, conversations are retained in a de-identified/aggregated form for 5 years and used to improve Claude.

c. A full and complete description of the corrective actions that Mr. Konidena has implemented or will implement to ensure that future violations of a Protective Order related to the use of AI will not occur in other proceedings, and specifically in the Sugarloaf Siting Application where he has been retained as a witness.

RESPONSE: Mr. Konidena has deleted the memory[5] of Claude\Sonnet 5 Medium from Settings\Memory. Mr. Konidena has ensured that "Search and reference chats" and "Generate memory from chats" is also disabled. Finally, Mr. Konidena will not paste any materials from the Sugarloaf Siting Application in Claude\Sonnet 5 Medium.

d. Any other information Mr. Konidena believes is relevant to the violation and/or actions he has taken to correct it.

RESPONSE: None.

Claude
If you opt out (or don't opt in), standard retention is 30 days, with no training use.
Claude
Even when used for training, this isn't "public" — it's Anthropic's internal process, and outputs go through de-identification. It's theoretically possible (as with any LLM) that patterns from training data could indirectly influence outputs, but this is not the same as your raw content being published or searchable."

[5] As confirmation, please see this response from Claude when Mr. Konidena asked "do you have any memory of Tomhicken project?" – Claude's response – "I don't have any memory of a "Tomhicken project" — I don't actually have persistent memory across conversations unless the memory feature is turned on in your settings, and it looks like it isn't enabled for you right now (I don't have access to any stored memories from past chats).

So each conversation I have starts fresh — I wouldn't retain anything from a previous session unless you share it with me here.

If you want, you can:

Tell me about the Tomhicken project now and I can help with whatever you need
Check if you have it referenced in a past conversation you can find in your chat history
Turn on memory in Settings if you'd like me to start remembering things across conversations going forward

What's the project about?".

Also, please see this Claude's response when Mr. Konidena asked, "do you have any memory of Sugarloaf project" – Claude's response was "Same answer, I'm afraid — no memory of a "Sugarloaf project" either. As I mentioned, I don't have persistent memory across conversations unless that feature is enabled in your settings, and it doesn't look like it is right now.

If Sugarloaf and Tomhicken are related projects you've discussed with me before, that context would be in an earlier conversation rather than something I can recall here. You could look back through your chat history to find it, or just fill me in and I'll pick it up from there." Both these responses confirm that any Memory is deleted.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania	:	Docket No. A-2025-3059443

VERIFICATION

I, Rao Konidena, hereby state that the facts above set forth in this written statement are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. Section 4904 (relating to unsworn falsification to authorities).

DATED: September 18, 2026

Signature: Rao Konidena

Rao Konidena

Address: Rakon Energy LLC
Roseville, MN 55113

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Build Approximately 1.1 Miles of New Parallel Double Circuit 230 kV Transmission Taps that are Needed to Connect the Existing Susquehanna-Harwood #1 & #2 Transmission Lines on the New Tomhicken 230 kV Switchyard that are Respectively Located in Luzerne County, Pennsylvania	:	Docket No.: A-2025-3059443

DIRECT TESTIMONY

OF

Frank A. Felder, Ph.D.

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Date Served: July 8, 2026

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Introduction

Q. Please state your name and business address.

A. My name is Frank A. Felder, and my business address is 1855 Saint Francis Street, #1612, Reston, VA, 20190.

Q. By whom are you employed and in what capacity?

A. I am a Principal at Independent Electricity Consultants LLC.[1]

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to identify and describe the applicable public policy issues of reliability and affordability in this matter and how they can be addressed in the context of the interconnection of large loads to the electric power system. I am providing testimony at the request of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. Have you previously provided testimony before the Pennsylvania Public Utility Commission?

A. I have not previously provided testimony before the Pennsylvania Public Utility Commission ("Commission").

Q. What are your qualifications to provide this testimony in this case?

A. I am a long-standing consultant and former professor whose research, teaching, and consulting have centered on the engineering, economics, and public policy of electricity markets in the U.S. and internationally. From 2004 to 2020 I was an Assistant, Associate, and Research Professor of the Bloustein School of Planning and Public Policy, at Rutgers University, New Jersey. I also directed the Center for Energy, Economic and Public Policy and the Rutgers Energy Institute. In both capacities, I led research and teaching initiatives on the power sector including numerous studies for the New Jersey Board of Public

[1] https://www.independentelectricityconsultants.com/.

Utilities. As a consultant, I have advised every sector of the power industry – utility generation, independent power producers, Regional Transmission Organizations/Independent System Operators ("RTOs/ISOs"), transmission utilities, non-utility transmission developers, distribution utilities, retail load aggregators/electric generation suppliers, public utility commissions, and federal and state government agencies on the topics of reliability, electricity markets and regulation, electricity policy, and economic development. I also have extensive international experience in electricity markets and in training industry professionals.

Since April 2024, I have been engaged by the OCA to assist it with its filings for the Commission's Distributed Energy Resource and Large Load Model Tariff proceedings.[2] Since August 2025, I have also been engaged by the OCA on matters relating to large loads and the PJM Interconnection ("PJM"), the power system operator, wholesale market administrator, and transmission planner for the Mid-Atlantic region, which includes Pennsylvania.[3] I have been involved in PJM's several and extensive stakeholder processes since September 2025 aimed at addressing the challenges large loads pose to the bulk power system (generation and transmission) and wholesale electricity markets.

I hold a Ph.D. in Technology, Management, and Policy and a master's in science in Technology and Policy from the Massachusetts Institute of Technology, and a bachelor's in science in applied mathematics and a bachelor's in arts in mathematics from Columbia University.

Please see Exhibit 1, Frank A. Felder, curriculum vitae, for additional information.

[2] Pennsylvania Public Utility Commission, Distributed Energy Resources Participation in Wholesale Markets, Docket No. L-2023-3044115, and Pennsylvania Public Utility Commission, Interconnection and Tariffs for Large Load Customers, Docket No. M-2025-3054271.
[3] https://www.pjm.com/about-pjm.

Q. Have you prepared Exhibits to accompany your testimony?

A. Yes. Exhibit 1 is my curriculum vitae.

Summary

Q. Please summarize your conclusions and recommendations.

A. I find the following:

Matters of Fact

1. The massive and rapid build-out of data centers and AI facilities is resulting in substantial ongoing and expected increases in electricity demand in Pennsylvania and the Mid-Atlantic region.
2. This ongoing and expected increase in electricity demand risks reductions in the reliability of the electric power system.
3. This ongoing and expected increase in electricity demand is shifting the electricity-related costs caused by large loads to ordinary ratepayers.
4. Federal and Pennsylvania policies affirm that large loads should not reduce the reliability of the electric power system.
5. Federal and Pennsylvania policies are that large loads pay for their costs, not ordinary ratepayers.
6. The PPL Electric Utilities Corporation ("PPL") electric distribution tariff does not have provisions that protect non-large load ratepayers from the reliability reductions and cost shifting that federal and Pennsylvania policies are aimed at preventing.

Matters of Policy

7. There is a policy gap between federal and Pennsylvania policies and the PPL tariff.

8. This policy gap can be filled by modifying the PPL tariff with the following six provisions:
    a. Large Load Registry
    b. Large Load New Supply
    c. PJM Reliability Backstop Procurement ("RBP") Cost Allocation
    d. Large Load Cost Allocation/Expansion Rate Policy and Stranded Costs Protections
    e. Large Load Credit and Collateral
    f. Large Load Curtailment
9. These six provisions assign any costs to cost-causing ratepayers and not to non-cost-causing ratepayers.

I. Description of the Proposed Project and Issues

Q. Please summarize your understanding of proposed project.

A. PPL submitted a Letter of Notification ("LON") requesting that the Commission approve the construction of approximately 1.1 miles of new double-circuit 230 kilovolt ("kV") transmission taps ("Tap Lines") that are needed to connect the existing Susquehanna-Harwood #1 & #2 230 kV Transmission Lines to the new Tomhicken 230 kV Switchyard (the "Project").[4] The Project also includes the construction of two new 0.1-

[4] Letter of Notification of PPL Electric Utilities Corporation Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Build Approximately 1.1 Miles of New Parallel Double Circuit 230 kV Transmission Taps that are Needed to Connect the Existing Susquehanna-Harwood #1 & #2 Transmission Lines on the New Tomhicken 230 kV Switchyard that are Respectively Located in Luzerne County, Pennsylvania, Docket No. A-2025-3059443, June 15, 2026. Hereafter "LON".

mile-long 230 kV transmission lines ("Connecting Lines") from the Tomhicken 230 kV Switchyard to a new customer-owned 230-34 kV substation.[5]

Q. What is the stated immediate need for the Project?

A. PPL submits that the Project is immediately needed to serve one new customer ("New Customer") based upon its request for 230 kV electrical service by March 2027. According to PPL's direct testimony, the New Customer's load ramping schedule will increase in stages from an initial load of 12 megawatts ("MW") to approximately 276 MW by December 2027, and approximately 965 MW by 2033.[6] In his direct testimony, Mr. Rao Konidena provides additional information regarding the size and timing of the New Customer's facility. For the purposes of my testimony, what is critical is that the New Customer's project is large and phased in over time. My understanding is that this New Customer is a Data Center.

Q. According to PPL, will the Project be needed for future customers?

A. Yes. PPL claims that the Project, along with a second phase (Docket No. A-2026-3061547), will be needed to address both the New Customer's future needs as well as those of future customers and PPL's system needs.[7]

[5] Direct Testimony of Joseph Lookup, Statement No. 1, Docket No. A-2025-3059443, May 13, 2026, page 2, lines 2-9.
[6] Direct Testimony of Joseph Lookup, Statement No. 1, Docket No. A-2025-3059443, May 13, 2026, page 3, lines 18-23.
[7] PPL Electric Utilities Corporation, Statement No. 1, Direct Testimony of Joseph Lookup, Statement No. 1, Docket No. A-2025-3059443, May 13, 2026, page 4, lines 5-10.

II. Public Policy Issues

A. Overall Context of Large Loads and Data Centers

Q. Please describe the overall context regarding large loads and data centers in Pennsylvania and the region.

A. Pennsylvania, the region that includes PJM, and the United States are experiencing a dramatic increase in electricity demand driven primarily by new, large loads that are almost exclusively data centers.[8] The head of Exelon, the largest U.S. utility by customer count, has warned that the U.S. could face blackouts starting in 2027 due to AI and that electricity bill increases are needed to fund new infrastructure.[9] These large loads are physically connected to an electric distribution company ("EDC"), such as PPL, which is connected to the transmission system that PJM operates. They consume large amounts of electricity and are growing both in size and in number.[10] PJM forecasts summer peak load growth of 3.6% per year for the next 10 years and 2.4% for the next 20 years, resulting in a 10-year increase of 65,733 megawatts ("MW") and a 20-year increase of 96,704 MW, driven almost exclusively by data centers.[11] PJM forecasts approximately 30 gigawatts ("GW") of new load from data centers between 2025 and 2030.[12] For instance, in May

[8] NERC, Large Loads Task Force White Paper, Characteristics and Risks of Emerging Large Loads, July 2025, p. 2, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf,"Emerging large loads have grown substantially in recent history, and forecasts that data centers alone may account for as much as 12% of all U.S. electricity consumption by 2028 (up from 4.4% in 2023)."

[9] Martha Muir, Financial Times, Utility boss warns US faces blackouts due to power supply shortfall, June 27, 2026, https://www.ft.com/content/14d2e591-7cd5-4456-904f-1b7fdc5cbc1a?syn-25a6b1a6=1.

[10] McKinsey & Company, Scaling bigger, faster, cheaper data centers with smart designs, August 1, 2025, https://www.mckinsey.com/industries/private-capital/our-insights/scaling-bigger-faster-cheaper-data-centers-with-smarter-designs.

[11] PJM, 2026 PJM Load Forecast Report, January 14, 2026, p. 6, https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf. See also Modo Energy, Data centers define PJM's 2046 load forecast, undated, https://modoenergy.com/research/en/pjm-load-forecast-data-centers-2046.

[12] PJM Inside Lines, 2025 Year in Review: Planning Prepares for Burgeoning Electricity Demand, January 8, 2026, https://insidelines.pjm.com/2025-year-in-review-planning-prepares-for-burgeoning-electricity-demand/. Also see Modo Energy, Data centers define PJM's 2046 load forecast, undated, https://modoenergy.com/research/en/pjm-load-forecast-data-centers-2046, which, using PJM data, finds "The large load component, principally data center

2026, PPL announced that its data center pipeline had increased to 28.3 gigawatts ("GW") by 2034 up from 25.2 GW three months earlier.[13] As a point of comparison, 1 GW, which is the equivalent of 1,000 MW, is the size of a very large power plant. As another point of comparison, PJM's peak demand in 2025 was 161 GW.[14]

For ease of explanation, I use the term *large load* generically to refer to data centers and AI facilities. I recognize that there are more specific definitions of large loads used by different organizations. Where appropriate, I refer to those specific definitions and use the capitalized term *Large Load*.

Q. What are the public policy challenges related to the electric power system due to the rapid and substantial deployment of large loads?

A. Large loads can contribute to national security and economic development. Their public acceptability, presumably, depends, in part, on the ability to address two key public policy issues: reliability and affordability.[15]

additions, accounts for more than 100% of peak demand growth over the next five years as base demand contracts. PJM's large load adjustments grow by 35.1 GW between 2026 and 2031, against total demand growth of 34.6 GW. Beyond 2031, the balance shifts slightly. The base layer begins to contribute and data center additions decelerate, but remain dominant."

[13] Ethan Howland, Utility Dive, PPL 'advanced' data center pipeline grows to 28.3 GW in Pennsylvania, May 11, 2026, https://www.utilitydive.com/news/ppl-data-center-pipeline-pjm-blackstone-earnings/819804/. See PPL Electric Utilities Corporation, Response to the Set II Data Requests of the Office of Consumer Advocate (OCA), Docket No. A-2025-3059443, Joseph B. Lookup, OCA II-8, March 27, 2026, "Large load adjustments, per the 2026 PJM Load Report is as follows: 2026: 189 MW, 2027: 394 MW, 2028: 1,274 MW, 2029: 1,876 MW, 2030: 4,996 MW. PJM issues the load report, which includes the large load adjustments, based on utility. To the extent that "organic load growth" means non-large load customer load growth, the Company is not anticipating any significant load growth over the next five years. '

[14] PJM, Summer 2025 Weather Normalized RTO Coincident Peaks (MW), November 4, 2025, https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2025-peaks-and-5cps.pdf?ref=blog.gridstatus.io.

[15] Rachel Mural, Dipesh Pherwani, Chaitanya Gupta, Yiqi Yu, Ai Takahashi, Dongjoo Kim, Subir Majumder, Henry Lee, Minlan Yu, and Le Xie, AI, Data Centers, and the U.S. Electric Grid: A Watershed Moment, February 2026, p. 2, https://www.belfercenter.org/sites/default/files/2026-02/Mural%20et%20al_AI%20Data%20Centers%20Grid_20260206.pdf, "While overregulation could hinder AI development, insufficient regulation risks grid instability, rising consumer costs, reliance on high-emission energy sources, public backlash, and setbacks to state and corporate climate goals."

Regarding reliability, if large loads are added to the electric power system without sufficient new supply to serve them or without meaningful policies to curtail their electricity consumption during times of supply shortages, then the reliability, specifically the resource adequacy, of the system will be degraded.[16] This degradation could result in mandatory load shedding of ordinary ratepayers, such as residential customers. As more load is added to PJM that is not sufficiently supplied or curtailable, the frequency, magnitude, and duration of potential mandatory load-shedding events increase.

The second public policy challenge is affordability. The rapid connection of massive amounts of large loads has the potential to increase wholesale market prices for energy, capacity, and ancillary services,[17] and increase transmission and distribution rates. With proper transmission and distribution rate design, however, it is possible (but not guaranteed) to protect non-large load customers from transmission and distribution rate

[16] See PPL Electric Utilities Corporation, Response to the Set II Data Requests of the Office of Consumer Advocate (OCA), Docket No. A-2025-3059443, Joseph B. Lookup, OCA II-23, March 27, 2026, "Resource adequacy is required for Electric Distribution Companies ("EDCs") to provide reliable service, however, EDCs cannot own generation to ensure resource adequacy." The Necessity Statement, Attachment 1 to the LON, on page 5, states the following: "PJM then studies the proposed solution to ensure that the changes do no harm (DNH test) to the system by creating overloads, voltage violations, or other criteria violations."
NERC, Large Loads Task Force White Paper, Characteristics and Risks of Emerging Large Loads, July 2025, p. 16, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf. Large loads also have important implications for operational reliability. Operational reliability is the ability of the electric power grid to withstand the sudden outages of large power plants or transmission facilities by maintaining grid stability without resulting in load curtailments. See NERC, NERC Issues Level 3 Alert, Reliability Guideline Focused on Large Load Challenges, May 4, 2026, https://www.nerc.com/newsroom/nerc-issues-level-3-alert-reliability-guideline-focused-on-large-load-challenges.

[17] Monitoring Analytics (the PJM Independent Market Monitor), 2026 Quarterly State of the Market Report for PJM: January through March, p. 20, May 14, 2026, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q1-som-pjm.pdf, finds that comparing the first quarter of 2025 to the first quarter of 2026, energy prices have increased 78.5%, capacity prices 398.1%, ancillary service prices 69.0%, and transmission 5.3%. The report further states on p. 2, "Data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices." Monitoring Analytics, 2025 State of the Market Report, Volume 1: Introduction, March 12, 2026, p. 18, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025-som-pjm-vol1.pdf, finds that energy prices have increased 47.3%, capacity prices 252.0%, ancillary service prices 16.8%, and transmission 1.8%.

increases, and perhaps even lower them. In addition to protecting ratepayers from higher costs due to large loads, ratepayers should be protected from stranded costs, that is, the costs that ratepayers end up paying because large loads did not interconnect at the time and amount that were forecasted or halted service prematurely. The result is stranded assets – generation, transmission, and distribution facilities. When this occurs, EDCs, such as PPL, do not receive the expected payment from large loads and then attempt to recover their costs from ordinary ratepayers. Increasing electricity rates through cost shifting from large loads to ordinary ratepayers, whether directly due to large loads or due to the risk of stranded costs, is an affordability issue, particularly given the challenges that almost 20% of Pennsylvanian families have in paying their utility bills.[18]

Q. Is stranded cost a concern with large loads?

A. Yes. As stated from the start of the Commission docket on Interconnection Tariffs for Large Load Customers, protecting customers from stranded costs is the Commission's primary concern: "First and foremost, the Commission must protect the Commonwealth's ratepayers. In this case, that means ensuring that if any upgrades are undertaken to enable the interconnection of large loads, they are made with a high degree of ratepayer protection

[18] The Pennsylvania Independent, Pennsylvania lawmakers introduce legislation to lower energy costs, May 1, 2026, https://pennsylvaniaindependent.com/economy/pennsylvania-lawmakers-introduce-legislation-to-lower-energy-costs/, reports that electricity shutoffs in the Commonwealth increased about 21% between October 2024 and October 2025 and one inf five households have difficulty in paying their utility bills. See also, CAUSE-PA, Distributed Energy Resources Participation in Wholesale Markets, Chapter 57 Docket No., L-2023-3044115, June 9, 2026, p. 3, https://www.puc.pa.gov/pcdocs/1934550.pdf, "Pennsylvania is experiencing these same trends. Energy insecurity impacts roughly 1 in 4 Pennsylvania households. According to the latest United States Census Bureau Household Pulse Survey, around 24.4 percent of Pennsylvania households could not afford their home energy bills in 2024, compared to 23 percent nationwide. And costs are only going up. Over the past year, electric generation prices have skyrocketed across the Commonwealth, driving up residential rates as much as 40 percent in some service areas. Hundreds of thousands of Pennsylvania families pay more than 10 percent of their household income on home energy costs, with many facing energy burdens of 30 percent or higher. In 2025, nearly 390,000 Pennsylvania households faced involuntary termination of electric or gas service—a 10 percent increase from 2024."

against the risk of utility investment for projects that may not materialize. In such cases, questions may arise about who will ultimately bear these stranded costs."[19]

Q. How would you characterize the federal and state policies that are being considered and implemented regarding large loads and the electric power system?

A. The federal and state policies regarding large loads and the electric power system are emerging. Both federal and state governments have important roles in ensuring that large loads do not adversely affect the reliability of the electric power system or shift costs to ordinary ratepayers. The federal government, the Federal Energy Regulatory Commission ("FERC"), PJM, the Commonwealth of Pennsylvania, the Pennsylvania Commission, and the data center community all acknowledge the need for and the importance of policies to protect ordinary ratepayers from the potential adverse reliability and cost consequences of rapidly interconnecting massive amounts of large loads to the power system.

Q. What is the White House's policy regarding large loads?

A. On March 5, 2026, the White House issued the Ratepayer Protection Pledge ("Pledge"), which many large owners and users of data centers (some of the most well financed companies in the world), such as Amazon, Google, Meta, Microsoft, OpenAI, Oracle, and xAI have signed.[20] The Pledge states:

"Today, pursuant to the Ratepayer Protection Pledge, leading United States hyperscalers and AI companies guarantee that data centers' energy needs will not increase household electricity costs for American citizens. Instead, **these companies will build, bring, or buy the new generation resources and electricity needed to satisfy their energy demands, and pay for all new power delivery infrastructure upgrades to service their data centers**. They will voluntarily negotiate new, separate rate structures with

[19] PA PUC, En Banc Hearing Concerning Interconnection and Tariffs for Large Load Customers, Public Meeting of March 27, Agenda No. 3054271-CMR, Motion of Chairman Stephen M. DeFrank, https://www.puc.pa.gov/pcdocs/1871997.pdf.

[20] The White House, President Trump Secures Historic Commitment to Keep Electricity Costs Down Amid Data Center Boom, March 5, 2026, emphasis added, https://www.whitehouse.gov/releases/2026/03/president-trump-secures-historic-commitment-to-keep-electricity-costs-down-amid-data-center-boom/.

their utilities and relevant State governments, and pay those rates, and for their infrastructure, whether they use the electricity or not. They will also invest in local communities and coordinate with grid operators to **contribute to a more reliable grid**. These measures will ensure that Americans are protected from higher energy prices, benefit from grid upgrades and increased grid resilience, and benefit from this technological boom while the United States continues its global leadership in innovation and advanced technology."

On January 16, 2026, the White House National Energy Dominance Council and the thirteen governors of the states within the PJM footprint signed a Statement of Principles Regarding PJM. These principles recognized the resource adequacy risk due to data centers due to their size, the need to assign the costs of new capacity to these data centers, and the need for PJM and states to act.[21]

Q. What is the FERC's policy regarding large loads?

A. On June 18, 2026, the FERC ordered PJM, along with other system operators, to demonstrate to the FERC how they are interconnecting large load customers in a reliable manner and affordable manner.[22]

"FERC today issues tailored show cause orders under Section 206 of the Federal Power Act to each of the six regional grid operators under its jurisdiction. These groundbreaking proceedings represent historic action by the Commission to push our country's electric markets and economy into the future by speeding the integration of large energy users, like data centers and manufacturing operations, onto the electric grid. **These actions are designed to ensure that consumers nationwide continue to enjoy reliable, affordable power, as demand soars and technology leaps forward**." [23]

[21] National Energy Dominance Council and PJM Governors, Statement of Principles Regarding PJM, January 16, 2026, https://www.energy.gov/documents/statement-principles-regarding-pjm.
[22] Docket No. EL24-118, *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,211, June 18, 2026, https://www.ferc.gov/media/e-7-el26-67-000.
[23] FERC, Fact Sheet: FERC Takes Action to Supercharge America's Grid for Efficiency, Reliability, and a Bold Energy Future, June 18, 2026, https://www.ferc.gov/news-events/news/fact-sheet-ferc-takes-action-supercharge-americas-grid-efficiency-reliability-and, emphasis added.

Q. What is the view of the North American Reliability Corporation (NERC) on the impact of large loads on reliability?

A. NERC is concerned with the reliability impacts of large loads. Its Chief Executive Officer has said, "I've called this a hyper-complex risk environment for the sector. I've been quoted as describing the situation as a five-alarm fire."[24] According to NERC, "Projected annual energy demand rose to nearly 4.95 million GWh in 2025, while actual summer peak demand in several areas approached or exceeded the normal forecast. Data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[25]

In the NERC Reliability First-PJM region, NERC's long-term reliability assessment is that this region is "High Risk", the highest risk designation.[26] According to NERC, "In high-risk areas, planned resources as of July 2025 would result in energy shortfalls that exceed resource adequacy targets or baseline criteria for unserved energy or loss of load."[27] Specifically for PJM, NERC states:

> "Current projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements. The anticipated resource margin falls below the Reference Margin Level starting in 2029. Recently approved new generation projects for expedited interconnection under the PJM Reliability Resource Initiative were not far enough along to include in the LTRA [Long-Term Reliability Assessment] risk analysis."[28]

[24] Jennifer Hiller, The Wall Street Journal, The 'Five Alarm' Risks Facing the Power Grid This Summer, July 2, 2026, https://www.wsj.com/business/energy-oil/the-five-alarm-risks-facing-the-power-grid-this-summer-3404b031.
[25] NERC, 2026 State of Reliability: Assessment Overview of 2025 Bulk Power System Performance, June 24, 2026, p. vii, https://www.nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_overview.pdf.
[26] NERC, Long-Term Reliability Assessment, January 2026, p. 7.
[27] NERC, Long-Term Reliability Assessment, January 2026, p. 6. NERC states in footnote 8, "The criteria used for risk determination in the LTRA include resource adequacy targets established by regulatory authorities." traditional 1-day-in-10 years load-loss criteria, and probabilistic loss-of-load-hour and expected unserved energy metrics.
[28] NERC, Long-Term Reliability Assessment, January 2026, p. 8.

Q. What is PJM Board of Managers' policy regarding large loads?

A. The PJM Board of Managers ("PJM Board") is concerned with both the reliability and cost allocation issues with large loads. Regarding reliability:

> "The Board analyzed the various proposals through a particular frame that we thought would be helpful to explain. That frame begins with the organization's mandate to maintain grid **reliability**. As the results of the 2027/2028 Base Residual Auction (BRA) display, the RTO has cleared short of its reliability requirement for the first time in history. The 2027/2028 BRA cleared 5.6% short of our target reserve margin indicating that the system is at higher risk than previous years. The Board views this outcome as a clear signal that current trends are not acceptable and warrant corrective action."[29]

To underscore the urgency of the situation, on June 24, 2026, PJM adopted a new capacity advisory emergency procedure because "PJM is now seeing forecasted or actual capacity deficits outside of extreme hot or cold periods and expects these instances to increase as demand growth outpaces the addition of new power resources and the percentage of intermittent generation resources on the grid continues to increase."[30]

Regarding cost allocation, the PJM Board of Managers stated:

> "Further, as a mission-driven organization that fundamentally exists as part of a larger system serving consumers, PJM must be conscious of the **affordability** challenges facing the 67 million consumers in our footprint today. There is much that our states can be doing to contend with higher wholesale costs at the retail level. At the same time, as the market administrator, PJM should seek to balance the design of its markets to simultaneously set transparent prices that incent the desired behavior from market participants while not being punitive to consumers."[31]

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[29] PJM, Board Decisional Letter on Critical Issue Fast Path – Large Load Additions, January 16, 2026, p. 1, https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260116-pjm-board-letter-re-results-of-the-cifp-process-large-load-additions.pdf. Emphasis in the original. Also see, PJM Independent Market Monitor, CIFP-LLA [Critical Issues Fast Path – Large Load Additions], October 9, 2025, p. 1, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251024/20251024-item-04g---imm-memo.pdf, "The current tight/short conditions in the PJM Capacity Market are almost entirely the result of large data center load additions, both actual historical and forecast. The current supply of capacity in PJM is not adequate to meet the demand from large data center loads and will not be adequate in the foreseeable future."

[30] PJM Inside Lines, PJM Adds Emergency Procedures to Maintain Reliability June 24, 2026, https://insidelines.pjm.com/pjm-adds-emergency-procedures-to-maintain-reliability/?utm_source=news.energycentral.com&utm_medium=newsletter&utm_campaign=daily-template-june-2026-26th-fri.

[31] PJM, Board Decisional Letter on Critical Issue Fast Path – Large Load Additions, January 16, 2026, p. 2, https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260116-pjm-board-letter-re-results-of-the-cifp-process-large-load-additions.pdf. Emphasis in the original. Also see, PJM Inside Lines, PJM

Note that the PJM Board states that it is important for states to act as well.

Q. What is the status of PJM's efforts to address large loads?

A. Presently, PJM is wrapping up its Critical Issues Fast Path ("CIFP") stakeholder process that addresses two key aspects of connecting large loads to the PJM system: procuring additional suppliers and curtailing selected large loads when suppliers are short. The next step in this process is PJM submitting a filing to FERC in July 2026 its Reliability Backstop Procurement ("RBP") and Connect and Manage ("C&M") proposals. The objective of the RBP is to procure additional supplies through bilateral contracts and a centralized auction to serve large loads that do not bring their own capacity ("BYOC") of generation and demand response. The objective of C&M is to determine under what conditions large loads that did not BYOC should be curtailed.

Q. What are the two major concerns with PJM Staff's RBP and C&M proposals?

A. PJM Staff's most recent RBP and C&M proposals have two glaring concerns.[32] The RBP proposal may result in non-large load customers being assigned the costs of the centralized RBP in some situations. According to PJM Staff's proposal: "If states have not established frameworks to appropriately allocate costs to new data center loads, it is unclear to which customers those costs would be assigned. As a backstop, If [sic] EDC does not allocate via LLC Obligation, PJM will allocate to all loads in the zone (including non-large

Files Price Collar, Expedited Interconnection as Part of Large Load Plan, March 2, 2026, https://insidelines.pjm.com/pjm-files-price-collar-expedited-interconnection-as-part-of-large-load-plan/, "Further efforts directed by the Board remain the focus of intensive deliberation among PJM Members and stakeholders as they address longer-term solutions to issues of insufficient power supplies, affordability and grid reliability in the face of extraordinary demand."

[32] Note that the PJM Board of Manages may not adopt PJM Staff's proposal.

loads) using existing PLC assignments."[33] The proposed RBP is scheduled to start on September 10 and be completed by November 20, 2026.[34]

PJM Staff's C&M proposal is voluntary, meaning that large loads that interconnect without bringing their own new supplies and required reserves are not curtailed before ordinary ratepayers.[35] It is very unlikely that a large load would volunteer to be C&M as it would be curtailed before other loads and receive no additional benefit from doing so.

Both proposals are contrary to federal and Pennsylvania policies discussed above. The RBP potentially assigns the costs of new supply procured on behalf of large loads to non-load customers. The voluntary C&M proposal allows for new large loads to avoid bringing new supplies and curtailment and therefore reduces resource adequacy in PJM.[36]

Given the ongoing and dynamic nature of the RBP and C&M discussions at PJM and expected PJM and stakeholder filings, the key takeaway is that Pennsylvania needs to act now to protect ordinary ratepayers from reduced reliability and shifting costs, regardless of what PJM files and what FERC approves.

[33] PJM, CIFP Reliability Backstop Proposal, June 26, 2026, p. 4, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-item-02a---pjm-stage-4-proposal---reliability-backstop-procurement---executive-summary.pdf.

[34] PJM, CIFP Reliability Backstop Proposal, June 26, 2026, p. 1, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-item-02a---pjm-stage-4-proposal---reliability-backstop-procurement---executive-summary.pdf.

[35] PJM, PJM Connect & Manage CIFP Proposal Stage 4, June 23, 2026, pp. 3-4, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-item-02a---pjm-stage-4-proposal---connect-and-manage---executive-summary.pdf.

[36] PJM Governors' Collaborative, June 24, 2026, p. 1, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-written-comments---pjm-governors-collaborative.pdf, "By summarily abandoning the mandatory protective mechanism outlined in the Decisional Letter, moving to a voluntary pre-emergency program and handing the implementation of safeguards over to the states without notice or sufficient time to develop practical solutions, the revised staff package abdicates PJM's responsibility to ensure reliable affordable grid."

Q. What is the Governor of Pennsylvania's policy regarding large loads?

A. The Governor's policy focuses on reliability and affordability. "Governor Shapiro's 'all-of-the-above' energy strategy is focused on diversifying Pennsylvania's power grid to secure the Commonwealth's energy future while building more reliable, affordable, and sustainable energy."[37] The policy further states:

> "In its initial application for GRID certification, a project developer must provide DOR and OTO with an energy plan detailing how it will provide for its energy needs without imposing costs on Pennsylvanians and other utility ratepayers. Developers must agree to build, bring online, or buy incremental electric capacity needed to meet new energy demand while paying the full cost of the capacity. That capacity must generally come from resources located within the same deliverability area as the proposed GRID project, and must also include increasing percentages of energy coming from dispatchable clean firm energy resources located within the Commonwealth, up to 32 percent in 2035. Developers must also pay all costs associated with interconnection, transmission, distribution, network upgrades, ancillary services, or dedicated facilities caused in whole or in part by the project's electricity demand."[38]

Q. What is the Pennsylvania Commission's policy regarding large loads?

A. On May 13, 2026, the Commission issued its final order establishing a Large Load Model Tariff Framework ("Model Tariff"). The Model Tariff recommends cost responsibility protections that reinforce "cost causation principles to help ensure that large load customers are responsible for infrastructure and interconnection costs associated with serving their projects, reducing the risk of shifting those costs onto existing residential and

[37] Commonwealth of Pennsylvania, Governor Shapiro Releases Full Governor's Responsible Infrastructure Development (GRID) Standards to Protect Pennsylvanians and Establish Strict Guardrails to Hold Data Center Developers Accountable, May 27, 2026, https://www.pa.gov/governor/newsroom/2026-press-releases/gov-shapiro-releases-full-grid-standards-to-protect-pennsylvania.

[38] Commonwealth of Pennsylvania, Governor Shapiro Releases Full Governor's Responsible Infrastructure Development (GRID) Standards to Protect Pennsylvanians and Establish Strict Guardrails to Hold Data Center Developers Accountable, May 27, 2026, https://www.pa.gov/governor/newsroom/2026-press-releases/gov-shapiro-releases-full-grid-standards-to-protect-pennsylvania. Also, see PAPUC, Interconnection and Tariffs for Large Load Customers, Docket No. M-2025-3054271, Final Order, May 12, 2026, https://www.puc.pa.gov/pcdocs/1929842.pdf.

small business customers"[39] and contract terms and exit provisions that provide "guidance related to load ramping schedules, minimum contract terms, and customer exit provisions to support long-term cost recovery and system stability."[40] PPL considers the Model Tariff as a "guidance document."[41]

B. PPL's Positions and Tariff Create Policy Gaps and Risks to Reliability and Affordability

Q. What is PPL's position regarding the reliability and affordability implications of interconnecting large load customers?

A. PPL's position is that it is not responsible for the reliability and affordability implications of large loads. PPL has not determined whether the New Customer, or its suppliers, is bringing its own new capacity; what the New Customer's impact on resource adequacy, energy, capacity, and ancillary costs is; or whether the New Customer is compliant with the White House Ratepayer Protection Pledge.[42] PPL's tariff is silent on all these issues, as well.

PPL claims that it "has an obligation to provide non-discriminatory service to existing and new customers."[43] PPL does not provide any further explanation of how to apply its obligation to serve in a situation when there are insufficient supply to meet demand, such as the situation that presently exists in PJM and is likely to persist and increase over time.

[39] PAPUC, PUC Releases Final Order Establishing First-of-Its-Kind Large Load Model Tariff Framework, May 13, 2026, https://www.puc.pa.gov/press-release/2026/puc-releases-final-order-establishing-first-of-its-kind-large-load-model-tariff-framework-05132026.
[40] PAPUC, PUC Releases Final Order Establishing First-of-Its-Kind Large Load Model Tariff Framework, May 13, 2026, https://www.puc.pa.gov/press-release/2026/puc-releases-final-order-establishing-first-of-its-kind-large-load-model-tariff-framework-05132026.
[41] Joseph B. Lookup, Response to the Set X Data Requests of the Office of Consumer Advocate (OCA), Docket No. A-2025-3059443, May 21, 2026, OCA X-1 f.
[42] Joseph B. Lookup, Response to the Set X Data Requests of the Office of Consumer Advocate (OCA), Docket No. A-2025-3059443, May 21, 2026, OCA X-1 (a), (g), (h), and (i).
[43] Joseph B. Lookup, Response to the Set X Data Requests of the Office of Consumer Advocate (OCA), Docket No. A-2025-3059443, May 21, 2026, OCA X-1 e.

In my opinion, by interconnecting new large loads without ensuring that they or their suppliers have sufficient new supplies and reserves to maintain resource adequacy, PPL's practice creates three risks for PPL's existing customers: (1) to experience a degradation in service reliability, (2) to pay increased wholesale electricity costs, and (3) by interconnecting new large loads without ensuring appropriate transmission cost allocation PPL's practice creates avoidable cost shifting from large loads to ordinary ratepayers. These three risks can be largely mitigated or avoided.

Q. Please further explain the reliability and cost risks that you identify above.

A. In Section II.A. above, I observed that data centers are the predominant driver of new large load interconnection requests and differ materially from legacy large load customers in scale, pace of development, and operational characteristics.[44] As customers, data centers present unique risks to reliable electric utility service due to their large peak demands high load factors, and development uncertainty. Data centers also materially influence transmission and generation planning outcomes by requiring large amounts of new generation and transmission facilities to serve them.[45] Data centers also will increase costs for bulk grid services and present unique cost-shifting risks to existing customers if

[44] Rachel Mural, Dipesh Pherwani, Chaitanya Gupta, Yiqi Yu, Ai Takahashi, Dongjoo Kim, Subir Majumder, Henry Lee, Minlan Yu, and Le Xie, AI, Data Centers, and the U.S. Electric Grid: A Watershed Moment, February 2026, p. 2, https://www.belfercenter.org/sites/default/files/2026-02/Mural%20et%20al_AI%20Data%20Centers%20Grid_20260206.pdf, "In July 2024, a voltage fluctuation in northern Virgina triggered the simultaneous disconnection of 60 data centers, prompting a 1,500-megawatt (MW) power surplus, which forced emergency adjustments to prevent cascading outages." The report states, on page 5, "Data centers use large, steady electricity loads with limited ability to reduce (or ramp down) their power usage; simultaneously, their energy demand can fluctuate according to equipment usage and job complexity."

[45] See, for example, State of Maryland Office of People's Counsel, PJM Transmission Cost Impacts on Electricity Customers in Maryland An Overview of PJM Transmission Planning and Costs, March 2026, p. 1, https://opc.maryland.gov/Portals/0/Files/Publications/Rising%20Transmission%20Costs%202026-03-25%20CORRECTED%20FINAL.pdf, which finds that PJM may assign Maryland ratepayers an additional $5.4 billion in new capacity costs between 2031 and 2035. See also, Union of Concerned Scientists, New UCS Analysis Reveals Billions of Dollars in Unreported Data Center Costs Passed onto PJM Customers, September 29, 2025, https://www.ucs.org/about/news/billions-dollars-unreported-data-center-costs-pjm, states "A new analysis by the Union of Concerned Scientists (UCS) reveals how millions of people across Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia are footing the bill for an additional $4.3 billion in electricity infrastructure projects approved in 2024 solely to connect wealthy private companies' data centers."

interconnection and service proceed without adequate customer protection mechanisms.[46] PPL is forecasting a significant quantity of new data center customers in its service territory.

Q. Please explain your statement that these risks can be mitigated?

A. The risks can be mitigated by PPL because PPL controls the interconnection of these new data center customers and controls the terms and conditions of their interconnection, subject to its Commission-approved distribution tariff. Also, the risk can be mitigated by PPL putting into place appropriate rules at the distribution tariff level that protect ordinary ratepayers from the unique reliability and costs risks created by new data centers.

Q. Please explain why you believe the PPL tariff is relevant to your opinion in this case?

A. Based on the way PPL has structured its retail tariff and interconnection policies, the data center seeking to interconnect PPL's distribution system cannot do so unless and until the high-voltage transmission infrastructure is sited and constructed.[47] Thus, the two go together: data centers interconnect to PPL's distribution system and the regional bulk power grid at the same time. It is, of course, an engineering necessity that for the data center to be able to receive power from PPL's distribution facilities, those facilities must be connected to the transmission system and the rest of PJM. The rules and regulations of

[46] Rachel Mural, Dipesh Pherwani, Chaitanya Gupta, Yiqi Yu, Ai Takahashi, Dongjoo Kim, Subir Majumder, Henry Lee, Minlan Yu, and Le Xie, AI, Data Centers, and the U.S. Electric Grid: A Watershed Moment, February 2026, p. 2, https://www.belfercenter.org/sites/default/files/2026-02/Mural%20et%20al_AI%20Data%20Centers%20Grid_20260206.pdf, "While overregulation could hinder AI development, insufficient regulation risks grid instability, rising consumer costs, reliance on high-emission energy sources, public backlash, and setbacks to state and corporate climate goals."

[47] PPL Retail Distribution Tariff, Supplement No. 2 to Electric Pa. P.U.C. No. 202 at Original Page 35C ("This Rate Schedule is for large general service supplied from available lines of 69,000 volts or higher to large load (data center) customers…").

interconnection are governed by PPL's tariff subject to the Commission's oversight and approval.[48] Data center impacts, while reflected upstream in transmission and generation systems, are initiated through distribution-level interconnection. I am advised by counsel that retail level customer protection decisions that are contained in the distribution tariff fall within the Commission's jurisdiction. PPL's tariff provisions addressing interconnection and service to large customers therefore have a direct and foreseeable connection to the reliability risks and costs that manifest on the broader electric system because of PPL serving new large loads.

Q. Would you recommend that the Commission incorporate additional customer protection measures into PPL's tariff to the extent that it can do so without exceeding the scope of its jurisdiction?

A. Yes. Although transmission planning and wholesale energy market rules are regulated at the federal level, the Commission has clear authority and tools to mitigate the potential impacts of large load interconnections on existing customers and system reliability through retail tariffs and service conditions. I am advised by the OCA's attorneys of the same, and this understanding is consistent with my public policy understanding of the Commission's oversight of public utilities and its authority under the Public Utility Code, as well as the statutory obligation to ensure public utilities provide safe, reasonable, and adequate service.[49]

Q. What is PPL's position regarding transmission upgrade costs incurred for interconnecting large load customers?

A. PPL's position regarding transmission upgrades costs caused by large loads that interconnect to the PPL's system is that large loads only directly pay for the upgrades

[48] PPL Retail Distribution Tariff, Supplement No. 2 to Electric Pa. P.U.C. No. 202 at Original Pages 35C-35F.
[49] See, e.g., 66 Pa. C.S. §§ 102, 501, 508, 1301, 1302, 1303, 1304, 1501, 1502, 1505, 2805(a), 2807(a).

necessary to serve their load so long as PPL determines, in its significant discretion, that the upgrades do not have any degree of integration with PPL's transmission network (i.e. "network upgrades").[50] If PPL determines, in its significant discretion, that any portion of the upgrades are non-network upgrades, then PPL will assign the related costs to be paid for directly by the large load customer and PPL will not claim those amounts in rate base. However, if PPL determines that any portion of the upgrades are network upgrades, it will claim the network upgrade costs in PPL's transmission rate base and recover the rate base and related depreciation expense through socialized transmission rates called Network Integrated Transmission Services (NITS) charges.[51] This means that for upgrades to the transmission system that would not have been needed but-for the interconnection of the large load customer, PPL determines to include the costs of the network upgrade in PPL's transmission rate base and recover the related costs from transmission customers at large via wholesale and retail rates. Currently, PPL determines at its discretion not to recover the network upgrades costs from rates charged only to the large load customer that caused the network upgrade to occur.

Q. What do you mean when you talk about PPL's discretion to determine network upgrades and how to recover the costs of network upgrades?

A. I am advised by OCA counsel that PPL has significant discretion on how to recover the costs of network upgrades caused by large loads under FERC's transmission pricing policy. Specifically, PPL has significant discretion to determine whether certain transmission infrastructure is a network upgrade and that its determinations are rarely

[50] PPL Electric Utilities Corporation, Policy on Cost Allocation for Large Customer Interconnections, OCA I-6, Attachment 1.
[51] PPL Electric Utilities Corporation, Policy on Cost Allocation for Large Customer Interconnections, OCA I-6, Attachment 1, p. 1.

challenged or denied at the FERC level. This discretion is reflected in the document referred to as PPL's "cost allocation policy."[52] Given this, PPL can exercise its cost recovery discretion in a way that both respects (1) FERC's transmission pricing policy, and (2) state level retail terms and conditions that prevent cost shifting to non-large load customers, as set forth in Commission-approved tariff and tariff-compliant-ESA provisions.

Q. Can you please expand on this discretion discussion?

A. Yes. I am advised by counsel that the Commission recognized this discretion of transmission public utilities and the state jurisdiction to protect customers at the retail level in its Large Load Model Tariff order by deciding that tariffs should contain appropriate retail protections so that large loads pay for the costs of transmission network upgrades where they are the but-for causer (i.e., the interconnecting customer) of the network upgrades.[53]

Q. Have the OCA and FirstEnergy recently addressed this discretion before FERC, and if so, how does this relate to this proceeding?

A. Yes. At FERC's Advanced Notice of Proposed Rulemaking (ANOPR) docket RM26-4-000[54], in its Supplemental Comments, FirstEnergy Service Company[55] argued that for supplemental projects, like PPL's LON and Sugarloaf Application, a large load customer can pay an expansion rate under an ESA-type contract plus embedded cost rate

[52] PPL Electric Utilities Corporation, Policy on Cost Allocation for Large Customer Interconnections, OCA I-6, Attachment 1

[53] Interconnection and Tariffs for Large Load Customers, Docket No. M-2025-3054271, Final Order at 41-43.

[54] *Interconnection of Large Loads to the Interstate Transmission System*, Notice Inviting Comments, Docket No. RM26-4-000 (Oct. 27, 2025) (the Commission issued the ANOPR following a directive from the Secretary of Energy ("Secretary") pursuant to section 203 of the Department of Energy Organization Act); *see also* the full text of the proposed ANOPR, *Ensuring the Timely and Orderly Interconnection of Large Loads*, Advance Notice of Proposed Rulemaking, Docket No. RM26-4-000 (Oct. 23, 2025).

[55] FirstEnergy Supplemental Comments, RM26-4 (Jun. 6, 2026), available here: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20260605-5169&sid=247f6232-2ae0-44dd-a821-7ac2070e1660.

via NITS (an "Expansion Rate Policy" similar to that used in the interstate natural gas pipeline context) without raising concern under FERC's transmission pricing policy. In the OCA's Supplemental Comments,[56] the OCA agreed that FERC need not change its transmission pricing policy to allow the use of an Expansion Rate Policy[57] by transmission owners in the context of data centers and supplemental projects. The OCA explained that under FERC's existing pricing policy, FERC has the flexibility to determine when special circumstances exist to provide exceptions to a strict application of the "higher of" rate policy. The OCA submitted that FERC's *Transmission Pricing Policy*[58] clearly provides that the use of a disaggregated approach is "or" pricing because it does not charge the same customer for the same facilities twice. Because a line-by-line incremental rate would exclude the expansion transmission facilities from the embedded network rate base, the large load customer would be charged once for using the expansion facilities (via the incremental rate) and once for using the existing transmission network (via the embedded rate). Hence, the use of an Expansion Rate Policy by a transmission owner would be consistent with FERC's transmission pricing policy.

Q. In your opinion, what would an Expansion Rate Policy achieve?

A. It accomplishes two things. First, it achieves the promises in the White House's Ratepayer Protection Pledge with respect to transmission and distribution costs. Second, it aligns well with the principle of cost causation and avoids having existing customers

[56] Joint Consumer Advocates Supplemental Comments, RM26-4 (Jun. 15, 2026), available here: https://elibrary.ferc.gov/eLibrary/docinfo?accession_number=20260615-5141&sid=247f6232-2ae0-44dd-a821-7ac2070e1660

[57] Joint Consumer Advocates Supplemental Comments, RM26-4 (Jun. 15, 2026) at 11-14.

[58] Joint Consumer Advocates Supplemental Comments, RM26-4 (Jun. 15, 2026) at 14 (*citing* Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, 69 FERC P61,086, n. 34 (1994) (*Transmission Pricing Policy*)).

subsidize the costs of network facilities from which existing customers derive no benefit commensurate to the benefits that large load interconnecting customers derive.

Q. Should the Commission require PPL's tariff to require PPL and the data center large load customer to enter a negotiated rate structure to pay for the expansion rate facilities where such agreement protects PPL's existing customers and protects PPL's and the data center's rights under FERC ratemaking requirements?

A. Yes. One key feature of the Expansion Rate Policy is providing a negotiated rate structure for the expansion facilities rate over the duration of a long-term contract. The expansion-facilities costs would be depreciated over the term of agreement and the transmission owner's return on equity, capital structure, and debt assumptions would mirror those already embedded in the incumbent zonal transmission rate, to avoid preferential treatment or punitive pricing. The agreement would require a data center customer to maintain creditworthy collateral support equal to the remaining unrecovered balance of the expansion facilities over the life of agreement to protect existing customers from residual exposure. At end of term of agreement and the expansion facilities have been fully recovered through the expansion rate, the expansion facilities would transition into the integrated system rate base. Here, the expansion facilities include those transmission facilities addressed in PPL's LON and related Sugarloaf Application.

Q. What is PPL's position regarding new PJM costs assigned or allocated to PPL related to interconnecting large load customers?

A. PPL's tariff is silent regarding new PJM costs assigned or allocated to PPL related to interconnecting large load customers. This means PPL's tariff is silent regarding RBP (Reliability Backstop Procurement) obligations.

Q. Based upon your synopsis of federal, PJM, and state policies and PPL's position regarding large load, in your opinion, is there a gap in policy related to large loads, reliability, and affordability?

A. Yes, in my opinion, a policy gap exists between the aspirations of federal and state policy and PPL's tariff. Federal and state policies are adamant that new large loads should not cause reliability problems or impose any costs on ordinary ratepayers. As just indicated by PPL's positions on the issues of costs impacts and reliability impacts, its tariff does not have provisions that fill this gap.[59]

C. Addressing the Policy Gap Between Federal and State Goals and PPL's Retail Tariff and Addressing the Increased Risks to Reliability and Affordability through PPL's Retail Tariff

Q. What do you propose to fill the gap between federal and state goals and PPL's Tariff?

A. To achieve federal and state policy goals with respect to large loads, PPL's tariff needs to have the following components, each of which I describe in more detail below:

1. Large Load Registry
2. Large Load Supply Requirement
3. PJM RBP Cost Allocation Stipulation
4. Large Load Stranded Cost Allocation
5. Large Load Credit and Collateral Provisions
6. Large Load Curtailment Provisions

[59] See Energy Systems Integration Group's Large Load Task Force, Interconnection Processes for Large Loads: Current Practices and Recommendations, June 2026, p. xi, https://www.esig.energy/wp-content/uploads/2026/06/ESIG-Large-Loads-Interconnection-Process-report-2026a.pdf, which notes in general the "lack of clarity around regulatory authority over large load interconnection standards and procedures" and the need for "coordination between independent system operators (ISOs) and regional transmission organizations (RTOs) and utilities."

Q. Please describe the Large Load Registry and how it helps to ensure reliability and avoid cost shifting.

A. The proposed Large Load Registry would be a mandatory, public database of large loads that would provide PJM and states with the necessary information for reliability and cost allocation purposes.[60] New large loads would be required to register in the database six months before their initial in-service date, and existing large loads would be required to register within three months of the adoption of this proposed tariff provision.[61]

The Large Load Registry would contain the following information for those loads that meet either the PJM or the Commission's definition of a Large Load[62]:

- Large load customer information and description
- Interconnecting EDC
- PJM Control Zone
- In-service date
- Delivery point

[60] Rachel Mural, Dipesh Pherwani, Chaitanya Gupta, Yiqi Yu, Ai Takahashi, Dongjoo Kim, Subir Majumder, Henry Lee, Minlan Yu, and Le Xie, AI, Data Centers, and the U.S. Electric Grid: A Watershed Moment, February 2026, p. 4, https://www.belfercenter.org/sites/default/files/2026-02/Mural%20et%20al_AI%20Data%20Centers%20Grid_20260206.pdf, "The opacity of data center operations, site planning, and energy efficiency complicate energy estimations and projections."

[61] See, for example, PJM, PJM Connect and Mange CIFP Proposal Stage 4, June 23, 2026, p. 2, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-item-02a---pjm-stage-4-proposal---connect-and-manage---executive-summary.pdf. ESIG, Interconnection Processes for Large Loads: Current Practices and Recommendations, June 2026, p. xiv, https://www.esig.energy/wp-content/uploads/2026/06/ESIG-Large-Loads-Interconnection-Process-report-2026a.pdf, notes "Coordination among utilities and ISOs/RTOs needs to be enhanced throughout the interconnection process, including formal information-sharing protocols and joint study procedures for facilities that interact with multiple grid layers."

[62] PJM defines Large Loads as End-use customer load that has a cumulative peak load quantity greater than or equal to 50 MWs at each delivery point or Point of Interconnection. See PJM, PJM Connect & Manage CIFP Proposal Stage 4, June 23, 2026, p. 2, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-item-02a---pjm-stage-4-proposal---connect-and-manage---executive-summary.pdf. The Commission defines Large Loads as We proposed a threshold for a Large Load Customer of 50 MW individually and 100 MW in aggregate. Pennsylvania Public Utility Commission, Interconnection and Tariffs for Large Load Customers, Docket No. M-2025-3054271, Final Order, May 12, 2026, p. 11, https://www.puc.pa.gov/pcdocs/1929842.pdf.

- Load quantity (MW)
- Ramping Schedule (a forecast or contractual plan defining the timeline at which the customer's electricity demand will increase until it reaches full commercial capacity)
- Identification of the large load's Load Serving Entity ("LSE") and verification that its registered with PJM
- Status of large load bringing its own capacity or participation in PJM's Connect and Manage Program
- Additional details as necessary

Q. Please describe your proposal regarding supply requirements for Large Loads.

A. Recall from above that the PJM C&M (Connect & Manage) proposal allows large loads to connect to the PJM grid without having to bring new supplies or be required to curtail their demand during periods of supply shortages. As noted above, it is unlikely that large loads will curtail their demand voluntarily, although they may run their backup generation if permitted. Given this gap with PJM's C&M proposal, Pennsylvania needs to act. As part of PPL's tariff and its contracts with the customers interconnecting through the proposed facilities consistent with its tariff, new large loads requesting interconnection from PPL if, at the time of the interconnection PJM does not have sufficient capacity, would be required to have procured new PJM qualified capacity resources[63] including the required reserve margin or be subject to C&M. If PPL's tariff does not specifically provide for the ability to curtail new large load customers at the direction of PJM, it is possible that PPL may be unable to do so; furthermore, this tariff change would have to be incorporated

[63] PJM, Proposed Backstop Mechanism: A Parallel Path Approach, June 23, 2026, p. 2, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-item-02a---pjm-stage-4-proposal---reliability-backstop-procurement---executive-summary.pdf.

into PPL's procedures for controlling load and emergency conservation during its emergency procedures. This can be done bilaterally, through the PJM RBP, co-located with generation, or participate in PJM's C&M program. According to the Data Center Coalition, the membership association of the data center industry,[64] "We agree that reliability must be maintained and that new capacity should accompany significant new load additions."[65]

The purpose of this supply requirement is to ensure resource adequacy. New large loads will either have brought sufficient new capacity to meet their load and associated reserve requirements or will be curtailed before all other non-large load customers without having the option of taking the same firm service as non-large load customers.

