BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of Metropolitan Edison Company for Approval of a Default Service Program for the Period Beginning June 1, 2019 through May 31, 2023	:	P-2017-2637855
Petition of the Pennsylvania Electric Company for Approval of a Default Service Program for the Period Beginning June 1, 2019 through May 31, 2023	:	P-2017-2637857
Ellen L. Cooper v. Pennsylvania Electric Company	:	C-2018-2643217
Betty Dusicsko v. Pennsylvania Electric Company	:	C-2018-2643249
Joseph Dusicsko v. Pennsylvania Electric Company	:	C-2018-2643274
Angela C. Esters v. Pennsylvania Electric Company	:	C-2018-2643222
Debra A. Gibbs v. Pennsylvania Electric Company	:	C-2018-2643260
Catherine M. Hartzell v. Pennsylvania Electric Company	:	C-2018-2643211
Dennis T. Husted v. Pennsylvania Electric Company	:	C-2018-2643280

Cynthia Glover Muhammed v. Pennsylvania Electric Company	: : : :	C-2018-2643212
David Nies v. Pennsylvania Electric Company	: : : :	C-2018-2643243
Carl E. Palotas, Jr. v. Pennsylvania Electric Company	: : : :	C-2018-2643225
Richard S. Powierza v. Pennsylvania Electric Company	: : : :	C-2018-2643248
Bernadine Randhanie v. Pennsylvania Electric Company	: : : :	C-2018-2643284
Matthew J. Sciarrino v. Pennsylvania Electric Company	: : : :	C-2018-2643239
Mark L. Spaeder v. Pennsylvania Electric Company	: : : :	C-2018-2643244
Kenneth C. Springirth v. Pennsylvania Electric Company	: : : :	C-2018-2641907
Kathleen B. Walls v. Pennsylvania Electric Company	: : : :	C-2018-2643213
Robert H. Walls v. Pennsylvania Electric Company	: : : :	C-2018-2643214
Julie Whaling v. Pennsylvania Electric Company	: : : :	C-2018-2643277

Robert G. Whaling, Sr. v. Pennsylvania Electric Company	: : : :	C-2018-2643280
Joseph A. and Dianne L. Yochim v. Pennsylvania Electric Company	: : :	C-2018-2643246
Petition of Pennsylvania Power Company for Approval of a Default Service Program for the Period Beginning June 1, 2019 through May 31, 2023	: : : :	P-2017-2637858
Petition of West Penn Power Company for Approval of a Default Service Program for the Period Beginning June 1, 2019 through May 31, 2023	: : : :	P-2017-2637866

RECOMMENDED DECISION

Before
Mary D. Long
Administrative Law Judge

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I. HISTORY OF THE PROCEEDING

On December 11, 2017, Metropolitan Edison Company (MetEd), Pennsylvania Electric Company (Penelec), Pennsylvania Power Company (Penn Power) and West Penn Power Company (West Penn) (collectively, the Companies) filed a joint petition for the approval of default service and procurement programs covering a four-year period from June 1, 2019 through May 31, 2023. By law, the Commission must render a final decision on the Companies' Default Service Programs (DSPs) on or before September 11, 2018.[1]

By hearing notice dated December 21, 2017, the petitions were assigned to me and a telephonic prehearing conference was scheduled for January 17, 2018 at 1:30 p.m. Notice of the petitions and the prehearing conference was also published in the Pennsylvania Bulletin on December 23, 2017.[2]

PA PUC Bureau of Investigation & Enforcement (BIE), Office of Consumer Advocate (OCA), and Office of Small Business Advocate (OSBA) (collectively, the Statutory Parties) each filed interventions. Petitions to intervene were also filed by Calpine Energy Solutions, LLC (Calpine), Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA), Constellation NewEnergy, Inc. (Constellation) and Exelon Generation Company, LLC (ExGen), MetEd Industrial Users Group (MEIUG), Penelec Industrial Customer Alliance (PICA), West Penn Power Industrial Intervenors (WPPII)[3], NextEra Energy Marketing, LLC (NextEra), Pennsylvania State University (PSU), Retail Energy Supply Association (RESA), and Respond Power LLC (Respond Power). On January 8, 2018, Kenneth C. Springirth, a ratepayer, filed a formal complaint challenging the petition of Penelec.[4]

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1 66 Pa.C.S. § 2807(e)(3.6).

2 47 Pa.B. 7809-7811 (December 23, 2017).

3 MEIUG, PICA and WPPII are hereafter collectively referenced as the "Industrials."

4 C-2018-2641907.

An additional 19 formal complaints were filed by consumers which also challenged the petition of Penelec.

A prehearing conference was held on Wednesday, January 17, 2018. Counsel for the Companies, the statutory parties, and the interveners attended the conference. Mr. Springirth also appeared. Christine Rush of State Representative Pat Harkins' office, along with Father Jerry Priscaro and John Shubert, appeared and participated in the discussion regarding public input hearings. Sean Ajazi of Progressive Energy Group also called in to observe the proceedings. A litigation schedule was established which set deadlines for the exchange of written testimony, and the parties agreed to a date for a public input hearing and evidentiary hearings. The parties also agreed to a briefing schedule.

A petition to intervene by Direct Energy Services, LLC (Direct Energy) was granted on February 14, 2018.

Public input hearings were held on March 13, 2018, in Erie, the service territory of Penelec. Forty people testified at the hearing held at 1:00 p.m. and 26 additional people testified at the 6:00 p.m. hearing. The subject of the testimony was the Companies' proposed Bypassable Retail Market Enhancement Rate Mechanism (PTC Adder).

The parties undertook discovery and served written direct, rebuttal and surrebuttal testimony. The evidentiary hearing convened on April 10, 2018. The Companies offered the oral rejoinder testimony of Kevin R. Siedt. Although the parties had not achieved an agreement on all of the issues raised in the proceeding, all parties agreed to waive the cross-examination of witnesses. Any argument necessary on unresolved claims would rely solely on the written testimony admitted into the record. Accordingly, the written testimony of the Companies, BIE, OCA, OSBA, CAUSE-PA, the Industrials, PSU, Constellation and ExGen, Calpine, RESA, and Respond Power was admitted into the record.[5] Additionally, six stipulations were admitted into the record as Stipulations 1-6:

[5] Neither NextEra nor Direct Energy submitted written testimony for admission into the record.

Joint Stipulation	Stipulating Parties	Subject of the Joint Stipulation
No. 1	All parties	Non-commodity billing and time-of-use rates
No. 2	Companies, BIE, Respond Power, RESA	POR Clawback Charge
No. 3	Companies and CAUSE-PA	Costs associated with unrestricted shopping by PCAP customers June 2013-March 2018
No. 4	Calpine and ExGen/Constellation	NITS and other EGS issues
No. 5	Calpine and RESA	NITS and other EGS issues
No. 6	RESA and CAUSE-PA	Bundling energy management devices referenced by RESA witness Richard J. Hudson

A common brief outline was submitted on April 9, 2018, which set forth the topic headings that the parties agreed to use for the presentation of their arguments. Main briefs were filed by the Companies, BIE, OCA, OSBA, CAUSE-PA, the Industrial Intervenors, PSU, RESA and Respond Power. These briefs presented each party's legal argument in regard to issues regarding the default service plans that had not been resolved by settlement. Not every issue was of consequence to every party. Each party noted those issues upon which it either did not oppose or did not take a position in the litigation.

A Joint Petition for Partial Settlement (Settlement or Partial Settlement) was filed on May 15, 2018, along with reply briefs. Parties joining the Settlement included statements in support of the relevant issues in their respective reply briefs.

By order dated May 16, 2018, the parties who did not actively participate in the litigation were provided an opportunity to join or object to the Settlement. These responses were due on or before May 25, 2018. By order dated May 29, 2018, the record was closed.

II. LEGAL STANDARDS

The Companies have the burden of proof in this proceeding to establish that they are entitled to the relief they are seeking.[6] The Companies must establish their case by a preponderance of the evidence.[7] To meet their burden of proof, the Companies must present evidence more convincing, by even the smallest amount, than that presented by any opposing party.[8]

In this case, the Companies request that the Commission approve the joint filing establishing the proposed DSPs. They must prove that their proposed default service provider program is just and reasonable. Any party contesting the proposed DSPs has the burden of persuading the Commission that the filing is not just and reasonable.[9] Where competing proposals are introduced, the sponsoring party must show that the alternative proposal will better serve customers.[10]

The Competition Act[11] requires that default service providers acquire electric energy through a "prudent mix" of resources that is designed: (i) to provide adequate and reliable service; (ii) to provide the least cost to customers over time; and (iii) to achieve these results through competitive processes that include auctions, requests for proposals and/or bilateral

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6 66 Pa.C.S. § 332(a).

7 *Samuel J. Lansberry, Inc. v. Pa. Pub. Util. Comm'n*, 578 A.2d 600 (Pa.Cmwlth. 1990), *alloc. den.*, 602 A.2d 863 (Pa. 1992).

8 *Se-Ling Hosiery v. Margulies*, 70 A.2d 854 (Pa. 1950).

9 *Brockway Glass Co. v. Pa. Pub. Util. Comm'n*, 437 A.2d 1067 (Pa.Cmwlth. 1981).

10 *Joint Petition of Metropolitan Edison Company and Pennsylvania Electric Company for Approval of Their Default Service Programs*, Docket No. P-2009-2093053 and P-2009-2093054 at 19 (Opinion and Order entered November 6, 2009).

11 Electricity Generation Customer Choice and Competition Act, Act 138 of 1996, as amended by Act 129 of 2008 (Act 129), codified at 66 Pa.C.S. § 2801 *et seq*.

agreements.[12] The Competition Act does not, however, require a specific default service rate design methodology.[13]

The Competition Act also mandates that customers have direct access to a competitive retail generation market.[14] This mandate is based on the legislative finding that "competitive market forces are more effective than economic regulation in controlling the cost of generating electricity."[15] Thus, a fundamental policy underlying the Competition Act is that competition is more effective than economic regulation in controlling the costs of generating electricity.[16]

In addition to the foregoing statutory guidelines, the Commission has enacted default service regulations,[17] and a policy statement,[18] addressing default service plans. The regulations first became effective in 2007 and have been amended to incorporate the Act 129 amendments to the Competition Act.[19]

This is the Companies' fifth DSP filing and is often referenced as DSP V. Prior DSPs include:

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12 66 Pa.C.S. §§ 2807(e)(3.1) and 2807(e)(3.4).

13 *Id*.

14 66 Pa.C.S. § 2802(3).

15 66 Pa.C.S. § 2802(5). *See, Green Mountain Energy Company v. Pa. Pub. Util. Comm'n*, 812 A.2d 740, 742 (Pa.Cmwlth. 2002).

16 66 Pa.C.S. § 2802(5).

17 52 Pa.Code §§ 54.181 to 54.189.

18 52 Pa.Code §§ 69.1802 to 69.1817.

19 *See* Implementation of Act 129 of October 15, 2008; Default Service and Retail Electric Markets, Docket No. L-2009-2095604 (Final Rulemaking Order entered October 4, 2011) (Act 129 Final Rulemaking Order).

Delivery Period	Docket Nos.	Final Order Date
January 1, 2011 - May 31, 2013 (DSP I)	P-2009-2093053 P-2009-2093054	November 6, 2009
June 1, 2013 - May 31, 2015 (DSP II)	P-2011-2273650 P-2011-2273668 P-2011-2273669 P-2011-2273670	August 16, 2012
June 1, 2015 – May 31, 2017 (DSP III)	P-2013-2391368 P-2013-2391372 P-2013-2391375 P-2013-2391378	July 24, 2014
June 1, 2017 – May 31, 2021 (DSP IV)	P-2015-2511333 P-2015-2511351 P-2015-2511355 P-2015-2511356	May 19, 2016

III. FINDINGS OF FACT

1. The Companies' current default service programs (DSPs) began on June 1, 2017. (DSP IV).[20]

2. Pursuant to the settlement of the DSP IV proceeding, the Companies agreed to hold a stakeholder collaborative during the DSP IV term to discuss: (a) the current procurement and market conditions; (b) the establishment of a bypassable retail market enhancement rate mechanism; (c) the scope of shopping available to customers enrolled in the Companies' customer assistance programs; (d) the continuation of the purchase of receivables (POR) clawback charge; and (e) any changes to customer classes. The Companies were required to make a Commission filing, including but not limited to a new DSP petition, with regard to its position on the collaborative topics in a docketed proceeding by January 31, 2018.

[20] The Companies' current DSPs were approved by Commission order entered May 19, 2016, at Docket Nos. P-2015-2511333 (MetEd), P-2015-2511351 (Penelec), P-2015-2511355 (Penn Power), and P-2015-2511356 (West Penn) (collectively, the "DSP IV Proceeding").

(*DSP IV Proceeding*, Docket Nos. P-2015-2511333, *et seq.* at 5-22 (Joint Petition for Settlement dated April 1, 2016)).

3. The Companies are proposing a DSP V period of June 1, 2019 through May 31, 2023. (Joint Petitions).

4. A four-year term provides certainty for customers and electric generation suppliers (EGSs) regarding the terms of the DSP, while also providing administrative efficiencies and cost savings for customers compared to filing on a more frequent basis. (Companies St. 1).

5. The Companies are proposing to acquire full-requirements, load-following energy and energy-related products through multiple-round, descending-price clock auctions (DCAs). (Companies St. 2 at 5).

6. DCAs have been frequently used for electricity procurement by electric distribution companies (EDCs) in Pennsylvania, including the Companies, since the late 1990s. (Companies St. 2 at 12).

7. The auction format is transparent and nondiscriminatory to prospective bidders, which promotes competitive procurement results. (Companies St. 2 at 17).

8. The Companies will maintain their current load cap, which restricts the amount of supply any one bidder can win in an auction to 75%. (Companies St. 2 at 10).

9. The Companies are continuing to use CRA International, Inc., for their default service procurements, and the Brattle Group for their solar photovoltaic alternative energy credit (SPAEC) procurements. (Companies St. 2 at 7, 23-24).

10. The Supplier Master Agreement (SMA) proposed by the Companies is identical to their current SMA with the exception of reflecting the 100 kW industrial class

change and certain other cleanup changes related to new PJM Interconnection, LLC (PJM) billing line items. (Companies St. 2 at 21-22).

11. Winning bidders in the Companies' DCAs must fulfill all obligations imposed on a load serving entity (LSE) by PJM, including: (a) providing energy, capacity and transmission service, including Network Integration Transmission Service (NITS) charges; (b) paying all ancillary service costs and PJM administrative expenses; and (c) providing any other services and paying any other fees as required by PJM of an LSE. (Companies St. 2 at 7).

12. The Companies will assume responsibility for Regional Transmission Expansion Plan charges (RTEP); Expansion Cost Recovery Charges; Reliability Must Run/generation deactivation charges (RMR) associated with generating plants for which specific RMR charges began after July 24, 2014; historical out of market tie line, generation and retail customer meter adjustments; unaccounted for energy; and any Federal Energy Regulatory Commission (FERC) approved reallocation of PJM RTEP charges related to Docket No. EL05-121-009 (collectively referred to as "non-market based charges," or "NMB charges"). NMB costs will be recovered from customers in a competitively-neutral manner under the Companies' non-bypassable Default Service Support (DSS) Riders. (Companies St. 2 at 21-22).

13. Winning bidders in the DCAs in the MetEd, Penelec and Penn Power service territories will be responsible for meeting all non-solar Tier I alternative energy credit (AEC) and Tier II AEC requirements. Winning bidders in West Penn's service territory will be responsible for all Tier I and Tier II requirements less any Tier I AECs that are allocated under existing long-term purchases made by West Penn. (Companies St. 2 at 6, 23).

14. Penelec also will continue to make market-priced sales of excess AECs acquired under existing Commission-approved non-utility generator (NUG) contracts. (Companies St. 2 at 28).

15. MetEd, Penelec, and Penn Power will conduct two requests for proposal (RFPs) to solicit bids for the provision of a fixed number of SPAECs based on each Company's

most recent distribution load forecasts. MetEd, Penelec, and Penn Power expect to obtain approximately 100% of the SPAEC requirements for both shopping and default service customers, after taking into account previous SPAEC purchases. (Companies St. 2 at 23).

16. All costs associated with the procurement of SPAECs by MetEd, Penelec, and Penn Power are collected via their Solar Photovoltaic Requirements Charge (SPVRC) Riders. (Companies St. 1 at 18-19).

17. For West Penn, default service suppliers will be responsible for procuring all SPAECs less any SPAECs that are allocated to the suppliers under existing long-term purchases made by West Penn. (Companies St. 2 at 23).

18. The Companies will continue to utilize their current contingency plans, which address the following circumstances: (a) an auction is not fully subscribed; (b) the Commission rejects the bid results from an auction; and (c) a winning bidder defaults prior to or during a delivery period. (Companies St. 2 at 30).

19. Each residential class tranche includes a 95% fixed-priced product and a 5% real-time hourly load locational marginal price (LMP) product plus a fixed adder of $20.00 per megawatt hour (MWh) to cover the costs of other supply components associated with serving the contracted load, including capacity, ancillary services, Alternative Energy Portfolio Standards (AEPS) compliance, and other costs. (Companies St. 2 at 7).

20. The Companies propose to procure 12 and 24-month full requirements contracts (FRCs) with a 5% portion of each contract priced at spot market prices. (Companies St. 2 at 7-10).

21. The residential procurement plan includes sufficient temporal diversity, spreading the procurements over auctions scheduled at different points during the DSP V term,

which will balance any commodity price changes in the power markets over time. (Companies St. 2-R at 3).

22. The Companies propose to end all supply contracts on May 31, 2023. (OCA St. 1 at 11-12).

23. Allowing the DSP supply contracts to conclude at the end of the DSP V term removes the regulatory risk associated with significant changes in default service rules that may be implemented after the DSP delivery period ends. (Companies St. 2-R at 3-4).

24. To the extent market conditions change in the middle of the DSP V term, the Companies' Bidding Rules would govern any changes. (Companies St. 2-R at 4).

25. Each commercial class tranche features a 100% fixed-priced product, which will have staggered three-month, twelve-month and twenty-four-month terms. The commercial tranches will be secured over eighteen procurement dates. (Companies St. 2 at 8).

26. The industrial class product is an hourly-priced service based upon the PJM real-time zonal hourly market price. Suppliers will bid for the right to serve a portion of the industrial load for 12-month terms. Winning suppliers will be paid the winning price bid in the hourly-priced auction, the hourly PJM real-time zonal LMP, and an additional fixed adder of $4/MWh to capture the estimated costs of other supply components, including capacity, ancillary services, NITS, AEPS compliance, and other costs. (Companies St. 2 at 8).

27. The Companies propose a procurement plan for all customer classes using eighteen separate procurement dates occurring in October/November 2018, 2019, 2020, 2021, and 2022; January 2019, 2020, 2021, 2022, and 2023; April 2019, 2020, 2021, and 2022; and June 2019, 2020, 2021, and 2022. (DSP IV, Joint Petition for Partial Settlement at 7).

