PENNSYLVANIA
PUBLIC UTILITY COMMISSION
Harrisburg, PA 17105-3265

Public Meeting held January 15, 2015

Commissioners Present:

Robert F. Powelson, Chairman
John F. Coleman, Jr., Vice Chairman
James H. Cawley
Pamela A. Witmer
Gladys M. Brown, Statement

Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period June 1, 2015 Through May 31, 2017 — P-2014-2417907

OPINION AND ORDER

BY THE COMMISSION:

Before the Pennsylvania Public Utility Commission (Commission) for consideration and disposition are the Exceptions of PPL Electric Utilities Corporation (PPL or the Company) and the Retail Energy Supply Association (RESA), filed on November 19, 2014, to the Recommended Decision (R.D.) of Administrative Law Judge (ALJ) Susan D. Colwell, issued on October 30, 2014, relative to the above-captioned proceeding. Replies to Exceptions were filed by PPL, the Office of Small Business Advocate (OSBA), and the PP&L Industrial Customer Alliance (PPLICA) on December 1, 2014.

I. History of the Proceeding

On April 18, 2014, PPL filed its Petition for approval of a Default Service Program and Procurement Plan (DSP III) for the period from June 1, 2015, through May 31, 2017. The Company served the Petition on the public advocates and the electric generation suppliers (EGSs) doing business in its territory.

On May 10, 2014, notice of the Petition was published in the *Pennsylvania Bulletin*, 44 *Pa. B.* 2832, along with notice of the prehearing conference scheduled for June 5, 2014. The deadline for filing interventions and protests was set for May 30, 2014.

A Notice of Appearance was filed by the Commission's Bureau of Investigation and Enforcement (I&E) on May 20, 2014. A Notice of Intervention and Answer was filed by the Office of Consumer Advocate (OCA) on May 8, 2014, and by the OSBA on May 28, 2014.

Timely petitions to intervene were filed by: (1) RESA; (2) PPLICA; (3) Citizens for Pennsylvania's Future (PennFuture); (4) the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA); (5) Direct Energy Services, LLC (Direct Energy); (6) Exelon Generation Company, LLC (ExGen); (7) FirstEnergy Solutions Corporation (FES); (8) NextEra Energy Power Marketing, LLC (NextEra); (9) Noble Americas Energy Solutions, LLC (Noble Americas); and (10) the Sustainable Energy Fund (SEF).

A prehearing conference was held as scheduled on June 5, 2014. No Party objected to any of the interventions and all were granted in the Scheduling Order issued by the ALJ on June 6, 2014, which also adopted the litigation schedule agreed upon at the prehearing conference, and incorporated proposed modifications to the Commission's rules of discovery.

On June 10, 2014, PPL filed a Motion for Protective Order, which was issued by the ALJ without objection on July 16, 2014. A Revised Protective Order was issued on July 23, 2014, to correct a typographical error.

The Parties submitted prepared testimony according to the schedule set forth in the Scheduling Order. Shortly before the scheduled hearing, the Parties informed the ALJ that they had achieved a settlement on almost all issues. All Parties waived cross-examination of all witnesses and the hearing was held on August 19, 2014, to accept the prepared testimony, exhibits, and verifications or affidavits into the record.

On September 12, 2014, a Joint Petition for Approval of Partial Settlement (Partial Settlement) was filed by PPL, OCA, OSBA, PPLICA, CAUSE-PA, SEF, PennFuture, NextEra, RESA, and ExGen (collectively, Signatory Parties). The Signatory Parties also filed individual Statements in Support of the Partial Settlement, which were attached to the Partial Settlement as Appendices B through K.[1]

Also on September 12, 2014, Main Briefs on the outstanding issues were filed by PPL, OSBA, PPLICA, RESA, and Noble Americas. Reply Briefs were filed on September 26, 2014 by PPL, OSBA, PPLICA, RESA, and ExGen. The record closed with the filing of the Reply Briefs.

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[1] The Partial Settlement indicates that I&E, FES, Noble Americas, and Direct Energy are not parties to the Partial Settlement, but do not oppose it. Partial Settlement at 2, n.1. Also, specific letters indicating non-opposition to the Partial Settlement were filed by FES and Direct Energy, and were attached to the Settlement as Appendices L and M, respectively. In addition, Noble Americas filed a letter stating that it does not oppose the Partial Settlement, provided that its understanding of the Partial Settlement, as described in the letter, is correct.

On October 30, 2014, the Commission issued the Recommended Decision of ALJ Colwell, which recommended, *inter alia*: 1) approval of PPL's DSP III as modified by the Partial Settlement; (2) denial of PPL's proposal to change the customer size demarcation between Small Commercial and Industrial (Small C&I) and Large Commercial and Industrial (Large C&I) customers; and (3) denial of a proposal to require PPL to assume responsibility for non-market-based (NMB) transmission-related costs for all load on its system, and to recover those costs through a non-bypassable surcharge from all distribution customers. R.D. at 55.

As noted above, Exceptions were filed by PPL and RESA on November 19, 2014. Replies to Exceptions were filed by PPL, OSBA, and PPLICA on December 1, 2014.

II. Legal Standards

A. Burden of Proof

The Company has the burden of proof in this proceeding to establish that it is entitled to the relief it is seeking. 66 Pa. C.S. § 332(a). The Company must establish its case by a preponderance of the evidence. *Samuel J. Lansberry, Inc. v. Pennsylvania Pub. Util. Comm'n*, 578 A.2d 600 (Pa. Cmwlth. 1990), *alloc. den.*, 602 A.2d 863 (Pa. 1992) To meet its burden of proof, the Company must present evidence more convincing, by even the smallest amount, than that presented by any opposing party. *Se-Ling Hosiery v. Margulies*, 70 A.2d 854 (Pa. 1950).

In this case, the Company requests that the Commission approve its proposed DSP III, and therefore, it has the burden of proving that the proposed DSP III is just, reasonable, and in the public interest. In addition, the Signatory Parties have reached an accord on many of the issues and claims that arose in this proceeding, and submitted the Partial Settlement. Thus, the Signatory Parties have the burden of proving that the Partial Settlement is just, reasonable, and in the public interest.

B. Standards for Default Service

The requirements of a default service plan appear in Chapter 28,[2] Section 2807(e) of the Public Utility Code (Code), 66 Pa. C.S. § 2807(e). The requirements include that the default service provider follow a Commission-approved competitive procurement plan that includes auctions, requests for proposal, and/or bilateral agreements as well as 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. 66 Pa. C.S. § 2807(e). The default service provider is also required to offer a time-of-use program for customers who have smart meter technology. 66 Pa. C.S. § 2807(f).

In a prior order, we also found as follows:

> The Competition Act also mandates that customers have direct access to a competitive retail generation market. 66 Pa. C.S. § 2802(3). 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." 66 Pa. C.S. § 2802(5). *See*, *Green Mountain Energy Company v. Pa. PUC*, 812 A.2d 740, 742 (Pa.Cmwlth. 2002). Thus, a fundamental policy underlying the Competition Act is that competition is more effective than economic regulation in controlling the costs of generating electricity. 66 Pa. C.S. § 2802(5).