Q. Please describe your proposal regarding PJM's Reliability Backstop Procurement proposal.

A. PPL's tariff and contract with each customer interconnecting through the proposed facilities should be modified to ensure that all costs that PJM may assign to PPL related to the RBP will only be assigned to large loads and not any non-large customers. As noted above, PJM in certain circumstances may assign the costs associated with its RBP to non-large load customers unless states act to prevent this even though the purpose of the RBP is to procure new supplies for new large loads.

Q. How would your recommendation change if PJM's proposals regarding the Reliability Backstop Procurement and Connect & Manage are changed or not adopted?

A. PJM's Staff C&M and RBP proposals may change as the PJM Board of Managers finalizes its decision in the next several weeks. If the PJM Board of Managers mandate

[64] https://www.datacentercoalition.org/cpages/home.

[65] Data Center Coalition, DCC Connect & Manage Alternative: State-Led Implementation with Immediate Residential Consumer Protection, June 23, 2026, https://www.pjm.com/-/media/DotCom/committees-groups/cifp-rbp/2026/20260630/20260630-item-02i---data-center-coalition---cm---executive-summary.pdf.

C&M, instead of it being voluntary, and do not permit the assignment of RBP costs to ordinary ratepayers, these would be two welcome changes. Nonetheless, it would be prudent for Pennsylvania to take steps to ensure that ordinary ratepayers are protected from reliability reductions and cost-shifting regardless of what PJM finally decides, what the FERC finally approves, and what the courts rule, if the FERC decision is appealed.

Q. Please describe your cost allocation proposal for transmission and distribution costs.

A. PPL should demonstrate that its transmission cost assignment policies and tariff provisions ensure that non-large load does not pay any of the costs or bear any of the risk of stranded investment due to large loads or propose modifications to its tariff that do so, as I discussed above regarding the Ratepayer Protection Pledge and my proposed Expansion Rate Policy. This recommendation is consistent with the Commission's Large Load Model Tariff, which requires all but-for costs of interconnection and service to be directly assigned to the large load and recovered through a customer contribution.[66]

Q. Please describe your proposal regarding credit and collateral for large loads.

A. PPL should demonstrate that its tariff requires sufficient credit and collateral from large loads to cover all their costs including potential stranded investment or propose modifications to its contract with the interconnecting customer to do so.

Q. Please describe your proposal regarding the mandatory load shedding of large load customers.

A. PPL should ensure that all large loads are curtailed before residential consumers and subject to substantial, timely state penalties, in addition to any imposed by the FERC

[66] PAPUC, PUC Releases Final Order Establishing First-of-Its-Kind Large Load Model Tariff Framework, May 13, 2026, p. 42, https://www.puc.pa.gov/press-release/2026/puc-releases-final-order-establishing-first-of-its-kind-large-load-model-tariff-framework-05132026.

or NERC,[67] to ensure compliance with this requirement. Presently, the PPL Emergency Load Control Procedure does not stipulate that large loads are curtailed before residential consumers.[68] An exception to this large load curtailment-first policy could be warranted for the certified portion of a large load deemed critical or vital[69] by the federal government or Pennsylvania, so long as the large load can curtail all its remaining non-critical load. The PPL Emergency Load Control Procedure does not envision partial curtailment at a location that has vital facilities and instead removes the entire facility from the load shed table.[70]

Q. Your recommendations touch on issues regarding resource adequacy, load shed priority, and cost allocation. Are these issues related to the facilities proposed in this proceeding?

A. Yes. For PPL to ensure the long-term reliability of its system, and that its rates and services remain just, reasonable, and non-discriminatory, it must make improvements to its tariff and the contracts it enters with interconnecting customers. Otherwise, the construction of and provision of service through the facilities proposed in this proceeding will make PPL's service less reliable and, I am advised by counsel, may compromise its ability to satisfy the requirements of the Public Utility Code. While the connection between resource adequacy, cost allocation, and load shed priority and the proposed facilities in this

[67] NERC is the North American Electric Reliability Corporation, which has authority via FERC to enforce NERC and regional reliability standards including issuing monetary penalties and/or non-monetary sanctions, https://www.nerc.com/programs/enforcement.

[68] See PPL Electric Utilities Corporation, Response to the Set X Data Requests of the Office of Consumer Advocate (OCA), Docket No. A-2025-3059443, Joseph B. Lookup, OCA X-7, May 21, 2026, Attachment, PPL Emergency Load Control Procedure.

[69] PPL Electric Utilities Corporation, Response to the Set X Data Requests of the Office of Consumer Advocate (OCA), Docket No. A-2025-3059443, Joseph B. Lookup, OCA X-7, May 21, 2026, Attachment, PPL Emergency Load Control Procedure, 5.8.1.8.

[70] See PPL Electric Utilities Corporation, Response to the Set X Data Requests of the Office of Consumer Advocate (OCA), Docket No. A-2025-3059443, Joseph B. Lookup, OCA X-7, May 21, 2026, Attachment, PPL Emergency Load Control Procedure, 5.8.1.8.

proceeding may not seem apparent, it is imperative that PPL take specific steps previously discussed in addressing the unique challenges associated with the undisciplined interconnection of large load customers.

III. Summary and Conclusion

Q. Does this conclude your testimony?

A. Yes. I reserve the right to update any portion of my testimony as needed if additional relevant information is made available during this proceeding.

Exhibit FF-1

Curriculum Vitae of Frank A. Felder, Ph.D.

FRANK A. FELDER, Ph.D.

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SUMMARY

Internationally recognized inter-disciplinary researcher, advisor, and educator in the electricity sector

- Author/co-author of 53 peer-reviewed publications and numerous research reports, book chapters, discussion papers, policy briefs, and presentations (Google Scholar profile)
- Rank in top 1.2% of researchers worldwide and 0.51% in energy by ScholarGPS
- Advised national and state governments on clean energy policy, electricity markets, renewables and energy efficiency in China, India, Gulf Cooperation Council, and elsewhere
- Awarded over $23 million in research grants and contracts
- Presented in 15 countries and trained 3,000+ professionals from 40+ countries in electricity markets
- Directed large research and advisory teams at major research university and international think tank
- Consulted with all parts of the electric power industry domestically and internationally

PROFESSIONAL AND ACADEMIC EXPERIENCE

Principal, Independent Electricity Consultants, LLC, 1998 to present, expert witness, consulting, and training services to the electric power industry on wholesale and retail electricity markets throughout North America, Canada, Africa, Asia, and Europe. Clients included RTOs/ISOs, USAID, EPA, EIA, NARUC, NASEO, generators, transmission companies, energy service companies, rate payer advocates, and law firms.

Senior Visiting Researcher, Oxford Institute for Energy Studies, Jun. 2023 to present

Program Director, Renewables and Utilities (formerly Energy Transitions and Electric Power), KAPSARC, International Energy Think Tank, Riyadh, Saudi Arabia, Dec. 2020 to Dec. 2022

- Led program of 10 engineers and economists with a budget of $3.2 million conducting research and providing advisory services involving power system modeling, renewable integration, demand management, smart meters, rate design, cost of service, industrial development, electric vehicles, electricity innovation, and green hydrogen
- Also*, Acting Program Director, Markets and Industrial Development*, Jun. 2021 to Oct. 2021
  Led program of 12 economists, MBAs, and analysts on oil, natural gas, and petrochemicals with a budget of $5.5 million conducting research and providing advisory services on oil supply-demand modeling, hydrocarbon markets and policies, storage, and blue hydrogen
- Visiting Researcher, March 1, 2023 to February 28, 2025

Research Professor, Edward Bloustein School of Planning and Public Policy, Rutgers University, New Jersey, Jul. 2018 to Nov. 2020*, Associate Research Professor*, Sep. 2007 to Jun. 2018, *Assistant Research Professor*, Sep. 2004 to Aug. 2007

- *Director,* Rutgers Energy Institute, July 2018 to September 2020, led 70+ interdisciplinary faculty and staff institute on research, education and outreach initiatives sponsored by the Deans of Arts and Sciences, Business, Engineering, Environmental and Biological Sciences, and Planning and Policy
- *Director*, Center for Energy, Economics & Environmental Policy, October 2006 to November 2020, *Acting Director*, Feb. 2006 to Sep. 2006, conducted policy and economic analyses for the New Jersey Board of Public Utilities

- *Program Director*, Public Informatics, Bloustein School of Planning and Public Policy, Jul. 2018 to Nov. 2020, developed new master's program in data science and analytics for planning and policy students

Assistant Professor of Management, Manhattan College, School of Business, NYC, 2002-2004

Senior Consultant, The Economics Resource Group, Inc., Cambridge, MA, 1994-1998

Nuclear Engineer and Officer, U.S. Navy, 1987-1992

EDUCATION

Massachusetts Institute of Technology, Cambridge, MA
- Ph.D. in Technology, Management and Policy (Engineering Systems Division), September 2001, Probabilistic Risk Analysis of Restructured Electric Power Systems: Implications for Reliability Analysis and Policies
- M.S. in Technology and Policy, 1994

Columbia University, New York, NY, B.S. Applied Mathematics, 1987; B.A. Mathematics, 1987

PUBLICATIONS AND RESEARCH (*indicates student or post-doctoral advisee)

Peer-Reviewed Publications

Albalawi, A., Nezamuddin, N., Muhsen, A., Gertin, T., Felder, F. A., Almansour, A., & Elshurafa, A. M. (2026). A spatial and technical assessment of floating offshore wind energy in the red sea using a GIS–AHP framework. *Scientific Reports*, https://doi.org/10.1038/s41598-026-49570-4.

Alhadhrami, K., Petitet, M., Abouof, S., Darandary, A., Laing, T., Felder, F., and Elshurafa, A. (2026). Achieving Net-Zero in Saudi Arabia's Power Sector by 2060 considering land and mineral availability, Energy, 140067, https://doi.org/10.1016/j.energy.2026.140067.

Kumar,* P., Caggiano, H., Shwom, R., Felder, F., and Andrews C., (2025). "Reflections on Energy Efficiency Policies in Sustainable Transition: Bedrock, Gramechanger, or More of the Same?" Environmental Policy and Governance, https://doi.org/10.1002/eet.70022.

Petitet, M., Felder, F., and Elshurafa, A. (2025). "Cross-Border Electricity Trading in the GCC Countries, Egypt, Jordan and Iraq: Hourly Market Coupling or Bilateral Agreements?" Energy, 136320, https://doi.org/10.1016/j.energy.2025.136320.

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Collaborative Research: CAS: Electrochemical Approaches to Sustainable Dinitrogen Fixation, CHE/CAS 1955014, $295,216, Senior Investigator, August 1, 2020 through July 31, 2023.

Collaborative Research Modeling Strategic Regulators in Network Infrastructure Planning, $399,002, (Rutgers University grant of $85,890), Principal Investigator, CMMI 1825225, September 1, 2018 through August 31, 2021.

Electrochemical Approaches to Sustainable Dinitrogen Fixation, $300,000, Senior Investigator, CHE 1665146, September 1, 2017 through August 31, 2020.

EAGER: Smart & Connected Communities, National Science Foundation, $250,000, Senior Investigator, AGS1645786, August 1, 2016 through July 31, 2018.

EaSM-3: Regional decadal predictions of coupled climate-human systems, National Science Foundation, OCE1419584, $1,200,000, co-PI, June 1, 2014 through August 31, 2017. Designated Bloustein PI for $414,615.

Green Energy Technology for Undergraduates Program (GET UP!), National Science Foundation, EEC1263250, $367,890, Senior Personnel, March 15, 2013 through February 29, 2016. Presented to high school teachers and undergraduate students on July 9, 2014.

Climate to Humans: A Study of Urbanized Coastal Environments, Their Economics and Vulnerability to Climate Change, National Science Foundation, OCE1049088, $3,853,332, co-PI, March 1, 2010 through February 28, 2016. Designated Bloustein PI for $525,448. Additional $225,000 assigned Bloustein.

IGERT: Solutions for Renewable and Sustainable Fuels in the 21st Century, National Science Foundation OCE1049088, $3,197,329, co-PI and Lead on Policy and Infrastructure Logistics for Efficient Fuel Technology Deployment, September 1, 2009 through August 30, 2014. Funded 24 doctoral students (including 2 Bloustein students) and 4 master students. Served on Leadership, Committee and Admission Committee. Developed and taught two new graduate seminars.

Public

Nanotechnology for Clean Energy, National Science Foundation, 0903661, Faculty, $1,218,737, 2008-2013. Developed graduate course given to Rutgers and Princeton Universities.

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Felder, F. (2004). Review of the book *Electricity Pricing in Transition*, by A. Faruqui & K. Eakin. *The Energy Journal*, 25(2), 143-144.

Felder, F. (2004). Review of the book *Efficiency Versus Sustainability in Dynamic Decision Making: Advances in Intertemporal Compromising*, by B. Blaser. *Interfaces*, 34(2), 162-163.

Felder, F. (2004). Review of the book *Stochastic Models in Reliability and Maintenance*, by S. Osaki. *Interfaces*, 34(1), 74-75.

Felder, F. (2003). Review of the book *Electricity Economics: Regulation and Deregulation*, by G. S. Rothwell & T. Gómez. *The Energy Journal*, 24(3), 151-152.

Felder, F. (2003). Review of the book *Power System Operations and Electricity Markets*, by F. I. Denny & D. E. Dismukes. *The Energy Journal*, 24(3), 153.

Felder, F. (2002). Review of the book *Power System Economics: Designing Markets for Electricity*, by Steven Stoft. *The Energy Journal*, 23(4), 112-114.

Felder, F. (2001). Review of the book *Pricing in Competitive Electricity Markets*, by A. Faruqufsi & K. Eakin. *The Energy Journal*, 22(4), 112-114.

Felder, F. (1999). Review of the book *Deregulation of Electric Utilities*, by G. Zaccour. *The Energy Journal*, 20(3), 160-162.

Felder, F. (1998). Review of the book *Electric Utility Restructuring: A Guide to the Competitive Era*, by P. Fox-Penner. *The Energy Journal*, 19(3), 133-135.

Felder, F. (1998). Review of the book *International Comparisons of Electricity Regulation*, R. J. Gilbert & E. P. Kahn. *The Energy Journal*, 19(1).

Felder, F. (1997). Review of the book *A Shock to the System: Restructuring America's Electricity Industry*, by T. J. Brennan. *The Energy Journal*, 18(3), 140-142.

Felder, F. (1996). Review of the book *The Privatization of Public Utilities*, by L. S. Hyman. *The Energy Journal*, 17(4), 163-165.

Felder, F. (1994). Review of the book *Electric Utility Mergers: Principles of Antitrust Analysis*, by M. W. Frankena & B.M. Owen. *The Energy Journal*, 15(4), 233-234.

Sponsored Research

Study of Public Procurement, Financial, and Legal Authorities Necessary to Facilitate the Development of Town Center Distributed Energy Resources (Microgrids), $60,000, New Jersey Board of Public Utilities, Senior Investigator, March 1, 2019 through February 28, 2021.

Rutgers Energy Institute, Rutgers University, $900,000, Director, July 2018 through June 2021.

Clean Energy Evaluation and Market Assessments, New Jersey Board of Public Utilities, $926,284, Principal Investigator, July 2016 through October 2017.

Clean Energy Evaluation and Market Assessments, New Jersey Board of Public Utilities, $926,284, Principal Investigator, September 2015 through June 2016.

Clean Energy Evaluation and Market Assessments, New Jersey Board of Public Utilities, $908,231, Principal Investigator, June 24, 2014 through November 6, 2015.

New Jersey Energy Resilience Bank, New Jersey Board of Public Utilities (funded by U.S. Department of Housing and Urban Development), $230,000, Principal Investigator, October 17, 2014 to March 31, 2017.

Solar Utility Networks: Replicable Innovations in Solar Energy (SUNRISE), U.S. Department of Energy (Subcontractor to PHI Services Company), $30,000, Principal Investigator, September 1, 2014 to August 31, 2016.

Clean Energy Evaluation and Market Assessments, New Jersey Board of Public Utilities, $1,356,553, Principal Investigator, June 2013 through November 2014.

Review of Impact Evaluation Contractors and Work Product, PSE&G, $113,479, Principal Investigator, January 15, 2012 to December 30, 2015.

Electricity Demand and the Impacts on Air Quality, Rutgers University Faculty Grant Proposal, $10,261, Principal Investigator, December 6, 2011 to December 30, 2012.

Evaluation of Reports re: Proposed Atlantic Wind Connection Backbone Transmission Project, Atlantic Wind Connection, $13,860, co-Principal Investigator, September 1, 2011 to October 31, 2011.

Review of Connecticut Renewable Portfolio Standards, Connecticut Energy Advisory Board, $58,963, Principal Investigator, February 18, 2011 to December 31, 2011.

Collection of Wind Resource Data, New Jersey Board of Public Utilities, $4,889, Principal Investigator, January 1, 2011 to September 30, 2011.

Economic Impacts of Water Main Infrastructure Investments, Winning Strategies, $40,782, Principal Investigator, December 20, 2010 to June 1, 2011.

Economic Impact of Accelerated Infrastructure Improvement Projects, New Jersey Natural Gas Company, $13,436, Principal Investigator, November 8, 2010 to January 14, 2011.

Economic Impacts of Water Main Infrastructure Investments, Aqua America, Inc., $17,702, Principal Investigator, November 15, 2010 to March 31, 2011.

Energy Technology Grants, PSEG Services Corporation, $236,000, Principal Investigator, December 1, 2009 to December 31, 2011.

Impacts of Energy Infrastructure, New Jersey Natural Gas, $13,587, June 17, 2010 to August 3, 2010.

Describe and Quantify the Economic Benefits of the NJ DEP Action Plan for the NJ Global Warming Response Act, New Jersey Department of Environmental Protection, $15,630, Principal Investigator, July 14, 2009 to October 14, 2009.

MOA between Rutgers' Center for Energy, Economic and Environmental Policy (CEEEP) and the New Jersey BPU/Clean Energy Program, New Jersey Board of Public Utilities, $1,830,281, Principal Investigator, June 1, 2009 through May 31, 2013 (covering four contracts).

Innovative Partnership Institute, New Jersey Department of Environmental Protection, $6,000, co-Principal Investigator, April 2009.

New Jersey Department of Environmental Protection: Assessing the Potential for New Jersey Forests to Sequester Carbon and Contribute to Greenhouse Gas Emission Avoidance, $7,000, co-Principal Investigator, May 2009.

New Jersey Office of Clean Energy Program: Research and Related Activities Regarding the Energy Efficiency Program, Principal Investigator, $244,367, September 1, 2008, to April 30, 2009.

Comprehensive Assessment of the PA Technical Reference Manual, Clean Power Markets, $187,950, Principal Investigator, October 1, 2008 to December 31, 2012.

New Jersey Hydrogen Learning Center, New Jersey Board of Public Utilities, Principal Investigator, $73,928, May 1, 2008 to June 20, 2009.

New Jersey State Energy Master Plan (Part 3), New Jersey Board of Public Utilities, Principal Investigator, $200,127, November 1, 2007 to October 31, 2008.

New Jersey State Energy Data Center (Part 2), New Jersey Board of Public Utilities, $175,989, Principal Investigator, Nov. 14, 2006 through December 31, 2007.

New Jersey State Energy Master Plan (Part 2), $216,570, New Jersey Board of Public Utilities, Principal Investigator, October 1, 2006 to June 30, 2008.

Diesel Generator and Performance Standard Abstract, Clean Energy Group, $10,000, Principal Investigator, April 30, 2007 to December 31, 2007.

Rutgers Energy Institute, The Future Electric Power System in a Carbon Constrained World, $30,000, co-Principal Investigator, 2007-2008.

New Jersey Meadowlands Renewable Energy Task Force, New Jersey Meadowlands, $100, 000, Principal Investigator, May 15, 2006 to October 31, 2008.

Natural Resources Defense Council, Energy Efficiency, $15,000, Principal Investigator as of Oct. 30, 2006 (co-Principal Investigator prior), July 26, 2005 through Dec. 31, 2006.

New Jersey Board of Public Utilities, New Jersey State Energy Data Center, $99,965, Principal Investigator as of Oct. 30, 2006 (co-Principal Investigator prior), Dec. 1, 2005 through Dec. 31, 2006.

New Jersey Board of Public Utilities, New Jersey State Energy Master Plan, $140,747, co-Principal Investigator, Feb. 1, 2005 through May 24, 2006.

New Jersey Board of Public Utilities, New Jersey Hydrogen Learning Center, $200,000, Principal Investigator as of Oct. 30, 2006, Feb. 1, 2005 through Aug. 31, 2007.

New Jersey Board of Public Utilities, New Jersey Energy Efficiency Evaluation, $523,837, Principal Investigator as of Oct. 30, 2006, (investigator prior), Jan. 1, 2005 through Dec. 31, 2006.

New Jersey Board of Public Utilities, State Technologies Advancement Collaborative, $43,881, co-Principal Investigator, May 11, 2005 through August 31, 2006.

New Jersey Board of Public Utilities, Evaluation of CO_2 Emission Allocation as part of the Regional Greenhouse Gas Initiative, $15,000, co-Principal Investigator, April 15, 2005 through June 30, 2005.

Retail Electricity Supply Association, Assessment of Customer Response to Real Time Pricing, $41,000, co-Principal Investigator, Jan. 1, 2005 through Oct. 31, 2005.

New Jersey Board of Public Utilities, Economic Impact Analysis of a 20% New Jersey Renewable Portfolio Standard, *2004,* $204,247, Senior Investigator*,* Nov 1, 2003 through Jan. 31, 2005.

New Jersey Board of Public Utilities, New Jersey Electric Distribution Reliability Standards, $33,999, Investigator, Feb. 1, 2004 through Dec. 31, 2004.

Rutgers University Teaching

Data Analytics: Using Big Data (graduate)
Climate Change, Public Health and Policy (undergraduate)
Sustainable Energy Policy and Planning (graduate)
Introduction to Statistics (undergraduate and graduate)
The Science, Technology and Policy of Global Climate Change (undergraduate Byrne seminar, honors undergraduate seminar, undergraduate seminar at University of Konstanz)
Energy Engineering, Economics and Policy (graduate seminar; joint course with Princeton University)
Integrated Energy Challenges and Opportunities I and II (year-long graduate seminar)
Energy Planning for Communities Living in Landfills (Planning Studio)
Directed Studies: Victoria Nielsen (Fall 2013); Allison Bridges, Kathryn McKelvey, and Ishanie Niyogi (Spring 2013); Shankar Chandramowli (Summer 2012, Fall 2012, Fall, 2013), Zachary Froio (Fall 2017), Pratyusha Kiran (Fall 2017), Pranay Kumar (Fall 2017), Ashley Scull (Fall 2017)
In-depth Introduction to Electricity Markets (two-day professional short course)
Cost Benefit Analysis of Energy Efficiency and Renewable Energy Projects (one-day professional short course)
Environmental Management (four-day professional short course)

Rutgers University Student Advising and Service

Post-doctoral, Dissertation, Master Thesis, and Undergraduate Advisor/Committees:

- Jose Espiritu Nolasco, System Reliability Estimation and Component Replacement Analysis for Electricity Transmission and Distribution Systems, Oct. 2007 (external department doctoral committee member)

- Hatice Tekiner, Multi-Objective Power Generation Expansion Planning Considering Environmental Impacts and Smart Grid Technologies, Jan. 2008 to May 2010 (external department doctoral committee member)
- Ariel Martin, Development of a Decision Support System to Operate the Supplemental Lighting System in a Tomato Greenhouse Equipped with an On-site Power Generator, October 2013 (external department doctoral committee member)
- Bernhard Brauß, The Issue-Attention Cycle in Energy Policy, Bachelor Thesis, University of Konstanz, Department of Politics & Public Administration, March 2012 (Appraiser)
- Shuya Li, Robust Optimization of Generation Expansion Planning Problems Considering Climate Change's Uncertain Impact, September 2012 to May 2014 (external department masters committee member)
- Caroline Farkas, Impact and Sensitivity Analyses of Energy Sector Emissions: Air Quality Modeling of the PJM Region, Dec. 21, 2015, (external department doctoral committee member)
- Saltuk Bugra Selcuklu, Multi-objective Generation Expansion Planning Considering Uncertainty and Modeling with the Pareto Uncertainty Index, October 2015 (external department doctoral committee member)
- Shankar Chandramowli, Impact of Climate Change on Electricity Systems and Markets, January 2015 (doctoral committee chair)
- Xiaojun (Gene) Shan, Ph.D., Improving the Modeling of Offshore Wind and Electric Distribution Reliability for Public Policy Formulation, post-doc advisor, Jan. 2014-Dec. 2014
- Rebeca Meier, "Feed-in Tariff or Renewable Portfolio Standard – A Quantitative Analysis of the Impact of current Energy Policies on the Provision of Renewable Energy," Joint Masters Thesis with University of Konstanz and Rutgers University, Spring 2016
- Shane Patel, Fall 2014, "Characteristic Problems of Government-Supported Demonstration Scale Energy Innovation: Establishing A Framework for the Evaluation of Energy Innovation Government Programs, undergraduate research paper
- Chhayang Patel, 2014-2015 academic year, undergraduate Arresty Research Program Adviser
- Rutgers Energy Institute Summer Intern co-Adviser (Kaila Roffman, Summer 2015; Christopher Cohane, Summer 2014)
- Allison Bridges, Leveraging Amenity-Led Growth and Collective Action For Sustainable Development In Florianópolis, 1965-2016, April 2016, (doctoral committee member)
- Eric Zimmermann, Internship Supervisor, Summer 2016
- Brian Kemp, Internship Supervisor, Summer 2016
- Mark Rodgers, Simulation-based Optimization Models for Electricity Generation Expansion Planning Problems Considering Human Health Externalities, August 2016 (co-chair, doctoral committee)
- Sanling Song, Improving the Modeling of Offshore Wind and Electric Distribution Reliability for Public Policy Formulation, Feb. 2016 to Mar. 2017
- Carla Corona, Understanding Transitions to Sustainability in Developing Countries: The Chilean Energy Transition, May 2016
- Jacob Yu, Solar Market Analysis, Rutgers Energy Institute Summer Internship, 2017
- Ioanna Tsoulou, A Social-ecological Approach for Heat Adaptation of Senior Low-income Housing, March 2020, (doctoral committee member)
- Jian Zhou, Joint Optimization of System Hardening and Restoration for Resilience Enhancement against Cascading Failures, August 2020 (doctoral committee member)
- Hieu Nguyen, Collaborative Research Modeling Strategic Regulators in Network Infrastructure Planning, post-doctoral supervisor, August 2019 to August 2020
- Jip Kim, Strategic Planning for Low-Carbon Power Systems, May 2021, NYU (doctoral committee member)
- Pranay Kumar, Energy Conservation Behaviors in U.S. Households: Combining Top-Down and Bottom-up Approaches, May 2023 (doctoral committee member)

Rutgers University Senate (July 1, 2019 to September 30, 2020)
Bloustein Search Committee, Research Analyst in Urban Informatics (January to February 2019)
Bloustein Faculty Search Committee (Fall 2018 to Spring 2019)
Bloustein Teaching and Advising Committee (Spring 2018)
Bloustein School Non-tenure Track Appointment and Promotion Committee (April 2018 to present)
Bloustein School Strategic Planning Committee for Research, Practice and Service (March-April 2018)
Hult Prize Challenge, Judge (December 2017)
Bloustein School Search Committee, Research Professor/Director of Research and Evaluation, Heldrich Center for Workforce Development (2017 to 2018)
School of Graduate Studies, Graduate Faculty in Energy Systems (Spring 2015 to present)
Bloustein School Liaison with School of Engineering regarding Masters of Energy Systems (Spring 2015)
Board of Advisors, Rutgers EcoComplex Advisory Board, Member, May 6, 2014 to present
Bloustein Faculty Council: Non-tenure Track Committee, May 2014
Lead Instructor for a class on "Sustainable Energy" for New Jersey Governor's School in Engineering & Technology (Summer 2012); Lecturer Summer 2018
Steering Committee, Edward J. Bloustein School of Planning and Public Policy, September 2006 to August 2008
Associate Director, Rutgers Energy Institute, May 2007 to April 2009
New Jersey State Sustainability Institute, Expert Advisory Board (July 2006 to Dec. 2007)

Other Academic Activities

Editorial Boards
Member of Editorial Board, *Energy Efficiency* (January 2020 to present)
Member of Editorial Board, *Utilities Policy* (September 2016 to present)
Member of Editorial Board, *The Electricity Journal* (January 2013 to date)
Book Review Editor, *The Energy Journal* (January 2012 to July 2019)
Member of Editorial Board, *KIEE International Transactions on Power Engineering* (2005 to 2006)
Member of Editorial Board, *SAM Advanced Management Journal*, (December 2002 to August 2004)

Reviewer
Utilities Policy (February 2025; July 2025), *Journal of Critical Infrastructure Policy* (August 2024), *Reliability Engineering & System* Safety (March 2022), *Energy Policy* (October 2020), *Applied Energy (*June 2018*), WIREs Energy and Environment* (December 2017), *Journal of Planning Education and Research* (June 2017; July 2018), *Energy Research and Social Science* (January 2017), *Energy Efficiency Journal* (November 2020, October 2020, October 2019, February 2018, October 2016), The *Energy Journal* (May, 2025; April, 2025; August 2019, August 2016; March 2017), *Netherlands Foundation for Fundamental Research on Matter, FOM* (May 2016); *International Political Science Review* (April 2016), *MIT Press* (January 2016), *CSEE Journal of Power and Energy* Systems (November 2015), *Sustainable Cities and* Society (August 2015), *IBM Journal of Research and* Development (May 2015), *Nature Climate Change* (April 2015), *Utilities Policy* (December 2018, June 2018, March 2018, Jan. 2017, Oct. 2016, Jan. 2015, June 2015, July 2015, August 2015, Oct. 2015, April 2016; July 2016), PNAS (Dec. 2014), *Environmental Science & Technology* (Nov. 2014, March 2016; April 2018), *European Journal of Transport and Infrastructure Research* (Sept. 2014, Nov. 2017), *Climatic Change* (June 2018, Sept. 2014)*, Transportation Research Part D: Transport and Environment* (June 2014, March 2018), *Electric Power Systems Research* (Mar. 2014), *International Journal of Management Science and Engineering Management* (August 2013), *Policy Sciences* (June 2013), *Environmental Science and Technology* (August 2013), Academy of Finland (April 2013), Nazarbayev University (Winter 2013; Fall 2013; Winter 2017), *Journal of Regulatory Economics* (January 2013), New Jersey Department of Environmental Protection (May 2013)

Invited Academic Activities

Peer Reviewer, U.S. Environmental Protection Agency, Integrated Planning Model, Fall 2020.
International Conference of Applied Energy, "Applied Energy Symposium: MIT A+B," Session co-Chair, May 22-23, 2019.
Geographical Sciences Committee, National Academies of Sciences, Engineering and Medicine, "Climate Change, Coastal Flooding, and the Electric Power Grid," December 6, 2018.
China-US 2018 Joint Eco-environmental Symposium: Advances in Critical Needs for the Nexus of Food, Energy, and Water Systems, Invited Keynote Speaker, October 24-28, 2018
Symposium on Realizing the Value of Nuclear Engineering – A Celebration of Michael Golay's Career, Cambridge, MA, March 26-27, 2018
Peer Reviewer, US Department of Energy, International Electricity Market Model (Nov. 2016)
University of Texas Interdisciplinary Electricity Conference, "The Nexus of Markets and the Environment," Austin, TX, April 21-22, 2016
Initiative for Sustainable Electric Power Systems Workshop, Penn State University, November 19-20, 2015, invited speaker
INFORMS 2015, organized session on Optimizing Reliability and Resiliency of Electric Power Systems, November 2015
University of Texas Interdisciplinary Electricity Conference, "The Nexus of Markets and the Environment," Austin, TX, April 9-10, 2015
Organizing Committee, Center for Research in Regulated Industries, Rutgers Business School, 34th Annual Eastern Conference
Session Chair, FERC Workshop/Trans-Atlantic Infraday, Electricity Markets Restructuring, Nov. 7, 2014
Invited Lecturer, Center for Sustainable Electric Power Systems Seminar, Penn State University, October 14, 2014
Rutgers Energy Institute, 9th Annual Symposium, "Will the Potential for a Death Spiral in Electricity Rates Hinder Transformation of the Electric Power System?", May 6, 2014
Invited Panelist, 2014 Biennial Workshop in Service Engineering (BeWiSE), Penn State University, September 16-17, 2014
Technical Program Committee, Council of Engineering Systems Universities (June 8-11, 2014)
Invited Participant, KAPSRC, Workshop on Energy Systems Modeling (October 3, 2013)
Invited Participant, MIT Conference on Modeling Social, Technical and Natural Systems for Policy (September 25-27, 2013)
Discussant, Center for Research in Regulated Industries (May 16 & 17, 2013)
Expert participant in *Gathering Global Intelligence to Accelerate Development—Foreign Experts Traveling in Anhui Specialized in New Energy*, (September 24-27, 2012)
Participant, Council of Engineering Systems Universities Conference, Delft, (June 18-20, 2012)

OTHER PROFESSIONAL ACTIVITIES

International Activities

- Peer Review of Multilateral Cross-Border Power Trade, U.S. Department of State and National Association of Regulatory Utility Commissioners, Kuching Malaysia, August 28-29, 2024
- Peer Review of Competitive Wholesale Electricity Market Establishment Strategies, U.S. Department of State and National Association of Regulatory Utility Commissioners, Ulaanbaatar, Mongolia, May 27-29, 2024
- Sustainable Development of Power Sector and Enhancement of Electricity Trade in the South Asian Region: Policy, Regulatory Issues and Challenges, USAID, January 15, 2016, New Delhi, India
- Capacity Building Program for Designing, Managing and Operating a Power Trading Entity in Nepal, USAID, September 14-18, 2015
- Workshop on Efficient and Effective Electricity Market Design, Operation and Management, Kenya, USAID, Feb. 1-5, 2010
- Regional Electricity Markets Workshop, Libreville, Gabon, USAID, January 25-30, 2009

- Electricity Market Development Program, Bentota, Sri Lanka USAID, August 18-20, 2008
- Electricity Market Development Program, Dhaka, Bangladesh, USAID, August 13-15, 2008

Senior Advisor, Digital Wind, January 1, 2025 to present

Consumer Advisory Council, New York Independent System Operator, March 18, 2011 to December 1, 2013,
Co-Chair.

Energy Services Providers, Troy, NY, Director, March 2005 to July 2006
Member of the Board of Directors of a retail electricity supplier.

Validigm Corporation, New York, NY, *Director*, June 2000 to December 2000
Member of the Board of Directors of a high-tech, computer network evaluation and applications company.

HONORS AND AWARDS

Associate Member, Sigma Xi, Scientific Research Honor Society of North America
Member, Tau Beta Pi, National Engineering Honor Society
Member, Alpha Sigma Nu, American Nuclear Society Honor Society
Twice awarded the Navy Achievement Medal

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania	:	Docket No. A-2025-3059443

VERIFICATION

I, Frank A. Felder, Ph.D., hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 1, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. Section 4904 (relating to unsworn falsification to authorities).

DATED: July 8, 2026 Signature: Frank A. Felder

Frank A. Felder, Ph.D.

Address: Independent Electricity Consultants LLC
1855 Saint Francis Street
#1612
Reston, VA 20190

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Build Approximately 1.1 Miles of New Parallel Double Circuit 230 kV Transmission Taps that are Needed to Connect the Existing Susquehanna-Harwood #1 & #2 Transmission Lines on the New Tomhicken 230 kV Switchyard that are Respectively Located in Luzerne County, Pennsylvania	:	Docket No.: A-2025-3059443

SURREBUTTAL TESTIMONY

OF

Frank A. Felder, Ph.D.

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Date Served: September 4, 2026

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Introduction

Q. Please state your name and business address.

A. My name is Frank A. Felder, and my business address is 1855 Saint Francis Street, #1612, Reston, VA, 20190.

Q. By whom are you employed and in what capacity?

A. I am a Principal at Independent Electricity Consultants LLC.[1]

Q. Are you the Frank A. Felder who submitted direct testimony in this matter?

A. Yes.[2]

Q. What is the purpose of your surrebuttal testimony in this case?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of John D. Taylor (Witness Taylor).[3] I am providing surrebuttal testimony at the request of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. Have you prepared Exhibits to accompany your testimony?

A. No.

Q. Please summarize PPL's proposed project (Project).

A. As I stated in my direct testimony, PPL submits that the proposed Project is needed immediately to serve one new customer ("Customer"), a data center, based on its request for 230 kV electrical service by March 2027 ("Project"). According to PPL's direct

[1] https://www.independentelectricityconsultants.com/.

[2] Before the Pennsylvania Public Utility Commission, Letter of Notification of PPL Electric Utilities Corporation Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Build Approximately 1.1 Miles of New Parallel Double Circuit 230 kV Transmission Taps that are Needed to Connect the Existing Susquehanna-Harwood #1 & #2 Transmission Lines on the New Tomhicken 230 kV Switchyard that are Respectively Located in Luzerne County, Pennsylvania, Docket No. A-20253059443, Statement NO. 1-R, Direct Testimony of Frank A. Felder, July 8, 2026, hereafter "Felder Direct".

[3] Before the Pennsylvania Public Utility Commission, Letter of Notification of PPL Electric Utilities Corporation Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Build Approximately 1.1 Miles of New Parallel Double Circuit 230 kV Transmission Taps that are Needed to Connect the Existing Susquehanna-Harwood #1 & #2 Transmission Lines on the New Tomhicken 230 kV Switchyard that are Respectively Located in Luzerne County, Pennsylvania, Docket No. A-20253059443, Statement NO. 5-R, Rebuttal Testimony of John D. Taylor, August 7, 2026, hereafter "Taylor Rebuttal".

testimony, the Customer's load ramping schedule will increase in stages from an initial load of 12 megawatts ("MW") to approximately 276 MW by December 2027, and approximately 965 MW by 2033.[4]

I. PPL Rebuttal Testimony Related to Frank A. Felder's Direct Testimony

Q. Please summarize PPL's rebuttal testimony responding to your direct testimony.

A. I am responding to the following claims from the Rebuttal testimony of John D. Taylor: 1) there is no policy gap; 2) the tariff issues I raise are out of scope; 3) large loads should not be curtailed before the loads of ordinary ratepayers; 4) PPL does not have extensive discretion in its arrangements with large loads; 5) Federal Energy Regulatory Commission ("FERC") and PJM are addressing resource adequacy; 6) requiring PPL to have a large load registry is premature and potentially duplicative; 7) Reliability Backstop Procurement ("RBP") costs should not be assigned in this proceeding; and 8) the PPL tariff provision LP-6 addresses the stranded cost issues that I raise.

Q. Please summarize your rebuttal.

A. I rebut each of the points that Witness Taylor raises. First, Witness Taylor misconstrues ongoing FERC, PJM, and Pennsylvania Public Utility Commission (Commission or PUC) activity as resolving the policy gap, when it instead shows that a policy gap needs to be addressed. Further developments since my Direct Testimony on July 8, 2026, some before and some after the date of Witness Taylor's Rebuttal, make it crystal clear that this policy gap exists and that the Commission needs to act. If the Commission does not act to address these policy gaps regarding this Project, whether in this proceeding

[4] Felder Direct, p. 5, lines 4-12.

or another proceeding, it will not be maintaining reliability and protecting ordinary ratepayers from unwarranted cost increases.

Second, Witness Taylor ignores that PPL, not the OCA, raised its obligation to serve customers in this proceeding to justify the Project. Witness Taylor also ignores that, on July 23, 2026, PPL signed the Ratepayer Protection Pledge, which commits PPL to preventing ordinary ratepayers from negative reliability and cost impacts due to large loads. Thus, it is PPL, not the OCA, that opened the door regarding the need for tariff provisions to protect consumers from the reliability and cost impacts of this project.

Third, Witness Taylor does not dispute any of the evidence I presented in my Direct Testimony regarding the reliability reductions, specifically resource adequacy reductions, due to large loads or their potential cost impacts on ordinary ratepayers. He does not question the underlying logic and evidence I presented in my Direct Testimony to show that if large loads are connected to PPL's distribution system without sufficient tariff protections, they will reduce reliability and raise costs and risks for ordinary ratepayers.

Q. Given the importance of recent developments, please provide a timeline of key dates and their importance.

A. Table SR1 lists the key dates relevant to my Rebuttal.

Table SR1: Key Dates and Issues Related to Witness Felder's Surrebuttal Testimony

Date	Topic
May 13, 2026	PPL Witness Joseph Lookup submits Direct Testimony in this proceeding. "The Project is required to comply with PPL Electric's obligation to provide non-discriminatory service to a customer facility at 69 kV or above, and PPL Electric's general right and obligation to serve customers in its service territory, subject to the terms and conditions of its tariffs and certificate of public convenience."[5]

[5] Direct Testimony of Joseph Lookup, May 13, 2026, p. 3, lines 14-17.

Date	Topic
June 22, 2026	The PUC issues requests for comments for Potential Regulations for Interconnecting Electric Loads Docket No. L-2025-3059032.[6]
July 8, 2026	OCA Witness Felder submits Direct Testimony.
July 23, 2026	PPL signs the Ratepayer Protection Pledge,[7] which states that data centers will build, bring or buy new power supplies, pay for new power delivery infrastructure upgrades, and contribute to a more reliable grid.[8]
July 27, 2026	PJM Board issues its decisions regarding Reliability Backstop Procurement (RBP) and Interim Resource Adequacy Service and Large Load Registry (IRAS), with the associated FERC filings to follow.
July 31, 2026	PJM submits its FERC RBP filing.[9]
August 6, 2026	Statement of Chairman Stephen M. DeFrank, PA PUC, noting the work that lies ahead regarding large load interconnections.[10]
August 7, 2026	PPL Witness Taylor submits his Rebuttal Testimony.
August 13, 2026	PJM submits its FERC IRAS filing.[11]
August 18, 2026	PA Governor Executive Order 2026-05 makes clear that the PUC needs to act with "the rapid development of rules, procedures and orders" to limit the reliability and cost impacts caused by data centers.[12]
August 27, 2026	Statement of Chairman Stephen M. DeFrank, PA PUC, commending the example of a data center bringing new capacity and fully paying for transmission upgrades, and urging others to follow it.[13]

1

[6] PAPUC, Potential Regulations for Interconnecting Electric Loads Docket No. L-2025-3059032, June 22, 2026.

[7] PPL, PPL Corporation signs Ratepayer Protection Pledge and highlights existing customer protections in Pennsylvania and Kentucky, July 23, 2026**,** https://investors.pplweb.com/2026-07-23-PPL-Corporation-signs-Ratepayer-Protection-Pledge-and-highlights-existing-customer-protections-in-Pennsylvania-and-Kentucky

[8] The White House, Ratepayer Protection Pledge, March 4, 2026, https://www.whitehouse.gov/releases/2026/03/ratepayer-protection-pledge/.

[9] PJM Interconnection, L.L.C., *Reliability Backstop Procurement to Address Resource Adequacy Concerns Stemming From Large Loads*, Docket No. ER26-3380-000 (F.E.R.C. filed July 31, 2026), hereafter PJM RBP FERC Filing.

[10] Statement of Chairman Stephen M. DeFrank, Letter of Notification of PPL Electric Utilities Corporation for Approval to Construct 138 kV Transmission Lines, Public Meeting of August 6, 2026, Agenda No. 3062201-TUS, Docket No. A-2026-3062201.

[11] PJM Interconnection, L.L.C., *Proposal of PJM Interconnection, L.L.C. to Establish Interim Resource Adequacy Service and a Large Load Registry to Address System Reliability*, Docket No. ER26-3515-000 (F.E.R.C. filed August 13, 2026), hereafter PJM IRAS FERC Filing.

[12] Commonwealth of Pennsylvania Governor's Office, Executive Order 2026-05 – Protecting Pennsylvania Consumers from Data Center Impacts, August 18, 2026, p. 6, https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/eo2026_05_protecting%20pennsylvania%20consumers%20from%20data%20center%20impacts_final_executed.pdf.

[13] Statement of Chairman Stephen M. DeFrank, Letter of Notification of Mid-Atlantic Interstate Transmission, LLC (MAIT), Public Meeting of August 27, 2026, Agenda No. 3063643-TUS, Docket No. A-2026-3063643.

II. There is a Policy Gap Requiring Commission Action

Q. What reasons does Mr. Talyor provide to support his claim that there is no policy gap?

A. Witness Taylor provides several reasons why there is no policy gap. First, he asserts that "The Commission has already addressed large load tariff policy through its model tariff proceeding, and the respective roles of the Commission and FERC are established."[14] Second, Witness Taylor states that the recent FERC Show Cause Order[15] and PJM developments demonstrate that the issues I identify are being addressed.[16]

Q. What is your response to these reasons offered by Witness Taylor?

A. Witness Taylor's claim that the Commission has already addressed the large load tariff policy through its model tariff proceeding is not held by the Chairman of the Commission. On August 6, 2026, the day prior to Witness Taylor submitting his Rebuttal, Chairman DeFrank issued the following statement regarding a PPL request to build transmission facilities, which is worth reading in full (emphasis added):[17]

> Before the Commission is the Letter of Notification filed by PPL Electric Utilities Corporation (PPL or the Company) on May 1, 2026. PPL seeks approval to build approximately 0.25 miles of new double circuit 138 kV transmission taps, connect existing transmission lines to the new Pitney 138 kV Switchyard, and build two 0.1-mile-long double circuit transmission lines to a new customer-owned substation located in East Lampeter Township, Lancaster County. As explained in PPL's filing, this LON Project is needed to meet the electric needs and demands of an existing customer requesting upgrades to its transmission-level service. The customer is requesting an upgrade to receive an initial load of 130 MW in 2027. The customer then plans to increase its load to approximately 350 MW by 2028. Consequently, upon energization this customer will fall within the category of a "large load" interconnection pursuant to the Commission's Large Load Model Tariff, defined as individual customers exceeding 50 MW of demand.

[14] Taylor Rebuttal, p. 12, lines 10-11.
[15] Taylor Rebuttal, p. 12, line 14 and p. 13, lines 6-17.
[16] Taylor Rebuttal, p. 13, lines 6-7.
[17] Statement of Chairman Stephen M. DeFrank, Letter of Notification of PPL Electric Utilities Corporation for Approval to Construct 138 kV Transmission Lines, Public Meeting of August 6, 2026, Agenda No. 3062201-TUS, Docket No. A-2026-3062201.

> **I find it appropriate to use this proceeding to note the work that lies ahead for this Commission in the large load interconnection arena, particularly regarding cost allocation.** Herein, PPL estimates a total cost for the project of $36.4 million. The Company proposes to recover $21.3 million from the customer seeking interconnection while placing the responsibility for the remaining $14.9 million on the Company itself, and therefore ultimately its existing ratepayers.
>
> The Commission has taken a significant step in addressing large load interconnection issues through our aforementioned Large Load Model Tariff. Furthermore, PPL is to be commended for being the first utility in the Commonwealth with a large load tariff approved by this Commission that addresses a number of key issues, including universal service cost recovery, load ramping, MW size, security obligations, exit fees, and interruptibility options. **However, as I noted in my statement approving PPL's Tariff, the Company has not adopted the Commission supported "but for" test when allocating network upgrade costs for large load interconnection.**
>
> We must strive to navigate this energy transition toward an affordable and reliable outcome. **It is evident from review of this LON Project that more work is needed here at the Commission, in coordination with our regulated utilities, customers, and stakeholders, to craft policies that fairly allocate costs of large load interconnection in a way that encourages economic development while maintaining affordability and reliability. With that said, I encourage our electric distribution companies to consider operational and tariff modifications that can support these endeavors.**
>
> Chairman DeFrank's statement made it clear that "work lies ahead" to protect consumers from data center costs while maintaining reliability, including "operational and tariff modifications."

Q. Is Chairman DeFrank the only one who believes that the Commission needs to act?

A. No, the Governor of Pennsylvania also believes rapid action is required. On August 18, 2026, after the submission of the Taylor Rebuttal, the Office of the Pennsylvania Governor issued Executive Order 2026-05 – Protecting Pennsylvania Consumers from

Data Center Impacts (Governor's Executive Order).[18] In Section 3, the Governor's Executive Order states (emphasis added):[19]

> **a. To limit reliability impacts on the electric system caused by data centers, the Governor's Special Counsel for Energy Affordability ("Special Counsel") shall engage with the Pennsylvania Public Utility Commission ("Commission"), and shall advocate for the rapid development of rules, procedures, and orders** that would:
>
> **(1)** Ensure each electric utility that has received a request to interconnect a data center in its territory files with the Commission revisions to both its pre-emergency interim resource adequacy service (IRAS) and emergency load control procedures so that utilities curtail data centers prior to any other customer during pre-emergency IRAS or emergency events, unless the data center customer has secured incremental electric capacity for the entirety of its demand; and
>
> **(2)** Ensure that utilities do not classify a data center as critical load exempt from curtailment during pre-emergency or emergency events.
>
> **b. To limit electric system costs caused by data centers from being imposed on other customers, the Special Counsel shall engage with the Commission, and shall advocate for the rapid development of rules, procedures, and orders that would allow for the timely approval of utility tariffs** that accomplish the following:
>
> **(1)** Charge the appropriate data center customers for any PJM reliability backstop auction costs in accordance with the procedures ultimately approved by the Federal Energy Regulatory Commission in docket ER26-3380-000; and
>
> **(2)** Prevent an electric utility from charging non-data center customers for backstop auction costs, including in the event that a data center becomes insolvent or is otherwise not able to pay the auction costs assigned to it; and
>
> **(3)** Ensure that data center customers pay all Commission-jurisdictional interconnection costs that the utility incurs due to the development of data centers.
>
> **c. In advance of PJM's reliability backstop auction and related actions, the Special Counsel shall engage with the Commission, and shall advocate for the rapid development of rules, procedures, and orders**:
>
> **(1)** For electric utilities to submit megawatt adjustments for any reliability backstop auction target in accordance with the procedures ultimately

[18] Commonwealth of Pennsylvania Governor's Office, Executive Order 2026-05 – Protecting Pennsylvania Consumers from Data Center Impacts, August 18, 2026, p. 6, https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/eo2026_05_protecting%20pennsylvania%20consumers%20from%20data%20center%20impacts_final_executed.pdf.

[19] Commonwealth of Pennsylvania Governor's Office, Executive Order 2026-05 – Protecting Pennsylvania Consumers from Data Center Impacts, August 18, 2026, pp. 6-7, https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/eo2026_05_protecting%20pennsylvania%20consumers%20from%20data%20center%20impacts_final_executed.pdf.

approved by the Federal Energy Regulatory Commission in docket ER26-3380-000; and
(2) For electric utilities to register large loads in PJM's large load registry, including any locational requirements for incremental electric capacity; and
(3) For implementation of credits pertaining to PJM's pre-emergency IRAS program following the Federal Energy Regulatory Commission's ultimate disposition of relevant rules and procedures in docket ER26-3515-000.

The Governor's Executive Order makes clear that, in general, rapid action needs to be taken, specifically taken in advance of the PJM RBP (PJM's reliability backstop auction). The Commission should avail itself of this proceeding to act rapidly.

Q. What is your response to Witness Taylor's reason that ongoing FERC and PJM activities demonstrate that the policy gap has been addressed?

A. The key word is "ongoing."[20] The activities that Witness Taylor refers to are, as he observed, ongoing, that is, not complete.[21] As the PJM Board of Managers emphasized in its Decisional Letter related to the RBP and IRAS and the associated FERC filings, its FERC proposals require cooperation among Public Utilities Commissions, transmission owners, and electric distribution companies.[22] Furthermore, as both the Governor of Pennsylvania and the Chairman of the PUC have made clear, regardless of what has happened or is happening, there is still a policy gap that needs to be addressed to protect ordinary ratepayers from the reliability and cost impacts of large loads.

Q. What major PJM developments have occurred since you filed your direct testimony on July 8, 2026?

A. PJM made two recent FERC filings, one proposing the Reliability Backstop Procurement (RBP) on July 31, 2026, and the other the Interim Resource Adequacy Service

[20] Taylor Rebuttal, p. 7, line 2.
[21] Although the Commission issued its final Large Load Tariff Framework on May 13, 2026, it issued a request for PAPUC, Potential Regulations for Interconnecting Electric Loads Docket No. L-2025-3059032 on June 22, 2026.
[22] Paula Conboy, Chair, PJM Board of Managers, PJM Interconnection L.L.C., Board Decisional Letter on Critical Issue Fast Path – Reliability Backstop Procurement and Connect and Manage, July 27. 2026, https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2026/20260727-board-decisional-letter-on-cifp-reliability-backstop-procurement-and-connect-and-manage.pdf.

(IRAS) and Large Load Registry on August 13, 2026.[23] Given the ongoing and dynamic nature of the RBP and IRAS filings at FERC, the key takeaway is that Pennsylvania needs to act now to protect ordinary ratepayers from reduced reliability and shifting costs, regardless of what FERC approves.