28. Non-shopping residential and commercial customers obtain default service under the Price to Compare Default Service Rider (PTC Rider). Non-shopping industrial

customers receive default service under the Hourly Pricing Default Service Rider (HPS Rider). The Companies will collect all remaining default service-related costs via their DSS Riders. (Companies St. 1 at 16-18).

29. Consistent with the settlement of the DSP IV Proceeding, beginning June 1, 2019, the Companies will lower the hourly default service pricing threshold from 400 kW to 100 kW, when the Companies expect to have billing-capable smart meters installed in their service territories. In accordance with the settlement of the DSP IV Proceeding, the Companies are developing an outreach and educational communication plan to inform shopping and default service customers with demand between 100 kW and 400 kW of the change. (Companies St. 1 at 11).

30. Under the Companies' current tariffs, if an existing customer's billing demand is equal to or greater than 400 kW for two consecutive months in the most recent 12-month period, the customer may no longer be eligible for service under the current commercial customer rate schedule. (RESA St. 1 at 12).

31. On an annual basis, the Companies will review a non-shopping commercial customer's demand from the prior year period. If the demand of the customer was at or higher than 100 kW for all twelve months, the customer will be transitioned to the HPS Rider. Otherwise, the customer will continue to receive default service as part of the commercial class via the PTC Rider. All commercial customers, even those with demand below 100 kW, will continue to have the right to request hourly-priced service, which would cause the Companies to move the customer to the HPS Rider. (Companies St. 1 at 11; Companies St. 4-R at 15; *see also* RESA St. 1 at 11).

32. If the Companies were to move commercial customers whose demand exceeded 100 kW for only two consecutive months to the HPS Rider or to base the transition to the HPS Rider on peak load contribution or installed capacity, the change could impact

unsophisticated commercial customers who do not have the resources to devote to shopping for their generation supply or to manage hourly pricing. (Companies St. 4-R at 15).

33. RESA suggested an alternative of basing the procurement classification on the customer's peak load contribution or Installed Capacity (ICAP) tag as a measure under the PJM 5 CP model, which is more complex than the customer's monthly metered billing demand, and is a measure that commercial customers in that size range would normally understand. (PSU St. 1-SR at 8).

Bypassable Retail Market Enhancement Rate Mechanism

34. The Bypassable Retail Market Enhancement Rate Mechanism (PTC Adder) is based on the $30 Customer Referral Charge (CRP) to EGSs for each customer enrolled by an EGS under the CRP. (Companies St. 1 at 24-25).

35. The Companies divided $30 by an assumed EGS customer retention period of 24 months, resulting in a charge of $1.25 per residential default service customer per month. (Companies St. 1 at 25-26).

36. The Companies then propose to divide $1.25 per month charge by the average residential usage for the four Companies to arrive at a per kWh charge which will be a component of the PTC Adder rate calculation. (Companies St. 1 at 26).

37. Using the average residential customer monthly consumption of 869 kWh for the twelve-month period ended August 31, 2017, the application of this calculation would result in a PTC Adder of $0.00144 per kWh for the June 1, 2019 through May 31, 2023 DSP term. (Companies St. 1 at 25-26; OCA St. 1 at 15).

38. The Companies intend to return 95% of the revenues collected via the PTC Adder to all customers via the Companies' non-bypassable Default Service Support Riders (DSS). (Companies St. 1 at 27).

39. The Companies will retain 5% of the revenue they collect by the PTC Adder in order to recover expenses associated with the PTC Adder. (Companies St. 1 at 27).

40. The Companies do not know what their expenses associated with the PTC Adder will be and do not plan to track their expenses. (OCA St. 1 at 18; BIE Ex. 1).

41. The Companies will not impose the PTC Adder on larger commercial and industrial customers. (Joint Petition at 16; Companies St. 1 at 25).

42. The PTC Adder will result in an increased volumetric charge for residential default service customers, but it is not predicated on the cost of generation. (BIE St. 1-R at 5).

43. EGS customer acquisition costs are not causally related to incentives to customers to encourage retail switching. (OCA St. 1-S at 10; BIE St. 1-SR at 4-5).

44. The current competitive market is robust and not characterized by oppressive economic barriers. (OCA St. 1-R at 4).

45. A significant number of EGSs have been able to effectively compete in the residential generation supply market and continue to participate in that market by providing a range of products that the utility does not provide, and fixed-price products of varying durations. (OCA St. 1-R at 5).

46. There is no evidence that the PTC Adder will foster measurable results. (OCA St. 1 at 16-18; BIE Ex. 1; *see also* Companies St. 1 at 24).

Purchase of Receivables Clawback Provision

47. At present, the Companies purchase account receivables from EGSs at a zero discount rate, which means that the Companies pay the full value of the accounts receivable regardless of whether the customer pays the full amount owed. (BIE St. 1 at 10).

48. The Companies recover the POR expenses from all ratepayers through the DSS Rider, meaning that the ratepayers bear the risk of nonpayment and costs of associated collection. (Companies St. 1 at 30; BIE St. 1 at 10).

49. The Companies impose an administrative charge upon EGSs only under limited circumstances, and they refer to this charge as the purchase of receivables clawback charge. (Companies St. 1 at 20-21).

50. The Companies' POR clawback charge, approved as a two-year pilot in the DSP IV Proceeding, will continue with the next assessment of the charge in September 2018 based on a review of the data for the twelve months ending August 31, 2018, and ending with charges to be assessed in September 2021. (Joint Stipulation No. 2).

51. The Companies will continue to use a two-prong test to determine the clawback charge. The first prong will identify those EGSs whose average percentage of write-offs as a percentage of revenues over the twelve-month period ending August 31 each year exceeds 200% of the average percentage of total EGS write-offs as a percentage of revenues per operating company. The second prong of the test will identify, of those EGSs identified in the first test, EGSs whose average price charged over the same twelve-month period exceeds 150% of the average price-to-compare (PTC) for the period. For those EGSs identified by both prongs of the test, the annual clawback charge assessed each September would be the difference between the EGS's actual write-offs and 200% of the average percentage of write-offs per operating company. (Joint Stipulation No. 2).

Customer Referral Program

52. The Companies first implemented their customer referral program in 2013. (OCA St. 2 at 7).

53. The purpose of the CRP is intended to incent consumers who have never shopped to enter the competitive market by providing an initial price of 7% off the then-current price to compare. *Investigation of Pennsylvania's Retail Electricity market Intermediate Work Plan,* Docket No. I-2011-2237952. (Final Order Mary 2, 2012).

54. The CRP has contributed to the overall level of residential customer shopping over the years. (*See* RESA St. 1-R at 15).

55. The Companies will continue their CRP through May 31, 2023. (Companies St. 1 at 19).

56. Under the settlement of the DSP IV Proceeding, the Commission approved the Companies' continuation of the CRP through May 31, 2021. (DSP IV Proceeding; Docket Nos. P-2015-2511333, et seq. (Opinion and Order dated May 19, 2016)).

57. The Companies adopted revised CRP scripting in response to the settlement of the DSP IV Proceeding. (Companies St. 1 at 5).

58. The Companies undertake a bifurcated presentation of the CRP and provide scripts to their customer service representatives as well as to their third party agent, AllConnect. (OCA St. 2 at 8-9).

59. AllConnect earns a fee each time it enrolls a customer in the CRP. (OCA St. 2 at 9).

60. Many factors contribute to swings in CRP enrollment. (OCA St. 2 at 9-10).

61. A decrease in enrollment occurred after the Polar Vortex in 2014, at which time complaints, formal investigations, and public controversy plagued many EGSs in Pennsylvania. (OCA St. 2 at 9-10).

62. A decrease in CRP enrollment occurred in 2015 when PTC rates were low. (OCA St. 2 at 9-10).

Customer Assistance Program Shopping

63. The Companies' low-income residential CAP is called the Pennsylvania Customer Assistance Program (PCAP). Through PCAP, eligible customers receive discounted payment amounts and arrearage forgiveness. The amount that PCAP customers pay is based on a percentage of their income, and they must be enrolled in an equal payment plan, which is based on the customer's usage over the last twelve months. The difference between the equal payment plan amount and the PCAP customer's "asked to pay" amount is the monthly PCAP credit. (BIE St. 1 at 17-18; BIE Ex. No. 1).

64. PCAP subsidy credits are paid for by all residential, non-PCAP customers through the Companies' Universal Services rider. (BIE St. 1 at 17-18; BIE Ex. 1).

65. The Companies have offered unrestricted PCAP shopping since they were directed to do so by the Commission in 2013. (*Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*, Docket No. I-2011-2237952 (Final Order dated February 15, 2013)).

66. The Companies' CAP shopping customers have, on average, paid more than the PTC. (Companies St. 1-R at 28; CAUSE-PA St. 1 at 23).

67. The net impact of unrestricted PCAP shopping in the Companies' service territories, or shopping above the Companies' PTC, during the period of June 2013 through December 2017, is an increase in the cost of the PCAP shopping program for other ratepayers and CAP customers of over $17 million, or over $3.8 million per year. (CAUSE-PA St. 1, at 22-25).

68. A significant majority of PCAP customers who switch to a competitive electric supplier are charged rates that create an obligation for greater costs to be incurred by PCAP than if these customers were charged the utility default service price for energy. (CAUSE-PA St. at 24).

69. The Companies' data revealed that during the period of June 2013 through December 2017, an average of 63%, 62%, 65%, and 72% of MetEd, Penelec, Penn Power, and West Penn PCAP customers paid rates that exceeded the Companies' PTC, respectively. (BIE No. 1 at 19-20; BIE Ex. 1).

70. As a result of how the PCAP program calculates PCAP credits, PCAP customer credits will be insufficient to maintain an affordable bill if a shopping decision drives up the energy portion of that customer's electric bill. (OCA St. 2 at 37-38).

71. Increased costs not only impact affordability of PCAP bills for PCAP customers, but the costs are borne by all of the Companies' non-PCAP residential customers, including more than 160,000 confirmed low-income customers who are not enrolled in PCAP. (OCA St. 2 at 38; CAUSE-PA St. 1 at 16).

72. The Companies could implement a PTC price ceiling by adding CAP participation flags to their eligible customer lists, which would inform suppliers before they attempt to enroll a CAP customer. In order to enroll CAP customers, suppliers would agree to rate ready billing, which would allow the Companies to adjust the supplier's price by the required percentage-off the PTC for CAP customers. Any enrollment request by a supplier for a

CAP customer outside of those parameters would be automatically rejected by the Companies. (Companies St. 1-R at 30-33).

73. All costs associated with implementing the Companies' system changes and notifying suppliers and PCAP customers regarding these changes would be recovered through the Companies' PTC Riders. (Companies St. 1-R at 30-33).

IV. DISCUSSION

A. Uncontested Issues

The term of the Companies' DSPs is proposed to be for the forty-eight months spanning June 1, 2019 through May 31, 2023.[21] For each of the residential, commercial, and industrial customer classes, the Companies propose to procure full-requirements, load-following energy and energy-related services for those customers who have not chosen an EGS or whose EGS fails to provide service.[22]

The proposed plans have been identified as "DSP V." The Companies' current plans, identified as "DSP IV," were approved as four year plans set to expire on May 31, 2021.[23] The settlement of DSP IV required the Companies to make filings concerning multiple settlement commitments by January 31, 2018. The Companies determined, however, that the lack of consensus in DSP IV settlement stakeholder meetings required the filing of a new DSP at this time.[24]

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21 Companies St. 1 at 9; Companies St. 2 at 3.

22 Companies St. 2 at 5.

23 In the Commission-approved settlement of DSP IV, paragraph A.1.a stated, "The Parties agree that the plan term will be four years." *Joint Petition of MetEd, Penelec, Penn Power, and West Penn for Approval of their Default Service Programs*, Docket No. P-2015-2511333, et al. (Recommended Decision issued April 15, 2016, at 8).

24 *See* Companies St. at 7.

Certain aspects of the Companies' proposed default service plans were not contested by any parties and are described below.

1. General Provisions of the Default Service Plan

The load of each class will be divided into tranches, approximately fifty megawatts (MW) each for the residential and commercial rate classes and approximately 100 MW each for the industrial rate class, with each tranche constituting a fixed percentage of the respective Company's non-shopping load.[25] Qualified suppliers will bid to serve tranches in simultaneous descending clock auctions (DCAs) for all four Companies.[26] The Companies have proposed to continue use of their current approach, which is a DCA format for procurement of default service supply under which simultaneous auctions are conducted for all four Companies' multiple products and/or tranches on the proposed procurement dates.[27]

Auctions to procure default service supply are expressly permitted under the Public Utility Code[28] and DCAs have been used in numerous electricity procurements in Pennsylvania and other states since the late 1990s.[29] The auction format is non-discriminatory, open, fair, transparent, provides low barriers to participation for a variety of prospective bidders, and is designed to achieve competitive results. The Companies have successfully conducted DCAs for default service supply under their current and past default service programs.[30]

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[25] The actual load served will vary based on many factors, including customer migration to EGSs. Companies St. 2 at 3, 7 and 5.

[26] Companies St. 2 at 3, 7 and 5. *See* discussion of Residential, Commercial and Industrial Portfolios below.

[27] Companies St. 2 at 7.

[28] 66 Pa.C.S. § 2807(e)(3.1).

[29] Companies St. 2 at 12.

[30] Companies St. 2 at 17.

Under the DCA approach, multiple products and/or multiple tranches are bid on simultaneously. Bidding takes place online using web-based software in a series of bidding rounds, with pre-specified starting and ending times for each round. Prior to the start of each round, the announced price for each product is disclosed to bidders. At the end of each round, the bidding software (with oversight by the Independent Evaluator) determines which products are over-subscribed and which products are under-subscribed. A product is over-subscribed if suppliers bid to supply more tranches than the number of tranches needed of that product. Likewise, a product is under-subscribed if fewer tranches were bid on than it needed. If a product is over-subscribed, the announced price for that product will be reduced by a decrement for the next round.[31] If a product is not over-subscribed, its announced price will not change for the next round. The bidding process continues in this manner, with prices tending to tick down like a countdown clock. As prices change across the products, bidders are allowed to change the number of tranches they bid, subject to certain restrictions. In each round, a bidder simply specifies the number of tranches that it is willing and able to supply for each product at the announced price for each product.[32] There is no pre-determined number of rounds before the close of the auction, which occurs after the first round in which no product is over-subscribed. The winning bidders are those bidders who bid tranches at a price no higher than the clearing price, which is the lowest price at which the tranche product is not under-subscribed.[33]

As part of their respective procurement plans, the Companies have proposed to retain their current limit of 75% of the available tranches that any one supplier can win in its default service supply auctions.[34] No party has contested the Companies' proposed load cap.

The Companies have selected CRA International, Inc. (CRA) to serve as the independent evaluator of the Companies' default service procurements for the delivery term at

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31 Companies St. 2 at 12-13.

32 *Id.*

33 Companies St. 2 at 13.

34 Companies St. 2 at 10.

issue.[35] The Companies have used CRA as their independent evaluator under their most recent DSPs since the delivery term beginning June 1, 2013.[36]

For procurements of SPAECs, the Companies proposed to continue to use The Brattle Group (Brattle) to serve as the independent evaluator. Brattle has considerable expertise in competitive energy matters and has been involved in several request-for-proposal (RFP) design and management processes, including the procurement of electric power and renewable energy supplies under long-term contracts. Brattle has served as the independent evaluator in all past SPAEC procurements held by the Companies.[37]

Winning bidders will enter into a standard supply master agreement (SMA) for the products they successfully bid to supply. In this proceeding, the Companies are proposing to continue the use of their current Commission-approved SMA,[38] with only limited modifications. As described in the testimony of Mr. Catanach, the proposed SMA differs from the Companies' current Commission-approved SMA in only two limited ways: (1) modifications were made to reflect the expansion of the industrial class to include customers with demand of 100 kilowatts and above; and (2) cleanup modifications were made regarding assignment of new PJM billing line items that have been established since the Companies' DSP IV proceeding.[39]

Default service (DS) suppliers will be responsible for fulfilling all the obligations of a PJM LSE.[40] As such, each DS supplier will be required to provide energy, capacity, and

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35 *See* 52 Pa.Code § 54.186(c)(3).

36 Companies St. 2 at 7. *See also* DSP II.

37 Companies St. 2 at 23-24.

38 A uniform SMA was agreed upon in a working group which was directed by the Commission's Office of Competitive Market Oversight (OCMO) due to an Order entered on February 15, 2013 in *Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*, Docket No. I-2011-2237952. The Companies proposed a similar SMA that was developed in the OCMO working group. Companies St. 2 at 18-22.

39 *Id*.

40 Companies St. 2 at 5-6 and 19.

transmission service (including NITS), as well as all PJM administrative expenses and any other services or fees as required by PJM of an LSE, except for the following charges: RTEP; Expansion Cost Recovery Charges; RMR associated with generating plants for which specific RMR charges began after July 24, 2014; historical out of market tie line, generation and retail customer meter adjustments; unaccounted for energy; and any Federal Energy Regulatory Commission (FERC) approved reallocation of PJM RTEP charges related to Docket No. EL05-121-009 (collectively referred to as "non-market based charges," or "NMB charges").[41] The NMB charges will be paid by the Companies on behalf of all customers and recovered from all customers through the DSS Rider in the respective Company tariff.[42]

In addition, DS suppliers will have certain obligations related to AEPS requirements. These obligations are discussed in more detail below. Of all of these obligations, the only obligations which were challenged in this proceeding were those related to NMB charges. The issues related to NMB charges were resolved by the Joint Petition for Partial Settlement and are discussed in that section below.

The AEPS Act requires the Companies to obtain an increasing percentage of electricity sold to default service customers from certain alternative energy sources, such as wind, solar energy and biomass. Compliance is measured in alternative energy credits (AECs), which are equal to one megawatt-hour (MWh) of energy from approved Tier I or Tier II alternative energy sources, as defined by the AEPS Act.[43] The AEPS Act also includes a solar set-aside, which mandates that a specific portion of the Companies' Tier I requirements be satisfied through AECs derived from solar photovoltaic energy. The AEPS Act defines Tier I and Tier II alternative energy sources and the dates and percentages of supply required for compliance.[44]

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41 Companies St. 2 at 5-6 and 19.

42 Companies St. 2 at 6.

43 *See generally* 73 P.S. § 1648.1 *et. seq.*; Companies St. 2 at 23.

44 73 P.S. §§ 1648.2 and 1648.3.