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

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, P-2011-2273668, P-2011-2273669, and P-2011-2273670 (Order entered August 16, 2012) (*FirstEnergy DSP II Order*) at 7-8.

Also applicable are the Commission's default service Regulations, 52 Pa. Code §§ 54.181-54.189, and a Policy Statement addressing default service plans, 52 Pa. Code §§ 69.1802-69.1817. The Commission has directed that electric distribution companies (EDCs) consider the incorporation of certain market enhancement programs into their DSPs in order to foster a more robust retail competitive market. *Investigation of Pennsylvania's Retail Electricity Market: Recommendations Regarding Upcoming Default Service Plans,* Docket No. I-2011-2237952 (Final Order entered December 16, 2011); *Investigation of Pennsylvania's Retail Electricity Market: Intermediate Work Plan,* Docket No. I-2011-2237952 (Final Order entered March 2, 2012).

Finally, before we address the merits of the positions espoused by the various Parties in this proceeding, we note that any issue or Exception that we do not specifically address has been duly considered and will be denied without further discussion. It is well settled that the Commission is not required to consider, expressly or at length, each contention or argument raised by the Parties. *Consolidated Rail Corporation v. Pa. PUC*, 625 A.2d 741 (Pa. Cmwlth. 1993); *see also, generally, University of Pennsylvania v. Pa. PUC*, 485 A.2d 1217 (Pa. Cmwlth. 1984).

III. PPL's Proposed DSP III

The following is a summary of the substantive provisions of PPL's proposed DSP III program, as presented in its DSP III Petition. As discussed below, the Signatory Parties are proposing to modify some of these provisions pursuant to the Partial Settlement.

A. Procurement and Rate Design

1. Residential Fixed-Price Procurement and Rate Design

Under the proposed DSP III program, PPL will acquire 100% of the fixed-price Residential customer class default service supply, exclusive of supply previously committed under block contracts for Residential customers,[3] through a series of load-following, full-requirements contracts with six- and twelve-month terms using a laddering or staggered approach so that all the products are not procured at the same time. The costs incurred by PPL to provide default service to the Residential customer class will be recovered through the Generation Supply Charge-1 (GSC-1), separately computed with respect to the Residential customer class. Costs incurred prior to June 1, 2015, related to procurement of supply and other costs related to development and implementation of the DSP III program will be included in the GSC-1, as applicable, and will be amortized ratably over the twenty-four-month term of the DSP III program. The GSC-1 will be adjusted every six months to reflect the cost of the default service supply contracts in place for the upcoming six-month period, and will be reconciled every six months for over- and under-recoveries by customer class. DSP III Petition at 14-15.

[3] PPL has pre-existing block supply contracts for 150 MW through December 31, 2015, and 50 MW committed from January 1, 2016, through May 31, 2021. DSP III Petition at 14, n.8.

2. Small C&I Fixed-Price Procurement and Rate Design

Similar to its proposal for the Residential class, PPL will acquire 100% of the Small C&I customer class fixed-priced default service supply through a series of load-following supply contracts with six- and twelve-month terms using a laddering or staggered approach. The costs incurred by PPL to provide default service to the Small C&I class will be recovered through the GSC-1, separately computed with respect to the Small C&I class. Costs incurred prior to June 1, 2015, related to procurement of supply and other costs related to development and implementation of the DSP III program will be included in the GSC-1, as applicable, and will be amortized ratably over the twenty-four-month term of the DSP III program. The GSC-1 will be adjusted every six months to reflect the cost of the default service supply contracts in place for the upcoming six-month period, and will be reconciled every six months for over- and under-recoveries by customer class. *Id*. at 16-17.

Under PPL's DSP II program, the Small C&I class included customers with a peak demand of 500 kW or less. However, in the DSP II proceeding, the Company agreed to reduce the peak demand level for the Small C&I class in its next filing. Accordingly, as discussed more fully below, PPL is proposing to reduce the peak demand limitation for the Small C&I class from 500 kW to 100 kW, consistent with the Commission's discussion in *Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service,* Docket No. I-2011-2237952 (Order entered February 15, 2013) *(End State Order)*. DSP III Petition at 16.

3. Large C&I Procurement and Rate Design

For the Large Commercial and Industrial (Large C&I) customer class, PPL is proposing to obtain default service supply on a real-time hourly basis through the PMJ spot market using a single annual solicitation. These annual procurements will coincide with the PJM planning period, and will be held in April for the upcoming PJM planning period. The costs incurred by PPL to provide default service to the Large C&I class will be recovered through the Generation Supply Charge-2 (GSC-2), which will remain unchanged from the GSC-2 tariff provisions approved under PPL's DSP II program. The GSC-2 will be revised annually, effective June 1, on thirty days advance notice to reflect changes in costs. The GSC-2 will continue to be reconciled on an annual basis, and any remaining under-/over-collections from the DSP II program will be included in this reconciliation. *Id*. at 18-19.

Under PPL's DSP II program, the Large C&I class included customers with a peak demand of 500 kW or greater. However, in the DSP II proceeding, the Company agreed to reduce the peak demand level for the Large C&I class in future filings. Accordingly, as discussed more fully below, PPL is proposing to reduce the peak demand minimum for the Large C&I class from 500 kW to 100 kW, consistent with the *End State Order*. *Id*. at 17-18.

4. Time-of-Use Procurement and Rate Design

As part of its DSP III program, PPL is proposing to continue the Time-of-Use (TOU) program approved by the Commission in *Petition of PPL Electric Utilities Corporation for Approval of a New Pilot Time-of-Use Program,* Docket No. P-2013-2389572 (Order entered September 11, 2014) (*September 2014 TOU Order*). Under the terms of that TOU program, PPL will provide a TOU rate option to customers in its tariff, but will rely on the retail market and EGSs to provide actual TOU service to customers. Retail EGSs that choose to participate in the TOU program would offer TOU rate options and provide TOU service to customers in PPL's service territory. DSP III Petition at 19-22.

5. AEPS Procurement

Under the DSP III program, PPL will procure certain alternative energy credits (AECs) to meet its obligation under the Alternative Energy Portfolio Standards (AEPS) Act as a component of its fixed-price and spot-market default supply contracts. The seller must provide its proportional share of AECs to fulfill PPL's AEPS obligation, in accordance with the terms of the Supply Master Agreement (SMA). Also, the SMA requires the seller to complete its transfer of AECS into PPL's Generation Attribute Tracking System (GATS) account(s) in the amount necessary to fulfill the seller's AEPS obligation, pursuant to the schedule set forth in the SMA. *Id*. at 22-23.

