COMMONWEALTH OF PENNSYLVANIA

DARRYL A. LAWRENCE
Acting Consumer Advocate

OFFICE OF CONSUMER ADVOCATE
555 Walnut Street, 5th Floor, Forum Place
Harrisburg, Pennsylvania 17101-1923
(717) 783-5048
(800) 684-6560

@pa_oca
/pennoca
FAX (717) 783-7152
consumer@paoca.org
www.oca.pa.gov

March 25, 2025

Via Electronic Mail
Administrative Law Judge John M. Coogan (Via Email: jcoogan@pa.gov)
Office of Administrative Law Judge
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

Re: Petition of PPL Electric Utilities Corporation for Approval of its Second Distributed Energy Resources Management Plan
Docket Nos. P-2024-3049223

Dear Judge Coogan:

Please find enclosed a copy of the Main Brief being submitted on behalf of the Office of Consumer Advocate in this proceeding.

Copies have been served on the parties as indicated on the enclosed Certificate of Service.

Respectively,

/s/Christy Appleby
Christy Appleby
Senior Assistant Consumer Advocate
PA Attorney I.D. # 85824
CAppleby@paoca.org

Enclosures
cc: Secretary Rosemary Chiavetta (Cover Letter and Certificate of Service Only)
Certificate of Service

CERTIFICATE OF SERVICE

Petition of PPL Electric Utilities Corporation for Approval of its Second Distributed Energy Resources Management Plan	:	Docket No. P-2024-3049223

I hereby certify that I have this day filed electronically on the Commission's electronic filing system and served a true copy of the following document, the Office of Consumer Advocate's Main Brief, upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below.

Dated this 25th day of March 2025.

SERVICE BY E-MAIL ONLY

Steven C. Gray, Esquire
Rebecca Lyttle, Esquire
Office of Small Business Advocate
555 Walnut Street
1st Floor, Forum Place
Harrisburg, PA 17101
sgray@pa.gov
relyttle@pa.gov
Counsel for OSBA

Andrew J. Karas, Esquire
Fair Shake Environmental Legal Services
647 E. Market Street
Akron, OH 44302
akaras@fairshake-els.org
Counsel for Natural Resources Defense Council

Adam E. Gersh, Esquire
Flaster Greenberg P.C.
1717 Arch Street, Suite 3300
Philadelphia, PA 19103
adam.gersh@flastergreenberg.com
Counsel for Sunrun, Inc.

Allison Kaster, Esquire
Pennsylvania Public Utility Commission
Bureau of Investigation & Enforcement
400 North Street, 2nd Floor West
Harrisburg, PA 17120
akaster@pa.gov
Counsel for I&E

Beren Argetsinger, Esquire
Keyes & Fox LLP
PO Box 166
Burdett, NY 14818
bargetsinger@keyesfox.com
Counsel for Sunrun, Inc.

Bernice I. Corman, Esquire
BICKY CORMAN LAW PLLC
1250 Connecticut Avenue, NW, Suite 700
Washington, DC 20036
bcorman@bickycormanlaw.com
Counsel for Tesla, Inc., Sun Directed, American Home Contractors, Sunrun, Inc., and Solar Energy Industries Association

<u>SERVICE BY E-MAIL ONLY</u>

Adeolu A. Bakare, Esquire
Rebecca Kimmel, Esquire
McNees Wallace & Nurick LLC
100 Pine Street
P.O. Box 1166
Harrisburg, PA 17108-1166
abakare@mcneeslaw.com
rkimmel@mcneeslaw.com
Counsel for PPLICA

Judith D. Cassel, Esquire
Micah R. Bucy, Esquire
Hawke, McKeon & Sniscak LLP
100 North Tenth Street
Harrisburg, PA 17101
jdcassel@hmslegal.com
mrbucy@hmslegal.com
Counsel for Sustainable Energy Fund

<u>/s/ Christy Appleby</u>
Christy Appleby
Senior Assistant Consumer Advocate
PA Attorney I.D. # 85824
CAppleby@paoca.org

Harrison Breitman
Assistant Consumer Advocate
PA Attorney I.D. # 320580
HBreitman@paoca.org

Counsel for:
Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
717-783-5048

Dated: March 25, 2025

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation	:	
for Approval of its Second Distributed	:	
Energy Resources Management Plan	:	Docket No. P-2024-3049223
	:	

MAIN BRIEF
OF THE
OFFICE OF CONSUMER ADVOCATE

Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
Phone: 717-783-5048
Fax: 717-783-7152

Harrison W. Breitman
Assistant Consumer Advocate
PA Attorney I.D. #320580
HBreitman@paoca.org

Christy Appleby
Senior Assistant Consumer Advocate

Counsel for:
Darryl A. Lawrence
Acting Consumer Advocate

Dated: March 25, 2025

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I. INTRODUCTION

A. Position of the Office of Consumer Advocate

The Office of Consumer Advocate (OCA) is the statutory advocate with the authority and duty to represent consumers as a party before the Pennsylvania Public Utility Commission (Commission), and state and federal courts in public utility rate requests. 71 P.S. § 309-4. After significant discovery and investigation, the OCA submits that PPL Electric Utilities Corporation's (PPL or the Company) Second Distributed Energy Resources (DER) Management Plan (Plan) should be rejected. Alternatively, should the Commission consider approving the plan, then the recommendations contained herein should be included in any such approval.

B. Background and Procedural History

On December 17, 2020, the Commission approved PPL's First DER Management Plan as modified by the terms and conditions of the Joint Petition for Settlement of All Issues (DER Settlement). *Petition for PPL Electric Utilities Corporation for Approval of its First Distributed Energy Resources Management Plan*, Docket No. P-2019-3010128, Order (Dec. 17, 2020) (PPL First DER Petition). The DER Settlement set forth the following: (1) requirements for the use of smart inverters in PPL Electric's service territory effective January 1, 2021; (2) the terms and conditions for PPL Electric's Pilot Program, including the submission of a Pilot Implementation Plan; (3) a provision addressing cost recovery of PPL Electric's DER Management devices; (4) a provision concerning the Company's agreement to participate in any statewide proceeding initiated by the Commission that focuses on smart inverters, DER management devices, IEEE 1547-2018, IEEE 1547.1, and/or UL 1741; (5) several reporting requirements, including annual reports to the Commission and to customers participating in the Pilot Program; (6) the Company's compliance tariff supplement; (7) an exemption for electric vehicles (EVs) from the Pilot Program; and (8) a provision addressing certain data on program performance to be sent to SEF. PPL St. 1 at 12.

On May 20, 2024, PPL filed a Petition through which it seeks approval from the Commission of its Second DER Plan. Petition ¶ 37. The Plan governs the interconnection and operation of DERs deployed in PPL's service territory. PPL originally proposed that the Plan would be effective on March 22, 2025, the day after PPL's First DER Management Plan's pilot program ends. Petition ¶ 129. The original procedural schedule was designed to coincide with the original end date for PPL's First DER Management Plan. The procedural schedule for the instant proceeding was extended, and the Commission approved a petition extending PPL's DER I until thirty days after the Commission's final order is entered in PPL's DER II proceeding. *Petition of PPL Electric for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan*, Docket No. P-2019-3010128, Order (Sept. 12, 2020)

The Petition was assigned to the Office of Administrative Law Judge (OALJ) and was further assigned to ALJ Coogan for investigation and the scheduling of hearings. On June 25, 2024, the ALJ issued a Prehearing Conference Order setting August 6, 2024, as the Prehearing Conference date and establishing the parties' obligations with respect to the Prehearing Conference.

On July 2, 2024, the OCA filed an Answer in response to the Company's Petition. An Answer was also filed by the Joint Solar Parties (JSP), comprised of American Home Contractors, Inc., Enphase Energy, Inc., the Solar Energy Industries Association, SolarEdge Technologies, Inc., Sun Directed, Sunnova, Inc, Tesla, Inc. and Trinity Solar, Inc. The list of JSPs was later amended to remove Sunnova, Inc. The JSPs, the Office of Small Business Advocate (OSBA), PPL Industrial Customer Alliance (PPLICA), and the Sustainable Energy Fund (SEF) intervened in the proceeding.

On August 6, 2024, a Prehearing Conference was held at which time a procedural schedule and discovery rule modifications were established, and Scheduling Order was issued on August 7, 2024.

On September 13, 2024, PPL filed a Motion to Dismiss Objections and to Compel Responses to Interrogatories Propounded on the Joint Solar Parties, Set I, and an Answer was filed by the Joint Solar Parties. The ALJ issued an Order granting the Motion to Compel on September 24, 2024. On September 26, 2024, the Joint Solar Parties filed a Petition for Certification of Petition for Interlocutory Review and Stay of Order. On the following day, the JSPs filed a Petition to withdraw the Petition, and the ALJ issued an Order granting the Petition to Withdraw on October 9, 2024.

On September 24, 2024, the Office of Consumer Advocate submitted the Direct Testimony of Ron Nelson.[1] The OSBA, JSPs, and SEF also filed Direct Testimony.

On September 26, 2024, PPL filed a Motion for Protective Order, and the ALJ issued the Protective Order on September 27, 2024.

On October 21, 2024, the ALJ issued an Order suspending the existing procedural schedule and extended the schedule to provide that Rebuttal Testimony would be due on December 5, 2024 and Surrebuttal Testimony would be due January 22, 2024. Hearings and Oral Rejoinder testimony would be on February 11-13, 2025.

The Company and the JSPs submitted Rebuttal Testimony on December 5, 2024.

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[1] Ron Nelson is a Founding Partner of Current Energy Group, LLC (CEG). CEG specializes in the areas of cost-service modeling, regulatory innovation, performance-based regulation, distributed energy resources, rate design, renewable program development, grid modernization, new grid technologies, integrated resource planning and electric vehicles. Prior to founding CEG, Mr. Nelson worked for a sole proprietorship and was a Senior Director at Strategen Consulting for six years. Before working at Strategen, he worked for the Minnesota Attorney General's Office for five years. Mr. Nelson has a Master of Science from Colorado State University in Agriculture and Resource Economics, and a Bachelor of Arts in Environmental Economics and a minor in Mathematics from Western Washington University. *See*, OCA St. 1 at 1-2, Exh. RN-1.

On January 22, 2024, the OCA submitted the Surrebuttal Testimony of Ron Nelson. PPL, the JSPs, and OSBA also submitted Surrebuttal Testimony. On January 27, 2025, PPL filed a Motion in Limine to Strike Certain of the JSPs' Testimony and Exhibits (both a Confidential and Public version). The JSPs filed an Answer with Exhibits and Motion for Sanctions (both a Confidential and Public version). The JSPs also filed on January 27, 2025, to amend their Surrebuttal Testimony. On January 30, 2025, the ALJ issued an Order Denying PPL's Motion in Limine to Strike Certain of the JSPs' Testimony and Exhibits and Motion for Sanctions.

On January 30, 2025, PPL filed a Motion to Dismiss Objections and Compel Responses to Interrogatories and Requests for Production of Documents Propounded on the JSPs- Set XIX, Nos. 2 through 4 (Second Motion to Compel). On January 31, 2025, PPL filed a letter withdrawing its Second Motion to Compel.

On February 4, 2025, PPL submitted Rejoinder Testimony (both Public and Highly Confidential).

On February 8, 2025, the JSPs filed a Motion for Leave to File Surrejoinder Testimony.

The OCA and the Company mutually waived cross-examination of its witnesses and stipulated to the admission of the OCA's testimony at the evidentiary hearings. The ALJ held evidentiary hearings on February 11 and 12, 2025, at which cross-examination of PPL and JSP witnesses was held. At the hearings, the ALJ granted the JSPs' Motion for Leave to Amend Surrebuttal Testimony and Motion for Leave to File Surrejoinder Testimony. The February 13, 2025, evidentiary hearing was canceled.

On February 13, 2025, ALJ Coogan issued a Briefing Order.

In accordance with the procedural schedule established by the ALJ, the OCA submits this Main Brief.

II. LEGAL STANDARD

The issue in this proceeding is how PPL Electric should meet its continued and ongoing obligations to provide adequate, efficient, safe, reliable and reasonable service under Section 1501 of the Public Utility Code. 66 Pa. C.S. § 1501. PPL avers that its new proposal is necessary to provide safe, adequate and reliable service, but as the OCA discusses below, PPL's proposal moves significantly beyond the provision of safe, adequate and reliable service.

Moreover, the Commission's Regulations at 52 Pa. Code Chapter 75, the Alternative Energy Portfolio Standards (the AEPS), set forth the requirements and standards that Electric Distribution Companies (EDCs) must meet if customer-generators on their system intend to pursue net-metering opportunities and interconnect with the electric distribution grid. *See* 52 Pa. Code § 75.21; *see also* 73 P.S. § 1648.5 (directing the Commission to develop technical and net metering interconnection rules for customer-generators). Furthermore, the AEPS limits EDCs from requiring additional equipment or imposing any other requirement upon DER applicants that is not specifically required by the AEPS. 52 Pa. Code § 75.13(k). As discussed below, PPL has not met the requirements under Chapter 75 as to the need for its proposal.

In seeking a Commission order to implement its proposed pilot program which will potentially cost ratepayers at least $80.1 million by 2030 with projections increasing to potentially *half a billion dollars* as discussed below[2], the Public Utility Code provides in relevant part:

> (a) Burden of proof. Except as may be otherwise provided in section 315 (relating to burden of proof) or other provisions of this of other relevant statute, the proponent of a rule or order has the burden of proof.

66 Pa. C.S. §332(a). As petitioner for a Commission Order in this matter, PPL has the burden of proof.

[2] OCA St. 1 at 2.

In addition to the burden of proof, the petitioner must provide substantial evidence in the record as support for its case before the Commission. The Pennsylvania Supreme Court has also provided that even where a party has established a prima facie case, the litigant must establish that:

> The elements of that cause of action are proven with substantial evidence which enables the party asserting the cause of action to prevail, precluding all reasonable inferences to the contrary.

Burleson v. Pa. PUC, 501 Pa. 433, 436 (1983) (*Burleson*).The party with the burden of proof has a formidable task to show that the Commission may lawfully adopt its position. *Id.* Furthermore, it is well-established that the "degree of proof before administrative tribunals as well as before most civil proceedings is satisfied by establishing a preponderance of the evidence." *Lansberry v. Pa. PUC*, 578 A.2d 600, 602 (Pa. Cmwlth. 1990) (*Lansberry*).

The "term 'burden of proof" is comprised of two distinct burdens, the burden of production and the burden of persuasion." *Hurley v. Hurley*, 754 A.2d 1283, 1285 (Pa. Super. Ct. 2000) (*Hurley*) The burden of production dictates which party has the duty to introduce enough evidence to support a cause of action. *Id.* at 1286. The burden of persuasion determines which party has the duty to convince the finder-of-fact that a fact has been established. *Id.* "The burden of persuasion never leaves the party on whom it is originally cast." *Id.*; *see also Pa. PUC v. Equitable Gas Co.*, 57 Pa. PUC 423, 471 (1983).