The Companies propose to satisfy most of their AEPS Act requirements as part of the solicitation of default service supply.[45] Default service suppliers in the MetEd, Penelec and Penn Power service territories will be responsible for meeting 100% of the non-solar Tier I and Tier II AEPS Act requirements.[46] In the West Penn service territory, default service suppliers will be responsible for all Tier I and Tier II AEPS Act requirements less any Tier I AECs that are allocated to the default service suppliers from existing long-term purchases made by West Penn.[47] In addition, Penelec will continue to have the added flexibility to make market-priced sales of excess AECs acquired under existing Commission-approved non-utility generator contracts for use in meeting the Companies' AEPS requirements.[48]

Under the current DSPs of MetEd, Penelec, and Penn Power, the solar AEPS requirements associated with the customer load of both default service customers and shopping customers are met with SPAECs obtained by those Companies through separate SPAEC-only procurements. West Penn, in turn, will continue to require each DS supplier to provide SPAECs associated with the load served by the DS supplier. However, SPAECs that West Penn procured under existing long-term contracts previously approved by the Commission will be used to reduce the number of SPAECs that those DS suppliers would otherwise be obligated to transfer to West Penn under the SMAs. These SPAECs will be allocated on a pro rata basis in accordance with the percentage of default service load served by DS suppliers, and DS suppliers will be informed through the frequently asked question feature, prior to the first auction, of the exact amount of SPAECs that will be allocated in each procurement of default service supply so that the reduction in SPAEC obligations may be factored into default service supplier bids.[49]

The Companies plan to continue using Brattle as the independent third-party evaluator for the procurement of SPAECs. MetEd, Penelec and Penn Power will conduct two

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45 52 Pa.Code § 54.185(e)(1).

46 Companies St. 2 at 23.

47 *Id*.

48 Companies St. 2 at 28.

49 Companies St. 2 at 23-25.

RFPs for two-year SPAEC products in each of March 2019 and March 2021 to procure the estimated additional SPAEC requirements for the DSP V term beginning June 1, 2019, after adjusting for the SPAECs already purchased through the ten-year SPAEC RFPs conducted under previously approved DSPs. The estimated volumes under the RFP will be determined based upon the most recent load forecast for the Companies at the time of the RFP. At the end of the 2019/2020, 2020/2021, 2021/2022 or 2022/2023 AEPS compliance periods, if necessary for compliance purposes, the Companies will conduct short-term SPAEC procurements at market prices.[50] As explained by the Companies' witness, Dr. Reitzes, the SPAEC procurement is designed to achieve the "least cost over time."[51]

The Companies propose to continue utilizing the contingency plans in their current Commission-approved default service plans, which address the following three possible scenarios: (i) an individual solicitation is not fully subscribed; (ii) the Commission rejects the bid results from a solicitation; or (iii) a winning supplier defaults prior to the start of the delivery period or at any time during the delivery period.[52]

In the event that a scheduled solicitation is not fully subscribed during the initial proposed procurement date, the Companies will rebid the unfilled tranches from that solicitation in the next scheduled procurement. For any unfilled tranches still remaining, the Companies will purchase the necessary physical supply through PJM-administered markets and serve as LSEs for the affected default service customers. The Companies' procurements will be made at real-time zonal spot market prices, and the Companies will not enter into hedging transactions to attempt to mitigate the associated price or volume risks to serve these tranches. At the next quarterly rate adjustment, the Companies will include an estimate of these costs in the weighted cost of supply calculation and utilize the reconciliation process to recover differences between the estimated

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50 *Id*.

51 Companies St. 3 at 20.

52 Companies St. 2 at 30.

and actual costs that the Companies incur as a result of purchasing the necessary supply and AEPS requirements.[53]

If a winning bidder defaults prior to the start of or during the delivery period, the Companies will offer the unfilled tranches to the other registered bidders who participated in the most recent solicitation. The Companies may enter into an agreement with the registered bidder or bidders offering the best terms for the unfilled tranches resulting from the default, provided the prices offered by such bidder or bidders are consistent with the original prices under which the unfilled tranches were procured, adjusted for changes in market conditions from the time when the original tranches were procured. If the Companies are not able to enter into such an agreement and a minimum of thirty calendar days exists prior to the start of the delivery period, the Companies will seek to bid the defaulted tranches in a separate supplemental competitive solicitation. As with other unfilled tranches described above, if insufficient time exists to conduct an additional competitive solicitation, or if the supplemental solicitation is unsuccessful, the Companies will supply the tranches using PJM-administered markets with recovery and reconciliation of estimated and actual costs as described previously.[54]

If some SPAEC tranches remain unfilled or if a winning SPAEC supplier defaults before or during the delivery period, the affected Company will conduct short-term procurements at market prices to ensure compliance for all solar photovoltaic AEPS requirements until such time as the Commission approves an alternative mechanism.[55]

2. Default Service Plan Portfolio -- Industrial Portfolio

The industrial class product is the hourly pricing service (HPS), which is consistent with the Companies' current DSPs.[56] HPS contracts will be for twelve-month terms

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53 Companies St. 2 at 30-31.

54 Companies St. 2 at 30-31.

55 Companies St. 2 at 32.

56 Companies St. 2 at 8.

beginning June 1 of each year of the delivery period.[57] The HPS is a variable hourly service that is priced to the PJM real-time hourly total LMP for each Company's PJM delivery point.[58] DS suppliers will bid to serve a portion of a Company's HPS load (thirty-one tranches across all the Companies).[59] Customers on HPS will pay, and winning DS suppliers will receive: 1) the winning price bid by the winning DS supplier in the hourly-priced auction; 2) the applicable PJM zonal real-time hourly LMP; and 3) a fixed adder of $4/MWh, which will cover an estimate of costs of other supply components associated with meeting this full-requirements obligation, including capacity, ancillary services, NITS, AEPS compliance, and other costs.[60]

The total industrial class load will be procured through four separate auctions in January 2019, January 2020, January 2021 and January 2022 for twelve-month agreement terms beginning June 1 of the auction year.[61]

3. Default Service Plan Term

The Companies propose a four-year default service plan term, beginning June 1, 2019, through May 31, 2023. The settlement of the Companies' current DSP IV anticipated a four-year DSP ending May 31, 2021. A four-year term provides certainty for customers and EGSs regarding the terms of the DSP, while also providing administrative efficiencies and cost savings for customers compared to filing on a more frequent basis.[62] The OCA strongly supports the use of four-year DSPs. A four-year plan will avoid the time and expense associated with more frequent filings, savings that will ultimately accrue to ratepayers. The OCA submits that

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57 *Id*.

58 *Id*.

59 *Id*.

60 *Id*.

61 Companies St. 2 at 12.

62 Companies St. 1.

all of the major EDCs have transitioned to four-year DSPs and that the Companies' commitment to four-year plans going forward is appropriate.[63]

No other party objected or presented any position to the proposed four-year plan term.

4. Recommendation

I recommend the Commission approve the provisions of the Companies' DSP plans described above. No party, including the statutory advocates, have raised any objection to these portions of the Companies' DSPs. These terms are not materially different from similar terms which have been approved by the Commission in the past and found to be consistent with the Public Utility Code and the Commission's regulations on default service plans. Therefore, they should be approved as proposed without modification.

B. Contested and Litigated Issues and Recommendations

1. Default Service Plan Portfolio -- Residential Portfolio

Each residential class tranche (approximately fifty MW) will be comprised of a load-following full requirements product with a ninety-five percent fixed-priced portion, and a five percent variable priced product.[64] The fixed-price for the 95% fixed-price option will be established through the Companies' DCA process.[65] Residential products will have staggered twelve and twenty-four-month terms.[66] The remaining five percent of the residential product is a

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63 In 2016, the Commission approved four-year default service plans for PPL Electric Utilities, PECO Energy, and Duquesne Light Company.

64 Companies St. 2 at 3 and 7-8.

65 Companies St. 2 at 7.

66 *Id*.

real-time hourly load locational marginal price (LMP) for the delivery point plus a fixed adder of $20.00 per MWh to cover the costs of other supply components associated with serving the contracted load, including capacity, ancillary services, AEPS compliance, and other costs.[67]

The residential tranches will be secured over twelve procurement dates.[68] In particular, the Companies proposed that the following auctions will be held for each residential class product:

> The residential twelve-month product auctions will be held: October/November[69] 2018, 2019, 2020 and 2021; January 2019, 2020, 2021 and 2022; April 2019, 2020, 2021 and 2022; and
>
> The residential twenty-four-month product auctions will be held: October/November 2018 and 2020; January 2019, 2020 and 2021; April 2019, 2020 and 2021.[70]

OCA witness Steven Estomin reviewed the Companies' procurement plan and recommended one modification to ensure price stability through the end of the DSP term.[71] While the OCA does not oppose the continued use of 12 and 24-month full requirements contracts, Mr. Estomin opines that concerns remain regarding the Companies' proposal to end all supply contracts on May 31, 2023, i.e., a "hard stop" of all contracts. By terminating all contracts on a single date, OCA argues that the Companies will be fully exposed to market conditions at the time of the procurements for its next default service plan, which "reduces the degree to which residential default service customers can benefit from temporal diversification of the portfolio in the subsequent default service period, that is, the one that would commence

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67 Companies St. 2 at 7-8.

68 Companies St. 2 at 8.

69 The Companies will conduct each fall auction at some point after October 20 and before November 20 to allow participants in the fall auction to have access to any applicable proposed formula NITS rates filed in October for the upcoming calendar year before the auction occurs. (Companies St. No. 2 at 11).

70 Companies St. 2 at 11-12.

71 OCA St. 1 at 11-12.

June 1, 2023."[72] Energy markets have been subject to volatility, and the Companies' plan would fully expose customers to potentially dramatic rate increases on June 1, 2023. According to OCA, eliminating the "hard stop" reduces the potential for price volatility at the end of the DSP term and is consistent with the Act 129 "least cost to customers over time" mandate as well as the goals of the General Assembly that default service achieve "price stability over time."[73]

Therefore, OCA recommends a procurement plan modification that 16 of the 46 twelve-month contracts proposed in the Companies' procurement plans be converted to two-year contracts. OCA's proposal would allow these two-year contracts to extend beyond the May 31, 2023 term end-date proposed by the Companies.[74]

The Companies oppose this proposal. In the Companies' view, the proposed procurement plan already provides significant temporal diversity, spreading the procurements over auctions scheduled at different points during the DSP V term, which will balance any commodity price changes in the power markets over time.[75] Since DSP II,[76] the Companies' default service supply contracts have ended at the prescribed DSP delivery period, which the Commission has consistently supported. The Commission has stated that the Companies' use of "shorter, more frequent procurements should ensure a smoother transition into the next procurement period without requiring the procurements extend beyond May 2015…."[77] Furthermore, the "hard stop," permits the Companies to mitigate any regulatory risk associated

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72 OCA St. 1 at 11.

73 66 Pa.C.S. § 2807(e)(3.4); Preamble to Act 129, 2008 Pa. Laws 129.

74 OCA St. 1 at 12-13.

75 Companies St. 2-R at 3.

76 The delivery period for DSP II began on June 1, 2013 and ran through May 31, 2015. Companies St. No. 2-R at 3-4.

77 *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company for Approval of Their Default Service Programs*, Docket Nos. P-2011-2273650, et al. at 26 (Order entered August 16, 2012).

with significant changes in default service rules that may be implemented beyond the end of a DSP delivery period.[78]

I agree with the Companies and recommend that OCA's modification be rejected. The Companies' procurement plan is consistent with prior Commission-approved DSPs for the Companies. The Companies based their auction proposal on their past DSPs and structure the auctions to mitigate regulatory risk. While OCA's recommended approach of layering contracts is a viable alternative approach used by other EDCs, OCA has not identified a specific issue with the Companies' past procurements that would require a change in procurement strategy. Nor does OCA argue that the Companies' procurement strategy violates Section 2807.[79] In order to overcome a company proposal which meets statutory requirements and is otherwise just and reasonable, OCA must do more than present an alternative which also meets statutory requirements and is just as reasonable. OCA's proposal raises a mitigation for price volatility which may or may not be a problem for the Companies. It is not persuasive that other EDCs ladder their contracts. Laddering, as proposed by OCA, may be important to managing the residential portfolio to avoid rate shock and mitigate identified price volatility in those EDC markets. There is not sufficient evidence adduced by OCA to overcome the Companies' auction proposal which appears to be sufficient to comply with the Commission's DSP rules. OCA has not demonstrated that the auction schedule proposed by the Companies will not provide adequate price stability for their customers.

2. Default Service Plan Portfolio -- Commercial Portfolio

Each commercial class tranche (approximately fifty MW) features a 100% fixed-priced product, which will be bid out through the Companies' DCA process.[80] Commercial

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78 Companies St. 2-R at 3-4.

79 66 Pa.C.S. § 2807.

80 Companies St. 2 at 7- 8.

products will have staggered 3, 12 and 24-month terms. Non-shopping commercial customers with demand less than 100 kWs will be eligible for this product.[81]

The commercial tranches will be secured over 18 procurement dates.[82] Specifically, the Companies proposed that the following auctions will be held for each commercial class product:

> The commercial three-month product auctions will be held: October/November 2019, 2020, 2021 and 2022; January 2020, 2021, 2022 and 2023; April 2019, 2020, 2021 and 2022; June 2019, 2020, 2021 and 2022; and
>
> The commercial 12-month product auctions will be held: October/November 2018, 2019, 2020 and 2021; January 2019, 2020, 2021 and 2022; April 2019, 2020, 2021 and 2022.
>
> The commercial 24-month product auctions will be held: October/November 2018 and 2020; January 2019 and 2021; April 2019, 2020 and 2021.[83]

OSBA did not directly object to the proposed procurement schedule. However, OSBA witness Robert D. Knecht expressed concern over the increase in implied risk premiums for the Companies' Commercial class default service procurements, as shown in the Companies' filed evidence.[84] He recommended that the Companies review the procurements at the half-way point, after the second round of 12-month and 24-month contracts has been finalized, to see whether the implied risk premiums continue to rise. If they do, Mr. Knecht recommended convening a stakeholders meeting to address the problem and to propose potential solutions.[85]

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81 Companies St. 2 at 8.

82 *Id*.

83 Companies St. 2 at 12.

84 OSBA St.1 at 9-10.

85 In testimony, RESA also advocated for a mid-term stakeholders' meeting. However, in briefing RESA stated that it is not advancing an alternative procurement plan at this time. RESA Main Brief at 6.

The Companies oppose a mid-term portfolio review. First, modifying the DSP midstream (*e.g.*, changing the products being procured or their term length, or modifying the procurement schedule halfway through the plan), may create confusion for participants in default service supply auctions or otherwise cause suppliers to increase the time and expense needed to prepare a bid, which could reduce supplier participation and induce increased prices for default service supplies. Second, the Companies' proposed DSP offers temporal diversity by holding 18 different procurements for the commercial class throughout the four-year term, which potentially smooths out any cyclical movements in risk premiums. Third, as the Companies' witness Dr. Reitzes testified, "the use of a full-requirements load-following (FRLF) product to serve default service customers, consistent with the current plan, has had a good track record in Pennsylvania."[86]

Importantly, the Companies point out that the procurement process itself provides solutions to address OSBA's concerns in real time. Specifically, Section 4.4 of the Bidding Rules addresses the issue of extraordinary events by allowing the development of a revised schedule to the extent conditions dictate.[87] Also, the Commission has the ability to reject the results of an auction if the bids do not appear to be in alignment with the market conditions.

Finally, the Companies are concerned that the administrative and cost savings to the parties, the Commission and the Companies' customers that follow the implementation of a four-year program may well be lost if the Commission allows a two-year opt out provision to be included. The Companies' experience related to their DSP IV program mid-term stakeholder process is that it ultimately leads to filing a new DSP after the first two years, thereby causing the Companies and other parties to incur additional costs to file and litigate a new program and eliminating one significant benefit of having a four-year DSP term.[88]

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[86] OSBA St. 1 at 11.

[87] Companies St. 2 at 4.

[88] DSP IV was originally established to span the June 1, 2017 through May 31, 2021 delivery period. Companies St. 1-R at 4.

The Industrials agree that the Companies' concerns regarding OSBA's proposals are reasonable. Notably, the Industrials are troubled by the idea that a mid-term review may present other parties with the opportunity to propose overarching changes to the default service plans. As a result, the Industrials support the Commission adopting a four-year term for the default service plans without allowing mid-term modification.

I agree with the Companies' position. OSBA does not explain why the concern about risk premiums cannot be adequately addressed within the context of current DSP rules or in the Companies' next DSP proceeding. If the risk premium problem identified by OSBA continues to exacerbate to the point that the Companies' commercial procurements are no longer prudent, OSBA has recourse without disrupting the DSP. Instead, it simply takes the position that the Companies' administrative cost concerns do not outweigh the continuing harm of increasing risk premiums.

As explained in the discussion of the DSP term, a four-year term for default service plans is favored by the Commission because of the stability and predictability. A mid-term review may result in significant disruption which may or may not benefit ratepayers. While OSBA has identified a trend of increasing risk premiums in some program procurements, it has also identified some uncertainty created by the proposed reclassification of the over-100 kW customers. The appropriate time to consider what effect, if any, that may have on DSP procurements is in the next DSP.[89]

3. Procurement Classes

In their DSPs, the Companies propose to continue procuring default service supplies separately for each of the three retail customer classes: residential, commercial, and industrial. The only change proposed in this proceeding is to lower the existing hourly pricing

89 *Id.*

threshold from 400 kW to 100 kW.[90] The Companies made a commitment in the DSP IV Joint Petition for Settlement to lower the hourly pricing threshold from 400 kW to 100 kW by June 1, 2019, to the extent smart meters will be available to be used for hourly priced billing.[91] Second, the Companies are following the Commission's End State Order related to its Retail Market Investigation (RMI), which established the following recommended structure for hourly pricing:

> As to the proposed delineation point of above 100 kW of demand, the Commission acknowledges that the more compelling point of delineation is whether the customer has an interval meter, as no EDC suggested any difficulty creating a subclass for default service. Therefore, at this time, the Commission continues to support the threshold of 100 kW for purposes of determining medium and large C&I customers, but expects EDCs to offer hourly LMP products only to the customers above that demand level who have interval meters. We expect the EDCs to continue adding medium C&I customers to the hourly LMP product as interval meters are deployed.[92]

The Companies will develop an outreach and educational communication plan consistent with the DSP V Settlement[93] to inform shopping and default service customers with

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[90] MetEd/Penelec/Penn Power/West Penn Statement No. 1 at 10. MetEd and Penelec rate schedule GS-Medium, Penn Power GM, Penn Power GS-Large, and West Penn Schedule 30 are affected by the change. *See* MetEd/Penelec/Penn Power/West Penn Exhibits KLB-1 through KLB-5 (which reflect changes to the tariff definitions in each of the Companies tariffs); MetEd/Penelec/Penn Power/West Penn Exhibits KLB-6 and KLB-7 (which reflect revisions to each of MetEd and Penelec's Rate GS-Medium); MetEd/Penelec/Penn Power/West Penn Exhibit KLB-8 (which indicates Penn Power Rate GM modifications); MetEd/Penelec/Penn Power/West Penn Exhibit KLB-9 (which presents the changes to West Penn Schedule 30); MetEd/Penelec/Penn Power/West Penn Exhibit KLB-10 (which shows the changes to Penn Power Rate GS-Large); MetEd/Penelec/Penn Power/West Penn Exhibits KLB-11 through KLB-14 (which show the changes to the Companies' PTC Riders); and MetEd/Penelec/Penn Power/West Penn Exhibits KLB-15 through KLB-19 (which present the modifications to the Companies' HP Riders).