For the purposes of this filing, the RBP proposal has the following relevant elements:

a. Establishes a final RBP target based on the observed MW unforced capacity ("UCAP") shortfall in the Base Residual Auction (BRA) for the delivery year 2028/2029[24] and any qualifying RBP offset UCAP MW;[25]

b. PJM makes a one-time procurement[26] of RBP UCAP from RBP resources for a fixed term of up to 15 years, starting with the 2028/2029 delivery year and ending with the 2042/2043 delivery year;[27]

c. PJM serves as the counterparty that directly procures the RBP resources on behalf of buyers;[28]

d. Load is allocated responsibility as RBP UCAP will be allocated RBP charges[29] and must post credit associated with the obligation;[30]

e. RBP charges are allocated to electric distributor zones/areas to load serving entities (LSE) within the relevant zone/area.[31]

f. Requires states to assign the RBP costs to retail loads[32] via the RBP obligation (RBO), which is the state and/or RERRA [relevant

[23] PJM Interconnection, L.L.C., *Reliability Backstop Procurement to Address Resource Adequacy Concerns Stemming From Large Loads*, Docket No. ER26-3380-000 (F.E.R.C. filed July 31, 2026), hereafter PJM RBP FERC Filing, and PJM Interconnection, L.L.C., *Proposal of PJM Interconnection, L.L.C. to Establish Interim Resource Adequacy Service and a Large Load Registry to Address System Reliability*, Docket No. ER26-3515-000 (F.E.R.C. filed August 13, 2026), hereafter PJM IRAS FERC Filing.
[24] PJM RBP FERC Filing, p. 8
[25] PJM RBP FERC Filing, p. 32
[26] PJM RBP FERC Filing, p. 25.
[27] PJM RBP FERC Filing, p. 8.
[28] PJM RBP FERC Filing, p. 47.
[29] PJM RBP FERC Filing, p. 82.
[30] PJM RBP FERC Filing, p. 114.
[31] PJM RBP FERC Filing, pp. 96-97.
[32] PJM RBP FERC Filing, p. 11.

electric retail regulatory authority]-determined allocation of RBP UCAP MW to LSEs within each zone/area;[33]

g. If RBOs are not reported to PJM, PJM will allocate the RBO to all load in the zone/area based on its peak load contribution;[34]

Relevant to the purposes of this filing, PJM's IRAS and Large Load Registry proposal has the following elements:

h. Establishes the Large Load Registry that PJM maintains[35] to improve the accuracy and transparency of load forecasts and to administer the RBP and IRAS;[36]

i. Proposes IRAS, a new capacity product for large loads that, after May 31, 2027,[37] neither brings new capacity (bring your own new capacity or BYONC)[38] nor purchases capacity from the RBP; such loads are to be curtailed before pre-emergency load management response[39] by electric distributors based on state-sanctioned load reduction plans;[40]

j. Encourages states to re-evaluate their load reduction plans;[41]

k. Proposes that curtailed IRAS load is compensated[42] and the costs assigned through electric distribution tariffs;[43] and

l. Excludes certain new large loads from the Variable Resource Requirement (VRR) Curve to protect ordinary ratepayers from further capacity price increases.[44]

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[33] PJM RBP FERC Filing, p. 98
[34] PJM RBP FERC Filing, p. 99.
[35] PJM IRAS FERC Filing, p. 5.
[36] PJM IRAS FERC Filing, p. 17 and, pp. 45-46, "In addition, PJM proposes to obtain information from Electric Distributors, to coordinate with applicable Transmission Owners and Electric Distributors, as needed, to validate the information provided in the Large Load Registry, and/or to consult with relevant Large Loads."
[37] PJM IRAS FERC Filing, p. 52.
[38] PJM RBP FERC Filing, p. 23.
[39] PJM IRAS FERC Filing, p. 21.
[40] PJM IRAS FERC Filing, p. 6 and p. 76, "Interim Resource Adequacy Service may be called on, as necessary, to maintain required RTO/Zonal Reserves, IROLs [Interconnection Reliability Operating Limits] within limits, and/or prevent cascading outages if available economic generation is not sufficient."
[41] PJM IRAS FERC Filing, p. 3.
[42] PJM IRAS FERC Filing, p. 17.
[43] PJM IRAS FERC Filing, p. 104: "The IRAS rate is compensation for a wholesale load reduction service, but the entities to be paid the rate and the loads to be charged to support such compensation must be determined at the state level consistent with the Electric Distributor's state-approved load reduction plans and other state-approved programs, ratees, and rules."
[44] PJM IRAS FERC Filing, pp. 5-6.

All these provisions, except for the last one (item l.), require state action by the Commission and electric distribution utilities.

III. Tariff Issues Raised by Witness Felder Are in Scope

Q. Witness Taylor claims that tariff issues you raised are out of scope. What reasons does he give to support his claim?

A. Witness Taylor claims that the "tariff-related issues raised by Witness Felder are outside the scope of relief in this proceeding"[45] since PPL is seeking approval to construct transmission facilities in a LON proceeding and not "seeking approval of a new tariff, modifications to Rate Schedule LP-6, or approval of new statewide large-load proceedings."[46] He further points out that many of the points I raised were either recently considered by the Commission in its large-load proceedings or are currently being addressed by FERC and PJM.[47]

Q. Do you agree with Witness Taylor that the tariff-related issues you raised are out of scope?

A. No. First, PPL has a statutory obligation to provide safe and reliable service to all customers. Title 66, Chapter 28 of the Pennsylvania Code states:

> **§ 2807. Duties of electric distribution companies.**
> **(a) General rule.--**Each electric distribution company shall maintain the integrity of the distribution system at least in conformity with the National Electric Safety Code and such other standards practiced by the industry in a manner sufficient to provide safe and reliable service to all customers connected to the system consistent with this title and the commission's regulations. In performing such duties, the electric distribution company shall implement procedures to require all electric generation suppliers to deliver energy to the electric distribution company at locations and in amounts which are adequate to meet the energy supplier's obligations to its customers.

[45] Taylor Rebuttal, p. 39, lines 1-2.
[46] Taylor Rebuttal, p. 39, lines 1-5.
[47] Taylor Rebuttal, p. 39, lines 6-11.

By interconnecting large-load customers without ensuring sufficient supply to serve them, PPL is not providing safe and reliable service to all customers. As my direct testimony makes clear, and as neither Witness Taylor nor any PPL witness rebutted, interconnecting large loads without the protections I recommend reduces resource adequacy and may raise costs for ordinary ratepayers.[48]

Second, in this proceeding PPL made clear that "The Project is required to comply with PPL Electric's obligation to provide non-discriminatory service to a customer facility at 69 kV or above, and PPL Electric's general right and obligation to serve customers in its service territory, subject to the terms and conditions of its tariffs and certificate of public convenience."[49] Thus this project is intended to satisfy PPL's obligation to serve the customer of the Project and "to serve customers in its service territory." PPL cannot claim it is acting under its obligation to serve customers while also taking actions that reduce reliability and potentially raise customer costs, which it does not dispute. Furthermore, PPL has signed the Ratepayer Protection Pledge, which, as discussed above, commits it to maintaining reliability for ordinary ratepayers and protecting them from cost increases.

Third, the policy gap discussion above makes clear that the Large Load Model Tariff did not completely address large load issues and that more needs to be done. Furthermore, as discussed above, ongoing activities at FERC and PJM also require action to support those efforts and fill any remaining gaps depending on how FERC disposes of PJM's RBP and CIFP filings.

[48] Felder Direct, p. 18, lines 1-7.
[49] Direct Testimony of Joseph Lookup, Statement No. 1, Docket No. A-2025-3059443, May 13, 2026, p. 3, lines 14-17.

Fourth, on August 27, 2026, Chairman DeFrank highlighted as an "exemplary" transaction the example of the Mid-Atlantic Interstate Transmission, LLC project using a LON process to maintain reliability and protect ordinary ratepayers (emphasis added):[50]

> Our electrical grid is facing an unprecedented challenge from the growth of data centers and other large loads on our system. My main priority is allowing these customers to interconnect to our system in an orderly fashion while maintaining reliability and protecting ordinary ratepayers from unwarranted cost increases. **Transactions like this one are exemplary of what such a process should look like.** This shows all the relevant parties - generators, transmission owners, and large load customers - working together responsibly to achieve that deployment. I appreciate all the entities involved for working towards a good outcome and urge others to look to this example going forward.

Thus, according to the Chairman of the Commission, it is not only appropriate to use a LON process to maintain reliability and protect ordinary ratepayers from unwarranted cost increases, but it is also a model process.

Q. Witness Taylor raises the issue of resource adequacy as an example of tariff-related issues that are out of scope. What reasons does he provide for this claim?

A. Witness Taylor makes several points in responding to my direct testimony. First, he claims FERC and PJM are addressing resource adequacy.[51] Second, that my proposal requires PPL to make a resource adequacy determination before PJM acts.[52] Third, resource adequacy is not directly relevant.[53] Fourth, that the Commission did not adopt a bring your own generation ("BYOG") in its Interconnection and Tariffs for Large Load Customer.[54] Finally, that I consistently use the two terms reliability and resource adequacy interchangeably.[55]

[50] Statement of Chairman Stephen M. DeFrank, Letter of Notification of Mid-Atlantic Interstate Transmission, LLC (MAIT), Public Meeting of August 27, 2026, Agenda No. 3063643-TUS, Docket No. A-2026-3063643.
[51] Taylor Rebuttal, p. 41, lines 16-23 and p. 47, line 15 through p. 49, line 4.
[52] Taylor Rebuttal, p. 48, lines 17-19.
[53] Taylor Rebuttal, p. 52, line 11, p. 53, line 4.
[54] Taylor Rebuttal, p. 54, lines 7-16.
[55] Taylor Rebuttal, p. 54, starting line 18, p. 55, line 4.

Q. What is your assessment of Witness Taylor's reasons for resource adequacy being out of scope in this proceeding?

A. I do not find Witness Taylor's reasoning persuasive. First, for the reasons I presented above, the issues of maintaining reliability and protecting ordinary ratepayers from unwarranted cost increases are within this proceeding's scope.

Second, PJM's RBP and IRAS filings require EDCs like PPL to act. The RBP filing requires EDCs to provide PJM with key information regarding large loads that are planning to interconnect to an EDC's system so that PJM can set the amount of capacity to be procured in the RBP auction. PJM needs information by September 2026 regarding the timing and size of these large loads, and whether they plan to bring their own new capacity (BYONC) to accurately determine how much capacity it procures. If these values are inaccurate, PJM may under-procure capacity, reducing resource adequacy and potentially increasing the frequency, duration, and magnitude of rolling blackouts. Or they may over-purchase RBP capacity, the costs of which may end up being assigned to ordinary ratepayers.[56] If PPL's filing is approved without the protections I recommend in my direct testimony,[57] the Commission risks reduced reliability and increased stranded investments.

Third, Chairman's DeFrank's August 27, 2026, statement makes it clear that having customers bring their own generation via a LON process is commendable:[58]

> I would like to commend the parties involved in this project, because this is a perfect example of how transmission buildout to serve new large loads should be planned and paid for. In this instance, we have a tech company Microsoft bringing new capacity onto our system. Restarting the reactor at the Crane Clean Energy Center will add 859 MW of highly reliable power to a system in serious need of new generation. Importantly, this new power being commissioned by Constellation will be funded entirely by Microsoft.

[56] PJM RBP FERC Filing, p. 99.
[57] Felder Direct, p. 18, lines 1-7.
[58] Statement of Chairman Stephen M. DeFrank, Letter of Notification of Mid-Atlantic Interstate Transmission, LLC (MAIT), Public Meeting of August 27, 2026, Agenda No. 3063643-TUS, Docket No. A-2026-3063643.

Fourth, Witness Taylor takes issue with my use of the terms 'reliability" and 'resource adequacy.' As my direct testimony and interrogatory response to PPL make clear, I use the term 'reliability" broadly to include resource (generation) adequacy.[59] Reliability also includes operational security, that is, the ability of the transmission system to withstand outages and maintain service to customers while operating within transmission limits, such as thermal, stability, contingency, and other restrictions. My general use of the term is also consistent with its use in the broader public policy discussions, such as the Ratepayer Protection Pledge, the Governor's Executive Order, and the two statements of Chairman DeFrank. The Public Utility Code also defines "reliability" to include resource adequacy.[60] Witness Taylor's underlying point, I believe, is to try to restrict this proceeding to the transmission reliability issues that the PPL Project is intended to address, which I have already covered.

Q. Witness Taylor states that stranded costs are out of scope for this proceeding. What are the reasons he gives for making this claim?

A. Witness Taylor acknowledges that "customer nonperformance and stranded cost risk are legitimate issues."[61] He states, however, that stranded-cost protections such as minimum load commitments and credit support provisions, among others, were recently considered by the Commission in the PPL Electric distribution rate case and in the Commission's broader large-load proceedings.[62]

[59] Felder Direct, p. 8, lines 1-4 and associated footnote 16, which notes that reliability consists of resource adequacy and operational security and cites PPL Witness Lookup's statement that resource adequacy is required for EDUs. Also, see OCA Response to Interrogatories of PPL Electric Utilities Corporation Set I to OCA, PPL to OCA-I-7.
[60] 66 Pa. C.S. § 2803 ("'Reliability.' Includes adequacy and security. As used in this definition, 'adequacy' means the provision of sufficient generation, transmission and distribution capacity so as to supply the aggregate electric power and energy requirements of consumers, taking into account scheduled and unscheduled outages of system facilities…").
[61] Taylor Rebuttal, p. 42, lines 11-13.
[62] Taylor Rebuttal, p. 39, lines 6-10. See also p. 42, line 1 through p.44, line 16.

Q. What is your assessment of Witness Taylor's reasons that the issue of stranded costs being out of scope in this proceeding?

A. I do not find Witness Taylor's reasoning persuasive. First, for the reasons just presented above, protecting ordinary ratepayers from unwarranted cost increases is within this proceeding's scope.

Second, since the PPL rate case and the Commission's publication of the Model Large Load Tariff that Witness Taylor refers to, PPL has signed the Ratepayer Protection Pledge. Thus, if the pledge is to be meaningful, PPL must demonstrate that the Project completely protects ordinary ratepayers from stranded costs. Witness Taylor does not claim that ordinary ratepayers are protected from stranded costs under all circumstances. He does not testify that, if the Customer's projected load does not materialize, even given the provisions of LP-6, ordinary ratepayers would not pay for stranded costs.

Q. Witness Taylor states that transmission cost allocation is out of scope for this proceeding. What are the reasons he gives for making this claim?

A. Witness Taylor states that "FERC-approved tariffs and processes govern those transmission-rate issues [approval of the recovery, allocation, or ratemaking treatment of the Project's transmission costs] and should not be adjudicated indirectly through this project-specific LON proceeding."[63]

Q. What is your assessment of Witness Taylor's reasons that transmission cost allocation is out of scope in this proceeding?

A. I do not find Witness Taylor's reasoning persuasive. First, for the reasons just presented above, protecting ordinary ratepayers from unwarranted cost increases is within this proceeding's scope. Second, recall that on August 6, 2026, Chairman DeFrank, in reference to the PPL Pitney transmission Project, stated: "It is evident from review of this

[63] Taylor Rebuttal, p. 4, lines 11-16.

LON Project that more work is needed here at the Commission, in coordination with our regulated utilities, customers, and stakeholders, to craft policies that fairly allocate costs of large load interconnection in a way that encourages economic development while maintaining affordability and reliability."[64] Third, transmission cost allocation is directly relevant to stranded costs, which, as I discuss above, are within the scope of this proceeding.

IV. Tariff Recommendations by Witness Felder to Protect Ordinary Consumers

Q. Witness Taylor critiques your tariff-related recommendations? What is your response?

A. I would like to respond to each of the following claims by Witness Taylor: 1) large loads should not be curtailed before the loads of ordinary ratepayers; 2) PPL does not have extensive discretion over its arrangements with large loads; 3) FERC and PJM are addressing resource adequacy; 4) requiring PPL to have a large load registry is premature and potentially duplicative; 5) RBP costs should not be assigned in this proceeding; and 6) the PPL Tariff provision LP-6 addresses the stranded cost issues that I raise.

First, large loads should be curtailed before ordinary ratepayers. Witness Taylor asserts without evidence that PPL's load curtailment policies are sufficient but does not demonstrate that they comply with the Ratepayer Protection Pledge. Witness Taylor does not rebut my direct testimony that large-load data centers have backup generation and the financial resources to respond to electricity curtailments, whereas the typical residential ratepayer does not.

[64] Statement of Chairman Stephen M. DeFrank, Letter of Notification of PPL Electric Utilities Corporation for Approval to Construct 138 kV Transmission Lines, Public Meeting of August 6, 2026, Agenda No. 3062201-TUS, Docket No. A-2026-3062201.

In the case that a large load has not BYONC, the Governor's Executive Order states: "**(1)** Ensure each electric utility that has received a request to interconnect a data center in its territory files with the Commission revisions to both its pre-emergency interim resource adequacy service (IRAS) and emergency load control procedures so that utilities curtail data centers prior to any other customer during pre-emergency IRAS or emergency events, unless the data center customer has secured incremental electric capacity for the entirety of its demand."[65]

Witness Taylor responds that this curtailment "could constitute discriminatory service"[66] if part of a mandatory rate but does not dispute that it is permissible as part of an EDC's coordinated load curtailment plans to prevent cascading outages (i.e., blackouts). Notably, this is at odds with PJM's proposed IRAS, which envisions EDCs, such as PPL, curtailing large loads that did not BYONC or purchase capacity via the RBP auction before pre-emergency curtailments. PPL may consider PJM's IRAS proposal discriminatory and therefore not acceptable to implement as an EDC tariff provision, which is why the Commission must act in this proceeding. If the Commission does not act, PPL will interconnect a large load that will exacerbate PJM's resource adequacy shortfalls, which, if it results in the need for load curtailment, may allow large loads with backup generation to continue to receive power from the grid while ordinary ratepayers are curtailed.

Second, my statement that PPL has extensive discretion over its arrangements with large loads was based on PPL's own "cost allocation policy"[67] and advice from OCA Counsel. Witness Taylor confirms this fact in his testimony multiple times. For example,

[65] Governor's Executive Order, 3.a.(1).
[66] Talyor Rebuttal, p. 51, lines 13-14.
[67] PPL Electric Utilities Corporation, Policy on Cost Allocation for Large Customer Interconnections, OCA I-6, Attachment 1.

"The Company [PPL] uses a project-specific engineering and functional analysis to determine the allocation between facilities that primarily serve the Customer and facilities that provide broader transmission system benefits pursuant to PPL Electric's Policy on Cost Allocation for Large Customer Interconnection."[68] Furthermore, PPL interprets the Commission's Large Load Model Tariff as a guideline, claiming that it has discretion as to whether to apply it.[69]

Third, as noted previously, FERC and PJM have discussed resource adequacy extensively but have not finalized the issue. As a result, unless that policy gap is filled, the Customer being supported by the Project will degrade the resource adequacy of PJM unless my recommendations are adopted, as noted previously.

Fourth, requiring PPL to have a large load registry is not premature or potentially duplicative. As noted above, PJM depends on EDCs to provide key information for its proposed large load registry. Even if there were some duplications between PJM and PPL's efforts, Witness Taylor does not claim that any such duplication is costly or burdensome.

Furthermore, the Governor's Executive Order supports a registry: "**(1)** For electric utilities to submit megawatt adjustments for any reliability backstop auction target in accordance with the procedures ultimately approved by the Federal Energy Regulatory Commission in docket ER26-3380-000; and **(2)** For electric utilities to register large loads in PJM's large load registry, including any locational requirements for incremental electric capacity; and **(3)** For implementation of credits pertaining to PJM's pre-emergency IRAS

[68] Taylor Rebuttal, p. 22, lines 2-5. See also, p. 22, lines 8-12, p. 24, line 20 through p. 25, line 6, p. 25, lines 9-10 and lines 18-21, p. 26, lines 10-12, p. 27, lines 15-18, p. 28, lines 18-20, and p. 29, lines 17-19.
[69] OCA Response to Interrogatories of PPL Electric Utilities Corporation Set I to OCA, PPL to OCA-I-20.

program following the Federal Energy Regulatory Commission's ultimate disposition of relevant rules and procedures in docket ER26-3515-000."[70]

Fifth, RBP cost should be assigned in this proceeding, if applicable. To satisfy the Ratepayer Protection Pledge, PPL must determine whether the Customer for the Project plans to take IRAS, pay for RBP capacity, or BYONC. If PPL does not make this determination and PJM assigns RBP costs (referred to as Reliability Backstop Obligations, or RBO) to the PPL zone, ordinary ratepayers may end up paying the RBO. If the Customer plans to BYONC, PPL needs to know so it can inform PJM to reduce RBP capacity for the PPL zone. The Governor's Executive Order states: "**(1)** Charge the appropriate data center customers for any PJM reliability backstop auction costs in accordance with the procedures ultimately approved by the Federal Energy Regulatory Commission in docket ER26-3380-000; and **(2)** Prevent an electric utility from charging non-data center customers for backstop auction costs, including in the event that a data center becomes insolvent or is otherwise not able to pay the auction costs assigned to it."[71]

Six, LP-6 offers some stranded-cost protections, but PPL has not adopted the Commission-supported "but for" test when allocating network upgrade costs for large load interconnection.[72] Furthermore, the Governor's Executive Orders states: "**(3)** Ensure that data center customers pay all Commission-jurisdictional interconnection costs that the utility incurs due to the development of data centers."[73] The Governor's Executive Order provision would provide further stranded-cost protections.

[70] Governor's Executive Order, 3.c.(1), (2), and (3).
[71] Governor's Executive Order, 3.b.(1) and (2).
[72] Statement of Chairman Stephen M. DeFrank, Letter of Notification of PPL Electric Utilities Corporation for Approval to Construct 138 kV Transmission Lines, Public Meeting of August 6, 2026, Agenda No. 3062201-TUS, Docket No. A-2026-3062201.
[73] Governor's Executive Order, 3.b.(3).

V. Conclusion

Q. Does this conclude your testimony?

A. Yes. I reserve the right to update any portion of my testimony as needed if additional relevant information is made available during this proceeding.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania	:	Docket No. A-2025-3059443

VERIFICATION

I, Frank A. Felder, Ph.D., hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 1SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. Section 4904 (relating to unsworn falsification to authorities).

DATED: September 4, 2026

Signature: F Felder

Frank A. Felder, Ph.D.

Address: Independent Electricity Consultants LLC
1855 Saint Francis Street
#1612
Reston, VA 20190

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Build Approximately 1.1 Miles of New Parallel Double Circuit 230 kV Transmission Taps that are Needed to Connect the Existing Susquehanna-Harwood #1 & #2 Transmission Lines on the New Tomhicken 230 kV Switchyard that are Respectively Located in Luzerne County, Pennsylvania	:	Docket No.: A-2025-3059443

DIRECT TESTIMONY

OF

Rao Konidena

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Date Served: July 8, 2026

PUBLIC VERSION

OCA Statement 2 – Direct Testimony of Rao Konidena

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Tomhicken Konidena Testimony DRAFT

I. Introduction

Q: Please state your name and company.

A: My name is Rao Konidena. My business address is Rakon Energy LLC, Roseville, MN 55113.

Q: By whom are you employed and in what capacity?

A: I am the President of Rakon Energy LLC. Rakon Energy is owned and operated by me.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Office of Consumer Advocate ("OCA").

Q: Please describe your background and state your qualifications in transmission planning.

A: I have been an independent energy consultant for almost a decade, primarily focusing on transmission and distribution reliability studies and policy. I worked in Transmission Asset Management at Midcontinent Independent System Operator ("MISO"), similar to PJM, from September 2003 to May 2018. I started as an Applications Engineer for Planning, where I ran transmission reliability studies, transmission capacity calculations, and analysis for the MISO Transmission Expansion Plan ("MTEP").

I was later promoted to Lead, Resource Forecasting in 2006, responsible for a team of engineers running the capacity forecasting software. That forecasting work is incorporated in the MTEP non-transmission alternatives section. After a promotion to Manager of Resource Forecasting in 2009, I led Demand Response and Energy Efficiency forecasting for MTEP.

I worked in compliance, process, and project management for the Transmission Asset Management ("TAM") division as Senior Manager of TAM Operations from 2013 to 2015. In this role, my team and I were responsible for division-wide financial and strategic planning, supporting corporate planning and compliance efforts. I came back to the Policy Studies department in the Principal Policy Advisor role for MISO in 2015, leading the long-term load forecasting project with Purdue University's State Utility Forecasting Group and Applied Energy Group demand response ("DR"), energy efficiency ("EE") and distributed generation ("DG") potential study at MISO.

Before leaving MISO in 2018, I led policy efforts on energy storage and distributed energy resources within economic transmission planning. I presented to MISO state commissions, including the Iowa Utilities Board, the South Dakota State Public Utilities Commission, and the Organization of MISO States.

As an independent consultant, I have submitted direct testimonies on behalf of my clients at the Public Service Commission of Wisconsin (Transmission Line Certificate of Public Convenience & Need docket), Minnesota Public Utilities Commission (Aggregator of Retail Customer docket), Kansas Corporation Commission (Demand Response Aggregator docket), California Public Utilities Commission (Diablo Canyon Power Plant extension docket), North Carolina Utilities Commission (Duke Energy

Carolinas General Rate Case and Duke Energy Consolidated Carbon Plan and Integrated Resource Plans), Maryland Public Service Commission (Transmission Line Certification of Public Convenience And Necessity docket) and Illinois Commerce Commission (Transmission Line Certificate of Public Convenience and Necessity).

I have also provided energy storage expertise to the OCA in the Pennsylvania Public Utilities Commission energy storage Docket No. M-2020-3022877. I provide generic electrical engineering expertise for OCA in the transmission, distribution services and miscellaneous electric issues.

My resume is attached as Appendix A.

Q: Please provide your educational background.

A: I received a Bachelor of Engineering in Electrical & Electronics Engineering from Bangalore University, a Master of Science in Electrical Engineering from the University of Texas at Arlington, and a Master of Business Administration from the University of Minnesota.

Q: In the past, have you provided written testimony before this Commission?

A: Yes. I have previously testified before this Commission in the Letter Of Notification Of PPL Electric Utilities Corporation ("PPL"), Filed Pursuant To 52 Pa. Code Chapter 57 Subchapter G, For Approval To Rebuild The Existing Double- Circuit Stanton-Summit #3 And #4 230 kV Transmission Lines Connecting the Stanton 230 kV Substation And A Two-Pole Turn Structure That Are Respectively Located In Luzerne And Lackawanna Counties, Pennsylvania. Docket No. A-2022-3037374.

I have also testified in the FirstEnergy Pennsylvania Electric Company Base Rate Case. Docket No. R-2024-3047068.

Q: Are you sponsoring any exhibits?

A: Yes. I am sponsoring the following exhibit.

Exhibit RK-1 — PPL Electric Utilities Corporation Policy on Cost Allocation for Large Customer Interconnections (OCA I-6 Attachment 1). This document is PPL's internal cost allocation policy that governs the customer-versus-ratepayer split for large load interconnection projects. PPL confirmed this policy has never been reviewed or approved by this Commission.

Q: Throughout your testimony you use certain terms interchangeably. Can you clarify your use of those terms?

A: Yes. When I refer to "the Tomhicken Switchyard," "the Switchyard," or "the Project," I am referring to the same facility — the Tomhicken 230 kV Switchyard and associated Phase 1 infrastructure that is the subject of this proceeding at Docket No. A-2025-3059443. When I refer to "the network" or "the system" in the transmission context, I am referring to the same thing — PPL's bulk electric transmission system. When I refer to "the Customer" or "the customer," I am referring to the large load customer whose interconnection request is the need driver for this project. These terms are used interchangeably throughout my testimony.

When I refer to an "N-1 contingency," I am referring to the loss of a single transmission element such as a transmission line or transformer — a routine event that all transmission systems must be designed to survive. When I refer to an "N-1 reliability deficiency," I am referring to a planning failure — the finding that the system cannot survive an N-1 contingency without violating thermal ratings or voltage limits. These are distinct concepts: an N-1 contingency is the event; an N-1 reliability deficiency is the consequence when the system was not adequately planned to handle that event.

Q: What is your recommendation to this Commission?

A: The Commission should not approve the $38.4 million ratepayer allocation as proposed. At minimum, the Commission should require PPL to reallocate to the customer all costs attributable to Phase 2-driven design features and the Breaker and a half switchyard configuration, require PPL to submit its cost allocation policy for formal Commission review and approval, and condition any ratepayer allocation on a quantitative demonstration that ratepayer benefits equal or exceed ratepayer costs. The full basis for these recommendations is set forth in the body of my testimony.

In OCA Statement 1, Dr. Frank A. Felder also provides testimony as to why, as a matter of public policy, PPL's proposed cost allocation is inappropriate, addressing matters such as the federal Ratepayer Protection Pledge and the Commission's policy statements regarding cost responsibility for new large load customers, indicating a broad consensus that new large loads (data centers) should pay all of the costs they are causing. I defer to Dr. Felder's testimony on matters of electric policy, but note that our recommendations are aligned.

II. Tomhicken Switchyard Description

Q: Please provide a description of Tomhicken Switchyard.

A: The Tomhicken Switchyard consists of:

- "[A]pproximately 1.1 miles of new double-circuit 230 kilovolt ('kV') transmission taps ('Susquehanna-Tomhicken #1 & #2 230 kV and Tomhicken-Harwood #1 & #2 230 kV lines' or 'Tap Lines') that are needed to connect the existing Susquehanna-Harwood #1 & #2 230 kV Transmission Lines to the new Tomhicken 230 kV Switchyard (the 'Project') and
- the construction of two new 0.1-mile-long 230 kV transmission lines ('Connecting Lines') from the Tomhicken 230 kV Switchyard to a new customer-owned 230-34 kV substation."[1]

PPL states that the "new 230 kV Connecting Lines, Tap Lines and Tomhicken Switchyard are located in Hazle Township, Luzerne County, Pennsylvania."[2]

Q: What is PPL's stated need for the Tomhicken Switchyard?

A: PPL's stated need is Customer load interconnection. The initial load request, the in-service date of the initial load request, the peak load, and the in-service date of the peak load have changed since the Letter of Notification was filed on December 19, 2025.

[1] Page I-1, Attachment I Necessity Statement.
[2] *Id.*

Specifically, in the Letter of Notification ("LON"), PPL stated that a "prospective Customer is requesting 230 kV electrical service with an in-service date of December 15, 2026 and an initial load of 240 MW. The Customer's load will increase in stages to approximately 1,980 MW by 2033."[3]

PPL updated the Customer's peak load to 965 MW in Discovery – "The Customer has since revised their total load request to 965 MW. The Customer's current initial load request is for 12kV with an in-service date of December 15, 2026, and a total load request of 965 MW by 2031."[4]

PPL further updated the initial load request to 12 MW "with an in-service date of March 2027"[5] and stated that the "Customer's load will increase in stages to approximately 276 MW by December 2027, and to approximately 965 MW by 2033."[6]

A further discrepancy exists between PPL's direct testimony stating the customer reaches 965 MW by 2033 and OCA I-1 Attachment 2 HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS.[7] PPL confirmed that the HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS

Similarly, the 276 MW intermediate milestone date differs between direct testimony (December 2027) and OCA I-1(a) (March 2027). PPL confirmed that the

[3] Page 7, LON.
[4] PPL Response to OCA I-1(a).
[5] Line 19, Page 3, PPL Statement No. 1.
[6] Lines 22-23, Page 3, PPL Statement No. 1.
[7] PPL Response to HIGHLY CONFIDENTIAL OCA-I-1 Attachment 2.
[8] PPL Response to HIGHLY CONFIDENTIAL OCA VII-1 (a).

HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS.

Q: Is Tomhicken Switchyard addressing a reliability need?

A: No, the Tomhicken Switchyard is not addressing a pre-existing system reliability need. Rather, it addresses a reliability need that was created by this Customer's peak load interconnection request — specifically, the N-1 reliability deficiency[10] that arises when the customer's 965 MW/1,016 MVA peak load[11] is added to the existing Susquehanna-Harwood lines.

Absent this Customer's peak load request, no reliability need requiring this switchyard would exist because PPL stated that "the existing capacity will be utilized to serve the customer's initial load request".[12] Meaning, the existing Susquehanna-Harwood lines can accommodate the customer's initial load request of 12 MW mentioned above, but cannot accommodate the peak load request of 965 MW.

[9] PPL Response to HIGHLY CONFIDENTIAL OCA VII-1 (a).
[10] Existing Susquehanna – Harwood lines have each summer normal rating of 718 MVA. Source: PPL Response to OCA I-4(b). But if one of them trips, they cannot handle the Customer's 1,016 MVA peak load on top of the existing load.
[11] Megawatts (MW) measure real power — the actual power consumed by the customer's load to perform useful work. Megavolt-amperes (MVA) measure apparent power — the total power the transmission system must carry, which includes both real power (MW) and reactive power (MVAR). The relationship between MW and MVA is governed by the power factor, which represents the ratio of real power to apparent power. A power factor of 0.95 — as assumed here — means that for every 1,016 MVA the transmission system must carry, 965 MW is real power actually consumed by the customer, with the remainder attributable to reactive power requirements. Transmission lines are rated in MVA rather than MW because the physical heating effect on conductors — which determines thermal ratings — depends on the total current flowing through the line, which corresponds to apparent power (MVA) rather than real power (MW) alone. For this reason, comparing the customer's peak demand to transmission line thermal ratings requires converting MW to MVA. The customer's peak demand of 965 MW, assuming a power factor of 0.95, corresponds to approximately 1,016 MVA. 965 MW divided by 0.95 power factor = 1,016 MVA.
[12] PPL Response to OCA I-4(d).

PPL's Mr. Lookup testified that the existing Susquehanna-Harwood lines "are heavily loaded and have a history of transmission congestion."[13] I agree that the existing Susquehanna-Harwood lines have a history of transmission congestion, but I disagree that they are currently heavily loaded due to the following reasons.

First, neither circuit exceeded 100% of its normal thermal rating in any year from 2021 through 2025 — meaning no reliability violation existed on the S-H path prior to this customer's request.[14] Loading below 100% of normal rating is not a reliability violation under North American Electric Reliability Corporation (NERC) or PJM standards. **Second**, PPL confirmed that "the installation of [Dynamic Line Rating] on the Susquehanna-Harwood path along with terminal equipment upgrades resolved the congestion on the Susquehanna-Harwood #1 & #2 230 kV Transmission Lines."[15] The congestion PPL cited was resolved three years before this project was proposed. The only reliability need requiring the Tomhicken Switchyard is the N-1 deficiency created by this customer's peak load addition.

PPL further confirmed that “[w]hile the lines would be considered heavily loaded, the emergency ratings of the Susquehanna-Harwood #1 & #2 230 kV Transmission Lines were not exceeded in the 2022 or 2023 RTEP cycles. Therefore, they were not included in the list of violations of which PJM solicited solutions”.[16] Most significantly, PPL

[13] Referring to the “existing Susquehanna-Harwood #1 and #2 230 kV Transmission Lines”, Mr. Lookup stated that “[t]hese lines are heavily loaded and have a history of transmission congestion.” Line 9-10, Page 3, PPL Statement No. 1.
[14] PPL Response to OCA VI-2(a). SUSQ-HARW #2 peaked at 98.4% of normal Ambient Adjusted Rating during a February 2021 winter storm event; SUSQ-HARW #1 peaked at 95.5% during a May 2022 summer congestion event. Following DLR activation in October 2022, both circuits show zero hours above 80% of normal rating in 2023 and 2025, and only minor events in 2024 peaking at 88.5% with no hours above 90%.
[15] PPL Response to OCA VI-2(d).
[16] PPL Response to OCA VIII-1(a).

confirmed that "[t]here were no planned supplemental or baseline projects involving the Susquehanna-Harwood #1 & #2 230 kV Transmission Lines prior to the Customer's interconnection request".[17] No transmission investment on this corridor was in PPL's capital plan or PJM's RTEP queue before this customer arrived. In other words, but for this customer's interconnection request, no transmission investment on the Susquehanna-Harwood corridor would have been required, no reliability violation would exist, and no Tomhicken Switchyard would be proposed.

Q: Did PPL perform the planning analysis that would normally validate this need determination?

A: No. I asked PPL to produce the complete NERC TPL-001-5.1 planning assessment[18] supporting the Tomhicken need determination, including whether the P1 and P4 overloads appear in base case planning studies or only in sensitivity cases, and the results of all P0-P7 contingency analyses performed.[19] PPL confirmed that it performed no NERC TPL-001-5.1 Planning Assessment for the Tomhicken project, stating that TPL-

[17] PPL Response to OCA VIII-1(b)(c).
[18] NERC TPL-001-5.1 is the North American Electric Reliability Corporation's Transmission System Planning Performance Standard, which governs how transmission planners assess whether the bulk electric system can survive contingencies under various load and operating conditions. Under this standard, a Planning Assessment evaluates the system against a defined set of contingency categories (P0 through P7, ranging from normal conditions to extreme multiple contingency events) and requires the planner to identify violations and develop corrective action plans before selecting a transmission solution. This assessment is the standard analytical framework that would ordinarily precede the selection of a major transmission project like the Tomhicken Switchyard. Available at: https://www.nerc.com/globalassets/standards/reliability-standards/tpl/tpl-001-5.1.pdf (Last Accessed on July 6, 2026).
[19] OCA VI-3 (a), (b), (c).

001-5.1 applies to Transmission Planners and Planning Coordinators — roles PJM holds, not PPL.[20]

PPL's Tomhicken Switchyard need determination rests on FAC-002 facility interconnection studies[21] and PJM's DNH analysis.[22] PPL confirmed the P1 and P4 overloads were identified in the 2027 RTEP and 2027 RTEP "do no harm" ("DNH")[23] base cases.[24] Neither FAC-002 nor the DNH process requires evaluation of demand-side management alternatives or other corrective action alternatives before selecting a transmission solution. No entity produced TPL-001-5.1 sensitivity cases varying controllable loads or demand-side management in this proceeding.

Q: Which specific contingencies did PPL identify as driving the need for Phase 2?

A: PPL confirmed it studied P1, P2, P3, P4, P6, and P7 contingencies under its FERC 715 criteria, and that HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS No

[20] "No Planning Assessment was completed as PPL is not registered as a Transmission Planner or Planning Coordinator. TPL-001-5.1 applies to Transmission Planners and Planning Coordinators. PPL Electric is registered as a Transmission Owner and Distribution Provider." PPL Response to OCA VI-3(a).
[21] NERC FAC-002-2 (Facility Interconnection Studies) is the reliability standard governing the studies a Transmission Owner must perform when a new facility requests interconnection to the bulk electric system. Unlike TPL-001-5.1, which requires comprehensive planning assessments including alternatives analysis and corrective action plans, FAC-002-2 is focused on ensuring the interconnecting facility does not adversely affect system reliability — it does not require evaluation of demand-side management alternatives or other corrective action alternatives before selecting a transmission solution. "PPL Electric follows the FAC-002 Facility Interconnection Studies standard for the interconnection of new customers." PPL Response to OCA VI-3(a).
[22] "PPL Electric follows the FAC-002 Facility Interconnection Studies standard for the interconnection of new customers. …The interconnection of the Customer served by the Tomhicken 230 kV Switchyard passed the PJM DNH analysis and was issued supplemental number S3528." PPL Response to OCA VI-3(a).
[23] The DNH analysis is discussed in more depth below.
[24] "The overloads were identified based on the 2027 RTEP and 2027 RTEP DNH cases." PPL Response to OCA VI-3(c).
[25] PPL Response to HIGHLY CONFIDENTIAL OCA VII-3 (a).

other contingency category produced violations requiring Phase 2 infrastructure — confirming that all Phase 2 need is attributable to this customer's load addition. I discuss the interrelation between Phase 1 – the Tomhicken Switchyard proposal – and Phase 2 below, in Section VII.

Q: Do you agree with PPL regarding this stated need?

A: Yes. PPL identified "one new customer"[26] as the need driver for this project. Mr. Lookup further confirmed that "the current Customer is the farthest along the development process amongst those customers, and is the need driver for this Letter of Notification."[27] This admission is significant — PPL's Mr. Lookup characterizes the project as driven by this specific Customer, not by an independent system reliability need or by the collective weight of future queue customers. Furthermore, the load growth on the Susquehanna-Harwood corridor from PPL's existing customers was not creating any reliability need — PPL confirmed no planned transmission projects existed on that corridor prior to this customer's interconnection request.[28]

As discussed throughout this testimony, that admission — that the project exists to serve this Customer which is farthest along the development process — supports my testimony's position that the customer, not ratepayers, should bear the costs of the infrastructure built to serve that need.

[26] Line 18, Page 3, PPL Statement No.1.
[27] Lines 7-8, Page 5, PPL Statement No.1.
[28] "There were no planned supplemental or baseline projects involving the Susquehanna-Harwood #1 & #2 230 kV Transmission Lines prior to the Customer's interconnection request." PPL Response to OCA VIII-1 (b).

Q: What is PJM's designation for this Tomhicken Switchyard?

A: PPL stated that PJM designated this Switchyard as a Supplemental Project – "[t]his Project is part of PJM Supplemental Number S3528, specifically segments S3528.1, S3528.6, and S3528.11."[29]

Q: What does PJM's definition of Supplemental Project tell you about the Tomhicken Switchyard's relationship to PJM reliability criteria?

A: PJM Manual 14B defines Supplemental Projects as transmission expansions or enhancements "not needed to comply with PJM reliability, operational performance, FERC Form No. 715 or economic criteria."[30] By definition, the Tomhicken Switchyard — as a Supplemental Project — is not required to meet PJM reliability criteria. It exists solely to serve the Customer's interconnection request. This is consistent with PPL's own acknowledgment that the project's need driver is the Customer's load interconnection and further supports my testimony's position that the costs of this Customer-driven project should be borne by the Customer rather than existing ratepayers.

Q: Are Supplemental Projects approved by PJM Board?

A: No. Supplemental Projects are not approved by PJM Board.[31]

[29] Page 9, LON.
[30] Page 15, PJM Manual 14B, Revision: 59, Effective Date: 04/22/2026 PJM © 2026. Available at https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf (Last Accessed on May 26, 2026).
[31] "Supplemental Projects are not approved by the PJM Board." Page 15, PJM Manual 14B, Revision: 59, Effective Date: 04/22/2026 PJM © 2026. Available at https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf (Last Accessed on May 26, 2026).

Q: Does PJM review Supplemental Projects for their need?

A: PJM does not independently verify or approve a Transmission Owner's need determination for Supplemental Projects. While PJM conducts a review process through a PJM stakeholder committee, the Transmission Expansion Advisory Committee (TEAC), including Assumptions, Needs, and Solutions meetings with stakeholder comment periods[32] — the need determination itself rests entirely with the Transmission Owner. PJM's role is to ensure the project meets the definition of a Supplemental Project and can be associated with the need identified by the Transmission Owner, not to validate whether that need is correctly identified or whether the proposed solution is the most cost-effective option for ratepayers.

Q: What analysis does PJM conduct for Supplemental Projects?

A: PJM conducts a "do no harm" study to evaluate whether the Supplemental Project will adversely impact transmission system reliability as represented in PJM's planning models. PJM also reviews the project through TEAC in a three-part process as mentioned above.[33] Additionally, PJM will inform the Transmission Owner if a baseline upgrade made pursuant to PJM's regional transmission expansion planning process might alleviate or partially mitigate the need for the Supplemental Project. However, none of these reviews constitute an independent validation of the Transmission Owner's need

[32] PJM Manual 14B, Section 1, Revision 59, Effective Date 04/22/2026, Page 15, available at https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf (Last Accessed on June 2, 2026).
[33] *Id.*

determination or an evaluation of whether the proposed solution is the most cost-effective option for ratepayers.

Q: What is the "do no harm" - DNH case year and load level for the Tomhicken Switchyard?

A: PPL stated that the DNH case year is 2027 with the projected 2028 Summer Load Level.[34]

Q: Is the load level used for the DNH network upgrade analysis consistent with the load level used to design the Tomhicken Switchyard?

A: No. PPL confirmed that while system network upgrades are based on this DNH 2028 Summer load level[35], the Tomhicken Switchyard itself was designed to accommodate the customer's ultimate requested load[36] — not just the Phase 1 DNH load level. This distinction between the DNH-based network upgrade scope and the ultimate-load-based substation design is examined further in the Phase 1 and Phase 2 Interdependency section below.

Q: Is the Customer connecting at an existing substation?

[34] PPL Response to OCA V-1(a).
[35] "The system network upgrades included in the supplemental project are based on the DNH Load Level." PPL Response to OCA V-1(c).
[36] "The substation was designed to accommodate the customer's ultimate requested load." PPL Response to OCA V-1(b).

A: No. The Customer is constructing its own 230-34 kV substation on its property.[37] PPL is constructing the new Tomhicken 230 kV Switchyard as a separate facility to interconnect the Customer to PPL's transmission system.[38]

Q: Is there a reason why the Customer would be connecting at a transmission voltage instead of a distribution voltage?

A: The Customer is connecting at the transmission voltage because of the peak load. PPL confirmed that its 12 kV lines have a typical capacity of 11 MVA — meaning serving even the customer's initial 240 MW load request would require at least 22 distribution circuits, with dozens more needed to serve the final 965 MW load.[39] The conductor sizes and infrastructure required to serve 965 MW at distribution voltage are not feasible, making transmission-level interconnection the only viable option.

Q: With respect to transmission line capacity, how are normal and emergency ratings defined?

A: Normal ratings represent the maximum continuous capacity (MVA) a line can carry indefinitely under assumed ambient conditions without exceeding the conductor's

[37] "The proposed Tomhicken 230 kV Switchyard will be constructed on the same Customer-owned parcel as the Customer's 230-34 kV substation and facilities." Page 8, LON.
[38] "PPL Electric will acquire the necessary land and right-of-way ("ROW") from the customer for the new Tomhicken 230 kV Switchyard, Tap Lines, and Connecting Lines." Page 8, LON.
[39] PPL Response to OCA I-8 (c) "PPL Electric's 12 kV lines have a typical capacity of 11 MVA. At least 22 distribution circuits, plus additional circuits for redundancy, would be required to serve 240 MW of load" and "As explained above, 22 distribution level circuits would be required to serve the Customer's initial 240 MW load request, and dozens more would be needed to serve the final load request amount of 965 MW." PPL Response to OCA I-8 (e).

maximum allowable temperature. Emergency ratings allow higher capacity for a defined short duration — typically 15 minutes to a few hours — before the conductor reaches a temperature that causes excessive sag, risking ground clearance violations, or causes permanent metallurgical damage to the conductor. Emergency ratings typically apply under N-1 contingency conditions (loss of a single transmission element) when a line outage forces remaining lines to carry higher-than-normal power flows.

Q: What are Ambient Adjusted Ratings?

A: FERC Order 881 defines Ambient Adjusted Rating as a transmission line rating that "(1) applies to a time period of not greater than one hour; (2) reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies; and (3) is calculated at least each hour, if not more frequently."[40]

Q: Were the conductor ratings used in PPL's need determination AAR-compliant under FERC Order 881?

A: Yes. PPL confirmed that the ratings in Table 2-3, Attachment 2 – Engineering Statement of the LON use 35°C for summer and 10°C for winter, consistent with AAR methodology, and were in use in transmission planning prior to Order 881.[41] PPL stated

[40] FERC Order 881 Managing Transmission Line Ratings issued December 16, 2021, Paragraph 87, available at https://www.ferc.gov/media/e-1-rm20-16-000 (last accessed May 24, 2026).
[41] PPL Response to OCA V-7(a).

that it is in compliance with Order 881 as of March 4, 2026 per FERC-approved extension.[42]

Q: Do you agree with PPL's AAR explanation?

A: Yes, I agree with PPL that AAR was already incorporated into its transmission planning analysis prior to FERC Order 881, and that the ratings used in the Tomhicken need determination reflect AAR-compliant values.[43] The normal and emergency ratings discussed in the following question are the AAR ratings. I note that PPL's planning AAR uses fixed seasonal ambient temperature assumptions rather than dynamic hourly updates as described in Order 881. For transmission planning purposes, however, this seasonal approach is consistent with standard industry practice, and I accept it as an appropriate planning basis. Therefore, AAR does not provide incremental capacity beyond what PPL already evaluated.

Q: What is the normal and emergency ratings of existing Susquehanna – Harwood double circuit 230 kV transmission lines?

A: PPL stated the normal and emergency ratings of the existing Susquehanna–Harwood double circuit 230 kV lines are 718/843 MVA (summer) and 768/894 MVA (winter) per circuit[44], with a combined rating of 1,436/1,686 MVA (summer) and 1,536/1,788 MVA (winter).

[42] PPL Response to OCA V-7(b).
[43] PPL Response to OCA V-7(a).
[44] PPL Response to OCA I-4(b).

Q: Can the Customer load be accommodated under the normal and emergency ratings of the existing Susquehanna – Harwood double circuit 230 kV transmission lines?

A: No. Under normal operating conditions with both circuits in service, the total combined rating is 1,436 MVA (summer normal)[45]. However, the existing lines already serve load at Harwood, East Palmerton, and Siegfried substations.[46] Under N-1 contingency conditions — which transmission planning requires the system to survive — a single surviving circuit rated at 718 MVA normal and 843 MVA emergency cannot serve the customer's 1,016 MVA peak demand.

PPL confirmed that under the 2027 RTEP case, a P1 single contingency loss of one Susquehanna-Harwood circuit results in thermal overload of the remaining circuit at approximately 858 MVA total path load under summer normal conditions, 997 MVA under summer emergency conditions, 925 MVA under winter normal conditions, and 1,067 MVA under winter emergency conditions.[47]

PPL's supporting power flow study confirms these findings. Under the 2027 Summer case with customer load added at Harwood, loss of either S-H circuit produces contingency flows of CONFIDENTIAL START [redacted] CONFIDENTIAL END, both exceeding the 718 MVA summer normal rating but within the 843 MVA summer emergency rating.[48] Under the 2027 Winter case, loss of either S-H circuit produces contingency flows of CONFIDENTIAL START [redacted]

[45] PPL Response to OCA I-4(d).
[46] Lines 6-9, Page 3, PPL Statement No. 1.
[47] PPL Response to OCA VI-1(a).
[48] PPL Response to OCA VI-1(b) Attachment CONFIDENTIAL.

[redacted] CONFIDENTIAL END, both exceeding the 768 MVA winter normal rating.[49]

Critically, PPL confirmed that the customer's initial load of 276 MW — due at commercial operation — is sufficient to exceed both summer and winter normal ratings under a P1 contingency on the existing S-H lines.[50] Emergency ratings are exceeded at approximately 470 MW of load at Harwood — less than half the customer's 965 MW peak demand.[51] This means the reliability need arises at the customer's first day of full initial operation and intensifies with every stage of the customer's load ramp. Without this customer's load addition, no P1 reliability violation exists on the existing S-H lines.

Q: Where does the new Customer substation connect to the PPL transmission system?

A: As shown in Figure 1-2[52], the new Customer substation connects directly to the new Tomhicken substation via a dedicated 230 kV interconnection. The Tomhicken substation is a new substation being constructed as part of this Switchyard.

Q: What is the relationship between the new Tomhicken substation and the new Customer's interconnection?

[49] PPL Response to OCA VI-1(b) Attachment CONFIDENTIAL.
[50] "Using the 2027 RTEP (2022 Series) case and applying 276 MW of load to the Harwood 230 kV bus, a P1 single contingency loss of one Susquehanna-Harwood circuit would result in the summer and winter normal rating being exceeded." PPL Response to OCA VI-1(c).
[51] "The summer and winter emergency ratings would be exceeded with approximately 470MW of load being added at the Harwood Substation." PPL Response to OCA VI-1(c).
[52] Attachment I Necessity Statement

A: The new Tomhicken substation is the point of interconnection for the new Customer. Without the new Customer's load, there would be no need to construct the Tomhicken substation or the two new line segments — Susquehanna–Tomhicken and Tomhicken–Harwood — that connect it to the existing transmission network. The entire proposed system configuration in Figure 1-2[53], including the new substation and both new line segments, is being built to accommodate the new Customer's interconnection.

Q: What is the normal and emergency ratings of the new Susquehanna – Tomhicken and Tomhicken-Harwood double circuit 230 kV transmission lines?

A: PPL stated that the new Susquehanna–Tomhicken and Tomhicken–Harwood 230 kV lines are double-circuit construction using 1590 kcmil, 54/19 stranding, "Falcon" ACSR conductors[54] with a per-circuit normal and emergency rating of 3,000/4,000 Amps (summer) and 3,700/4,500 Amps (winter)[55], based on which I calculate[56] 2,390/3,187 MVA (summer) and 2,948/3,585 MVA (winter).

Q: What is the increase in capacity compared to the existing Susquehanna – Harwood double circuit 230 kV transmission lines?

[53] Attachment I Necessity Statement
[54] Page 2-4, Attachment 2 – Engineering Statement.
[55] Table 2-3, Conductor Thermal Rating 1590 kcmil 54/19 Stranding Falcon ACSR – 125°C Normal Maximum Conductor, Attachment 2 – Engineering Statement.
[56] 2,390 MVA summer normal combined rating calculated from PPL's reported normal current rating of 3,000 amperes per circuit for the new 230 kV lines: (230,000 V × 3,000 A × √3 / 1,000 × 2) / 1,000 = 2,390 MVA. Source: Table 2-3, Attachment 2 – Engineering Statement.

A: The existing Susquehanna–Harwood double circuit 230 kV line is being replaced by two new double-circuit 230 kV line segments — Susquehanna–Tomhicken and Tomhicken–Harwood, each separately routed through the new Tomhicken substation. Each new segment consists of two circuits, with each individual circuit rated 1,195 MVA normal / 1,594 MVA emergency (summer).[57] Combining both circuits, each new segment independently provides a combined normal capacity of 2,390 MVA (summer) and 2,948 MVA (winter)[58] — an increase of 954 MVA (summer normal) and 1,412 MVA (winter normal) over the existing Susquehanna-Harwood combined two-circuit rating[59] of 1,436 MVA and 1,536 MVA respectively.

Q: Can the new Susquehanna–Tomhicken and Tomhicken–Harwood double circuit 230 kV transmission lines accommodate the Customer's peak demand under an N-1 contingency?

A: Yes, unlike the existing Susquehanna–Harwood line. As discussed above, the existing Susquehanna–Harwood line's combined two-circuit rating is 1,436 MVA normal — but under N-1 contingency, if one circuit trips, only the single surviving circuit remains in service, rated just 718 MVA normal / 843 MVA emergency. That single-circuit rating is below the Customer's 1,016 MVA/965 MW peak demand.

By contrast, each new segment — Susquehanna–Tomhicken and Tomhicken–Harwood — has a combined two-circuit rating of 2,390 MVA normal, but more

[57] Table 2-3, Attachment 2 – Engineering Statement; 3,000 A × 230,000 V × √3 / 1,000,000 = 1,195 MVA per circuit (summer normal); 1,195 × 2 circuits = 2,390 MVA combined.
[58] *Id*.
[59] PPL Response to OCA I-4(b); 718 MVA per circuit × 2 circuits = 1,436 MVA combined.

importantly, each individual circuit within that segment is independently rated 1,195 MVA normal / 1,594 MVA emergency (summer).[60] So if one circuit within either new segment trips under N-1, the single surviving circuit on that segment can still carry approximately 1,195 MVA normal — comfortably above the Customer's 1,016 MVA peak demand. This demonstrates that the new infrastructure was sized specifically to ensure N-1 reliability for this Customer's peak load — single-circuit capacity that the existing Susquehanna-Harwood configuration could not provide.

III. Proposed Switchyard

Q: Why did PPL split the Susquehanna-Harwood lines at Tomhicken rather than adopting an alternative routing?