The burden of proof does not shift to parties challenging the proposed order but rather must be met by the utility. *Pa. PUC v. Pa.-American Water Co.*, 2004 Pa. PUC LEXIS 29 at *16-18 (Order entered Jan. 29, 2004) (citing *Berner v. Pa. PUC*, 116 A.2d 738, 744 (Pa. 1955)). The Commission recognizes in its rate determinations that the burden of proof will not shift to a complainant or intervener that is challenging the requested order. *Pa. PUC v. Equitable Gas Co.*, 57 Pa. PUC 423, 471 (1983); *see also University of Pa. v. Pa. PUC*, 485 A.2d 1217 (Pa. Cmwlth. 1984); *Pa. PUC v. PPL Elec. Util. Corp.*, Docket No. R-00049255 (Order entered Dec. 22, 2004).

III. SUMMARY OF ARGUMENT

With DER II, PPL proposes an unprecedented program which mandates utility-owned active control of DERs on its system – no matter the size. If approved, PPL's plan would mean that every residential solar installation from the smallest to the largest and every commercial or industrial installation would be treated the same. No such program currently exists anywhere in the United States.

PPL supported its proposal with a cost-benefit analysis which was not filed until PPL's rebuttal testimony. This cost benefit analysis is contrary to the prior settlement, exaggerates the benefits of PPL's strategy, highlights the dramatic cost shift to ratepayers, and demonstrates that the program is uneconomical for 99% of DERs on PPL's system. PPL has failed to satisfy its burden of proof that PPL DER II will result in just and reasonable rates.

As the OCA and other intervening parties demonstrated, there are viable and more cost-effective alternatives to PPL's proposal. However, PPL dismissed every alternative proposed by the intervening parties, refused to provide assessments of benefits or costs of these alternatives, and presented a false narrative of the necessity of active management and the inadequacy of any other option to maintain system safety and reliability.

The OCA opposes PPL's proposal to make utility control of DER mandatory and requiring the installation of a PPL owned DER management device, paid for by ratepayers, on almost all of the DERs connected to PPL's system. The costs of PPL's DER II highlights growing concerns over ballooning costs of DER management, cost-shifting, and the funding of hosting capacity for DERs. When PPL's DER II strategy is expanded to other non-solar DER, such as electric vehicles, the

PPL DER II plan could triple in costs by 2030, and add more than half a billion dollars in management costs by 2039. PPL's proposal to recover the costs of DER II from ratepayers through base rates is unreasonable, fails to assign costs to the cost causers or beneficiaries, and results in a dramatic cost shifting from DER owners to PPL's ratepayers as a whole.

The OCA recommends that the Commission reject PPL's DER II. PPL should be permitted to re-file a DER management plan after it has completed a DER Orchestration plan as further described herein.

IV. ARGUMENT

PPL has the burden of proof and the burden to demonstrate that the proposed program is necessary for the provision of safe and adequate service. For the reasons set forth below, PPL has failed to meet this burden, and the proposed program should be denied.

A. Background

Understanding Distributed Energy Resources (DER) is essential to evaluating PPL's proposed DER II. DERs interact with the distribution system and impact grid operations. DERs are solar photovoltaic ("Solar") systems, battery energy storage, electric vehicles, and many other smart devices, such as thermostats, which allow loads to be controllable. OCA St. 1 at 8. DER is defined as "Small, modular, energy generation and storage technologies that provide electric capacity or energy connected to the distribution system." *Id.* (internal citations omitted).

A DER typically requires an inverter to connect to the distribution system. OCA St. 1 at 9. An inverter converts the direct current (DC) power produced by solar panels and used in batteries and many other electronic devices into the alternating current (AC) power transported on the electric distribution system. OCA St. 1 at 10. Smart inverters go beyond this basic function to provide grid support functions, such as voltage regulation, frequency support[3], and ride-through capabilities.[4] OCA St. 1 at 11.

Smart inverter features have the ability to minimize the DER's potential negative impacts due to voltage and frequency events. As such, smart inverters provide grid support to support reliability and resiliency. A smart inverter's grid supporting functions dictate how the inverter operates and responds to the current conditions on the grid where the DER is connected. OCA St. 1 at 10-11. Settings for these functions can be set by default at installation to allow the inverter to perform autonomously. OCA St. 1 at 12. For example, a utility may establish a uniform voltage management setting, like Volt/VAR, and thresholds for activation for all smart inverters on their system. *Id.* Alternatively, default settings can be uniquely determined based on characteristics like the interconnection location and DER specifications. *Id.*

New facilities and devices capable of exporting energy to the distribution system require approval to interconnect to PPL.[5] OCA St. 1 at 9; 52 Pa. Code Ch. 75. Since DERs import and export energy onto the distribution system, which alters the conditions on the system, the distribution system must be capable of moving adequate amounts of power while maintaining power quality. OCA St. 1 at 10.

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[3] Frequency support, also known as frequency droop and frequency-watt, requires a DER to increase output when frequency drops (if possible) and to decrease output when frequency increases in order to support the grid in maintaining the proper frequency. OCA St. 1 at 11.

[4] Ride-through functions define operating regions in which a DER may not trip offline (turn off) due to voltage or frequency anomalies, which includes both thresholds for tripping offline and minimum durations before tripping. OCA St. 1 at 11.

[5] For those DERs which undergo interconnection, there are very different processes depending on the size of the DER. OCA St. 1 at 9. Pennsylvania recognizes four levels of interconnection with varying rigors of evaluation requirements. *Id.* Level 1 interconnections allow DERs less than 10 kilowatts to interconnect with few requirements within 15 days. *Id.* Level 3 connections, by contrast, require DERs up to 5 megawatts to undergo an interconnection system impact study, and potentially a feasibility study, at the applicant's expense. *Id.* This tiered connection system is replicated by nearly every utility or jurisdiction across the country, recognizing the difference in impacts larger and smaller DERs have on the system. *Id.*

To communicate with a utility, a smart inverter needs to connect to the utility's control center, or at least the nearest substation. OCA St. 1 at 12. This connection could be made through a fiber optic cable, wireless communications referred to as gateways, or through the Cloud (i.e. the internet). OCA St. 1 at 13. PPL's current pilot program uses wireless communication through a dedicated management device. OCA St. 1 at 13. Many smart inverters, however, are beginning to provide communications through the Cloud. OCA St. 1 at 13. These inverters feature built-in gateways for internet access allowing the inverter to communicate with the utility through the DER customer's internet service provider, with no external device required. OCA St. 1 at 13.

Planning for DER involves determining changes to the distribution system in response to DER, for example, modifying distribution equipment settings, or installing new components to increase capabilities. OCA St. 1 at 14. This requires knowledge of the DER on the system and primarily relies on monitoring and modeling capabilities. *Id.* Monitoring DER can be as simple as tracking DER capacity on a circuit through interconnections, or as complicated as real-time DER status provided to the utility through smart inverter communications. *Id.*

Smart inverters can be actively managed. OCA St. 1 at 15. In other words, the smart inverter's setting can be altered through its communications capability to ensure optimal system performance by system operators, equipment manufacturers, or DER aggregators. *Id.* As such, active network management uses continuous monitoring of local distribution system conditions to determine when DERs must adapt to avoid adverse impacts. This is performed through a DER Management System device (DERM) which monitors, models, processes, and commands data for actively managed DER. OCA St. 1 at 17.

Costs associated with managing DER vary greatly depending on the level of DER management. OCA St. 1 at 18. Some forms of DER management require little to no infrastructure or capital investment, such as rate design or autonomous smart inverter settings. *Id.* However, increased levels of monitoring and active management require increasingly expensive infrastructure. *Id.*

B. Summary of PPL's Proposal

PPL's original DER Management Pilot Program (Pilot or DER I) was initiated as a result of a settlement in January, 2021. *Petition of PPL Electric for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan*, Docket No. P-2019-3010128, Order (Dec. 17, 2020) (*PPL DER I Order*). PPL's DER I was designed to evaluate "(1) the costs and benefits to distribution system operation and design of monitoring DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means (e.g., automated meter reading equipment, ADMS systems, modeling); and (2) the costs and benefits to distribution system operation of active management of DERs as compared to the benefits available through the use of inverter autonomous grid support functions." OCA St. 1 at 19 (internal citations omitted). PPL's DER I was originally approved for three years[6] and PPL has installed 6,878 DER Management Systems (DERMs) to enable the Pilot's management capabilities. OCA St. 1 at 19. PPL's DER I costs totaled approximately $6.51 million. OCA St. 1 at 19-20. Under the Settlement for DER I, PPL deferred cost recovery through a regulatory asset and will propose to recovery these costs from ratepayers in its next base rate case. OCA St. 1 at 20 (internal citations omitted).

Through PPL's Second DER Management Program (DER II), PPL proposes to expand on DER I by authorizing PPL to:

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[6] The Commission approved a petition extending PPL's DER I until thirty days after the Commission's final order is entered in PPL's DER II proceeding. *Petition of PPL Electric for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan*, Docket No. P-2019-3010128, Order (Sept. 12, 2020)

> (1) actively monitor and manage the smart inverter settings on all DERs that are in the Pilot Program's control groups; (2) utilize the Volt/Watt functionality, with customer consent, when the interconnecting DER could create a localized high voltage issue on the distribution system at the time of interconnection, which would not be resolved by the Volt/VAR or Constant Power Factor grid support functions; and (3) make the Pilot Program permanent. As such, provisions in the Settlement that limit the scope of the Pilot Program's requirements, such as the annual cap of 3,000 DER Management devices, would be eliminated. Moreover, the Company proposes to install DER Management devices on: (1) solar photovoltaic systems interconnected before the Pilot Program started on January 1, 2021; and (2) inverter-based DERs interconnected after the Pilot Program started without DER Management devices installed on them.

OCA St. 1 at 20; PPL St. 1 at 23.

PPL's DER II only applies to distributed generation, primarily solar, located behind the meter and any co-located storage. OCA St. 1 at 21. DER II excludes electric vehicles (EVs) and other controllable loads from potential management. *Id.* DER II also does not directly control storage, thus omitting any capability to manage the dispatch of stored energy or charging. *Id.*

PPL proposes to actively monitor and control every eligible DER connected to its distribution system through the use of a utility-owned DERM installed at every DER location. OCA St. 1 at 21. As the OCA will discuss below, PPL's proposal is an extreme and expensive approach that is out of line with what all other public utilities, both nationally and internationally, are doing. Moreover, PPL's DER II does not propose any rate design or pricing mechanisms and leaves the allocation of costs for this expensive program to be determined in the next base rate proceeding. *Id.* Instead, DER II enables autonomous reactive power control, Voltage Ride-through, and Frequency Ride-through functions for all connected inverters. OCA St. 1 at 22.

PPL listed the following capabilities to actively monitor and control DERs, which PPL enables through its DERMs:

- Monitoring the real power production;

- Monitoring the reactive power production;
- Monitoring the voltage at the DER location;
- Modifying settings for the Volt/VAR curve autonomous grid support function;
- Modifying the settings for the ride-through autonomous grid support function; and
- Adjusting the power factor in response to distribution system conditions.[38]

OCA St. 1 at 22.

PPL reports DER growth on its system with 153 megawatts (MW) of DER interconnected in the three years since the DER Pilot's inception. OCA St. 1 at 32 (internal citations omitted). PPL forecasts an additional 121 MW of residential and 1,421 MW of commercial behind-the-meter (BTM) DER to be installed by 2030. *Id.* This will have the net result of one in six residential households having solar or more than 300,000 installations, by 2031 or 2032. *Id.*

Under PPL's DER II, PPL will continue recovering costs of the program through base rates. OCA St. 1 at 23. At this point, PPL has not specified how it will propose to allocate and recover DER II costs in its next rate case. *Id.*

C. PPL's DER II is the only program that mandates full monitoring and control of DERs through utility-owned devices.

PPL's proposed pilot moves far beyond the scope of its PPL DER I and would dramatically expand the scope of monitoring and control of DER devices. The Company has not met its burden to demonstrate that such control and monitoring is necessary or prudent for the provision safe, adequate and efficient service to customers under Section 1501 of the Public Utility Code. 66 Pa. C.S. § 1501.

1. <u>PPL's DER II is a radical departure from how other jurisdictions approach DER management and is unnecessary for PPL's distribution system.</u>

OCA witness Nelson testified that he is not aware of any other utility which mandates full monitoring and control of DERs by the utility, as proposed by PPL. OCA St. 1 at 24. PPL's proposed DER II is unnecessary for managing small DER (less than 200 kW), and PPL has failed to meet its burden of proof that PPL DER II costs are prudent and would result in just and reasonable rates when recovered through base rates. Moreover, PPL has not demonstrated that the benefits derived from direct utility control over small DERs would justify the associated costs. *Id.*

PPL's DER growth historically is not exceptionally high compared to other utilities in the United States. Overall, Pennsylvania ranks 14th nationally in Distributed Solar Capacity as of June 2024 with 875MW installed and 28th in per capita distributed solar capacity. *Id.* Despite projected growth, states like Arizona, California, Hawaii, Massachusetts, and Rhode Island have five to ten times more DER per capita today than Pennsylvania and are likely to remain far ahead of PPL into the future. OCA St. 1 at 33.

Other jurisdictions, which are further ahead of PPL in terms of DER deployment and penetration levels, demonstrate that other management strategies are more effective and economical. OCA witness Nelson testified as follows:

> For example, many states have adopted autonomous settings to address the impacts of high DER penetrations. In the jurisdictions with the highest penetrations, active control is an *optional* offering to address constraints for interconnecting customers. PPL would make this active control *mandatory* for all customers, including small residential customers. However, PPL did not sufficiently evaluate pathways outside of universal monitoring and control requirements for all eligible DERs.

OCA St. 1 at 26.

All other utilities have demonstrated that direct control of all connected eligible DERs is unnecessary to maintain reliability, safety and efficiency of electric service. OCA St. 1 at 33. PPL touts San Deigo as "PPL Electric's post card from 10-15 years in the future." PPL St. 7 at 14. PPL is correct insofar as San Diego is years ahead of Pennsylvania in DER adoption, as are many other utilities, but even San Diego has not utilized the measures proposed here by PPL even though San Deigo has far more DER on its system. OCA St. 1 at 33.

Other jurisdictions are demonstrating today that DER can be managed reliably, safely, and efficiently in the absence of dedicated controls used in PPL DER II and PPL has not met its burden showing otherwise. For example, Hawaii has implemented autonomous control for all DER including volt-watt for curtailment of active power, demonstrating that this type of functionality can deliver the type of hosting capacity and reliability benefits touted by PPL's DER II. OCA St. 1 at 33. PPL reports that it has not yet attempted to deploy volt-watt settings to any customer DER. *Id.* Both San Diego and Hawaii have DER that are a decade or more ahead of PPL's projected growth and they both continue to operate their grids safely and reliably without utilizing the measures proposed by PPL. OCA St. 1SR at 5.