[91] *See Joint Petition for Settlement, Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company for Approval of Their Default Service Programs*, Docket Nos. P-2015-2511333, et al. (DSP IV Settlement) at 7, para. 2(d) (approved by Commission Opinion and Order on May 19, 2016).

[92] Final Order *Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*, Docket No. I-2011-2237952 at 29 (Final Order dated February 14, 2013) (RMI End State Order).

[93] In the DSP IV Settlement, the parties agreed to the following: (i) the communication plan will be circulated to the parties to the DSP IV Settlement for comment at least nine months prior to the effective date of the new hourly pricing threshold, or by September 1, 2018; and (ii) the Companies will notify customers at least six months before the effective date of the change, or by December 1, 2018. *See* DSP IV Settlement at 7, para. 2(d).

demand between 100kW and 400kW of the changes in eligibility for default service in the commercial class through their PTC Riders as compared to default service as part of the industrial class through the HPS Riders.[94]

While no party directly opposes the transition of commercial customers,[95] RESA raised concerns with the criteria the Companies will use to identify commercial customers that exceed the 100 kW threshold.[96] In particular, the Companies proposed to conduct an annual review (on April 1) of each commercial customer's measured demand for the previous year (April 1 to March 31). If the actual measured demand in any of the twelve months is less than 100 kW, then the non-shopping commercial customer will receive default service under the provisions of the applicable PTC Rider. Otherwise, the commercial customer will receive default service under the provisions of the applicable HPS Rider. Any changes will become effective June 1 of every year and the commercial customer will remain on the designated rider for a twelve-month period, or until they elect to shop with an EGS.[97] RESA believes that the Companies' criteria leaves too many commercial customers on the fixed-priced commercial PTC Rider rates and recommended that the Companies be required to use two consecutive months in a twelve-month period as the Companies' criteria or, in the alternative, to base a customer's migration on the customer's peak load contribution (PLC).[98] PSU takes the position that the Companies should use the formula in the current tariff, as recommended by RESA, to determine which customers should be transitioned.

The Companies disagree with RESA's recommendations for several reasons. If the Companies were to adopt RESA's recommendation and instead use two consecutive months

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94 Companies St. at 11-12.

95 In its main brief, OSBA raises "policy concerns," but does not oppose the Companies' proposal which is consistent with settlement in DSP IV.

96 RESA St. 1 at 11.

97 Companies St. 1 at 13.

98 RESA St. 1 at 10.

in a twelve-month period as the Companies' criteria, unsophisticated commercial customers who do not have the resources to devote to shopping for their generation supply or to manage hourly pricing will be pushed onto the HPS Riders.[99] As the Companies' witness Mr. Siedt testified, many of these commercial customers have had the option to voluntarily elect service under the applicable HPS Rider since 2011 (an option which remains available today) and have chosen not to do so.[100]

OSBA agrees with this assessment. Based on the Companies' rebuttal testimony, combined with the absence of any customer impact analysis from RESA and PSU, the OSBA respectfully submits that the Companies' proposal is the best option in this proceeding. Moreover, the OSBA observes that the Companies' proposal is the most conservative, in that it will force the fewest number of customers onto hourly default service or into the competitive marketplace against their current wishes. If better impact analysis is conducted in the future, the Companies and the Commission can consider whether a less restrictive standard is appropriate. If all of the customers under a less restrictive standard are removed from the Commercial class now, it will not be possible to undo the damage later.

RESA's alternative recommendation that the Companies utilize PLCs, or installed capacity (ICAP), to determine which customers would move to hourly service will force even more customers either onto the HPS Riders or into the shopping market for competitive generation supply contracts. PSU does not support this proposal. The Companies explain that a PLC analysis is based on the highest capacity level for a customer, which is set once annually. Because of the inflexibility of the test, many more small customers will be pushed onto hourly pricing.[101] Furthermore, PSU raised valid concerns with regard to the adoption of this criteria, noting that the use of the PLC or ICAP will likely cause customer confusion, as the PLC or ICAP is not used for billing purposes and will not be understood by the impacted customers.

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99 Companies St. 4-R at 15.

100 *Id*.

101 Companies St. 4-R at 15.

Specifically, PSU's witness Mr. Crist testified PLC or ICAP is more complex than the customer's monthly metered billing demand, which is a measure that commercial customers in that size range would normally understand.[102]

While the Companies agree with (and have proposed) moving the hourly pricing threshold level to 100 kW and above, the Companies do not agree with setting the eligibility criteria based upon the use of either only two consecutive months' data or PLCs to determine which customers would move to hourly service. The customers in question do consume more energy than residential customers; however, the use of a standard requiring twelve months' data in excess of 100 kW will ensure that only the larger energy consumers are required to move to hourly pricing. Under the Companies' proposal, those customers that are close to, but not at, the 100 kW threshold will have the ability to stay on the commercial PTC Rider rates, opt for hourly-priced default service, or shop for competitive generation supply. If commercial default service customers at or above 100 kW are generally more sophisticated energy consumers as RESA argues, those customers would likely have chosen an hourly pricing option by now.[103]

I agree with the Companies' proposal. The Companies' approach is reasonable and likely to be the least disruptive to the affected commercial class customers who will transition to the PTC rate schedule. Mr. Siedt observes that using the current tariff formula for transitioning these customers is likely to be detrimental to many small businesses. Further, the Companies' approach permits the smaller, less sophisticated commercial customers the option to remain default service customers but retains the ability of those customers to choose hourly pricing or to continue to shop for their generation. The Companies have sustained their burden of proving that their proposal to identify customers who exceed the 100 kW threshold is appropriate.

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[102] PSU Statement No. 1-SR at 8.

[103] Companies St. 4-R at 15.

4. Purchase of Receivables Clawback Provision

At present, the Companies purchase accounts receivables from electric generation suppliers (EGSs) at a zero discount rate, which means that the Companies pay the full value of the accounts receivable regardless of whether customers pay the full amount owed.[104] The Companies recover their POR expenses from all ratepayers through the Default Service Support Rider (DSS Rider), meaning that ratepayers bear the risk of nonpayment and the costs of associated collection.[105] The Companies impose an administrative charge upon EGSs only under limited circumstances, and they refer to this charge as the purchase of receivables clawback charge (clawback charge).[106]

The clawback mechanism was implemented as a result of the settlement of DSP IV, as a two-year pilot for the two twelve-month periods ending on August 31, 2016 and August 31, 2017, respectively. The clawback charge, as approved in the DSP IV Settlement, was designed to collect a portion of uncollectible accounts expense from those EGSs whose practices objectively drive significantly higher write-offs to the Companies' customers than their EGS peers.

The DSP IV pilot has been successful in the Companies' view. In DSP V, the Companies proposed a continuation of the clawback mechanism as a permanent element of the Companies' POR programs as a mechanism to protect customers from those EGSs driving uncollectible accounts expense to unreasonable levels.

BIE, RESA and Respond Power objected to the continuation of the clawback charge as designed in DSP IV. BIE acknowledged that the results from the Companies' 2016 and 2017 clawback charge have indicated that EGSs have modified their pricing behaviors and reduced their uncollectibles, however, BIE expressed concern that the clawback charge fails to

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104 BIE St. 1 at 10.

105 BIE St. 1 at 10; Companies St. 1 at 20.

106 Companies St. 1 at 20-21.

address all EGS uncollectibles. Therefore, BIE recommended addressing the Companies' uncollectible expense through establishing a merchant function charge for default service customers and a POR discount rate addressed to EGSs for application to retail customers. RESA did not object to the clawback charge itself, but recommended several modifications to the program. Respond Power opposed the clawback charge in its entirety, and also had specific criticisms related to the calculation of the clawback, the timing of its re-establishment or continuation, and various protections it believes should be established for EGSs to the extent the Commission permits the clawback as a permanent part of the Companies' POR programs.

Despite these various claims, the Companies have reached a stipulation with BIE, Respond Power and RESA, which was admitted into the record as Joint Stipulation No. 2, with BIE, RESA and Respond Power (collectively, the Stipulating Parties as described below), under which those Stipulating Parties agree to a proposal that resolves each of their concerns regarding this topic, as follows:

> 1. The Stipulating Parties agree to a four-year extension of the Companies' Clawback Charge pilot, to begin with charges assessed in September 2018 based on a review of data for the twelve months ending August 31, 2018 and ending with charges to be assessed in September 2021.
>
> 2. The Companies will continue to use a two-prong test to determine the clawback charge. The first, as described in testimony, will identify those electric generation suppliers (EGSs) whose average percentage of write-offs as a percentage of revenues over the twelve-month period ending August 31 each year exceeds 200% of the average percentage of total EGS write-offs as a percentage of revenues per operating company. The second prong of the test will identify, of those EGSs identified in the first test, EGSs whose average price charged over the same twelve-month period exceeds 150% of the average price-to-compare for the period. For those EGSs identified by both prongs of the test, the annual clawback charge assessed each September would be the difference between that EGS's actual write-offs and 200% of the average percentage of write-offs per operating company.

> 3. The Companies will develop an EGS-specific customer arrears report with unpaid aged EGS account balances. This report will be provided to EGSs participating in the Companies' purchase of receivables programs on a quarterly basis, beginning no later than October 20, 2018, reflecting EGS arrears for third quarter 2018.[107]

The Companies take the position that the stipulation is in the public interest and in the interest of the Companies. Although the original proposal will be modified consistent with this joint stipulation, such that the continuation of the clawback would be for a four-year extension of the pilot, the stipulation provides for the same terms for the calculation of the charge.

BIE also supports Joint Stipulation No. 2. The first of these terms, the Stipulating Parties' agreement to limit the term of the clawback charge to operating on a four-year pilot basis, was the defining term that solidified its support for the Joint Stipulation 2. Specifically, this term is consistent with BIE's recommendation that the clawback charge operate only on a pilot basis in order to allow further time to evaluate its success in reducing the Companies' uncollectibles and benefitting ratepayers. On this basis, BIE avers that retaining the ability to review the success of the clawback charge before the Companies assess it on an indefinite basis is in the public interest. Additionally, as BIE's witness Mr. Keller explained, confining the clawback charge to operating on a fixed-term pilot basis will enable BIE, other interested parties, and the Commission to retain the option to recommend that the Companies initiate a POR discount program if the clawback charge does not prove to be effective or results in other concerns that must be addressed. Through the Joint Stipulation, the ability to recommend that the Companies establish a POR discount program will not be foreclosed in the future; therefore, the public interest is served by ensuring that the ability to utilize other mechanisms to reduce the Companies' uncollectible is preserved, protecting both the Companies and its ratepayers.

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[107] Joint Stipulation No. 2.

BIE also supports the concerns expressed by RESA and Respond Power regarding unintended consequences, such as an EGS unwittingly triggering the clawback penalty,[108] and therefore BIE takes the position that limiting the continuation of the Companies' clawback charge to a four-year pilot term also benefits EGSs by ensuring that they are not exposed to the charge indefinitely if it negatively impacts their operations. Simply put, this term protects the Companies, their ratepayers, and EGSs; therefore, BIE avers that it is in the public interest and it should be approved.

BIE supports Joint Stipulation No. 2 in its entirety, even though it does not take a position regarding the second and third terms of Joint Stipulation No. 2, regarding the two-pronged criteria or the EGS-specific arrears report that the Companies will provide to participating EGSs on a quarterly basis. BIE also does not take a position regarding the EGS-specific arrears reporting, but states that the record supports the concerns of both RESA and Respond Power. Both RESA and Respond Power indicated that absent timely reporting from the Companies, their ability to monitor whether their customers were paying bills was frustrated, compromising their ability to address the nonpayment in a timely manner so as to avoid application of the clawback charge.[109] Accordingly, as the Joint Stipulation provides for quarterly reporting that would enable EGSs to be informed of and monitor customers' nonpayment, a result that could help EGSs reduce uncollectible expense for all ratepayers, BIE submits that it too is in the public interest.

Accordingly, BIE respectfully avers that all of the terms of the Joint Stipulation No. 2 are in the public interest and should be approved.

RESA does not oppose continuing the clawback mechanism as modified by Joint Stipulation No. 2. According to RESA, with the Companies' agreement to develop an EGS-specific customer arrears report with unpaid aged EGS account balances on a quarterly basis

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108 RESA St. 1 at 14; Respond Power St. 1 at 9-10.

109 RESA St. 1 at 15-16; Respond Power St. 1 at 10.

beginning no later than October 22, 2018 reflecting EGS arrears for the third quarter 2018, EGSs can undertake a range of proactive measures to address customer non-payment if they are provided timely data about the customer's payment status.[110]

Respond Power also supports Joint Stipulation No. 2 as a resolution of its dispute with the Companies regarding the clawback charge. Respond Power explains that it entered into the Joint Stipulation No. 2 because the Companies have agreed to provide EGS-specific customer arrears reports with unpaid aged supply charge balances on a quarterly basis beginning no later than October 20, 2018. In exchange for this commitment from the Companies, agreed to by both BIE and RESA, Respond Power determined not to pursue its other challenges regarding the clawback mechanism in this proceeding.

OCA does not object to Paragraphs 1 or 2 of Joint Stipulation No. 2. However, OCA objects to Paragraph 3 of Joint Stipulation No. 2.[111] According to OCA, the information that is to be provided pursuant to this provision of the stipulation refers to customer-specific information, rather than aggregate information. In OCA's view, EGSs are not entitled to receive or permitted to access such customer information without the customer's full, knowing consent because Section 54.8 of the Commission's regulations prohibit the release of this data by EDCs to third parties.[112] A customer has a right to restrict the release of billing information and arrears information should not be automatically relayed to EGSs by an EDC. This is particularly the case when the EGS is not responsible for collecting unpaid charges from the customer. The OCA submits that the Commission should reject Paragraph 3 of Joint Stipulation No. 2.

As explained in more detail below, I recommend that the Commission approve Joint Stipulation No. 2 Paragraphs 1 and 2 as written. I also recommend approval of

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110 Joint Stipulation No. 2 at ¶ 3.

111 OCA takes no position regarding ¶¶ 1 or 2.

112 52 Pa.Code § 54.8.

Paragraph 3, but with a modification to clarify the scope of the customer arrearage information that is exchanged between the Companies and EGSs.

OCA advocates an overly broad reading of Section 54.8. That section, one of several with the purpose of enabling "customers to make informed choices regarding the purchase of electricity services . . ."[113], provides for the privacy of customer information:

> An EDC or EGS may not release private customer information to a **third party** unless the customer has been notified of the intent and has been given a convenient method of notifying the entity of the customer's desire to restrict the release of the private information. Specifically, a customer may restrict the release of either the following:
>
> (1) The customer's telephone number.
>
> (2) The customer's historical billing data.[114]

In the context of the other regulations in the subchapter, the purpose of Section 54.8 is to protect consumers from unwanted marketing contact by suppliers. There is nothing in this regulation, which addresses the exchange of customer information contemplated by Paragraph 3 of Joint Stipulation No. 2. The customers which are the subject of the agreement are the EGS' own customers. In this sense, the EGS is not a "third party." These customers have already provided their address and telephone number to the EGS, and the customers' usage information is already exchanged between the EDC and the EGS. In the numerous proceedings regarding the exchange of data between EDCs and EGSs, the Commission has recognized this distinction:

> Touchstone agrees with our position on whether the disclosure of customer non-payment information constitutes a potential breach of privacy. **In our Secretarial Letter, dated February 5, 1999, we stated that, provided billing parties share non-payment information relating only to the non-billing entity's charges, the Commission is satisfied that the customer's privacy would not be compromised.** Allegheny also

113 52 Pa.Code § 54.1.

114 52 Pa.Code § 54.8(a) (emphasis added).

> agrees with this statement, adding that the non-billing party is entitled to know the status of payments toward its charges and that the billing party should not be allowed to withhold information that, in all likelihood, the non-billing party requires for the proper administration of its own business practices.[115]

In its support for Paragraph 3, Respond Power explains the necessity for receiving non-payment information for its customers. The clawback charge introduces a level of exposure to EGSs participating in the POR program such that the Companies have recourse against them if their customers fail to pay their supply charges. Having access to the information about its non-paying customers is the most critical change advocated by Respond Power in this proceeding and would enable it – in the future – to monitor the payment patterns of its supply customers and take appropriate steps to minimize or avoid the imposition of clawback charges. Through this tool, Respond Power would be in a position to review the data showing which of their supply customers are not paying their bills and make business decisions designed to avoid the imposition of clawback charges. Respond Power's customers would also benefit because it incents Respond Power to reach out to payment-troubled customers and explore solutions such as potentially renegotiating the terms of contracts to terms that may be more affordable to customers. Respond Power could also elect to return those non-paying customers to the Companies for default service.[116]

RESA echoes Respond Power's advocacy for Paragraph 3. Since the customers at issue are the EGS's customers, EGSs are required – by both Commission regulations and other laws – to safeguard customer data.[117] Giving EGSs important information about <u>their own</u> customers is reasonable and, as is the case here, takes on even greater importance when that information is the basis upon which the EGSs may be assessed a future financial penalty.

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[115] *In Re Elec. Data Transfer & Exch.*, M-00960890, F0015, 1999 WL 632789 (March 19, 1999) (emphasis added).

[116] Respond Power St. 1 at 10-11.

[117] 52 Pa.Code. § 54.8.

In sum, Section 54.8 of the Commission's regulations does not prohibit the Companies from providing the arrearage reports contemplated by Paragraph 3 of Joint Stipulation No. 2. In this context, an EGS is not a "third party," but is receiving information about its own customers which will enable it to reach out to those payment-troubled customers. OCA's argument that by participating in the Companies' POR, the EGS has no collection responsibilities and therefore has waived all access to their customers' payment data is not persuasive. The clawback charge is meant, in part, to incent EGSs to provide customers with affordable supply contracts or face the potential consequence of the imposition of the charge. EGSs should have the ability to renegotiate more affordable agreements with their payment-troubled customers or return them to default service, which not only benefits the EGS by enhancing its ability to avoid assessment of the clawback charge but may also benefit the Companies and its ratepayers by reducing uncollectible expenses.