PPL previously acquired long-term solar Tier I AECs associated with its 10-year, 50 MW block product in its DSP I program. PPL may also need to acquire additional Tier I non-solar and Tier II AECs to cover the period from June 1, 2015, through May 31, 2017, associated with its 10-year long-term product obligation. Because PPL only needs to acquire additional AECs to cover 50 MW of supply, it proposes to continue the practice put in place under DSP II of soliciting at least three pricing offers from AEC brokers in June of 2015 and 2016 for Tier I non-solar and Tier II credits required to cover this long-term contract obligation. PPL will accept the least cost offer and will document the entire process, including the brokers contacted and price offerings by AEC vintage. All AEC transfers will take place through PJM GATS. The quantities of AECs procured will be sized such that no significant banking will take place, and cost recovery takes place on a current basis for those AECs purchased by the compliance period. The costs incurred to procure the AECs will be recovered through the GSC-1, which is the cost recovery method used under DSP II. *Id*. at 23.

B. DSP III Program RFP Process

PPL will implement its DSP III program by holding solicitations pursuant to a request for proposals (RFP) to obtain the default service products for the Residential, Small C&I, and Large C&I customer classes, from competitive wholesale power suppliers.[4] Separate bids will be solicited for each customer class. After receiving Commission approval of the solicitation results, PPL will execute transaction confirmations with the winning suppliers. The prices in the resulting wholesale supply agreements will form the basis of the rates charged to each of the customer classes. *Id*. at 25-26.

Each solicitation will be designed to procure a percentage of the fixed-price default service load for each customer class, which percentage will be further divided into "tranches." Each winning supplier must provide all products and services required by the Company to fulfill its obligations as default service provider. However, an individual bidder cannot bid on more than 85% of the available tranches for a customer class offered in each solicitation. In addition, for the Residential and Small C&I customer classes, an individual bidder cannot supply more than 50% of the default service load for a class during the DSP III period. *Id*. at 26-28.

C. Supply Master Agreement

PPL's proposed SMA is generally based on the current draft of the uniform supply master agreement developed by the Procurement Collaboration Working Group,

[4] PPL's *pro forma* RFP Process and Rules document, which was included as Attachment A to its DSP III Petition, is based on the documents approved by the Commission in its DSP II proceeding. DSP III Petition at 25.

in which PPL participated. PPL stated that its proposed SMA is also based on lessons learned from the SMA approved under its DSP II program.[5] *Id*. at 29.

D. Third-Party Manager

PPL has retained NERA Economic Consulting (NERA) as the independent third-party to administer each procurement, analyze the results of the solicitations for each customer class, select the supplier(s) that will provide services at the lowest cost, and submit all necessary reports to the Commission. PPL noted that NERA has successfully administered its Competitive Bridge Plan and its DSP I and DSP II program procurements. According to PPL, using NERA as a third-party procurement manager, as opposed to providing this service internally, will result in lower costs to customers. *Id*.

E. RTO Compliance

PPL asserted that its proposed SMA and RFP Rules require that both PPL and any bidder in the procurement process must be in compliance with PJM requirements, consistent with 52 Pa. Code § 54.185(e)(4), which requires default service plans to include documentation that the program is consistent with the requirements regarding the generation, sale and transmission of electricity of the regional transmission organization (RTO) in the control area where the default service provider is providing service. *Id*. at 30.

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[5] The proposed *pro forma* SMA document is included as Attachment B to PPL's DSP III Petition.

F. Contingency Planning

If the Commission rejects all bids for a given product in any solicitation, or if some tranches of a given product in a particular solicitation do not receive bids, PPL will expeditiously seek guidance and approval from the Commission to address this shortfall in procurement of default service supply. To the extent that unfilled tranches remain at the commencement of delivery for a given product, PPL will obtain default service supply through the spot market administered by PJM. PPL proposes to recover all the costs of such purchases from default service customers in the retail rates charged for the service for which the purchases are made. *Id*. at 31.

In the event a supplier defaults, PPL will offer full-requirements supply assignment to other winning bidders for the same product consistent with the step-up process described in the default service SMA. If this assignment is not successful, PPL will offer full-requirements supply assignment to all default service suppliers consistent with the default Service SMA, even if a default service supplier does not serve tranches for that product. These assignments will be offered at the original bid price in the event of default(s), or at the average price from the last successful bid for that product in the event of insufficient bids. *Id*.

G. Standard Offer Referral Program

PPL is proposing to continue to offer the Standard Offer Program (SOP) approved by the Commission under its DSP II program.[6] That SOP is available to all Residential customers, including customers enrolled in a CAP program, as well as Small C&I customers with a peak demand under 25 kW. The SOP provides participants with a standard 7% discount off the then-current Price to Compare (PTC) for a twelve-month term. A customer who elects the standard offer price may choose to receive service from a particular EGS, or will be randomly assigned to an EGS if it does not choose one. Customers may exit a standard offer contract without penalty. PPL solicits EGSs to participate in the SOP on a quarterly basis, and EGSs are required to commit to offering the product for the duration of the effective PTC. The expense of the SOP is recovered from participating EGSs as follows:

- Payment of a $500 per EGS registration fee for market certification testing costs. This only applies if the EGS is not currently rate ready certified.
- Payment of $28 per referred customer by participating EGSs.

Id. at 32-33.

PPL's SOP is currently promoted during all customer calls other than those regarding emergencies or terminations. Under its DSP III program, PPL is proposing to expand the promotion of the SOP to include customers that contact the Company using the Web Self Service application. Similar to customers who call the Company,

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[6] PPL stated that, as of April 14, 2014, approximately 66,100 eligible customers had been transferred to its third-party provider for further information on the Standard Offer Program, and approximately 56,600 of those customers enrolled in the program. Thus, PPL asserted that its Standard Offer Program under the DSP II program has had a success rate of 86%. PPL further stated that, of those customers that opted to participate in the Standard Offer Program, approximately 55,500, or 98%, were new or moving customers. DSP III Petition at 33-34.

customers who have signed up to utilize the Web Self Service program will be able to choose to participate in the SOP. PPL stated that there will be no other material changes to the SOP approved under its DSP II program. *Id*. at 34.

Under its DSP II program, PPL selected an affiliate, PPL Solutions, as the third-party service provider to administer the SOP.[7] PPL is proposing to extend the current third-party SOP service contract during the DSP III period, or until the Commission eliminates EDCs' default service obligations. The terms, conditions, and cost of the extended third-party SOP service contract will remain the same as the existing service contract. *Id*. at 34-35.

H. End State

PPL anticipates that it will continue in the role of default service provider beyond May 31, 2017. Therefore, in order to avoid procuring all default service supplies at one time to be effective June 1, 2017, PPL's final default service supply procurement under DSP III (October 2016) will continue to obtain both twelve- and six-month fixed price products. Should the Commission determine, at any time prior to that final solicitation, that the Company will not continue in its role as default service provider beyond May 31, 2017, PPL will file an appropriate petition with the Commission requesting to amend the DSP III program to ensure that no fixed-price contracts extend beyond that date, or the date set by the Commission for the termination of PPL's role as default service provider. In addition, PPL's proposed SMA contains provisions that anticipate the possibility that the Commission may determine that the Company will no longer continue in its role as default service provider, and as a result, PPL may be required to terminate or transfer/assign its default service obligations to a third-party

[7] The Company stated that PPL Solutions was the lowest bidder in the RFP process held to choose the third-party provider. DSP III Petition at 34.

supplier. PPL stated that these provisions can be used to implement any change to its role as default service provider that may be made in the future. *Id*. at 35.