PPL has not met its burden of proof in providing substantial evidence that DER II is needed to provide adequate, efficient, safe, reliable and reasonable service under Section 1501 of the Public Utility Code. Other utilities operate with far more MWs of DER on its system than PPL but still have not needed to implement a program similar to PPL's. While PPL has approximately 150 MW of solar on its system, PG&E has over 8,000 MWs, Southern California Edison has over 5,700 MWs, Eversource has approximately 2,600 MWs with over 1,000 MWs more in development in Massachusetts, Commonwealth Edison has over 1,000 MWs, Xcel Energy's upper Midwest territory has over 1,000 MWs, Hawaiian Electric has over 1,000 MWs, and Nevada Power has approximately 950 MWs. OCA St. 1SR at 5-6 (internal citations omitted). This is not an exhaustive list. *Id.*

None of the above utilities require mandatory active control of eligible DERs and OCA witness Nelson testified that he is not aware of any of these utilities having DER reliability issues.

OCA St. 1SR at 6. PPL, however, has not yet even attempted to deploy volt-watt settings to any customer DER. OCA St. 1 at 33 (internal citations omitted). There is no imperative to controlling DERs through a mandatory PPL owned DERM, as the means with which San Diego, Hawaii, and multiple other jurisdictions, have been managing their grids are safe and reliable. OCA St. 1SR at 6.

PPL also provided examples of utility DER management programs that refute its claim that mandatory control is necessary to manage all DERs. In rebuttal, PPL references Green Mountain Power's Bring Your Own Device Program and Duke Energy's PowerPair + Battery Control Program, ostensibly to demonstrate that other utilities are controlling DER in the same way as PPL proposes. OCA St. 1 SR at 12; PPL St. 2R at 7. However, neither Green Mountain Power's nor Duke Energy's DER programs are mandatory and neither use utility-owned communications devices, relying instead on cloud-based communications using the customer's internet service. OCA St. 1SR at 13 (internal citations omitted). Duke Energy's program is also managed by a third-party aggregator, rather than the utility. *Id.*

In fact, there are many examples of third-party aggregators providing such services, and zero examples of utilities enacting the type of mandatory management strategy proposed by PPL. OCA St. 1SR at 42. In dismissing the option of using third-party aggregators, PPL mischaracterized the role of aggregators in providing "distribution system reliability and power quality," takes developmental challenges of new programs as evidence that they are imprudent and mistakes a failure to seek such services as evidence that they do not exist. *Id.* PPL has not provided substantial evidence that PPL DER II is necessary compared to using a third-party aggregator.

These programs demonstrate a clear alternative to mandatory utility control of all eligible DERs that PPL did not adequately study as an alternative to its proposal. OCA St. 1SR at 13.

Indeed, PPL witness Krevat describes, in detail, the alternative options taken by San Diego Gas & Electric Company (SDG&E) and Hawaii Electric Company, Inc. (HECO) to manage DER, including Advanced Energy Storage, Phase Measurement Units, line capacitor upgrades, dynamic voltage control, CPUC's Phase 3 advanced functions including Scheduled power values and modes, VAR inverters, and line sensors. OCA St. 1SR at 13; PPL St. 7R at 6-8. Indeed, any combination of DER management strategies and these other electric infrastructure options can be employed to maintain safe and reliable service. OCA St. 1SR at 13. However, PPL refrained from evaluating the costs and benefits of any of these alternative options for maintaining system reliability. OCA St. 1SR at 13-14.

2. <u>PPL's DER II fails to reasonably differentiate between DER sizes.</u>

PPL also did not address whether the management strategy is cost-effective for small DERs. The further deployment and dedicated monitoring and control infrastructure is not necessary or cost-effective for small DERs 200kW and below. OCA St. 1 at 24. OCA witness Nelson testified as follows:

> Smaller DERs are inherently the least valuable to control, simply because a small DER generates less energy than a larger DER, while many of the costs to control each DER are similar. The Company omitted costs and exaggerated benefits in the evaluation of the DER management pilot, which rightfully calls into question the cost-effectiveness of the proposed strategy for small DERs, as well as medium and large DERs.

OCA St. 1 at 26-27.

The benefits of the Pilot, valued per unit of capacity being managed, suggests that small DERs under 200 kW do not produce benefits in excess of the costs to manage them as proposed by PPL. OCA St. 1 at 25-32. Small and large DERs impact the grid differently and interconnection processes recognize differently sized DERs as there are distinct impacts on the circuits they reside on, among other reasons. OCA St. 1 at 26-27. PPL's own interconnection processes recognize multiple different size categories for interconnection, with DERs above 500 kW requiring additional evaluation and direct control requirements. OCA St. 1 at 26-27. These unique interconnection processes recognize the expected impact from these various systems. OCA St. 1 at 27.

Large DERs represent a significant capacity on the circuit they are connected to. OCA St. 1 at 26. As such, a single large DER may have significant impact on voltage, thermal loading, or power quality. *Id.* Small DERs, on the other hand, are insignificant fractions of circuit capacity. *Id.*

OCA witness Nelson is not aware of any jurisdiction that is seriously considering small DER control because it is not cost-effective and other more cost-effective pathways exist. OCA St. 1 at 30. PPL highlights multiple other utilities exploring DER management strategies, however, each utility program cited by PPL explicitly identifies larger DERs as the target for direct control capabilities. OCA St. 1 at 28. Meanwhile, other jurisdictions are exploring flexibility for small DERs through autonomous control, including California, Maryland, and Illinois. OCA St. 1 at 28-30. Australia, with one of the highest penetrations of solar PV in the world, with nearly one third of households having rooftop solar, only has mandatory dedicated monitoring and control for systems larger than 200 kW. Ameren Illinois stated that it does not control small DERs using a DERM due to the unjustified cost as follows:

> Currently, Ameren Illinois has no intent to directly control small (Level 1) DERs[7] using a DERMS. The logistics and cost of dedicated communications equipment for small (Level 1) DER sites cannot be justified at this time. The Company anticipates that if new programs or grid resiliency efforts require control of smaller DER, this would be accomplished through a third party or through the existing manufacturer's link to the DER. … The Company expects that if DER control scenario' (sic) emerge, DERs smaller than 200 kW would typically not be subject to

[7] Ameren's Level 1 interconnection includes DER up to 25 kW. See https://www.ameren.com/illinois/residential/supply-choice/renewables/developer-resources.

> control unless special circumstances such as program participation warrant it.[8]

OCA St. 1 at 29-30 (internal citations omitted). Ameren Illinois identified more cost-effective pathways for controlling small DERs, such as using third parties or equipment manufacturers. OCA St. 1 at 30.

PPL's DER management plan could have recognized the difference between small and large DER but failed to do so. OCA witness Nelson testified that active monitoring and control should only be required for large DERs which represent a significant fraction of the demand on a distribution circuit, creating an acute risk to reliability and safety. OCA St. 1 at 31. Nevertheless, utility owned devices installed on interconnected DERs is neither the only option nor the most cost-effective option. Again, PPL is the only utility that requires all eligible DERs to have PPL mandatorily install a company-owned device on a customer DER.

D. PPL's DER II is not cost-effective.

1. <u>Mandatory control of all DERs through PPL's device is expensive</u>.

PPL projects that PPL DER II will cost $80.1 million through 2030. OCA St. 1 at 35. However, this projection considers only solar facilities through 2030. *Id.* PPL assumes that the average cost of the PPL DERM is $1,051 per device. OCA St. 1SR at 35. PPL's mandatory utility-owned devices have a weighted average cost of $959 per unit. PPL St. 10R at 13.

As the impacts of other types of DERs become significant, including energy storage and electric vehicles (EV), PPL may recommend that these DERs be similarly managed, and the number of DERs under PPL's management would increase even further. OCA St. 1SR at 35.

[8] See ICC Docket 22-0487 and 23-0082. Surrebuttal Testimony of Andy Parker at pages 34-35. Ameren Exhibit 54.0. July 27, 2023.

Mandatory control of all DERs significantly increases the costs of PPL DER II. OCA witness Nelson testified as follows:

> PPL projects 145,825 Light Duty EVs by 2030, nearly double the number of behind-the-meter DER PPL projects in its cost analysis. Similarly managing these EVs would add $153.2M, tripling the total cost of DER management. Looking further to 2039, 524,252 EVs add $550.1M to the cost of DER management.

OCA St. 1SR at 35. In other words, when PPL's DER II strategy is expanded to other non-solar DER, such as electric vehicles, the PPL DER II plan could triple in costs by 2030, and add more than half a billion dollars in management costs by 2039. OCA St. 1 at 2.

Although alternative methods of managing all DERs could be developed in the future that reduce these costs, PPL's DER II is proposed as a permanent solution, contains no clauses requiring reconsideration, and makes no commitments to pursuing and deploying lower cost alternative program designs in the future. PPL's proposal to deploy expensive hardware on small DERs without understanding which locations are valuable to manage, and without discerning between circuits that may not have high DER penetration for many years, is unreasonable. OCA St. 1SR at 36. While PPL recognized the need for grid orchestration, it prescribed its own technological solution, rather than providing just and reasonable service options to its customers. *Id.*

If PPL is permitted by the Commission to control and monitor small DERs, exponential increases in DER are likely to exponentially increase the cost of PPL's DER program. OCA St. 1 at 36. OCA witness Nelson testified as follows:

> The cost implications of an expansion in the number of DERs connected to PPL's distribution system is why evaluating cost-effective pathways (e.g., third-parties and manufacturers providing monitoring and control) for managing small DERs is so important for ratepayers. Most DERs in PPL's territory are small (approximately 98 percent are under 25 kW).

OCA St. 1 at 36.

The OCA recommends that the Commission deny PPL's DER II because the Company has failed to demonstrate that its proposal is cost-effective, necessary, or capable of providing greater net benefits compared to alternative options. If, however, the Commission were to adopt a recommendation to only control large DER, it would significantly reduce the Company's proposed costs of controlling DERs. *See* OCA St. 1 at 36.

2. <u>PPL omits costs from DER I that are associated with DER II</u>.

The total cost of PPL's original DER Pilot was $6.38 million in capital and $128,000 in operations and maintenance (O&M). OCA St. 1 at 34. These costs are primarily related to the purchase and installation of DERMS at DER facilities, with the costs per participating DER between $863 and $1,349, according to PPL's estimates. *Id.*

PPL's reported costs for DER I, however, omitted costs associated with DER II. OCA witness Nelson testified as follows:

> First, PPL reports that there are start-up costs amounting to $4.37 million, bringing the total cost of the pilot to $11.66 million. Second, the Company also recognizes that there are significant and unquantified costs for telecommunications networks to enable DER management, including $900,000 in SCADA costs just to enable the management pilot through 2025, and a yet unknown amount for AMI network upgrades.

OCA St. 1 at 34.

PPL's identified "start-up" costs should be included in the evaluation of DER II. OCA St. 1 at 34. OCA witness Nelson testified as follows:

> The Company may not "expect to incur [these costs] under the Second DER Management Plan" however, these are costs spent to enable the DER management plan. You cannot simply ignore one-time costs in analyzing the cost-effectiveness of a program because they are already spent. Further, it is not clear that the costs which the Company asserts to be start-up costs are not recurring costs. For example, program management and analysis costs (totaling $1.3 million), are likely continuing costs that the Company will incur if it plans to continue managing the program and recovering program expenses. Further, if the Company ever intends to alter program details as technology changes, additional program management

> costs should be expected. At best, these costs are truly one-time costs which will be spread across many managed DERs, but there is a real possibility that many of these expenses will recur in expanding and continuing the program.

OCA St. 1 at 34-35. While PPL does not expect to incur additional start-up costs under DER II, costs that are part of implementing DER II should not simply be ignored when analyzing the cost-effectiveness of a program because the costs were already spent. OCA St. 1 at 34.

PPL's identified communications system costs should have also been included in the evaluation of the Pilot program. OCA witness Nelson testified as follows:

> These costs are a direct result of the DER management plan and will scale with the number of DERs. For every additional DERs added to the management plan, the Company notes that "the Company's SCADA system requires a dedicated slot." The Company's reported costs of SCADA alone add $131 per device to the cost of DER management. The AMI network, which must carry the communications could have equal or greater costs than the SCADA connections. These costs will grow exponentially as the number of DERs grow on the system, representing a very real concern for the cost-effectiveness of the DER management plan.

OCA St. 1 at 25.

OCA witness Nelson testified that "[t]he total cost of PPL's DER I is likely closer to $13.46 million assuming, potentially conservatively, that the costs of upgrading the AMI network are equivalent to the costs of upgrading the SCADA network. This doubles the average cost per DERM to $1,957." OCA St. 1 at 35-36. PPL has not provided substantial evidence showing that the cost of PPL DER II is reasonable, or even accurate.

E. The costs of PPL's DER II significantly outweigh its benefits.

PPL has also failed to provide substantial evidence showing that the costs of PPL's DER II significantly outweigh the benefits. PPL bears the burden of proof showing that the benefits of DER II furnishes and maintains adequate, efficient, safe, and reasonable service. However, PPL has not shown that PPL's mandatory program requiring actively monitoring and controlling DERs through PPL-owned DERMS is adequate, efficient, safe, or reasonable. Additionally, PPL has not shown that the benefits of DER II outweigh the costs.

1. The benefit of PPL's ability to control the capability of DERs is unclear.

Smart inverters provide the capability to change DER operational characteristics autonomously, based on predetermined criteria, or by active communication with a management system, such as a utility's DERMS or an aggregator. OCA St. 1 at 41. PPL's proposed DER management plan uses both control capabilities, with autonomous ride-through and reactive power settings operating by default, and active controls for modifying these settings in response to system conditions. *Id.* Each of these capabilities can benefit the system by providing grid support. Active control provides an incremental value over autonomous control, because it can be adapted to coordinate multiple DERs to respond to larger grid needs. *Id.*

For DER II, PPL proposes to install DERMs, which would be unnecessary for autonomous capabilities alone, for an average cost of up to $1957 per DER.[9] OCA St. 1 at 42. The incremental value of active control matters because enabling active control requires additional investments, while autonomous capabilities are effectively free, or very low cost, for ratepayers. OCA St. 1 at 42.

PPL was required to compare autonomous and active DER control under DER I. OCA St. 1 at 42. OCA witness Nelson testified as follows regarding PPL's initial cost-benefit analysis:

> Most of the quantified benefits of the DER pilot program are attributed to active control, except for "ease of integration," "learning and adaptation," and a portion of "flexibility in energy supply" value related to increased hosting capacity. Increased hosting capacity is derived from monitoring, autonomous control, and active management, and the Company's evaluation found that just 18% of increased hosting capacity from the pilot resulted from active control. Removing these non-active control values from the DER pilot benefits results in a reported incremental

[9] PPL assumes that the average cost of the DER program is $1,051 per device. OCA St. 1SR at 35. However, as discussed *supra*, PPL's cost estimate is likely flawed.