However, the language of Paragraph 3, is somewhat vague in that it does not appear to explicitly limit the arrearage report that an EGS receives to the arrearages of only that EGS's customers. Therefore, I recommend that the Commission approve Paragraph 3 as modified below to more explicitly limit the information that an EGS receives:

> The Companies will develop an EGS-specific customer arrears report with unpaid aged EGS account balances. This report will be provided to EGSs participating in the Companies' purchase of receivables programs on a quarterly basis, beginning no later than October 20, 2018, reflecting EGS arrears for third quarter 2018. **<u>Information contained in the customer arrears report provided to each EGS shall only contain information regarding customers of that specific EGS.</u>**

5. Bypassable Retail Market Enhancement Rate Mechanism (PTC Adder)

The Companies have proposed the introduction of a PTC Adder as part of this proceeding. The PTC Adder would essentially be a surcharge added to the residential default service rate for each Company in order to incentivize non-shopping residential customers to participate in the retail market. The reason the Companies have proposed the PTC Adder be applicable only to the residential customer class is due to the fact that this particular class has the lowest level of customer shopping across each of the Companies' footprints. In particular, only about 30% of the Companies' residential customers are shopping, on average. By contrast, commercial and industrial customers are shopping in significantly greater proportion, thereby indicating that commercial and industrial customers may be more aware of their opportunities to shop for, and further, do not need an additional incentive to shop for, their electricity.

Once collected, the Companies intend to return 95% of the revenues collected to all residential customers – shopping and default service – through their respective non-bypassable DSS Riders. The 5% of the revenue collected through the PTC Adder and retained by the Companies would be used for the Companies' expenses associated with administering the PTC Adder. Given this design, the Companies state that the mechanism is designed to be revenue neutral to the Companies. The calculation of the PTC Adder is designed to be based on the $30 Customer Referral Program Charge (CRP charge) to EGSs for each customer enrolled by EGSs under the Companies' CRP, which is in turn divided by a period of twenty-four months. The twenty-four-month period was selected as a reasonable proxy for the Companies to assume as representing an EGS's average retention period in the absence of any other verifiable data. By using these inputs, the PTC Adder would amount to a charge of $1.25 per residential default service customer per month. The $1.25 per month charge is then divided by the average residential usage for the four Companies, which establishes a per kWh charge which is intended to be used as a component of the PTC Riders' rate calculation, with the charge expected to remain constant for the four-year DSP term. Meanwhile, DSS Rider rates to be effective on June 1, 2020 will include the refund of 95% of the PTC Adder collected from residential default service customers in the PTC Rider between June 1, 2019 and March 31, 2020.

The citizens of Erie who testified at the March 13, 2018 public input hearings, were, without exception, opposed to the PTC Adder.[118] Many complained that "a choice is not a choice if you have to pay for the privilege of not choosing"[119] and felt that it was unfair to

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118 Most witnesses adopted the convention of Kenneth Springirth's testimony and referenced the PTC Adder as a "surcharge."

119 Searle-White, Lisbet, N.T. 101.

impose a charge for choosing default service.[120] Many did not want to be forced to switch to an EGS to avoid paying the charge, at least in part based on their own experience with shopping, or the experiences of close friends and relatives.

Many witnesses adopted the testimony of community activist Kenneth C. Springirth who testified in opposition to approval of the PTC Adder.[121] Mr. Springirth testified that he is a proponent of electric choice and when the ability of a consumer to shop for an electric supplier became available in 1996, consumers could easily save money by switching. However, it was his view that the shopping experience has become too complicated and many customers simply do not want to switch from default service "because of a poor prior experience with an EGS, finding an EGS that offered meaningful savings, or the customer's desire to remain with Penelec." Mr. Springirth stated that rather than assessing a charge on customers who elect default service, the shopping experience should be reformed instead by disallowing variable rate contracts, mandating greater transparency in contracts and presenting offers in such a way that it is easier to compare EGS offers.

Several witnesses offered testimony which was consistent with Mr. Springirth's observations. They objected to being required to pay the PTC Adder because they had made a

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120 Audet, Jeffrey, N.T. 109-111; Brumagin, Roger, N.T. 117-18; Via, Andrew, N.T. 124-26; Watkins, William, N.T. 126-29; Murphy, Judy, N.T. 129-30; Walker, Robert, N.T. 132-33; Kosiorek, Martha, N.T. 147-151; Johnson, William, N.T. 157-61; Fensel, Charles, N.T. 161-63; Schweichler, Gloria, N.T. 198-200; Swantek, Leo, N.T. 206-207; Castorina, Jean, N.T. 232-33; Fineman, Andrew, N.T. 234-36; Chapman, Carol, N.T. 243-44; Hetz, Garth, N.T. 256; Dalton, Gail, N.T. 257-29; Trott, Allan, N.T. 265-69; Johnson, Hattie, N.T. 281-84; Roan, David, N.T. 300-302; Moravek, John, N.T. 92-93; Meyers, Ronald, N.T. 95-97; Prectl, Roger, N.T. 96-97; Byrnes, Timothy, N.T. 111-15; Hermann, Patrick, N.T. 119-20; Blazek, Robert J., N.T. 260-63;Kerner, Gerald, N.T. 151-55; see also, Shubert, John, N.T. 183-85 (Penelec shouldn't charge him a fee for remaining with default service, but give him a loyalty discount).

121 N.T. 63-97; 227-31.

conscious decision to choose default service.[122] Many of the 66 witnesses had specific experiences with shopping. Some had reviewed EGS offers but decided not to switch.[123] A similar number had actually switched to an EGS but had chosen to return to default service for a variety of reasons, including a bad customer experience with a supplier, or because they did not end up saving money on their bills.[124] Many desired default service simply because they were happy with the service they received from Penelec.[125] Others wanted the benefit of Commission oversight of Penelec and the expertise of Penelec customer service or expressed concern for low income and elderly customers in an unregulated marketplace.[126] Twenty-seven witnesses expressed concern because either they did not feel they had the interest or skill to navigate the marketplace and shop effectively, or because they were concerned that the elderly or less educated may find it difficult. Some found it difficult to understand and compare all of the different offers that were available. Others were concerned about cancellation fees if a variable rate went up.[127]

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[122] Shaaf, Kathleen, N.T. 130-32; Federsen, Robert, N.T. 278-79; Swaney, Ruth, N.T. 132; Walker, Robert, N.T. 132-33; Hyde, Gary, N.T. 137-40; Acks-Welsbacher, Susan, N.T. 140-45; Fensel, Charles, N.T. 161—63; Peterson, Shane, N.T. 167-68; Kubia, Bonny, N.T. 174-83; Ellis, Matthew, N.T. 191-94; Hill, Mary, N.T. 270-72; Dalton, Gail, N.T. 257-29; Castorina, Jean, N.T. 232-33; Starrett, Karen, N.T. 287-91; Montgomery, Allan, N.T. 247-51; Willis, Raymond, N.T. 163-65; Johnson, William, N.T. 157-61; Pollock, James, N.T. 186-90; Murphy, Judy, N.T. 129-30; Prectl, Roger, N.T. 96-98; Sciarrino, Matthew, N.T. 98-100; Fineman, Andrew, N.T. 234-36; Shubert, John, N.T. 183-85; Kosiorek, Martha, N.T. 147-51; Yockim, Joseph, N.T. 135-37; Schweichler, Gloria, N.T. 198-200; Chapman, Carol, N.T. 243-44; McCartney, Hugh, N.T. 239-40; Sussann, Philip, N.T. 253-55.

[123] Hyde, Gary, N.T. 137-40; Acks-Welsbacher, Susan, N.T. 140-45; Pollock, James, N.T. 186-90; Murphy, Judy, N.T. 129-30; Sciarrino, Matthew, N.T. 98-100; Fineman, Andrew, N.T. 234-36; Yockim, Joseph, N.T. 135-37; Sussann, Philip, N.T. 253-55; Meyers, Ronald, N.T. 95-96; Ellis, Matthew, N.T. 191-94; Mitchell, Christine, N.T. 245-46; Byrnes, Timothy, N.T. 111-115; Brumagin, Roger, N.T. 117-18: McCartney, Hugh, N.T. 239-40; Blazek, Robert J., N.T. 260-63; Audet, Jeffrey, N.T. 109-111; Prectl, Roger, N.T. 96-97; Hermann, Patrick, N.T. 119-20.

[124] Love, John, N.T. 170-71; Swantek, Leo, N.T. 206-207; Krauza, Barbara, N.T. 165-66; Czajkowski, Margaret, N.T. 237-38; Samec, William, N.T. 272-78; Willis, Raymond, N.T. 163-65; Montgomery, Allan, N.T. 247-51.

[125] Montgomery, Allan, N.T. 247-51; Kosiorek, Martha, N.T. 147-51.

[126] Schweichler, Gloria, N.T. 198-200; McCartney, Hugh, N.T. 239-40 Jarmolowicz, Casimir, N.T. 87-91; Dalton, Gail, N.T. 257-59.

[127] Searle-White, Lisbet, N.T. 100-108; Henderson, Charles, N.T. 155-57; Schweichler, Gloria, N.T. 198-200; Castorina, Jean, N.T. 232-33; Chapman, Carol, N.T. 243-44; Sciarrino, Matthew, N.T. 98-100; Kosiorek, Martha, N.T. 147-51; Tepfer, Freda, N.T. 171-73; Ellis, Matthew, N.T. 191-94; Kerner, Gerald, N.T. 151-55; Mitchell, Christine, N.T. 245-46; Byrnes, Timothy, N.T. 111-15; Priscaro, Jerry, N.T. 120-124; Pollock, James, N.T. 186-90; Otteni, Allan, N.T. 168-170; Byrnes, Timothy, N.T. 111-15; Swaney, Ruth, N.T. 132; Johnson, William, N.T. 157-

A few customers explained that they do shop for alternative supply, but still oppose the PTC Adder. Robert Blazek testified that he enjoys shopping for an EGS, but understands that others do not share his interest and should not be penalized. He also thought the charge is unfair because he wants the option to return to default service when the price to compare is the lowest offer.[128]

The overwhelming concern expressed by people who did not want to be forced to switch to an EGS in order to avoid paying the PTC Adder were the general sales tactics used by many suppliers and unscrupulous sales tactics. Many individuals complained about telemarketing[129] and door-to-door sales.[130] All felt that they were a nuisance. Others complained that the door-to-door salespeople often employed high pressure sales tactics or were not honest about who they were representing.[131]

At least two witnesses told stories of an elderly person in their care who was confused about why their electric bills were suddenly so high.[132] The caretakers discovered that the elderly person had a supplier who was charging an exorbitantly high rate and the person had no recollection of switching. These two and many others expressed concern that the PTC Adder would force the elderly and other vulnerable populations into an EGS marketplace that they were not well-equipped to navigate or protect themselves from unscrupulous entities.

61; Springirth, Kenneth, N.T. 227-31; Fensel, Charles, N.T. 161-63; Kosiorek, Martha, N.T. 147-51; Cipola, Doris, N.T. 241-42; Brumagin, Roger, N.T. 117-18; Audet, Jeffrey, N.T. 109-11; Jarmolowicz, Casimir, 87-93.

[128] Blazek, Robert J., N.T. 260-63.

[129] Searle-White, Lisbet, N.T. 100-108; Brumagin, Roger, N.T. 117-18; Kerner, Gerald, N.T. 151-55; Willis, Raymond, N.T. 163-65; Kubia, Bonny, N.T. 174-83; Pollock, James, N.T. 186-90; Czajkowski, Margaret, N.T. 237-38; McCartney, Hugh, N.T. 239-40; Blazek, Robert J., N.T. 260-63; Trott, Allan, N.T. 265-69; Bierley, Harry, N.T. 280; Johnson, Hattie, N.T. 281-84; Sciarrino, Matthew, N.T. 98-100.

[130] Meyers, Ronald, N.T. 95-96; Henderson, Charles, N.T. 155-57; Kerner, Gerald, N.T. 151-55; Krauza, Barbara, N.T. 165-66.

[131] Springirth, Kenneth, N.T. 227-31; Czajkowski, Margaret, N.T. 237-38; Priscaro, Jerry, N.T. 120-124; Via, Andrew, N.T. 124-26; Kubia, Bonny, N.T. 174-83.

[132] Searle-White, Lisbet, N.T. 100-108; Montgomery, Allen, N.T. 247-51.

Many witnesses were concerned about how low-income people would be affected by an additional charge.[133] One witness was concerned that she would lose her access to budget billing[134] and another that she could not qualify for heating assistance if she used an EGS.[135]

A handful of witnesses echoed Mr. Springirth's concern regarding the notice of the default service filing and the availability of the filing for public review.[136] Mr. Springirth recommended that in the future, Penelec rate filings should be made available in the public library rather than at the Company's office.

A few other witnesses expressed concern about how Penelec arrived at the rate for the PTC Adder[137] and were concerned about the mechanics of how it would work.[138]

RESA supports the PTC Adder, but not because it will incent switching. Rather, in RESA's view, the adder is desirable to "level the playing field" and serve to unbundle costs which will enhance the ability of EGSs to compete with default service. RESA proposes an alternate calculation of the PTC Adder and proposes that the revenue be distributed to low-income programs rather than to all residential customers.

BIE, OCA, CAUSE-PA, NextEra oppose the PTC Adder. OSBA and the Industrials also oppose the PTC Adder as a matter of policy. OSBA opposes it because some commercial customers could be subject to residential rates because of the reclassification of the commercial procurement class. Further, although the proposal is currently to apply the PTC

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133 Searle-White, Lisbet, N.T. 100-108; Priscaro, Jerry, N.T. 120-124; Watkins, William, N.T. 126-29; Shaaf, Kathleen, N.T. 130-32; Schweichler, Gloria, N.T. 198-200; Jarmolowicz, Casimir, N.T. 87-94.

134 Johnson, Hattie, N.T. 281-84.

135 Dalton, Gail, N.T. 257-59.

136 N.T. 62-86; Byrnes, Timothy, N.T. 111-15; Priscaro, Jerry, N.T. 120-124.

137 Culmer, Terry, N.T. 292-93.

138 Otteni, Allan, N.T. 168-170.

Adder to only residential ratepayers, OSBA and the Industrials oppose it because if approved, it could be expanded to include commercial and industrial rate classes in the future.

NextEra also contends that the PTC Adder should not be adopted because it will be detrimental to the retail generation market. Specifically, NextEra points out that the proposed adder (1) distorts the price signals for both the residential default service customers and for the residential shopping customers; (2) results in a cross-subsidy from residential default service customers to residential customers receiving competitive supply service; (3) may result in higher competitive prices, which would represent a subsidy from residential customers receiving competitive service to generation suppliers; and (4) is not an appropriate price signal to encourage residential customers to decide to leave default service.

The parties opposing the PTC Adder do so on a variety of grounds: the justification for and mechanics of the PTC Adder are arbitrary; the proposal violates the Public Utility Code because it is not related to providing generation and has no cost-based justification; the proposal is virtually identical to a proposed "market adjustment charge" rejected by the Commission in the Companies' DSP II; and the proposal is not just and reasonable and is unfair to both shopping and non-shopping customers.

As explained more fully below, I agree that there is no justification for the PTC Adder and that the Companies have failed to prove that the proposal is just and reasonable. Accordingly, I recommend that the Commission reject the proposal.

Under the Public Utility Code, as EDCs, the Companies have an obligation to provide default service. Specifically, as set forth in the Code, EDCs are required to provide default service to customers at no greater cost than the cost of obtaining generation.[139] The Companies are entitled to full recovery of all costs of providing default service on a dollar-for-dollar basis through an automatic adjustment surcharge.[140] The PTC Adder will result in an

139 66 Pa.C.S. § 2807(e).

140 66 Pa.C.S. § 2807(e)(3.9).

increased volumetric charge for residential default service customers, but it is not predicated on the cost of generation. Instead, the PTC Adder is calculated arbitrarily, and it is being assessed solely to influence residential default customers' decisions to enter the retail market.

Although the stated purpose of the PTC Adder is to incent "shopping," the real purpose of the adder is to incent "switching." The Companies propose to charge the PTC Adder to residential customers who do not switch to an EGS. As pointed out by the public input testimony, many customers do review EGS offers and therefore "shop," but choose to remain with default service. As one individual put it – many people "shop" but simply choose not to "buy." Those who choose not to buy will be assessed the PTC Adder even though they have shopped.

The calculation of the PTC Adder itself is speculative and based on false assumptions. The PTC Adder rate was calculated based on the charge to EGSs for each customer enrolled in the Companies' standard offer program. Ms. Bortz testified on behalf of the Companies that the EGS charge for participating in the standard offer program was used because it is the "amount that EGSs have demonstrated that they are willing to pay for customers referred by an EDC." [141] I agree with OCA's expert who explains that using a proxy for EGS customer acquisition costs is unrelated to the stated purpose of the PTC Adder, and "is fundamentally an arbitrary figure."[142]

The remaining portion of the PTC Adder calculation, the assumption of a twenty-four-month EGS customer retention rate, is also unsupported and not related to the stated purpose of the PTC Adder. According to the Companies, they had to assume the length of the retention period because they did not have access to the proprietary information they would need to establish the true retention rate.[143] The twenty-four-month retention rate is not based upon

141 Companies St. 1 at 23.

142 OCA St. 1-S at 10.

143 Companies St. 1 at 26.

actual, verifiable data; therefore, like the CRP fee, it too fails to provide a valid basis to underlie calculation of a PTC Adder surcharge.

There is also no basis in fact or support with data for the Companies' proposal to return 95% of the amounts collected to *all* residential customers, including those who do not pay the adder because they have switched to an EGS, and to retain 5% for administrative costs. The Companies admit that they have no estimates of what their administrative costs will be. Nor do they intend to track their administrative costs to determine whether 5% is a reasonable estimate. The Companies offer no justification for the return of revenue collected from default service customers to all customers, nor do they explain how the return of revenue will effectuate enhanced switching.

The Commission rejected a proposal with similar elements when it considered the Companies' "Market Adjustment Charge (MAC)" in the DSP II proceeding. As proposed, the MAC was a "bypassable charge that would be imposed on non-shopping residential and commercial customers."[144] The stated purpose of the MAC was to compensate the Companies for the risk they bear in providing default service, and to compensate the Companies for the value they provide as default service providers. RESA recommended that the MAC be modified to cover the costs of implementing the retail market enchantments and leftover revenues be "returned to all ratepayers through a non-bypassable charge."[145] Under RESA's modifications, "[o]nly default service customers would be charged for the MAC, but all residential customers . . . would receive the credit from the leftover MAC revenues." [146] As such, the MAC was a non-cost-based charge similar to the PTC Adder proposed here. The ALJ concluded that charging

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144 *Joint Petition of MetEd, Penelec, Penn Power, and West Penn for Approval of their Default Service Programs*, Docket No. P-2011-2273650, et al. (Order entered August 2, 2012, at 53).

145 *Joint Petition of MetEd, Penelec, Penn Power, and West Penn for Approval of their Default Service Programs*, Docket No. P-2011-2273650, et al. (Recommended Decision issued June 15, 2012, at 57).