A: PPL stated in discovery that "[t]he splitting of the Susquehanna-Harwood #1 & #2 230kV Transmission Lines was designed to allow the future Phase 2 lines to terminate into the Tomhicken Switchyard and Harwood Substation without requiring line crossings. The Tomhicken 230kV Switchyard will have a line termination point for the Phase 2 scope."[61]

This confirms that the line split configuration was designed around Phase 2 requirements, not Phase 1 necessity alone. As discussed further in the Phase 1 and Phase 2 Interdependency section below, this design choice has direct implications for the ratepayer cost allocation — ratepayers are being asked to fund a Phase 1 configuration

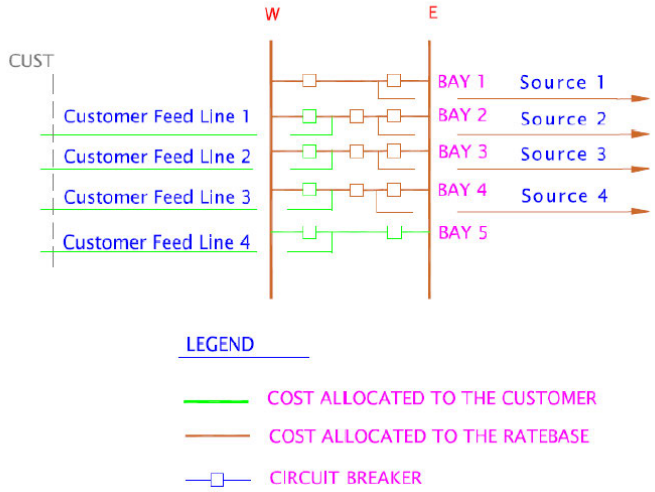
[60] Table 2-3, Attachment 2 – Engineering Statement; 3,000 A × 230,000 V × √3 / 1,000,000 = 1,195 MVA per circuit (summer normal); 4,000 A × 230,000 V × √3 / 1,000,000 = 1,594 MVA per circuit (summer emergency).
[61] PPL Response to OCA I-10(c).

whose routing and physical layout were determined by Phase 2 considerations that have not yet received Commission approval.

Q: What is a Breaker and a half (BAAH) design and why is it relevant to the ratepayer cost allocation?

A: PPL stated in the LON that the Tomhicken 230 kV Switchyard is built with a "breaker-and-a-half" ("BAAH") design.[62] In a breaker-and-a-half configuration, "three circuit breakers are used in a bay for two independent circuits; hence, each circuit shares the common center circuit breaker, so there are 1.5 circuit breakers per circuit."[63] In a discovery response, PPL provided the below Responsibility of Asset Matrix for a Breaker and a Half switchyard design:

Responsibility of Asset Matrix for Breaker and a Half (BAAH) Example 1:



[64]

[62] Page 8, LON.
[63] National Academies of Sciences, Engineering, and Medicine. 2012. Terrorism and the Electric Power Delivery System. Washington, DC: The National Academies Press. https://www.nationalacademies.org/read/12050/chapter/19#135 (Last Accessed on June 2, 2026).
[64] OCA I-6 Attachment 1, Page 3 of 8.

The Tomhicken Switchyard has 5 bays in this BAAH design, connected between two bus bars (W and E).[65] As shown in the Responsibility of Asset Matrix for the BAAH configuration, the cost allocation between the customer and ratepayers is not uniform across all bays. Notably, Bay 1 — a pure source bay with no customer feed line — is allocated entirely to rate base at approximately $1.7 million,[66] despite serving no direct customer interconnection function under Phase 1. When asked in discovery to confirm whether Bay 1 serves any function under Phase 1 alone independent of Phase 2 construction, PPL stated that Bay 1 serves two functions: delivering power from Susquehanna Circuit #1 and "delivers a direct customer feed to the customer point of interconnection."[67] However, PPL's own Responsibility of Asset Matrix — produced in this same proceeding — shows no customer feed line connected to Bay 1. The Matrix depicts Bay 1 entirely in orange (cost allocated to ratebase), with no green customer feed line on the left side of the bay.[68] This is a direct inconsistency between PPL's discovery response and its own cost allocation document.

This design choice is directly relevant to the cost allocation question in this proceeding. As discussed below, PPL stated in the LON that the Tomhicken Switchyard is required due to the number of lines needed by the Customer and the size of the requested load.[69] I will examine whether the ratepayer cost allocation — particularly for Bay 1 and the bus infrastructure — is appropriate given that the switchyard exists solely to serve this Customer's interconnection.

[65] OCA I-6 Attachment 1, Page 3 of 8.
[66] PPL Response to OCA III-3(b).
[67] PPL Response to OCA XI-7(a).
[68] OCA I-6 Attachment 1, Page 3 of 8.
[69] "The Tomhicken 230 kV Switchyard is required due to the number of lines needed by the Customer and the size of the requested load." Page 8, LON.

Q: Why is PPL proposing a BAAH design, and what alternatives did PJM's standards permit?

A: PPL stated that BAAH is required by PJM. In Attachment I – Necessity Statement, PPL stated that "Section III of the PJM minimum planning and design standards refers to Substation Bus Configurations and Substation Design Recommendations. Under PJM's standards, three terminal lines and radial bus station configurations are discouraged for use in new BES substation construction because of the considerable potential for detrimental effects on transmission system reliability. Acceptable standards for substations are noted as ring bus configurations, breaker-and-a-half-arrangements, and double breaker–double bus arrangements. Breaker-and-a-half arrangements are the preferred design because of the balance of operational flexibility and cost that this design affords."[70]

This means PJM requires one of three acceptable configurations — ring bus, BAAH, or double breaker-double bus. The choice among these three options was PPL's. PPL selected BAAH as the preferred design. This choice is relevant to the ratepayer cost allocation because different configurations carry different costs.

Q: Did PPL evaluate a ring bus configuration as an alternative to BAAH?

[70] Page I-8, Attachment I – Necessity Statement.

A: No. PPL confirmed in discovery that it did not evaluate a ring bus configuration and cannot provide the incremental cost difference between ring bus and BAAH.[71] PPL stated that its own internal System Planning Development Standards prohibit ring buses for new construction — this is a PPL policy choice, not a PJM requirement.[72] PJM explicitly identifies ring bus as an acceptable standard.

PPL's ring bus prohibition was adopted on July 1, 2018 through PPL's System Planning Development Standards Revision #8.[73] Since that date, PPL has not evaluated a ring bus configuration against a BAAH configuration for any transmission project — and has not granted a single exception to the prohibition.[74] The prohibition was explicitly in effect during the planning, development, and engineering of the Tomhicken Switchyard.[75]

When asked in this proceeding to provide an engineering cost estimate comparing ring bus versus BAAH for Phase 1 line terminations only, PPL confirmed that switching to a ring bus configuration would reduce costs by approximately $540,000.[76] This is the cost premium ratepayers are bearing for a design choice governed by an internal standard that: (1) was adopted without Commission review or approval; (2) has been applied categorically to every PPL transmission project for eight years without exception; and (3) was never subjected to comparative analysis — in this proceeding or any other — to determine whether the additional reliability benefit justifies the additional cost.

[71] "No, a ring bus was not evaluated for the Tomhicken Switchyard". PPL Response to OCA V-4 (c).
[72] "PJM's standards allow for ring bus substations, but PPL Electric's System Planning Development Standards do not allow ring buses to be used for new construction." *Id.*
[73] PPL Response to OCA XI-4(a).
[74] PPL Response to OCA XI-3(a); PPL Response to OCA XI-4(b).
[75] PPL Response to OCA XI-4(c).
[76] PPL Response to OCA XI-2(a).

PPL further explained that ring buses present a segmentation risk during planned and unplanned outages — the ring can fragment into multiple isolated sections, increasing the risk of load drop or loss of network flow.[77] PPL cited PJM's own standards noting that segmentation risk increases with the number of bus positions. This is a legitimate reliability concern that I acknowledge. However, PPL has never demonstrated — quantitatively or otherwise — that the $540,000 BAAH premium is commensurate with the reliability improvement it provides over a ring bus configuration, particularly given that the nine-line justification for avoiding ring bus segmentation risk is itself premised on Phase 2 lines that have not yet been approved.

Q: Is PPL's justification for selecting BAAH over ring bus dependent on Phase 2?

A: Yes. PPL justified selecting BAAH over a ring bus configuration partly on the basis that nine lines will terminate at Tomhicken.[78] However, PPL separately confirmed in discovery that the line split configuration was designed to accommodate future Phase 2 line terminations.[79] This means PPL's nine-line justification for the BAAH design is premised on Phase 2 lines that have not yet been approved by this Commission. Under Phase 1 alone, the number of line terminations is lower. PPL has therefore justified a Phase 1 design decision — and the ratepayer cost allocation that flows from it — using

[77] "The ring bus arrangement can become segmented during planned and unplanned outages, increasing the risk of load drop or loss of network flow." PPL Response to OCA V-5(c).
[78] "The proposed Tomhicken Switchyard is to have nine lines connected as part of Phase 1 and Phase 2." PPL Response to OCA V-4(c).
[79] "The splitting of the Susquehanna-Harwood #1 & #2 230kV Transmission Lines was designed to allow the future Phase 2 lines to terminate into the Tomhicken Switchyard and Harwood Substation without requiring line crossings. The Tomhicken 230kV Switchyard will have a line termination point for the Phase 2 scope." PPL Response to OCA I-10(c).

Phase 2 infrastructure that remains speculative. This is precisely the interdependency problem I address in the Phase 1 and Phase 2 section below.

Q: What benefits does PPL claim for the BAAH design?

A: When asked in Discovery about the benefits of this BAAH design[80], PPL stated that the BAAH design supports "[s]ectionalization of existing 230kV lines and provide new capacity and alternative route for power flow" and provides "system reliability, increased operational flexibility and additional capacity to area."[81]

Additionally, PPL stated that "[a]ll parties benefit from the use of breaker-and-a-half arrangements as they provide system reliability and the ability to operate the system while not being as expensive as double breaker – double bus designs".[82] However, PPL provided no quantitative analysis supporting that claim — consistent with its broader pattern of asserting ratepayer benefits without demonstrating them. An unquantified assertion that all parties benefit is not a sufficient basis for a $38.4M ratepayer allocation.

Q: Are these benefits realized under Phase 1 alone, or do they depend on Phase 2?

A: These are system-level benefit claims. However, as I will demonstrate in the Phase 1 and Phase 2 Interdependency section below, PPL has not established that these benefits are realized under Phase 1 alone. The network benefits PPL claims for Phase 1 — sectionalization, additional 230 kV paths, increased capacity, and operational flexibility,

[80] OCA III-3(a).
[81] PPL Response to OCA III-3(a).
[82] PPL Response to OCA V-4(b). See also PPL Response to OCA V-5(d).

are described in the Network Benefits section below[83]. PPL confirmed that "[t]he Tomhicken 230 kV Switchyard and additional Phase 2 transmission lines will increase system reliability by adding additional 230 kV paths from the Susquehanna area to the Hazleton area. The proposed phases will increase capacity of the transmission system."[84] This shows PPL's admission that the reliability benefits of Tomhicken 230 kV Switchyard are dependent on Phase 2 construction.

Under Phase 1 alone — which is the instant proceeding before this Commission — the Tomhicken Switchyard serves a single function: interconnecting this Customer. On that basis, it is the Customer, not ratepayers, who primarily benefits from the BAAH design under Phase 1.

Q: Do you agree with PPL regarding the BAAH design?

A: I agree that BAAH provides greater operational reliability than a ring bus configuration for the reasons discussed above. PPL stated in the LON that "Tomhicken 230 kV Switchyard is required due to the number of lines needed by the Customer and the size of the requested load"[85] and the BAAH design enables PPL to "extend four 230 kV lines to the Customer's substation, all located within the Customer-owned parcel"[86]. This is PPL's own characterization — the switchyard and its BAAH configuration exist to serve this Customer.

[83] Page 11, LON; PPL Response to OCA III-3(a); PPL Response to OCA V-5(b).
[84] PPL Response to OCA V-5(b).
[85] Page 8, LON.
[86] Page 8, LON.

Furthermore, as shown in the Responsibility of Asset Matrix, Bay 1 — a pure source bay with no customer feed line — is allocated entirely to ratepayers at approximately $1.7 million[87], despite serving no direct customer interconnection function under Phase 1.

PPL claimed in discovery that Bay 1 serves a direct customer feed function — a claim directly contradicted by its own Responsibility of Asset Matrix, which shows Bay 1 with no customer feed line.[88,89] Under PPL's own function-based cost allocation methodology — which allocates costs based on the function of the upgrade[90] — a bay serving only a source function with no customer feed should not be allocated to ratepayers without a demonstrated network benefit. PPL has provided neither a quantitative demonstration of independent network benefit nor an explanation for why its own function-based methodology produces a ratepayer allocation for a bay its own diagram shows serving no customer feed function.

Q: What is your recommendation?

A: The Commission should direct PPL to reallocate the BAAH switchyard costs currently assigned to ratepayers to the Customer. PPL's own LON establishes that the Tomhicken Switchyard "is required due to the number of lines needed by the Customer and the size

[87] PPL Response to OCA III-3(b).
[88] PPL Response to OCA XI-7(a).
[89] OCA I-6 Attachment 1, Page 3 of 8.
[90] PPL Response to OCA VI-5(c).

of the requested load."[91] The ratepayer-allocated costs — including Bay 1 and the bus infrastructure — serve no independent ratepayer function under Phase 1 and should be borne by the Customer who caused them.

IV. Switchyard Alternatives

Q: Did you evaluate alternatives to the proposed Tomhicken Switchyard configuration?

A: Yes. I evaluated four categories of alternatives: Dynamic Line Ratings, Non-Transmission Alternatives, distribution system connection, and direct connection to the Nescopeck Switchyard. As discussed below, none of these alternatives eliminates the need for a physical 230 kV switching facility for this customer's interconnection.

IV.a. Dynamic Line Rating (DLR) Alternative

Q: What are Dynamic Line Ratings (DLRs) and when were they activated on the Susquehanna-Harwood path?

A: Dynamic Line Rating (DLR) is defined as "transmission line rating that applies to a time period of not greater than one hour and reflects up-to-date forecasts of inputs such as (but not limited to) ambient air temperature, wind, solar heating, transmission line tension, or transmission line sag."[92]

[91] Page 8, LON.
[92] FERC Order 881 Managing Transmission Line Ratings issued December 16, 2021, Paragraph 235, available at https://www.ferc.gov/media/e-1-rm20-16-000 (last accessed May 24, 2026).
[92] PPL Response to OCA V-7(a).

PPL activated DLR on the Susquehanna-Harwood path on October 6, 2022[93] — over three years before PPL submitted the Tomhicken need to PJM on December 19, 2025.[94]

Q: Did PPL evaluate installing Dynamic Line Ratings on the existing Susquehanna – Harwood double circuit 230 kV transmission lines to connect the customer load?

A: No, PPL explained that "[a]fter the Tomhicken 230 kV Switchyard is placed in service, the DLR will remain in service on the Susquehanna-Tomhicken #1 & 2 and Tomhicken-Harwood #1 & #2 230 kV Transmission Lines."[95] And "DLR does not address the planning need for the new Tomhicken 230 kV Switchyard, nor the Phase 2 upgrades."[96]

Connecting Customer load with DLR alone is not a viable alternative because "the Tomhicken 230 kV Switchyard is still required to physically connect the customer to the 230 kV network and to serve the requested load. PPL Electric does not allow for taps from 230 kV transmission lines. Also, the requested load amounts would not meet the NERC TPL-001 or PPL Electric FERC 715 Planning Requirements in a line tapped configuration."[97]

Q: Do you agree with PPL's DLR explanation?

[93] PPL Response to OCA V-9(d).
[94] LON.
[95] PPL Response to OCA V-7(c).
[96] *Id.*
[97] PPL Response to OCA V-9(b).

A: Yes, I agree with PPL's explanation. Specifically, I agree that "requested load amounts would not meet the NERC TPL-001 or PPL Electric FERC 715 Planning Requirements in a line tapped configuration."[98] I also note that DLR was active on the Susquehanna-Harwood path for over three years before PPL submitted the Tomhicken need to PJM.[99] However, given that the physical interconnection requirement exists independently of line ratings, this timing observation does not change my conclusion. Finally, I agree with PPL that "DLR is not a valid solution for Transmission Planning load flow analysis" and that "as the ratings from DLR are dynamic, they cannot be used in Transmission Planning load flow analysis."[100].

PPL further confirmed that DLR activation on the Susquehanna-Harwood path — combined with terminal equipment upgrades — resolved the congestion PPL's witness cited in direct testimony.[101] The congestion was quantifiable — approximately $20 million in 2021 and $15 million in 2022, for a total of approximately $35 million over two years.[102] DLR resolved that congestion. The physical switchyard remains necessary for the customer's interconnection, but DLR addressed the operational condition PPL cited as a system justification for this project at a fraction of the $38.4 million ratepayer allocation now before the Commission.

Q: What is your recommendation?

[98] PPL Response to OCA V-9(b).
[99] PPL Response to OCA V-9(d).
[100] PPL Response to OCA V-7(c).
[101] "The installation of DLR on Susquehanna-Harwood path along with terminal equipment upgrades resolved the congestion on the Susquehanna-Harwood #1 & #2 230 kV Transmission Lines." PPL Response to OCA VI-2(d).
[102] "The Susquehanna-Harwood #1 & #2 230 kV Transmission Lines had approximately $20 million in congestion in 2021 and approximately $15 million in 2022." PPL Response to OCA VIII-1(a).

A: No further action is needed to evaluate DLR as an alternative.

IV.b. Non-Transmission Alternatives

Q: What are Non-Transmission Alternatives (NTA)?

A: Non-Transmission Alternatives (NTA) are "programs and technologies that complement and improve operation of existing transmission systems that individually or in combination defer or eliminate the need for upgrades to the transmission system."[103] Typical NTA programs and technologies are:

- "End-use efficiency,
- End-user demand response,
- Generation alternatives, including distributed generation,
- Transmission system capability and efficiency improvements within existing corridors, and
- Developing storage technologies, such as batteries and electric and plug-in hybrid electric vehicles."[104]

Q: Did PPL evaluate any non-transmission alternatives to Tomhicken Switchyard?

[103] Updating the Electric Grid: An Introduction to Non-Transmission Alternatives for Policymakers, Prepared by The National Council on Electricity Policy September 2009, Available at https://www.energy.gov/oe/articles/updating-electric-grid-introduction-non-transmission-alternatives-policymakers (Last Accessed on May 25, 2026).
[104] *Id.*

A: No, PPL did not evaluate any NTA stating that "[a] 230 kV switchyard is required to connect the customer to the 230 kV network. Demand response, energy storage, or load management would not eliminate the need to connect the customer to the 230 kV network."[105]

Q: Do you agree with PPL's assessment of non-transmission alternatives?

A: Yes — largely. A 965 MW physical transmission interconnection cannot be replaced by a NTA technology like demand response or energy storage. Furthermore, when asked directly whether any alternative capable of deferring or eliminating the need for the Tomhicken Switchyard was identified, PPL simply referenced the LON without providing any analysis.[106] NTAs may have relevance to Phase 2 scope even if not Phase 1.

As discussed above in connection with PPL's need determination, PPL confirmed that no sensitivity cases varying controllable loads and demand side management were performed for the Tomhicken Switchyard project, stating that TPL-001-5.1 R2.1.3 applies to Transmission Planners and Planning Coordinators — roles held by PJM, not PPL — and that PPL follows FAC-002 Facility Interconnection Studies standards instead.[107] The planning framework applied to this project therefore did not require evaluation of demand-side management as a sensitivity case or as a corrective action alternative before

[105] PPL Response to OCA V-3(c).
[106] PPL Response to OCA V-3(d).
[107] PPL Response to OCA VI-3(b).

selecting the Tomhicken Switchyard as the solution. No DSM sensitivity results were produced in this proceeding by any party.

Q: What is your recommendation?

A: No further action is needed to evaluate NTAs for Phase 1. However, as discussed above, the FAC-002 framework PPL applied to this project does not require evaluation of non-transmission alternatives, and the TPL-001-5.1 sensitivity case requirements that would otherwise call for such evaluation do not apply because PPL is not registered as a Transmission Planner or Planning Coordinator. This is a meaningful gap: a Supplemental Project of this size and customer-driven nature can proceed with construction without any documented consideration of whether demand-side management, storage, or other non-transmission alternatives could defer or reduce the need. The Commission should require PPL to conduct and produce a documented NTA analysis — addressing demand response, storage, and load management specifically — as part of any Phase 2 proceeding, rather than dismissing alternatives in a single sentence without supporting analysis as PPL did here.

IV.c. Distribution System Connection Alternative

Q: Did PPL evaluate connecting the customer at the distribution system?

A: No. PPL identified an existing 12 kV distribution line — the Cando 59-2 — crossing the project area with approximately 7 MW of capacity.[108] PPL did not evaluate distribution-

[108] PPL Response to OCA I-8(a).

level interconnection as an alternative because the existing line has insufficient capacity to serve the customer's load.[109] PPL stated that its 12 kV lines have a typical capacity of 11 MVA, and that at least 22 distribution circuits plus additional redundancy circuits would be required to serve the customer's initial 240 MW load request[110] — with dozens more needed to serve the final 965 MW load[111].

Q: Do you agree with PPL's explanation?

A: Yes. A 965 MW customer load cannot be served from a 12 kV distribution system. The arithmetic is straightforward — serving even the initial 240 MW load would require approximately 22 distribution circuits at 11 MVA each[112], and the final 965 MW load would require nearly 90 circuits[113]. Distribution-level interconnection is not a viable alternative for a customer of this size and the distribution connection alternative does not warrant further analysis.

Q: What is your recommendation?

A: No further action is needed on the distribution system connection alternative.

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[109] "The existing distribution line was not identified in the alternatives analysis because it does not have sufficient capacity to serve the Customer's initial load request." PPL Response to OCA I-8(d).
[110] "PPL Electric's 12 kV lines have a typical capacity of 11 MVA. At least 22 distribution circuits, plus additional circuits for redundancy, would be required to serve 240 MW of load." PPL Response to OCA I-8(c).
[111] "22 distribution level circuits would be required to serve the Customer's initial 240 MW load request, and dozens more would be needed to serve the final load request amount of 965 MW." PPL Response to OCA I-8 (e).
[112] Per PPL Response to OCA I-8(c): "PPL Electric's 12 kV lines have a typical capacity of 11 MVA. At least 22 distribution circuits...would be required to serve 240 MW of load." 22 distribution circuits times 11 MVA = 242 MVA. Assuming 1 power factor, 242 MVA = 242 MW.
[113] Using PPL's 11 MVA per circuit figure from OCA I-8(c): 965 MW ÷ 11 MVA = approximately 87.7 circuits, rounded to approximately 90. 90 distribution circuits times 11 MVA = 990 MVA. Assuming 1 power factor, 990 MVA = 990 MW.

IV.d. Direct Connection to Phase 2 Nescopeck Switchyard

Q: Did PPL evaluate connecting the customer directly to the Phase 2 - Nescopeck Switchyard instead of splitting the Susquehanna-Harwood lines at Tomhicken?

A: No. PPL stated this alternative was not evaluated because the proposed Nescopeck Switchyard is approximately 9 miles from the customer's location, requiring two sets of double-circuit 230 kV transmission lines to be extended from Nescopeck to the customer's substation, with greater siting and right-of-way impact than the proposed solution.[114]

Q: What would direct connection at Nescopeck have meant for ratepayers?

A: A direct connection from Nescopeck would have eliminated the Susquehanna-Harwood line split — as PPL confirmed the split would not be required under a Nescopeck configuration, though PPL noted the project would need to be re-evaluated and additional upgrades would be required.[115]

The 9 miles of new double-circuit 230 kV transmission line required to reach the customer's substation[116] would have been customer-specific infrastructure, likely

[114] "This alternative was not evaluated as the proposed Nescopeck Switchyard is approximately 9 miles from the customer's location. Two sets of double-circuit 230kV transmission lines would need to be extended from the Nescopeck Switchyard to the Customer's substation. This would have greater siting and ROW impact than the proposed solution." PPL Response to OCA III-8(b) Supplemental.
[115] OCA III-8 (d) – "If the customer's substation were connected directly to Nescopeck — the Phase 2 substation — rather than to Tomhicken, would the splitting of the Susquehanna-Harwood #1 & #2 230kV lines still be required? Please answer yes or no and explain". "No, but if the Customer was served directly from the Nescopeck Switchyard the Project would need to be re-evaluated." PPL Response to OCA III-8(d) Supplemental.
[116] "This alternative was not evaluated as the proposed Nescopeck Switchyard is approximately 9 miles from the customer's location." PPL Response to OCA III-8(b) Supplemental.

allocated entirely to the customer rather than to ratepayers. Under the Tomhicken approach, ratepayers are allocated $38.4 million. Under a Nescopeck approach, the customer would bear the cost of approximately 9 miles of new 230 kV line — an amount PPL has not quantified or compared against the Tomhicken ratepayer allocation.

Q: Do you agree with PPL's decision not to evaluate the Nescopeck alternative?

A: I agree in part and disagree in part. I agree that the 9-mile distance and right-of-way considerations are legitimate engineering factors that may favor the Tomhicken approach from a siting standpoint.[117]

I disagree because PPL never performed a cost comparison between the two approaches — specifically, whether the customer bearing the full cost of 9 miles of new 230 kV line would be more or less costly to ratepayers than the $38.4 million Tomhicken ratepayer allocation.[118] Without that comparison, the Commission cannot determine whether the Tomhicken approach is actually more cost-effective for ratepayers than the Nescopeck alternative.

Q: Does PPL's failure to evaluate Nescopeck raise a cost allocation problem beyond the missing cost comparison?

[117] "This alternative was not evaluated as the proposed Nescopeck Switchyard is approximately 9 miles from the customer's location. Two sets of double-circuit 230kV transmission lines would need to be extended from the Nescopeck Switchyard to the Customer's substation. This would have greater siting and ROW impact than the proposed solution." PPL Response to OCA III-8(b) Supplemental.

[118] "This alternative was not evaluated as the proposed Nescopeck Switchyard is approximately 9 miles from the customer's location." PPL Response to OCA III-8(b) Supplemental.

A: Yes. The failure to evaluate Nescopeck is not merely a procedural gap — it is a substantive cost allocation problem. PPL confirmed that its cost allocation methodology "relies on the function of the upgrade, not a set percentage split between the customer and the Company."[119] Under a Nescopeck configuration, nine miles of new 230 kV transmission line running directly from Nescopeck to the customer's substation would be radial, customer-specific infrastructure serving one customer with no independent network function. Under PPL's own function-based methodology, infrastructure whose function is to serve a single customer is the customer's responsibility — precisely the principle that produced 89% customer allocation for Customer 2.[120] By choosing the Tomhicken configuration without evaluating Nescopeck, PPL classified functionally equivalent customer-specific infrastructure as network infrastructure and allocated it to ratepayers. PPL's own methodology, applied to the Nescopeck configuration it declined to evaluate, would likely have produced an allocation closer to Customer 2's 89% customer responsibility than Tomhicken's 36%. The Commission cannot know the correct result because PPL never ran the analysis its own methodology required.

Q: Does the Tomhicken Switchyard's design support PPL's decision not to evaluate Nescopeck, or does it undermine PPL's ratepayer benefit claims?

A: It undermines PPL's ratepayer benefit claims. PPL confirmed that the Tomhicken Switchyard "allows for multiple future new transmission electrical paths" and "new customer interconnections directly from transmission or indirectly for future load

[119] PPL Response to OCA VI-5(c).
[120] PPL Response to OCA I-5(d) Supplemental.

growth."[121] This admission — combined with PPL's Mr. Lookup direct testimony that the switchyard is designed to eventually serve multiple customers — confirms that the Tomhicken Switchyard is shared interconnection infrastructure for the large load customer queue, not infrastructure that provides independent benefits to existing ratepayers.

Q: What is your recommendation?

A: Before approving the $38.4 million ratepayer allocation, the Commission should require PPL to provide a quantitative cost comparison between the Tomhicken approach and the Nescopeck direct connection alternative — specifically showing the total customer cost under each scenario and the total ratepayer cost under each scenario. If the Nescopeck approach would have resulted in all costs being borne by the customer at comparable or lower total project cost, the rationale for the Tomhicken ratepayer allocation is further undermined.

IV.e. Switchyard Alternatives Summary

Q: Please summarize the Switchyard Alternatives section.

A: I evaluated four categories of alternatives to the Tomhicken Switchyard project:

[121] "The Tomhicken Switchyard allows for multiple future new transmission electrical paths outside of the current proposed Phase 2 transmission line to be interconnected at Tomhicken. It also allows for PPL Electric to provide new customer interconnections directly from transmission or indirectly for future load growth via new distribution facilities." PPL Response to OCA III-8 (e) Supplemental.

1. **DLR**: DLR has been operational on the Susquehanna-Harwood lines since October 2022. However, DLR is an operational tool used for real-time and day-ahead market efficiency — it is not applicable to transmission planning load flow analysis. Additionally, a physical switchyard is required to connect a 965 MW customer to the 230 kV network regardless of line ratings. PPL does not allow 230 kV line taps and NERC TPL-001 requirements preclude a tapped configuration for this load size.
2. **Non-Transmission Alternatives**: Demand response, energy storage, and load management cannot substitute for a physical 230 kV transmission interconnection for a 965 MW customer.
3. **Distribution System Connection**: A 12 kV distribution interconnection is not viable — serving even the initial 240 MW load would require approximately 22 distribution circuits, with dozens more needed for the final 965 MW load.
4. **Nescopeck Direct Connection**: PPL did not evaluate direct connection to the Nescopeck Switchyard. The 9-mile distance and ROW considerations are legitimate engineering factors, but PPL never performed a cost comparison between the Tomhicken approach — which allocates $38.4 million to ratepayers — and the Nescopeck approach, under which the customer would bear the cost of new transmission line construction.

Q: Does FERC or NERC mandate any of the alternatives discussed?

A: FERC supports Dynamic Line Ratings as a grid-enhancing technology[122] but did not mandate their use in transmission planning load flow analysis. NERC standards — including FAC-002-2 and TPL-001 — govern facility interconnection studies and planning reliability standards but do not mandate specific alternatives for customer interconnection projects.

However, NERC's recent work is directly relevant to this proceeding. In August 2024, NERC established the Large Loads Task Force to address reliability risks from large load interconnections. In July 2025, NERC published a white paper — "Characteristics and Risks of Emerging Large Loads" — identifying long-term planning and system stability as high-priority concerns for large load interconnections.[123] In September 2025, NERC issued a Level 2 Alert on Large Load Interconnection, Study, Commissioning, and Operations, addressing reliability challenges from large load behavior.[124] The customer in this proceeding — a 965 MW load — falls squarely within NERC's definition of a Large Load[125]. NERC's guidance underscores the need for rigorous planning analysis, including the sensitivity cases required by TPL-001-5.1 R2.1.3 that PPL has been asked to confirm it performed.

[122] FERC Notice of Inquiry, Use of Dynamic Line Ratings to Promote Grid Efficiency, Docket No. AD22-5 (Feb. 17, 2022), available at https://www.ferc.gov/news-events/news/ferc-opens-inquiry-use-dynamic-line-ratings-promote-grid-efficiency (Last Accessed on June 2, 2026).
[123] NERC, Characteristics and Risks of Emerging Large Loads (July 2025), available at https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/whitepaper-characteristics-and-risks-of-emerging-large-loads.pdf (Last Accessed on June 2, 2026).
[124] NERC Level 2 Alert, Large Load Interconnection, Study, Commissioning, and Operations (Sept. 9, 2025), available at https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/nerc-alert-level-2--large-loads.pdf (Last Accessed on June 2, 2026).
[125] "Any commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS due to its demand, operational characteristics, or other factors. Examples include, but are not limited to, data centers, cryptocurrency mining facilities, hydrogen electrolyzers, manufacturing facilities, and arc furnaces." Source: https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/nerc-alert-level-2--large-loads.pdf (Last Accessed on June 2, 2026).

Q: Does the alternatives analysis affect your testimony's position on the need for the Tomhicken Switchyard or the ratepayer cost allocation?

A: **On project need** — no. The alternatives analysis confirms that no viable alternative exists to a physical transmission switchyard for a 965 MW customer requiring 230 kV interconnection. My testimony does not contest the need for the Tomhicken Switchyard to serve this customer.

On ratepayer cost allocation — yes. The alternatives analysis strengthens my testimony's position that ratepayers should not bear $38.4 million for this project. Every alternative examined — DLR, NTAs, distribution connection, and Nescopeck direct connection — confirms that the Tomhicken Switchyard exists solely to serve this customer's physical interconnection requirement. No alternative analysis identified an independent system reliability need that would have required this switchyard absent the customer's request. The project is entirely customer-driven, and the cost allocation should reflect that finding.

V. Customer Reliability Benefits

Q: What are the reliability benefits to the Customer from the Tomhicken Switchyard?

A: PPL confirmed the project meets NERC FAC-002-2 facility interconnection standards, PPL's FERC 715 criteria, and PPL's System Planning Development Standards, and that "flow studies performed by the Company and PJM demonstrate that the proposed project

meets these standards."[126] The BAAH configuration enables PPL to "extend four 230 kV lines to the Customer's substation,"[127] and PPL stated that breaker-and-a-half arrangements "provide system reliability and the ability to operate the system."[128] The Tomhicken 230 kV Switchyard is, in PPL's own words, "required due to the number of lines needed by the Customer and the size of the requested load."[129]

These reliability benefits — a dedicated 230 kV interconnection with four circuits designed specifically for this Customer's load requirements — accrue primarily to the Customer, not to existing ratepayers.

Q: Did PPL provide any quantitative analysis of the reliability benefits to the Customer?

A: No. When asked to provide quantitative results demonstrating that the proposed solution meets reliability standards — including specific metrics such as loss of load probability or load delivery reliability — PPL stated that it "does not have any additional quantitative analyses" beyond the flow studies performed for standards compliance.[130] PPL did not quantify the reliability improvement the Customer receives, the value of N-1 redundancy for a load of this size, or how the reliability benefits compare to the cost of the infrastructure providing them.

[126] PPL Response to OCA V-5(a).
[127] Page 8, LON.
[128] PPL Response to OCA V-4(b).
[129] Page 8, LON.
[130] "The flow studies performed by the Company and PJM demonstrate that the proposed project meets these standards. PPL Electric does not have any additional quantitative analyses." PPL Response to OCA V-5(a).

Q: Do you agree with PPL's characterization of Customer reliability benefits?

A: I agree that the Tomhicken Switchyard provides real and substantial reliability benefits to the Customer. A 965 MW load receiving a dedicated BAAH-configured 230 kV interconnection with four redundant circuits is receiving a high level of service reliability that the Customer specifically requested and that the switchyard was designed to provide.

However, this finding cuts against PPL's cost allocation, not for it. The reliability benefits established above — PPL's own record confirms the switchyard provides "system reliability and the ability to operate the system,"[131] meets NERC FAC-002-2 facility interconnection standards,[132] and extends four 230 kV lines designed specifically for this Customer's load[133] — are benefits to the Customer, not to existing ratepayers. PPL's LON itself states the switchyard "is required due to the number of lines needed by the Customer and the size of the requested load."[134] A project that exists to provide reliability benefits to a specific customer should be funded by that customer.

Q: What is your recommendation?

A: The Commission should recognize that the reliability benefits of the Tomhicken Switchyard — including the BAAH configuration and four 230 kV lines that PPL confirmed are "required due to the number of lines needed by the Customer and the size of the requested load"[135] — accrue primarily to the Customer. These Customer reliability

[131] PPL Response to OCA V-4(b).
[132] PPL Response to OCA V-5(a).
[133] Page 8, LON.
[134] Page 8, LON.
[135] Page 8, LON.

benefits do not justify allocating $38.4 million to ratepayers. The Customer who receives the reliability benefits should bear the costs that produce them.

VI. Network Benefits

Q: According to PPL, what are the network benefits of the Tomhicken Switchyard?

A: PPL's LON establishes the applicable framework. Under Tariff Rule 4(C)(4), LP-5 customers are required to pay for upgrades necessary to serve their load.[136] PPL's policy permits an exception — certain upgrades "that also benefit other PPL Electric customers and/or the transmission grid may be excluded from the interconnecting customer's obligation and added to PPL Electric's transmission rate base."[137] However, PPL's LON is explicit that this exception requires a case-by-case evaluation: "PPL Electric substations/switchyards will be evaluated on a case-by-case basis to determine if the upgrades provide benefits to other customers."[138]

As examples of benefits that would trigger ratepayer allocation, PPL identifies:

- "Added system reliability;
- Increased capacity/lower congestion;
- Lower impedance;
- Improved asset condition of existing facilities;
- Service to multiple transmission customers and/or retail feeders;
- Increased resiliency and operational flexibility;

[136] Page 10, LON.
[137] Page 10, LON.
[138] Page 10, LON.

- Expanded capacity for new generation flow and interconnections."[139]

As discussed below, PPL has not provided quantitative analysis supporting any of these claimed benefits in the context of the Tomhicken Switchyard specifically, nor has it demonstrated that these benefits are fully realized under Phase 1 alone. The case-by-case evaluation PPL's own LON requires was never performed.

Q: Did PPL provide any quantitative analysis of the network benefits?

A: When asked in Discovery to "explain why quantification was not performed and what qualitative basis PPL Electric relies upon to justify inclusion of Project costs in transmission rates"[140], PPL **first** stated that it "relied on its policy"[141] - the PPL Electric Utilities Corporation – Policy on Cost Allocation for Large Customer Interconnections.[142]

Second, PPL stated that the Tomhicken Switchyard provides network benefits because it is part of PPL's 230 kV network and the Switchyard "will see network flow through the yard as well as serving the customer's requested load" and "will allow for service for other customers, as needed".[143]

Third, PPL stated that "[t]here is not an industry standard to calculate and measure benefits of network upgrades as described by this question" and "[i]n

[139] Page 11, LON.
[140] OCA I-6(c).
[141] PPL Response to OCA I-6(c).
[142] OCA I-6 Attachment 1.
[143] PPL Response to OCA I-6(c).

transmission ratemaking, the quantification of benefits from network system upgrades is a highly contentious and litigated topic."[144]

PPL also stated that "[a]lthough complex tools have been developed to measure use of a transmission facility, they can only be implemented once the line is built and flows can be measured. Even then, they change in real time—to say nothing about changes over the decades of expected useful life of a transmission network facility."[145]

On that **last point**, when I followed up with PPL and asked if it "mean[s] PPL did not perform any forward-looking quantitative analysis of ratepayer benefits prior to making its cost allocation determination for this project? Please answer yes or no, and if no, produce that analysis"[146], PPL's response was "PPL Electric did not perform a forward-looking quantitative analysis which is consistent with FERC policy. Network facilities benefit all network users and there is no need to identify actual benefits in order to include the costs of network transmission facilities in transmission rates. See City of Anaheim, Cal., 113 FERC ¶ 61,091, at P 58 (2005), reh'g denied, 114 FERC ¶ 61,311 (2006)."[147]

PPL's own LON required a case-by-case evaluation of benefits before invoking the ratepayer allocation exception. PPL's response confirms that evaluation was never performed.

Q: Which PJM RTEP model was modeled for justifying the need?

[144] PPL Response to OCA I-6(c).
[145] PPL Response to OCA I-6(c).
[146] OCA III-4(a).
[147] PPL Response to OCA III-4(a).

A: PPL stated that the "2025 RTEP summer case for 2030 model" was used to justify the need for Tomhicken Switchyard.[148] Based on that model, PPL stated that the Tomhicken Switchyard will have approximately 700 MVA of network flow through the switchyard under normal conditions, and up to 1,200 MVA of network flow under contingency conditions.[149]

Q: What assumptions underly the RTEP 2030 model — specifically, is Phase 2 assumed to be in service in that RTEP case?

A: Yes, PPL confirmed that "[b]oth Phase 1 and Phase 2 are included in supplemental project S3528 scope of work and are modelled in the 2025 RTEP summer case for 2030"[150]. The 700 MVA network flow figure PPL cited as evidence of ratepayer benefit therefore assumes Phase 2 is constructed and in service — it does not represent a benefit realized under Phase 1 alone.

Q: Do you agree with PPL that there are network benefits of the Tomhicken Switchyard?

A: I agree that the Tomhicken Switchyard, as part of PPL's 230 kV network, will produce some network benefits. However, agreeing that benefits exist is not the same as agreeing that those benefits justify the $38.4M ratepayer allocation PPL is seeking. Without any

[148] PPL Response to OCA III-4(c).
[149] PPL Response to OCA III-4(c).
[150] PPL Response to OCA VIII-2(b).

quantitative analysis, there is no basis to conclude that ratepayer benefits equal or exceed ratepayer costs. Table 1 below summarizes this analysis across five project scenarios.

Q: Can you summarize whether ratepayer benefits exist across the relevant project scenarios?

A: Yes. Table 1 below summarizes five scenarios — before the project, after Phase 1 only, and after both phases — with and without the customer's load. Under no scenario does an independent ratepayer benefit exist under Phase 1 alone.

Table 1 - Scenario Analysis Table

#	Scenario	Violations / flows	Result	Ratepayer benefit	Source
1	Before project, no customer	No reliability violations. Lines in top 10-11% by contingency loading but emergency ratings never exceeded. No planned projects on S-H corridor.	**Status quo**	Not applicable	PPL Response to OCA VIII-1(a)(b)(c); VI-2(a)
2	Before project, with customer	P1 loss of one S-H circuit exceeds summer and winter normal ratings at 276 MW initial load. Emergency ratings exceeded at ~470 MW. At 965 MW peak, far exceeds all ratings under N-1.	**Phase 1 needed**	None — need is customer-driven. No pre-existing reliability violation.	PPL Response to OCA VI-1(a)(b)(c)
3	After Phase 1, no customer	No violations. ~1,400 MVA flows through Tomhicken under normal conditions (~1,500 MVA contingency) — existing S-H corridor load rerouted through new switching point. Not new capacity.	**S-H load rerouted**	None — rerouted existing load, not new ratepayer benefit. No new capacity created.	PPL Response to OCA VIII-2(a); VIII-1(b)(c)
4	After Phase 1, with customer	P1/P4 thermal overloads on new S-T lines at ~400 MW (April 2028). P7 voltage violations at Tomhicken and Harwood at ~700 MW (August 2028). Phase 2 needed to resolve both.	**Phase 2 needed**	None — Phase 2 still required. Benefits not yet realized. PPL confirmed Phase 2 is part of the solution to serve the customer's requested load.	Lookup testimony, Page 4 Lines 5-20
5	After Phase 1 and Phase 2, no customer	~1,100 MVA flows through Tomhicken under normal conditions (~1,600 MVA contingency). No violations. The 700 MVA figure PPL cited as ratepayer benefit is measured in this configuration with customer load added.	**Network flows present**	Possible — but only after Phase 2 is approved and constructed. Benefits contingent on Phase 2 approval at Docket No. A-2026-3061547.	PPL Response to OCA VIII-2(b)(c)

Q: Do you agree with PPL's explanation for why it did not perform quantitative analysis of network benefits?

A: No. I disagree with PPL's explanation on each of four points: reliance on its internal cost allocation policy, the existence of network flow through the switchyard, the absence of an industry standard to measure benefits, and the claim that quantification tools cannot be used until the facility is built.

On the **first point** regarding PPL's Policy on Cost Allocation for Large Customer Interconnections, PPL confirmed that the Commission did not review or approve this Policy.[151] The Commission is therefore being asked to allocate $38.4M to ratepayers based on a methodology that has never been subjected to the Commission's scrutiny. That is procedurally backwards — the cost allocation framework should be established and approved before it is applied, not ratified after the fact in an LON proceeding.

On the **second point** about network flows going through Tomhicken Switchyard, PPL confirmed that the 700 MVA network flow figure PPL cited as evidence of ratepayer benefit[152] assumes both Phase 1 and Phase 2 are in service in the 2030 RTEP model.[153] That figure does not represent a benefit realized under Phase 1 alone. PPL also confirmed that the customer's load is not included in the 700 MVA, it represents existing network

[151] "PPL Electric's cost allocation policy has not been reviewed or approved by the Pennsylvania PUC. The Company applies its cost allocation policy consistent with FERC regulations and guidance on the recovery of transmission investments. While the cost allocation policy has not been approved, all of PPL Electric's decisions made with respect to cost allocation of transmission investment is subject to oversight and review by FERC." PPL Response to OCA III-6.
[152] "Based on the 2025 RTEP summer case for 2030, the Tomhicken Switchyard will have approximately 700 MVA of network flow through the switchyard under normal conditions." PPL Response to OCA III-4(c).
[153] "Yes - Both Phase 1 and Phase 2 are included in supplemental project S3528 scope of work and are modelled in the 2025 RTEP summer case for 2030." PPL Response to OCA VIII-2(b).

flow passing southward toward Harwood, not new capacity created for ratepayers.[154] The existence of some network flow through the switchyard is therefore not a demonstration that ratepayer benefits under Phase 1 alone are commensurate with the $38.4 million allocation.

On the **third point**, I disagree with PPL that "the quantification of benefits from network system upgrades is a highly contentious and litigated topic"[155] because PJM conducts such a network analysis to determine who pays for regional projects so that it can allocate costs appropriately.

I understand that Tomhicken is a Supplemental project, not a regional project. However, PPL is asking the Commission to approve ratepayer cost allocation for a Supplemental project on the explicit basis that it provides network benefits — the same category of benefits that PJM quantifies when allocating regional project costs. PPL cannot invoke network benefits to justify ratepayer allocation while simultaneously declining to perform the quantitative analysis that network benefit claims require.

I also disagree with PPL that "[t]here is not an industry standard to calculate and measure benefits of network upgrades".[156] Benefit to cost ratio calculations at Regional Transmission Organizations (RTOs) like PJM is an established practice. Yes, it could be contentious if the allocated Transmission Owners do not agree with the cost allocation

[154] "The 700 MVA of flow was the amount of load passing through the Tomhicken 230 kV Switchyard south towards the Harwood 230-69kV Substation. The customer's load was not included in the 700 MVA. As the 230 kV system is a network, the flow through the substation will vary with generation and system conditions." PPL Response to OCA VIII-2(d).
[155] PPL Response to OCA I-6(c).
[156] PPL Response to OCA I-6(c).

and several cost allocations have been litigated at FERC. But that does not mean that PPL should not perform network benefit calculations for the Tomhicken Switchyard project.

On the **final point**, I disagree with PPL's final point of "[a]lthough complex tools have been developed to measure use of a transmission facility, they can only be implemented once the line is built and flows can be measured".[157] This is not true given that as an RTO, PJM performs these benefit calculations using complex tools like production cost simulation models[158]. In my experience as a former RTO transmission planning professional, Transmission Owners like PPL routinely perform their own production cost simulations to verify PJM cost allocation assignments — making PPL's claim that forward-looking quantitative analysis cannot be performed is inconsistent with standard industry practice. PPL's claim that forward-looking quantitative analysis is impossible is directly contradicted by its own routine participation in PJM's RTEP Market Efficiency process[159].

Q: Does City of Anaheim excuse PPL from performing quantitative analysis here?

A: No. PPL's response cited a FERC proceeding — City of Anaheim — as the basis for not performing forward-looking quantitative analysis. I note that this is a federal transmission

[157] PPL Response to OCA I-6(c).
[158] See "The percentage of net energy flow on the facility in each direction will be determined via an 8,760 hourly **production cost simulation**. Those load zones having distribution factors that indicate they contribute to power flow on the facility in the same direction as the net energy flow from the **production cost simulation** will be responsible for the portion of the cost assigned to the use of the upgrade in that direction." Page 65, PJM Manual 14B: PJM Region Transmission Planning Process Attachment A: PJM Baseline Reliability Upgrade Cost Allocation Procedures Revision: 59, Effective Date: 04/22/2026 PJM © 2026 Available at https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.ashx (Last Accessed on June 2, 2026)
[159] PJM Problem Statement & Issue Charge - https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/20171214/20171214-item-03-market-efficiency-problem-statement-and-issue-charge.ashx (Last Accessed on June 2, 2026)

ratemaking precedent. I am advised by counsel that the Commission has provided a policy statement indicating that 100% of the but-for plant investment costs for the service and interconnection of a large load customer should be paid up-front by the customer. Questions regarding jurisdiction over cost assignment between a utility's transmission rate base and an interconnecting customer, and the extent to which this cost assignment is an acceptable term or condition of retail distribution service because it does not conflict with FERC's jurisdiction over transmission rates, is a matter which will be addressed by counsel if necessary. OCA Witness Frank Felder also discusses these issues and the Expansion Rate Policy in his testimony.

Q: What would a quantitative analysis under Phase 1 alone actually show?

A: As a matter of transmission planning practice, the absence of quantitative analysis is not standard. The record evidence developed in this proceeding permits me to draw the quantitative conclusion PPL declined to make. Under Phase 1 alone, the demonstrable network benefit to existing ratepayers is zero on three independent measures.

First, capacity and reliability. As discussed above, the new Susquehanna–Tomhicken and Tomhicken–Harwood segments were sized to ensure that, under an N-1 contingency, the surviving circuit on either segment — rated approximately 1,195 MVA normal[160] — can still serve the customer's 1,016 MVA peak demand. The existing Susquehanna-Harwood line could not have done so. This sizing was driven entirely by

[160] Table 2-3, Attachment 2 – Engineering Statement; 3,000 A × 230,000 V × √3 / 1,000,000 = 1,195 MVA per circuit (summer normal).

the customer's peak load; it does not provide existing ratepayers with any incremental N-1 reliability margin beyond what is needed to serve this customer.

Second, network flow. Without Phase 2 and without the customer, the Tomhicken Switchyard carries approximately 1,400 MVA of existing corridor flow[161] — the same Susquehanna-Harwood load that was being served before the project, now rerouted through a new switching point. Rerouting creates no new value for existing ratepayers.

Third, congestion relief. The congestion PPL cited as a system condition — approximately $35 million over 2021 and 2022[162] — was resolved by DLR three years before this project was proposed.[163] Phase 1 provides no incremental congestion relief beyond what DLR already achieved.

This is the quantitative analysis PPL was required to perform under its own case-by-case evaluation standard before allocating $38.4 million to ratepayers. The record shows what that analysis would have found: under Phase 1 alone, no demonstrable independent benefit to existing ratepayers.

Q: Are the network benefits PPL claims for Phase 1 contingent on Phase 2 being built?

A: Yes, the network benefits PPL claims for Phase 1 are contingent on Phase 2 being built. Phase 2, as described in the Necessity Statement, "includes additional reinforcements of

[161] "Without the Phase 2 Nescopeck-Tomhicken and Nescopeck-Harwood 230 kV Transmission Lines and the customer's load at the Tomhicken Switchyard, the Tomhicken 230 kV Switchyard will have approximately 1,400 MVA of network flow through the switchyard under normal conditions." PPL Response to OCA VIII-2(a).
[162] "the Susquehanna-Harwood #1 & #2 230 kV Transmission Lines had approximately $20 million in congestion in 2021 and approximately $15 million in 2022." PPL Response to OCA VIII-1(a).
[163] "PPL Electric was able to address the congestion driver with the application of DLR on the Susquehanna-Harwood #1 and #2 230kV Transmission Lines." PPL Response to OCA VIII-1(a).

the 230 kV system from the Susquehanna 230 kV Switchyard to the Tomhicken 230 kV Switchyard and Harwood 230-69 kV Substation, via a new 230 kV switchyard ("Nescopeck 230 kV Switchyard")".[164]

PPL's claimed network benefits for Phase 1 span three categories across its discovery responses and LON. The LON identifies "added system reliability," "increased capacity/lower congestion," "increased resiliency and operational flexibility," and "expanded capacity for new generation flow and interconnections" as examples of benefits justifying ratepayer allocation.[165] For the ratepayer-allocated infrastructure specifically, PPL stated the purpose is to "[s]upport Sectionalization of existing 230kV lines and provide new capacity and alternative route for power flow."[166]

When asked to quantify the reliability benefit "to the Bulk Electric System (BES) attributable to the proposed solution, including any improvement in BES performance metrics compared to the pre-project baseline"[167], PPL stated that "the Tomhicken 230 kV Switchyard and additional Phase 2 transmission lines will increase system reliability by adding additional 230 kV paths from the Susquehanna area to the Hazleton area," that "the proposed phases will increase capacity of the transmission system," and that the "additional 230 kV transmission lines and Tomhicken Switchyard provide additional system resiliency and greater operational flexibility to take outages."[168]

Additionally, as mentioned above, PPL confirmed directly that the 2030 RTEP case used to derive the 700 MVA network flow figure models both Phase 1 and Phase 2

[164] Page I-9, Attachment I Necessity Statement.
[165] Page 11, LON.
[166] PPL Response to OCA III-3(a).
[167] OCA V-5(b).
[168] PPL Response to OCA V-5(b).

in service.[169] The 700 MVA network flow figure, which PPL claims as evidence for ratepayer benefits[170], does not exist under Phase 1 alone.

Q: Does the Tomhicken Switchyard's design confirm this Phase 2 dependency?

A: Yes. PPL stated that "[t]he splitting of the Susquehanna-Harwood #1 & #2 230kV Transmission Lines was designed to allow the future Phase 2 lines to terminate into the Tomhicken Switchyard and Harwood Substation without requiring line crossings."[171] This means that Tomhicken Switchyard was designed to accommodate Phase 2.

Q: Has PPL acknowledged any uncertainty about whether the project has independent value?

A: Yes. PPL's Mr. Lookup acknowledged uncertainty about whether the project provides any independent value at all. PPL's Mr. Lookup, when asked whether the project would still be needed if the customer does not complete their facility, answered only "potentially."[172] This is not an affirmative statement that independent network benefits justify this project. It is an acknowledgment that the project's justification is contingent on the customer's

[169] PPL Response to OCA VIII–2(b).
[170] When asked in OCA III-4(c), "Please provide power flow projections showing the magnitude of network flow through the Tomhicken Switchyard under normal and contingency conditions, attributable solely to loads and sources other than this customer. If no such projections exist, please so state.", PPL's response was "Based on the 2025 RTEP summer case for 2030, the Tomhicken Switchyard will have approximately 700 MVA of network flow through the switchyard under normal conditions. In contingency conditions, the yard could have up to 1,200 MVA of network flow through the switchyard based on the 2025 RTEP summer case for 2030." PPL Response to OCA III-4(c).
[171] PPL Response to OCA I-10(c).
[172] Line 6, Page 5, PPL Statement No.1.

completion — precisely the opposite of an independent system reliability need that would justify ratepayer cost allocation.

Q: According to PPL's witness Mr. Lookup, who is the Tomhicken Switchyard designed to serve?