> value of active control of $18.4 million. Of this incremental value, the vast majority, $15 million, relate to the truck roll and hosting capacity savings.

OCA St. 1 at 42.

However, the new CBA, discussed *infra*, reduced the relative benefits from 51% to 16% of the total benefits of PPL DER II. OCA St. 1SR at 16. As such, the benefits of PPL's ability to control DER are unclear.

2. <u>PPL actively monitoring DERs provides minimal benefit at a high cost</u>.

Monitoring DERs provides information to help the utility plan and operate the system. OCA St. 1 at 43. In its initial CBA, PPL estimated that 61% of increased hosting capacity from the pilot resulted from DER monitoring, equating to $4.8 million. *Id.* PPL also studied, though did not specifically quantify, the value of monitoring load that is hidden by DER, to provide additional load-serving capacity on the system. OCA St. 1 at 43. PPL's DER II proposes a DER management device on every eligible interconnected DER to provide dedicated communications for real time monitoring. *Id.*

The benefit of this dedicated communications channel is in providing real time visibility, however, this use case does not align with how PPL quantified the value of DER monitoring. OCA St. 1 at 43. OCA witness Nelson testified as follows:

> Based on the Company's assessment, the quantifiable value of DER monitoring is overwhelmingly in improving planning models for increased load and DER capacity. These use cases do not require real time monitoring and could be served by much less frequent, and less costly, monitoring to inform, for example, monthly, quarterly, or annual planning updates. Thus, the active monitoring use cases do not support the Company's proposed DER management strategy, as the active management provides minimal additional value.

OCA St. 1 at 43-44.

Active monitoring is only needed for large DERs. OCA St. 1 at 44. OCA witness Nelson testified:

> There are alternative, more cost-effective approaches to obtaining monitoring data from small DERs that could be used to improve modeling and address many, if not all, of the active monitoring use cases covered by the Company. Requiring active monitoring for small DERs will increase costs for ratepayers will little, to no, incremental benefit.

OCA St. 1 at 44.

F. PPL's cost benefit analysis is flawed.

The objective for a just and reasonable DER management program should be to evaluate which of the many DER management pathways (autonomous vs. active control, mandatory vs. incentive-based, utility vs. third-party ownership) provides the greatest net benefits. OCA St. 1SR at 14. PPL, however, did not provide a clear assessment of other pathways for DER management and instead submitted a flawed cost-benefit analysis of its own proposal. OCA St. 1SR at 14.

The costs of management need to be explicitly and comprehensively evaluated against the benefits of management. OCA witness Nelson testified as follows regarding the differences between large and small DERs:

> There are costs associated with managing DER, and these costs vary depending on the management capabilities. Some forms of management require little, to no, infrastructure or capital investment, such as rate design or autonomous smart inverter settings. Increasing levels of monitoring and active management, however, require increasingly greater infrastructure for communicating with, processing information from, and delivering commands to DER. The costs of this management generally increase with this complexity and the number of systems to be managed. The costs of this management need to be explicitly and comprehensively evaluated against the benefits of managing those systems. The largest DERs may warrant dedicated fiber-optic communication connections to utility control systems to provide the most reliable and low-latency communication because their output is large enough to cause significant damage to the system during abnormal events. Opposite on the spectrum, small DERs whose individual output is insignificant to the system, may only be economically managed through rate structures and management that does not require additional infrastructure investment.

OCA St. 1 at 18.

PPL introduced a new CBA analysis through rebuttal testimony that significantly deviates from PPL's analysis presented in direct testimony. *See* PPL St. 3; PPL St. 10R. OCA witness Nelson testified that "[t]he largest benefit from PPL's original analysis was from reduced truck rolls associated with voltage violations, which represented 51% of the total benefits. OCA St. 1SR at 15. OCA witness Nelson testified as follows:

> Contrary to the Company's claim, the new CBA submitted in rebuttal had significant deviations from the analysis presented in direct testimony, which would imply that one or the other presented CBA is inaccurate. For instance, the new CBA study decreased the relative benefits related to reduced truck rolls to mitigate voltage violations, reducing them from the 51% stated above to 16% of the total benefits of the 2nd DER Plan presented in the new CBA. A similar magnitude of change is reflected in the treatment of deferred capital costs resulting from the 2nd DER Plan. The analysis provided in direct testimony included 12% of the total pilot benefits under the "cost-effective investment" category, while the new CBA filed in rebuttal includes 28% of the total benefits stack as deferred distribution capital investments related to improved hosting capacity. Finally, the evaluation of the pilot benefits included $1.48M in benefits attributed to "learning & adaptation" that was entirely removed from the new CBA filed in rebuttal testimony.

OCA St. 1SR at 16.

PPL's new CBA does not alleviate the OCA's concerns regarding DER II. PPL's additional CBA presented in rebuttal testimony is a new methodology and is unrecognizable when compared to PPL's initial filing. OCA St. 1SR at 17. The two PPL cost-benefit analyses contradict each other. *Id.*

PPL's new CBA exaggerates benefits and obfuscates the incremental benefits of PPL's DER II over other alternative management strategies, such as autonomous settings. OCA St. 1SR at 18. While PPL's new CBA may be more voluminous, it is still as inadequate as the first CBA, suffers from several methodological flaws, and does not fulfill the requirements of the PPL DER I Settlement.

1. Increased hosting capacity is not a ratepayer benefit but is instead a cost-shift onto ratepayers.

The most significant and fundamental flaw in the new CBA is that PPL assigned increased hosting capacity as the primary benefit to ratepayers. "Hosting capacity" refers to the amount of DERs that can be accommodated on the distribution system at a given time and at a given location under existing grid conditions and operations, without adversely impacting safety, power quality, reliability or other operational criteria, and without requiring significant infrastructure upgrades. OCA St. 1SR at 18. OCA witness Nelson testified as follows:

> The most significant and fundamental flaw in the new CBA is that the Company assigned increased hosting capacity as the primary benefit to ratepayers, claiming $27,393,149 of total benefits associated with increases in hosting capacity related to active management, and another $98,615,335 in benefits associated with monitoring for a total benefit of $126,008,484. These benefits represent 57% and 86% of the total benefits the Company finds for active management and the active management plus monitoring cases, respectively. However, the Company does not have an obligation to serve export facilities and to provide hosting capacity the same way that it does for load customers. For load customers, the Company has an obligation to provide a service to these customers; no such obligation to serve exists for customers desiring to export onto the distribution system. This is evidenced by the fact that export facilities are directly assigned upgrade costs when triggered during interconnection. While I am not a lawyer, it is further evidenced by the fact that the Company does not earn a return on equity for upgrades caused by export facilities. If the Company had an obligation to serve export, it would be a financial taking from shareholders not to pay the Company a return on its investment.
>
> The Company, however, seems confused about its obligation to serve customers on its system stating in a response to discovery that inquiring about its obligation to serve export it stated "the Company … offer(s) net metering to eligible customer-generators." It is clearly distinct to have an optional net metering tariff and an obligation to serve export facilities. The Company adds further confusion to its obligation to serve by stating in in the same OCA discovery question that "PPL has a responsibility to provide adequate, safe, efficient, reliable, and reasonable service to its customers, including customer-generators participating in net metering." However, PPL does not have service standards for export service quality, reliability, or available hosting capacity that parallel load requirements.

OCA St. 1SR at 18-19.

Increased hosting capacity is not a ratepayer benefit, it is a cost shift from ratepayers to DER developers that do not have to pay for system upgrades or any of the investments used to increase said hosting capacity (e.g., DERMS). OCA St. 1SR at 19. PPL does not have an obligation to plan for hosting capacity or to serve export facilities that require hosting capacity. *Id.*

2. PPL's hosting capacity benefits analysis contains several methodological flaws.

PPL failed to provide a clear comparison of the value of autonomous smart inverter functions in comparison to the active management benefits in the DER Pilot. OCA St. 1 at 26. PPL also failed to consider whether autonomous function can maintain distribution system reliability in the face of substantial DER growth. *Id.*

Contrary to the prior settlement of PPL's DER I, PPL's assessment of hosting capacity benefits, however, have not been properly assessed against the "base case" scenario of using autonomous advanced inverter settings. A primary purpose for the DER Pilot was to evaluate the costs and benefits of active management of DERs as compared to the benefits available through the use of the smart inverter's autonomous grid support functions. The Settlement, which PPL agreed to and was subsequently approved by the Commission, states as follows:

> 54. **The Company shall be authorized to conduct a pilot program ("pilot" or "pilot program") to test and evaluate:** (1) the costs and benefits to distribution system operation and design of *monitoring* DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means (e.g., automated meter reading equipment, ADMS systems, modeling); and **(2) the costs and benefits to distribution system operation of *active management* of DERs as compared to the benefits available through the use of inverter autonomous grid support functions.** The pilot program will begin on January 1, 2021, and will end three years after the second control group is established pursuant to Paragraph 57, *infra*. The three years after the second control group is established will be referred to as Program Year 1, Program Year 2, and Program Year 3.

Petition of PPL Electric for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan, Docket No. P-2019-3010128, *Recommended Decision* at 16 (Nov. 17, 2020) (*PPL DER I RD*) (emphasis added).

The author of the CBA admitted that, contrary to the Settlement, he did not see the value of conducting an assessment comparing the benefits of direct management against autonomous management. Tr. 226-27. PPL witness Wishart testified as follows under cross-examination:

> Q. You're aware, aren't you, that there's a Commission Order requiring the PPL compare the benefits of direct settings against autonomous management?
>
> A. I am aware of that Commission Order, and I did my best to comply with that Order. What I am showing is that the incremental benefits of the Company's proposal above and beyond the baseline of autonomous operation. Again, going back to the pilot study that the Company did on their DER management program. It was great analysis and great data supporting the incremental benefits associated with active management and monitoring to the DER management devices. When it comes to autonomous operations, I really view that as the baseline to measure against the benefits of active management over and above that.
>
> Q. I'm reading your testimony saying that you didn't see the value of conducting an assessment of a technology that's already required.
>
> A. And I kind of view that as analogous to sunk costs. There was a discussion of sunk costs at various places in the testimony. You know, costs or standards or technologies that are going to be there whether or not the Company moves forward with their second DER management plans and really don't play into the economic decision making of moving forward with this proposed plan.

Tr. 226-27.

The PPL DER I Pilot was conducted to test and evaluate these costs and benefits. *See PPL DER I RD* at 16. A fundamental concern in this proceeding is comparing PPL's proposal for active management of all DERs in the plan against the benefits of lower cost alternatives, *e.g.* relying on the smart inverter's autonomous settings to manage some instances of negative grid impact. OCA St. 1SR at 21. In a cost-benefit analysis, this is commonly referred to as a "base case." *Id.*

PPL's decision to not comply with the Settlement disadvantages all parties, including PPL, when evaluating PPL's Pilot. Importantly, PPL's approach is not consistent with the terms of the settlement agreed to by the parties and approved by the Commission. *See* Tr. 226-27. PPL's analysis devalues the potential that autonomous smart inverter controls have for improving hosting capacity without the additional cost of the DER management device.

The assumed 'baseline' of using nameplate DER capacity to calculate incremental hosting capacity is a worst-case scenario, skews the results of the CBA, and is an unreasonable assumption. OCA St. 1SR at 22. Nameplate capacity is determined by the generator's manufacturer and indicates the maximum output of electricity a generator can produce without exceeding design limits. OCA St 1SR at 22 (internal citations omitted). The amount of energy produced by a solar panel varies throughout the day and year depending on the sun's relative position. *Id.* Even under conditions of highest solar resource availability (*e.g.*, a July day at noon), the actual output of a solar system will not reach its nameplate capacity due to factors such as losses from wiring, DC to AC conversion, and soiling of the panel. *Id.*

Using nameplate capacity is an unreasonable approach to identifying potential output of a solar PV system. OCA St. 1SR at 22. OCA witness Nelson testified as follows:

> The assumed 'baseline' of using nameplate DER capacity to calculate incremental hosting capacity analysis is a worst-case and unreasonable assumption. The reason it represents a worst-case scenario is that hosting capacity is often constrained during what is called the "daytime minimum load" period, typically falling in Spring or Fall when loads are reduced but there is still potential for significant solar output. As such, using the "nameplate" kW capacity of the solar DER would overstate expected output during such daytime minimums, compared to more accurate estimates of actual system output.

OCA St. 1SR at 22.

OCA witness Nelson recommended that PPL perform a rigorous alternatives analysis via a DER Orchestration Plan. OCA St. 1SR at 22. OCA witness Nelson testified as follows:

> The Company has significant data at its disposal, including Advanced Metering Infrastructure ("AMI") measurements of near-real-time net load for DER customers, not to mention two years of detailed, real-time generation data from geographically diverse DER from the Pilot. There is no reason for the only alternative against which the Company assesses the benefits of DER management be the use of nameplate capacity of DER.

OCA St. 1SR at 22-23.

PPL did not explain or even provide a rationale as to why it must have real-time data monitoring to achieve improved planning models. OCA St. 1SR at 22. To be clear, the DER Management device is not the only credible way to achieve higher confidence in small DER output. PPL should develop alternate plans for how to improve their analysis of hosting capacity that do not require real time data feeds from every DER to be installed in the future on its system. OCA St. 1SR at 23-24.

There are also issues with how the new CBA assesses the 5 MW of incremental hosting capacity that it claims is attributable to active management. OCA witness Nelson testified as follows:

> its 2024 DER Management Report, the Company states "As of the end of Program Year 2, PPL Electric's DER Pilot has resulted in an estimated increase of 29 MW of hosting capacity across the system **when compared to the "Nameplate" scenario, with 5 MW** of the 29 MW of hosting capacity **attributed to the active management of power factor**" (emphasis added). Therefore, the new CBA quantifies this 5 MW benefit from "active management" of DER and passes it off as an incremental benefit to using autonomous inverter controls, when in reality they were comparing it to an unmanaged base case without use of autonomous controls. This is evidenced by the fact that the Company reports autonomous inverter controls yield a benefit of 6 MW of incremental hosting capacity over the same base case (i.e., "nameplate") scenario, indicating that autonomous controls can reduce potential impacts by the same magnitude, or greater, than the Company's own analysis of its active management use case.

OCA St. 1SR at 24 (emphasis in original).

The analysis in the new CBA mischaracterizes a cost-shift as a benefit. PPL witness Wishart stated that "[i]n its 2024 DER Management Report, the Company identified 18 MW of new hosting capacity that resulted from monitoring DER production and 5 MW of new hosting capacity that resulted from active management of power factor." OCA St. 1SR at 20; PPL St. 10-R at 15. Mr. Wishart then calculates a ratio of the incremental 23 MW of combined hosting capacity claimed by the Company to the 6,878 DER Management devices installed by the DER pilot program. *Id.* He then scales that ratio to the annual number of DER installations in the forecast period of 2025-2030 to arrive at expected new incremental hosting capacity attributable to the DER II and mandatory use of the DER Management Device. OCA St.1SR at 20; PPL St. 10-R at 17.