146 *Id.*

non-shopping customers the MAC and returning leftover revenues to all customers was "inequitable on the surface" and rejected RESA's recommendation.[147]

The Commission cited the ALJ's reasoning on this point in its Order, which rejected the MAC in its entirety.[148]

The Commission further noted that the ALJ determined that the MAC is not a "legitimate retail market enhancement tool, and is an inappropriate and unnecessary financial adder."[149] In addition, the MAC conflicted with the Public Utility Code because "the Companies receive full recovery of all costs of providing default service on a dollar-for-dollar basis through an automatic adjustment surcharge as provided by 66 Pa. C.S. § 2807(e).[150] Moreover, EDCs are obligated to provide default service "at no greater than the cost of obtaining generation."[151] The Commission concluded:

> While under the Code the Companies are entitled to recover all actual costs to provide default service on a dollar-for-dollar basis, the Companies and other Parties failed to provide sufficient empirical support for any actual known and measurable costs that are not being recovered through existing or proposed rates and riders. Accordingly, we adopt the ALJ's recommendation and deny the Exceptions related to the establishment of a MAC.[152]

Like the MAC proposed in DSP II, the Companies propose a PTC Adder intended to "incent residential retail shopping."[153] The PTC Adder is a bypassable charge that will be

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147 *Id.* at 57.

148 *Joint Petition of MetEd, Penelec, Penn Power, and West Penn for Approval of their Default Service Programs,* Docket No. P-2011-2273650, et al. (Order entered August 2, 2012, at 59).

149 *Id.* at 58.

150 *Id*.

151 *Id.* at 59.

152 *Id*. at 62.

153 OCA St. 2 at 32 (*citing* Companies St. 1 at 25).

imposed on residential default service customers. The Companies propose to use 5% of the PTC Adder to cover unspecified "administrative costs" associated with the retail market enhancement rate mechanism and return 95% of revenues to all ratepayers through a non-bypassable rider. As the ALJ concluded and the Commission agreed in DSP II, the practice of charging default customers the PTC Adder and returning revenues to all customers is "inequitable" *per se*. In addition, as explained by OCA witness Estomin and OCA witness Alexander, the PTC Adder will allow the Companies to recover charges that are not demonstrated to be lawful – the charges do not reflect a cost of providing service – without any empirical support or measurable costs.[154] Therefore, the Commission must reject the Companies' proposal.

Even if the PTC Adder represented a cost of providing default service, none of the expert testimony provided by the Companies in support of the PTC Adder provides any data or explanation which demonstrates how the PTC Adder will result in increased switching. As pointed out by several of the experts, the Companies have not identified a threshold of acceptable residential customer switching by which the success or failure of the adder could be measured, nor have they presented data which supports the premise that the retail generation market in any of the service territories is not operating as it should be and requires enhancement by the Companies as the default service providers. While the Companies assert that they are proposing the PTC Adder "in order to incent residential retail shopping,"[155] the Companies admit they "have no evidence that increasing default service costs [through the PTC Adder] will have an identifiable effect on customer shopping."[156] In fact, the Companies plainly indicated that they "have no opinion on the appropriate level of residential customer shopping."[157]

The Commission should reject the PTC Adder. The design of the PTC Adder is arbitrary. There is no evidence that the design of the adder is connected in any way to

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154 OCA St. 1 at 17; OCA St. 2 at 33, 34.

155 Companies St.1 at 24.

156 CAUSE-PA St. 1 at 38 (*citing* Companies Response to OSBA Interrogatory Set I, No. 13(i)).

157 *Id.*

incentivizing switching or will achieve its stated goal. Nor does it represent the recovery of a cost to the Companies for providing default service. The Companies provide no justification for returning revenue collected from default service customers to all customers or for retaining a portion to cover unspecified costs. The modifications proposed by RESA do not resolve the lack of connection between the proposed PTC Adder and the costs to provide default service. Nor does RESA's proposal resolve the lack of data to support the calculation of the adder.

6. Customer Referral Program

The Companies propose to continue the customer referral program (CRP) as designed, and to extend the program from May 31, 2021 to May 31, 2023, the end date of the proposed DSPs. OCA, CAUSE-PA and RESA object and propose modifications to the design of the program.

The Companies' witness, Kimberly Bortz, offered no particular reason for the continuation of the CRP until 2023, other than to observe that the CRP is consistent with the Commission's regulations and guidelines and has been approved by the Commission in the past.[158] In its brief, the Companies state that the extension of the CRP to 2023, simply makes the term of the program coincide with the term of DSP V.

OCA opposes the continuation of the program beyond May 31, 2021, recommending that the Companies should either terminate the program in its entirety at that time, or should make a filing which demonstrates why the program should continue, based on demonstrated benefits to customers. The OCA further took issue with the scripting and training materials currently in place for this program, arguing they do not provide sufficient customer disclaimers and education.[159]

158 Companies St. 1-R at 5-6.

159 CAUSE-PA supports the OCA's position.

RESA supports the continuation of the program through 2023 as proposed by the Companies, but suggests that the current scripts and program rules require modification to reduce the existing disclosures, as well permit bill-ready billing. In order to accomplish this, RESA suggests that a stakeholder process be convened to develop new scripts and procedures.

Customer referral programs have been encouraged by the Commission in order to encourage consumers to enter the competitive market.[160] On September 14, 2007, the Commission adopted Section 69.1815 of its regulations,[161] which provides that "[t]he public interest would be served by consideration of customer referral programs in which retail customers are referred to EGSs." On March 2, 2012, the Commission provided guidance on the implementation of customer referral programs in its Intermediate Work Plan (IWP) Order addressing retail market enhancements.[162] The IWP Order established the following guidelines for EDCs implementing customer referral programs:

- The terms and conditions of the standard offer must be presented to customers before they decide to enter the program;
- The program will be on an "opt-in" basis for customers, or voluntary;
- Participating EGSs must offer a 7% reduction in the PTC as compared to the PTC effective on the date the offer is made;
- The contract term must be a minimum of four months and a maximum of 12 months;
- There will be no termination fee during the term of the contract;
- Prior to the end of the program, EGSs must notify participating customers of options to continue service – without the obligation of a 7% discount – and inform customers that they

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160 *See Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*, Docket No. I-2011-2237952 (Final Order entered February 15,2013).

161 52 Pa.Code § 69.1815.

162 *See Investigation of Pennsylvania's Retail Electricity Market*, Docket No. I-2011-2237952 (Order entered March 2, 2012) (IWP Order).

> will remain with the EGS on a month-to-month basis unless they take affirmative action to select a product offered by the EGS, select a product offered by another EGS, or move to default service; and
>
> • The bulk of the costs, including costs for maintaining the programs once they are put into place, will be the responsibility of the participating EGSs.[163]

In the Companies' concurrent default service proceeding, DSP II, the Commission ordered that the Companies' Customer Referral Programs (CRP) must provide participating customers a "seven percent discount at the time the offer is made and should extend for a one-year service term."[164] On reconsideration, the Commission clarified that the "customer will be offered a rate of seven percent below the prevailing PTC *at the time the offer is made* and that rate will then be fixed for a period of twelve months," meaning that even if the PTC changed, the price for energy supply would not. [165]

The Companies implemented their CRP in 2013.[166] The Companies offer their CRP to residential and small commercial customers that contact the Companies to establish new service, move within Companies' service territories, complain regarding a high bill, or learn about EGS shopping.[167] In terms of program design, the Companies undertake a bifurcated presentation of the CRP.[168] In particular, the Companies provide scripts to their customer service representatives (CSR) as well as their third party agent, AllConnect.[169] The CSR scripts include

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163 *Id*. at 20, 31-32, 73-74.

164 *Joint Petition of MetEd, Penelec, Penn Power, and West Penn for Approval of their Default Service Programs*, Docket No. P-2011-2273650, et al. (Order entered August 2, 2012, at 156) (emphasis in original).

165 *Joint Petition of MetEd, Penelec, Penn Power, and West Penn for Approval of their Default Service Programs*, Docket No. P-2011-2273650, et al. (Reconsideration Order entered September 27, 2012, at 20).

166 OCA St. 2 at 7.

167 OCA St. 2 at 8.

168 OCA St. 2 at 9.

169 OCA St. 2 at 8-9.

a statement regarding “potential rate savings” associated with the CRP followed by a statement attempting to transfer the customer to a “connections program.”[170] Once transferred to AllConnect, the AllConnect representatives present the CRP to the customer and actively attempt to enroll the customer with an EGS.[171] AllConnect earns a fee each time it enrolls a customer in the CRP.[172]

OCA contends that the script used by CSRs should be modified. OCA’s witness, Barbara Alexander, believes that the customers were not given the required disclosures, and that AllConnect was not stressing the voluntary nature of the programs to the customer.[173]

In negotiating a settlement of DSP IV, the parties, including OCA, agreed to the following modifications to the CRP:

> The currently-effective Customer Referral Program (CRP), including the cost recovery mechanisms last approved by the Commission in the Companies' DSP III Proceeding, will continue until May 31, 2021.
>
> The Customer Referral Program scripts will be modified to include the following:
>
> AllConnect script will continue to state that the EGS "rate could be higher or lower than the PTC;" and,
>
> The Companies' CSR script initiating the transition to the program specialist will provide as follows:
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> "In Pennsylvania, you can choose the company that provides your electricity without impacting the quality of service. Would you like to speak to a representative who can offer you a potential savings opportunity by enrolling with an electric generation

170 OCA St. 2 at 8-9.

171 OCA St. 2 at 9.

172 *Id*.

173 OCA St. 2 at 18-19

> supplier?" The AllConnect script will be revised to include the following language: "The CRP offers a fixed price of _/kWh for one year provided by an Electric Generation Supplier. The fixed CRP price provides an initial discount off of today's Price to Compare which is /kWh. The Price to Compare will change again on [March/June/September/December] first. The CRP price will not change through twelve monthly bills, but the PTC could be higher or lower than the CRP price during this period."[174]

This negotiated modification to the scripting used by the Companies' CSRs and AllConnect was based upon OCA's argument that the scripts negotiated in DSP III, required revision. The arguments made by OCA now are similar to the arguments OCA made regarding the scripting negotiated in DSP IV. Essentially, OCA is attempting to relitigate issues regarding the design of the CRP that have been raised and resolved in prior proceedings without introducing any specific evidence that the design of the CRP actually confuses or misleads customers.

The script adequately describes the relationship between the price-to-compare and the price offered through the CRP. The program includes a provision which permits a consumer to exit the contract with the EGS at any time without incurring a termination fee. There does not appear to be any inherently deceptive language in the CRP as designed and previously agreed to by OCA. Moreover, the Commission has already determined that the language agreed to by the parties in DSP IV is in the public interest and compliant with Commission guidance and regulations.[175]

OCA has also raised concerns regarding the implementation of the CRP by the Companies. Specifically, OCA takes the position that the Companies are not adequately training or overseeing CSR representatives who have not always used the correct script language. In reply, the Companies take issue with OCA's characterization of their implementation of the CRP.

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174 Joint Petition for Settlement, DSP IV at Section H.

175 *Petition of MetEd et al.,* Docket No. P-2015-2511333 (cons.) (Final Order entered May 19, 2016).

The purpose of this proceeding is to review the design of the CRP. If the Companies are not properly implementing the program, as with any tariff or Commission-approved rule, OCA could file a complaint and seek enforcement. Similarly, the Commission could institute an investigation itself.

OCA also contends that the CRP should be terminated because many customers do not actually realize savings and may pay more than the PTC over a 12-month period. There is nothing in the CRP as it is designed which guarantees a consumer any particular level of savings. The formula for the CRP price was established by the Commission in the IWP Order. The protection offered to consumers is the ability to exit the contract at any time without paying a cancellation or termination fee. The script negotiated in the DSP IV settlement explicitly tells a customer that the PTC can change. The script also tells a customer that the price the EGS will offer is a fixed price that will not change. This is sufficient to give a consumer the choice of accepting a fixed price for 12 months or choosing a price that will change four times per year, by remaining in default service.[176] If market conditions change and the PTC always increases, customers in the CRP may save money in the future. However, if the PTC decreases, a customer may not save money. This factor does not point to a design defect of the Companies' CRP. Any customer engaging in the competitive marketplace, whether independently or through the Companies' CRP, runs the risk of not saving money or saving very little money. The purpose of a CRP is to stimulate participation in the supply market by providing customers with a simplified offer formula rather than comparison shopping.[177] The purpose of the program is not to guarantee savings.

In short, OCA has not proven that the CRP is so defective as designed that it should be immediately terminated or re-designed by Commission mandate.

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[176] It goes without saying, that a customer is free to contact any EGS and enter into a contract that may include terms different from those offered either in default service or the CRP.

[177] *See* public input testimony where many witnesses testified that the myriad of competitive offers were confusing and difficult to navigate.

RESA also advocates for changes in the script. According to RESA, the script should revert to the version negotiated in the DSP III settlement because participation in the CRP has declined. RESA's witness, Richard Hudson, makes the bald statement attributing the reduction in participation to DSP IV script change. He does not offer any facts to support his claim.

OCA disputes RESA's conclusion that the DSP IV script caused the decline in CRP enrollment. OCA's witness, Ms. Alexander, attributes the decline to a variety of factors, including the Polar Vortex and high EGS variable prices and the ensuing complaints and formal investigations, few EGS participants in the CRP due to the low PTC, and the change in policy of the Companies to complete a customer's EDC transaction prior to being transferred to AllConnect.[178]

Like OCA, RESA failed to prove that there is an inherent defect in the design of the Companies' CRP, or that it does not comply with the Commission's regulations.

The design of the current CRP was negotiated and agreed to in DSP IV. The Commission approved the plan and concluded that its approval was in the public interest and met the Commission's requirements for CRP. Although the Companies' only articulated reason to continue the program without changes for an additional two years is convenience (and perhaps some frustration with the lack of progress in the stakeholder discussions), no party has adduced any evidence of a change in circumstances since the time it was approved to support the plans' termination or alteration. Therefore, I recommend that the Commission grant the Companies' request to extend the CRP.

OCA has raised some issues regarding the Companies' reliance on AllConnect, including the Companies' governance and implementation of the CRP, the incentive agreement between AllConnect and the Companies and the degree to which AllConnect is used to sell non-

[178] OCA St. 2 at 9-10. The declining interest in enrolling with an EGS identified by Ms. Alexander is anecdotally supported by some of the Erie Public Input testimony.

utility services which may interfere with the intent and goals of the CRP. A stakeholder meeting proposed by RESA may be useful in resolving some of these issues, and the Companies should consider continuing the discussion on a voluntary basis in preparation for presentation of the CRP after May 2023.

In sum, I recommend that the Commission approve the continuation of the Companies' CRP until the conclusion of DSP V.

7. Customer Assistance Program Shopping

The Companies' low-income residential customer assistance program is called the Pennsylvania Customer Assistance Program (PCAP). Through PCAP, eligible customers receive discounted payment amounts and arrearage forgiveness for remaining current on their PCAP payment. The amount that PCAP customers pay is based on a percentage of their income, and they must be enrolled in an equal payment plan, which is based on the customer's usage over the last twelve months. The difference between the equal payment plan amount and the PCAP customer's "asked to pay" amount is the monthly PCAP credit.[179] PCAP subsidy credits are paid for by all residential, non-PCAP customers through the Companies' Universal Services rider.[180] Currently, PCAP customers of the Companies are permitted to switch to an EGS without a price cap or any other limit.

As part of the settlement of the Companies' DSP IV, the Companies agreed to convene stakeholder collaboratives regarding the scope of PCAP shopping and associated cost recovery. In conjunction with that obligation, the Companies also agreed that thirty days prior to the PCAP customer shopping collaboratives, the Companies would provide the total PCAP shortfall amount paid by residential customers, broken down by Company, from the period June 2013 through the billing period immediately prior to providing these numbers, as well as other

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179 BIE St. 1 at 17-18; BIE Ex. No. 1, Sch. 2.

180 BIE St. 1 at 17-18.

PCAP shopping data. Finally, the Companies also agreed to make a proposal in their next default service proceeding regarding the scope of PCAP shopping.[181]

The Companies did convene stakeholder collaborative sessions with parties to the prior default service settlement on September 13, 2016; November 30, 2016; May 25, 2017; and on October 4, 2017.[182] Although the Companies provided the required information to stakeholders in conjunction with the collaborative sessions, no PCAP shopping resolution was reached.

In the instant proceeding, the Companies' initial proposal regarding PCAP shopping was to not propose any modifications to the scope of shopping, meaning that the Companies will continue to permit PCAP customers to shop for alternative generation supply without restriction.[183] In the Companies' view at the time, the legal framework regarding limits to PCAP shopping were unsettled. To date, the Companies' opposition to PCAP shopping restrictions was based on the Commission's directives in the RMI Final Order.[184] Specifically, in the 2013 RMI Final Order, the Commission held that PCAP customers should be allowed to participate in the competitive market without restriction.[185] BIE, OCA and CAUSE-PA, all contend that the evidence presented in this case demonstrates that unrestricted PCAP shopping allowed with the Companies' current programs results in continuing financial harm to both PCAP participants and non-PCAP residential ratepayers. Therefore, PCAP participants should be restricted from purchasing supply at a rate above the Companies' PTC.

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181 DSP IV Settlement, ¶ J.

182 Companies St. 1 at 3.

183 Companies St. 1 at 3.

184 *Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service*, Docket No. I-2011-2237952 (Final Order entered Feb. 15, 2013)(RMI Final Order).

185 "One of the basic intents of the Competition Act – to 'permit retail customers to obtain direct access to a competitive generation market' – was intended to include all customers." *Id.* at 61.

The Commission has the necessary authority to impose reasonable PCAP shopping restrictions.[186] As explained by the Commonwealth Court, the universal service provisions of the Choice Act tie the affordability of electric service to a customer's ability to pay for that service.[187] The Commission has the responsibility to ensure that the means to achieve the affordability of electric service is appropriately funded and available in each electric distribution company territory.[188] This requires the enactment, establishment, and maintenance of policies, practices and services that allow low-income customers to retain their electric service at an acceptable level of affordability.[189]

Any plan which allows the Companies' PCAP customers to receive service from an EGS must continue to tie the affordability of electric service to a customer's ability to pay for that service through policies, practices, and services that help low income customers maintain utility service. The Commonwealth Court recently refined this framework in the recent case of *RESA v. Pa. Public Utility Commission,* where the court held that there must be evidence to show a substantial reason why a restriction on competition is necessary.[190] A restriction on competition is necessary "when one, there is a harm associated with competition, and two, there is no reasonable alternative to the rule that restricts competition."[191] In light of the *RESA* decision, the Companies now agree that there is sufficient legal authority for PCAP shopping restrictions, such as the price ceiling proposed by CAUSE-PA, BIE, and OCA in this

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186 *Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania v. Pa. Pub. Util. Comm'n*, 120 A.3d 1087 (Pa.Cmwlth. 2015)(CAUSE-PA).

187 *CAUSE-PA,* 120 A.3d at 1103-1104; 66 Pa.C.S. § 2804(9).

188 66 Pa.C.S. § 2803.