I. Affiliated Interest Agreements and Waivers

PPL noted that its unregulated affiliates will be permitted to participate in the Company's default service supply solicitations, pursuant to 52 Pa. Code § 54.186(b)(5). If one of those affiliates is the successful bidder for one or more tranches of default service supply, PPL would enter into a SMA with that affiliate. Therefore, PPL requests that the Commission approve the proposed SMA as an affiliated interest agreement under 66 Pa. C.S. § 2102. Also, as explained above, PPL is proposing to extend the current third-party SOP service contract with its affiliate, PPL Solutions, during the DSP III period, or until the Commission eliminates EDCs' default service obligations. For this reason PPL requests that the Commission approve the Third-Party Standard Offer Referral Program Services Contract extension as an affiliated interest agreement under 66 Pa. C.S. § 2102. *Id*. at 35-36.

In addition, PPL is requesting a waiver of the Commission's directive, as set forth in the *End State Order*, that EDCs offer quarterly PTCs that are synchronized with the PJM energy year for Residential and Small C&I customer classes. *See, End State Order* at 33. PPL averred that its proposed semi-annual PTC changes and associated six-month reconciliations are consistent with its six- and twelve-month procurements, and will reduce volatility in the PTC. PPL also asserted that the six-month PTC changes support retail competition by providing customers greater certainty when evaluating shopping opportunities and by providing EGSs greater certainty when developing offers. *Id*. at 37.

PPL is also requesting a waiver of the requirement to issue a final PTC no less than forty-five days prior to the effective date of the PTC. *See, End State Order* at 41. PPL stated that if the PTC is issued forty-five days before becoming effective, the PTC would be on a different schedule from its underlying components, including GSC-1, which is required to be filed ten days prior to the implementation of the rate, and GSC-2 and the Transmission Service Charge (TSC), which are required to be filed thirty days prior to the implementation of the rate. In addition, PPL contended that collections would be on-going during the forty-five day issuance period, which would change the E-factor and affect the actual PTC. PPL also asserted that a PTC issued forty-five days before becoming effective would not reflect the current market as accurately as a shorter issuance period. *Id*. at 37-38.

Should the Commission deny PPL's request for a waiver of the forty-five day PTC issuance period, PPL requests that the forty-five day rule not be enforced for the first procurement under the DSP III program, because it may not be practical to conduct and complete the first procurement in sufficient time to meet the forty-five day PTC rule. *Id*. at 38.

IV. Partial Settlement

A. Terms and Conditions of the Partial Settlement

The Partial Settlement consists of a seventeen-page document with attached Appendices A through M. The body of the document contains the terms and conditions of the Settlement as agreed to by the Signatory Parties. Appendix A consists of the product portfolio and procurement schedule agreed to under the terms of the Partial Settlement. Appendices B through K contain the Signatory Parties' individual Statements in Support of the Partial Settlement. Appendices L and M consist of the letters of non-opposition to the Partial Settlement submitted by FES and Direct Energy, respectively.

The Signatory Parties state that the terms of the Partial Settlement reflect a carefully balanced compromise of their respective interests in this proceeding, and they unanimously agree that the Partial Settlement is in the public interest. The Signatory Parties request that the proposals set forth in PPL's DSP III Petition be granted, subject to the terms and conditions of the Partial Settlement and a decision on the issues reserved for litigation.[8] Partial Settlement at 6.

The substantive terms of the Partial Settlement are set forth in paragraphs 20 through 56, pages 6 through 14, of the Partial Settlement, as follows:

> **A. GENERAL**
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> 20. Subject to the terms and conditions of the Settlement, and a decision on the issues reserved for litigation, the Parties agree that the proposals set forth in PPL Electric's Petition requesting approval of its DSP III Program, including the Default Service SMA, RFP, Program Product Procurement Schedule, and Tariff provisions for the Generation Supply Charge-1 ("GSC-1"), the Generation Supply Charge-2 ("GSC-2") and the Transmission Service Charge ("TSC"), are acceptable as modified below and should be adopted by the Commission.
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> 21. The parties agree that PPL Electric's DSP III Program, as modified by the terms and conditions of the Settlement, and subject to the resolution of the issues reserved for litigation, includes and/or addresses all of the elements prescribed by Section 2807 of the Public Utility Code, the Commission's regulations, and the Commission's policies for a Default Service plan.

8 The Partial Settlement resolved all issues among the Signatory Parties except for: (1) PPL's proposal to change the customer size demarcation between Small Commercial and Industrial and Large Commercial and Industrial customers from a peak demand of 500 kW to a peak demand of 100 kW; and (2) the issue of cost responsibility for NMB transmission-related costs. These issues were reserved for litigation, and will be discussed more fully below.

B. PRODUCT PORTFOLIO AND PROCUREMENT SCHEDULE

22. The Parties agree that the final October 2016 procurements under the DSP III Program will continue to obtain both 12- and 6-month fixed-price products for the Residential and Small C&I rate class categories.

23. The parties agree that the product portfolio and procurement schedule for the final October 2016 procurements under the DSP III Program will be modified so that 55% of the Residential portfolio will expire on May 31, 2017, and 45% of the Residential portfolio will extend beyond May 31, 2017. The Parties acknowledge that this modification is consistent with the product portfolio and procurement schedule approved by the Commission in PPL Electric's DSP II Plan. Attached [to the Partial Settlement] as Appendix A is a product portfolio and procurement schedule that has been modified to reflect this settlement term.

24. Should the Commission determine, any time prior to the last solicitation under the DSP III program in October 2016, that PPL Electric will not continue in its role as Default Service provider beyond May 31, 2017, PPL Electric agrees to file an appropriate petition with the Commission requesting to amend the DSP III Program to ensure that no fixed-priced contracts extend beyond May 31, 2017, or the date set by the Commission for the termination of PPL Electric's role as Default Service provider.

C. CONTINGENCY PLAN

25. PPL Electric agrees to modify the RFP to provide that, if the Commission rejects all bids for a given product, in any solicitation, or if some tranches of a given product in a particular solicitation do not receive bids, the Independent Auction Manager will [be] responsible to contact suppliers, including all suppliers that submitted bids and suppliers that registered as potential bidders in response to the RFP, in an attempt to gain an understanding of the underlying cause of any shortfall or supplier failure, and to include such understanding in a report to the Commission. Nothing in this provision shall be construed to require any supplier contacted

by the Independent Auction Manager to provide confidential or proprietary business information, whether the supplier registered as a potential bidder or not, or submitted bids or not.