Additionally, PPL witness Wishart touts avoided distribution capital investments associated with incremental hosting capacity from active management of DERs as one of the single largest benefits underpinning the CBA valued at $13,336,556. OCA St. 1SR at 24-25. However, the finding that avoided distribution upgrades are solely attributable to active management is at odds with evidence from PPL's own DER Pilot findings. OCA St. 1SR at 25. In the Company's 2024 DER Management Report under the subsection describing its analysis of capital deferral opportunities, the Company states that "As of March 21, 2024, PPL Electric has identified three (3) studies which can result in $1,664,000, all attributed to autonomous volt/var curves for customers applying to interconnect to the distribution system." *Id.* (internal citations omitted). Therefore, the CBA contradicts the DER I Pilot findings that the three major avoided capital upgrade deferrals identified in their own analysis are attributable, not to active management through DER Management Devices, but instead to autonomous inverter settings in the form of volt/var curves. *Id.*

Autonomous controls can reduce potential impacts by the same magnitude, or greater, than the Company's own analysis of its active management use case. OCA St. 1SR at 25. A study funded by the US Department of Energy demonstrated that autonomous inverter settings can provide substantial benefits to the grid, particularly around managing voltage impacts. Importantly, the study's authors also recognize that DER integration costs and associated hosting capacity can be very dependent on the specific conditions present on a given distribution feeder, such as the length of the line, the type of customer classes present, and the existing utility assets. OCA St. 1SR at 25-26. The fact that autonomous inverter settings can play a large role in managing potential DER impacts to the grid, coupled with the fact that costs to increase hosting capacity are very dependent on the case-by-case nature of the grid and the interaction with existing equipment, emphasizes the need to target the use of more expensive active management. OCA St. 1SR at 26. A more rigorous study on the part of PPL to justify a mandatory active management approach in all instances of DER adoption, as agreed to in Settlement, would have been appropriate.

Increased hosting capacity investment does not benefit the system as a whole. Instead, avoided infrastructure costs are a benefit to DER customers that are paid for by all other ratepayers. OCA St. 1SR at 27. Currently, hosting capacity is assessed and paid for on a case-by-case basis for DER seeking to interconnect to the grid. OCA St. 1SR at 26. Connecting DER customers benefit from avoided capital costs from incremental hosting capacity from DER II. OCA St. 1SR at 26-27. Yet, most of the costs of the DER II will be paid by the more than 90% of customer who do not have DER. OCA St. 1SR at 27. However, PPL proposes that all customers will pay for the costs of the DER II, as the costs would be incorporated into base rates. OCA St. 1SR at 27 (internal citations omitted).

Wholesale energy purchase costs are not an appropriate standard to assess benefits for active management of DERs. OCA witness Nelson testified as follows:

> Similar to the infrastructure investments, the reduction in wholesale energy benefit of $22/MWh is not appropriate for this analysis since it fails to account for PPL's [Net Energy Metering] rate structure. While it is true that PPL may see a reduction in the need to purchase wholesale energy to meet its load obligations with

> incremental DER adoption, those reduced costs are only one half of the equation. PPL, in fact, raises this issue, while not fully integrating its implications, stating that "DERs already benefit from net metering that compensates them at the full retail rate, which substantially exceeds the value of the energy they displace."

OCA St. 1SR at 28. Under PA statute, PPL must compensate Net Energy Metering (NEM) customers at the retail rate for any excess kWh. *Id.* (internal citations omitted). Therefore, the kWh from additional DER generation espoused under DER II would reduce wholesale energy costs but will also lead to additional expenses to compensate customers for their net-exports. *Id.*

G. PPL's refusal to analyze the cost and benefit of any other program structure obstructs the development of an optimal DER management solution.

PPL primarily evaluated the costs and benefits of its own proposal to deploy DER management devices to enable real-time monitoring and control on every connected DER. OCA St. 1SR at 31. PPL did not demonstrate that actively managing all DERs is cost-effective. OCA St. 1SR at 32.

PPL's filing presents a false dichotomy where the Commission is seemingly required to choose between PPL controlling and monitoring all eligible DERs, or unmonitored and uncontrolled DERs with little, to no, required capabilities. OCA St. 1 at 24. To be clear, these are not the only options for the Commission. *Id.*

PPL did not consider alternatives for addressing DER impacts outside of its proposed solution of directly monitoring and controlling all sizes of DERs through mandatory installation of PPL owned DER management device.

However, the outcomes sought by PPL can be realized by other management pathways and with other capabilities. OCA St. 1 at 25. For example, identifying hidden load and improving distribution models does not require monitoring DERs through a utility-owned DER management device. OCA St. 1 at 25. Instead, cloud communication-enabled smart inverters can be used to collect the same information PPL is obtaining through its DER management devices. *Id.* Also, advanced DER forecasting tools can provide accurate aggregate modeling of small DERs without monitoring. *Id.* This fact undermines many of the benefits the Company ascribes to DER II, including the benefits of monitoring real power, reactive power, and voltage monitoring because the same benefits could be more cost-effectively realized through other approaches. *Id.*

There are at least three alternative management strategies that PPL could have chosen to employ: 1) advanced DER modeling; 2) cloud-based communications, and; 3) third-party aggregations to deliver management capabilities. These strategies have been deployed by a number of utilities with far higher DER penetration than PPL.

1. <u>Advanced DER Modeling is a viable alternative to PPL's proposal to have PPL exercise mandatory control over DERs through PPL's DERMS.</u>

Advanced DER monitoring can provide an accurate prediction of aggregated DER operations with little monitoring of the DER.[10] OCA St. 1 at 14, 25. Additionally, advanced DER forecasting tools can provide accurate aggregate modeling of small DERs without monitoring. OCA St. 1 at 25. This fact undermines many of the benefits PPL ascribes to DER II because the same benefits could be more cost-effectively realized through other approaches. *Id.*

Several studies have demonstrated the usefulness and accuracy of advanced forecasting models pertaining to the prediction of rooftop solar, particularly in the case of many aggregated small-scale devices such as in typical residential installations. OCA St. 1SR at 38. The Electric Power Research Institute (EPRI) has conducted extensive research working with Con Edison in New York on using advanced solar disaggregation and forecasting techniques to support utility

[10] Most planning decisions are made on an annual basis, so low-latency monitoring capabilities (in other words, very fast or real time monitoring through a fiber-optic cable directly connected to the DER), have minimal benefit for planning. OCA St. 1 at 14.

planning and operations, which PPL could use in its hosting capacity evaluation and potentially even in an operational setting. *Id.*

OCA witness Nelson also testified that PPL likely already has access to such advanced DER modeling capabilities, through its grid orchestration product vendor. OCA St. 1SR at 38. In fact, PPL has been working with Camus Energy since May, 2022. *Id.* Camus's website[11] specifically highlights that part of their orchestration platform is an advanced forecasting which can uncover "hidden load" via meter-level forecasting (i.e. using AMI measurements). *Id.* PPL has not shown that mandatory control is needed as opposed to using advanced DER modeling. Additionally, PPL has failed to evaluate what the potential costs and benefits would be for a viable alternative to their proposal.

2. Cloud-Based Communications

Cloud communication-enabled smart inverters can be used to collect the same information PPL would obtain through its DERMs. OCA St. 1 at 25. While PPL states that it is interested in cloud-based alternatives, PPL did not analyze the costs, benefits, or service providers as a serious alternative. OCA St. 1SR at 40. Importantly, PPL makes no commitment to pursue and deploy lower cost alternative program designs in the future. OCA St. 1SR at 40. PPL's DER II also contains no requirement allowing for reconsideration of its DER management strategy. *Id.* Without either of these guarantees that future cost savings will be pursued, PPL's interest in a cloud-based communication alternative to mandatory control of DERs through PPL's DERM is meaningless. *Id.*

3. Third-Party Aggregators

[11] Camus Energy, *How Forecasting Will Transform Grid Operation*, https://www.camus.energy/blog/how-forecasting-will-transform-grid-operations (previously accessed on March 20, 2025).

DERs can communicate system needs to aggregators or equipment manufacturers with the capability to manage DER settings to respond to system needs. OCA St. 1 at 15. Reliance on third-party aggregators or equipment manufacturers to actively manage DERs, rather than the utility, can avoid expensive utility investment in active management. OCA St. 1 at 15. There are many examples of alternative utility DER management programs provided by the parties that rely on third-party aggregators to manage the program. OCA St. 1SR at 41. In fact, PPL provided its own example of Duke Energy's PowerPair Program, which is managed by a third-party aggregator. OCA St. 1SR at 41; PPL St. 2-R at 7.

For existing third-party managed utility DER programs, aggregators fulfill a communications role. OCA witness Nelson testified as follows regarding third-party aggregators:

> In such programs, utilities remain fully responsible and in control of their system operations, they issue commands for DER through the aggregator, who distributes those commands to appropriate DER, and returns information from DER to the utility. This replaces the utility's investment in DER devices, communications networks, and servers, which are the vast majority of the 2nd DER Plan cost. These services can be rendered potentially at a fraction of the cost if aggregators (often working through OEMs) already have communications established with DER through cloud-connection.

OCA St. 1SR at 42.

PPL did not seek out an aggregator service from the market or through a Request for Proposal (RFP). OCA St. 1SR at 43. An RFP is necessary for third-party aggregator services as it is unreasonable to assume that potential third-party aggregators would approach PPL with fully-formed products tailored to PPL's needs, potentially divulging their own valuable intellectual property, when there is no solicitation by PPL. OCA St. 1SR at 43-44.

4. Conclusion

PPL inadequately evaluated and summarily rejected any alternatives to PPL's DER II. Throughout this proceeding, PPL conveyed no intention of reasonably modifying or optimizing

PPL DER II. This illustrates the importance of OCA witness Nelson's recommendation that PPL should be required to conduct a DER Orchestration Plan which would evaluate the cost-effectiveness of several pathways for monitoring and controlling DERs. OCA St. 1 at 6-7. PPL's refusal to evaluate the costs and benefit of these alternatives, or to consider other options, is unreasonable.

H. PPL should complete a DER Orchestration Plan and design its DER Management Plan to reflect a reasonable orchestration strategy.

It is not prudent to advance such a high-cost program focusing on solar PV when PPL did not clearly and convincingly incorporate the 6,800+ pilot DER Management device installations into their advanced Energy Orchestration activity with an explanation as to how additional devices are needed to increase the level of monitoring and control. PPL has not sufficiently described its baseline method for calculating hosting capacity, and whether the changes to hosting capacity methodology that yielded the incremental 18 MW from "monitoring" could be achieved with other improvements to hosting capacity modeling, and not solely from the collection and use of measured, real-time power and voltage readings. OCA St. 1SR at 47. OCA witness Nelson provided the following examples to consider regarding how to treat the interrelated nature of hosting capacity and grid planning analysis with respect to the types of investments PPL seeks to realize with DER II:

> 1) Finding ways to direct DER installations to portions of the grid that are better able to integrate DERs under existing conditions is one of the technically simplest and lowest cost ways to increase DER deployment. I recommend all avenues of leveraging voluntary means of accomplish this targeting, for example through use of innovative customer incentives or tariff changes, be explored before resorting to costly requirements for individual DER management.
>
> 2) Undertake a systematic and detailed review of PPL Electric's current methodologies for conducting hosting capacity analysis, and compare to emerging industry best practices for integrating greater penetrations DER. As mentioned elsewhere in my testimony, I question the necessity of relying on real, measured,

> real-time data from DER Management Devices for purposes of improving the Company's hosting capacity analysis over using the "nameplate scenario" as described in its 2024 DER Management Report. The importance of regulatory oversight for utilities conducting the data validation for their hosting capacity analyses is underscored by a recent report funded by the US DOE, which demonstrates numerous examples of utilities conducting flawed hosting capacity analysis that result in overly conservative findings.
>
> 3) Lastly, any future cost benefit study considering alternatives to direct utility control of DERs must appropriately account for and demonstrate the effectiveness of leveraging autonomous inverter control functionality to mitigate potential grid issues, before relying on more advanced communication and control functions capable of being deployed through smart inverters. In California, where DER penetration greatly exceeds that in Pennsylvania, the Smart Inverter Working Group recommended that the functionalities be required in a phased manner, with Phase 1 requiring certain autonomous control settings, and Phase 3 exploring more advanced functionality. The Phase 3 Impact report for Rule 21 implementation, which was led by EPRI and analyzes actual grid impacts of leveraging autonomous inverter functionality, ran thousands of power flow simulations to determine which combination of volt-VAR settings, DER location, and load/feeder conditions would increase hosting capacity by 25%. This is a substantial effort supported by the California Energy Commission and learnings can be leveraged to apply to PPL's system modeling to justify going beyond autonomous controls.

OCA St. 1SR at 47-49.

I. Export tariffs should be evaluated by PPL at some point in the future.

PPL did not provide any cost allocation proposals for allocating and recovering PPL DER II costs to the cost causers. As such, OCA witness Nelson recommended that export tariffs should be evaluated prior to having costly and mandatory DER requirements to avoid shifting the cost of DER management to ratepayers that do not own DERs. OCA St. 1 SR at 49-50. Connecting DERs drive the cost associated with the DER devices. OCA St. 1SR at 50.

An export tariff is a contractual agreement that governs how system upgrade costs are allocated to and recovered from DER which export energy onto the grid. OCA St. 1 at 52. OCA witness Nelson explained export tariffs as follows:

> Rather than an upfront costs to interconnect to the distribution system, as is currently assessed to DERs, an export tariff allocates costs for the use of the system

> over time similar to traditional load tariffs. The purpose of an export tariff is to treat exporting facilities more similarly, and therefore fairly, to customers that consume electricity. Exporting customers use the distribution system in a similar fashion to importing (i.e., load) customers and should be charged using similar ratemaking principles. Doing so, will create a truly bi-directional distribution system that is more capable of sending efficient price signals and incenting grid services overtime, adding much needed flexibility to the system.

OCA St. 1 at 52.

Export tariffs that allocate and recover costs from exporting customers, as they are the cost causers, have been investigated in both Massachusetts and Australia. OCA St. 1 at 51. However, OCA witness Nelson noted that it is too early for PPL or other Pennsylvania utilities to examine the reasonableness of export tariffs. OCA St. 1 at 52. This is due to the fact that PPL has very low DER penetration. *Id.* According to OCA witness Nelson, export tariffs may not need to be implemented for several years. *Id.*

Export tariffs, however, are an important tool for allocating costs to the cost-causers. If PPL's DER II is approved without modification, the cost of PPL DER II over time may exceed half a billion dollars. *See* OCA St. 1 at 2. Given the low DER penetration in PPL's service territory and the unprecedented nature of PPL's DER II, if PPL's DER II is approved as filed, export tariffs may be necessary to allocate costs to the cost causers at some point in the future.