189 *Id*.

190 *Retail Energy Supply Ass'n v. Pa. Pub. Util. Comm'n*, ___ A.3d ___ (Pa.Cmwlth. 230 C.D. 2017, filed May 2, 2018)(RESA)(affirming the Commission's approval of PPL's standard offer program for CAP participants). The *RESA* decision was filed on May 2, 2018, the day the parties' main briefs were due. No party had an opportunity to submit a thoughtful analysis of that decision until the reply briefs were filed on May 15, 2018.

191 Slip op. at 35.

proceeding.[192] The Companies would not object to the establishment of a price ceiling if the Commission determines that substantial evidence in this proceeding supports its adoption.

There is ample support in this record to conclude that unrestricted PCAP shopping is harming both PCAP participants and non-PCAP residential ratepayers. BIE, OCA and CAUSE-PA extensively reviewed data regarding shopping of PCAP participants and the resulting costs over a 55-month period.[193] First, the evidence demonstrates that a significant number of the Companies' PCAP customers are shopping:[194]

Year	Total Number of PCAP customers across all Companies who remained on default service the entire year	Total Number of PCAP customers across all Companies who received generation supply from an EGS at some point during the year	Total number of PCAP customers
2013	32,987	34,971	67,958
2014	37,565	28,065	65,630
2015	39,700	24,186	63,886
2016	37,996	27,612	65,608
2017	44,073	22,035	66,108

Second, the evidence demonstrates that of the PCAP customers who shopped, the overwhelming majority paid more than the price to compare.[195] CAUSE-PA witness Mr. Geller concluded that this data collected demonstrates that "a significant majority of PCAP customers who switch to a competitive electric supplier are charged rates that create an obligation for greater costs to be incurred by PCAP than if these customers were charged the utility default

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192 OCA M.B. at 58-60; CAUSE-PA M.B. at 41-43; BIE M.B. at 37-39.

193 Some of the data was updated to include the period of June 2013 through March 2018, a 58-month period. *See* Joint Stipulation No. 3.

194 CAUSE-PA St. 1 at 22, Table 6 (citing Companies Response to CAUSE-PA Interrogatory Set I, No. 2(b) and (c), attached to CAUSE-PA St. No. 1 as Appendix B). Totals were calculated by summing the total for each Company for each year from 2013-2017.

195 *See* Companies St. 1-R at 28; Ex. KLB 35.

service price for energy."[196] Additionally, the Companies' data revealed that during the same period, an average of 63%, 62%, 65%, and 72% of MetEd, Penelec, Penn Power, and West Penn Power PCAP customers paid rates that exceeded the Companies' PTC, respectively.[197] This data demonstrates that – over a prolonged period of time – a significant majority of PCAP customers who switch to a competitive electric supplier are charged rates that exceed the price to compare and, thus, cause greater costs to be incurred by PCAP customers – and the PCAP program as a whole – than if these customers were charged the utility default service price for energy.[198] Aggregated, the data shows that over a nearly five-year period (58 months), two-thirds (65%) of all PCAP customers who shop have contracted for, and obligated PCAP to assume, rates higher than the price to compare.[199]

The economic impact of this unrestricted PCAP shopping is significant. From June 2013 through March 2018, the evidence in the record shows the following <u>net</u> harm to PCAP customers and other ratepayers, which factors in both the savings and the costs of those who switched:[200]

Company	Total Net Cost Above PTC Costs 58 Months (June 2013 – March 2018)	Net Monthly Cost Above PTC Costs	Net Annualized Cost Above PTC Costs
Met Ed	$3,421,210	$58,986	$707,837
Penelec	$3,414,520	$58,871	$706,452
Penn Power	$653,044	$11,259	$135,113
West Penn	$10,847,665	$187,029	$2,244,345
Total	**$18,336,440**	**$316,146**	**$3,793,746**

196 CAUSE-PA St. 1 at 24.

197 BIE St. 1 at 19-20; BIE Ex. No. 1, Sch. 5.

198 *See* CAUSE-PA St. No. 1 at 23, Table 7.

199 *Id*.

200 Joint Stipulation No. 3, ¶ 3.

This more than $18.3 million in increased PCAP costs over a 58-month period (nearly five years) is a direct result of the Companies' current practice of allowing PCAP customers to accept any EGS offer regardless of cost.[201] These increased costs effect the affordability of PCAP bills for PCAP customers on a monthly basis – particularly before their PCAP bill subsidy credits are adjusted to catch up to these increased costs or when they already receive the maximum monthly bill credit. In turn, other ratepayers who pay for PCAP also bear cost increases in the aggregate because of the currently permitted unrestricted PCAP shopping. None of the $18.3 million in additional PCAP costs – which translates into $3.79 million more per year – are used to promote universal service goals under the Choice Act to assist low-income customers to better meet their home energy needs. CAUSE-PA argues that because program costs are intended to assist low-income customers to afford and maintain essential utility service, they should not be increased by more than $3.79 million more per year simply to pay an EGS charging rates higher than the default service price. This is especially so when the higher EGS payments result in tangible harm to low-income PCAP customers and other residential ratepayers, including the more than 160,000 confirmed low-income customers who are not enrolled in PCAP. The Choice Act expressly requires the Commission to administer these programs in a manner that is cost effective for the PCAP participants and the non-CAP participants, who share the financial consequences of a PCAP participant's EGS choice.[202] There is no cost efficiency, and significant unnecessary and impermissible cost, in continued implementation of a PCAP shopping protocol permitting participants to accept any EGS offer above the price to compare.

RESA contends that the analysis of the harm caused by unrestricted PCAP shopping fails to consider value-added components of EGS products. RESA's witness provides examples of value-added components such as Amazon Prime membership and smart thermostats.[203] However, RESA offers no data to substantiate its claims that these benefits result

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[201] This assessment by Mr. Geller accounts for both PCAP customers who contracted for prices above the PTC as well as those who contract for prices below the PTC.

[202] *CAUSE-PA*, 1020 A.3d at 1103.

[203] RESA St. 1-R at 25-26.

in savings on PCAP customers' utility bills. Further, it is inappropriate to use PCAP credits to subsidize services when they are nonessential products and services which increase the commodity price for basic service and are in part paid by the PCAP customer and in part passed through the Companies' universal service rider. The Commission's PCAP Policy Statement explicitly prohibits PCAP participants from subscribing to "nonbasic services that would cause an increase in monthly billing and would not contribute to bill reduction."[204] While the policy statement provides that nonbasic services may be allowed if the service reduces the customer's bills, RESA's testimony falls far short of proving that any of these services in fact lower any customer's bills.

In sum, the evidence produced by BIE, OCA and CAUSE-PA demonstrates that unless PCAP customers are restricted from shopping at rates above the price to compare, the resultant increase in costs will cause harm to PCAP and non-PCAP customers alike. The Companies do not contest this evidence or the conclusions to be drawn from it.

Having determined that BIE, OCA and CAUSE-PA have proven that unrestricted CAP shopping is causing harm to the Companies' ratepayers, the Commission must next determine whether there is no reasonable alternative to the proposed restriction. All three parties propose to limit PCAP participants to purchasing electricity at a rate no greater than the current PTC. Should the Commission direct a limit to PCAP shopping, the Companies support the implementation of a price ceiling as proposed within the record of this proceeding.[205] Specifically, the Companies could add PCAP participation flags to their eligible customer lists, which would inform suppliers before they attempt to enroll a PCAP customer.[206] In order to enroll PCAP customers, suppliers would agree to rate ready billing utilizing a percentage off variable priced product, which would allow the Companies to adjust the supplier's price by the

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[204] 52 Pa.Code § 69.265(3)(ii).

[205] Companies Reply Brief at 20 (*See also* OCA Main Brief at 58-60; CAUSE-PA Main Brief at 41-43; BIE Main Brief at 37-39).

[206] Companies St. 1-R at 31-33.

required percentage off of the PTC for PCAP customers.[207] Beginning June 1, 2019, any enrollment request by a supplier for a PCAP customer outside of those parameters would be automatically rejected by the Companies.[208] All costs associated with implementing the Companies' system changes and notifying suppliers and PCAP customers regarding these changes would be recovered through the Companies' PTC Default Service Riders.[209]

Further, the Companies would support the transition plan proposed by CAUSE-PA.[210] After June 1, 2019, at the end of a PCAP customer's shopping contract, the customer could choose to be served by a supplier who agrees to the PCAP-approved percentage-off PTC product or return to default service.[211] For PCAP customers enrolled in month-to-month contracts, within 120 days of June 1, 2019, suppliers would be obligated to either provide the customer the approved percentage off product or return the customer to default service.[212] PCAP customers also would have the right to terminate their supplier contracts early without supplier termination fees.[213] The Companies take the position that it should be the supplier's, as opposed to the Companies', obligation to ensure that month-to-month customers are transitioned appropriately and no early termination fees are charged.

The Companies would oppose any PCAP shopping restrictions that would require the Companies to monitor or police supplier activities, including a PCAP Standard Offer Program (SOP). The record in this proceeding offers no evidentiary support for a PCAP SOP, and therefore, a PCAP SOP should be rejected for this reason alone.[214] None of the parties

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207 *Id.*

208 *Id.*

209 *Id.*

210 CAUSE-PA M.B. at 42-43; *RESA*, 2018 Pa.Cmwlth. LEXIS 153, *16-18.

211 CAUSE-PA M.B. at 42-43.

212 *Id.*

213 *Id.*

214 Similarly, RESA's proposed alternatives to a PTC price ceiling are not supported by record evidence and must be rejected. *See* RESA M.B. at 28.

advocating limits on PCAP shopping suggest that a PCAP standard offer program similar to that approved for PPL Electric Utilities Corporation (PPL) is appropriate for the Companies.[215] The PTC for the Companies, which is adjusted quarterly, is more volatile than the PTC of PPL. Further, these parties point out that the PPL SOP has not yet been implemented. For the Companies, a PTC price ceiling is significantly more straightforward to implement than a PCAP SOP, promoting a more seamless implementation by the Companies and transparent rules for PCAP customers.[216]

I recommend that the Commission direct the Companies to implement a PCAP shopping program which prohibits customers who wish to participate in the Companies' PCAP from entering into a contract with an EGS for a price which exceeds the PTC. This program should be phased in on the schedule recommended by CAUSE-PA and agreed to by the Companies. The phased-in approach would permit the transition of PCAP customers to the limited price program without the necessity of immediately suspending shopping by PCAP customers as advocated by OCA. Further, directing the phase-in deadlines permits the Companies sufficient time to implement the program in a reasonable amount of time without the necessity of Commission approval of a timeline as suggested by BIE.

C. Joint Petition for Partial Settlement

1. Description and Terms

On May 15, 2018, the Companies filed a Joint Petition for Partial Settlement, which resolved a number of issues related to the Companies' DSP filing. OCA, OSBA, RESA and the Industrials are signatories to the Joint Petition. BIE, Direct Energy, PSU, CAUSE-PA, ExGen and Constellation, NextEra, and Respond Power, which are parties to this proceeding, have authorized the Joint Petitioners to represent that they do not oppose the Partial Settlement.

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[215] OCA M.B. at 58-60; CAUSE-PA M.B. at 41-43; BIE M.B. at 37-39.

[216] Companies M.B. at 40-41.

In addition, Calpine takes no position on the Partial Settlement, and specifically does not oppose the Partial Settlement as it relates to NITS.

The Partial Settlement consists of the following terms and conditions:[217]

A. Non-Commodity Products

1. Subject to the appropriate approvals by the Commission, issues related to supplier consolidated billing shall be addressed in the Commission's generic proceeding on the topic in Docket M-2018-2654254.

2. No party to this Partial Settlement will object to any other party to this Partial Settlement recommending at Docket M-2018-2654254 that the Commission take administrative notice of the record in this proceeding with respect to the issue of access to electric distribution company (EDC) bills for EGS non-commodity products, and no party will object to any other party's submittal of testimony or other record evidence from this DSP V proceeding in Docket M-2018-2654254.

B. FERC 494 Settlement

1. The parties agree that the Companies' proposal related to the distribution and recovery of FERC 494 Settlement allocations will be considered uncontested in this matter.

C. Net Metering

1. The parties agree that concerns related to net metering will not be addressed in this proceeding.

D. Time of Use (TOU)

1. The Companies are currently providing residential TOU service under the terms and conditions of the Companies' Price to Compare Default Service Rate Riders as described in each Company's Rider K, Time-Of-Use Default Service Rider. The Companies will make a specific proposal regarding their residential time of use rate offerings in the earlier of their first base rate increase requests or default service proceedings following full implementation of smart meter back office functionality, which is

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217 The labelling and paragraph numbers from the petition are retained here for ease of reference.

planned for fourth quarter 2019 as of the date of this Partial Settlement.

E. Network Integration Transmission Services

1. NITS will remain the responsibility of both default service and electric generation suppliers.

The Partial Joint Settlement petition also included the usual "additional terms and conditions" that are typically included in settlements. These terms, which, among other things, protect the parties' rights to file exceptions if any part of the settlement is modified, condition the agreement upon approval by the Commission and provide that no party is bound in future rate cases by any particular position taken in this case. These additional terms and conditions will not be repeated here verbatim. The reader is directed to the petition itself.

The signatory parties filed statements in support which were included as part of their reply briefs.[218] Following a review of the settlement petition and the statements in support, I recommend that the Commission approve the provisions of the Joint Petition for Partial Settlement without modification.

2. Non-Commodity Billing

The Joint Petition for Settlement filed on May 15, 2018, includes a term intended to resolve, for purposes of the instant proceeding, the issues and concerns raised at the above-referenced docket relating to the provision of non-commodity, or non-basic, products and services. Specifically, the Joint Petition provides, in relevant part, that "[s]ubject to the appropriate approvals by the Commission, issues related to supplier consolidated billing shall be addressed in the Commission's generic proceeding on the topic in Docket No. M-2018-2654254." This provision effectively "tables" all of the issues raised by the parties in testimony

[218] While OSBA noted in its reply brief that it erred in setting forth an argument regarding time of use rates in its main brief, and clarified its support for the resolution of the other issues as a signatory to the Joint Petition for Partial Settlement, it did not explicitly explain its support for the specific provisions of the Joint Petition for Partial Settlement.

regarding those topics. These issues would be considered in the Commission's proceeding at the above-referenced M-docket.

The Companies submit the resolution reached on this topic is in the public interest for several reasons. Apart from the Commission's stated preference that parties reach resolution of issues through settlements as compared to litigation, the very set of issues deferred to the referenced generic docket are appropriately deferred for review in that docket because they have already been cited, by a Secretarial Letter issued midway through the instant proceeding, as included in the panoply of topics to be considered by the Commission at that docket. The issues related to supplier consolidated billing (SCB) in this matter are consistent with those identified in the Commission's March 27, 2018 Secretarial Letter, which provides that the proceeding and en banc hearing will address: "(1) whether SCB is legal under the Public Utility Code and Commission regulations; (2) whether SCB is appropriate and in the public interest as a matter of policy; and (3) whether the benefits of implementing SCB outweigh any costs associated with implementation."[219] To consider these topics – which impact the larger electric industry and market as a whole – on a limited basis through the Companies' individual default service proceedings would lead to an exclusion of key stakeholders from the discussion on these important topics, raising due process concerns and risking a limited fact base from which a determination would be made.

Further, to address these issues within the context of this proceeding while they are contemporaneously being addressed in another unrelated proceeding runs the risk of conflicting outcomes and sets the stage for the Companies being put in the impossible position of having been given two differing sets of directives by which they must abide. Finally, the parties to this set of issues in this DSP proceeding are active participants in the generic proceeding as well. According to the Companies, it would be a waste of resources for not only the Commission and the ALJ, but also the parties to address the various parties' positions in this case on these topics when they could be more comprehensively addressed by including all key

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219 *En Banc Hearing on Implementation of Supplier Consolidated Billing*, Docket No. M-2018-2645254 (Secretarial Letter March 27, 2018, at 1).

stakeholders in the Commission's established generic proceeding. For all of these reasons, the Companies submit that this provision is in the public interest and should be approved without modification.

OCA echoes the Companies' support for similar reasons. OCA agrees that addressing these issues in the generic proceeding will conserve administrative resources and save costs associated with fully litigating supplier consolidated billing issues in two separate proceedings. Therefore, the OCA submits that the Commission should approve the non-commodity billing provisions of the Joint Partial Settlement Agreement.

RESA also supports the settlement on this issue. In testimony, RESA raised concerns related to billing for non-commodity products and services and recommended that the Commission direct the Companies take action to address these concerns. More specifically, RESA Witness Mr. Hudson testified about inherent competitive disparity regarding the billing practices for the Companies based on: (1) the obstacles that EGSs face in their ability to bring innovations to market in Pennsylvania because of utility bill limitations such as restricting charges under the POR program to "basic service" charges only; and, (2) the fact that FirstEnergy offers and markets non-commodity products and services and offers customers the ability to bill for these products on the utility consolidated bill. To address these concerns, RESA recommended that the Commission require the Companies to implement a pilot supplier consolidated billing program, and until such program is in place, allow EGSs to bill non-commodity products with the utility bill.

RESA retains the ability to raise these issues because any party retains the ability to request that the Commission – as part of the supplier consolidated billing docket – take administrative notice of the record in this proceeding regarding the current non-commodity billing practices of the Companies for their own products and services. RESA supports the resolution of this issue as a reasonable compromise to most effectively utilize resources and in recognition that the Commission is in the process of investigating supplier consolidated billing. Because RESA secured the agreement of the other parties that they would not object to a request that the Commission take judicial notice of the record developed here, the Settlement retains the ability of RESA to continue to pursue its advocacy regarding this issue in a broader context. As such, RESA supports the Settlement regarding this issue.

The Industrials also support the provision of the settlement which provides for the issue of non-commodity billing to be addressed in the generic proceeding for the same reasons articulated by the other signatory parties.

3. Non-Market Based Charges

The Companies classify certain PJM-related cost components as "non-market based" (NMB) charges and, for these cost components, the Companies have assumed the cost obligation on behalf of all load on their system, including default service load and load served by EGSs. The Companies are proposing to add, as an NMB charge, charges related to the reallocation of PJM RTEP costs resulting from FERC Docket No. EL05-121-009 but, as part of the settlement, the Companies are not proposing any changes to the current treatment of NITS.

The Companies explain that this resolution is reasonable and in the public interest because, as the Companies' witness Mr. Siedt explained in his rebuttal testimony, EGSs should not be entitled to the charges and/or credits that result from any FERC-approved settlement. Specifically, EGSs did not bear the responsibility for RTEP costs on behalf of their shopping customers for most of the time-period that the FERC 494 Settlement addresses. As Mr. Siedt testified, "of the total January 2007 through May 2013 (five years and five months) settlement period in question, the maximum period of time that any EGS could have potentially been responsible for RTEP costs amounts to two years and five months, or January 2011 through May 2013." Even if EGSs could argue that they were responsible for RTEP costs for two years and five months of the settlement period in question, EGSs most likely recovered the RTEP costs from their customers for that time period.[220] Therefore, in the Companies' view, it is in the public interest to approve the Joint Petition for Partial Settlement, which reallocates the RTEP

[220] Companies St. 2 at 6.

expenditures from any FERC-approved settlement to customers as the Companies proposed in their direct case.