A: Mr. Lookup confirmed in direct testimony that "the Tomhicken Switchyard is designed to eventually serve multiple customers"[173] and that "there is other load growth in the Hazleton area that this project will support."[174] PPL produced in discovery a list of projects currently in its interconnection queue through March 31, 2026 — spanning eight pages and including dozens of large load customers requesting 230 kV service at loads ranging from hundreds to thousands of MW.[175] These are the large load customers — requesting hundreds to thousands of MW at transmission voltage — that PPL's Mr. Lookup identified as benefiting from the Tomhicken Switchyard. They are not the existing ratepayers who are being asked to pay $38.4 million for this infrastructure.

Q: Has PPL's witness characterized this project as customer-driven?

A: Yes. Mr. Lookup confirmed that, “[t]he current Customer is the farthest along the development process amongst those customers, and is the need driver for this Letter of

[173] Line 6-7, Page 5, PPL Statement No.1.
[174] Line 9-10, Page 5, PPL Statement No.1.
[175] OCA II-12 Attachment 1.

Notification."[176] PPL's own witness therefore characterizes the project as customer-driven — not as a network upgrade independently justified by system reliability needs.

Q: In your opinion, if the Customer whose interconnection needs are driving the construction of the Switchyard does not interconnect, are the facilities still needed?

A: No. As established throughout this testimony, but for this Customer's interconnection request, no reliability need requiring this switchyard would exist. If the Customer does not interconnect, the need driver for this project disappears, and the Tomhicken Switchyard serves no demonstrated independent system reliability purpose.

Q: If the Customer is ultimately unable to interconnect to the proposed Switchyard, would it be appropriate for the Commission to authorize the construction of the interconnection facilities?

A: No. Authorizing construction before the Customer's ability to interconnect is resolved would expose Pennsylvania ratepayers to $38.4 million in costs for infrastructure that may never serve its intended purpose. The specific conditions the Commission should impose before authorizing construction — including reallocation of customer-driven design costs, a cost recovery mechanism for future benefiting customers, and formal review of PPL's cost allocation policy — are set forth in the Phase 1 and Phase 2 Interdependency and Switchyard Cost sections of this testimony.

[176] Lines 7-8, Page 5, PPL Statement No.1.

Q: Did PPL identify whether other queue customers contribute to the 400 MW and 700 MW thresholds?

A: PPL stated that the 400 MW and 700 MW thresholds HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS PPL did not identify any other customer by name, load level, or projected in-service date as the question required. Notably, PPL has stated that it "only has one ESA [Electric Service Agreement] with a customer connecting to the Tomhicken Switchyard."[178]

This evasive response is notable: PPL neither confirmed the thresholds are based solely on this customer's load nor identified the specific other customers whose load would contribute. What PPL did confirm is that this customer's maximum demand of 965 MW alone exceeds both the 400 MW and 700 MW thresholds — meaning this customer's load is independently sufficient to trigger both the P1/P4 overloads and the P7 voltage violations that drive Phase 2, regardless of whether other queue customers also contribute. If other queue customers do contribute to these thresholds, that further confirms that Phase 2 costs should be shared among those future customers rather than allocated entirely to existing ratepayers.

[177] PPL Response to HIGHLY CONFIDENTIAL OCA VII-2(b).
[178] PPL Response to OCA X-2.

Q: What system function does the Tomhicken Switchyard serve for ratepayers if Phase 2 is never constructed?

A: PPL stated in Discovery that the "Tomhicken Switchyard allows for multiple future new transmission electrical paths outside of the current proposed Phase 2 transmission line to be interconnected at Tomhicken. It also allows for PPL Electric to provide new customer interconnections directly from transmission or indirectly for future load growth via new distribution facilities."[179]

PPL's own answer is telling — every system function it identifies is forward-looking and customer-driven. The switchyard serves future transmission paths, future customer interconnections, and future load growth. Not one of the functions PPL identifies provides a benefit to existing ratepayers today under Phase 1 alone.

As established in the preceding question, the customers who will benefit from these future transmission paths and new interconnections are the large load customers in PPL's interconnection queue — not the existing ratepayers being asked to pay $38.4 million today.

Under Phase 1 alone, with Phase 2 never constructed, the Tomhicken Switchyard serves one function: connecting this customer to the 230 kV network. That is a customer function, not a ratepayer function.

Q: What is your recommendation?

[179] PPL Response to OCA III-8 (e) Supplemental.

A: The Commission should not approve the $38.4 million ratepayer allocation without first requiring PPL to perform and file a forward-looking quantitative analysis demonstrating that ratepayer benefits equal or exceed the amount allocated to them. PPL performed no such analysis.[180] Without it, the Commission has no basis to conclude the allocation is just and reasonable. Additionally, the Commission should require PPL to submit its Cost Allocation Policy for Large Customer Interconnections for formal Commission review and approval before it is applied to any future project in PPL's interconnection queue for purposes of ensuring that the Policy is compliant with the Commission's direction in the Large Load Model Tariff for computation of the applicable CIAC.

VII. Phase 1 and Phase 2 Interdependency

VII.a. Establishing the two-phase structure

Q: What is Phase 1 of the Tomhicken Switchyard and what does it include?

A: Phase 1 is the subject of this proceeding at Docket No. A-2025-3059443. As described in the Tomhicken Switchyard Description section above, it consists of approximately 1.1 miles of new Tap Lines, the new Tomhicken 230 kV Switchyard, and 0.1-mile Connecting Lines to the customer-owned substation, all located in Hazle Township, Luzerne County, Pennsylvania.

[180] "PPL Electric did not perform a forward-looking quantitative analysis which is consistent with FERC policy." PPL Response to OCA III-4(a).

The Tomhicken 230 kV Switchyard itself is a breaker-and-a-half[181] configured switchyard with five bays.[182] The total estimated cost of Phase 1 is $59.9 million, with $21.5 million allocated to the customer.[183] PPL's direct testimony states the ratepayer allocation is approximately $38.4 million.[184] However, PPL confirmed in discovery that the primary ratepayer-allocated asset, HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS The Commission should require PPL to confirm the current authoritative Phase 1 ratepayer allocation before approving any cost recovery.

Q: What is Phase 2 of the Tomhicken Switchyard and what does it include?

A: Phase 2 is a separate but related project filed at Docket No. A-2026-3061547, currently pending before this Commission.

In Phase 2, PPL is seeking Commission's approval to:

> "(1) Bifurcate and Rebuild 4.4 Miles of the Existing Sunbury-Susquehanna #1 230 kV Transmission Line;

[181] Page 8, LON.
[182] Responsibility of Asset Matrix for Breaker and a Half (BAAH) Example 1, Page 3 of 8, OCA I-6 Attachment 1.
[183] Lines 12-14, Page 7, PPL Statement No. 1.
[184] *Id.*
[185] PPL Response to HIGHLY CONFIDENTIAL OCA XIII-1(a).

(2) Construct 0.9 Miles of New Transmission Line Tap for Future 230 kV Double-Circuit Operation;

(3) Raise Approximately 0.5 Miles of the Sunbury-Susquehanna 500 kV Transmission Line; and

(4) Construct 11.2 Miles of New Double-Circuit 230 kV Transmission Line for Future Double-Circuit 500 kV Capacity, Located in Black Creek, Hazle, Hollenback, Nescopeck, and Sugarloaf Townships in Luzerne County, Pennsylvania."[186]

Phase 2 is needed because, as PPL acknowledged in the LON, "[a]s the Customer's load continues to ramp up, additional improvements to the 230 kV network in this area will be required to continue to provide reliable service to the area"[187] and Phase 2 is required "to prevent the thermal overload of the Susquehanna-Tomhicken #1 & #2 230 kV and Tomhicken-Harwood #1 & #2 230 kV lines"[188] constructed in Phase 1. In other words, the transmission lines built in Phase 1 will themselves become thermally overloaded as the customer's load grows — making Phase 2 a direct consequence of Phase 1.

Q: What is the total cost of Phase 2, and what is the cumulative ratepayer exposure across both phases?

A: The total estimated cost of Phase 2 covered by the application at Docket No. A-2026-3061547 is approximately HIGHLY CONFIDENTIAL STARTS [redacted]

[186] Application for Transmission Line - PPL Electric, available at https://www.puc.pa.gov/pcdocs/1921888.pdf (Last Accessed on May 27, 2026).
[187] Page 5, LON.
[188] Page I-9, Attachment I – Necessity Statement.

HIGHLY CONFIDENTIAL ENDS — reduced from the $118.5 million stated in the original application.[189] PPL stated that "the cost for the Project will be allocated to PPL Electric customers"[190] — meaning ratepayers are expected to bear the full Phase 2 cost with no customer contribution. However, PPL confirmed in discovery that the HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS The Commission should require PPL to identify that proceeding before approving any cost allocation in this docket.

The combined ratepayer exposure across all identified components is therefore:

- Phase 1 ratepayer allocation: HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS and $38.4 million[192] Phase 2 ratepayer allocation HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS
- Item 7 HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS

[189] PPL Response to HIGHLY CONFIDENTIAL OCA XIII-1(b).
[190] Page ES-3, Phase 2 application.
[191] PPL Response to HIGHLY CONFIDENTIAL OCA XIII-1(b).
[192] PPL Response to HIGHLY CONFIDENTIAL OCA XIII-1(a); Lines 12-14, Page 7, PPL Statement No. 1.
[193] PPL Response to HIGHLY CONFIDENTIAL OCA XIII-1(b).
[194] OCA I-6 Attachment 2 HIGHLY CONFIDENTIAL

- Total ratepayer exposure: HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS

This figure is significantly greater than the $156.9 million this testimony originally estimated based on PPL's application figures. The progression from 36% customer responsibility in Phase 1 to 0% in Phase 2 — for a project whose Phase 2 is a direct consequence of Phase 1 customer load growth — is not supported by any quantitative benefit analysis in either proceeding. Furthermore, HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS in which this Commission will have the opportunity to review the cost allocation methodology.

Q: What is reactive compensation and did PPL evaluate it as a lower-cost alternative to the Phase 2 transmission solution?

A: Reactive compensation refers to electrical devices — such as capacitor banks, STATCOMs (Static Synchronous Compensators), or Static VAR Compensators — that supply or absorb reactive power to maintain voltage levels within acceptable limits on the transmission system. Unlike active power (measured in megawatts), reactive power (measured in megavars, or MVAR) does not perform useful work but is essential for maintaining voltage stability. As NERC has recognized, reactive power should be supplied locally near the point of deficiency[195], and in some situations static shunt

[195] "Reactive power should be supplied locally because of its dependence on voltage difference. Unlike real power, reactive power cannot be transferred long distances across the BPS. It is usually necessary to site reactive power

compensation is adequate to alleviate low-voltage conditions[196]. When voltage violations occur — as PPL identified at the Tomhicken Switchyard and Harwood Substation under P7 contingency conditions — reactive compensation devices can often address those violations at significantly lower cost than constructing new transmission lines.

No. PPL confirmed that P7 planning events permit non-consequential load loss as an acceptable system response under its own FERC 715 Criteria.[197] PPL also confirmed that the P7 voltage violations are voltage change violations — 9.17% at Tomhicken and 8.78% at Harwood, both exceeding PPL's 8% change limit — while the voltage magnitude at both buses (0.925 pu and 0.927 pu) approaches without exceeding the 0.92 pu limit.[198]

Reactive compensation already exists in the project area — 125 MVAR at Tomhicken and 80 MVAR at Harwood — and PPL confirmed that "[a]dditional capacitance would increase the amount of load that could be added into the area before the P7 Tower contingency caused Voltage Violations."[199] PPL did not provide any cost comparison between additional reactive compensation and Phase 2's $118.5 million transmission solution.

Instead, PPL stated that a Remedial Action Scheme for load shedding would constitute only a "temporary measure until a permanent transmission facility upgrade can

devices very near to or at the location that is deficient." Reliability Guideline Reactive Power Planning, December 2016. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/sams/reliability-guideline---reactive-power-planning.pdf (Last Accessed on July 6, 2026).

[196] "The type of resource selected to mitigate any reactive power deficiency is driven by the system characteristics. In some situations, static shunt compensation is adequate to alleviate low-voltage conditions. In other situations, dynamic reactive support is necessary to ensure reliable pre- and post-contingency voltage levels and a robust response in voltage following a disturbance." *Id.*

[197] PPL Response to OCA VI-4(a).

[198] PPL Response to OCA VI-4(b).

[199] PPL Response to OCA VI-4(e).

be implemented"[200] — applying a standard stricter than NERC TPL-001-5.1 requires for P7 events, which expressly permits non-consequential load loss as a compliant system response, which PPL agreed is acceptable under its own FERC 715 Criteria[201].

The need for Phase 2 as a $118.5 million transmission solution — rather than a potential lower-cost reactive compensation alternative — has not been demonstrated by cost comparison in this record.

Q: Were Phase 1 and Phase 2 designed concurrently?

A: PPL did not explicitly state that Phase 1 and Phase 2 were designed concurrently. However, the record establishes that Phase 1's physical design was determined by Phase 2 requirements — which is functionally equivalent to concurrent design.

Four admissions from PPL's own discovery responses establish this:

First, PPL confirmed that the splitting of the Susquehanna-Harwood lines "was designed to allow the future Phase 2 lines to terminate into the Tomhicken Switchyard and Harwood Substation without requiring line crossings"[202] and that "the Tomhicken 230 kV Switchyard will have a line termination point for the Phase 2 scope."[203] The Phase 1 line routing was determined by Phase 2 termination requirements.

[200] PPL Response to OCA VI-4(d).
[201] "Yes, PPL Electric's consequential and non-consequential load loss limits are defined in Table 4.5-1 of PPL Electric FERC 715 Criteria." PPL Response to OCA VI-4(a).
[202] PPL Response to OCA I-10(c).
[203] *Id.*

Second, PPL confirmed a critical design distinction — while the system network upgrades are based on the Phase 1 DNH load level[204], the Tomhicken Switchyard itself was designed to accommodate the customer's ultimate requested load[205], not just the Phase 1 DNH load level. This means the switchyard's physical configuration — including its BAAH design, five bays, and line termination points — was sized beyond what Phase 1 alone requires. The Tomhicken switchyard itself was sized to scale Phase 2 even though Phase 2, filed at Docket No. A-2026-3061547, has not yet been scheduled for hearing by this Commission.

Third, PPL justified its BAAH configuration over a ring bus by citing nine line terminations — a number that includes Phase 2 lines.[206] The switchyard's configuration was determined by Phase 2 line count at the time of Phase 1 design.

Fourth, PPL's own cost allocation document labels the HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS However, when asked to reconcile this characterization with the ratepayer allocation figure in direct testimony, PPL stated that HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS These two PPL responses are irreconcilable

[204] "The system network upgrades included in the supplemental project are based on the DNH Load Level." PPL Response to OCA V-1(c).
[205] "The substation was designed to accommodate the customer's ultimate requested load." PPL Response to OCA V-1(c).
[206] "The proposed Tomhicken Switchyard is to have nine lines connected as part of Phase 1 and Phase 2." PPL Response to OCA V-4(c).
[207] PPL Response to HIGHLY CONFIDENTIAL OCA IX-1.
[208] PPL Response to HIGHLY CONFIDENTIAL OCA XIII-1(a).

— and the inconsistency itself confirms that PPL has not maintained a clear, consistent account of which costs in Phase 1 are attributable to Phase 2-driven design requirements.

Taken together, these four admissions demonstrate that Phase 1 was designed with Phase 2 requirements embedded in its physical configuration from the outset — regardless of whether the two phases were formally designated as concurrent.

Q: What is the current regulatory status of Phase 2?

A: Phase 2 is filed as a separate Full Siting Application at Docket No. A-2026-3061547, currently pending before this Commission. As of the date of this testimony, no hearing has been scheduled in that proceeding. Phase 2 has not been reviewed on the merits, no evidentiary record has been developed, and no Commission decision on Phase 2's need, design, cost, or cost allocation has been issued.

This procedural posture is directly relevant to the cost allocation question in this proceeding. The system-level benefits PPL attributes to Phase 1 — including "added system reliability," "increased capacity/lower congestion," "increased resiliency and operational flexibility,"[209] and "additional 230 kV paths from the Susquehanna area to the Hazleton area"[210] — are contingent on Phase 2 being constructed. Yet Phase 2 has not progressed beyond the filing stage. The Commission is being asked to approve a $38.4 million ratepayer allocation in this proceeding based on benefits that depend entirely on a future project that has not yet been scheduled for hearing, let alone approved.

[209] Page 11, LON.
[210] PPL Response to OCA V-5(b).

Q: Has the Pennsylvania PUC approved Phase 2?

A: No.

Q: Is Phase 2 approval guaranteed?

A: No.

VII.b. Establishing Phase 1's design dependence on Phase 2

Q: Was the location of the Tomhicken Switchyard determined by system reliability needs independent of this customer's interconnection request, or was it determined by the customer's development location and site layout?

A: PPL confirmed in discovery that the Tomhicken Switchyard is located on the customer's property, and that this location was chosen because it decreases line distance and new right-of-way requirements and minimizes the time and cost for the customer to interconnect.[211] This is a customer-driven location decision. PPL also claims the switchyard provides sectionalizing and network upgrade benefits[212], but those benefits are a consequence of placing the switchyard at the customer's chosen site — they did not independently determine the location. No evidence in the record suggests the Tomhicken

[211] "The location of the Tomhicken 230kV Switchyard was determined by the Customer's development location and site layout." PPL Response to OCA I-10(c). See also "By locating the Switchyard on the Customer property's, it decreases line distance and new right-of-way required, and minimizes the time and cost for a customer to interconnect." PPL Response to OCA III-8(a) Supplemental.

[212] "The Tomhicken Switchyard provides sectionalizing and network upgrades benefits outside of the single Customer interconnection request." PPL Response to OCA III-8(a) Supplemental.

location was identified through a system-needs analysis independent of this customer's interconnection request. The switchyard exists at this location because the customer is here — not because transmission system reliability independently required a new switching facility at this specific site.

Q: Was the splitting of the Susquehanna-Harwood #1 and #2 230 kV Transmission Lines required to serve the customer's initial load request, or was it designed to accommodate Phase 2 line terminations?

A: PPL confirmed in discovery that the splitting of the Susquehanna-Harwood lines was designed to allow future Phase 2 lines to terminate into the Tomhicken Switchyard without requiring line crossings.[213] The split was not driven by Phase 1 necessity — it was a Phase 2 design decision embedded in the Phase 1 project. PPL further confirmed that the substation was designed to accommodate the customer's ultimate requested load, not the DNH case year load level that governs Phase 1 network upgrades.[214]

When asked to quantify the cost savings if the S-H line split had not been required to accommodate Phase 2 terminations, PPL stated only that the cost estimate would be the same as the Phase 1-only switchyard design — approximately $33.97 million.[215] PPL did not separately identify or quantify the line split cost, despite it being a physically distinct design choice affecting 1.1 miles of new transmission line routing. The Commission cannot fully evaluate the cost impact of the Phase 2-driven line split on

[213] "The splitting of the Susquehanna-Harwood #1 & #2 230kV Transmission Lines was designed to allow the future Phase 2 lines to terminate into the Tomhicken Switchyard and Harwood Substation without requiring line crossings." PPL Response to OCA I-10(c).
[214] PPL Response to OCA V-1(b), and (c).
[215] PPL Response to OCA XI-6(b).

ratepayers because PPL has not disaggregated that cost from the broader switchyard figure.

Q: If Phase 2 is never built, would the splitting of the Susquehanna-Harwood lines still have been necessary?

A: No. PPL confirmed in discovery that the S-H line split is not required if the customer is served from an alternative configuration.[216] This admission establishes that the line split — and the entire physical routing of the new Susquehanna-Tomhicken and Tomhicken-Harwood lines — was not independently required to serve this customer under Phase 1 alone. It was a design choice made to accommodate Phase 2 line terminations. If Phase 2 is never built, ratepayers will have funded a line split configuration whose primary purpose — enabling Phase 2 terminations without line crossings — is never realized.

Q: Does the Tomhicken Switchyard have physical design features — including bay count, bus configuration, and line termination points — that serve no function under Phase 1 alone and exist solely to accommodate Phase 2?

A: PPL confirmed in discovery that the Tomhicken Switchyard was designed to accommodate the customer's ultimate requested load rather than the Phase 1 DNH load level[217], and that nine lines will terminate at Tomhicken as part of Phase 1 and Phase 2 combined.[218] The line split configuration was designed to allow Phase 2 lines to

[216] "No, but if the Customer was served directly from the Nescopeck Switchyard the Project would need to be re-evaluated." PPL Response to OCA III-8(d).
[217] PPL Response to OCA V-1(b) and (c).
[218] PPL Response to OCA V-4(c).

terminate without line crossings.[219] These admissions establish that Phase 2-driven design features are embedded in the Phase 1 switchyard.

PPL's cost allocation document confirms this, HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS However, PPL did not separately identify which HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS are Phase 2-specific —bundling the Phase 2-driven features into a single combined asset without itemization. The inability to separate Phase 2-specific physical features and their associated costs from Phase 1 infrastructure is a direct consequence of PPL designing Phase 1 as a combined Phase 1 and Phase 2 asset from the outset.

When asked in this proceeding to identify specific Phase 1 components that were sized or configured to accommodate Phase 2 requirements, PPL stated that "no components in Phase 1 would have been sized differently to accommodate Phase 2 electrical ratings" — but simultaneously confirmed that the Tomhicken Switchyard is "space-proved for the additional equipment to connect the new line upgrades in Phase 2."[221] PPL further confirmed that the electrical bus length could potentially be reduced by one bay if Phase 2 were not contemplated, saving approximately $120,000 — but stated this reduction would not conform to PPL's standard configuration.[222] The term "space-

[219] PPL Response to OCA I-10(c).
[220] PPL Response to HIGHLY CONFIDENTIAL OCA IX-1.
[221] PPL Response to OCA XI-5(a).
[222] PPL Response to OCA XI-5(b).

proved" is an engineering admission that Phase 1's physical layout was deliberately configured to accommodate Phase 2 equipment without requiring reconstruction. This confirms the concurrent design argument: PPL did not merely design Phase 1 to meet Phase 1 needs and happen to leave room for Phase 2 — it affirmatively designed Phase 1's physical layout around Phase 2 requirements.

Q: What is the cost attributable to those Phase 2-ready design features that is currently allocated to ratepayers under Phase 1?

A: PPL's cost allocation document confirms that the primary ratepayer-allocated asset, HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS However, when asked directly to reconcile the HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS PPL has not explained this inconsistency.

PPL further confirmed that HIGHLY CONFIDENTIAL STARTS [redacted]

[223] PPL Response to HIGHLY CONFIDENTIAL OCA IX-1.
[224] PPL Response to HIGHLY CONFIDENTIAL OCA XIII-1(a).

[redacted] HIGHLY CONFIDENTIAL ENDS

PPL confirmed that under a hypothetical Phase 1-only design — with the substation sized for the DNH load level rather than ultimate load, and without Phase 2 line termination accommodation — the estimated switchyard cost would be approximately $33.97 million.[226] Compared to the current HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS million, this represents a difference of approximately HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS million attributable to Phase 2-driven design features within the switchyard itself.

PPL further stated that eliminating the Susquehanna-Harwood line split requirement would cost approximately $33.97 million.[227] PPL did not separately identify or quantify the cost of the line split configuration itself, despite it being a physically distinct design choice affecting 1.1 miles of new transmission line routing. The $1.56 million figure therefore represents PPL's own narrow quantification of Phase 2-driven switchyard costs — it does not capture Phase 2-driven costs embedded in the line segment routing, which PPL failed to disaggregate.

[225] PPL Response to HIGHLY CONFIDENTIAL OCA XIII-1(a).
[226] PPL Response to OCA XI-6(a).
[227] PPL Response to OCA XI-6(b).

PPL's responses are also internally inconsistent on this point. PPL's response to OCA XI-5 identified only a $120,000 bus-length reduction as the cost attributable to Phase 2 accommodation within the switchyard, while PPL's response to OCA XI-6 implies a $1.56 million difference between the current design and a Phase 1-only design. PPL has not explained the approximately $1.44 million gap between these two figures.[228] This internal inconsistency in PPL's own discovery responses further confirms that PPL has not conducted the rigorous cost segregation analysis this Commission would need to evaluate whether the $38.4 million ratepayer allocation is appropriately calibrated to the benefits ratepayers actually receive.

Taken together, PPL's discovery responses reveal three unresolved inconsistencies: whether Item 5 spans both phases or Phase 1 only; whether the authoritative ratepayer allocation is $38.4 million or $35.53 million; and whether the Phase 2-driven cost premium within the switchyard is $120,000 or $1.56 million. The Commission should require PPL to provide a single, consistent, fully reconciled cost accounting before approving any ratepayer allocation.

VII.c. Establishing the reliability benefit dependency

Q: What network reliability benefits does PPL attribute to the Tomhicken Switchyard for transmission ratepayers?

A: PPL attributes the following network reliability benefits to the Tomhicken Switchyard for transmission ratepayers:

[228] PPL Response to OCA XI-5(b); PPL Response to OCA XI-6(a).

PPL stated that the switchyard "will increase system reliability by adding additional 230 kV paths from the Susquehanna area to the Hazleton area,"[229] will "increase capacity of the transmission system,"[230] will provide "additional system resiliency and greater operational flexibility to take outages,"[231] and will allow "additional 230 kV transmission lines to supply other customers or add system capacity."[232]

PPL's Mr. Lookup further testified that based on the 2025 RTEP summer case for 2030, the Tomhicken Switchyard will have approximately 700 MVA of network flow through the switchyard under normal conditions, and up to 1,200 MVA of network flow under contingency conditions.[233]

The full list of benefit categories PPL invokes to justify ratepayer allocation is set forth in the Network Benefits section above.

Q: Are those network reliability benefits fully realized under Phase 1 alone, or do they depend on Phase 2?

A: The network reliability benefits PPL attributes to the Tomhicken Switchyard are not fully realized under Phase 1 alone, they depend on Phase 2 being constructed. PPL's own discovery responses establish this.

[229] PPL Response to OCA V-5(b).
[230] *Id.*
[231] *Id.*
[232] *Id.*
[233] PPL Response to OCA III-4(c).

First and most directly, PPL stated that "[t]he Tomhicken 230 kV Switchyard and additional Phase 2 transmission lines will increase system reliability by adding additional 230 kV paths from the Susquehanna area to the Hazleton area."[234] The conjunction is telling — PPL linked the reliability benefit explicitly to both the switchyard and Phase 2 transmission lines together. The additional 230 kV paths PPL describes do not exist under Phase 1 alone. The Tomhicken Switchyard under Phase 1 is connected to the same Susquehanna-Harwood corridor it replaces — split into two segments but not adding new paths to the network until Phase 2 lines are constructed.

Second, PPL confirmed that the Tomhicken Switchyard "allows for multiple future new transmission electrical paths outside of the current proposed Phase 2 transmission line to be interconnected at Tomhicken"[235] and "allows for PPL Electric to provide new customer interconnections directly from transmission or indirectly for future load growth via new distribution facilities."[236] Every system function PPL identifies is forward-looking and contingent on future construction — none is realized under Phase 1 alone.

Third, whether the 700 MVA[237] network flow PPL's Mr. Lookup cited as a ratepayer benefit is attributable to Phase 1 infrastructure alone or assumes Phase 2 is in service in the 2030 RTEP case is examined in the following question. That answer is critical to evaluating whether PPL's primary quantitative reliability benefit claim survives Phase 1 scrutiny.

[234] PPL Response to OCA V-5(b).
[235] PPL Response to OCA III-8(e) Supplemental.
[236] *Id.*
[237] PPL Response to OCA III-4(c).

Fourth, PPL's Mr. Lookup identified a 400 MW load threshold at which the new Susquehanna-Tomhicken lines become overloaded under P1/P4 contingency conditions.[238] When asked to explain how this 400 MW threshold compares to the P1 overload threshold on the existing Susquehanna-Harwood lines and to identify the specific engineering differences between the two line segments accounting for any difference, PPL did not provide that comparison. Instead PPL responded that interconnecting at the existing Harwood Substation rather than at the proposed Tomhicken location would allow approximately 70 MW more load before summer emergency ratings are exceeded, due to three additional miles of line impedance at Harwood reducing power flow from Susquehanna.[239] PPL provided no engineering explanation for why the new S-T lines have a 400 MW P1 normal rating threshold or how that threshold relates to the existing S-H line configuration. The absence of this explanation means the record contains no basis for evaluating whether the 400 MW Phase 2 trigger is a consequence of Phase 1 design choices or an independent system reliability constraint — a distinction directly relevant to whether Phase 2 costs should ultimately be attributed to this customer's load growth or to an independent system need.

Q: Was Phase 2 a foreseeable, near-certain consequence of Phase 1's design, or a speculative future contingency?

[238] "Specifically, the Susquehanna-Tomhicken #1 and #2 230 kV Transmission Lines become overloaded when the load increases by approximately 400 MW in the Hazleton area. The loss of one of the Susquehanna-Tomhicken 230 kV lines in a single contingency (P1) or multiple contingency with a fault plus stuck breaker (P4) category overloads the remaining in-service line." Lines 14-18, Page 4, PPL Statement No.1.

[239] "Interconnecting the load at the Harwood bus results in the system being able to serve an additional ~70MW before the summer emergency ratings of the Susquehanna-Harwood #1 & #2 Transmission Lines are exceeded." PPL Response to OCA VI-1(d).

A: It was foreseeable and near-certain — not speculative. PPL confirmed that the Susquehanna-Tomhicken lines are projected to first exceed their normal thermal rating under P1 contingency in HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS That leaves only 12 to 15 months between Phase 1's commercial operation and the first overload. HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS This timing holds regardless of which load ramp figure is used, since HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS — not 2033 as PPL's direct testimony states.

More importantly, this was not a contingency PPL discovered after Phase 1 was already built — it was known at the time Phase 1 was designed. PPL confirmed that HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS an explicit admission that Phase 2 exists to serve this customer, not to provide independent benefits to existing ratepayers. PPL confirmed the HIGHLY CONFIDENTIAL STARTS [redacted]

[240] PPL Response to HIGHLY CONFIDENTIAL OCA VII-1(d).
[241] PPL Response to HIGHLY CONFIDENTIAL OCA VII-2(a)(c).
[242] PPL Response to HIGHLY CONFIDENTIAL OCA VII-1(a).
[243] PPL Response to HIGHLY CONFIDENTIAL OCA VII-2(d).
[244]PPL Response to HIGHLY CONFIDENTIAL OCA VII-2(d).

[redacted] HIGHLY CONFIDENTIAL ENDS In other words, the very load level PPL used to design Phase 1 already exceeded the thresholds that trigger Phase 2. PPL also stated that Phase 2 "resolves the thermal overloads on the Susquehanna-Tomhicken #1 & #2 230 kV Transmission Lines as well as voltage violations at the Tomhicken Switchyard and Harwood Substation"[245] and "allows for planned and unplanned outages, and to serve additional load growth in the area."[246] Every function PPL identifies for Phase 2 exists solely because of this customer's load.

Q: If Phase 2 is not in service, what is the projected network flow through the Tomhicken Switchyard attributable to loads and sources other than this customer?

A: PPL confirmed that the customer's load is not included in the 700 MVA figure — the 700 MVA represents flow passing southward through the Tomhicken Switchyard toward the Harwood Substation from other network sources.[247] Without Phase 2 in service but with Phase 1 built, PPL confirmed that approximately 1,400 MVA flows through the Tomhicken Switchyard under normal conditions — representing the existing Susquehanna-Harwood corridor load rerouted through the new switching point created for this customer's interconnection.[248]

[245] PPL Response to HIGHLY CONFIDENTIAL OCA VII-2(d).
[246] *Id*.
[247] "The 700 MVA of flow was the amount of load passing through the Tomhicken 230 kV Switchyard south towards the Harwood 230-69kV Substation. The customer's load was not included in the 700 MVA. As the 230 kV system is a network, the flow through the substation will vary with generation and system conditions." PPL Response to OCA VIII-2(d).
[248] "Without the Phase 2 Nescopeck-Tomhicken and Nescopeck-Harwood 230 kV Transmission Lines and the customer's load at the Tomhicken Switchyard, the Tomhicken 230 kV Switchyard will have approximately 1,400 MVA of network flow through the switchyard under normal conditions. Under contingency conditions, there could be up to 1,500 MVA of network flow through the Tomhicken 230 kV switchyard." PPL Response to OCA VIII-2(a).

This 1,400 MVA does not represent new capacity or new benefits to ratepayers — it is the same network flow that previously traveled directly on the Susquehanna-Harwood lines, now routed through a new switchyard that exists solely because of this customer's interconnection request. With Phase 2 in service but without the customer, the flow through Tomhicken drops to 1,100 MVA under normal conditions[249] — because Phase 2 creates alternative paths that divert some flow away from the Tomhicken routing.

Q: What system function does the Tomhicken Switchyard serve for transmission ratepayers if Phase 2 is never constructed?

A: PPL stated in discovery that the Tomhicken Switchyard "allows for multiple future new transmission electrical paths outside of the current proposed Phase 2 transmission line to be interconnected at Tomhicken" and "allows for PPL Electric to provide new customer interconnections directly from transmission or indirectly for future load growth via new distribution facilities."[250]

PPL's own answer is telling — every system function it identifies is forward-looking and customer-driven. The switchyard serves future transmission paths, future customer interconnections, and future load growth. Not one of the functions PPL identifies provides a benefit to existing ratepayers today under Phase 1 alone.

[249] "With the Phase 2 Nescopeck-Tomhicken and Nescopeck-Harwood 230 kV Transmission Lines and without the customer's load at the Tomhicken Switchyard, the Tomhicken 230 kV Switchyard will have approximately 1,100 MVA of network flow through the switchyard under normal conditions. Under contingency conditions, there could be up to 1,600 MVA of network flow through the Tomhicken 230 kV Switchyard." PPL Response to OCA VIII-2(c).
[250] PPL Response to OCA III-8(e) Supplemental.

This is consistent with PPL's Mr. Lookup's testimony that the Tomhicken Switchyard "is designed to eventually serve multiple customers"[251] and that "there is other load growth in the Hazleton area that this project will support."[252] The customers who will benefit from these future transmission paths and new interconnections are the large load customers in PPL's interconnection queue — not existing ratepayers being asked to pay $38.4 million today.

Under Phase 1 alone, with Phase 2 never constructed, the Tomhicken Switchyard serves one function: connecting this customer to the 230 kV network. That is a customer function, not a ratepayer function.

VII.d. Establishing the cost allocation consequence

Q: Under PPL's current proposal, ratepayers are being asked to pay approximately $38.4 million for Phase 1. What is the basis for that allocation?

A: As discussed in the Switchyard Cost section of this testimony, PPL's allocation rests on its unapproved internal cost allocation policy, unquantified network benefit assertions, and FERC precedent. The question this section addresses is whether those bases hold up when the Phase 1 and Phase 2 interdependency is properly accounted for.

[251] Line 6-7, Page 5, PPL Statement No. 1.
[252] Line 9-10, Page 5, *Id.*

Q: Is the ratepayer benefit that justifies the $38.4M allocation present today, or does it depend on future events — specifically Phase 2 construction — that have not yet been approved?

A: The ratepayer benefits PPL asserts to justify the $38.4 million allocation are not present today. They depend on Phase 2 being constructed — a future event that has not been approved by this Commission.

As established in section c above, PPL's own discovery responses confirm this. PPL linked its primary reliability benefit claim — additional 230 kV paths from the Susquehanna area to the Hazleton area — explicitly to "the Tomhicken 230 kV Switchyard and additional Phase 2 transmission lines" together.[253] Those additional paths do not exist under Phase 1 alone. PPL also confirmed that the switchyard's system functions — future transmission paths, new customer interconnections, and load growth support — are all forward-looking and contingent on future construction.[254]

As established in the Network Benefits section, PPL's 700 MVA network flow figure assumes Phase 2 is in service and does not represent a benefit realized under Phase 1 alone.

Additionally, PPL confirmed the DNH case was studied at HIGHLY CONFIDENTIAL STARTS [redacted]

[253] PPL Response to OCA V-5(b).
[254] PPL Response to OCA III-8 (e) Supplemental.
[255] PPL Response to HIGHLY CONFIDENTIAL OCA VII-2(d).

[redacted] HIGHLY CONFIDENTIAL ENDS

PPL's Mr. Lookup, when asked whether the project would still be needed if the customer does not complete their facility, answered only "potentially."[256] This is not an affirmative statement that independent network benefits justify this project without the customer — it is an acknowledgment of uncertainty that directly undermines PPL's claimed independent ratepayer benefits.

PPL further confirmed that HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS This is an explicit admission that Phase 2 exists to serve this customer — not to provide independent benefits to existing ratepayers. Every ratepayer benefit PPL attributes to Phase 1 depends on Phase 2 that, by PPL's own characterization, exists solely to serve this customer's load.

Under Phase 1 alone — the only project before this Commission — the Tomhicken Switchyard delivers no demonstrable independent benefit to existing ratepayers.

Q: If the ratepayer benefit of Phase 1 is contingent on Phase 2 being built, is it appropriate for ratepayers to bear that cost allocation now, in a proceeding that does not include Phase 2?

[256] Line 6, Page 5, PPL Statement No.1.
[257] PPL Response to HIGHLY CONFIDENTIAL OCA VII-2(d).

A: No. It is not appropriate to require ratepayers to bear a $38.4 million cost allocation today based on benefits that depend entirely on a future project that has not been approved, has not been scheduled for hearing, and may never be built.

The fundamental problem is one of timing and conditionality. PPL is asking this Commission to approve a ratepayer obligation now — in this proceeding — based on system-level benefits that are only realized if Phase 2 is subsequently approved in a separate proceeding. If Phase 2 is never approved, ratepayers will have paid $38.4 million for infrastructure that provides them no demonstrated independent benefit. The Commission would have approved a cost allocation based on a benefit that never materialized.

This is precisely backwards from sound regulatory practice. Cost allocations should be based on benefits that are demonstrated, quantified, and present — not on benefits that are speculative, unquantified, and contingent on future regulatory approvals outside this proceeding.

Moreover, this Commission has no basis in this proceeding to evaluate the full picture. The total ratepayer exposure across Phase 1 and Phase 2 combined — examined in the following question — cannot be assessed here because Phase 2 costs, design, and ratepayer allocation are not before this Commission in this proceeding. Approving Phase 1's ratepayer allocation in isolation, without that complete picture, forecloses the Commission's ability to make a fully informed cost allocation decision.

Q: What is the total ratepayer exposure across Phase 1 and Phase 2 combined if both phases are approved?

A: If both phases are approved on PPL's proposed terms, the total ratepayer exposure is approximately $156.9 million.

Phase 1 allocates $38.4 million to ratepayers — approximately 64% of the $59.9 million total Phase 1 cost.[258] Phase 2 carries a total estimated cost of approximately $118.5 million, and PPL stated in the Phase 2 application that "the cost for the Project will be allocated to PPL Electric customers"[259] — meaning ratepayers are expected to bear the full Phase 2 cost with no customer contribution.

The combined ratepayer exposure is therefore:

- Phase 1 ratepayer allocation: $38.4 million
- Phase 2 ratepayer allocation: $118.5 million
- Total ratepayer exposure: $156.9 million

This figure deserves the Commission's full attention. In Phase 1 alone, the customer contributes $21.5 million — approximately 36% of Phase 1 costs. In Phase 2, PPL stated only that "the cost for the Project will be allocated to PPL Electric customers"[260] — with no disclosure of any customer contribution. The progression from 36% customer responsibility in Phase 1 to 0% in Phase 2 — for a project whose Phase 2 is a direct

[258] Lines 12-14, Page 7, PPL Statement No. 1.
[259] Page ES-3, Executive Summary, Application for Transmission Line - PPL Electric, available at https://www.puc.pa.gov/pcdocs/1921888.pdf (Last Accessed on May 27, 2026).
[260] *Id*.

consequence of Phase 1 customer load growth — is not supported by any quantitative benefit analysis in either proceeding.

The Commission's decision on cost allocation methodology in this Phase 1 proceeding will directly influence the framework applied in Phase 2. Approving PPL's Phase 1 methodology without scrutiny establishes a precedent under which ratepayers bear $156.9 million for infrastructure whose primary driver is a single large load customer and whose claimed ratepayer benefits have never been quantified.

Q: Is it possible to evaluate the appropriateness of the Phase 1 ratepayer cost allocation without knowing whether Phase 2 will be approved, and at what cost?

A: No. A complete and fully informed evaluation of the Phase 1 ratepayer cost allocation is not possible in this proceeding without knowing the outcome of Phase 2.

First, the system-level benefits PPL uses to justify the Phase 1 ratepayer allocation are contingent on Phase 2 being constructed. Evaluating whether those benefits justify $38.4 million requires knowing whether Phase 2 will actually be built — information this proceeding cannot provide.

Second, the total ratepayer exposure from this project is $156.9 million across both phases — not $38.4 million. Evaluating the appropriateness of the Phase 1 allocation in isolation, without the Phase 2 cost and allocation before the Commission, means the Commission is approving one piece of a two-piece project without seeing the complete picture of what ratepayers are ultimately being asked to fund.

Third, PPL's cost allocation methodology — which has never been approved by this Commission[261] — will govern both proceedings. Approving that methodology in Phase 1 without requiring quantitative benefit justification establishes a precedent that binds the Phase 2 proceeding before it has even been heard.

Fourth, as discussed above, PPL has not demonstrated that Phase 2's $118.5 million transmission solution is necessary, given PPL's own admission that reactive compensation could address the P7 voltage violations and PPL's failure to perform any cost comparison between the two alternatives. The Commission cannot evaluate whether Phase 1's allocation is justified by Phase 2's benefits when Phase 2's own necessity has not been established at the cost PPL has assumed.

For these reasons, the Commission should not approve the Phase 1 ratepayer cost allocation unconditionally. The appropriate path forward is set forth in the recommendation section below.

VII.e. Recommendation

Q: What is your recommendation to the Commission regarding the Phase 1 ratepayer cost allocation given the Phase 1 and Phase 2 interdependency?

A: My testimony recommends that the Commission not approve the $38.4 million ratepayer allocation unconditionally. The record in this proceeding demonstrates that Phase 1's physical design was determined by Phase 2 requirements, that the claimed ratepayer

[261] "PPL Electric's cost allocation policy has not been reviewed or approved by the Pennsylvania PUC." PPL Response to OCA III-6.

benefits are contingent on Phase 2 being constructed, and that PPL performed no quantitative analysis demonstrating that ratepayer benefits equal or exceed ratepayer costs.[262] Approving the allocation unconditionally under these circumstances would lock ratepayers into a $38.4 million obligation based on undemonstrated, Phase 2-dependent benefits — before this Commission has had the opportunity to evaluate the complete $156.9 million ratepayer exposure across both phases.

My testimony does not contest the need for the Tomhicken Switchyard to serve the customer's physical interconnection requirements, nor does it seek to delay construction or service. PPL's responsibilities to new customers and existing customers under Pennsylvania law will be addressed by OCA counsel. I disagree with PPL that non-large load ratepayers should bear costs of new transmission infrastructure that PPL's own record establishes are customer-driven, Phase 2-dependent, and allocated under an unapproved methodology without quantitative justification. OCA Witness Frank Felder addresses PPL's discretion in cost recovery of network upgrades and how PPL can exercise its cost recovery discretion in a way that both respects (1) FERC's transmission pricing policy, and (2) state level retail terms and conditions that prevent cost shifting to non-large load customers, as set forth in Commission-approved tariff and tariff-compliant-ESA provisions.

Q: Specifically, do you recommend that the Commission approve the $38.4M ratepayer allocation for Phase 1 unconditionally, conditionally, or not at all?

[262] "PPL Electric did not perform a forward-looking quantitative analysis." PPL Response to OCA III-4(a).

A: Conditionally. My testimony recommends conditional approval — permitting Phase 1 construction to proceed while imposing specific conditions on the ratepayer cost allocation that protect Pennsylvania ratepayers from bearing costs that are not supported by the record. The specific conditions are set forth in the following answer.

Q: If conditionally, what condition do you recommend?

A: My testimony recommends the following three conditions:

Condition 1 — Reallocation of customer-driven design costs. The Commission should direct PPL to reallocate to the customer all costs currently assigned to ratepayers that are attributable to Phase 2-driven design features — specifically the BAAH switchyard configuration sized for nine line terminations including Phase 2 lines, Bay 1 and the bus infrastructure that serve no direct customer interconnection function under Phase 1 alone, and the Susquehanna-Harwood line split configuration designed for Phase 2 terminations. PPL's own LON, discovery admissions, and Mr. Lookup's direct testimony collectively establish that these costs are customer-driven. PPL confirmed that the switchyard "is required due to the number of lines needed by the Customer and the size of the requested load"[263] and that the line split "was designed to allow the future Phase 2 lines to terminate into the Tomhicken Switchyard."[264]

Condition 2 — Cost recovery from future benefiting customers. PPL's own witness testified that the Tomhicken Switchyard "will eventually facilitate service to

[263] Page 8, LON.
[264] PPL Response to OCA I-10(c).

multiple customers, due to multiple customer requests"[265] and that there is "other load growth in the Hazleton area that this project will support."[266] PPL's interconnection queue contains dozens of large load customers who will benefit from the infrastructure being built in Phase 1.[267] The Commission should require PPL to develop a cost recovery mechanism under which future customers interconnecting through or benefiting from the Tomhicken infrastructure contribute to Phase 1 costs currently allocated to ratepayers. Ratepayers should not bear the full cost of shared interconnection infrastructure when the primary beneficiaries are future large load customers who have not yet been asked to contribute.

Condition 3 — Commission review and approval of PPL's cost allocation policy. PPL confirmed that its Policy on Cost Allocation for Large Customer Interconnections has never been reviewed or approved by this Commission.[268] The Commission is being asked to approve a $38.4 million ratepayer allocation based on a methodology that has never been subjected to the Commission's scrutiny. Before that methodology is applied to any future project in PPL's eight-page interconnection queue, the Commission should require PPL to submit its cost allocation policy for formal Commission review and approval. The Commission's decision in this proceeding should not be treated as implicit endorsement of a policy it has never reviewed.

The comprehensive cost allocation remedy flowing from these findings is set forth in the Switchyard Cost section below.

[265] Line 6-7, Page 4, PPL Statement No.1.
[266] Line 9-10, Page 5, PPL Statement No.1.
[267] OCA II-12 Attachment 1.
[268] PPL Response to OCA III-6.

VIII. Switchyard Cost

Q: What is the total cost of Tomhicken Switchyard?

A: PPL's Mr. Lookup stated in direct testimony that the total estimated cost of the proposed project is $59.9 million, with the customer responsible for approximately $21.5 million and PPL Electric responsible for approximately $38.4 million.[269] The LON states a slightly different customer allocation of approximately $21.8 million, with PPL's share of $38.4 million remaining the same in both documents.[270] The $300K difference in the customer's stated responsibility — and the corresponding difference in total project cost between the two documents — is addressed in the following question.

A further reconciliation question revealed an additional discrepancy. PPL confirmed that HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS The Commission should require PPL to confirm the current authoritative Phase 1 ratepayer allocation before approving any cost recovery.

[269] Lines 12-14, Page 7, PPL Statement No. 1.
[270] Page 11, LON.
[271] PPL Response to HIGHLY CONFIDENTIAL OCA XIII-1(a).

Q: How did you reconcile the cost discrepancy between the LON ($21.8M customer) and Direct Testimony ($21.5M customer)?

A: PPL confirmed that "[t]he current estimate for the customer's cost responsibility is $21.5 million"[272]. Hence the value in Mr. Lookup's Direct Testimony is accurate.

Q: Out of the total cost of the Tomhicken Switchyard, how much does the Pennsylvania ratepayer pay?

A: Based on PPL's Direct Testimony, Pennsylvania ratepayers are responsible for approximately $38.4 million — approximately 64% of the total project cost of $59.9 million.[273] This means ratepayers bear nearly two-thirds of the cost of a project that, as discussed throughout this testimony, was designed to serve a single large load customer and whose physical configuration was determined by that customer's site location and Phase 2 requirements.

Q: What is PPL's reason for this ratepayer cost?

A: PPL's cost allocation rests on three bases.

First, PPL relies on its internal "Policy on Cost Allocation for Large Customer Interconnections" to determine what costs are allocated to ratepayers versus the customer.[274] PPL confirmed that this cost allocation methodology "relies on the function

[272] PPL Response to OCA VI-5(a).
[273] Lines 12-14, Page 7, PPL Statement No. 1.
[274] "PPL Electric Utilities Corporation – Policy on Cost Allocation for Large Customer Interconnections", OCA I-6 Attachment 1.

of the upgrade, not a set percentage split between the customer and the Company."[275] As discussed in the Network Benefits section, PPL confirmed that this Commission has never reviewed or approved this Policy.[276]

Second, PPL asserts that the Tomhicken Switchyard provides network benefits to ratepayers — including added system reliability, increased capacity, sectionalization[277], and operational flexibility — that justify ratepayer cost responsibility.[278] As discussed in the Network Benefits section, PPL provided no quantitative analysis supporting any of these claimed benefits in the context of this project specifically.[279]

Third, PPL cited FERC precedent — City of Anaheim, Cal., 113 FERC ¶ 61,091 (2005) — as the basis for not performing forward-looking quantitative analysis of ratepayer benefits, asserting that network facilities benefit all network users and there is no need to identify actual benefits to include costs in transmission rates.[280] As discussed in the Network Benefits section, whether that federal precedent applies to this Commission's evaluation of the assignment of the costs of these facilities directly to the interconnecting customer as a term of retail service is a legal question I leave to counsel.

[275] PPL Response to OCA VI-5(c).
[276] "PPL Electric's cost allocation policy has not been reviewed or approved by the Pennsylvania PUC. The Company applies its cost allocation policy consistent with FERC regulations and guidance on the recovery of transmission investments. While the cost allocation policy has not been approved, all of PPL Electric's decisions made with respect to cost allocation of transmission investment is subject to oversight and review by FERC." PPL Response to OCA III-6.
[277] "Support Sectionalization of existing 230kV lines and provide new capacity and alternative route for power flow." PPL Response to OCA III-3(a).
[278] Page 11, LON.
[279] "PPL Electric did not perform a forward-looking quantitative analysis which is consistent with FERC policy." PPL Response to OCA III-4(a).
[280] "Network facilities benefit all network users and there is no need to identify actual benefits in order to include the costs of network transmission facilities in transmission rates. See City of Anaheim, Cal., 113 FERC ¶ 61,091, at P 58 (2005), reh'g denied, 114 FERC ¶ 61,311 (2006)." PPL Response to OCA III-4(a).

Q: Has PPL allocated costs for comparable large load 230 kV interconnections differently than it is proposing for the Tomhicken customer?

A: Yes. PPL confirmed in discovery that Customer 2 — a large load 230 kV customer with a peak load of 1,512 MW placed in service April 2026 — had total infrastructure costs of approximately $30.2 million, with the customer responsible for $26.8 million (89%) and PPL responsible for $3.4 million (11%).[281] The Tomhicken Switchyard presents a materially similar fact pattern — a large load 230 kV interconnection — yet PPL is seeking to allocate $38.4 million to ratepayers. PPL has not explained why its cost allocation methodology produces such dramatically different ratepayer exposure between two comparable large load 230 kV interconnections.

Furthermore, PPL provided in discovery eight pages of pending large load interconnection projects in its queue.[282] The Commission's decision on cost allocation methodology in this proceeding will therefore have implications well beyond the Tomhicken Switchyard alone. Approving PPL's ratepayer allocation methodology without requiring quantitative benefit justification establishes a precedent that could expose Pennsylvania ratepayers to significant cumulative costs across PPL's entire interconnection queue.

PPL confirmed in discovery that Customer 2's interconnection did not require a new switching facility — the customer's location allowed it to be sourced from three

[281] "Customer 2 infrastructure upgrade costs were approximately $30.2 million, with the customer being responsible for $26.8 million, and PPL Electric being responsible for $3.4 million." PPL Response to OCA I-5 Supplemental 1.
[282] OCA II-12 Attachment 1.

existing switchyards[283] — and did not require splitting any existing transmission lines.[284] PPL stated in discovery that it "has consistently maintained that each interconnection is evaluated on a case by case basis".[285] However, two findings from PPL's own discovery responses cut against any meaningful distinction between the two projects under that standard. First, Customer 2's project also had a phased structure — filed under one LON docket but completed in phases[286] — yet still received 89% customer allocation. PPL's own "phased project" characterization of Tomhicken therefore does not explain the difference in ratepayer exposure between the two projects. Second, Customer 2's substation was also designed for the customer's ultimate requested load[287] — the same feature PPL used to justify Tomhicken's ratepayer allocation in the Phase 1 and Phase 2 Interdependency section — yet Customer 2 still bore 89% of infrastructure costs. The differences PPL may identify between the two projects do not explain a swing from 89% customer responsibility to 36% customer responsibility under the same function-based cost allocation methodology PPL applied to both.

Q: What happens to the ratepayer-allocated $38.4M if Phase 2 is never built?

A: PPL has not directly addressed this question. However, the record established in this proceeding leads to a clear conclusion.

[283] "The location of Customer 2's interconnection allowed the load to be sourced from three different existing switchyards. A new switching facility was not required." PPL Response to OCA XII-1(a).
[284] "Customer 2's interconnection did not require the splitting of existing transmission lines." PPL Response to OCA XII-1(c).
[285] PPL Response to OCA XI-1(a).
[286] "The transmission facilities required were filed under one LON docket but will be completed in phases as outages and as the customer buildout allows." PPL Response to OCA XII-1(b).
[287] "The transmission lines and substation equipment installed to serve the customer were designed for the ultimate requested load." PPL Response to OCA XII-1(d).

PPL confirmed that the Tomhicken Switchyard was designed to accommodate Phase 2 line terminations,[288] that the substation was designed for the customer's ultimate load rather than the Phase 1 DNH load level,[289] and that the switchyard's system functions — including multiple future new transmission electrical paths and new customer interconnections — depend on Phase 2 being constructed.[290] PPL's own Mr. Lookup testified that the switchyard "will eventually facilitate service to multiple customers, due to multiple customer requests"[291] and that "there is other load growth in the Hazleton area that this project will support."[292]

If Phase 2 is never built, ratepayers will have paid $38.4 million for a switchyard whose:

- Physical configuration — including its BAAH design, five bays[293], and line termination points — was sized for Phase 2 load levels not present under Phase 1 alone.
- Line split routing was designed to avoid line crossings for Phase 2 terminations that never materialize.

[288] "The Tomhicken 230kV Switchyard will have a line termination point for the Phase 2 scope." PPL Response to OCA I-10(c).
[289] "The system network upgrades included in the supplemental project are based on the DNH Load Level. The substation was designed to accommodate the customer's ultimate requested load. The substation needs to be designed to accommodate the customer's ultimate requested load and network flows." PPL Response to OCA V-1(c).
[290] "The Tomhicken Switchyard allows for multiple future new transmission electrical paths outside of the current proposed Phase 2 transmission line to be interconnected at Tomhicken. It also allows for PPL Electric to provide new customer interconnections directly from transmission or indirectly for future load growth via new distribution facilities." PPL Response to OCA III-8 (e) Supplemental.
[291] Line 6-7, Page 4, PPL Statement No. 1.
[292] Lines 9-10, Page 5, PPL Statement No. 1.
[293] Responsibility of Asset Matrix for Breaker and a Half (BAAH) Example 1, Page 3 of 8, OCA I-6 Attachment 1.