J. The DER Management Plan will likely shift costs from DER owners to other consumers.

Under the DER Pilot settlement, the Company is authorized to propose recovery of the capital costs and expenses associated with the DER Management devices that the Company purchases, owns, installs, and maintains in the next rate case. OCA St. 1 at 50. The Company presents no proposal for allocating or recovering the costs of the DER management plan going forward. While none of the costs of DER management have yet to be collected from consumers, the Company states that it will seek cost recovery in its next base rate case. OCA St. 1 at 50.

PPL's DER II lacks any focus on the customer and the services to incentivize cost-effective integration through improved interconnection process and rate design. By approving PPL's DER II, and then putting off the consideration of the rate impact for ratepayers who do not own DER to a later rate base proceeding, the Commission cannot determine whether PPL's DER II results in just and reasonable rates in accordance with 66 Pa C.S. Sections 1301 and 1501. The Commission will decide in this proceeding whether to approve PPL's DER II and the subsequent costs of the program will likely be paid for through rates. PPL did not provide substantial evidence that DER II satisfies the legal standards of Sections 1301 and 1501 of the Public Utility Code. Stating that the costs of DER II can be allocated in a future base rate case does not make the costs reasonable.

Improving interconnection and rate design creates value for ratepayers. Specifically, a suite of standardized flexible interconnection options needs to be developed, such as optional autonomous volt-watt options for small DERs, export limits, and active network management options for larger facilities. OCA St. 1 at 51. This suite of options should be complemented by a pricing paradigm that better reflects cost causation by allocating and recovery costs that are caused by export. OCA St. 1 at 51.

K. Recommendations

PPL's DER II should not be approved. Until a more suitable DER management plan and cost recovery is designed and re-evaluated, the Commission should not require the proposed mandatory active control and the associated devices for DER of any size. OCA St. 1SR at 2. While OCA witness Nelson made constructive suggestions in Direct Testimony about necessary analysis of alternatives to the high cost of PPL's DER II, PPL did not properly evaluate the costs and benefits of alternatives, doubled down on the narrative that PPL's proposed DER II alone is necessary. OCA St. 1SR at 2-3.

Given the flaws in PPL's CBA, without sufficient evaluation of alternative options, and without a clearer understanding of potential total costs and how they will be allocated, PPL's DER should be rejected. OCA St. 1SR at 3. However, in the event that the Commission decides to approve PPL's DER II, the costs identified by PPL for purposes of this filings are likely understated. Importantly the Commission and interested stakeholders need to obtain a view of the DER management costs involved with all types and sizes of DERs to ensure that a cost-effective pathway is being taken. OCA St. 1 at 53-54. PPL included submitted a CBA in the rebuttal testimony phase of the proceeding that is laden with unsupported assumptions. OCA St. 1SR at 3.

The Commission should require PPL to provide more transparency regarding its plans for orchestrating all DERs and delivering value to ratepayers. Within 12 months after the Commission's order is issued in this docket, the OCA recommends requiring PPL to file a DER Orchestration Plan that consists of, but is not limited to, the following:

1) PPL's DER integration strategy, including a technology maturity and investment plan, for electric vehicles, energy storage systems, solar, thermostats, microgrids, and other controllable loads;

2) Alternatives analysis that considers the size and type of DER, third-party services and procurements (including third-party/aggregator DERMS integration), and the enabling costs for integration, and;

3) A cost-benefit or cost-effectiveness framework used to evaluate the alternatives analysis and selected approach;

Moreover, PPL should be required to provide an evaluation of three different flexible interconnection approaches that are applicable to both exporting and importing facilities including export (i.e., generation) and import (i.e., load) limitation schemes, scheduled interconnections, and actively managed interconnections. An evaluation of each approach includes the following:

1) A description;
2) Industry benchmarks and examples;
3) Benefits & Risks;
4) Current implementation status of approach;
5) Future state & next steps, including future rate and DER program offerings.

OCA St. 1 at 54-55.

The Commission has several options in implementing these recommendations. If the Commission wishes to keep the evaluation PPL specific, the filings could occur in this docket. However, the transparency needed for PPL's future DER orchestration plans are not unique to PPL. OCA St. 1 at 55. Many utilities are planning DER investments at this time. *Id.* If the Commission wishes to more broadly evaluate Pennsylvania utilities DER orchestration plans, a generic docket may be most appropriate. Conducting an evaluation across utilities could lead to many lessons learned that reduce costs for ratepayers. OCA St. 1 at 55. Regardless of the venue and number of utilities, a work group process should be used to further inform the scope, depth and assumptions used within the studies the above. OCA St. 1 at 55.

V. CONCLUSION

For the reasons set forth above, he Office of Consumer Advocate respectfully requests that PPL's Petition be denied.

Respectfully Submitted,

/s/Harrison W. Breitman
Harrison W. Breitman
Assistant Consumer Advocate
PA Attorney I.D. # 320580
E-Mail: HBreitman@paoca.org

Christy Appleby
Assistant Consumer Advocate
PA Attorney I.D. # 324763
E-Mail: CAppleby@paoca.org

Counsel for:
Darryl A. Lawrence
Acting Consumer Advocate

Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
Phone: (717) 783-5048
Fax: (717) 783-7152

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Appendix A

Proposed Findings of Fact

APPENDIX A

Proposed Findings of Fact

Definitions

1. DERs are solar photovoltaic ("Solar") systems, battery energy storage, electric vehicles, and many other smart devices, such as thermostats, which allow loads to be controllable. OCA St. 1 at 8.

2. DER is defined as "Small, modular, energy generation and storage technologies that provide electric capacity or energy connected to the distribution system." OCA St. 1 at 8 (internal citations omitted).

3. A DER typically requires an inverter to connect to the distribution system. OCA St. 1 at 9.

4. An inverter converts the direct current ("DC") power produced by solar panels and used in batteries and many other electronic devices into the alternating current ("AC") power transported on the electric distribution system. OCA St. 1 at 10.

5. Smart inverters go beyond this basic function to provide grid support functions, such as voltage regulation, frequency support, and ride-through capabilities. OCA St. 1 at 11.

6. Smart inverter features have the ability to minimize the DER's potential negative impacts due to voltage and frequency events. OCA St. 1 at 10-11.

7. Smart inverters provide grid support to support reliability and resiliency. A smart inverter's grid supporting functions dictate how the inverter operates and responds to the current conditions on the grid where the DER is connected. OCA St. 1 at 10-11.

8. Settings for these functions can be set by default at installation to allow the inverter to perform autonomously. OCA St. 1 at 12.

9. For example, a utility may establish a uniform voltage management setting, like Volt/VAR, and thresholds for activation for all smart inverters on their system. OCA St. 1 at 12.

10. Alternatively, default settings can be uniquely determined based on characteristics like the interconnection location and DER specifications. OCA St. 1 at 12.

11. New facilities and devices capable of exporting energy to the distribution system require approval to interconnect to PPL. OCA St. 1 at 9.

12. Since DERs import and export energy onto the distribution system, which alters the conditions on the system, the distribution system must be capable of moving adequate amounts of power while maintaining power quality. OCA St. 1 at 10.

13. To communicate with a utility, a smart inverter needs to connect to the utility's control center, or at least the nearest substation. OCA St. 1 at 12.

14. This connection could be made through a fiber optic cable, wireless communications referred to as gateways, or through the Cloud (i.e. the internet). OCA St. 1 at 13.

15. PPL's current pilot program uses wireless communication through a dedicated management device. OCA St. 1 at 13.

16. Many smart inverters, however, are beginning to provide communications through the Cloud. OCA St. 1 at 13.

17. These inverters feature built-in gateways for internet access allowing the inverter to communicate with the utility through the DER customer's internet service provider, with no external device required. OCA St. 1 at 13.

18. Planning for DER involves determining changes to the distribution system in response to DER, for example, modifying distribution equipment settings, or installing new components to increase capabilities. OCA St. 1 at 14.

19. This planning for DER requires knowledge of the DER on the system and primarily relies on monitoring and modeling capabilities. OCA St. 1 at 14.

20. Monitoring DER can be as simple as tracking DER capacity on a circuit through interconnections, or as complicated as real-time DER status provided to the utility through smart inverter communications. OCA St. 1 at 14.

21. Smart inverters can be actively managed. OCA St. 1 at 15.

22. The smart inverter's setting can be altered through its communications capability to ensure optimal system performance by system operators, equipment manufacturers, or DER aggregators. OCA St. 1 at 15.

23. Active network management uses continuous monitoring of local distribution system conditions to determine when DERs must adapt to avoid adverse impacts. OCA St. 1 at 17.

24. Active network management is performed through a DER Management System device (DERM) which monitors, models, processes, and commands data for actively managed DER. OCA St. 1 at 17.

25. Costs associated with managing DER vary greatly depending on the level of DER management. OCA St. 1 at 18.

26. Some forms of DER management require little to no infrastructure or capital investment, such as rate design or autonomous smart inverter settings. OCA St. 1 at 18.

27. Increased levels of monitoring and active management require increasingly expensive infrastructure. OCA St. 1 at 18.

PPL's DER I

28. PPL's DER I was designed to evaluate "(1) the costs and benefits to distribution system operation and design of monitoring DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means (e.g., automated meter reading equipment, ADMS systems, modeling); and (2) the costs and benefits to distribution system operation of active management of DERs as compared to the benefits available through the use of inverter autonomous grid support functions." OCA St. 1 at 19 (internal citations omitted).

29. PPL's DER I was originally approved for three years. OCA St. 1 at 19.

30. PPL has installed 6,878 DER Management Systems (DERMs) to enable the Pilot's management capabilities. OCA St. 1 at 19.

31. PPL's DER I costs totaled approximately $6.51 million. OCA St. 1 at 19-20.

32. Under the Settlement for DER I, PPL deferred cost recovery through a regulatory asset and will propose to recovery these costs from ratepayers in its next base rate case. OCA St. 1 at 20 (internal citations omitted).

PPL DER II

33. PPL's DER II only applies to distributed generation, primarily solar, located behind the meter and any co-located storage. OCA St. 1 at 21.

34. DER II excludes electric vehicles (EVs) and other controllable loads from potential management. OCA St. 1 at 21.

35. DER II also does not directly control storage, thus omitting any capability to manage the dispatch of stored energy or charging. OCA St. 1 at 21.

36. PPL proposes to actively monitor and control every eligible DER connected to its distribution system through the use of a utility-owned DERM installed at every DER location. OCA St. 1 at 21.

37. PPL's DER II does not propose any rate design or pricing mechanisms and leaves the allocation of costs for this expensive program to be determined in the next base rate proceeding. OCA St. 1 at 21.

38. DER II enables autonomous reactive power control, Voltage Ride-through, and Frequency Ride-through functions for all connected inverters. OCA St. 1 at 22.

39. Under DER II, PPL listed the following capabilities to actively monitor and control DERs, which PPL enables through its DERMs: (a) monitoring the real power production; (b) monitoring the reactive power production; (c) monitoring the voltage at the DER location; (d) modifying the settings for the Volt/VAR curve autonomous grid support function; (e) modifying the settings for the ride-through autonomous grid support function; and (f) adjusting the power factor in response to distribution system conditions. OCA St. 1 at 22.

40. PPL reports DER growth on its system with 153 megawatts (MW) of DER interconnected in the three years since the DER Pilot's inception. OCA St. 1 at 32.

41. PPL forecasts an additional 121 MW of residential and 1,421 MW of commercial behind-the-meter (BTM) DER to be installed by 2030. OCA St. 1 at 32.

42. This will have the net result of one in six residential households having solar or more than 300,000 installations, by 2031 or 2032. OCA St. 1 at 32.

43. Under PPL's DER II, PPL will continue recovering costs of the program through base rates. OCA St. 1 at 23.

44. At this point, PPL has not specified how it will propose to allocate and recover DER II costs in its next rate case. OCA St. 1 at 23.

45. OCA witness Nelson testified that he is not aware of any other utility which mandates full monitoring and control of DERs by the utility, as proposed by PPL. OCA St. 1 at 24.

46. PPL's DER growth historically is not exceptionally high compared to other utilities in the United States. Overall, Pennsylvania ranks 14th nationally in Distributed Solar Capacity as of June 2024 with 875MW installed and 28th in per capita distributed solar capacity. OCA St. 1 at 24.

47. Despite projected growth, states like Arizona, California, Hawaii, Massachusetts, and Rhode Island have five to ten times more DER per capita today than Pennsylvania and are likely to remain far ahead of PPL into the future. OCA St. 1 at 33.

48. San Diego is years ahead of Pennsylvania in DER adoption, as are many other utilities, but even San Diego has not utilized the measures proposed here by PPL even though San Deigo has far more DER on its system. OCA St. 1 at 33.

49. Hawaii has implemented autonomous control for all DER including volt-watt for curtailment of active power, demonstrating that this type of functionality can deliver the type of hosting capacity and reliability benefits touted by PPL's DER II. OCA St. 1 at 33.

50. PPL reports that it has not yet attempted to deploy volt-watt settings to any customer DER. OCA St. 1 at 33.

51. Both San Diego and Hawaii have DER that are a decade or more ahead of PPL's projected growth and they both continue to operate their grids safely and reliably without utilizing the measures proposed by PPL. OCA St. 1SR at 5.

52. Other utilities operate with far more MWs of DER on its system than PPL but still have not needed to implement a program similar to PPL's. OCA St. 1SR at 5-6.

53. While PPL has approximately 150 MW of solar on its system, PG&E has over 8,000 MWs, Southern California Edison has over 5,700 MWs, Eversource has approximately 2,600 MWs with over 1,000 MWs more in development in Massachusetts, Commonwealth Edison has over 1,000 MWs, Xcel Energy's upper Midwest territory has over 1,000 MWs, Hawaiian Electric has over 1,000 MWs, and Nevada Power has approximately 950 MWs. OCA St. 1SR at 5-6.

54. None of the above utilities require mandatory active control of eligible DERs. OCA St. 1 at 33.

55. OCA witness Nelson testified that he is not aware of any of these utilities having DER reliability issues. OCA St. 1SR at 6.

56. PPL has not yet attempted to deploy volt-watt settings to any customer DER. OCA St. 1 at 33.

57. In rebuttal, PPL references Green Mountain Power's Bring Your Own Device Program and Duke Energy's PowerPair + Battery Control Program, ostensibly to demonstrate that other utilities are controlling DER in the same way as PPL proposes. OCA St. 1 SR at 12; PPL St. 2R at 7.

58. Neither Green Mountain Power's nor Duke Energy's DER programs are mandatory and neither use utility-owned communications devices, relying instead on cloud-based communications using the customer's internet service. OCA St. 1SR at 13.