The parties have agreed that NITS costs will remain the responsibility of the Companies' default service suppliers and EGSs serving the Companies' customers, which term is a part of the Joint Petition for Partial Settlement. The Companies explain that this provision of the settlement concerning NITS is in the public interest because it aligns with the Commission's historical guidance to exclude NITS from NMB charges.[221]

Moreover, NITS should also be manageable for wholesale or retail suppliers on the Companies' system given that NITS charges change once per year (January 1) and are known as of October of the preceding year. This fact, paired with the Companies' proposed adjustments to their auction timing, which are designed to give bidders ample time to consider new rates based on the publication dates for MAIT and ATSI, should offset any residual uncertainty regarding NITS. The Companies represent that avoiding any significant shifts in responsibilities for these charges by approving the Joint Petition for Partial Settlement gives large users, such as the customers represented by the Industrial Intervenors, certainty with regard to their existing energy contracts, and avoids administrative hassles and complications for all parties.

The OCA also supports the provision of the Joint Petition for Partial Settlement pertaining to the issue of NITS. The DSP IV settlement provided that NITS would "remain the obligation of default service providers and electric generation service providers during the default service delivery period beginning June 1, 2017."[222] The default service delivery period agreed to in DSP IV spans four years, from June 1, 2017, through May 31, 2021.[223] As the four year period ends on May 31, 2021, and any changes to NITS in instant proceeding would become effective before that date on June 1, 2019, maintaining the status quo is reasonable and

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221 Companies St. 3-R at 2.

222 *Joint Petition of MetEd, Penelec, Penn Power, and West Penn for Approval of their Default Service Programs*, Docket Nos. P-2015-2511333, et al. (Recommended Decision issued April 15, 2016, at 14).

223 *Id.* at 8.

appropriate at this time. Therefore, the OCA submits that the Commission should approve the non-market-based charges provision of the Joint Partial Settlement Agreement.

RESA also supports the settlement. RESA's concerns related to the FERC 949 Settlement charges were based on the complicated nature of this issue given the pendency of the settlement at FERC and how approval of the settlement will impact the reallocation of original transmission cost allocations. Based on further discussions with the Companies as well as the rebuttal testimony submitted on behalf of the Companies, RESA agrees to consider this issue as uncontested consistent with the terms of the settlement.

RESA explains that the Companies do not provide the same cost assignment treatment for NITS as they do for other NMB Charges. While RESA did not propose to change the Companies current treatment of NITS, RESA supported the testimony of ExGen to reassign the cost responsibility for residential customers to the Companies. Though RESA continues to support reclassifying NITS as a non-market-based charge wherein the Companies would assume these costs on behalf of all load and recover costs through non-bypassable charges and supported ExGen's attempt to place additional cost recovery methodologies on the table for consideration, the parties were unable to find a mutually agreeable way to move this issue forward and have ultimately agreed to maintain the status quo as reflected in the Settlement. Based on the discussions in this proceeding, RESA supports this resolution of the issue at this time but does not waive any rights to continue to pursue its preferred approach in future proceedings as may be appropriate.

4. Time-of-Use Rate

The Companies submit that the settlement regarding time-of-use rates is in the public interest because it allows the Companies to complete a reevaluation of their TOU offerings (as the OSBA and the OCA requested) once their smart meters are fully functional for TOU billing and the necessary data is available to support such an analysis. Until the Companies have the data sufficient to perform an informed evaluation of their TOU offerings, the Companies will continue to offer residential TOU service under the terms and conditions described in each Company's Rider K, Time-Of-Use Default Service Rider. Meanwhile, commercial customers will have the ability to select hourly pricing through the HPS tariff.

The OCA agrees and supports the provisions of the Joint Partial Settlement Agreement pertaining to the issue of the time-of-use (TOU) rate. The DSP IV settlement provided that "[FirstEnergy] currently offers an optional time-of-use (TOU) pricing rate to residential customers and will continue to do so in the manner approved by the Commission in the previous DSP proceeding (for Penn Power and West Penn) and in the most recent MetEd and Penelec base rate proceedings."[224] At this time, it is appropriate to maintain the status quo. In addition, it is appropriate for the Companies to make a specific proposal regarding TOU rates after the build out of their smart meter infrastructure has been completed. Therefore, OCA submits that the Commission should approve the TOU rate provision of the Joint Partial Settlement Agreement.

RESA did not raise any concerns related to the Companies' net metering policies or its TOU rate but does not oppose the agreement of the Companies in the Partial Settlement to make a specific proposal regarding their residential TOU in the earlier of their first base rate increase requests or default service proceedings following full implementation of smart meter back office functionality.

5. Recommendation

The Commission encourages parties in contested on-the-record proceedings to settle cases.[225] Settlements eliminate the time, effort and expense of litigating a matter to its ultimate conclusion, which may entail review of the Commission's decision by the appellate courts of Pennsylvania. Such savings benefit not only the individual parties, but also the

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224 *Joint Petition of MetEd, Penelec, Penn Power, and West Penn for Approval of their Default Service Programs*, Docket Nos. P-2015-2511333, et al. (Recommended Decision issued April 15, 2016, at 14).

225 *See* 52 Pa.Code § 5.231.

Commission and all ratepayers of a utility, who otherwise may have to bear the financial burden such litigation necessarily entails.

By definition, a "settlement" reflects a compromise of the positions that the parties of interest have held, which arguably fosters and promotes the public interest. When active parties in a proceeding reach a settlement, the principal issue for Commission consideration is whether the agreement reached suits the public interest.[226] In their supporting statements, the Joint Petitioners conclude, after extensive discovery and discussion, that this Partial Settlement resolves contested issues in this case, fairly balances the interests of the company and its ratepayers, is in the public interest, and is consistent with the requirements of the Public Utility Code.

In reviewing the settlement terms and the accompanying statements in support, the Joint Petition for Partial Settlement provides sufficient information to support the conclusion the settlement terms are in the public interest. I agree with the signatory parties that deferring resolution of the non-commodity billing question to the Commission's generic proceeding is sensible. Similarly, maintaining the status quo on the NITS and TOU issues is also reasonable in these circumstances. For the reasons set forth by the parties above, the Commission should approve these provisions of the settlement without modification.

Also, of note, the settlement finds support from a broad range of parties with diverse interests. Each party represents a variety of interests. The Companies advocate on behalf of their corporate interests and shareholders. The Office of Consumer Advocate is tasked with advocacy on behalf of consumers in matters before the Commission.[227] The Office of Small Business Advocate represents the interests of the Commonwealth's small businesses.[228] RESA

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[226] *Pa. Pub. Util. Comm'n v. CS Water and Sewer Associates*, 74 Pa. PUC 767, 771 (1991). *See also Pa. Pub. Util. Comm'n v. York Water Co.,* Docket No. R-00049165 (Order entered October 4, 2004); *Pa. Pub. Util. Comm'n v. Philadelphia Electric Company*, 60 Pa. PUC 1 (1985).

[227] Section 904-A of the Administrative Code of 1929, Act of April 9, 1929, P.L. 177, *as amended,* 71 P.S. § 309-4.

[228] Section 399.45 of the Small Business Advocate Act, Act of December 21, 1988, P.L. 1871, 73 P.S. § 399.45.

represents the interests of its member EGSs, and the Industrials represent their large industrial members. Each of these advocates maintain that the interests of their respective constituencies have been adequately protected and they further represent that the terms of the Settlements are in the public interest. These parties in a collaborative effort have reached agreement on a broad array of issues, demonstrating that the Partial Settlement is in the public interest and should be approved. None of the parties representing other interests object to the terms of the Joint Petition.

Resolution of these issues by negotiated settlement removes the uncertainties of litigation. In addition, all parties benefit by the reduction in expense and the conservation of resources made possible by adoption of the proposed settlement in lieu of litigation.

The individual complainants were served with a copy of the Joint Petition for Partial Settlement and offered an opportunity to comment or object to the terms and demonstrate why the case should be litigated rather than settled. No objections were filed.[229] Therefore, their due process rights have been fully protected.[230]

For all of the foregoing reasons, I find the settlements embodied in the Joint Petition for Partial Settlement are both just and reasonable and their approval is in the public interest. I recommend that the Commission approve the settlement without modification.

V. CONCLUSIONS OF LAW

1. The Commission has jurisdiction over the parties and the subject matter of this dispute. 66 Pa.C.S. § 2801 *et seq*.

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[229] One Complainant joined the Joint Petition for Settlement, Cynthia Glover Muhammed, Docket No. C-2018-2643212

[230] *See Schneider v. Pa. Pub. Util. Comm'n*, 479 A.2d 10 (Pa.Cmwlth. 1984) (Commission is required to provide due process to the parties; when parties are afforded notice and an opportunity to be heard, Commission requirement to provide due process is satisfied).

2. The party seeking affirmative relief from the Commission bears the burden of proof. 66 Pa.C.S. § 332.

3. Any party that offers a proposal that was not included in the Companies' original filing bear the burden of proof for such proposal. *Brockway Glass Co. v. Pa. Pub. Util. Comm'n*, 437 A.2d 1067 (Pa.Cmwlth. 1981).

4. Where competing proposals are introduced, the sponsoring party must show that the alternative proposal will better service customers. *Joint Petition of Metropolitan Edison Company and Pennsylvania Electric Company for Approval of Their Default Service Programs*, Docket No. P-2009-2093053 and P-2009-2093054 at 19 (Opinion and Order entered November 6, 2009).

5. The requirements of a default service plan include that the default service provider follow a Commission-approved competitive procurement plan, that the competitive procurement plan include auctions, requests for proposal, and/or bilateral agreements, that the plan include a prudent mix of spot market purchases, short-term contracts, and long-term purchase contracts designed to ensure adequate and reliable service at the least cost to customers over time, and shall offer a time-of-use program for customers who have smart meter technology. 66 Pa.Code §§ 2707(e), 2708.

6. The Companies' proposed default service procurement, SMA, contingency plans, and program term satisfies the requirements of default service programs. 66 Pa.C.S §§ 2801-2812; 52 Pa.Code §§ 54.181-54.189; 69 Pa.Code §§ 69.1802-69.1817.

7. The Companies' proposed rate design, including the HPS Rider and SPVRC Rider conform to the Commissions regulations. 66 Pa.C.S §§ 2801-2812; 52 Pa.Code §§ 54.181-54.189; 52 Pa.Code §§ 69.1802-69.1817.

8. The proposed bypassable retail market rate enhancement mechanism is inconsistent with the statutory mandate found in Act 129 that the Companies, as default service

providers, must procure electricity at the "least cost to customers over time." 66 Pa.C.S. § 2807(e)(3.4)(ii).

9. The Companies have failed to meet their burden of proof that their proposed bypassable retail market rate enhancement mechanism is lawful.

10. The Companies' PTC Riders and DSS Riders, exclusive of the proposed modifications connected to the bypassable retail market rate enhancement mechanism, are otherwise consistent with the Commission's default service regulations. 66 Pa.C.S §§ 2801-2812; 52 Pa.Code §§ 54.181-54.189; 52 Pa.Code §§ 69.1802-69.1817.

11. The Companies' proposal to transition commercial customers whose demand exceeds 100 kW for 12 months to the HPS Rider is consistent with the RMI Final Order, which indicates that "the Commission continues to support the threshold of 100 kW for purposes of determining medium and large Commercial and Industrial (C&I) customers, but expects EDCs to offer hourly LMP products only to customers above that demand level who have interval meters." RMI Final Order at 29.

12. The clawback charge, as described in Joint Stipulation No. 2, promotes least cost over time default service as required under Act 129. 66 Pa.C.S. § 2807(e)(3.4).

13. The Electricity Generation Customer Choice and Competition Act (Choice Act) requires the Commonwealth "continue the protections, policies and services that now assist customers who are low-income to afford electric service" in the competitive environment. 66 Pa.C.S. § 2802 (10).

14. The Choice Act mandates that customers have direct access to a competitive retail generation market. 66 Pa.C.S. § 2801(3).

15. The Commission has the authority under Section 2804(9) of the Choice Act, in the interest of ensuring that universal service plans are adequately funded and

cost-effective, to impose PCAP rules that would limit the terms of any offer from an EGS that a customer could accept and remain eligible for PCAP benefits. *Coal. for Affordable Util. Servs. & Energy Efficiency in Pennsylvania v. Pa. Pub. Util. Comm'n*, 120 A.3d 1087, 1103 (Pa.Cmwlth. 2015), *appeal denied*, 136 A.3d 983 (Pa. 2016).

16. OCA, BIE and CAUSE-PA have demonstrated by a preponderance of the evidence that, under the facts presented in this case, unbridled competition must bend and special PCAP rules must be imposed pursuant to the Choice Act. 66 Pa.C.S. § 2802(10).

17. The failure to impose PCAP shopping restrictions would allow PCAP customers' rates to remain unaffordable and would continue to jeopardize the overall adequacy, cost-effectiveness, or affordability of the PCAP program for PCAP customers and the ratepayers who pay for PCAP. *Coal. for Affordable Util. Servs. & Energy Efficiency in Pennsylvania v. Pa. Pub. Util. Comm'n*, 120 A.3d 1087, 1103 (Pa.Cmwlth. 2015), *appeal denied*, 136 A.3d 983 (Pa. 2016).

18. The Joint Petition for Partial Settlement filed on May 15, 2018 is in the public interest and should be approved by the Commission. *Pa. Pub. Util. Comm'n v. CS Water and Sewer Associates*, 74 Pa. PUC 767, 771 (1991). *See also Pa. Pub. Util. Comm'n v. York Water Co.*, Docket No. R-00049165 (Order entered October 4, 2004); *Pa. Pub. Util. Comm'n v. Philadelphia Electric Company*, 60 Pa. PUC 1 (1985).

VI. ORDER

THEREFORE,

IT IS RECOMMENDED:

1. That the Joint Petition for Partial Settlement filed on May 15, 2018, is approved without modification.

2. That Joint Stipulation No. 2, Paragraphs 1 and 2, relating to the proposed "clawback" mechanism, are approved without modification.

3. That Joint Stipulation No. 2, Paragraph 3 is modified as follows:

The Companies will develop an EGS-specific customer arrears report with unpaid aged EGS account balances. This report will be provided to EGSs participating in the Companies' purchase of receivables programs on a quarterly basis, beginning no later than October 20, 2018, reflecting EGS arrears for third quarter 2018. Information contained in the customer arrears report provided to each EGS shall only contain information regarding customers of that specific EGS.

4. That the request for a Bypassable Retail Market Enhancement Rate Mechanism and concomitant adjustments to the PTC and DSS Riders is denied.

5. That on or before June 1, 2019, the First Energy Companies shall implement the following PCAP shopping rules:

a. PCAP customers are prohibited from entering into any retail electricity contract with an EGS which would charge rates exceeding the applicable price to compare for the entire duration of the EGS contract.

b. EGSs are not permitted to enter into contracts with PCAP customers charging early termination or cancellation fees.

c. EGS enrollments submitted for any PCAP customers that do not meet these requirements will be rejected.

6. That for the purpose of transitioning PCAP customers who are currently being served by an EGS, as of June 1, 2019:

a. PCAP customers who are served under a fixed duration contract with an EGS as of June 1, 2019 (a "pre-existing fixed duration contract") may remain with their EGS until the expiration date of the fixed duration contract or the contract is terminated, whichever comes first.

b. Non-PCAP customers served under a fixed duration contract who subsequently enroll in PCAP (also considered to be served under a "pre-existing fixed duration contract") may remain with their EGS until the expiration date of the fixed duration contract or the contract is terminated, whichever comes first.

c. Upon expiration or termination of a pre-existing fixed duration contract, the EGS must either: (a) enroll the PCAP customer under a contract compliant with the new PCAP shopping rules; or, (b) return the PCAP customer to default service. For EGSs serving PCAP customers under a month-to-month contract as of June 1, 2019, the EGS must either: (a) return the PCAP customer to default service effective June 1, 2019; or, (b) enroll the PCAP customer under a contract compliant with the provisions, above, with an effective date of June 1, 2019.

d. For EGSs serving non-PCAP customers under a month-to-month contract who subsequently enroll in PCAP, the EGS must either, within 120 days of the customer's PCAP enrollment: (a) return the PCAP customer to default service; or, (b) enroll the PCAP customer under a contract compliant with the provisions, above.

7. That the proposed default service plans of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company are approved, except as set forth in the ordering paragraphs above.

8. That the following formal complaints against Pennsylvania Electric Company are sustained:

Ellen L. Cooper v. Pennsylvania Electric Company, Docket No. C-2018-2643217;
Betty Dusicsko v. Pennsylvania Electric Company, Docket No. C-2018-2643249;

Joseph Dusicsko v. Pennsylvania Electric Company, Docket No. C-2018-2643274;
Angela C. Esters v. Pennsylvania Electric Company, Docket No. C-2018-2643222;
Debra A. Gibbs v. Pennsylvania Electric Company, Docket No. C-2018-2643260;
Catherine M. Hartzell v. Pennsylvania Electric Company, Docket No. C-2018-2643211;
Dennis T. Husted v. Pennsylvania Electric Company, Docket No. C-2018-2643280;
Cynthia Glover Muhammed v. Pennsylvania Electric Company, Docket No. C-2018-2643212;
David Nies v. Pennsylvania Electric Company, Docket No. C-2018-2643243;
Carl E. Palotas, Jr. v. Pennsylvania Electric Company, Docket No. C-2018-2643225;
Richard S. Powierza v. Pennsylvania Electric Company, Docket No. C-2018-2643248;
Bernadine Randhanie v. Pennsylvania Electric Company, Docket No. C-2018-2643284;
Matthew J. Sciarrino v. Pennsylvania Electric Company, Docket No. C-2018-2643239;
Mark L. Spaeder v. Pennsylvania Electric Company, Docket No. C-2018-2643244;
Kenneth C. Springirth v. Pennsylvania Electric Company, Docket No. C-2018-2641907;
Kathleen B. Walls v. Pennsylvania Electric Company, Docket No. C-2018-2643213;
Robert H. Walls v. Pennsylvania Electric Company, Docket No. C-2018-2643214;
Julie Whaling v. Pennsylvania Electric Company, Docket No. C-2018-2643277;
Robert G. Whaling, Sr. v. Pennsylvania Electric Company, Docket No. C-2018-2643280;
Joseph A. and Dianne L. Yochim v. Pennsylvania Electric Company, Docket No. C-2018-2643246.

9. That the Secretary mark these dockets closed.

Date: May 31, 2018

/s/
Mary D. Long
Administrative Law Judge