26. If the Commission rejects all bids for a given product, in any solicitation, or if some tranches of a given product in a particular solicitation do not receive bids, PPL Electric agrees to issue a new RFP as soon as practicable and, if needed, to obtain Default Supply through the spot market in the interim. PPL Electric will make all reasonable efforts to minimize the Residential load that is unhedged, including but not limited to consideration of combined block and spot products, when it seeks Commission guidance following a failed solicitation.[2]

27. The Parties agree that the settlement makes no changes to the Contingency Plan described in the SMA in the event of a supplier default.

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[2] The Parties reserve their respective rights to present their arguments on the effectiveness of using block and spot purchases at such time.

D. AECs

28. PPL Electric agrees to modify Paragraph 5 of Appendix D to the Default Service SMA to require Default Service Suppliers to transfer Alternative Energy Credits ("AECs") into PPL Electric's Generator Attribute Tracking System ("GATS") account on a quarterly basis.

29. PPL Electric will procure Tier I (non-solar) and Tier II AECs through new individual long-term contracts in an amount necessary to cover the AEPS requirements associated with the pre-existing Long-Term Product contract for 50 MW committed through May 31, 2021. PPL Electric agrees that these new long-term contracts will be solicited in the first auction under the DSP III Program.

E. PTC AND TIMING OF PROCUREMENTS

30. The Parties agree that PPL Electric will issue its Price to Compare ("PTC") 30 days in advance of the effective date of the PTC.

31. The Parties agree that, in order to accommodate filing the PTC on 30 days advance notice, PPL Electric's procurements will be advanced by two weeks from the dates proposed by PPL Electric in the Petition.

32. The Parties agree that PPL Electric will discontinue its practice of issuing a preliminary PTC approximately 45 days before the effective date.

F. RECONCILIATION OF GSC-1, GSC-2, AND TSC

33. The Parties agree that the GSC-1 will be adjusted every 6 months to reflect the cost of the Default Service supply contracts in place for the upcoming 6-month period.

34. The Parties agree that, in order to accommodate filing the PTC on 30 days advance notice, the GSC-1 will be reconciled every 6 months, using the over/under collection balance for the 6-month period ending 2 months prior to the new PTC effective date.

35. The Parties agree that the GSC-2 will be reconciled every 12 months using the over/under collection balance for the 12-month period ending 2 months prior to the June 1 PTC effective date.

36. The Parties agree that the TSC will be reconciled every 12 months using the over/under collection balance for the 12-month period ending 2 months prior to the June 1 PTC effective date.

G. CREDIT RATINGS

37. PPL Electric agrees to modify Section 6.7(b) of the SMA to reduce the credit rating of a bank or other

financial institution from which a Default Supplier has obtained a letter of credit to a minimum "A-" senior unsecured debt rating (or, if unavailable, corporate issuer rating discounted one notch) from Standard & Poor's Financial Services LLC and "A3" from Moody's Investors Service, Inc. The Parties acknowledge that the modification of Section 6.7(b) of the SMA is consistent with the credit rating set forth in the SMA approved by the Commission in PPL Electric's DSP II plan.

H. SMA

38. The Parties agree that PPL Electric will delete Section 16.3(b) of the SMA regarding the termination of the SMA, and revise any cross-references thereto.

39. PPL Electric agrees to remove the reference to "pursuant to FERC Order No. 745" from Section 2.4(c) of the SMA.

40. PPL Electric agrees to modify Section 3.4 of the SMA to replace Financial Accounting Standards Board Statement No. 133 ("FAS 133") with Accounting Standards Codification 815 ("ASC 815"). PPL Electric also agrees to add Section 3.4 to the SMA Table of Contents.

41. PPL Electric agrees to modify the SMA to replace "sole discretion" with "reasonable discretion."

42. PPL Electric agrees to revise Section 9.2 of the SMA to add the phrase "Except as set forth in Section 2.5 and 2.6," to the beginning of the first sentence in Section 9.2.

43. PPL Electric agrees to reconcile the language in Sections 11.2 and 16.17 of the SMA regarding the Mobile-Sierra Doctrine so that both Sections provide, in pertinent part, as follows:

> To the extent permitted by law and absent agreement to the contrary, each party, for itself and its successors and assigns, hereby expressly and irrevocably waives its rights to argue before any governmental authority that any review,

modification, or rescission of this Agreement should be considered under any standard of review other than the "public interest" standard set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956), affirmed by Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County, Washington, et al., 554 U.S. 527 (2008) (the "Mobile-Sierra Doctrine").

I. STANDARD OFFER PROGRAM

44. PPL Electric agrees to revise its Standard Offer Program ("SOP") scripts within 90 days of the Commission approval of the settlement to provide more explicit disclosures explaining that:

(a) The initial discount of 7% is based on the current PTC;

(b) The PTC will change semiannually with the next change in [month];

(c) The percentage savings a customer will experience will vary as the PTC changes; and

(d) The SOP rate may be higher or lower than the next PTC.

45. With respect to PPL Electric's proposal to implement a SOP Web Self Service application, the Parties agree as follows:

(a) On or before September 30, 2014, PPL Electric will provide interested parties with details regarding the design, costs, and implementation of the SOP Web Self Service application;

(b) On or before October 31, 2014, PPL Electric will hold a collaborative open to all interested parties to seek input on the design, costs, and implementation of the SOP Web Self Service application;

(c) If all parties to the collaborative reach a consensus as to the design, costs, and implementation of the SOP Web Self Service application, the SOP Web Self Service application will become effective on June 1, 2015, consistent with the consensus; and

(d) If no consensus is reached at the collaborative, PPL Electric will file a petition with the Commission, on or before November 28, 2014, seeking a resolution of the unresolved SOP Web Self Service application. The Parties agree that all responses to the petition will be filed within thirty days from the date of filing. The intent of this process is to obtain resolution of the SOP Web Self Service application proposal in time to implement any SOP Web Self Service application effective June 1, 2015.

46. PPL Electric agrees that electric generation suppliers ("EGSs") may participate in the SOP for a 3-month term, and that EGSs have the ability to change their participation status with each 3-month period.

47. PPL Electric agrees to notify all EGSs via e-mail of the SOP price the same day the PTC is issued, and to post the SOP price to the web and supplier portal one day after the PTC becomes effective.

48. PPL Electric agrees to address SOP at a separate stakeholder meeting that will be open to all interested parties. The SOP stakeholder meeting will be held before January 31, 2015.

49. The SOP stakeholder meeting will address, at a minimum the following issues:

(a) EGS recommendations regarding administration of the SOP;

(b) EGS recommendation that the SOP program be open to EGSs using bill ready billing; and

(c) Recommended changes to the SOP scripts and administrative process.