59. Duke Energy's program is also managed by a third-party aggregator, rather than the utility. OCA St. 1SR at 13.

60. PPL also did not address whether the management strategy is cost-effective for small DERs. OCA St. 1 at 24.

61. The further deployment and dedicated monitoring and control infrastructure is not necessary or cost-effective for small DERs 200kW and below. OCA St. 1 at 24.

62. Smaller DERs are inherently the least valuable to control, simply because a small DER generates less energy than a larger DER, while many of the costs to control each DER are similar. OCA St. 1 at 26.

63. The Company omitted costs and exaggerated benefits in the evaluation of the DER management pilot, which rightfully calls into question the cost-effectiveness of the proposed strategy for small DERs, as well as medium and large DERs. OCA St. 1 at 27.

64. The benefits of the Pilot, valued per unit of capacity being managed, suggests that small DERs under 200 kW do not produce benefits in excess of the costs to manage them as proposed by PPL. OCA St. 1 at 25-32.

65. Small and large DERs impact the grid differently and interconnection processes recognize differently sized DERs as there are distinct impacts on the circuits they reside on, among other reasons. OCA St. 1 at 26-27.

66. PPL's own interconnection processes recognize multiple different size categories for interconnection, with DERs above 500 kW requiring additional evaluation and direct control requirements. OCA St. 1 at 26-27.

67. These unique interconnection processes recognize the expected impact from these various systems. OCA St. 1 at 27.

68. Large DERs represent a significant capacity on the circuit they are connected to. OCA St. 1 at 26.

69. A single large DER may have significant impact on voltage, thermal loading, or power quality. OCA St. 1 at 26.

70. Small DERs are insignificant fractions of circuit capacity. OCA St. 1 at 26.

71. OCA witness Nelson is not aware of any jurisdiction that is seriously considering small DER control because it is not cost-effective and other more cost-effective pathways exist. OCA St. 1 at 30.

72. PPL highlights multiple other utilities exploring DER management strategies, however, each utility program cited by PPL explicitly identifies larger DERs as the target for direct control capabilities. OCA St. 1 at 28.

73. Other jurisdictions are exploring flexibility for small DERs through autonomous control, including California, Maryland, and Illinois. OCA St. 1 at 28-30.

74. Australia, with one of the highest penetrations of solar PV in the world, with nearly one third of households having rooftop solar, only has mandatory dedicated monitoring and control for systems larger than 200 kW. OCA St. 1 at 29-30.

75. Ameren Illinois stated that it does not control small DERs using a DERM due to the unjustified cost. OCA St. 1 at 29-30.

76. Ameren Illinois expects that if DER control scenario emerged, DERs smaller than 200 kW would typically not be subject to control unless special circumstances such as program participation warrant it. OCA St. 1 at 29-30 (internal citations omitted).

77. Ameren Illinois identified more cost-effective pathways for controlling small DERs, such as using third parties or equipment manufacturers. OCA St. 1 at 30.

Costs of Mandatory DER

78. PPL projects that PPL DER II will cost $80.1 million through 2030. OCA St. 1 at 35.

79. This projection considers only solar facilities through 2030. OCA St. 1 at 35.

80. PPL assumes that the average cost of the PPL DERM is $1,051 per device. OCA St. 1SR at 35.

81. PPL's mandatory utility-owned devices have a weighted average cost of $959 per unit. PPL St. 10R at 13.

82. As the impacts of other types of DERs become significant, including energy storage and electric vehicles (EV), PPL may recommend that these DERs be similarly managed, and the number of DERs under PPL's management would increase even further. OCA St. 1SR at 35.

83. PPL projects 145,825 Light Duty EVs by 2030, nearly double the number of behind-the-meter DER PPL projects in its cost analysis. OCA St. 1SR at 35.

84. Similarly managing these EVs would add $153.2M, tripling the total cost of DER management. Looking further to 2039, 524,252 EVs add $550.1M to the cost of DER management. OCA St. 1SR at 35.

85. When PPL's DER II strategy is expanded to other non-solar DER, such as electric vehicles, the PPL DER II plan could triple in costs by 2030, and add more than half a billion dollars in management costs by 2039. OCA St. 1 at 2.

86. Most DERs in PPL's territory are small (approximately 98 percent are under 25 kW). OCA St. 1 at 36.

87. The total cost of PPL's original DER Pilot was $6.38 million in capital and $128,000 in operations and maintenance (O&M). OCA St. 1 at 34.

88. The costs of original DER Pilot are primarily related to the purchase and installation of DERMS at DER facilities, with the costs per participating DER between $863 and $1,349, according to PPL's estimates. OCA St. 1 at 34.

89. PPL's reported costs for DER I, however, omitted costs associated with DER II. OCA St. 1 at 34.

90. PPL reports that there are start-up costs amounting to $4.37 million, bringing the total cost of the pilot to $11.66 million. OCA St. 1 at 34.

91. The Company also recognizes that there are significant and unquantified costs for telecommunications networks to enable DER management, including $900,000 in SCADA costs just to enable the management pilot through 2025, and a yet unknown amount for AMI network upgrades. OCA St. 1 at 34.

92. PPL's identified "start-up" costs should be included in the evaluation of DER II. OCA St. 1 at 34.

93. One-time costs in analyzing the cost-effectiveness of a program are already spent. Further, it is not clear that the costs which the Company asserts to be start-up costs are not recurring costs. OCA St. 1 at 34.

94. For example, program management and analysis costs (totaling $1.3 million), are likely continuing costs that the Company will incur if it plans to continue managing the program and recovering program expenses. OCA St. 1 at 34.

95. If the Company ever intends to alter program details as technology changes, additional program management costs should be expected. OCA St. 1 at 34.

96. At best, these costs are truly one-time costs which will be spread across many managed DERs, but there is a real possibility that many of these expenses will recur in expanding and continuing the program. OCA St. 1 at 34.

97. PPL's identified communications system costs should have also been included in the evaluation of the Pilot program. OCA St. 1 at 25.

98. Communications system costs are a direct result of the DER management plan and will scale with the number of DERs. OCA St. 1 at 25.

99. For every additional DERs added to the management plan, the Company notes that "the Company's SCADA system requires a dedicated slot." OCA St. 1 at 25.

100. The Company's reported costs of SCADA alone add $131 per device to the cost of DER management. OCA St. 1 at 25.

101. The AMI network, which must carry the communications could have equal or greater costs than the SCADA connections. OCA St. 1 at 25.

102. These costs will grow exponentially as the number of DERs grow on the system, representing a very real concern for the cost-effectiveness of the DER management plan. OCA St. 1 at 25.

103. OCA witness Nelson testified that "[t]he total cost of PPL's DER I is likely closer to $13.46 million assuming, potentially conservatively, that the costs of upgrading the AMI network are equivalent to the costs of upgrading the SCADA network. This doubles the average cost per DERM to $1,957." OCA St. 1 at 35-36.

Benefits of DER

104. Smart inverters provide the capability to change DER operational characteristics autonomously, based on predetermined criteria, or by active communication with a management system, such as a utility's DERMS or an aggregator. OCA St. 1 at 41.

105. PPL's proposed DER management plan uses both control capabilities, with autonomous ride-through and reactive power settings operating by default, and active controls for modifying these settings in response to system conditions. OCA St. 1 at 41.

106. Each of these capabilities can benefit the system by providing grid support. OCA St. 1 at 41.

107. Active control provides an incremental value over autonomous control, because it can be adapted to coordinate multiple DERs to respond to larger grid needs. OCA St. 1 at 41.

108. For DER II, PPL proposes to install DERMs, which would be unnecessary for autonomous capabilities alone, for an average cost of up to $1957 per DER. OCA St. 1 at 42.

109. The incremental value of active control matters because enabling active control requires additional investments, while autonomous capabilities are effectively free, or very low cost, for ratepayers. OCA St. 1 at 42.

110. PPL was required to compare autonomous and active DER control under DER I. OCA St. 1 at 42.

111. Most of the quantified benefits of the DER pilot program are attributed to active control, except for "ease of integration," "learning and adaptation," and a portion of "flexibility in energy supply" value related to increased hosting capacity. OCA St. 1 at 42.

112. Increased hosting capacity is derived from monitoring, autonomous control, and active management, and the Company's evaluation found that just 18% of increased hosting capacity from the pilot resulted from active control. OCA St. 1 at 42.

113. Removing these non-active control values from the DER pilot benefits results in a reported incremental value of active control of $18.4 million. OCA St. 1 at 42.

114. Of this incremental value, the vast majority, $15 million, relate to the truck roll and hosting capacity savings. OCA St. 1 at 42.

115. The new CBA reduced the relative benefits from 51% to 16% of the total benefits of PPL DER II. OCA St. 1SR at 16.

116. In its initial CBA, PPL estimated that 61% of increased hosting capacity from the pilot resulted from DER monitoring, equating to $4.8 million. OCA St. 1SR at 16.

117. PPL also studied, though did not specifically quantify, the value of monitoring load that is hidden by DER, to provide additional load-serving capacity on the system. OCA St. 1 at 43.

118. PPL's DER II proposes a DER management device on every eligible interconnected DER to provide dedicated communications for real time monitoring. OCA St. 1 at 43.

119. The benefit of a dedicated communications channel is in providing real time visibility, however, this use case does not align with how PPL quantified the value of DER monitoring. OCA St. 1 at 43.

120. Based on the Company's assessment, the quantifiable value of DER monitoring is overwhelmingly in improving planning models for increased load and DER capacity. OCA St. 1 at 43-44.

121. These use cases do not require real time monitoring and could be served by much less frequent, and less costly, monitoring to inform, for example, monthly, quarterly, or annual planning updates. OCA St. 1 at 43-44.

122. The active monitoring use cases do not support the Company's proposed DER management strategy, as the active management provides minimal additional value. OCA St. 1 at 43-44.

123. Active monitoring is only needed for large DERs. OCA St. 1 at 44.

124. There are alternative, more cost-effective approaches to obtaining monitoring data from small DERs that could be used to improve modeling and address many, if not all, of the active monitoring use cases covered by the Company. OCA St. 1 at 44.

125. Requiring active monitoring for small DERs will increase costs for ratepayers will little, to no, incremental benefit. OCA St. 1 at 44.

126. Costs associated with managing DER vary depending on the management capabilities. OCA St. 1 at 18.

127. Some forms of management require little, to no, infrastructure or capital investment, such as rate design or autonomous smart inverter settings. OCA St. 1 at 18.

128. Increasing levels of monitoring and active management, however, require increasingly greater infrastructure for communicating with, processing information from, and delivering commands to DER. OCA St. 1 at 18.

129. The costs of this management generally increase with this complexity and the number of systems to be managed. OCA St. 1 at 18.

130. The costs of this management need to be explicitly and comprehensively evaluated against the benefits of managing those systems. OCA St. 1 at 18.

131. The largest DERs may warrant dedicated fiber-optic communication connections to utility control systems to provide the most reliable and low-latency communication because their output is large enough to cause significant damage to the system during abnormal events. OCA St. 1 at 18.

132. Opposite on the spectrum, small DERs whose individual output is insignificant to the system, may only be economically managed through rate structures and management that does not require additional infrastructure investment. OCA St. 1 at 18.

<u>Cost Benefit Analysis (CBA)</u>

133. PPL introduced a new CBA analysis through rebuttal testimony that significantly deviated from PPL's analysis presented in direct testimony. PPL St. 3; PPL St. 10R.

134. OCA witness Nelson testified that "[t]he largest benefit from PPL's original analysis was from reduced truck rolls associated with voltage violations, which represented 51% of the total benefits. OCA St. 1SR at 15.

135. The new CBA submitted in rebuttal had significant deviations from the analysis presented in direct testimony, which would imply that one or the other presented CBA is inaccurate. OCA St. 1SR at 16.

136. The new CBA study decreased the relative benefits related to reduced truck rolls to mitigate voltage violations, reducing them from the 51% stated above to 16% of the total benefits of the 2nd DER Plan presented in the new CBA. OCA St. 1SR at 16.

137. A similar magnitude of change is reflected in the treatment of deferred capital costs resulting from the 2nd DER Plan. OCA St. 1SR at 16.

138. The analysis provided in direct testimony included 12% of the total pilot benefits under the "cost-effective investment" category, while the new CBA filed in rebuttal includes 28% of the total benefits stack as deferred distribution capital investments related to improved hosting capacity. OCA St. 1SR at 16.

139. Finally, the evaluation of the pilot benefits included $1.48M in benefits attributed to "learning & adaptation" that was entirely removed from the new CBA filed in rebuttal testimony. OCA St. 1SR at 16.

140. The two PPL cost-benefit analyses submitted in the Company's Direct Testimony and Surrebuttal Testimony contradict each other. OCA St. 1SR at 17.

141. PPL assigned increased hosting capacity as the primary benefit to ratepayers, claiming $27,393,149 of total benefits associated with increases in hosting capacity related to active

management, and another $98,615,335 in benefits associated with monitoring for a total benefit of $126,008,484. OCA St. 1SR at 18-19.

142. These benefits represent 57% and 86% of the total benefits the Company finds for active management and the active management plus monitoring cases, respectively. OCA St. 1SR at 18-19.

143. The Company does not have an obligation to serve export facilities and to provide hosting capacity the same way that it does for load customers. OCA St. 1SR at 18-19.

144. For load customers, the Company has an obligation to provide a service to these customers; no such obligation to serve exists for customers desiring to export onto the distribution system. OCA St. 1SR at 18-19.

145. Increased hosting capacity is not a ratepayer benefit, it is a cost shift from ratepayers to DER developers that do not have to pay for system upgrades or any of the investments used to increase said hosting capacity (e.g., DERMS). OCA St. 1SR at 19.

146. Nameplate capacity is determined by the generator's manufacturer and indicates the maximum output of electricity a generator can produce without exceeding design limits. OCA St 1SR at 22.

147. The amount of energy produced by a solar panel varies throughout the day and year depending on the sun's relative position. OCA St. 1SR at 22.

148. Even under conditions of highest solar resource availability (*e.g.*, a July day at noon), the actual output of a solar system will not reach its nameplate capacity due to factors such as losses from wiring, DC to AC conversion, and soiling of the panel. OCA St. 1SR at 22.

149. Using nameplate capacity is an unreasonable approach to identifying potential output of a solar PV system. OCA St. 1SR at 22.

150. OCA witness Nelson recommended that PPL perform a rigorous alternatives analysis via a DER Orchestration Plan. OCA St. 1SR at 22.

151. The Company has significant data at its disposal, including Advanced Metering Infrastructure ("AMI") measurements of near-real-time net load for DER customers, not to mention two years of detailed, real-time generation data from geographically diverse DER from the Pilot. OCA St. 1SR at 22-23.

152. PPL did not explain or provide a rationale as to why it must have real-time data monitoring to achieve improved planning models. OCA St. 1SR at 22.