- Claimed network reliability benefits — multiple future new transmission electrical paths and new customer interconnections — are contingent on Phase 2 infrastructure that was never approved or constructed.
- System function for ratepayers reduces to a single purpose: connecting one customer to the 230 kV network.

PPL's Mr. Lookup testified that if the customer does not complete its facility, the project is "potentially" still needed because "there is other load growth in the Hazleton area."[294] Two observations are warranted. First, "potentially" is not a commitment — PPL's own witness expressed uncertainty about whether the project would be justified without this customer. Second, and more importantly, the "other load growth" PPL references consists of the large load interconnection customers in its queue,[295] each of whom would require their own separate interconnection proceedings and cost allocations. The existence of future queue customers does not justify asking existing ratepayers to fund infrastructure today on the speculative basis that future customers may eventually use it — particularly when those future customers will pay their own interconnection costs when they proceed.

In that scenario, ratepayers will have funded $38.4 million worth of infrastructure that provides them no independent system benefit — and the cost allocation methodology PPL applied will have produced precisely the outcome this proceeding should prevent.

Q: Do you agree with PPL that ratepayers should pay this cost?

[294] Lines 6-10, Page 5, PPL Statement No. 1.
[295] OCA II-12 Attachment 1.

A: No. Based on the full record developed in this proceeding, I do not agree that ratepayers should bear the $38.4 million PPL is seeking to allocate to them. My disagreement rests on five independent grounds, each supported by PPL's own admissions in discovery and direct testimony.

First — the project is entirely customer-driven. PPL confirmed that the Tomhicken Switchyard location was determined by the customer's development location and site layout, not by an independent system reliability need.[296] The switchyard exists at this location because the customer is here. PPL's LON states the switchyard "is required due to the number of lines needed by the Customer and the size of the requested load."[297] PPL's own engineering estimate confirms this: under a Phase 1-only design — sized for DNH load level, without Phase 2 line termination accommodation — the switchyard cost would be approximately $33.97 million rather than the HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS currently allocated to ratepayers HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS The HIGHLY CONFIDENTIAL STARTS [redacted] HIGHLY CONFIDENTIAL ENDS difference represents PPL's own quantification of the Phase 2-driven cost premium embedded in Phase 1's ratepayer allocation — a premium ratepayers are being asked to bear for infrastructure designed to serve a project that has not yet been approved.

[296] "The location of the Tomhicken 230kV Switchyard was determined by the Customer's development location and site layout." PPL Response to OCA I-10(c).
[297] "The Tomhicken 230 kV Switchyard is required due to the number of lines needed by the Customer and the size of the requested load." Page 8, LON.
[298] PPL Response to OCA XI-6(a); PPL Response to OCA HIGHLY CONFIDENTIAL IX-1.

Second — the cost allocation methodology has never been reviewed or approved by this Commission. PPL relies on its internal Policy on Cost Allocation for Large Customer Interconnections to justify the $38.4M ratepayer allocation.[299] PPL confirmed this Commission has never reviewed or approved that Policy.[300] The Commission is being asked to allocate $38.4 million to ratepayers based on a methodology that has never been subjected to the Commission's scrutiny. PPL confirmed that its cost allocation methodology "relies on the function of the upgrade, not a set percentage split between the customer and the Company."[301]

The Bay 1 allocation illustrates how PPL has misapplied its own standard. PPL's Responsibility of Asset Matrix shows Bay 1 as a pure source bay with no customer feed line — entirely orange, indicating full ratebase allocation.[302] Yet PPL claimed in discovery that Bay 1 serves a direct customer feed function.[303] These two PPL documents are irreconcilable: either Bay 1 serves a customer feed function — in which case the customer should bear some or all of its approximately $1.7 million cost[304] — or Bay 1 is a pure source bay with no customer feed function — in which case its ratebase allocation requires a demonstrated independent network benefit that PPL has never provided. PPL cannot have it both ways.

[299] OCA I-6 Attachment 1.
[300] "PPL Electric's cost allocation policy has not been reviewed or approved by the Pennsylvania PUC. The Company applies its cost allocation policy consistent with FERC regulations and guidance on the recovery of transmission investments. While the cost allocation policy has not been approved, all of PPL Electric's decisions made with respect to cost allocation of transmission investment is subject to oversight and review by FERC." PPL Response to OCA III-6.
[301] PPL Response to OCA VI-5(c).
[302] OCA I-6 Attachment 1, Page 3 of 8.
[303] PPL Response to OCA XI-7(a).
[304] PPL Response to OCA III-3(b).

Third — PPL performed no quantitative analysis of ratepayer benefits. PPL confirmed it did not perform any forward-looking quantitative analysis of ratepayer benefits prior to making its cost allocation determination.[305] PPL's own witness admitted the company has no additional quantitative analyses beyond standards compliance flow studies.[306] An unquantified assertion that ratepayers benefit is not a sufficient basis for a $38.4 million allocation.

Fourth — the claimed ratepayer benefits are contingent on Phase 2. Every system-level benefit PPL identifies — multiple future new transmission electrical paths and new customer interconnections[307] — depends on Phase 2 being constructed. PPL's own witness linked the reliability benefits explicitly to "the Tomhicken 230 kV Switchyard and additional Phase 2 transmission lines" together.[308] Under Phase 1 alone, the switchyard serves one function: connecting this customer to the 230 kV network. Benefits contingent on a future unapproved project cannot justify a present ratepayer cost allocation.

Fifth — PPL's own comparable precedent allocated 89% of costs to the customer. PPL confirmed that Customer 2 — a comparable large load 230 kV interconnection placed in service April 2026 — had 89% of infrastructure costs allocated to the customer and 11% to PPL.[309] The Tomhicken Switchyard allocates 64% to ratepayers and 36% to the customer — a dramatically different outcome for a materially similar fact pattern.

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[305] "PPL Electric did not perform a forward-looking quantitative analysis which is consistent with FERC policy." PPL Response to OCA III-4(a).
[306] "The flow studies performed by the Company and PJM demonstrate that the proposed project meets these standards. PPL Electric does not have any additional quantitative analyses." PPL Response to OCA V-5(a).
[307] PPL Response to OCA III-8(e) Supplemental.
[308] "The Tomhicken 230 kV Switchyard and additional Phase 2 transmission lines will increase system reliability by adding additional 230 kV paths from the Susquehanna area to the Hazleton area." PPL Response to OCA V-5(b).
[309] PPL Response to OCA I-5 Supplemental 1.

PPL stated in discovery that it "has consistently maintained that each interconnection is evaluated on a case by case basis."[310] Yet Customer 2 also had a phased project structure and a substation designed for ultimate load[311] — the same features PPL invokes to justify Tomhicken's ratepayer allocation — and still bore 89% of costs. Under PPL's own case-by-case standard, the record contains no explanation for a swing from 89% customer responsibility to 36% customer responsibility.

Taken together, these five grounds establish that the $38.4 million ratepayer allocation is not supported by the record in this proceeding.

Q: What is the ratepayer exposure if PPL applies the same cost allocation methodology to other large load interconnections in its queue?

A: PPL's queue contains projects requesting 169,774 MW of aggregate load out of which 144,728 MW is seeking interconnection at 230 kV and higher.[312] If even a fraction of those projects receive the same 64% ratepayer allocation as Tomhicken, the cumulative ratepayer exposure across PPL's service territory would dwarf the $38.4 million at issue here.

Q: What is your recommendation?

[310] PPL Response to OCA XI-1(a).
[311] PPL Response to OCA XII-1(b)(d).
[312] Calculation based of OCA II-12 Attachment 1 (summing all projects through March 31, 2026 and filtering by voltage level).

A: The Commission should not approve the $38.4 million ratepayer allocation as proposed by PPL. The record in this proceeding does not support it.

My testimony does not contest the need for the Tomhicken Switchyard to serve the customer's physical interconnection requirements, nor does it seek to delay or prevent service to the customer. PPL's responsibilities to new customers and existing customers under Pennsylvania law will be addressed by OCA counsel. I disagree with PPL's cost allocation given that PPL's own record establishes the project is customer-driven, Phase 2-dependent, and allocated using an unapproved methodology without quantitative benefit justification.

The Commission has two options:

Option 1 — Reallocate costs to the customer. The Commission should direct PPL to reallocate to the customer all costs currently assigned to ratepayers that are attributable to: (a) the BAAH switchyard configuration and Bay 1 infrastructure that serve no independent ratepayer function under Phase 1 alone[313]; (b) the Susquehanna-Harwood line split configuration designed for Phase 2 terminations[314]; and (c) the Tomhicken Switchyard's physical configuration — specifically sized to accommodate the customer's ultimate requested load[315] rather than the Phase 1 DNH load level that governs the network upgrades[316] — embeds Phase 2 scale requirements into Phase 1

[313] Page 3 of 8, OCA I-6 Attachment 1.
[314] "The splitting of the Susquehanna-Harwood #1 & #2 230kV Transmission Lines was designed to allow the future Phase 2 lines to terminate into the Tomhicken Switchyard and Harwood Substation without requiring line crossings. The Tomhicken 230kV Switchyard will have a line termination point for the Phase 2 scope." PPL Response to OCA I-10(c).
[315] "The substation was designed to accommodate the customer's ultimate requested load." PPL Response to OCA V-1 (b).
[316] "The system network upgrades included in the supplemental project are based on the DNH Load Level." *Id*.

infrastructure. PPL's own LON, discovery admissions, and Mr. Lookup's direct testimony collectively establish that these costs are customer driven.

Option 2 — Require PPL to perform quantitative benefit analysis. At minimum, before approving any ratepayer allocation, the Commission should require PPL to perform and file a forward-looking quantitative analysis demonstrating that ratepayer benefits equal or exceed the $38.4 million being allocated to them. PPL did not perform a forward-looking quantitative analysis.[317] Without it, the Commission has no basis to conclude the allocation is just and reasonable.

Additionally, as recommended in the Phase 1 and Phase 2 Interdependency section above, the Commission should require PPL to develop a cost recovery mechanism for future benefiting customers, submit its cost allocation policy for formal review, and provide a documented cost comparison with the Nescopeck alternative.

IX. Overall Summary

Q: Please summarize your overall concerns.

A: My testimony identifies six independent concerns with PPL's proposed $38.4 million ratepayer allocation.

First, the Tomhicken Switchyard is entirely customer driven. But for this customer's interconnection request, no transmission investment on the Susquehanna-Harwood corridor would have been required, no reliability violation would exist, and no Tomhicken Switchyard would be proposed. PPL confirmed no planned transmission

[317] PPL Response to OCA III-4(a).

projects existed on that corridor prior to the customer's request, emergency ratings were never violated, and DLR resolved the operational congestion three years before the project was proposed.

Second, Phase 1's physical design was determined by Phase 2 requirements. The line split configuration, the BAAH design sized for nine lines including Phase 2 terminations, and the substation designed for the customer's ultimate load rather than the Phase 1 DNH load level all reflect Phase 2 requirements embedded in Phase 1 infrastructure. PPL's own cost allocation document labels the primary ratepayer-allocated asset as a Phase 1 and Phase 2 combined item.

Third, the claimed ratepayer benefits are contingent on Phase 2 being constructed. PPL's own witness confirmed the 700 MVA network flow figure cited as ratepayer benefit assumes both Phase 1 and Phase 2 are in service. Under Phase 1 alone, the Tomhicken Switchyard serves one function: connecting this customer to the 230 kV network.

Fourth, PPL performed no forward-looking quantitative analysis of ratepayer benefits. PPL's own admission “PPL Electric did not perform a forward-looking quantitative analysis" is uncontested in this record. Without such analysis, there is no basis to conclude ratepayer benefits equal or exceed ratepayer costs.

Fifth, the cost allocation methodology has never been reviewed or approved by this Commission. The Commission is being asked to approve a $38.4 million ratepayer obligation based on a methodology that has never been subjected to its scrutiny.

Sixth, PPL's own comparable precedent — Customer 2, a comparable large load 230 kV interconnection placed in service April 2026 — allocated 89% of infrastructure costs to the customer and 11% to PPL. The Tomhicken project allocates 64% to ratepayers. PPL has provided no explanation for this difference.

Q: Please summarize your overall recommendations to the Commission.

A: My testimony makes the following recommendations.

First, the Commission should direct PPL to reallocate to the customer all costs currently assigned to ratepayers that are attributable to Phase 2-driven design features — specifically the BAAH configuration sized for nine lines including Phase 2 terminations, the Susquehanna-Harwood line split designed for Phase 2 terminations, and Bay 1 and bus infrastructure serving no independent ratepayer function under Phase 1 alone.

Second, at minimum, before approving any ratepayer allocation, the Commission should require PPL to perform and file a forward-looking quantitative analysis demonstrating that ratepayer benefits equal or exceed the amount allocated to them.

Third, the Commission should require PPL to submit its Policy on Cost Allocation for Large Customer Interconnections for formal Commission review and approval before it is applied to any future project in PPL's interconnection queue.

Fourth, the Commission should require PPL to develop a cost recovery mechanism under which future customers interconnecting through or benefiting from the Tomhicken infrastructure contribute to Phase 1 costs currently allocated to ratepayers.

Fifth, the Commission should require PPL to provide a documented cost comparison between the Tomhicken approach and direct connection to the Nescopeck Switchyard.

The full basis for each of these recommendations is set forth in the body of my testimony.

X. Conclusion

Q: Does this conclude your testimony?

A: Yes, it does.

RAO KONIDENA

Energy Market Expert • Transmission Planning, Wholesale Markets & Distributed Energy Resources

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Professional Summary

Independent energy regulatory consultant and expert witness with 20+ years of experience spanning transmission planning, wholesale electricity market design, and distributed energy resource integration. Has filed testimony and affidavits before **state commissions in 10+ jurisdictions and the Federal Energy Regulatory Commission**, primarily on behalf of consumer advocates, environmental intervenors, and market participants. Former MISO Principal Advisor who led demand-side potential and grid-scale energy storage studies. Co-author of a Wiley graduate textbook on modern electricity systems.

Areas of Expertise

- Transmission Planning & CPCN Review
- Distributed Energy Resources (DER)
- Demand Response & FERC Order 2222
- Non-Wires Alternatives & Grid-Enhancing Tech
- Cost Allocation & Cost Causation
- Energy Storage Tariffs & Deployment
- Resource Adequacy & Capacity Markets
- Generator Interconnection (MISO/PJM)

Analytical Capabilities: Builds Python-based analytical tools for multi-ISO LMP analysis, benefit-cost modeling, and RTO market-data extraction across PJM, MISO, NYISO, SPP, CAISO, and ISO-NE.

Expert Testimony & Regulatory Engagements

Testimony, affidavits, and regulatory analysis filed through Rakon Energy LLC (2018–present), organized by jurisdiction.

Federal Energy Regulatory Commission (FERC)

- **Voltus, Inc** — Affidavit on SPP's multi-nodal aggregation. Docket No. ER22-1697.
- **Kentucky Public Service Commission (via Engleman Fallon, PLLC)** — Expert testimony in a transmission cost allocation complaint. Docket No. EL25-67-000. [eLibrary]
- **Office of the People's Counsel of D.C. (OPC-DC)** — Affidavit on PJM's Reserves Pricing Proposal. [filing]
- **Municipal utilities (Wisconsin & Missouri)** — Affidavit on MISO's Resource Adequacy construct.
- **Missouri Joint Municipal Electric Utilities Commission, Missouri River Energy Services & WPPI Energy** — Affidavit on MISO's External Resource Zone proposal. Docket No. ER18-1173-001. [eLibrary]

Pennsylvania Public Utility Commission

- **PA Office of Consumer Advocate** — PPL Electric Utilities – LON Susquehanna-Harwood. Docket No. A-2025-3059443.
- **PA Office of Consumer Advocate** — Utility rate case. Docket No. R-2024-3047068. [filing]
- **PA Office of Consumer Advocate** — Transmission line rebuild CPCN. Docket No. A-2022-3037374 (begins p. 198). [filing]
- **PA Office of Consumer Advocate** — Policy proceeding — Utilization of Storage Resources as Electric Distribution Assets. Docket No. M-2020-3022877 (begins p. 18). [filing]
- **PA Office of Consumer Advocate** — Ongoing generic electrical engineering support on transmission, distribution, and miscellaneous electric issues.

Maryland Public Service Commission

- **MD Office of People's Counsel** — NextEra Energy Transmission MidAtlantic — CPCN for 500 kV line, MidAtlantic Resiliency Link Project (Allegany & Garrett Counties). PSC Case No. 9857.
- **MD Office of People's Counsel** — Carroll-Germantown 230 kV line and Potomac Edison Messick Road-Ridgeley 138 kV rebuild CPCNs. PSC Case Nos. 9803 & 9818.
- **MD Office of People's Counsel** — Transmission line rebuild CPCN. PSC Case No. 9698 (filed Sept. 13, 2023). [case]

Massachusetts Department of Public Utilities

- **MA Attorney General's Office, Office of Ratepayer Advocacy (via Center for Renewables Integration)** — Energy storage tariffs — Eversource (DPU 23-126), National Grid (DPU 23-115), Unitil (DPU 23-117). [dockets]

Illinois Commerce Commission

- **Citizens Utility Board & Environmental Defense Fund** — Ameren Transmission Co. of Illinois / Ameren Illinois — transmission line CPCN. Docket No. 24-0088. [docket]
- **Environmental Law & Policy Center & Citizens Utility Board** — Ameren Illinois / Ameren Transmission Co. — transmission line CPCN. Docket No. P2023-0658. [docket]

California Public Utilities Commission

- **San Luis Obispo Mothers for Peace** — PG&E recovery of Diablo Canyon extended-operation costs (Sept. 2023–Dec. 2025) and 2025 Volumetric Performance Fees. Proceeding A.24-03-018. [filing]
- **San Luis Obispo Mothers for Peace** — Proposed extension of Diablo Canyon Power Plant. Proceeding R.23-01-007. [filing]

North Carolina Utilities Commission

- **NC WARN** — Duke Energy Carolinas Biennial Consolidated Carbon Plan & IRP. Docket No. E-100, SUB 190. [filing]
- **NC WARN** — Duke Energy Carolinas rate case. Docket No. E-7, SUB 1276. [filing]

Colorado Public Utilities Commission

- **CO Office of the Utility Consumer Advocate** — Expert testimony on a utility distribution system plan. Proceeding No. 24A-0547E.

Minnesota PUC & Kansas Corporation Commission

- **Voltus, Inc (demand response aggregator)** — Aggregator of Retail Customers — MN PUC Docket No. E999/CI-22-600; Demand Response Aggregator — KS Docket No. 23-EKCE-588-TAR. [KS filing]
- **Vote Solar** — Xcel/IOU IRP filing. MN PUC Docket No. E002/RP-19-368. [filing]

Public Utilities Commission of Nevada

- **Vote Solar** — IOU IRP filings. Docket Nos. 21-06001 and 21-06002. [filing]

Public Service Commission of Wisconsin

- **Environmental Law & Policy Center** — MISO Multi-Value Project (MVP) transmission line CPCN. Docket No. 5-CE-146. [filing]

Georgia Public Service Commission

- **Georgia Public Service Commission** — Engaged as Battery Energy Storage System (BESS) consultant.

Consulting & Advisory Engagements

Litigation, Agency & Policy Support

- Earthjustice — Technical analysis on anticipated DOE action regarding the Campbell plant (MI) and Schahfer and Culley plants (IN).
- Earthjustice, Sierra Club, NRDC & EDF — Opinion on DOE/Energy Secretary Chris Wright's August 20, 2025 order to MISO and Consumers Energy.
- Earthjustice — Technical analysis of the NYISO reliability planning process.
- Environmental Defense Center (for Mothers for Peace) — Report on the need for Diablo Canyon, submitted to the California Coastal Commission.
- Advanced Energy United (via Center for Renewables Integration) — Report on opportunities for DERs in organized markets.
- Advanced Energy Economy & NRDC Sustainable FERC Project — Monitoring of MISO's FERC Order 2222 implementation.
- Voltus, Inc — Representation at RTO stakeholder committees on FERC Order 2222.
- Energy Storage Association — Advocacy support at MISO on FERC Order 841 compliance.

Developer & Market-Participant Advisory

- Commercial real estate firm's renewable division — Impact of RTO market reforms on existing PPAs and interconnection agreements.
- Spanish renewable developer (via CRI) — MISO/PJM interconnection queue evaluation for solar/storage sites.
- Minnesota solar developer — DER and BESS development opportunities in MISO.
- Community Solar Garden developer — MISO DER Affected Systems Study process.
- Independent Power Producer — MISO seasonal resource adequacy construct and its PPA impacts.
- Renewable developer — MISO Generator Interconnection Queue and seasonal capacity-credit impacts across study cycles.
- Technology companies — Representation at PJM and navigation of MISO market rules for data center interconnection.

Training & International

- USEA workshop — US energy, capacity, and retail markets for the Independent Electricity Market Operator Philippines (IEMOP).
- NARUC International Peer Review — DER and Demand Side Management plan review for Central American regulators.
- USEA / USAID / Power Africa — Ancillary services best practices, Eastern Africa regional workshop.
- Tuatara team — DER training for Colombia's grid operator XM; ESTA International — energy storage benefits for Mexican regulator CRE.

Professional Experience

Midcontinent Independent System Operator (MISO) • Eagan, MN Aug 2015 – May 2018
Principal Advisor, Policy Studies

- Recognized as an expert on energy storage and DERs from an economic transmission planning perspective.
- Project manager for the long-term independent load forecast and demand response / energy efficiency / distributed generation potential study.

- MISO representative on the DOE US DRIVE Grid Interaction Technical Team.

Senior Manager, Transmission Asset Management Operations Feb 2013 – July 2015

- Partnered with the division lead on strategic initiatives and operating plans.
- Chaired the Economic Modeling Framework Working Group of international grid operators (GO-15).

Manager, Resource Forecasting (started as Engineer II) Sep 2003 – Jan 2013

- Directed MISO's Demand Response & Energy Efficiency potential study (with Global Energy Partners).
- Directed the MISO Energy Storage Study identifying economic potential for grid-scale storage, advising utilities, asset owners, and investors.
- Owned analytical assessments meeting MISO's FERC compliance obligations (e.g., market-based rates).
- Supported state regulators and the MISO Board with technical analysis of policy drivers.

PwrSolutions, Inc. • Dallas, TX May 2001 – Aug 2003

Student Intern & Electrical Engineer (Consulting)

- Executed generator interconnection studies for Independent Power Producer clients.
- Analyzed future generator and transmission needs in the Eastern Interconnection.

Education

MBA, Global Executive Program — University of Minnesota, Carlson School of Management 2011
Emphases: Strategic Management, International Business. Capstone: marketing mobile EV charging services in the Singapore market.

M.S., Electrical Engineering — University of Texas at Arlington, Energy Systems Research Center 2002
Thesis: Economic Analysis of Distributed Generation (Photovoltaics and Fuel Cells).

Publications, Boards & Recognition

- Co-author, *Modern Electricity Systems: Engineering, Operations, and Policy to Address Human and Environmental Needs* (Wiley, 2022) — graduate-level textbook.
- Author of multiple publications in The Electricity Journal, Renewable Energy World, and other industry journals; regular Substack contributor for commissioners and regulatory staff.
- President, Board of Directors, Center for Renewables Integration (Dec 2023 – present).
- Board of Directors, Ever Green Energy (Sep 2019 – present).

Exhibit RK-1

PPL Electric Utilities Corporation's Response to
the Office of Consumer Advocate's (OCA) Interrogatories,
OCA-I-6, Attachment 1

PPL Electric Utilities Corporation – Policy on Cost Allocation for Large Customer Interconnections

PPL Electric serves customers taking service at 69 kV and above at its LP-5 rate class. LP-5 customers are required to pay for the costs of the upgrades necessary to serve their load. PPL Electric Retail Tariff, Rule 4 – (C).4. However, certain upgrades benefit other PPL customers and/or the transmission grid. The costs of these upgrades may be excluded from the interconnecting customer's obligation and added to PPL Electric's transmission rate base.

It is PPL Electric's policy that upgrades to the networked bulk electric system made in connection with LP-5 customer interconnections will generally be excluded from the customer's obligation and included in transmission rate base. This policy is informed by FERC policy, which generally favors charging network customers for the costs of network facilities without an individualized benefit calculation:

> "[D]ue to the integrated nature of the transmission network, network facilities benefit all network users," even if "the facilities were installed to meet a particular customer's request for service." "[T]here is no need to identify further actual benefits in order to include the costs of network transmission facilities in transmission rates."

City of Anaheim, Cal., 113 FERC ¶ 61,091, at P 58 (2005), *reh'g denied*, 114 FERC ¶ 61,311 (2006).

At a minimum, the customer's direct connection cost is the sole responsibility of the connecting customer, more specifically, the transmission lines sourced from PPL Electric's substation/switchyard that terminate into the customers substation.

All other upgrades, including PPL Electric substations/switchyards will be evaluated on a case-by-case basis to determine if they provide benefits to other customers and/or the transmission grid. Examples of benefits to other customers that would cause an upgrade to be included in transmission rates includes, but is not limited to:

- Added system reliability;
- Increased capacity/lower congestion;
- Improved asset condition of existing facilities;
- Service to multiple transmission customers and/or retail feeders;
- Increased resiliency and operational flexibility;
- Expanded capacity for new generation flow and interconnections

If the customer's interconnection results in upgrades that will be included in transmission rate base, the Company reserves the right to include revenue guarantee provisions in the customer's Electric Service Agreement.

PPL Electric Utilities Corporation – Cost Allocation Review and Methodology for Large Customer Interconnections

Cost Allocation Review Process:

The Interconnection Affairs PM will pull together the following groups within Transmission Asset Management to review each project for their functional area:

- Interconnection Affairs – Rapid Response (RR) to interconnection request, Project Feasibility Report (PFR), Electrical Service Agreements (ESA), Construction Service Agreement (CSA), and confirmation of project costs.
- Planning – Line and sub equipment review and determination of dedicated vs network benefit.
- Project Development – Lead the development of deliverables for project scope, schedule and budget. Includes but not limited to project cost estimating, construction feasibility, confirmation of CSA scope and one-line, and financial budget.
- VP Planning and Asset Management – Provides approval for final cost allocation decision.

Cost Allocation Methodology is as follows for Direct Connect Transmission Line:

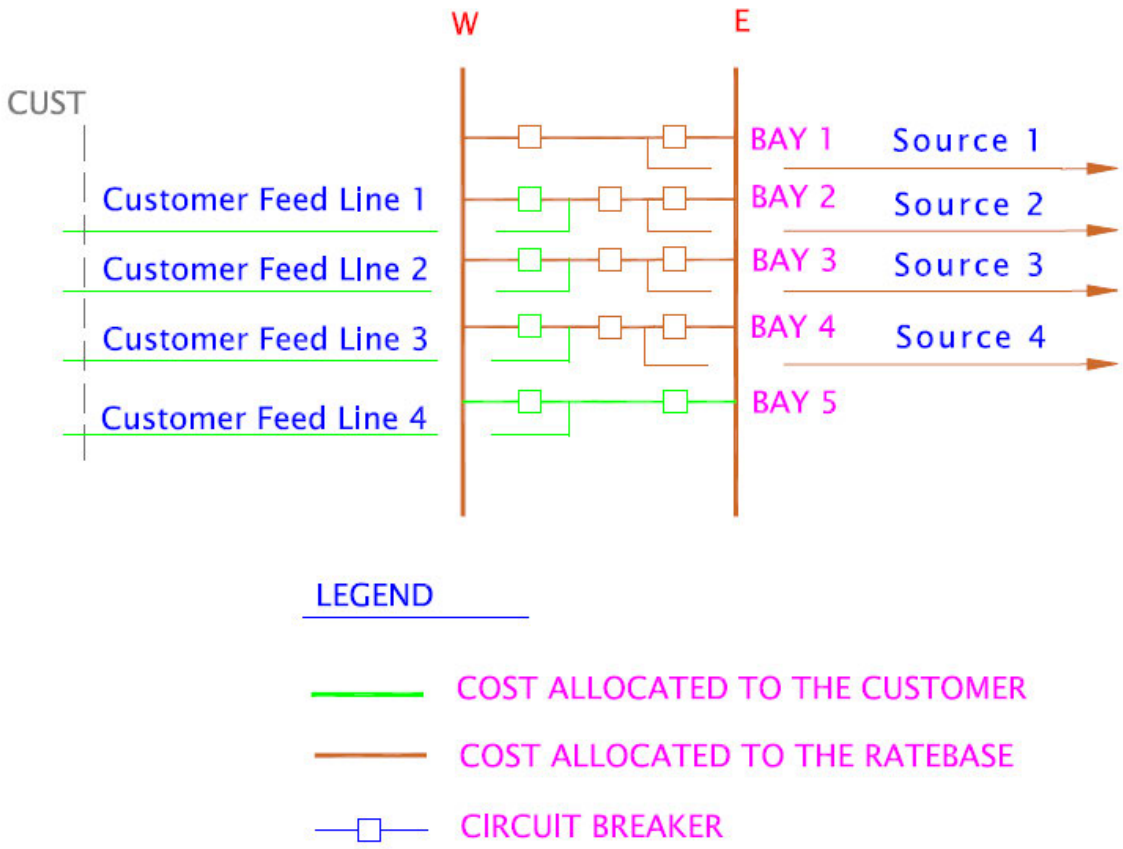
- All direct connection transmission lines that supplies customer substation. Below are typical assets but are not limited to:
    - Transmission Structures
    - Transmission conductor
    - Associated insulation and line hardware
    - Sectionalizing devices (i.e. switches, power circuit breakers, reclosers)
    - Grounding cable and hardware
    - Right of way easements and fee owned land

Cost Allocation Methodology is as follows for Substation equipment reviews:

The determining factor for cost allocation will be illustrated with the circuit breaker assets shown on Examples 1, 2, and 3 for ease of understanding at the highest level.

Interconnection Affairs will keep documented proof of each project site that is reviewed. A one-line will be color coded to denote direct customer costs vs network costs along with a cost spreadsheet.

Responsibility of Asset Matrix for Breaker and a Half (BAAH) Example 1:



Customer Responsible:

- Bay 1: No assets
- Bay 2:
  - Line: Customer Line 1
  - Sub: 2W down-lead and dead-end structure
  - Sub: CB 2W
  - Sub: Two switches: 2WW & 2WE
  - Sub: Three associated CCVT's
  - Sub: Three associated surge arrestors
- Bay 3:
  - Line: Customer Line 2
  - Sub: 3W down-lead and dead-end structure
  - Sub: CB 3W
  - Sub: Two switches: 3WW & 3WE
  - Sub: Three associated CCVT's

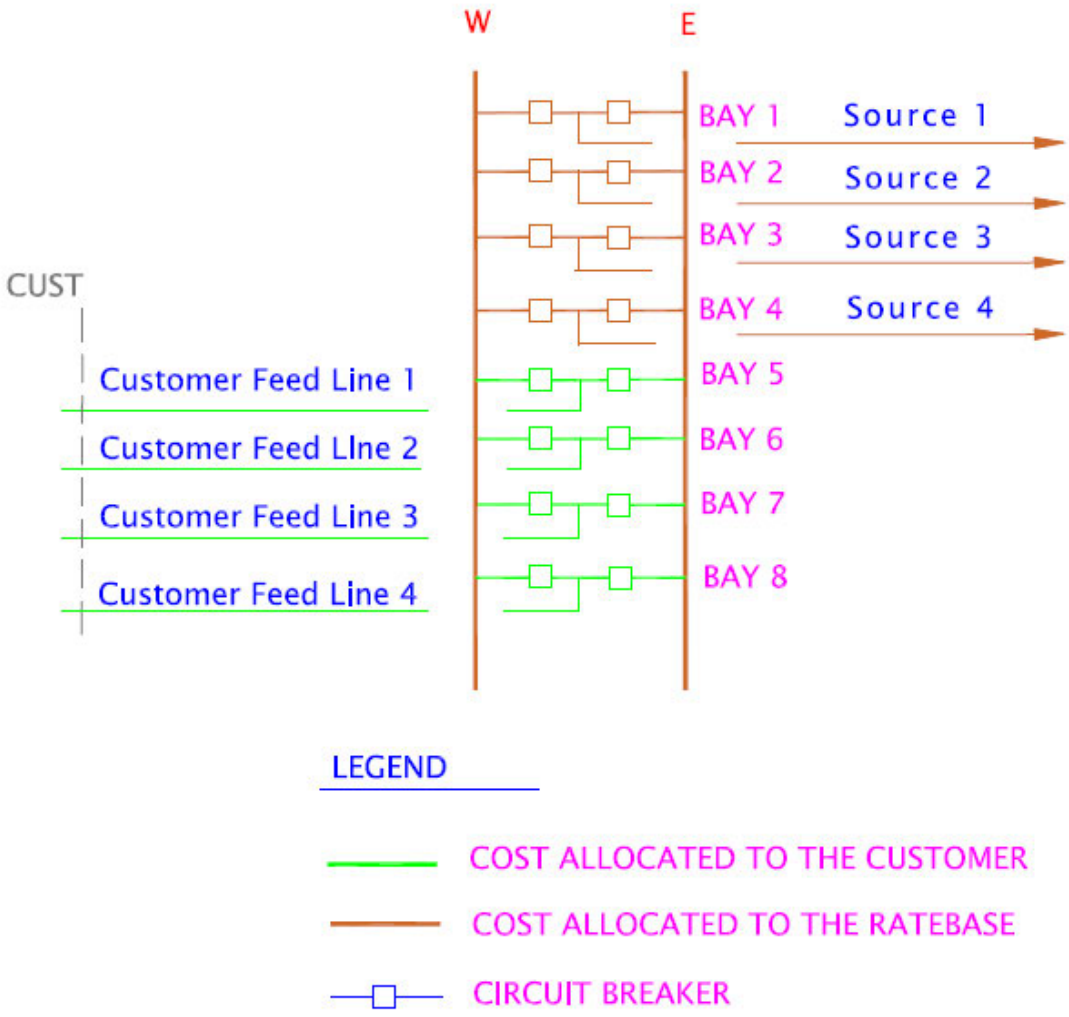
    - Sub: Three associated surge arrestors
- Bay 4:
    - Line: Customer Line 3
    - Sub: 4W down-lead and dead-end structure
    - Sub: CB 4W
    - Sub: Two switches: 4WW & 4WE
    - Sub: Three associated CCVT's
    - Sub: Three associated surge arrestors
- Bay 5:
    - Line: Customer Line 4
    - Sub: 5W down-lead, dead-end structure, bay conductor, and bay structures
    - Sub: CBs 5W & 5E
    - Sub: Four switches: 5WW, 5WE, 5TW, & 5EE
    - Sub: Three associated CCVT's
    - Sub: Three associated surge arrestors

All associated wiring, conduit, relays and other minor assets associated with the above equipment.

PPL Responsible:

- All other equipment and associated minor assets.

Responsibility of Asset Matrix for Double Breaker Double Buss (DBDB) Example 2:



Customer Responsible:

- Bay 1-4: No assets
- Bay 5:
  - Line: Customer Line 1
  - Sub: Bay 5 downleads, dead-end structure, bay conductor, and bay structures
  - Sub: CBs 5W &5E
  - Sub: Four switches: 5WW, 5WE, 5EW & 5EE
  - Sub: Three associated CCVT's
  - Sub: Three associated surge arrestors

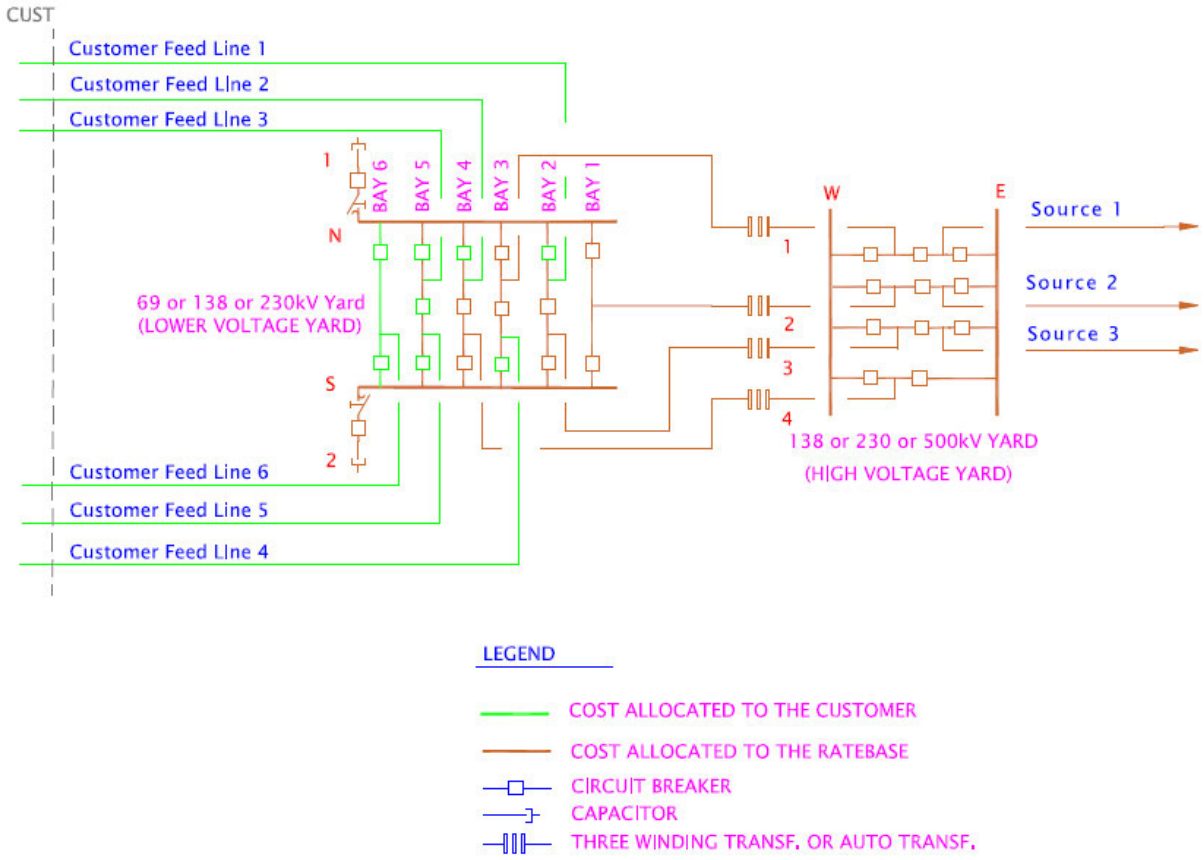
- Bay 6:
  - Line: Customer Line 2
  - Sub: Bay 6 downleads, dead-end structure, bay conductor, and bay structures
  - Sub: CBs 6W & 6E
  - Sub: Four switches: 6WW, 6WE, 6EW & 6EE
  - Sub: Three associated CCVT's
  - Sub: Three associated surge arrestors
- Bay 7:
  - Line: Customer Line 3
  - Sub: Bay 7 downleads, dead-end structure, bay conductor, and bay structures
  - Sub: CBs 7W & 7E
  - Sub: Four switches: 7WW, 7WE, 7EW & 7EE
  - Sub: Three associated CCVT's
  - Sub: Three associated surge arrestors
- Bay 8:
  - Line: Customer Line 4
  - Sub: Bay 8 downleads, dead-end structure, bay conductor, and bay structures
  - Sub: CBs 8W & 8E
  - Sub: Four switches: 8WW, 8WE, 8EW & 8EE
  - Sub: Three associated CCVT's
  - Sub: Three associated surge arrestors

All associated wiring, conduit, relays and other minor assets associated with the above equipment.

PPL Responsible:

- All other equipment.

Responsibility of Asset Matrix for Step Down Substation Example 3:



Customer Responsible:

- Higher voltage yard:
  - No assets

- Lower voltage yard:
- Bay 1: No assets
- Bay 2:
  - Line: Customer Line 1
  - Sub: 2N downleads and dead-end structure
  - Sub: CB 1N

    - Sub: Two switches: 2NN & 2NS
    - Sub: Three associated CCVT's
    - Sub: Three associated surge arrestors
- Bay 3:
    - Line: Customer Line 4
    - Sub: 3S downleads and dead-end structure
    - Sub: CB 3S
    - Sub: Four switches: 3SS & 3SN
    - Sub: Three associated CCVT's
    - Sub: Three associated surge arrestors
- Bay 4:
    - Line: Customer Line 2
    - Sub: 4N downleads and dead-end structure
    - Sub: CB 4N
    - Sub: Two switches: 4NN & 4NS
    - Sub: Three associated CCVT's
    - Sub: Three associated surge arrestors
- Bay 5:
    - Line: Customer Line 3 & 5
    - Sub: 5N & 5S downleads, dead-end structures, bay conductors, and bay structures
    - Sub: CBs 5N, 5T, & 5S
    - Sub: Six switches: 5NN, 5NS, 5TN, 5TS, 5SN, & 5SS
    - Sub: Six associated CCVT's
    - Sub: Six associated surge arrestors
- Bay 6:
    - Line: Customer Line 6
    - Sub: 6S downleads, dead-end structure, bay conductors, and bay structures
    - Sub: CBs 6N & 6S
    - Sub: Four switches: 6NN, 6TS, 6SN, & 6SS
    - Sub: Three associated CCVT's
    - Sub: Three associated surge arrestors

All associated wiring, conduit, relays and other minor assets associated with the above equipment.

<u>PPL Responsible:</u>

All other equipment.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania	:	Docket No. A-2025-3059443

VERIFICATION

I, Rao Konidena, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 2, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. Section 4904 (relating to unsworn falsification to authorities).

DATED: July 8, 2026

Signature: Rao Konidena

Rao Konidena

Address: Rakon Energy LLC
Roseville, MN 55113

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Build Approximately 1.1 Miles of New Parallel Double Circuit 230 kV Transmission Taps that are Needed to Connect the Existing Susquehanna-Harwood #1 & #2 Transmission Lines on the New Tomhicken 230 kV Switchyard that are Respectively Located in Luzerne County, Pennsylvania	:	Docket No.: A-2025-3059443

SURREBUTTAL TESTIMONY

OF

Rao Konidena

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Date Served: September 4, 2026

OCA Statement 2SR – Surrebuttal Testimony of Rao Konidena

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Introduction

Q: Please state your name and business address.

A: My name is Rao Konidena. My business address is Rakon Energy LLC, Roseville, MN 55113.

Q: Have you previously submitted testimony in this proceeding?

A: Yes. I submitted my Direct Testimony on July 8, 2026, which was marked as OCA Statement No. 2. My qualifications and experience are attached to my Direct Testimony**.**

Q: What is the purpose of your surrebuttal testimony?

A: The purpose of my surrebuttal testimony is to address the issues raised by PPL Electric Utilities Company ("PPL") witnesses Mr. Lookup (PPL Statement No. 1-R), Mr. Taylor (PPL Statement No. 5-R), and Mr. Swartzentruber (PPL Statement No. 2-R) in their rebuttal testimonies.

Q: How is your surrebuttal testimony organized?

A: My surrebuttal testimony is organized by topics as follows:

I. Scope / Separability of Design and Cost Allocation

II. Breaker-and-a-Half Design as a Cost-Allocation-Driven Choice

III. Phase 1 and Phase 2 Interdependency

IV. Bay 1 — Function and Cost Allocation Are the Same Question
V. Customer-Triggered vs. Customer-Specific
VI. Nescopeck Alternative
VII. Cost Allocation Comparator
VIII. Conclusion.

Q: Please summarize your testimony.

A: My testimony shows that PPL has not justified allocating $38.4 million of the Tomhicken Project's costs to ratepayers, and that the record contains multiple unresolved inconsistencies in PPL's own testimony and discovery responses that the Commission should require PPL to address before approving the construction of the Project. My testimony is summarized as follows:

- I recommend that the Commission review PPL's Cost Allocation Policy. My testimony does not ask the Commission to set FERC-jurisdictional transmission rates, only to assess the reasonableness of the policy as applied to the Project. The Commission cannot treat the switchyard's design as a separate question from its cost consequences, especially where PPL's witnesses confirm that cost classification comes from its engineering of the Project facilities.
- The Commission cannot rely on a design description that keeps shifting, or on a rebuttal that misstates the record it claims to respond to. PPL's own descriptions of the Tomhicken Switchyard keep changing. PPL's discovery response confirms

the physical facility has not changed, yet PPL's rebuttal testimony conflicts with responses provided in discovery regarding the number of bays in the switchyard.

- The Commission should not approve ratepayer funding for benefits that depend on an unapproved future project. PPL's own witness admits the Phase 1 design was built around Phase 2, and Phase 2 may never be approved.
- The Commission should require PPL to justify Bay 1's $3.99 million/$1.7 million cost split before relying on it. PPL has never explained how it derived that split, and PPL's own discovery confirms the split was fixed before PPL ever offered a functional justification for it.
- The Commission should reject PPL's claim that "customer-triggered" facilities justify shifting costs to ratepayers. PPL admits this terminology appears nowhere in its own cost policy and was invented after the allocation was already fixed.
- The Commission should require PPL to produce a real cost comparison for the Nescopeck alternative before crediting PPL's rejection of it. PPL admits it rejected Nescopeck without ever calculating what it would cost.
- The Commission should require PPL to explain why Tomhicken's customer pays only 36% when a comparable project, Susquehanna, allocated 89% to its customer under the same policy. PPL has never provided that explanation.

I. Scope / Separability of Design and Cost Allocation (Taylor, Lookup)

Q: Do you agree with Witness Taylor that your direct testimony characterizes PPL as "seeking Commission approval of the transmission costs related to the Project?"[1]

A: No, Mr. Taylor's rebuttal testimony responds to a narrower and more literal claim than the one I made. At the page Mr. Taylor cites, I stated that "PPL is asking this Commission to approve a ratepayer obligation now — in this proceeding — based on system-level benefits that are only realized if Phase 2 is subsequently approved in a separate proceeding."[2] I did not testify in my direct testimony that "PPL Electric is seeking Commission approval of the transmission costs related to the Project proposed in this proceeding" as Mr. Taylor framed the question in his rebuttal testimony.[3]

Mr. Taylor's answer — that "PPL Electric is seeking approval to construct the Project. This proceeding does not seek approval of the Project's transmission costs, their future recovery, or their allocation among transmission customers. Those issues are outside the scope of this siting proceeding and are addressed through separate regulatory processes,"[4] — addresses PPL's framing of its own request. It does not address the substance of the concern raised in my direct testimony: that approving this Project now, based on benefits contingent on the unapproved Phase 2 project, "is precisely backwards from sound regulatory practice. Cost allocations should be based on benefits that are demonstrated, quantified, and present — not on benefits that are speculative,

[1] Lines 20-22, Page 18 to Line 1, Page 19, PPL Statement No. 5-R.
[2] Lines 4-6, Page 90, OCA Statement No. 2.
[3] Lines 20-22, Page 18, PPL Statement No. 5-R.
[4] Lines 1-5, Page 19, PPL Statement No. 5-R.

unquantified, and contingent on future regulatory approvals outside this proceeding."[5] Mr. Taylor's rebuttal testimony does not engage with that concern.

Q: Do you agree with Mr. Lookup's response that requiring PPL to submit its Policy on Cost Allocation for Large Customer Interconnections for formal Commission review and approval would require the Commission to review matters subject to FERC's jurisdiction (Statement No. 1-R, p. 19)?

A: No, I disagree with Mr. Lookup's characterization of my recommendation. My direct testimony recommended that the Commission require PPL to "submit its Cost Allocation Policy for Large Customer Interconnections for formal Commission review and approval."[6] Mr. Lookup's rebuttal testimony characterizes this as requiring the Commission "to formally review and approve a policy that addresses the allocation of transmission costs subject to the jurisdiction of the FERC."[7] That characterization conflates two distinct things: review of the internal methodology PPL uses to classify facilities as customer-specific or network-related, and approval of the resulting transmission rates or cost allocation outcomes themselves. My recommendation addresses only the former.

[5] Lines 11-14, Page 90, OCA Statement No. 2.
[6] "[T]he Commission should require PPL to submit its Cost Allocation Policy for Large Customer Interconnections for formal Commission review and approval before it is applied to any future project in PPL's interconnection queue for purposes of ensuring that the Policy is compliant with the Commission's direction in the Large Load Model Tariff for computation of the applicable CIAC." Lines 5-9, Page 65, OCA Statement No. 2.
[7] "Mr. Konidena's recommendation would require the Commission to formally review and approve a policy that addresses the allocation of transmission costs subject to the jurisdiction of the FERC." Lines 17-19, Page 19, PPL Statement No. 1-R.

The Policy on Cost Allocation for Large Customer Interconnections is the document PPL itself relies upon to determine which facilities are assigned to a customer and which are included in transmission rate base — the same document at issue in the Bay 1 dispute addressed elsewhere in this testimony.[8] Commission review of that internal classification methodology, applied before a project's costs are locked in through the siting and construction process, does not require the Commission to approve or set FERC-jurisdictional transmission rates. It is precisely because PPL's design and cost-classification decisions are made before this Commission ever reaches this proceeding, and because Mr. Taylor's own rebuttal testimony confirms those design decisions inform the resulting cost allocation,[9] that Commission awareness of the methodology PPL applies is appropriate at the siting stage — not a usurpation of FERC's ratemaking authority.

Mr. Lookup's rebuttal testimony states that Mr. Taylor "describes in detail the established avenues for review of transmission cost allocation before FERC that make an additional Commission approval requirement unnecessary."[10] As addressed in my response to the prior question, Mr. Taylor's own rebuttal testimony does not consistently maintain that position. If PPL's cost allocation methodology may properly be argued and defended in this proceeding, my recommendation that the Commission review the Policy underlying that methodology should be considered on the same basis.

[8] Lines 1-14, Page 25, OCA Statement No. 2.
[9] "The Company uses a project-specific engineering and functional analysis to determine the allocation between facilities that primarily serve the Customer and facilities that provide broader transmission system benefits pursuant to PPL Electric's Policy on Cost Allocation for Large Customer Interconnections." Lines 1-5, Page 22, PPL Statement No. 5-R.
[10] Lines 19-21, Page 19, PPL Statement No. 1-R.

Q: Do you agree with Witness Taylor that PPL is not seeking, and this proceeding does not require, any Commission determination regarding the allocation of Project costs between the Customer and ratepayers?

A: No, I disagree. Mr. Lookup's own direct testimony states that "[t]he total estimated cost of the proposed Project is $59.9 million. The Customer is responsible for approximately $21.5 million, and PPL Electric is responsible for approximately $38.4 million."[11] That allocation is part of the record PPL itself filed in support of this Letter of Notification ("LON"). My direct testimony's recommendations respond directly to that allocation, which PPL placed before the Commission in the first instance.[12]

Mr. Taylor's rebuttal testimony also does not treat cost allocation as genuinely outside this proceeding. In the same rebuttal testimony in which he states that "PPL Electric is not seeking Commission approval in this proceeding of any accounting treatment, rate treatment, cost allocation, or cost recovery mechanism for the Tomhicken Project,"[13] Mr. Taylor devotes the entire Section V of his rebuttal testimony, titled "PPL Electric's Anticipated Cost Allocation," to explaining how PPL determined the $21.5 million/$38.4 million split and to opining that the resulting allocation is "reasonable" and "in line with FERC policy."[14] Mr. Taylor cannot maintain that cost allocation is outside the scope of this proceeding while simultaneously asking the Commission to credit his testimony defending the reasonableness of that same allocation.

[11] Lines 12-14, Page 7, PPL Statement No. 1.
[12] Lines 10-16, Page 5, OCA Statement No. 2.
[13] Lines 5-7, Page 28, PPL Statement No. 5-R.
[14] Lines 8-21, Page 25 to Lines 1-18, Page 26, PPL Statement No. 5-R.

PPL confirmed in discovery that, in Mr. Taylor's own understanding, "the Commission's determination of 'need' for an HV transmission line does not involve, and is not required to involve, any determination of the reasonableness of the costs of the project or the allocation of those project costs."[15] If that is Mr. Taylor's own understanding of what the Commission's "need" determination requires, Mr. Taylor's Section V testimony defending the reasonableness of PPL's cost allocation is unnecessary to anything the Commission must decide in this proceeding — yet Mr. Taylor offered it anyway. If PPL's cost allocation is genuinely not before the Commission in this proceeding, Mr. Taylor's testimony defending its reasonableness should not be part of the record either. If it is part of the record, the Commission should consider it with my direct testimony's position that the allocation is not justified by demonstrated, present, ratepayer benefits.[16]

Q: Do you agree with Witness Taylor that the design of the Tomhicken Switchyard can be evaluated for siting approval purposes without reference to how its costs are allocated between the Customer and ratepayers?

A: No, I disagree. As I stated in my direct testimony, PPL Electric's choice of breaker-and-a-half ("BAAH") configuration "is relevant to the ratepayer cost allocation because different configurations carry different costs."[17] I further explained that "[t]his design

[15] PPL Response to OCA XIV-7.
[16] Lines 10-16, Page 5, OCA Statement No. 2.
[17] Lines 16-17, Page 26, OCA Statement No. 2.

choice is directly relevant to the cost allocation question in this proceeding,"[18] specifically with respect to Bay 1 and the bus infrastructure.

Mr. Taylor's own rebuttal testimony confirms that PPL's cost allocation is derived directly from the switchyard's engineering design, not from a separate or independent inquiry. Mr. Taylor states that "[t]he Company uses a project-specific engineering and functional analysis to determine the allocation between facilities that primarily serve the Customer and facilities that provide broader transmission system benefits pursuant to PPL Electric's Policy on Cost Allocation for Large Customer Interconnections."[19] Design and cost allocation are, by PPL's own description, the same inquiry: the engineering function of each facility determines its cost classification.

Mr. Lookup's rebuttal testimony illustrates this directly. Mr. Lookup describes Bay 1 at the Tomhicken Switchyard as serving both a "Function 1 — Customer feed"[20] and "Function 2 — Network source"[21] role, and states that "direct-connection facilities that serve only the customer have been directly assigned to the customer"[22] while facilities providing network benefit are assigned to ratepayers.[23] That functional classification — an engineering and design determination — is the basis on which PPL allocated Bay 1's cost. The Commission cannot meaningfully evaluate whether Bay 1's design, bay count, or line terminations are reasonable for siting purposes while treating the cost consequences that PPL's own witnesses derive directly from those same design

[18] Lines 15-16, Page 25, OCA Statement No. 2.
[19] Lines 2-5, Page 22, PPL Statement No. 5-R.
[20] Line 5, Page 23, PPL Statement No. 1-R.
[21] Line 11, Page 23, PPL Statement No. 1-R.
[22] Lines 5-7, Page 23, PPL Statement No. 1-R.
[23] "It is this network source connection that integrates the switchyard into the bulk transmission system and makes the Tomhicken Switchyard a network facility rather than a facility dedicated solely to the customer." Lines 12-14, Page 23, PPL Statement No. 1-R.

facts as a separate matter reserved for FERC. The design determines the allocation; they are not two independent questions.