50. PPL Electric agrees to provide the statutory advocates and any interested party with the following information in advance of the SOP meeting:

(a) SOP scripts;

(b) Customer enrollment figures and SOP process for the first 12-month period of the SOP;

(c) Statistics regarding EGS participation in the SOP from inception through the enrollment period beginning December 1, 2014;

(d) A report of all informal and formal complaints related to the SOP received by the Company during the first 12-month period of the SOP; and

(e) A report on statistics, lessons learned, and best practices for the SOP program, including enrollment data, EGS participation data, and rate of successful enrollments.

51. Any changes or modifications agreed upon by all parties at the SOP stakeholder meeting will be presented to the Commission by the Company in a petition to modify the SOP, and the Company shall implement the modifications contained therein within six months of final approval of such petition by the Commission.

J. NET METERING

52. The parties acknowledge that the issue of a net metering option for Time-of-Use ("TOU") customers was

litigated before and is currently pending before the Commission for disposition at Docket No. P-2013-2389572. The Parties agree that for the DSP III Program period PPL Electric shall implement the TOU Program as approved by the Commission at Docket No. P-2013-2389572, including a net metering option if adopted.[9]

53. PPL Electric and the Sustainable Energy Fund ("SEF") agree to recommend and support in their respective statements in support that the Commission decide the TOU Program, which currently is pending before the Commission for disposition at Docket No. P-2013-2389572, in sufficient time to allow the TOU Program to be fully implemented at the beginning of DSP III Program period, *i.e.*, June 1, 2015.

54. The Parties acknowledge that currently pending before the Commission is a Proposed Rulemaking Order at Docket No. L-2014-2404361 that proposes to modify the Commission's regulations to, among other things, provide guidance and clarity regarding net metering and compensation under net metering. *See Implementation of the Alternative Energy Portfolio Standards Act of 2004,* Docket No. Docket No. [*sic*] L-2014-2404361 (Order entered Feb. 20, 2014). The Parties agree that PPL Electric will file a new net metering Tariff consistent with the outcome of the Commission's Proposed Rulemaking Order at Docket No. L-2014-240361 [*sic*]. The Parties retain the right to review and file testimony concerning such tariff filing as permitted by the normal Commission process for the review of a new tariff filing.

K. ISSUES RESERVED FOR LITIGATION

55. The Parties agree that PPL Electric's proposal to change the customer size demarcation between Small C&I and Large C&I customers from 500 kW to 100 kW is reserved for litigation.

56. The Parties agree that the issue of the cost responsibility for NMB Charges is reserved for litigation.

[9] As noted above, PPL's TOU Program was approved pursuant to the Commission's *September 2014 TOU Order*.

In addition to the specific terms to which the Signatory Parties have agreed, as set forth above, the Partial Settlement contains certain general, miscellaneous terms. The Partial Settlement is conditioned upon the Commission's approval of the terms and conditions without modification. The Partial Settlement establishes the procedure by which any of the Signatory Parties may withdraw from the Partial Settlement and proceed to litigation, should the Commission act to modify the Partial Settlement. Partial Settlement at 15, ¶ 61. In addition, the Partial Settlement states that it does not constitute an admission against, or prejudice to, any position which any of the Joint Petitioners might adopt during subsequent litigation of this proceeding or any other proceeding. Partial Settlement at 16, ¶ 63.

The Signatory Parties acknowledge that the Partial Settlement reflects a compromise of competing positions and does not necessarily reflect any Signatory Party's position with respect to any issues raised in this proceeding. In addition, the Signatory Parties state that the Partial Settlement may not be cited as precedent in any future proceeding, except to the extent required to implement the Partial Settlement. Partial Settlement at 16, ¶ 64.

B. ALJ's Recommendation

The ALJ found that the terms of the Partial Settlement meet the legal requirements of a default service plan. Specifically, the ALJ determined that the supply procurement terms constitute a prudent mix of supply methods, which is anticipated to result in adequate, reasonable and reliable service to customers, as well as service that is provided at the least cost over time. The ALJ also found that the TOU option available to Residential and Small C&I customers is consistent with the TOU program approved by the Commission in the *September 2014 TOU Order*. In addition, the ALJ found that AECs are provided for in a competitive fashion, contingency plans are established, and changes to the reconciliation of costs are reasonable and agreed upon by the Signatory Parties, and unopposed by the remaining parties. For these reasons, the ALJ stated that the Partial Settlement is in the public interest and should be approved without modification. R.D. at 31-32.

C. Disposition of Partial Settlement

Pursuant to our Regulations at 52 Pa. Code § 5.231, it is the Commission's policy to promote settlements. 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 Commission and all ratepayers of a utility, who otherwise may have to bear the financial burden such litigation necessarily entails. The Commission must, however, review proposed settlements to determine whether the terms are in the public interest. *Pa. PUC v. Philadelphia Gas Works,* Docket No. M-00031768 (Order entered January 7, 2004); *Pa. PUC v. C. S. Water and Sewer Assoc.*, 74 Pa. P.U.C. 767 (1991); *Pa. PUC v. Philadelphia Electric Co.*, 60 Pa. P.U.C. 1 (1985).

Upon our review of the Partial Settlement, we find it to be reasonable and in the public interest, and we will approve it. We agree with the ALJ that PPL's proposed generation supply procurement plan as set forth in its DSP III program and modified by the terms of the Partial Settlement encompasses a prudent mix of supply methods, which is anticipated to result in adequate, reasonable and reliable service to customers, as well as service that is provided at the least cost over time. We also agree that the TOU rate option for Residential and Small C&I customers is consistent with the TOU program approved in the *September 2014 TOU Order*. In addition, we agree that AECs are provided for in a competitive fashion, and a contingency plan is properly established. We also find reasonable the provisions regarding the timing of the PTC and procurements, the reconciliation of the GSC-1, GSC-2, and TSC, the terms of the SMA, the terms of the SOP, and net metering.

The Partial Settlement resolves the majority of the issues impacting Residential consumers, Small C&I customers, Large C&I customers, and the public interest at large. The benefits of the Partial Settlement are numerous and will result in significant savings of time and expenses for all Parties involved by avoiding the necessity of further administrative proceedings, as well as possible appellate court proceedings. For the reasons stated herein and in the Signatory Parties' Statements in Support, we agree with the ALJ's conclusion that the Partial Settlement is in the public interest. Accordingly, we shall adopt the ALJ's recommendation to approve the Partial Settlement without modification.

V. Contested Issues

As noted above, the Partial Settlement resolved all issues among the Signatory Parties except for: (1) PPL's proposal to change the customer size demarcation between Small C&I and Large C&I customers from a peak demand of 500 kW to a peak demand of 100 kW; and (2) the issue of cost responsibility for NMB transmission-related costs. These issues were reserved for litigation and will now be discussed in detail.