153. In its 2024 DER Management Report, the Company states "As of the end of Program Year 2, PPL Electric's DER Pilot has resulted in an estimated increase of 29 MW of hosting capacity across the system when compared to the "Nameplate" scenario, with 5

MW of the 29 MW of hosting capacity attributed to the active management of power factor" (emphasis added). OCA St. 1SR at 24.

154. The new CBA quantifies this 5 MW benefit from "active management" of DER and passes it off as an incremental benefit to using autonomous inverter controls, when in reality they were comparing it to an unmanaged base case without use of autonomous controls. OCA St. 1SR at 24.

155. The Company reports autonomous inverter controls yield a benefit of 6 MW of incremental hosting capacity over the same base case (i.e., "nameplate") scenario, indicating that autonomous controls can reduce potential impacts by the same magnitude, or greater, than the Company's own analysis of its active management use case. OCA St. 1SR at 24.

156. PPL witness Wishart touts avoided distribution capital investments associated with incremental hosting capacity from active management of DERs as one of the single largest benefits underpinning the CBA valued at $13,336,556. OCA St. 1SR at 24-25.

157. The finding that avoided distribution upgrades are solely attributable to active management is at odds with evidence from PPL's own DER Pilot findings. OCA St. 1SR at 25.

158. In the Company's 2024 DER Management Report under the subsection describing its analysis of capital deferral opportunities, the Company states that "As of March 21, 2024, PPL Electric has identified three (3) studies which can result in $1,664,000, all attributed to autonomous volt/var curves for customers applying to interconnect to the distribution system." OCA St. 1SR at 25(internal citations omitted).

159. The CBA contradicts the DER I Pilot findings that the three major avoided capital upgrade deferrals identified in their own analysis are attributable, not to active management through DER Management Devices, but instead to autonomous inverter settings in the form of volt/var curves. OCA St. 1SR at 25.

160. Autonomous controls can reduce potential impacts by the same magnitude, or greater, than the Company's own analysis of its active management use case. OCA St. 1SR at 25.

161. A study funded by the US Department of Energy demonstrated that autonomous inverter settings can provide substantial benefits to the grid, particularly around managing voltage impacts. OCA St. 1SR at 25-26.

162. The study's authors also recognize that DER integration costs and associated hosting capacity can be very dependent on the specific conditions present on a given distribution feeder, such as the length of the line, the type of customer classes present, and the existing utility assets. OCA St. 1SR at 25-26.

163, Increased hosting capacity investment does not benefit the system as a whole. OCA St. 1SR at 27.

164. Avoided infrastructure costs are a benefit to DER customers that are paid for by all other ratepayers. OCA St. 1SR at 27.

165. Currently, hosting capacity is assessed and paid for on a case-by-case basis for DER seeking to interconnect to the grid. OCA St. 1SR at 26.

166. Connecting DER customers benefit from avoided capital costs from incremental hosting capacity from DER II. OCA St. 1SR at 26-27.

167. Most of the costs of the DER II will be paid by the more than 90% of customer who do not have DER. OCA St. 1SR at 27.

168. PPL proposes that all customers will pay for the costs of the DER II, as the costs would be incorporated into base rates. OCA St. 1SR at 27.

169. Similar to the infrastructure investments, the reduction in wholesale energy benefit of $22/MWh is not appropriate for this analysis since it fails to account for PPL's [Net Energy Metering] rate structure. OCA St. 1SR at 28.

170. While it is true that PPL may see a reduction in the need to purchase wholesale energy to meet its load obligations with incremental DER adoption, those reduced costs are only one half of the equation. OCA St. 1SR at 28.

171. PPL states that "DERs already benefit from net metering that compensates them at the full retail rate, which substantially exceeds the value of the energy they displace." OCA St. 1SR at 28.

172. Under PA statute, PPL must compensate Net Energy Metering (NEM) customers at the retail rate for any excess kWh. OCA St. 1SR at 28.

173. The kWh from additional DER generation espoused under DER II would reduce wholesale energy costs but will also lead to additional expenses to compensate customers for their net-exports. OCA St. 1SR at 28.

174. PPL primarily evaluated the costs and benefits of its own proposal to deploy DER management devices to enable real-time monitoring and control on every connected DER. OCA St. 1SR at 31. PPL did not demonstrate that actively managing all DERs is cost-effective. OCA St. 1SR at 32.

175. Identifying hidden load and improving distribution models does not require monitoring DERs through a utility-owned DER management device. OCA St. 1 at 25.

176. Cloud communication-enabled smart inverters can be used to collect the same information PPL is obtaining through its DER management devices. OCA St. 1 at 25.

177. Advanced DER forecasting tools can provide accurate aggregate modeling of small DERs without monitoring. OCA St. 1 at 25.

178. This fact undermines many of the benefits the Company ascribes to DER II, including the benefits of monitoring real power, reactive power, and voltage monitoring because the same benefits could be more cost-effectively realized through other approaches. OCA St. 1 at 25.

179. Advanced DER monitoring can provide an accurate prediction of aggregated DER operations with little monitoring of the DER. OCA St. 1 at 14, 25.

180. Advanced DER forecasting tools can provide accurate aggregate modeling of small DERs without monitoring. OCA St. 1 at 25.

181. This fact undermines many of the benefits PPL ascribes to DER II because the same benefits could be more cost-effectively realized through other approaches. OCA St. 1 at 25.

182. Several studies have demonstrated the usefulness and accuracy of advanced forecasting models pertaining to the prediction of rooftop solar, particularly in the case of many aggregated small-scale devices such as in typical residential installations. OCA St. 1SR at 38.

183. The Electric Power Research Institute (EPRI) has conducted extensive research working with Con Edison in New York on using advanced solar disaggregation and forecasting techniques to support utility planning and operations, which PPL could use in its hosting capacity evaluation and potentially even in an operational setting. OCA St. 1SR at 38.

184. OCA witness Nelson also testified that PPL likely already has access to such advanced DER modeling capabilities, through its grid orchestration product vendor, Camus Energy. OCA St. 1SR at 38.

185. Camus's website specifically highlights that part of their orchestration platform is an advanced forecasting which can uncover "hidden load" via meter-level forecasting (i.e. using AMI measurements). OCA St. 1SR at 38.

186. Cloud communication-enabled smart inverters can be used to collect the same information PPL would obtain through its DERMs. OCA St. 1 at 25.

187. While PPL states that it is interested in cloud-based alternatives, PPL did not analyze the costs, benefits, or service providers as a serious alternative. OCA St. 1SR at 40.

188. PPL makes no commitment to pursue and deploy lower cost alternative program designs in the future. OCA St. 1SR at 40.

189. PPL's DER II also contains no requirement allowing for reconsideration of its DER management strategy. OCA St. 1SR at 40.

190. Without either of these guarantees that future cost savings will be pursued, PPL's interest in a cloud-based communication alternative to mandatory control of DERs through PPL's DERM is meaningless. OCA St. 1SR at 40.

191. DERs can communicate system needs to aggregators or equipment manufacturers with the capability to manage DER settings to respond to system needs. OCA St. 1 at 15.

192. Reliance on third-party aggregators or equipment manufacturers to actively manage DERs, rather than the utility, can avoid expensive utility investment in active management. OCA St. 1 at 15.

193. There are many examples of alternative utility DER management programs provided by the parties that rely on third-party aggregators to manage the program, including the example PPL provided of Duke Energy's PowerPair Program. OCA St. 1SR at 41; PPL St. 2-R at 7.

194. PPL did not seek out an aggregator service from the market or through a Request for Proposal (RFP). OCA St. 1SR at 43.

195. An RFP is necessary for third-party aggregator services as it is unreasonable to assume that potential third-party aggregators would approach PPL with fully-formed products tailored to PPL's needs, potentially divulging their own valuable intellectual property, when there is no solicitation by PPL. OCA St. 1SR at 43-44.

<u>Export Tariffs</u>

196. Export tariffs should be evaluated prior to having costly and mandatory DER requirements to avoid shifting the cost of DER management to ratepayers that do not own DERs. OCA St. 1 SR at 49-50.

197. Connecting DERs drive the cost associated with the DER devices. OCA St. 1SR at 50.

198. An export tariff is a contractual agreement that governs how system upgrade costs are allocated to and recovered from DER which export energy onto the grid. OCA St. 1 at 52.

199. Export tariffs that allocate and recover costs from exporting customers, as they are the cost causers, have been investigated in both Massachusetts and Australia. OCA St. 1 at 51.

200. OCA witness Nelson noted that it is too early for PPL or other Pennsylvania utilities to examine the reasonableness of export tariffs due to the fact that PPL has very low DER penetration. OCA St. 1 at 51.

201. Export tariffs may not need to be implemented for several years. OCA St. 1 at 52.

202. Export tariffs, however, are an important tool for allocating costs to the cost-causers. OCA St. 1 at 2.

203. If PPL's DER II is approved without modification, the cost of PPL DER II over time may exceed half a billion dollars. OCA St. 1 at 2.

Appendix B

Conclusions of Law

APPENDIX B

Conclusions of Law

1. PPL is a public utility as defined in Section 102 of the Public Utility Code. 66 Pa. C.S. § 102.

2. The Commission has jurisdiction over the parties and subject matter of this proceeding. 66 Pa. C.S. § 101, *et seq*.

3. PPL's original DER Management Pilot Program (Pilot or DER I) was initiated as a result of a settlement in January, 2021. *Petition of PPL Electric for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan*, Docket No. P-2019-3010128, Order (Dec. 17, 2020) (*PPL DER I Order*).

4. The PPL DER I Settlement provided, in relevant part:

> 54. The Company shall be authorized to conduct a pilot program ("pilot" or "pilot program") to test and evaluate: (1) the costs and benefits to distribution system operation and design of *monitoring* DERs through devices connected to inverters as compared to maintaining distribution system status visibility through other means (e.g., automated meter reading equipment, ADMS systems, modeling); and (2) the costs and benefits to distribution system operation of active management of DERs as compared to the benefits available through the use of inverter autonomous grid support functions. The pilot program will begin on January 1, 2021, and will end three years after the second control group is established pursuant to Paragraph 57, *infra*. The three years after the second control group is established will be referred to as Program Year 1, Program Year 2, and Program Year 3.

Petition of PPL Electric for Approval of Tariff Modifications and Waivers of Regulations Necessary to Implement its Distributed Energy Resources Management Plan, Docket No. P-2019-3010128, *Recommended Decision* at 16 (Nov. 17, 2020) (*PPL DER I RD*).

5. The Commission's Regulations at 52 Pa. Code Chapter 75, the Alternative Energy Portfolio Standards (the AEPS), set forth the requirements and standards that Electric Distribution Companies (EDCs) must meet if customer-generators on their system intend to pursue net-metering opportunities and interconnect with the electric distribution grid. *See* 52 Pa. Code § 75.21; *see also* 73 P.S. § 1648.5 (directing the Commission to develop technical and net metering interconnection rules for customer-generators).

6. The AEPS limits EDCs from requiring additional equipment or imposing any other requirement upon DER applicants that is not specifically required by the AEPS. 52 Pa. Code § 75.13(k).

7. The Public Utility Code provides in relevant part:

> (a) Burden of proof. Except as may be otherwise provided in section 315 (relating to burden of proof) or other provisions of this of other relevant statute, the proponent of a rule or order has the burden of proof.

66 Pa. C.S. §332(a).

8. As the proponent of an order in this proceeding, PPL has the burden of proof to establish that it is entitled to the relief it is seeking. 66 Pa. Code § 332(a). PPL must demonstrate its case by a preponderance of evidence. *Lansberry v. Pa. PUC*, 578 A.2d 600 (Pa. Cmwlth. 1990).

9. In addition to the burden of proof, the petitioner must provide substantial evidence in the record as support for its case before the Commission. *Burleson v. Pa. PUC*, 501 Pa. 433, 436 (1983).

10. The Pennsylvania Supreme Court has also provided that even where a party has established a prima facie case, the litigant must establish that:

> The elements of that cause of action are proven with substantial evidence which enables the party asserting the cause of action to prevail, precluding all reasonable inferences to the contrary.

Burleson v. Pa. PUC, 501 Pa. 433, 436 (1983).

11. The party with the burden of proof has a formidable task to show that the Commission may lawfully adopt its position. *Burleson v. Pa. PUC*, 501 Pa. 433, 436 (1983).

12. Furthermore, it is well-established that the "degree of proof before administrative tribunals as well as before most civil proceedings is satisfied by establishing a preponderance of the evidence." *Lansberry v. Pa. PUC*, 578 A.2d 600, 602 (Pa. Cmwlth. 1990).

13. The "term 'burden of proof" is comprised of two distinct burdens, the burden of production and the burden of persuasion." *Hurley v. Hurley*, 754 A.2d 1283, 1285 (Pa. Super. Ct. 2000).

14. The burden of production dictates which party has the duty to introduce enough evidence to support a cause of action. *Hurley v. Hurley*, 754 A.2d 1283, 1286 (Pa. Super. Ct. 2000).

15. The burden of persuasion determines which party has the duty to convince the finder-of-fact that a fact has been established. *Hurley v. Hurley*, 754 A.2d 1283, 1286 (Pa. Super. Ct. 2000) "The burden of persuasion never leaves the party on whom it is originally cast." *Hurley v. Hurley*, 754 A.2d 1283, 1286 (Pa. Super. Ct. 2000); *see also Pa. PUC v. Equitable Gas Co.*, 57 Pa. PUC 423, 471 (1983).

16. The burden of proof does not shift to parties challenging the proposed order but rather must be met by the utility. *Pa. PUC v. Pa.-American Water Co.*, 2004 Pa. PUC LEXIS 29 at *16-18 (Order entered Jan. 29, 2004).

17. The Commission recognizes in its rate determinations that the burden of proof will not shift to a complainant or intervener that is challenging the requested order. *Pa. PUC v. Equitable Gas Co.*, 57 Pa. PUC 423, 471 (1983); *see also University of Pa. v. Pa. PUC*, 485 A.2d 1217 (Pa. Cmwlth. 1984); *Pa. PUC v. PPL Elec. Util. Corp.*, Docket No. R-00049255 (Order entered Dec. 22, 2004).

18. PPL has not met its burden to demonstrate that the level of control and monitoring as proposed in DER II is necessary or prudent for the provision safe, adequate and efficient service to customers under Sections 1301 and 1501 of the Public Utility Code and the AEPS standards set forth in Section 1648.5 and the Commission's regulations. 66 Pa. C.S. §§ 1301, 1501; 52 Pa. Code § 75.21, 75.13(k); *see also* 73 P.S. § 1648.5

Appendix C

Proposed Ordering Paragraphs

APPENDIX C

Proposed Ordering Paragraphs

It is hereby ORDERED THAT:

1. PPL's Petition for its Second DER Management Plan is hereby denied without prejudice. PPL shall be permitted to file a DER Management Petition once it has completed a DER Orchestration Plan.