Q: Do you agree with Mr. Lookup's response that requiring PPL to perform a forward-looking quantitative analysis demonstrating that ratepayer benefits equal or exceed the amount allocated to them would be inconsistent with FERC policy (Statement No. 1-R, p. 19)?

A: No, I disagree. Mr. Lookup's answer asserts that "network transmission facilities provide benefits to all users of the transmission system and there is no requirement that a utility perform a project-specific quantitative analysis demonstrating that future benefits equal or exceed the costs included in transmission rates," and states that this position "is detailed in the rebuttal testimony of PPL Electric Witness Taylor."[24] As I noted in my direct testimony, PPL confirmed in discovery that it "did not perform a forward-looking quantitative analysis," relying on City of Anaheim, Cal., 113 FERC ¶ 61,091, at P 58 (2005), for the proposition that "[n]etwork facilities benefit all network users and there is no need to identify actual benefits in order to include the costs of network transmission facilities in transmission rates."[25]

Neither Mr. Lookup nor Mr. Taylor explains why City of Anaheim's general network-benefit doctrine should excuse a project-specific showing for the Tomhicken Switchyard specifically. As I explained elsewhere in my direct testimony, PPL confirmed

[24] Lines 5-9, Page 19, PPL Statement No. 1-R.
[25] Lines 7-15, Page 50, OCA Statement No. 2.

that the Tomhicken Switchyard is a PJM Supplemental Project — a category of project PJM does not independently validate for need, and which exists, by PJM's own definition, because it is "not needed to comply with PJM reliability, operational performance, FERC Form No. 715 or economic criteria."[26] Mr. Lookup's rebuttal testimony does not address whether the general network-benefit reasoning in City of Anaheim extends to a project of this kind — one identified, initiated, and justified entirely by a single customer's interconnection request, rather than validated through PJM's baseline reliability planning process.

As I stated in my direct testimony, "PPL provided no quantitative analysis supporting any of these claimed benefits in the context of this project specifically."[27] Mr. Lookup's rebuttal testimony does not cure that gap. My recommendation remains that PPL be required to make that demonstration before the associated costs are included in transmission rate base.

Q: Do you agree with Witness Taylor that the network upgrade components of the Project — "transmission line enhancements, switchyard and substation infrastructure, system reinforcement projects, voltage support facilities, and other transmission assets"[28] — "provide benefits beyond the interconnecting Customer and therefore are appropriately treated as network facilities"[29] (Statement No. 5-R, p. 23)?

[26] Lines 6-11, Page 13, OCA Statement No. 2.
[27] Lines 7-8, Page 99, OCA Statement No. 2.
[28] Lines 3-5, Page 23, PPL Statement No. 5-R.
[29] *Id.* at Lines 6-8.

A: No, I disagree. Mr. Taylor's rebuttal testimony asserts that PPL "determined that these facilities provide benefits beyond the interconnecting Customer and therefore are appropriately treated as network facilities."[30] As I explained in my direct testimony, "PPL provided no quantitative analysis supporting any of these claimed benefits in the context of this project specifically."[31] Mr. Taylor's rebuttal testimony does not cure that gap here. It lists categories of infrastructure and asserts, without project-specific quantification, that they provide benefit beyond this Customer. Listing categories of facilities is not the same as demonstrating, with evidence specific to this Project, that those facilities provide a quantified benefit to existing ratepayers that justifies their inclusion in transmission rate base.

Q: Do you agree with Mr. Lookup's response that your recommendation — that the Commission conditionally approve PPL's proposed cost allocation upon reallocation of customer-driven design costs, cost recovery from future benefitting customers, and review and approval of the Cost Allocation Policy — would require the Commission to intrude on FERC's jurisdiction (Statement No. 1-R, p. 20)?

A: No, I disagree. Mr. Lookup states that "this recommendation would require the Commission to intrude on FERC's jurisdiction and diverge from longstanding FERC principles and policies," citing Mr. Taylor's rebuttal testimony as support.[32] As addressed in my response above, Mr. Taylor's own rebuttal testimony is internally inconsistent on

[30] Lines 6-8, Page 23, PPL Statement No. 5-R.
[31] Lines 7-8, Page 99, OCA Statement No. 2.
[32] Lines 5-7, Page 20, PPL Statement No. 1-R.

this point. My recommendation does not ask the Commission to set FERC-jurisdictional transmission rates; it asks the Commission to condition its siting approval on PPL taking specific, identified steps — reallocating customer-driven design costs, addressing future-customer cost recovery, and subjecting its internal cost allocation methodology to review — before the Project's design and cost classification are effectively locked in through construction.

Neither Mr. Lookup nor Mr. Taylor identifies a specific FERC statute, rule, or order that a Commission-imposed condition of this kind would violate. The absence of such authority, combined with Mr. Taylor's own inconsistent treatment of whether cost allocation is properly before this Commission, does not support rejecting my recommendation on jurisdictional grounds.

Q: Do you agree with Witness Taylor that "[t]he network upgrade portion of the Project consists of transmission infrastructure that becomes part of the integrated transmission system and supports broader network operations,"[33] citing HIGHLY CONFIDENTIAL OCA I-6, Attachment 2 (Statement No. 5-R, p. 23)?

A: No, I disagree that Mr. Taylor's rebuttal testimony makes complete use of the document he cites. Mr. Taylor relies on HIGHLY CONFIDENTIAL OCA I-6, Attachment 2[34] to describe categories of network upgrade infrastructure, but does not disclose what that same attachment shows about total ratepayer exposure across this Project. As I explained

[33] Lines 1-3, Page 23, PPL Statement No. 5-R.
[34] Page 23, Footnote 16, PPL Statement No. 5-R.

in my direct testimony, that same confidential attachment supports a calculation of "[t]he combined ratepayer exposure across all identified components"[35] — consisting of the Phase 1 ratepayer allocation of $38.4 million together with the Phase 2 ratepayer allocation — which I stated is "significantly greater than the $156.9 million"[36] figure discussed elsewhere in my direct testimony.

Mr. Taylor's rebuttal testimony cites this document only to support a general description of network upgrade categories. He does not disclose anywhere in his rebuttal testimony the combined ratepayer exposure figure the same document supports. PPL's own witness has used this confidential attachment selectively — to describe the categories of facilities being funded, without disclosing the total ratepayer cost of $156.9 million[37] those categories represent when Phase 1 and Phase 2 are considered together.

II. Breaker-and-a-Half Design as a Cost-Allocation-Driven Choice (Lookup)

Q: Do you agree with Witness Lookup that the Tomhicken Switchyard is designed for "eight bays" (Statement No. 1-R, p. 27)?

A: No, I disagree. As I stated in my direct testimony, "[t]he Tomhicken Switchyard has 5 bays in this BAAH design, connected between two bus bars (W and E),"[38] citing PPL's own Responsibility of Asset Matrix. Mr. Lookup's rebuttal testimony now states that

[35] Line 13, Page 68, OCA Statement No. 2.
[36] Line 4, Page 69, OCA Statement No. 2.
[37] Lines 3-4, Page 91, OCA Statement No. 2.
[38] Lines 1-2, Page 25, OCA Statement No. 2.

"[t]he Tomhicken 230 kV Switchyard is designed for six initial bays with space for two additional bays for a total of eight bays, allowing for the termination of sixteen 230 kV lines."[39] This eight-bay figure does not reconcile with the five-bay configuration shown in PPL's own Matrix,[40] which I relied upon in my direct testimony and which PPL itself produced in this proceeding.

PPL confirmed in discovery that "[t]he physical bay configuration of the Tomhicken 230 kV Switchyard has not changed" since the Matrix was produced.[41] The discrepancy between the Matrix's five bays and Mr. Lookup's eight-bay figure is therefore not explained by any change to the facility itself. When I specifically asked PPL to explain this discrepancy, PPL responded only by repeating the same characterization of the Matrix as "a set of illustrative, generic examples," without reconciling the actual bay count.[42] I note that Mr. Lookup's rebuttal testimony takes a similar approach elsewhere with respect to the same Matrix, characterizing its depiction of Bay 1 as merely a "hypothetical bay in that illustrative example"[43] rather than reconciling it with PPL's own reliance on that same Matrix to calculate an actual cost allocation — an issue I address in Section IV. Using an illustrative, generic graphic to justify a specific engineering claim about the Tomhicken Switchyard's actual bay count, while simultaneously relying on that same graphic to calculate a real cost allocation for a specific bay at that same facility, is not a reliable basis for either determination. PPL cannot treat the Matrix as a generic illustration when its depiction is inconvenient and as the actual basis for Tomhicken's

[39] Lines 2-4, Page 27, PPL Statement No. 1-R.
[40] PPL Response to OCA I-6, Attachment 1, Page 3 of 8.
[41] PPL Response to OCA XIV-1(b).
[42] PPL Response to OCA XIV-1(c).
[43] Lines 16-17, Page 22, PPL Statement No. 1-R.

cost allocation when it is convenient. Without an explanation for either departure from the Matrix, the Commission has no basis to determine whether PPL's own cost allocation exhibit — which shows five bays — or Mr. Lookup's rebuttal testimony — which asserts eight — accurately reflects the facility PPL is asking the Commission to approve.

Q: Do you agree with Witness Lookup that the "eight lines to be terminated at the switchyard" (Statement No. 1-R, p. 16) justify the BAAH design under Phase 1 alone?

A: No, I disagree that this figure justifies the BAAH design, though I do not dispute PPL's discovery response confirming that eight named lines terminate at the Tomhicken Switchyard under Phase 1 alone — Susquehanna-Tomhicken #1 and #2, Tomhicken-Harwood #1 and #2, and Tomhicken-Hazelnut (Customer) #1 through #4.[44] My direct testimony's earlier six-line total was derived from PPL's own direct testimony description of the Phase 1 scope as "four double-circuit, 230 kV transmission Tap Lines" and "two new 0.1-mile-long 230 kV Connecting Lines."[45] PPL's discovery response does not reconcile that description with the eight-line inventory it has now provided, and PPL has not explained the discrepancy between its own direct testimony and its own discovery response.

Of the eight Phase 1 lines PPL has now identified, four — half— are Tomhicken-Hazelnut (Customer) lines dedicated to the Customer's interconnection. This confirms

[44] PPL Response to OCA XIV-4(a), (b), (d).
[45] Lines 10-12, Page 8, PPL Statement No. 1.

what I already stated in my direct testimony: that the Tomhicken Switchyard "extends four 230 kV lines designed specifically for this Customer's load," and that these "are benefits to the Customer, not to existing ratepayers."[46] PPL's own discovery response now confirms, by name, that half of the eight lines Mr. Lookup relies upon to justify the BAAH design are customer-dedicated lines rather than network facilities. Despite half the lines being dedicated to the Customer, the Customer is allocated only 36 percent of Phase 1 costs — not the 50 percent that would correspond to its share of the lines — and 0 percent of Phase 2 costs. As I stated in my direct testimony[47], PPL stated in its Phase 2 application that "the cost for the Project will be allocated to PPL Electric customers," meaning ratepayers are expected to bear the full Phase 2 cost with no customer contribution.

Q: Do you agree with Mr. Lookup's response that a double breaker-double bus ("DBDB") arrangement "was not selected as it would have required a longer 230 kV switchyard, additional terminal equipment, and additional 230 kV breakers" (Statement No. 1-R, p. 26)?

A: I do not take a position on whether DBDB was the correct alternative to BAAH. As I noted in my direct testimony, PJM's own standards identify ring bus, BAAH, and DBDB as the three acceptable substation configurations, and the choice among them was PPL's.[48] My concern is narrower: Mr. Lookup's rebuttal testimony asserts that DBDB

[46] Lines 8-10, Page 47, OCA Statement No. 2.
[47] Lines 5-9, Page 91, OCA Statement No. 2.
[48] Lines 4-16, Page 26, OCA Statement No. 2.

"would have required" a longer switchyard, additional terminal equipment, and additional breakers, without providing any cost estimate, engineering study, or quantified comparison supporting that assertion.[49] This is the same pattern present throughout PPL's rebuttal testimony — a qualitative assertion of increased cost or complexity offered in place of a quantified analysis. Absent such an analysis, the Commission has no basis to evaluate whether PPL's selection of BAAH over DBDB reflects a reasoned, cost-justified engineering decision or an unexamined default.

Q: Do you agree with Mr. Lookup's characterization that, "[b]y Mr. Konidena's own admission[,] the breaker-and-a-half operation is justified when a total of nine transmission lines will be terminated at the Tomhicken after the future Phase 2 is completed" (Statement No. 1-R, pp. 16-17)?

A: No, I disagree with Mr. Lookup's characterization of my direct testimony. My direct testimony did not admit that BAAH is justified by a nine-line total. My direct testimony stated that "PPL justified selecting BAAH over a ring bus configuration partly on the basis that nine lines will terminate at Tomhicken,"[50] and then explained that "PPL separately confirmed in discovery that the line split configuration was designed to accommodate future Phase 2 line terminations,"[51] such that "PPL's nine-line justification for the BAAH design is premised on Phase 2 lines that have not yet been approved by this Commission,"[52] and that "[u]nder Phase 1 alone, the number of line terminations is

[49] Lines 17-19, Page 26, PPL Statement No. 1-R.
[50] Lines 11-12, Page 28, OCA Statement No. 2.
[51] *Id.* at Lines 12-14.
[52] *Id.* at Lines 14-15.

lower."[53] I was describing and critiquing PPL's own justification, not conceding that the justification is sound.

I also note that the benefits Mr. Lookup's rebuttal testimony now claims for the BAAH design — that ring buses risk becoming "segmented during planned and unplanned outages"[54] and that BAAH "allows the ability to add additional 230 kV transmission lines to supply other customers or add system capacity"[55] — repeat the same unquantified claims present in PPL's discovery responses at the time of my direct testimony. As I explained in my direct testimony, PPL stated in discovery that the BAAH design provides "system reliability, increased operational flexibility and additional capacity to area,"[56] but "provided no quantitative analysis supporting that claim."[57] Mr. Lookup's rebuttal testimony does not cure that gap; it restates the same category of general, qualitative benefit claims — including language drawn from the same discovery response I addressed in my direct testimony — without any project-specific quantification.

[53] *Id.* at Lines 15-16.
[54] Lines 16-17, Page 16, PPL Statement No. 1-R.
[55] *Id.* at Lines 5-7, Page 17.
[56] Lines 7-8, Page 29, OCA Statement No. 2.
[57] *Id.* at Line 12.

III. Phase 1 and Phase 2 Interdependency (Lookup & Taylor)

Q: Do you agree with Mr. Lookup's response that the benefits of the Tomhicken 230 kV Switchyard are not contingent upon the Sugarloaf 500/230 kV Transmission Line Project (Statement No. 1-R, pp. 20-21)?

A: No, I disagree, and I note that Mr. Lookup's own rebuttal testimony concedes the central point of my direct testimony on this issue. Mr. Lookup states: "the initial Phase 1 scope does not directly increase the capacity of the Susquehanna–Harwood corridor."[58] This is consistent with my direct testimony's position that "PPL has not established that these benefits are realized under Phase 1 alone."[59]

Mr. Lookup's rebuttal testimony then asserts that the Tomhicken Switchyard nonetheless "provides the benefit of the expansion of the 230 kV network," "will allow for additional transmission lines," "will increase system reliability," and "provide[s] additional system resiliency and greater operational flexibility. . .."[60] As with the other benefit claims addressed elsewhere in this testimony, none of these assertions is supported by a quantitative analysis specific to this Project, and none identifies which of these claimed benefits, if any, are realized under Phase 1 alone as opposed to depending on the future, unapproved Phase 2 construction.[61] Mr. Lookup's own concession that Phase 1 does not increase corridor capacity supports rather than undermines my direct

[58] Lines 10-11, Page 20, PPL Statement No. 1-R.
[59] Lines 18-19, Page 29, OCA Statement No. 2.
[60] Lines 11-19, Page 27, PPL Statement No. 1-R.
[61] Lines 7-8, Page 99, OCA Statement No. 2.

testimony's conclusion that the network benefits PPL claims for the Tomhicken Switchyard remain contingent upon Phase 2.

Q: Do you agree with Witness Lookup that "the Tomhicken 230kV Switchyard would have been designed in a breaker-and-a-half arrangement regardless of the Phase 2 scope" (Statement No. 1-R, p. 26)?

A: No, I disagree with the conclusion Mr. Lookup draws, though I agree with a narrower point underlying it. As I stated in my direct testimony, "BAAH provides greater operational reliability than a ring bus configuration,"[62] and I do not dispute that PPL would likely have selected a BAAH configuration type independent of Phase 2. I disagree, however, that this resolves the question Mr. Lookup's rebuttal testimony actually addresses — whether the Tomhicken Switchyard as designed and sized is independent of Phase 2. The choice of configuration type is a different question from how that configuration was sized and built.

As I explained in my direct testimony, PPL confirmed that "[t]he splitting of the Susquehanna-Harwood #1 & #2 230kV Transmission Lines was designed to allow the future Phase 2 lines to terminate into the Tomhicken Switchyard and Harwood Substation without requiring line crossings,"[63] and that "[t]he Tomhicken 230kV Switchyard will have a line termination point for the Phase 2 scope."[64] As addressed further below, Mr. Lookup's rebuttal testimony confirms this same point in his own words.[65] Mr. Lookup's

[62] Line 13, Page 30, OCA Statement No. 2.
[63] Lines 5-7, Page 60, OCA Statement No. 2.
[64] Lines 15-16, Page 71, OCA Statement No. 2.
[65] Lines 15-16, Page 18, PPL Statement No. 1-R.

rebuttal testimony also relies on a line count — described variously as "eight lines"[66] and, elsewhere in PPL's discovery responses, as "nine lines connected as part of Phase 1 and Phase 2"[67] — to justify the specific bay configuration and termination capacity of the switchyard as built. Regardless of which configuration type PPL would have chosen, the specific design PPL is asking ratepayers to fund — its bay count, its line-split routing, and its termination capacity — was, by PPL's own admission, shaped by accommodating Phase 2. Agreeing that BAAH is generally the more reliable configuration does not mean I agree that the Tomhicken Switchyard as designed and costed in this proceeding is independent of Phase 2.

PPL's discovery response confirms this same conclusion, and also confirms that PPL has not answered the specific question presented. When asked to state whether the number of bays, the bus bar configuration, and the overall footprint of the Tomhicken Switchyard would be identical under a Phase-1-only scenario, PPL did not answer that question. PPL responded only that "[t]he use of a BAAH arrangement would still be required," and further stated that "Phase 2 is required to reliably serve the customer's requested load and therefore the switchyard is designed to accommodate the future Nescopeck – Tomhicken 230 kV line."[68] That response confirms, in PPL's own words, that the switchyard's design accommodates Phase 2 requirements. It leaves unanswered whether the bay count, configuration, or footprint of the Tomhicken Switchyard as actually built would be identical absent Phase 2. PPL has had the opportunity to state

[66] "Under Phase 1, PPL Electric proposes building the Tomhicken 230 kV switchyard as a breaker-and-a-half configuration due to the total of **eight lines** to be terminated at the switchyard." Lines 13-15, Page 16, PPL Statement No. 1-R (emphasis added).
[67] "The proposed Tomhicken Switchyard is to have **nine lines** connected as part of Phase 1 and Phase 2." PPL Response to OCA V-4(c) (emphasis added).
[68] PPL Response to OCA XIV-5(a), (b).

affirmatively that the design as built would be unchanged without Phase 2, and it has not done so.

Q: Do you agree with one of Witness Taylor's conclusions that "forward-looking design does not make a facility customer-specific"[69] as applied to the Tomhicken Switchyard?

A: No, I disagree with Mr. Taylor's framing of the design principle itself, not merely with how he applies it. Mr. Taylor states that "[t]ransmission facilities may reasonably be designed to accommodate foreseeable expansion, preserve operational flexibility, avoid future reconstruction and outages, and support the efficient long-term development of the integrated transmission system," and that "[t]he relevant question remains how the facility functions and what benefits it provides, not whether it includes capacity or design features that may support future needs."[70] In my opinion, the relevant starting question is not whether a facility might support future needs. It is whether an actual need has been demonstrated relative to the existing facility, and whether cost-effective, non-transmission alternatives were considered, before a transmission solution sized beyond that demonstrated need is selected and its cost assigned to ratepayers.

Mr. Taylor's principle presumes that forward-looking design decisions are made within a planning framework that has already tested cost-effectiveness and alternatives before capacity beyond immediate need is added. This is the same forward-looking

[69] Lines 14-19, Page 6, PPL Statement No. 5-R.
[70] Lines 14-19, Page 6, PPL Statement No. 5-R.

quantitative analysis I recommended in my direct testimony — that "before approving any ratepayer allocation, the Commission should require PPL to perform and file a forward-looking quantitative analysis demonstrating that ratepayer benefits equal or exceed the $38.4 million being allocated to them"[71] — a showing PPL has not made for the Project's claimed benefits generally, and has not made for this specific design margin either. As I explained in my direct testimony, PJM's review of the Tomhicken Switchyard as a Supplemental Project consists of only three things: a "do no harm" study, review through the Transmission Expansion Advisory Committee, and PJM informing the Transmission Owner "if a baseline upgrade made pursuant to PJM's regional transmission expansion planning process might alleviate or partially mitigate the need for the Supplemental Project."[72] As I concluded, "none of these reviews constitute[s] an independent validation of the Transmission Owner's need determination or an evaluation of whether the proposed solution is the most cost-effective option for ratepayers."[73]

PPL also confirmed that it is not registered as a Transmission Planner or Planning Coordinator, and that the NERC TPL-001-5.1 planning standard — which requires "comprehensive planning assessments including alternatives analysis and corrective action plans"[74] — does not apply to PPL's role in this Project.[75] PPL instead followed the FAC-002 Facility Interconnection Studies standard, which "does not require evaluation of demand-side management alternatives or other corrective action alternatives before selecting a transmission solution."[76] As I concluded in my direct testimony, no

[71] Lines 3-8, Page 109, OCA Statement No. 2.
[72] Lines 17-19, Page 14, OCA Statement No. 2.
[73] Lines 19-20, Page 14 to Lines 1-2, Page 15, OCA Statement No. 2.
[74] Page 11, Footnote 21, OCA Statement No. 2.
[75] Lines 1-2, Page 11, OCA Statement No. 2.
[76] Page 11, Footnote 21, OCA Statement No. 2.

documented non-transmission alternatives analysis was performed for this Project's forward-looking design features.[77]

Mr. Lookup's own rebuttal testimony confirms that the specific design feature at issue was not generic forward-looking margin, but a design choice made to accommodate a specific, named future project. Mr. Lookup states: "I acknowledge that bifurcation of the Susquehanna – Harwood #1 & #2 lines did take in account the future Phase 2, Nescopeck – Tomhicken 230 kV line."[78] This is not the kind of generalized accommodation of "foreseeable expansion"[79] that Mr. Taylor's principle contemplates; it is a specific design choice PPL's own witness admits was made for a specific, unapproved future project.

Under these circumstances, "forward-looking design does not make a facility customer-specific"[80] is not the correct threshold question. Before ratepayers are asked to fund design margin beyond the Customer's Phase 1 need, PPL should be required to show that a cost-effective alternative to that additional capacity was considered and that the additional capacity reflects an actual, demonstrated need rather than an unexamined default to building beyond what is presently required.

[77] Lines 19-20, Page 14 to Lines 1-2, Page 15, OCA Statement No. 2.
[78] Lines 15-16, Page 18, PPL Statement No. 1-R.
[79] Line 15, Page 6, PPL Statement No. 5-R.
[80] Lines 14-19, Page 6, PPL Statement No. 5-R.

IV. Bay 1 — Function and Cost Allocation Are the Same Question

Q: Do you agree with Witness Lookup that the Responsibility of Asset Matrix produced in discovery (OCA I-6, Attachment 1) is "illustrative" and does not depict the actual Bay 1 configuration at Tomhicken (Statement No. 1-R, pp. 22-23)?

A: No, I disagree. Mr. Lookup's rebuttal testimony states that "[t]he 'Bay 1' that appears in BAAH Example 1 is a hypothetical bay in that illustrative example; it is not the Tomhicken 230 kV Switchyard one-line diagram, and it does not depict the actual configuration or function of Bay 1 at Tomhicken."[81]

As I explained in my direct testimony, PPL did not treat the Matrix as merely illustrative when it used that same Matrix to determine an actual dollar allocation for Tomhicken's real Bay 1. The Matrix "depicts Bay 1 entirely in orange (cost allocated to ratebase), with no green customer feed line on the left side of the bay,"[82] and PPL relied on that depiction to allocate "Bay 1 — a pure source bay with no customer feed line — . . . entirely to rate base at approximately $1.7 million."[83]

PPL's discovery response confirms that the physical bay configuration of the Tomhicken 230 kV Switchyard "has not changed" since the Matrix was produced.[84] The discrepancy between the Matrix and Mr. Lookup's current characterization of Bay 1 is therefore not explained by any change to the facility itself. PPL's discovery response is also inconsistent regarding the Matrix's status. In responding to my request that PPL

[81] Lines 16-18, Page 22, PPL Statement No. 1-R.
[82] Lines 12-13, Page 25, OCA Statement No. 2.
[83] *Id.* at Line 5.
[84] PPL Response to OCA XIV-1(b).

reconcile the Matrix with Mr. Lookup's rebuttal testimony, PPL stated that its earlier discovery response "explained that it applied the methodology set forth in its policy [the Matrix]... to 'quantify or evaluate that benefit[s]'" for the Tomhicken Project, and that a separate attachment then "set[] forth the facility-specific justifications for the Tomhicken Project applying the Company's policy."[85] This describes the Matrix as the methodology PPL applied specifically to determine Tomhicken's actual cost allocation. It is difficult to reconcile with PPL's position, repeated in that same discovery response, that the Matrix "does not depict the actual configuration or function of Bay 1 at Tomhicken."[86]

If the Matrix's depiction of Bay 1 is, as Mr. Lookup contends, merely a hypothetical illustration that does not depict the actual configuration or function of Bay 1 at Tomhicken, PPL has not identified what Tomhicken-specific documentation actually supports the $1.7 million Bay 1 allocation it calculated using that same Matrix. I specifically asked PPL in discovery to identify that documentation, or to identify which elements of the Matrix are Tomhicken-specific as opposed to generic. PPL's response to both questions was to refer back to the same "illustrative, generic examples" characterization, without identifying any Tomhicken-specific documentation or distinguishing any Tomhicken-specific elements of the Matrix.[87]

[85] PPL Response to OCA XIV-1(a).
[86] PPL Response to OCA XIV-1(a), (c).
[87] PPL Response to OCA XIV-2(c), (d).

Q: Do you agree with Witness Lookup's characterization that Bay 1 serves both a "Function 1 — Customer feed" and "Function 2 — Network source" role (Statement No. 1-R, pp. 22-24)?

A: No, I disagree with how Mr. Lookup frames this characterization. Mr. Lookup's rebuttal testimony labels Bay 1's second function "Function 2 — Network source,"[88] a category I do not find anywhere in PPL's Policy on Cost Allocation for Large Customer Interconnections. Mr. Taylor's own rebuttal testimony describes the factors PPL's Policy uses to identify network benefits: "reliability, increased capacity, reduced congestion, improved operational flexibility, resiliency, service to multiple customers, and support for future system needs."[89] "Network source" is not among them.

PPL's discovery response confirms what "Network source" actually means: Susquehanna Circuit #1 "is a 'Network Source' as it is part of the greater 230kV BES network and can have power flow in or out of the Tomhicken 230kV Switchyard."[90] That is a description of physical connectivity to the bulk electric system, not a demonstration that Bay 1 provides any of the specific network benefits PPL's own Policy identifies — reliability, capacity, congestion relief, resiliency, operational flexibility, service to multiple customers, or support for future system needs. Being physically connected to the network, and capable of power flow in either direction, describes nearly any transmission facility; it does not by itself establish a network benefit under PPL's own stated methodology.

[88] Line 11, Page 23, PPL Statement No. 1-R.
[89] Lines 18-21, Page 25, PPL Statement No. 5-R.
[90] PPL Response to OCA XIV-3(f).

Labeling a bay's function does not, by itself, establish that the function qualifies as a network benefit under PPL's own Policy. Neither Mr. Lookup's rebuttal testimony nor PPL Electric's discovery response identifies which Policy factor Bay 1's connectivity to Susquehanna Circuit #1 satisfies. This is precisely the kind of unreviewed, after-the-fact application of PPL's Policy that my recommendation — that the Commission "require PPL to submit its cost allocation policy for formal Commission review and approval"[91] — is intended to prevent.

Q: Do you agree that PPL's cost allocation for Bay 1 is consistent with its own stated methodology of assigning customer-specific facilities to the Customer?

A: No, I do not agree. PPL's stated methodology is to assign customer-specific facilities to the Customer and network-benefit facilities to ratepayers. PPL confirmed in discovery that Bay 1 charges of approximately $3.99 million are assigned to the Customer, in addition to the approximately $1.7 million allocated to rate base.[92] Bay 1's cost is therefore split between the two categories PPL's methodology is supposed to distinguish, yet neither Mr. Lookup's rebuttal testimony nor PPL's discovery responses explain how that specific split — $3.99 million to the Customer, $1.7 million to rate base — was derived from Bay 1's two admitted functions. If Bay 1's customer-feed function and network-source function each correspond to a defined portion of the bay's cost, PPL has not identified what that correspondence is.

[91] Lines 13-14, Page 5, OCA Statement No. 2.
[92] PPL Response to OCA XIV-6(a).

This gap is compounded by timing. PPL confirmed that the $3.99 million/$1.7 million allocation "has not changed" and predates Mr. Lookup's rebuttal testimony characterizing Bay 1 as serving both "Function 1 — Customer feed" and "Function 2 — Network source."[93] If the dual-function characterization were the actual analytical basis for this split, one would expect PPL to have derived the $1.7 million/$3.99 million allocation from that functional analysis. Instead, PPL confirms the allocation predates and is unaffected by that characterization.[94] This suggests the "Function 1"/"Function 2" framework was constructed in rebuttal testimony to explain an allocation PPL had already fixed, rather than derived from an engineering and functional analysis that produced the allocation in the first instance.

PPL's own rebuttal testimony states that "[t]he Company applied the methodology in the Matrix... to the actual Tomhicken Switchyard arrangement" to determine Bay 1's allocation.[95] If that is accurate, PPL should be able to explain how the $3.99 million customer charge and $1.7 million rate base charge were each derived from Bay 1's two functions. Neither Mr. Lookup's rebuttal testimony nor PPL's discovery responses provide that explanation, and without it, I cannot conclude that Bay 1's cost allocation reflects a consistent application of PPL's own stated methodology.

[93] Page 23, PPL Statement No. 1-R; PPL Response to OCA XIV-6(b), (c).
[94] PPL Response to OCA XIV-6(c).
[95] Lines 21-22, Page 22, PPL Statement No. 1-R.

V. Customer-Triggered vs. Customer-Specific (Lookup/Taylor)

Q: Do you agree with Mr. Lookup's response that characterizing the Tomhicken Switchyard Project as existing solely for the Customer's benefit is unfair, based on the "customer-driven vs. customer-specific" distinction discussed in Sections VII and VIII of Mr. Taylor's rebuttal testimony (Statement No. 1-R, p. 21)?

A: No, I disagree, for the reasons explained in my responses to Mr. Taylor's testimony, below. Mr. Lookup's answer does not offer an independent basis for disagreement; it relies entirely on the "customer-driven vs. customer-specific"[96] distinction developed in Sections VII and VIII of Mr. Taylor's rebuttal testimony. I address that distinction, and why it does not support PPL Electric's position, in the questions and answers that follow.

Q: Do you agree with Witness Taylor that a "customer-triggered" facility can be distinguished from a "customer-specific" facility, and that this distinction determines whether ratepayers or the Customer should bear its cost (Statement No. 5-R, p. 34)?

A: No, I disagree. PPL confirmed in discovery that its Policy on Cost Allocation for Large Customer Interconnection "does not use the terms 'customer-triggered' or 'customer-specific,'" and that these terms were introduced in Statement No. 5-R "in response to OCA's testimony."[97] PPL maintains that this "was not a change in framework or method,"

[96] Lines 14-17, Page 21, PPL Statement No. 1-R.
[97] PPL Response to OCA XIV-9(a).

and that "the anticipated allocation provided in this case was determined prior to OCA's direct testimony and has not changed during this proceeding."[98] These two positions are in tension. If the customer-triggered/customer-specific distinction was created specifically to respond to my direct testimony, but the underlying dollar allocation it purports to justify was fixed before my direct testimony was filed, the terminology is not describing the methodology PPL actually applied to reach that allocation — it is a post-hoc explanation constructed after the fact.

Mr. Taylor draws a distinction between "customer-triggered" and "customer-specific" facilities to assert that the customer should not have to pay for the entire Tomhicken project because Tomhicken is a "customer-triggered" facility.

According to Mr. Taylor's definition, Tomhicken Switchyard is a customer-triggered facility because the "need arises from a customer's request for service, but that may ultimately serve broader transmission functions" as part of "facilities [that] may include both dedicated customer facilities and facilities that become integrated into the transmission network and provide broader reliability, operational, capacity, resiliency, or flexibility benefits."[99]

There are a couple of concerns with Mr. Taylor's "customer-triggered" facility definition. **First**, whether it is a "customer-triggered" or "customer-specific" facility, Tomhicken Switchyard is a facility that is driven by the customer need. As I mentioned in my direct testimony, "but for this Customer's interconnection request, no reliability need requiring this switchyard would exist. If the Customer does not interconnect, the need

[98] PPL Response to OCA XIV-9(b).
[99] Lines 18-22, Page 24, PPL Statement No. 5-R.

driver for this project disappears, and the Tomhicken Switchyard serves no demonstrated independent system reliability purpose."[100]As addressed in Section I of this testimony, Mr. Taylor's rebuttal testimony engages with this "but-for"[101] argument but remains internally inconsistent — arguing the merits of cost allocation at length while also maintaining that cost allocation is outside the scope of this proceeding.

Second, Mr. Taylor makes unsubstantiated claims to imply that Tomhicken "provide[s] broader reliability, operational, capacity, resiliency, or flexibility benefits".[102] These are unsubstantiated claims because as my direct testimony shows "PPL provided no quantitative analysis supporting any of these claimed benefits in the context of this project specifically."[103]

Mr. Taylor is drawing a distinction where there is no need between "customer-triggered" and "customer-specific" words to make his point that the ratepayers should pay. Mr. Taylor glosses over my testimony that PPL has not shown any quantitative analysis to substantiate its claims of benefits to ratepayers.

Q: Do you agree with Mr. Taylor that "facilities that become integrated into the transmission network and provide broader transmission benefits may be appropriately treated differently?"[104]

[100] Lines 6-9, Page 62, OCA Statement No. 2.
[101] Line 7, Page 35, PPL Statement No. 5-R.
[102] Lines 20-22, Page 34, PPL Statement No. 5-R.
[103] Lines 7-8, Page 99, OCA Statement No. 2.
[104] Lines 14-15, Page 35, PPL Statement No. 5-R.

A: I disagree. Mr. Taylor's statement that facilities providing broader transmission benefits "may be appropriately treated differently" is conditional language — it describes a possibility, not a finding.

Mr. Taylor never resolves that conditional language for Tomhicken specifically. He does not identify which portions of the Tomhicken Switchyard satisfy this standard, does not quantify the broader transmission benefits those portions supposedly provide, and does not explain why those benefits exist independent of this Customer's interconnection.

On the other hand, my direct testimony showed that "the demonstrable network benefit to existing ratepayers is zero on three independent measures"[105] – capacity and reliability, network flow, and congestion relief.

"May be appropriately treated differently" is not the same as "is appropriately treated differently," and Mr. Taylor's rebuttal testimony never closes that gap for this Project. A standard that is stated but never applied to the facts at hand cannot support the cost allocation PPL has proposed.

Q: Do you agree with Mr. Lookup's response that the Tomhicken 230 kV Switchyard will provide network benefits sufficient to justify the proposed cost allocation, including load flow continuing south to the Harwood substation and additional

[105] Lines 14-15, Page 57, OCA Statement No. 2.

capacity to serve other customers in the Hazleton area (Statement No. 1-R, pp. 20-21)?

A: No, I disagree. Mr. Lookup's answer asserts that "[t]he Tomhicken 230 kV Switchyard will be part of PPL Electric's 230 kV network with load flow continuing south towards the Harwood 230-69 kV substation" and "will have additional capacity and termination points to serve other customers in the Hazleton area."[106] Neither claim is supported by any quantitative analysis, study, or PJM planning document identifying an independent need for that capacity or that load flow benefit.

As I explained in my direct testimony, Mr. Lookup has already identified who these "other customers" are.[107] Mr. Lookup confirmed in his direct testimony that "the Tomhicken Switchyard is designed to eventually serve multiple customers" and that "there is other load growth in the Hazleton area that this project will support."[108] PPL produced in discovery a list of projects currently in its interconnection queue through March 31, 2026 — spanning eight pages and including dozens of large load customers requesting 230 kV service at loads ranging from hundreds to thousands of MW.[109] These are the customers Mr. Lookup's rebuttal testimony now describes generically as "other customers in the Hazleton area."[110] They are large load, transmission-voltage interconnection requesters — not the residential and small commercial ratepayers who are being asked to fund $38.4 million of this Project's costs. Mr. Lookup's rebuttal testimony does not explain why existing ratepayers should bear the cost of capacity

[106] Lines 22-23, Page 20 to Lines 1-6, Page 21, PPL Statement No. 1-R.
[107] Lines 4-14, Page 61, OCA Statement No. 2.
[108] Lines 6-7, Page 5, PPL Statement No. 1.
[109] Lines 8-11, Page 61, OCA Statement No. 2.
[110] Lines 5-6, Page 21, PPL Statement No. 1-R.

reserved for other large load customers who will, like the Customer here, be subject to their own transmission-level tariffs and their own cost responsibility for any facilities constructed to serve them.

Q: Do you agree with Witness Lookup that "load growth is a well-established transmission planning need recognized by PJM," and that this justifies including Tomhicken's network benefits in ratepayer cost allocation despite the Project's customer-driven origin (Statement No. 1-R, p. 17)?

A: No, I disagree with how Mr. Lookup applies this general statement to the Tomhicken Switchyard specifically. As I stated in my direct testimony, "[n]o transmission investment on this corridor was in PPL's capital plan or PJM's RTEP queue before this customer arrived."[111] Hence, the Tomhicken Switchyard was not identified through that PJM RTEP process. PPL stated that PJM designated this Switchyard as a Supplemental Project.[112] As my direct testimony discussed, PJM Manual 14B defines Supplemental Projects as transmission expansions or enhancements "not needed to comply with PJM reliability, operational performance, FERC Form No. 715 or economic criteria."[113] By PJM's own definition, the Tomhicken Switchyard is not a facility required to meet PJM's reliability criteria through the RTEP process Mr. Lookup describes in his rebuttal testimony.

As I further explained in my direct testimony, Supplemental Projects are not approved by the PJM Board,[114] and PJM does not independently verify or approve a

[111] Lines 3-4, Page 10, OCA Statement No. 2.
[112] Lines 2-4, Page 13, OCA Statement No. 2.
[113] Lines 8-10, Page 13, OCA Statement No. 2.
[114] Line 18, Page 13, OCA Statement No. 2.

Transmission Owner's need determination for a Supplemental Project;[115] the need determination rests entirely with the Transmission Owner.[116] PJM's only review is a "do no harm" study evaluating whether the project will adversely impact system reliability — not an affirmative determination that the project is needed for system reliability.[117]

Mr. Lookup's rebuttal testimony does not address any of these points from my direct testimony. PJM's general recognition that load growth is a legitimate transmission planning consideration, standing alone, does not establish that the Tomhicken Switchyard's network benefits were identified or validated through that planning process, particularly where my direct testimony shows the opposite.

Q: Do you agree with Witness Taylor that PPL's approach to distinguishing customer-funded facilities from transmission system facilities is "consistent with PJM's interconnection planning framework,"[118] specifically PJM Manual 14H's System Impact Study and Facilities Study process (Statement No. 5-R, pp. 23-25)?

A: No, I disagree with each part of Mr. Taylor's answer.

First, Mr. Taylor states that "PJM's interconnection planning framework distinguishes among different categories of facilities and does not treat all facilities associated with an interconnection request as a single category."[119] This describes PJM Manual 14H's Cycle process — a framework that applies, by its own terms, to

[115] Lines 3-4, Page 14, OCA Statement No. 2.
[116] Line 7, Page 14, OCA Statement No. 2.
[117] Lines 14-16, Page 14, OCA Statement No. 2.
[118] Lines 1-3, Page 22, PPL Statement No. 5-R.
[119] Lines 4-6, Page 22, PPL Statement No. 5-R.

Generation Project Developers, Transmission Project Developers, Eligible Customers seeking Long Term Firm Transmission Service, Upgrade Customers, Affected System Customers, Surplus Project Developers, and Replacement Generation Project Developers.[120] A retail, large-load customer request for transmission-level service — the nature of the Customer's request in this proceeding — does not appear among the categories Manual 14H governs.

Second, Mr. Taylor describes PJM's System Impact Studies and Facilities Studies as identifying Interconnection Facilities and Network Upgrades and developing cost estimates.[121] As I explained in my direct testimony, however, PJM's actual involvement in the Tomhicken Switchyard — a Supplemental Project — consists of only three things: a "do no harm" study, review through the Transmission Expansion Advisory Committee, and PJM informing the Transmission Owner "if a baseline upgrade made pursuant to PJM's regional transmission expansion planning process might alleviate or partially mitigate the need for the Supplemental Project."[122] As I concluded, "none of the three [reviews] constitute[s] an independent validation of the Transmission Owner's need determination or an evaluation of whether the proposed solution is the most cost-effective option for ratepayers."[123] A Manual 14H System Impact Study and Facilities Study — the process Mr. Taylor describes — is not among these three PJM reviews. Mr. Taylor's rebuttal testimony does not explain how a study process that his own testimony does not

[120] PJM Manual 14H, Revision 05, Effective Date 07/28/2026, "About This Manual — Applicability" and "Intended Audience," Available at https://www.pjm.com/-/media/DotCom/documents/manuals/m14h.pdf (last visited Aug. 14, 2026).
[121] Lines 6-12, Page 22, PPL Statement No. 5-R.
[122] Lines 14-19, Page 14, OCA Statement No. 2.
[123] Lines 19-20, Page 14 to Lines 1-2, Page 15, OCA Statement No. 2.

identify as having been performed for this Project supports his claim that PPL's classification approach is "consistent with" that process.

Third, Mr. Taylor cites Manual 14H's distinction between "Interconnection Facilities" and "Network Upgrades" as support for PPL's own customer-versus-network classification.[124] Manual 14H defines Interconnection Facilities specifically as "all facilities and equipment between the Generating Facility and the Point of Interconnection... necessary to physically and electrically interconnect the Generating Facility to the Transmission System."[125] This definition is written in terms of generator interconnection; it does not define or address facilities interconnecting a retail load customer such as the one at issue here.

Finally, Mr. Taylor concludes that, "[c]onsistent with that framework, PPL Electric evaluates facilities associated with large load interconnection requests on a facility-specific basis."[126] A company practice cannot be "consistent with" a PJM framework that does not, by its own terms, apply to the type of request at issue. Mr. Taylor's rebuttal testimony does not identify any provision of Manual 14H, or any other PJM manual, that actually governs large-load retail customer interconnections such as the Customer's request here. Absent such a citation, Mr. Taylor's claim of consistency with PJM'' framework is not supported.

[124] Lines 14-18, Page 24, PPL Statement No. 5-R.
[125] PJM Manual 14H, Section 4.9.6.2 ("Interconnection Facilities").
[126] Lines 19-20, Page 24, PPL Statement No. 5-R.

Q: If PPL's approach were nonetheless found consistent with some part of PJM's interconnection framework, would that framework support PPL's $38 million cost allocation to ratepayers?

A: No. Even setting aside whether Manual 14H's Cycle process applies to this Customer's request — which, as I explained above, it does not — the quantification methodology Manual 14H actually prescribes for cost allocation is absent from PPL's showing.

Manual 14H's Load Flow Cost Allocation Method, Section B.3.1, allocates cost to a Project Developer or Eligible Customer based on a calculated Distribution Factor ("DFAX") and MW-impact threshold specific to the facility at issue — for example, a cost allocation is triggered where a request's DFAX on a facility exceeds 5% and its MW impact exceeds 3% of the facility's rating.[127] This is a quantified, facility-specific calculation tying a customer's actual electrical impact to a specific percentage of cost responsibility.

PPL has performed no comparable calculation for Tomhicken. Neither Mr. Lookup nor Mr. Taylor identifies a DFAX calculation, an MW-impact threshold analysis, or any quantified facility-specific measure connecting the Customer's request to the ~$38 million ratepayer allocation. If Mr. Taylor wishes to rely on PJM's interconnection framework as precedent for PPL's classification approach, the framework's own quantification methodology — not just its category labels — should apply. PPL has not shown that it does.

[127] Section B.3.1 Load Flow Cost Allocation Method, PJM Manual 14H.

VI. Nescopeck Alternative (Swartzentruber)

Q: Do you agree with Witness Swartzentruber that the Nescopeck Alternative "would almost certainly result in a cost increase of some degree" (PPL Statement No. 2-R, p. 7)?

A: I disagree. The main point that I raised in my direct testimony when discussing the Nescopeck Alternative was that "[a] direct connection from Nescopeck would have eliminated the Susquehanna-Harwood line split — as PPL confirmed the split would not be required under a Nescopeck configuration, though PPL noted the project would need to be re-evaluated and additional upgrades would be required."[128]

Mr. Swartzentruber's rebuttal testimony does not engage with my main point. His rebuttal testimony lists several engineering factors such as 1) "landowner and right-of-way ('ROW') considerations," 2) "additional Erosion and Sediment controls for roads, construction pads, or other structures," 3) "the potential for more significant terrain challenges resulting from [Nescopeck] alternative because of the topography between the proposed Nescopeck and Tomhicken sites ... would raise costs and could require additional structures ... from 13 to approximately 60," 4) "additional permitting risk associated with [Nescopeck] alternative, as the Company would be required to obtain more permits and agency approvals for things like railroads, highways, streams, and airports," 5) "additional consideration of viewsheds, landowner impacts, and electrical and ground clearances," and 6) "the exposure resulting from the line length ... longer

[128] Lines 12-15, Page 39, OCA Statement No. 2.

transmission lines result in more exposure to elements and therefore a higher risk of outages."[129]

More importantly, Mr. Swartzentruber's list of cost-increasing factors does not account for the cost PPL's own discovery response confirms the Nescopeck Alternative would avoid. In response to OCA III-8(f), PPL confirmed that approximately $9 million is budgeted for the line work associated with the splitting of the Susquehanna-Harwood #1 & #2 230kV lines.[130] In response to OCA III-8(d), PPL confirmed that this line-split work would not be required if the Customer were served directly from the Nescopeck Switchyard, though PPL noted that the Project "would need to be re-evaluated" and that "additional upgrades would be required to serve the Customer's requested load" under that configuration.[131] Mr. Swartzentruber's rebuttal testimony does not quantify those additional upgrades, does not net the avoided $9 million line-split cost against the ROW, permitting, terrain, or structure-count factors he identifies, and does not state whether PPL ever performed that comparison internally. Without that analysis, Mr. Swartzentruber's list of cost-increasing factors describes only one side of a ledger PPL itself has never completed.

Discovery confirms this ledger has never been completed on either side. PPL confirmed it has performed no quantified, dollar-figure cost estimate — even preliminary — comparing the Tomhicken solution to the Nescopeck Alternative, and that its cost-

[129] Lines 1-19, Page 6, PPL Statement No. 2-R.
[130] "Approximately $9 million is budgeted for the line work to interconnect into the new PPL EU Tomhicken Switchyard. PPL Electric did not design the Project with line crossings and therefore does not have an estimate of the costs incurred to avoid line crossings." PPL Response to OCA III-8 (Supplemental)(f).
[131] "No, but if the Customer was served directly from the Nescopeck Switchyard the Project would need to be re-evaluated. Based on the proposed Nescopeck 230kV Switchyard and line arrangement, additional upgrades would be required to serve the Customer's requested load." PPL Response to OCA III-8 (Supplemental)(d).

increase conclusion rests on "substantial, general experience evaluating engineering solutions," not a formal analysis specific to this alternative.[132] The specific figures Mr. Swartzentruber's rebuttal testimony does provide are similarly unquantified: PPL confirmed the "approximately 60" structure estimate was derived by dividing 9 miles by an assumed 800-foot average span — not from any route-specific engineering study[133] — and that the underlying 9-mile distance is itself "a generalization of the minimum route length," not a surveyed or engineered route.[134] PPL further confirmed it has not identified or contacted any specific landowners along a potential Nescopeck route and could not state the number of additional parcels or easements the alternative would actually require.[135]

In my direct testimony I had already agreed that "the 9-mile distance and right-of-way considerations are legitimate engineering factors that may favor the Tomhicken approach from a siting standpoint,"[136] and Mr. Swartzentruber acknowledged that I have identified those two engineering factors.[137]

My concern remains that the Commission does not have in the record a cost comparison of the direct connection from Nescopeck because PPL admitted that such a connection would have eliminated the Susquehanna-Harwood line split. Hence, I disagree

[132] PPL Response to OCA XIV-11(a), (b).
[133] PPL Response to OCA XIV-13(a), (c).
[134] PPL Response to OCA XIV-14(a).
[135] PPL Response to OCA XIV-15(a), (b).
[136] Lines 7-9, Page 40, OCA Statement No. 2.
[137] "At the outset, this alternative is based upon the build-out of 9 miles of additional HV transmission lines that carry other, significant engineering factors, some of which were readily identified by Mr. Konidena." Lines 15-17, Page 5, PPL Statement No. 2-R.

with Mr. Swartzentruber that the Nescopeck Alternative "would almost certainly result in a cost increase of some degree."[138]

Q: Do you agree that PPL adequately evaluated the Nescopeck Alternative before rejecting it?

A: No, I disagree. Mr. Swartzentruber's own rebuttal testimony confirms the inadequacy of PPL's evaluation. He states that "[e]valuation of the purported Nescopeck Alternative was not warranted for the engineering reasons stated above, even setting aside any cost discrepancy."[139] By PPL's own admission, the Nescopeck Alternative was rejected on engineering grounds alone, without any cost evaluation — a conclusion consistent with PPL's response to OCA III-8(f), confirming it does not have an estimate of the costs incurred to avoid line crossings,[140] and OCA III-8(b), confirming no engineering analysis of a direct Nescopeck interconnection was ever performed.[141]

An adequate evaluation of an alternative requires, at minimum, some basis for comparing its costs and benefits to the proposed solution. PPL has not done so here.

Discovery confirms this inadequate evaluation was not a recent or reactive position. PPL confirmed that the engineering factors cited in Statement No. 2-R were identified "early in the project development process," and specifically "[p]rior to the filing of PPL Statement No. 1" on May 13, 2026.[142] If PPL had identified these

[138] Lines 6-7, Page 7, PPL Statement No. 2-R.
[139] Lines 3-4, Page 7, PPL Statement No. 2-R.
[140] PPL Response to OCA III-8 (Supplemental) (f).
[141] PPL Response to OCA III-8 (Supplemental) (b).
[142] PPL Response to OCA XIV-16(a), (b).

engineering factors before filing its own direct testimony, it does not explain why neither the original LON application nor Mr. Lookup's direct testimony disclosed those factors or PPL's basis for rejecting the Nescopeck Alternative.

Those reasons first appeared in this record in Mr. Swartzentruber's rebuttal testimony, filed August 7, 2026 — nearly three months after PPL confirmed it already had them.

Taken together, PPL's discovery responses describe an unquantified, unstudied, and largely undocumented set of justifications for rejecting the Nescopeck Alternative — general experience in place of a cost estimate, a rough mileage-by-span calculation in place of a route survey, and an undated internal judgment in place of a documented engineering evaluation. This is not the record of an adequate evaluation; it is a set of reasons developed to support a decision already made.

I reiterate my concern that "the Commission should require PPL to provide a documented cost comparison between the Tomhicken approach and direct connection to the Nescopeck Switchyard."[143]

VII. Cost Allocation Comparator (Susquehanna Project) (Lookup/Taylor)

Q: Do you agree with Witness Taylor that comparing PPL's anticipated cost allocation for the Tomhicken Project to the cost allocation approved for the Susquehanna 230

[143] Lines 1-3, Page 112, OCA Statement No. 2.

kV and 500 kV Transmission Line Project is not an appropriate benchmark, because "PPL Electric does not apply a fixed percentage or uniform allocation methodology across all large load projects"[144] and evaluates "each project individually?"[145]

A: No, I disagree. As I explained in my direct testimony, PPL confirmed in discovery that Customer 2/Susquehanna project — "a large load 230 kV customer with a peak load of 1,512 MW placed in service April 2026"[146] — had total infrastructure costs of approximately $30.2 million, with the customer responsible for $26.8 million (89%) and PPL responsible for $3.4 million (11%).[147] I explained that "PPL confirmed in discovery that Customer 2's interconnection did not require a new switching facility"[148] and "did not require splitting any existing transmission lines."[149] I also explained that two factors PPL might otherwise point to as distinguishing the projects do not, in fact, distinguish them: "Customer 2's project also had a phased structure... yet still received 89% customer allocation,"[150] and "Customer 2's substation was also designed for the customer's ultimate requested load... yet Customer 2 still bore 89% of infrastructure costs."[151] As I concluded, "[t]he differences PPL may identify between the two projects do not explain a swing from 89% customer responsibility to 36% customer responsibility under the same function-based cost allocation methodology PPL applied to both."[152]

[144] Lines 15-16, Page 27, PPL Statement No. 5-R.
[145] *Id.* at Line 16.
[146] Lines 3-4, Page 100, OCA Statement No. 2.
[147] *Id.* at Page 100, Footnote 281.
[148] Lines 18-19, Page 100, OCA Statement No. 2.
[149] *Id.* at Page 101, Footnote 284.
[150] *Id.* at Lines 5-6.
[151] *Id.* at Lines 8-11.
[152] *Id.* at Lines 11-14.