A. Small/Large C&I Customer Class Demand Split

1. Positions of the Parties

a. PPL's Position

PPL stated that under its DSP II program, the Small C&I customer Class included customers with a peak demand of less than 500 kW. As a result, customers on

Rate Schedules GS-3 and LP-4 with a demand level of 500 kW and above are classified as Large C&I customers and receive spot market-based default service, while customers on those same rate schedules with a peak demand below 500 kW are classified as Small C&I customers and receive fixed-price default service. PPL M.B. at 12. However, PPL asserted that the Commission adopted the Company's commitment, made in its DSP II proceeding, to reduce the peak demand for the Small C&I customer class from 500 kW to 100 kW in its next default service filing. *Id*. at 12-13 (citing *Petition of PPL Electric Utilities Corporation For Approval of a Default Service Program and Procurement Plan*, Docket No. P-2012-2302074 (*PPL DSP II*) (Opinion and Order entered January 24, 2013) (*PPL DSP II Order*) at 62-63. Accordingly, PPL has proposed in this proceeding to reduce the peak demand limitation for the Small C&I customer class from 500 kW to 100 kW, thus changing the demand level split between the Small C&I and Large C&I customer classes from 500 kW to 100 kW. PPL M.B. at 13; PPL Exh. 1 at 16, ¶ 50; PPL St. No. 1 at 30.

PPL stated that it proposed this change in the demand level split for three primary reasons. First, PPL asserted that in the *End State Order*, the Commission stated that it expected EDCs to implement a 100 kW demand split for commercial and industrial customers. PPL M.B. at 13 (citing *End State Order* at 31-32). Second, as noted above, PPL stated that in its DSP II proceeding, it committed to reducing the peak demand limitation for the Small C&I class in its DSP III program. PPL M.B. at 13. Third, PPL averred that the number of default service customers impacted by this change, as of May 2014, is very small at approximately 430 customers, which is only 0.4% of all default service commercial and industrial customers. PPL M.B. at 14; PPL St. No. 1-R at 20-21; PPL Exh. JMR-5R. PPL further averred that these 430 customers represent about 2.1% of all Small C&I customer load. PPL R.B. at 5.

PPL stated that all of its 3,200 commercial and industrial customers with demand between 100 kW and 500 kW have demand meters installed, and that 88% of these customers are currently shopping. Thus, PPL argued that it is clear that such customers "are well-equipped and educated to manage their commodity costs in an hourly spot market default service environment." PPL M.B. at 14; R.B. at 5. In addition, PPL asserted that the customers impacted by its proposal can still obtain fixed-price supply from the competitive market. PPL M.B. at 14.

b. OSBA's Position

The OSBA opposes PPL's proposal to reduce the peak demand demarcation between Small and Large C&I customers from 500 kW to 100 kW. The OSBA argued that moving 430 small business customers from the Small C&I to the Large C&I class will cause these customers to be removed from their current, more stable fixed-price default service at rates charged under GSC-1, and to be transferred to hourly spot-market-priced service under GSC-2. OSBA M.B. at 3-4. The OSBA contended that this result would be contrary to Section 2807(e) of the Code, particularly the requirement that a prudent mix of contracts be procured to ensure adequate and reliable service, and least cost to the customer over time. *Id*. at 5 (citing 66 Pa. C.S. §§ 2807(e)(3.2) and (3.4)). According to the OSBA, the Commission has rejected the argument that the least cost standard mandates that default service rates be market-reflective, and that such an interpretation of the least cost standard would be inconsistent with the price stability objective of Act 129. OSBA M.B. at 6-7 (citing *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) (*Final Default Service Rulemaking Order*) at 39-41).

The OSBA asserted that PPL's commitment to make such a change in its previous DSP II proceeding is no basis to approve its proposal here. Moreover, the OSBA contended that PPL is mistaken in its assertion that the proposal will impact only a small number of customers, stating that the affected load represents 13.7 percent of the total Small C&I default service load. OSBA M.B. at 4. The OSBA further argued that consistency with the *End State Order* is also "not a basis on which 13.7 percent of the Small C&I customer load should be disrupted from their current choice for stable rate default service." *Id*. at 8. According to the OSBA, the *End State Order* represents the Commission's "wish list" regarding the future of default service, and is not a legal mandate, which the Commission itself conceded. *Id*. In this regard, the OSBA noted that the Commission explicitly expressed concern about the legality of moving medium C&I customers from stable-rate default service to hourly-priced service, preferring instead to seek legislative changes to obtain the authority to do so. *Id*. at 8-9 (quoting *End State Order* at 45).

c. RESA's Position

RESA is supportive of PPL's proposal, and disagrees with the OSBA's contention that it will prevent affected customers from having access to stable pricing for electric service. RESA argued that PPL's proposal will result in the availability of more market-reflective rates for these customers. According to RESA, competitors will then be encouraged to enter the market, resulting in a variety of products and services from which these customers can choose, including products offered at more stable prices, if that is what customers desire. Thus, RESA asserted that the competitive retail market can be relied upon to achieve all policy objectives, including that of price stability. RESA M.B. at 5-6.

RESA also submitted that "PPL's proposal is clearly consistent with the Commission's *End State Order* which directed that "in the next round of default service plans that begin on June 1, 2015, we expect that EDCs will offer only hourly [locational marginal pricing (LMP)] to medium and large C&I customers with interval meters." *Id*. at 6 (quoting *End State Order* at 29). RESA argued that hourly default service pricing will better reflect current market conditions, and would be more appropriate and beneficial for medium to larger C&I customers. RESA M.B. at 6. RESA also contended that while the Commission expressed a preference to seek legislative amendments to provide the authority to move C&I customers to the hourly priced procurement group, nothing in the *End State Order* prohibits such a movement or requires the Commission to await legislative changes. *Id*. at 7.

2. ALJ's Recommendation

In her Recommended Decision, the ALJ first determined that the *End State Order* is not consistent with the Commission's Policy Statement set forth at 52 Pa. Code § 69.1805 regarding electric generation supply procurement. The ALJ stated that while the Policy Statement promotes the "prudent mix" standard, the *End State Order* prefers the LMP approach. R.D. at 41-43. The ALJ further opined as follows:

> For the Commission to adopt a standard other than the "prudent mix" standard as a general rule (as opposed to the specific exception presented by the Pike County situation), thus expanding the standard provided in the statute, the Commission would be well advised to do so in a formal rulemaking proceeding. While the *End State Order* most likely does not reach the level of exceeding the Commission's administrative authority, neither is it, as an implementation order, standing alone, enforceable law.
>
> The result is that the Commission has one policy statement published in the Pennsylvania Code, where anyone unfamiliar with the law in Pennsylvania would, nonetheless, be likely to search for and find it, and one order which amounts to a policy statement that has not been published in a service such as the Pennsylvania Code. Reliance upon the latter is antithetical to the Commission's usual practice of transparency. The result is that neither is legally binding and each acts as advisory to both the parties to a default service

> case and to the Commission itself. As such, the legal analysis turns back to the statute for authority.

Id. at 43-44 (footnote omitted).