Mr. Taylor's rebuttal testimony does not address any of these specific, PPL-admitted facts. Mr. Taylor's own answer does not identify a single fact distinguishing the Susquehanna project/Customer 2's project from the Tomhicken Project; he states only that "[t]he appropriate allocation depends on the specific facilities included in the project, their function within the transmission system, and the extent to which those facilities provide benefits beyond the interconnecting customer,"[153] and that "[t]hose project-specific considerations differ from one project to another."[154] Mr. Taylor does not say what those considerations were for either project. Stating that projects may differ in principle is not a substitute for identifying how they differed here — particularly where, as I explained in my direct testimony, two of the specific factors PPL might otherwise rely upon to distinguish the projects (a phased project structure and a substation designed for the customer's ultimate load) were also present in the Customer 2 project and did not prevent an 89 percent customer allocation there.

PPL's discovery response confirms that the same Policy governs both projects, and that the same facility-type logic explains Susquehanna's allocation. PPL confirmed it applied the principles of its "Policy on Cost Allocation for Large Customer Interconnections" to Susquehanna, even though the Policy is not "discussed directly by name" in that project's filings, and that direct connection facilities were assigned to the customer while networked BES upgrades were excluded from the customer's obligation.[155] PPL further confirmed that Susquehanna's 89 percent customer allocation was driven by the fact that "the facilities that were developed for the Susquehanna project

[153] Lines 15-18, Page 28, PPL Statement No. 5-R.
[154] *Id.* at Pages 18-19.
[155] PPL Response to OCA XIV-8(a).

were largely radial feeds directly to the customer," with PPL's 11 percent share limited to "re-terminations and the replacement of existing structures" within the existing substation.[156]

The same logic, applied to Tomhicken, does not produce the allocation PPL proposes. As I explained in Section II of this testimony, PPL's own discovery response confirms that four of the eight lines terminating at the Tomhicken Switchyard under Phase 1 — half — are direct customer connection facilities dedicated to the Customer's interconnection. If direct connection facilities drive the customer-side allocation percentage at Susquehanna, as PPL now confirms, PPL has not explained why an equally or more customer-dedicated facility mix at Tomhicken results in only a 36 percent customer allocation rather than an allocation closer to Susquehanna's 89 percent.

Q: Do you agree with Mr. Lookup's response that PPL's Cost Allocation Policy is "not a percentage-based methodology that requires all large customer interconnection projects to have similar cost allocations,"[157] and that this explains why the Susquehanna project's approximately 89 percent customer allocation does not align with the Tomhicken Project's approximately 36 percent customer allocation (Statement No. 1-R, pp. 24-25)?

A: No, I disagree that Mr. Lookup's three distinguishing points explain the difference in outcome between the two projects.

[156] PPL Response to OCA XIV-8(c).
[157] Lines 11-12, Page 24, PPL Statement No. 1-R.

First, Mr. Lookup states that "[t]he facilities required to serve Customer 2 were substantially more limited and were largely dedicated to serving that specific customer."[158] This does not explain the allocation percentage. As I explained in my direct testimony, PPL confirmed in discovery that "Customer 2's interconnection did not require a new switching facility"[159] and "did not require splitting any existing transmission lines."[160] Even accepting that Customer 2 required fewer new facilities than Tomhicken, the question at issue is not the absolute scope of infrastructure required, but the percentage of whatever infrastructure was required that ratepayers versus the customer funded. Mr. Lookup's rebuttal testimony does not explain why a customer requiring more limited facilities bore 89 percent of their cost, while the Customer here, requiring more extensive facilities, is asked to bear only 36 percent.

Second, Mr. Lookup states that "Customer 2 is located in close proximity to an existing generation source and transmission infrastructure, which reduced the need for significant network upgrades." [161]This is consistent with what I explained in my direct testimony — that Customer 2's "location... allowed the load to be sourced from three different existing switchyards."[162] Proximity to existing infrastructure may explain why fewer network upgrades were needed for Customer 2 overall. It does not explain why, of the infrastructure that was needed, the customer was assigned 89 percent rather than a smaller share consistent with the 36 percent proposed for Tomhicken. In any event, proximity to existing infrastructure is not unique to Customer 2. PPL's LON for

[158] *Id.* at Page 25, Lines 4-5.
[159] Lines 18-19, Page 100, OCA Statement No. 2.
[160] *Id.* at Page 101, Line 1.
[161] Lines 5-7, Page 25, PPL Statement No. 1-R.
[162] Page 101, Footnote 283, OCA Statement No. 2.

Tomhicken states that the Tomhicken Switchyard "will be constructed on the same Customer-owned parcel as the Customer's 230-34 kV substation and facilities,"[163] placing the Tomhicken Customer in an equally, if not more, proximate relationship to existing 230 kV infrastructure than Customer 2.

Third, Mr. Lookup states that the Tomhicken Project "includes significant transmission infrastructure that becomes part of the integrated 230 kV transmission network and performs functions that extend beyond simply connecting a single customer,"[164] citing "increased operational flexibility, reliability, and network capability."[165] As I explained in my direct testimony, "PPL provided no quantitative analysis supporting any of these claimed benefits in the context of this project specifically."[166] An unquantified assertion of broader network benefit does not, by itself, explain a swing from an 89 percent customer allocation to a 36 percent customer allocation between two large load 230 kV interconnections.

Even accepting Mr. Lookup's characterization that the Tomhicken Switchyard's facilities extend beyond serving this Customer alone, that characterization supports my position rather than PPL's. If the Tomhicken Switchyard's additional capacity and network functions will "serve other customers in the Hazleton area,"[167] as Mr. Lookup's rebuttal testimony states elsewhere, those other customers are the same large load, transmission-voltage interconnection requesters identified in PPL's own eight-page

[163] Page 8, LON.
[164] Lines 10-12, Page 25, PPL Statement No. 1-R.
[165] Lines 15-16, Page 25, PPL Statement No. 1-R.
[166] Lines 7-8, Page 99, OCA Statement No. 2.
[167] "The Tomhicken 230 kV Switchyard will have additional capacity and termination points to serve other customers in the Hazleton area." Lines 4-6, Page 21, PPL Statement No. 1-R.

interconnection queue,[168] I addressed in my direct testimony. If those future customers, rather than existing residential and small commercial ratepayers, are the parties who will actually use and benefit from the network functions Mr. Lookup describes, this supports my direct testimony's recommendation that "the Commission... require PPL to develop a cost recovery mechanism under which future customers interconnecting through or benefiting from the Tomhicken infrastructure contribute to Phase 1 costs currently allocated to ratepayers,"[169] rather than justifying allocating those costs to existing ratepayers now.

VIII. Conclusion

Q: Does this conclude your testimony?

A: Yes.

[168] Line 15, Page 96, OCA Statement No. 2.
[169] *Id.* at Lines 4-6.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania	:	Docket No. A-2025-3059443

VERIFICATION

I, Rao Konidena, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement No. 2SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. Section 4904 (relating to unsworn falsification to authorities).

DATED: September 4, 2026

Signature: Rao Konidena

Rao Konidena

Address: Rakon Energy LLC
Roseville, MN 55113

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Build Approximately 1.1 Miles of New Parallel Double Circuit 230 kV Transmission Taps that are Needed to Connect the Existing Susquehanna-Harwood #1 & #2 Transmission Lines on the New Tomhicken 230 kV Switchyard that are Respectively Located in Luzerne County, Pennsylvania	:	**Docket No.: A-2025-3059443**

TESTIMONY

OF

ZACHARY F. TETI, M.S.

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Date Served: July 15, 2026

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I. Introduction

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND BUSINESS DESCRIPTION.

A. My name is Zachary F. Teti, M.S. I am a Senior Regulatory Analyst at the Pennsylvania Office of Consumer Advocate ("OCA"). My office is located at 555 Walnut St, Harrisburg, PA 17101. The OCA is a state agency that represents the interests of Pennsylvania utility consumers before the Pennsylvania Public Utility Commission ("PUC"), federal regulatory agencies, and state and federal courts. The OCA was created by the Pennsylvania General Assembly in 1976 and is an independent office within the Office of Attorney General.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I received a B.A. degree in Economics from Millersville University (Millersville, PA) in 2013 and an M.S. in Energy Economics from Pennsylvania State University (University Park, PA) in 2021.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have twelve years of experience in the banking and energy industries, most recently specializing in organized wholesale and retail electricity markets. My background comprises energy market design and analysis; econometric research in an academic setting; and financial planning, analysis, and control in a banking setting. I was employed as a Senior Regulatory Analyst serving as a representative of the NEPOOL Markets Committee between 2021 and 2024, analyzing wholesale electricity market design and transmission planning policy. Since joining the OCA as a Senior Regulatory Analyst in April 2025, I have been focusing on a variety of topics including wholesale electricity markets and transmission planning at PJM, utility rate cases, and default service plans for electricity procurement. At the PJM Transmission Expansion Advisory Committee (TEAC), I closely

observe and participate in the conversation of needs and solutions presented by the transmission owners within PJM that result in transmission projects. In May 2025 – a month into my employment at the OCA – the solution to PJM Need Number PPL-2024-0003 was presented to the TEAC.

Q. ON WHOSE BEHALF ARE YOU OFFERING THIS TESTIMONY?

A. I am offering this testimony on behalf of the OCA and on behalf of public input hearing witnesses. My testimony is intended to address their issues, which are from the standpoint of residential customers of electric services.

Q. DO YOU HAVE ANY APPENDICES OR EXHIBITS TO YOUR TESTIMONY?

A. Yes, my Curriculum Vitae is included herein as Exhibit ZT-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony amplifies the concerns of residential customers expressed during public input hearings which are focused on a Letter of Notification ("LON") submitted by PPL Electric Utilities Corporation ("PPL") which requested approval of the construction of a transmission project needed to serve a data center. To firstly extend their concerns, the approval of this LON seems nested within, or should be only eligible to occur once two valid concerns expressed via public testimony are satisfied: (1) the customer and its underlying tenants need to be firm and not speculative and (2) Phase 2[1] which is highly related to this project – indeed it is grouped as one need and solution at PJM[2] – is fully litigated.

[1] Docket No. A-2026-3061547.

[2] Problem Statement for Need Number PPL-2024-0003 and PJM Upgrade ID s3528: A customer has submitted a request to have their facility served from a 230kV source in Hazleton, PA. The total facility load is approximately 1,980 MW (2033). The requested in-service date is 05/2026. Initial In-Service 2026 Load: 240MW Projected 2028 Load: 720 MW. Projected 2031 Load: 1,440 MW

Q. PLEASE SHARE THE PROJECT SUMMARY PROVIDED BY OCA WITNESS DR. FRANK FELDER IN HIS TESTIMONY.

A. The project consists of approximately 1.1 miles of new double-circuit 230 kilovolt ("kV") transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 230 kV Transmission Lines to the new Tomhicken 230 kV Switchyard (the "Project"). The Project also includes the construction of two new 0.1-mile-long 230 kV transmission lines ("Connecting Lines") from the Tomhicken 230 kV Switchyard to a new customer-owned 230-34 kV substation. PPL submits that the Project is immediately needed to serve one new customer ("New Customer") based upon its request for 230 kV electrical service by March 2027. According to PPL's direct testimony, the New Customer's load ramping schedule will increase in stages from an initial load of 12 megawatts ("MW") to approximately 276 MW by December 2027, and approximately 965 MW by 2033.[3]

Q. WHEN DID THE PENNSYLVANIA PUBLIC UTILITY COMMISSION (PUC OR COMMISSION) CONDUCT PUBLIC INPUT HEARINGS FOR THIS PROCEEDING?

A. The Pennsylvania Public Utility Commission (PUC) conducted two Public Input Hearings to gather testimony from ratepayers and local citizens to better understand the impact of the LON. On Tuesday, June 30, 2026, in-person Public Input Hearings were held at 1 p.m. and 6 p.m. at the Penn State University - Hazelton Campus.

Q. WHAT WAS THE OVERALL POSITION OF THE PUBLIC INPUT HEARING WITNESSES?

A. To be clear, the consensus or preference is that the Project be simply rejected. The turnout at these public input hearings was great and the various positions were fairly uniform. Above, I noted that two concerns should be addressed: (1) the customer and its underlying

[3] Direct Testimony of Dr. Frank Felder at P. 5.

tenants need to be firm and not speculative and (2) Phase 2, which is highly related to this Project, must be fully litigated. The public offered a litany of other intimate and legitimate reasons. While the OCA is not structured to take positions on matters such as generation technology promotion or the economic development of certain industries, in this case the overriding task is to amplify the voices of ratepayers, people that will live in the shadows of this proposed infrastructure.

Q. A NUMBER OF PUBLIC INPUT HEARING WITNESSES WERE ASKED HOW CLOSELY THEY LIVE TO THE PROPOSED TOMHICKEN SWITCHYARD. IN YOUR OPINION, SHOULD LIVING FAR FROM THE PROPOSED SWITCHYARD WARRANT GIVING THEIR TESTIMONY LESS WEIGHT?

A. No. In my opinion, the public input hearing testimony that was provided should not be given less weight merely because the testifying witness may live far away from the proposed facilities. As PPL customers or members of the community impacted by the facilities proposed in the LON, their testimony is a critical component of determining whether approval of the LON is in the public interest, as the members of the public most impacted by PPL's proposal, even if there is no direct impact to the non-adjacent property that they own.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section I is an introduction. Section II highlights testimony that focuses on the need of the Project – deliverability to an ostensibly speculative customer intending to operate in an industry undergoing rapid growth with an uncertain future. Section III highlights testimony that focuses on more intimate, local impacts to the community such as environmental and property value degradation. Section IV highlights testimony focused on wholesale processes such as transmission rate impact and cost causation. Section V highlights

testimony that suggests consolidating Phase 1 and Phase 2 into one regulatory proceeding for clarity.

II. Witnesses' Concerns About the Need for the Project

Q. WHAT IS THE NEED FOR THE PROJECT AS PERCEIVED BY THE PUBLIC?

A. The public is aware that there is corporate interest in developing data centers in the area and that the Project is designed to improve customer service, improve deliverability to these select large customers. As stated by Witness Todd Eachus, "This is no ordinary development. It serves a technical campus proposed for 15 data centers in Salem Township, a substation, a switchyard and more than 1,300 acres of - in Salem Township owned by [Talen] Energy and Amazon. That scale alone demands the highest level of public scrutiny and accountability by the Public Utility Commission." (Transcript, P. 163) Witness Todd Eachus stated this need plainly. To reinforce this lucid understanding, Witness Ashley Bahrt offered, "It is well known these load requests are solely for private industry and that the initial primary end user of this request is Northpoint Development and their client, Amazon Web Services for the denied development of the hyperscale data center compound in Hazle Township known as Project Hazelnut." (Transcript, P. 266)

Q. HOW IS THE PUBLIC REACTING TO THIS NEED?

A. Witness Doreen Cherenyock added her emotional reaction to this customer service need, "I'm here today because I want my voice heard. I am so saddened by our entire country today. I truly am. I'm tired of feeding greed. I'm tired of being lied to. I am tired of allowing billionaires to do this to our country. Do you know how many data centers are currently operating in the United States of America? 5,003. Do you know how many data centers - hyperscale data centers are in the country of China? 482. That's a whopping difference.

Isn't it? We don't need them."[4] (Transcript, P. 149) This feedback is echoed by many others who provided testimony. Witness Deborah Jordan worried, "Because by putting the structures here, the transmission lines and ultimately whatever - whatever other data center facilities need it, it's not to benefit the people here. It's to benefit the pocketbooks of someone else. So why here?" (Transcript, P. 292)

In consideration of these reactions, it seems that there is an imbalance of benefits and costs accruing to customers nearby the proposed infrastructure compared to the benefits and costs of individual corporate customers interested in developing an operational hub in the same area. Witness Brenda Rizzo chronicled the history of local sacrifice made for the benefit of the public, "When we first moved in, when my father-in-law first bought the property, there was no nuclear power plant. But we realized when it came in that's for all of us. We all use electricity from the power plant; we all enjoy that." (Transcript, P. 140) Witness Brenda Rizzo also discussed the benefits of Interstate 80 and how she is perplexed about this need, "I want to know what this station, the substation that's coming in and all the lines, how is that going to affect us as a community? Each one of us, us little people that don't mind giving some - some things up because we get something out of it." (Transcript, P. 141)

Q. IS THE PUBLIC CONCERNED THAT THE UNDERLYING INTERESTED CUSTOMER(S) ARE SPECULATIVE OR UNKNOWN?

A. Yes. Witness Todd Eachus followed Witness Brenda Rizzo, "A speculative rush, to rush us, to roll us and treat us like we're low-income, low-wealth, nothing. Brenda Rizzo, you're not small, you're large." (Transcript, P. 173) Witness Marguerite Woelfel added, "It's part

[4] Per Cleanview, "There are 1183 operating data centers in the US with a combined capacity of 54,563 MW, and 1658 planned projects that would add 368,465 MW of additional capacity." https://cleanview.co/data-centers/us Per Data Center Map, there are 4,507 data centers. https://www.datacentermap.com/usa/

of what's going to feed North Point and it's part of a larger regional AI buildout issue that has been done in complete secrecy certainly in this area, even respect to who the tenants are. And it turns out it's a secret because there isn't a tenant." (Transcript, P. 96) Witness Marguerite Woelfel also discussed her experiences and her view on the industry more broadly, "I've worked all around the country as an Economist and a City Planner, so I - and I've worked a lot of times in very - at a macro-level in economics. I've worked on the - the [Real Estate Investment Trust] REIT collapse, I've worked on the Savings and Loan collapse. I've worked on [Housing and Urban Development] HUD's problems and more recently did a little bit of work for the subprime crisis. All these crises, as an Economist who tends to work in the workout end have been the result of excess on all parties part and exuberance because everybody got excited, and everybody wanted a lot of money, and everybody wanted a lot of projections." (Transcript, P. 94-95)

Q. IS THE PUBLIC CONCERNED ABOUT THE CONSEQUENCE OF CUSTOMER(S) BEING SPECULATIVE AND NOT MATERIALIZING?

A. Yes. Witness Allan Dick asked, "If the project does not proceed as projected, or if the anticipated electrical demand never materializes, who bears that financial risk?" (Transcript, P. 88-89) Witness Ann Vinatieri answered, "If artificial intelligence booms that Marguerite and others have spoken about, if this AI boom experiences a market correction or there's company - tech companies, they shift to a localized power generation or - or whatever other reasons, residential ratepayers are again going to be left paying off multidecade infrastructure debt for obsolete lines." (Transcript, P. 176)

Q. DOES THE PUBLIC ASSERT THAT THERE SHOULD BE MORE CERTAINTY REGARDING THE CUSTOMER PROCEEDING WITH ITS BUSINESS PRIOR TO THE APPROVAL OF THE PROJECT?

A. Yes. Witness Alan Dick noted, "The customer nor the developer currently have the required land use approvals to construct the data center campus. The project was unanimously denied by the Hazel Township Board of Supervisors. The decision was then appealed to the Luzerne County Court of Common Pleas where the - where the denial was upheld. The matter is now on appeal before the Pennsylvania Commonwealth Court." (Transcript, P. 201) Witness Diane Bayait is also following relevant regulatory proceedings and noted, "It's my understanding that the main reason for this power line and expansion is Project Hazelnut. Currently this project is currently in the Land Use Conflict appeal with the Commonwealth Court and has been denied at the local and county level. Since this is the case, it's my opinion that it is premature and inappropriate at this time for the application to be approved, as they cannot move forward toward building the facility. If this is confirmed to be permanent, there will be no need for this expansion by [PPL]." (Transcript, P. 261) This suggestion seems very pragmatic given the local adverse impacts discussed in the next section.

Q. IS THE OCA OPPOSED TO APPROVAL OF THE LON MERELY BECAUSE THE INTERCONNECTING CUSTOMER IS A DATA CENTER?

A. No. I understand that the position of the OCA is not one of opposition to data centers and that the OCA supports common sense rules of the road for interconnecting new large load customers, like data centers, such as stranded cost protections and consideration of resource adequacy. My restatement of the public input hearing testimony opposition to data centers, generally, is not an endorsement of the position, but an opportunity to highlight the very real and deeply felt concerns of this community. OCA Witness Dr. Frank Felder discusses

the OCA's recommendations regarding how the Commission should ensure that the impact of data center proliferation is mitigated. This impact is akin to some of the harm that the public input hearing witnesses are concerned about, such as the concern that data centers only be permitted to interconnect when there are cost assurances in place for speculative future interconnections.

III. Local Impacts of the Project

Q. DID PUBLIC INPUT HEARING WITNESSES DISCUSS LOCAL IMPACTS RESULTING FROM PHASE 2 OF THE PROJECT AS WELL AS THE END USE OF THE CUSTOMER INTERCONNECTING TO THE PROPOSED FACILITIES?

A. Yes; however, in this section of my testimony, I will not be discussing such statements. I will attempt to parse out the salient public input hearing testimony regarding the environmental, health, and other concerns and nuisances associated with the Project.

Q. IS THE PUBLIC CONCERNED ABOUT THE ENVIRONMENTAL IMPACT OF THE PROJECT?

A. Yes.

Q. PLEASE DISCUSS THESE ENVIRONMENTAL CONCERNS RAISED BY THE PUBLIC.

A. Public input reflects a growing concern regarding the impact that the construction and maintenance of the Project will have on the local area. Many individuals testified that they are concerned about the devastation of the environment associated with the Project, especially if the customer that will be interconnecting to the switchyard does not end up materializing. Across witnesses, there is a strong desire to ensure that the impact to the environment is minimized and only done if completely necessary. Witnesses specifically raised the following concerns:

- **Wetlands:** "[The Project site] is immediate proximity to nearly two dozen exceptional values wetlands as well and a series of large mine pools…And all of

this [development] can - would lead us to conclude that this land will pose serious challenges to heavy industrialization and utility duct bank installation. Not only that, but it poses serious interruption and degradation of watershed lifecycles. All kinds of animals and plants that rely on that unique series of water. Therefore, further life cycles will all be severely impacted." (Transcript, P. 181-82)

- **Endangered Species:** "[I]t has been identified by the U.S. Fish and Wildlife Service of the Department of the Interior that this project is within the range of three federally protected species of endangered bats." (Transcript, P. 267)
- **Wildlife:** "Then the EMFs…electromagnetic field, it goes 250 feet…completely around each of these towers that these EMFs are projected off and they cause a variety of issues, cancers and nervous system issues and that kind of thing. That's what they do to humans. I'm not sure what effect they might have on wildlife who also live around there and whose hearing is usually more acute than ours." (Transcript, P. 267)

Witness Allan Dick requested that "The Commission ensure that any commitments relied upon in approving this application are not merely statements of intent, but the legally enforceable obligations that remain in place regardless of future ownership or financial circumstances." (Transcript P. 89-90) Witness Angela Bahrt requested "The Commission require PPL to conduct proper environmental studies by an environmental consultant chosen by the Commission with input and approval from the petitioners to this case to ensure risks to nearby wetlands and protected species are mitigated." (Transcript, P. 268)

Q. IS THE PUBLIC CONCERNED ABOUT THE HEALTH IMPACT OF THE PROJECT?

A. Yes.

Q. PLEASE DISCUSS THE HEALTH CONCERNS RAISED BY THE PUBLIC.

A. A number of public input hearing witnesses discussed health concerns related to the electromagnetic fields (EMFs) associated with high voltage transmission lines. Witnesses raised concerns that the EMFs could cause cancers and nervous system issues, among other health concerns. Witness Jeffrey Fasnacht, who resides on a property immediately proximate to the proposed Tomhicken switchyard lot, testified that "In the area of health, I think there's been enough substantiated questions that the close proximity to a power line of this nature does present health questions for people living nearby, certainly in the proximity that I would be. I'm talking about rumors. I'm not thinking my fingernails are going to glow at night or my dog's going to grow an extra leg, which would be good because he only has three. But the documented things were concerns concerning the fact of cancer and other things that people have suffered near these lines, and especially as close of proximity as I live." (Transcript, P. 348-49)

Other public input witnesses identified additional concerns:

- **The Danger of Pesticides:** "Then I also see in other areas where these big towers are and they're spraying pesticides around them, I'm sure to maintain them. I understand why they're doing it, but these pesticides are also very dangerous. They cause cancers. There's been things in the news about all of these pesticides for years. So now they're going to spray these around all these lines - or all these towers. And where is all this runoff going? Into our ground, into our water tables, into our wells. We're drinking that water." (Transcript P. 336)
- **Causation of Leukemia:** "There are also valid health concerns related to living within such close proximity to electrical facilities of this scale. For nearly five decades there has been concern and studies conducted around EMFs from electrical

facilities being linked to exponentially increased rates of childhood leukemia. It is found that proximity to such infrastructure may as much as double" (Transcript, P. 270)

- **Helicopter Maintenance:** State Representative Jamie Walsh testified that use of helicopters to maintain transmission facilities is "extremely dangerous. In fact, I believe it was just last year a helicopter crashed in Pennsylvania." (Transcript, P. 381)

Q. IS THE PUBLIC CONCERNED ABOUT THE PROPERTY VALUE IMPACT OF THE PROJECT?

A. Yes.

Q. PLEASE DISCUSS THE PROPERTY VALUE CONCERNS RAISED BY THE PUBLIC.

A. Public input hearing witnesses expressed concern that living or owning property in close proximity to a high voltage substation would decrease the value of the owner's property and decrease the pool of potential buyers for that property. For example, Witness Anita Reber, a real estate agent of 40 years, testified that "You can't measure the negative impact" of proximity to a high voltage transmission line. (Transcript, P. 195) She further testified that "I'm really surprised that not more of my fellow realtors are here. I'm shocked. I'm it and I don't understand why because this is our livelihood. Who are we going to sell to? Who's going to want to live near this Armageddon that's coming our way?" (Transcript, P. 195)

Witness Jeffrey Fasnacht, as the witness owning the property most immediately impacted by the proposed switchyard, testified that "It doesn't take a lot of knowledge to understand that my property is going to take a major hit with this electrical substation that close." (Transcript, P. 350)

Q. IS THE PUBLIC CONCERNED ABOUT THE NOISE ASSOCIATED WITH THE PROJECT FACILITIES?

A. Yes.

Q. PLEASE DISCUSS THE NOISE CONCERNS RAISED BY THE PUBLIC.

A. Public input hearing witnesses voiced concerns that the proposed switchyard will create a disruptive level of noise. As Witness Jeffrey Fasnacht testified, "I am concerned about the noise and the general disruption of what had been a pristine forest." (Transcript, P. 352) State Representative Jamie Walsh specifically identified the nuisance concerns associated with helicopter maintenance: "Maintenance on the line is done by helicopter primarily, compounding the problems I've already mentioned. And they're not small ones. The ability to fly over people's homes not only raises serious privacy concerns, but also makes the parts of residents' homes that they still have subject to the unannounced and overwhelming noise and wind disruptions." (Transcript, P. 375)

Witness Diane Bayait raised concerns about the switchyard's impact, even for landowners who do not live adjacent to the proposed switchyard: "I understand that the noise from the substation is going to be quite loud and will be heard quite a distance into Eagle Rock." (Transcript, P. 260)

IV. Issues with Cost Causation and Cost Allocation of the Project

Q. IS THE PUBLIC GENERALLY CONCERNED ABOUT COST ALLOCATION OF THE PROJECT?

A. Yes. Witness Marguerite Woelfel noted, "I mean, there's tons of numbers out there. Sixty-four (64) percent is what the current ratepayers - payers are projected to be paying for all the power that they're trying to bring on with these new lines. That's an awful lot for something we don't benefit for at all." (Transcript, P. 97) Witness Ashley Bahrt expanded on this, "The Applicant states transmission rates would ultimately be reduced without mention of impact on distribution rates. Yet it is stated that 64 percent of the cost of this project would fall on ratepayers. This is important, so I would like to review some financial metrics. Regarding my personal electric rates between September of 2022 and June of 2026, for roughly the same kilowatt per hour metrics, my comprehensive bill rate has increased by 38.8 percent. For the same period of time PPL profits are as follows. 2022, $739 million. 2023, $740 million. 2024, $886 million. 2025, $1.181 billion. I want to reiterate that this is net profit, not revenue. Revenue numbers were $7.9 billion for 2022, $8.31 billion for 2023, $8.46 billion for 2024 and $9.04 billion for 2025. This means PPL revenue increased by 14.43 percent over these four years. With their profits grew by 59.81 percent. It is not unreasonable but fair to conclude from this information that PPL has been able to drastically slash expenses without passing any of these savings on to customers but has continued to increase customer rates in the same period of time. It is clear residential PPL ratepayers have already been paying for these projects for years before it would ever become known. The Application states the project's cost is $59.9 million, which is 5.1 percent of PPL's net profit for 2025. Why would 64 percent of the cost fall in ratepayers under these metrics, not only will hard working Americans pay for this through increased

utility costs, but also through loss of health, loss of land value, loss of safety, loss of aesthetics, loss of continuity of quality of life, all of which are constitutionally protected and provided to us as residents of the Commonwealth of Pennsylvania." (Transcript, P. 272-274)

Q. DO PUBLIC OFFICIALS SHARE THIS CONCERN?

A. Yes. State Representative Jamie Walsh noted, "Some numbers suggest that ratepayers, all the people behind me, are said to pay 64 percent of the cost of this project, while PPL's customer that doesn't exist right now will be hit with a - with 36 percent." (Transcript, P. 373-374)

Q. PLEASE SHARE THE EXTENSION THAT STATE REPRESENTATIVE JAMIE WALSH MADE TO THE RATEPAYER PROTECTION PLEDGE.

A. State Representative Jamie Walsh shared, "Under this best-case scenario, if one could call it that, PPL is failing to adhere to the federal ratepayer protection pledge proclamation signed by the President on March 4th. I'm going to read only two key tenets of that order, and I want all listening to consider whether PPL is fulfilling their obligations per the White House's ratepayer protection pledge. Number one, companies will pay for all new power delivery infrastructure upgrades required to service their data centers, including adequate network upgrade costs to ensure that these expenses are not passed on to ordinary households." (Transcript, P. 374)

Q. PLEASE DISCUSS THE "COST CAUSATION" PRINCIPLE.

A. It is a framework that aligns the allocation of costs associated with infrastructure to those that drive the need for this infrastructure. In its commentary entitled *Demystifying transmission cost allocation* the Niskanen Center stated, "Like general cost allocation, transmission cost allocation may rely on imperfect evidence, and different stakeholders

may have imperfectly aligned interests or goals. However, the core competency of 'art, science, and politics' means that state PUCs and their stakeholders are adept at navigating these waters. This competency is a powerful asset for cooperative analysis and negotiation among states and regions working together on cost allocation. With effort, openness, and trust among participants, states can overcome the difficulties, working together to identify portfolios of common transmission infrastructure along with mutually agreeable cost allocation plans."[5]

Q. PLEASE RESTATE THE VIEW OF THE PUBLIC REGARDING NEED AND COST CAUSATION.

A. The public that testified overwhelmingly believes that there is a specific subset of potentially speculative customer(s) driving the need for this project and are now participants to this difficulty. As stated by Witness Cassandra Book, "If this is not a public reliability issue, it can only be for a single customer." (Transcript, P.343) To extend the above commentary from the Niskanen Center, as we navigate these complex waters it is important that the voices of these stakeholders be heard and strongly considered.

Q. PLEASE RESTATE THE QUESTION RAISED TO THE COMMISSION BY WITNESS ALLAN DICK.

A. Witness Allan Dick asked, "The Commission to clearly explain who is paying for the initial transmission infrastructure proposed in this application. Before considering future expansion, the public deserves to understand how the costs of the facilities being requested today will be allocated between the proposed customer, PPL and existing ratepayers. If the project does not proceed as projected, or if the anticipated electrical demand never materializes, who bears that financial risk?" (Transcript, P. 88-89)

[5] https://www.niskanencenter.org/demystifying-transmission-cost-allocation/

Q. IS IT YOUR UNDERSTANDING THAT THE COMMISSION IS RESPONSIBLE FOR ALLOCATING THE COSTS OF TRANSMISSION RATE BASE?

A. No. I am advised by counsel that there is a complex jurisdictional relationship between what the Commission regulates regarding cost and cost causation for transmission facilities built in Pennsylvania and how those costs are reflected in customers' rates. However, I am also advised by counsel that cost considerations are part of the Commission's need determination in transmission line siting cases. Each of the witnesses who testified at the public input hearings pay PPL transmission rates, either as a PPL customer or as a UGI Utilities, Inc. – Electric Division customer, a utility that is within PPL's transmission footprint and which bears a portion of the costs of PPL's transmission grid.

V. Phase 1 and Phase 2 Consolidation for Clarity

Q. IS THE PUBLIC CONCERNED ABOUT PHASE 2 OF THE PROJECT?

A. Yes; however, I understand that the Administrative Law Judges for the Project and Phase 2 of the Project proceedings denied the OCA's request to consolidate the two cases. The purpose of this section of my testimony is not to reiterate or summarize the portions of the public input hearing which raised concerns about Phase 2 of the Project.

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I explore the public's interest in having the Administrative Law Judges and Commission consider the Project in light of Phase 2 and the interrelation between the two phases. OCA Witness Rao Konidena's testimony includes a substantial discussion as to the link between the two phases from an engineering perspective, which independently supports the public input hearing testimony on this issue.[6]

[6] OCA St. 2 at P. 65-97.

Q. PLEASE DISCUSS THE CONCERNS RAISED BY THE PUBLIC ABOUT THE CONSIDERATION OF PHASE 2 OF THE PROJECT WHEN DECIDING TO APPROVE OR DISAPPROVE THE LON.

A. Witness Marguerite Woelfel testified, "I would say these are not Phase 1 and Phase 2, this is one project because with one you can't have the other." (Transcript P. 93) Witness Joel Butala stated that "Now we're just talking about one side of [the Sugarloaf transmission line] as if the other side's not going to come. You have to connect two points, and everything matters in the middle. But we're talking about the far end." (Transcript P. 248-249) This sentiment dominated the public input hearing testimony, with a significant number of witnesses raising similar concerns. Taken together, these witnesses testified that PPL is:

- **Attempting to Take Advantage of the Commission:** "Phase 1, Phase 2, Phase 3, Phase 4, Salem, all these Township projects. Look, you can break this project of any way you have…This is a trick they're running. They can separate this, break this into segments that they know they can manipulate within your Public Utility process and then we don't get to talk about the whole process." (Transcript, P. 168)
- **Unfairly Breaking Up the Process to Make it More Difficult to Understand:** "[T]he idea of saying Phase One, Phase Two and then describing things with numbers but not clarifying what yous are actually talking about. That's very unfair to the young and to the older people and to the people that don't have TV for cable or get the newspaper… If the people were fully aware of what's going on, like Phase One, whatever the heck Phase One is, I have no idea. Or Phase Two, I have no idea what that is, because you're using terms that people are not understanding and they are not being aware of all the meetings." (Transcript, P. 299-300)

As summarized by Witness Mark Clark, "I see many people are advising you that you cannot consider Phase One until you consider the impact of Phase Two." (Transcript, P. 329)

Q. IS THE PUBLIC CONCERNED ABOUT THE INFORMATION PPL HAS PROVIDED ABOUT THE PROJECT?

A. Yes.

Q. PLEASE DISCUSS THE CONCERNS RAISED BY THE PUBLIC ABOUT PPL'S TRANSPARENCY REGARDING THE PROJECT.

A. The public input hearing witnesses were generally dissatisfied with the amount of information provided by PPL regarding the Project. The witnesses described PPL as not being transparent and not being forthcoming. State Representative Jamie Walsh testified that "Between myself, my staff, other representatives. It's probably 10 to 12 times over the last year, you know, here and there, sometimes multiple, multiple requests for the same meeting," and has had difficulty obtaining information from PPL on behalf of his impacted constituents. (Transcript, P. 383-384)

Several witnesses discussed PPL's science fair-style public information event at the Valley Country Club in the spring of 2025 and found that PPL did not provide satisfactory answers to questions raised by community members at the event. Regarding this event:

- State Representative Walsh testified that PPL "Wanted everybody to go through these stations and divide and conquer and basically water down the information to the community. And I don't think that was in good faith and transparent." (Transcript, P. 386)
- Witness Marguerite Woelfel testified, "I went to the PP&L hearing they had last spring, spring of 2025 at the Valley Country Club and there are PP&L stands all around with nice colored boards and stuff and a representative at each one. You'd

ask them questions; you couldn't get an answer on anything. Where it was going, who it was going to serve." (Transcript, P. 97)

- Witness Ann Vinatieri stated that "at the little country club affair [PPL] tried to give different answers to different people at different tables." (Transcript, P. 177)

Q. IN LIGHT OF THIS TESTIMONY, WHICH IS AN INTERPRETATION OF TESTIMONY OFFERED BY THE PUBLIC, WHAT ARE SOME IMPORTANT NEXT STEPS?

A. Given the financial and environmental stakes convincingly declared by public input hearing witnesses during these hearings, it is incumbent upon those that are involved in this Project to be judicious and transparent as this Project and associated projects continue to proceed in regulatory environments. As stated by Witness Marguerite Woelfel, "Sugarloaf Logistics has been trying to get permission for the subdivision and land - subdivision and land development ordinance for four years. It's a warehouse proposal. Five (5) million square - 4 million square feet up near where going to where they live on top of the mountain off of Tomhicken Road. It's still not really called the data center, it's a warehouse." (Transcript, P. 100) To proceed with this Project and ensure that other ratepayers do not pay for a warehouse abandoned from the jump, the public input hearing witnesses have made many reasonable requests which are raised in this testimony.

Given the stakes, it would be prudent to demonstrate that this customer is serious and that the locality is a willing host to the customer. Additionally, certainty that Phase 2 will also proceed, as it is key to the reliable utilization of the Project per the testimony of OCA Witness Rao Konidena, is also important. If these two steps are accomplished, the costs associated with this Project should be allocated by applying the "cost causation" principle, which public input hearing witnesses argue is a cost caused by a select group of customers that are not just erecting a warehouse, they are entering into a community with a splash.

Witness Stephanie Paden poignantly remarked, “I spent the first 30 years of my life here in this community. I’m now in Moscow for work, but I will return here. And this is my home. And it is my home - the home of my family for more than 200 years stewarding farms in the Sugarloaf Valley. And so, I speak tonight for that heritage, for so many of us who call this, this place home.” (Transcript, P. 368)

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CURRICULUM VITAE OF ZACH TETI

PROFESSIONAL EXPERIENCE

Pennsylvania Office of Consumer Advocate • Harrisburg, PA • April 2025-Present • Senior Regulatory Analyst
Customized Energy Solutions • Philadelphia, PA • April 2024-September 2024 (Contract) • Compliance Analyst
Avangrid • Orange, CT • May 2021-April 2024 • Regulatory Analyst – FERC, ISO New England & New York ISO
Penn State University • University Park, PA • August 2019-May 2021 • Research Assistant – Energy Economics
TD Bank • Mount Laurel, NJ • February 2018-July 2019 • Assistant Vice President – Retail Lending Financial Analysis
JP Morgan Chase • Newark, DE • July 2013-February 2018
Budgeting, Forecasting and Analysis - Associate – Consumer Banking Technology • July 2017-February 2018
Financial Control – Associate & Analyst – International Trade Finance • July 2013-July 2017
Lancaster County Workforce Investment Board • Lancaster, PA • December 2012-May 2013 • Research Intern

EDUCATION & OTHER UNDERTAKINGS

Penn State University • University Park, PA • May 2021 • MS in Energy Economics
Millersville University • Millersville, PA • May 2013 • BA in Quantitative Economics, minor in Statistics
Curator for the Global Shapers Philadelphia Hub – World Economic Forum Initiative • September 2017-May 2021

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania	:	Docket No. A-2025-3059443

VERIFICATION

I, Zachary F. Teti, hereby state that the facts above set forth in my Supplemental Direct Testimony, OCA Statement No. 3, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. Section 4904 (relating to unsworn falsification to authorities).

DATED: July 15, 2026

Signature: */s/ Zachary F. Teti*
Zachary F. Teti

Address: Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA. Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania.
Docket No. A-2025-3059443
OCA Response to Requests for Admissions of PPL Electric Utilities Corporation Set I to OCA

OCA is requested to admit or deny the truth of the following:

2. Admit neither OCA Statement 1 nor OCA Statement 2 disputes that there is a need for the Project.

Response: Dr. Felder admits that OCA Statement 1 "does not contest the need for the Tomhicken Switchyard to serve this customer".

Response: Mr. Konidena admits that OCA Statement 2 "does not contest the need for the Tomhicken Switchyard to serve this customer"[3] assuming that the customer identified in the letter of notification ultimately connects to the Project facilities[4].

Responding Witness: Frank A. Felder
Rao Konidena
Response Date: August 5, 2026

[3] OCA Statement 2 Page 45, Line 6-7.
[4] OCA Statement 2 Page 62, Lines 6-9.

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Docket No. A-2025-3059443
OCA Response to Requests for Admissions of PPL Electric Utilities Corporation Set I to OCA

OCA is requested to admit or deny the truth of the following:

3. Admit there is a need for the Project.

Response: Please see Dr. Felder's earlier response to PPL RFA to OCA, Set I-2.

Response: Please see Mr. Konidena's earlier response to PPL RFA to OCA, Set I-2.

Responding Witness: Frank A. Felder
Rao Konidena
Response Date: August 5, 2026

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA. Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania.
Docket No. A-2025-3059443
OCA Response to Requests for Admissions of PPL Electric Utilities Corporation Set I to OCA

OCA is requested to admit or deny the truth of the following:

5. Admit the Project will not create an unreasonable risk of danger to the health and safety of the public.

Response: Dr. Felder denies the statement. Specifically, if the Project proceeds and enables additional load to be added to the PJM system without sufficient supply and reserves, then there is an increased risk that loads may have to be curtailed due to supply shortages. Depending on which loads are curtailed, the curtailment may create an unreasonable risk of danger to the health and safety of the public.

Response: Mr. Konidena neither admits nor denies because OCA Statement 2 does not opine on whether "the Project will not create an unreasonable risk of danger to the health and safety of the public".

Responding Witness: Frank A. Felder
Rao Konidena
Response Date: August 5, 2026

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA. Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania.
Docket No. A-2025-3059443
OCA Response to Requests for Admissions of PPL Electric Utilities Corporation Set I to OCA

OCA is requested to admit or deny the truth of the following:

7. Admit the Project is in compliance with applicable statutes and regulations providing for the protection of the natural resources of this Commonwealth.

Response: Dr. Felder neither admits nor denies because OCA Statement 1 does not opine on whether "the Project is in compliance with applicable statutes and regulations providing for the protection of the natural resources of this Commonwealth".

Response: Mr. Konidena neither admits nor denies because OCA Statement 2 does not opine on whether "the Project is in compliance with applicable statutes and regulations providing for the protection of the natural resources of this Commonwealth".

Responding Witness: Frank A. Felder
Rao Konidena
Response Date: August 5, 2026

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA. Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania.
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OCA Response to Requests for Admissions of PPL Electric Utilities Corporation Set I to OCA

OCA is requested to admit or deny the truth of the following:

9. Admit the Project will have minimum adverse environmental impact, considering the electric power needs of the public, the state of available technology and the available alternatives.

Response: Dr. Felder neither admits nor denies because OCA Statement 1 does not opine on whether "the Project will have minimum adverse environmental impact".

Response: Mr. Konidena neither admits nor denies because OCA Statement 2 does not opine on whether "the Project will have minimum adverse environmental impact".

Responding Witness: Frank A. Felder
Rao Konidena
Response Date: August 5, 2026

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA. Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania.
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PPL to OCA-I-53

53. Please define each of the following terms based upon Mr. Konidena's understanding of the same.

    a. Siting;
    b. Location;
    c. Construction;
    d. Operation;
    e. Maintenance;
    f. Guideline(s);
    g. Policy(ies);
    h. Statute(s); and
    i. Regulation(s).

Response:

a. Siting for a proposed HV transmission line is defined as the specific location where the line starts and ends and the intermediate points in between.
b. Location for a proposed HV transmission line is defined as the specific county and parcel of land where the substation(s) reside for the starting, intermediate and ending line terminations.
c. Construction for a proposed HV transmission line is defined as the construction of all transmission facilities that are needed for the project including substations, transmission conductors, transformers, and line protection equipment.
d. Once a proposed HV transmission line is constructed, it is operated in accordance with all applicable Regional Transmission Organization operational requirements. So, the definition of Operation depends on the RTO definition.
e. A HV transmission line under the functional authority of a RTO should communicate in advance to the RTO Operations if maintenance is performed. So, the definition of Maintenance depends on the RTO definition for planned and unplanned maintenance.
f. A simple way to define a Guideline is, it is "nice to have" but not "must have".
g. A Policy is a "must have", it lays out that this is how it should be done. A Policy can apply to an entire Company or a State.
h. A Statute is also a "must have" but it has the legislative mandate behind it. Hence, a Statute applies mostly to a State/Federal authority.
i. A Regulation implements the State/Federal Statute.

Responding Witness: Rao Konidena
Response Date: August 5, 2026

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PPL to OCA-I-45

45. Please reference OCA Statement 2, page 5, line 10, where Mr. Konidena recommends "The Commission should not approve the $38.4 million ratepayer allocation as proposed."

    a. Identify with specificity any place in the subject letter of notification, supporting attachments, or the direct testimony of a PPL Electric witness where PPL Electric proposed a $38.4 million ratepayer allocation for Commission approval.

    b. Identify with specificity any place in the subject letter of notification, supporting attachments, or the direct testimony of a PPL Electric witness where PPL Electric sought Commission approval of the costs of the proposed HV transmission lines costs associated with the letter of notification.

    c. Identify with specificity any place in the subject letter of notification, supporting attachments, or the direct testimony of a PPL Electric witness where PPL Electric sought a finding or determination by the Commission that the proposed HV transmission lines costs associated with the letter of notification are reasonable and prudent.

    d. Identify with specificity any place in the subject letter of notification, supporting attachments, or the direct testimony of a PPL Electric witness where PPL Electric sought a finding or determination by the Commission that the allocation of the HV transmission lines costs associated with the letter of notification was reasonable.

    e. Identify with specificity which of the findings and determinations required by 52 Pa. Code 57.76(a) that Mr. Konidena believes requires the Commission to approve the costs of a proposed HV transmission line.

    f. Identify with specificity which of the findings and determinations required by 52 Pa. Code 57.76(a) that Mr. Konidena believes requires the Commission to determine the costs of a proposed HV transmission line are reasonable and/or prudent

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g. Identify with specificity which of the findings and determinations required by 52 Pa. Code 57.76(a) that Mr. Konidena believes requires the Commission to approve the allocation of the costs of a proposed HV transmission line.

h. Identify with specificity which of the findings and determinations required by 52 Pa. Code 57.76(a) that Mr. Konidena believes requires the Commission to determine the allocation of the costs of a proposed HV transmission line are reasonable.

Response:

a. In the letter of notification, PPL states that "[b]ased on a review of the proposed system improvements derived from this Project, it was determined that PPL Electric is responsible for approximately $38.4 Million (~64% of the total Project costs) and the Customer is responsible for approximately $21.8 Million (~36% of the total Project costs)."[1] In PPL Statement No. 1, Mr. Lookup stated that "The total estimated cost of the proposed Project is $59.9 million. The Customer is responsible for approximately $21.5 million, and PPL Electric is responsible for approximately $38.4 million."[2]
b. It is Mr. Konidena's understanding that PPL Electric is seeking "Commission approval of the costs of the proposed HV transmission lines costs associated with the letter of notification" implicitly because the Commission cannot separate the costs from the need of the proposed HV transmission line.
c. Even though PPL Electric is not seeking explicitly the Commission's approval of proposed HV transmission lines costs as reasonable and prudent, it is implicitly seeking the Commission's approval that those costs are reasonable and prudent because the costs are directly linked to the proposed system improvements as the Company prefaced the cost allocation in its letter of notification with "[b]ased on a review of the proposed system improvements derived from this Project"[3].
d. Please see Mr. Konidena's response to c.
e. With regards to 52 Pa. Code 57.76(a)(1), Mr. Konidena believes costs of a proposed HV transmission line and the need of a proposed HV transmission line are intricately tied together because the Commission cannot separate the costs from the need of the proposed HV transmission line as evidenced by Company's proposed system improvements preface to the cost allocation in the letter of notification. With regards to 52 Pa. Code 57.76(a)(2), Mr. Konidena cannot offer an opinion because OCA Statement No.2 does not opine on whether "the Project will not create an unreasonable risk of danger to the health and safety of the public". With regards to 52 Pa. Code 57.76(a)(3), Mr. Konidena cannot offer an opinion because OCA Statement No.2 does not opine on whether "the Project is in

[1] Page 11, LON.
[2] PPL Statement No.1, Lines 12-14, Page 7.
[3] Page 11, LON.

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compliance with applicable statutes and regulations providing for the protection of the natural resources of this Commonwealth". With regards to 52 Pa. Code 57.76(a)(4), Mr. Konidena cannot offer an opinion because OCA Statement No.2 does not opine on whether "the Project will have minimum adverse environmental impact".

f. Please see Mr. Konidena's response to c.
g. Please see Mr. Konidena's response to e.
h. Please see Mr. Konidena's response to e.

Responding Witness: Rao Konidena
Response Date: August 5, 2026

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA. Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania.
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Supplemental OCA Response to Requests for Admissions and Interrogatories of PPL Electric Utilities Corporation
Set I to OCA

PPL to OCA-I-46

46. Please reference OCA Statement 2, page 5, line 10, where Mr. Konidena recommends "The Commission should not approve the $38.4 million ratepayer allocation as proposed."
    a. Does Mr. Konidena render any opinion regarding the siting and construction of the HV transmission line facilities contemplated by the subject letter of notification?
    b. Does Mr. Konidena render any opinion regarding whether PPL Electric has shown that "there is a need" for the proposed HV transmission line facilities contemplated by the subject letter of notification under 52 Pa. Code 57.76(a)(1)?
    c. Does Mr. Konidena render any opinion regarding whether PPL Electric has shown that the proposed HV transmission line facilities contemplated by the subject letter of notification "will not create an unreasonable risk of danger to the health and safety of the public" under 52 Pa. Code 57.76(a)(2)?
    d. Does Mr. Konidena render any opinion regarding whether PPL Electric has shown that the proposed HV transmission line facilities contemplated by the subject letter of notification are "in compliance with applicable statutes and regulations providing for the protection of the natural resources of this Commonwealth" under 52 Pa. Code 57.76(a)(3)?
    e. Does Mr. Konidena render any opinion regarding whether PPL Electric has shown that the proposed HV transmission line facilities contemplated by the subject letter of notification are "will have minimum adverse environmental impact, considering the electric power needs of the public, the state of available technology and the available alternatives" under 52 Pa. Code 57.76(a)(4)?

Response:

a. No, Mr. Konidena does not render any opinion regarding the siting and construction of the HV transmission line facilities contemplated by the subject letter of notification because this is outside the scope of Mr. Konidena's expertise.
b. Mr. Konidena reiterates that his "testimony does not contest the need for the Tomhicken Switchyard to serve this customer"[8] assuming that the customer identified in the letter of notification ultimately connects to the Project facilities[9].
c. No, this is outside the scope of Mr. Konidena's expertise.
d. No, this is outside the scope of Mr. Konidena's expertise.

[8] OCA Statement No.2 Page 45, Line 6-7.
[9] OCA Statement No.2 Page 62, Lines 6-9.

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e. No, this is outside the scope of Mr. Konidena's expertise.

Supplemental Response:

b. Mr. Konidena clarifies that his initial response is limited to acknowledging that OCA Statement 2 does not contest the need for additional transmission facilities to be built by PPL to serve the identified customer. However, Mr. Konidena denies that his testimony does not dispute the need for the Project insofar as the Commission's determination of need encompasses consideration of the potential positive and negative impacts of the Project on Pennsylvania's citizens and consumers.
c. Mr. Konidena clarifies that his original response that a determination of whether the Project will create an unreasonable risk of danger to the health and safety of the public "is outside the scope of Mr. Konidena's expertise" was limited to PPL's claimed compliance with applicable Electrical Safety Code standards and other related legal requirements. Mr. Konidena does, however, offer an opinion regarding whether the Project, as proposed, could create an unreasonable risk of danger to the health and safety of the public based on the Project's anticipated operating conditions. Specifically, if the Project proceeds as proposed and the identified customer adds its projected load to the system, the resulting conditions may lead to thermal overloads and voltage violations. Accordingly, Mr. Konidena denies that the Project will not create an unreasonable risk of danger to the health and safety of the public.

Responding Witness: Rao Konidena
Response Date: September 16, 2026

Letter of Notification of PPL Electric Utilities Corporation filed pursuant to 52 PA. Code Chapter 57 with respect to the approval to build approximately 1.1 miles of new parallel double circuit 230 kV transmission taps that are needed to connect the existing Susquehanna-Harwood #1 & #2 transmission lines on the New Tomhicken 230 kV switchyard that are respectively located in Luzerne County, Pennsylvania.
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Rao Konidena is requested to admit or deny the truth of the following:

21. Admit Mr. Konidena does not recommend that the Commission deny the Project based upon any of the criteria set forth in 52 Pa. Code 57.76(a).

Response: With regards to 52 Pa. Code 57.76(a)(1), Mr. Konidena admits that OCA Statement 2 "does not contest the need for the Tomhicken Switchyard to serve this customer"[5] assuming that the customer identified in the letter of notification ultimately connects to the Project facilities[6]. With regards to 52 Pa. Code 57.76(a)(2) through 52 Pa. Code 57.76(a)(4), Mr. Konidena admits that OCA Statement 2 does not specifically recommend that the Commission deny the Project because "the Project will not create an unreasonable risk of danger to the health and safety of the public"; "the Project is in compliance with applicable statutes and regulations providing for the protection of the natural resources of this Commonwealth"; "the Project will have minimum adverse environmental impact".

Responding Witness: Rao Konidena
Response Date: August 5, 2026

[5] OCA Statement 2 Page 45, Line 6-7.
[6] OCA Statement 2 Page 62, Lines 6-9.

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Rao Konidena is requested to admit or deny the truth of the following:

22. Admit Mr. Konidena does not recommend that the Commission deny the Project because there is not a need for it.

Response: Mr. Konidena admits that OCA Statement 2 does not specifically include a recommendation "that the Commission deny the Project because there is not a need for it"[7].

Responding Witness: Rao Konidena
Response Date: August 5, 2026

[7] OCA Statement 2 Page 45, Line 6-7.

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Rao Konidena is requested to admit or deny the truth of the following:

23. Admit Mr. Konidena testified that there is a need for the Project.

Response: Mr. Konidena admits that OCA Statement 2 "does not contest the need for the Tomhicken Switchyard to serve this customer"[8] assuming that the customer identified in the letter of notification ultimately connects to the Project facilities[9].

Responding Witness: Rao Konidena
Response Date: August 5, 2026

[8] OCA Statement 2 Page 45, Line 6-7.
[9] OCA Statement 2 Page 62, Lines 6-9.