The ALJ then quoted, in pertinent part, from the Code at 66 Pa. C.S. §§ 2807(e)(3.1) and (3.2), as follows:

> (3.1) …. The electric power acquired shall be procured through competitive procurement processes and shall include one or more of the following:
>
> (i) Auctions.
> (ii) Requests for proposal.
> (iii) Bilateral agreements entered into at the sole discretion of the default service provider which shall be at prices which are:
>
> (A) no greater than the cost of obtaining generation under comparable terms in the wholesale market, as determined by the commission at the time of execution of the contract; or
>
> (B) consistent with a commission-approved competition procurement process. . . .
>
> (3.2) The electric power procured pursuant to paragraph (3.1) shall include a prudent mix of the following:
>
> (i) Spot market purchases.
> (ii) Short-term contracts.
> (iii) Long-term purchase contracts . . . .

Id. at 44-45. The ALJ concluded that "it is clear that the statute favors the published policy statement, and that any change to that policy statement and the statue itself needs to be supported by substantial evidence." *Id*. at 44-45. Therefore, the ALJ stated that the question of whether PPL carried its burden of proving that its proposal to shift customers who have a maximum load of 100 kW to 500 kW to hourly pricing is consistent with the statute. *Id*. at 45.

The ALJ appeared to agree with the OSBA that "430 customers, or approximately 13% of the rate class, is not *de minimis*." *Id*. Furthermore, the ALJ asserted that the *End State Order* recognizes that the Commission's position would be better grounded if there was legislative support for the use of hourly pricing without the hedging of short- and long-term contracts to meet the price stabilization requirement of Act 129. In addition, noting that the percentage of shopping Small C&I customers dropped from 93% under PPL's DSP II program to the present 88%, the ALJ opined that "[a]rguably, the product available from default service under the full-requirements load-following contracts approach is one which those customers see as desirable." *Id*. The ALJ concluded as follows:

> While PPL Electric has set forth a plan to comply with the *End State Order*, it has provided no evidence to support a finding that its proposal to move these small commercial customers to hourly pricing is consistent with the goal of the statute to establish a default plan which provides the least cost over time by using a prudent mix of products. With the knowledge that this issue can be revisited in future DSP cases, I recommend that the proposal be rejected and the Company be directed to continue to serve the Small C&I customers consistent with the plan approved in the DSP II.

Id.

3. Exceptions and Replies

a. PPL's Exceptions

In its Exceptions, PPL disputes the ALJ's recommendation that the Commission reject PPL's proposal to reduce the peak demand limitation for the Small C&I customer class from 500 kW to 100 kW. PPL argues that Section 2807(e)(3.2) of the Code does not require a default service provider to procure multiple default service products for each customer class (or a subset of a customer class in this case), but rather, provides for a default service plan that includes a "prudent mix" of products. According to PPL, its DSP III program, as a whole, will include a prudent mix of default service products. PPL Exc. at 4-5.

PPL also cites to *Popowsky v. Pa. PUC*, 71 A.3d 1112 (Pa. Cmwlth. 2013), *appeal denied*, 83 A.3d 416 (2013) (*Popowsky*), in which the Commonwealth Court upheld the Commission's approval of a default service plan for Pike County Light & Power Company (Pike County) that contained only spot market purchases. PPL notes that in that proceeding, the Court rejected the OCA's argument, on appeal, that a default service plan must include at least two of the sources enumerated in Section 2807 (e)(3.2)(i)-(iii) to be considered a "prudent mix." PPL Exc. at 5 (citing *Popowsky* at 1116). PPL states that the Commonwealth Court took the position that the word "prudent" must not be disregarded in Section 2807 (e)(3.2) of the Code, and that the Commission "must exercise some balance and discretion under the circumstances of the case in order for the 'mix' in question to be prudent.'" PPL Exc. at 5 (quoting *Popowsky* at 1117). In addition, PPL points to prior Commission decisions in which the Commission approved default service plans that included a single hourly-priced product for large commercial and industrial customers. PPL Exc. at 5, n.3.

PPL also argues that the Commission's expectation in the *End State Order* that EDCs implement a 100 kW demand split for commercial and industrial customers is in accordance with the Commission's Policy Statement at 52 Pa. Code § 69.1805. PPL quotes, in pertinent part, from the Policy Statement, as follows:

> (2) Nonresidential customers with 25—500 kW in maximum registered peak load. The DSP should acquire electric generation supply for these customers using a mix of resources as described in the introductory paragraph to this section. Fixed-term contracts may be laddered to minimize risk, with a minimum of two competitive bid solicitations a year to further reduce the risk of acquisition at a time of peak prices. *In subsequent programs, the mix percentage of supply acquired through long-term and short-term contracts and spot market purchases should be adjusted, depending on developments in retail and wholesale energy markets to ensure least cost to customers.*

PPL Exc. at 6 (quoting from 52 Pa. Code § 69.1805 (emphasis added by PPL)). PPL avers that the Policy Statement contemplates that the mix and types of products procured for nonresidential customers with a peak demand between 25 kW and 500 kW would and should be adjusted relative to changes in the competitive energy markets. Thus, PPL states that it is responding to a robust competitive market in its service territory by shifting its overall procurement mix toward shorter term products. PPL Exc. at 6 (citing PPL St. No. 2 at 12-18). From PPL's point of view, its current proposal to implement a 100 kW demand split is consistent with this shift and the Commission's Policy Statement. PPL Exc. at 6. Moreover, PPL contends that the *End State Order* is consistent with the Policy Statement because it directed EDCs to implement an adjustment in the mix of products procured for non-residential customers with a peak demand of 100 kW or higher to more accurately reflect market conditions. *Id*. at 6-7 (citing *End State Order* at 25, 29).

In conclusion, PPL reiterates its argument that, as the Commission and the Commonwealth Court have previously recognized, a single product can be viewed as a "prudent mix" for a specific customer class, given the relevant circumstances. Therefore, PPL contends that when an additional group of commercial and industrial customers exhibit shopping characteristics similar to those of the existing Large C&I class—which PPL avers is the case for the customers with demand between 100 kW and 500 kW—the Commission has the discretion to redefine the parameters of the Large C&I class to include these additional customers without violating the "prudent mix" standard, consistent with the Policy Statement at 52 Pa. Code § 69.1805.

b. RESA's Exceptions

RESA also faults the ALJ's recommendation that PPL's proposal be rejected, claiming that the ALJ did not conduct a thorough analysis of all the requirements of the Competition Act in arriving at her conclusion. RESA Exc. at 1-2. RESA argues that the ALJ correctly noted the "prudent mix" requirement in the Competition Act, but failed to recognize that the Competition Act contains other relevant sections that need to be considered. Specifically, RESA asserts that the ALJ's analysis ignored the fact that the Competition Act also states that transitioning customers to the competitive market is in the public interest because of the effectiveness of market forces in controlling the cost of electric generation. *Id*. at 5 (citing 66 Pa. C.S. §§ 2802(3) and 2802(5)). In this regard, RESA notes the Commonwealth Court's statement that the Competition Act was enacted to establish competition in the sale of electric power, placing an affirmative mandate on the Commission to foster competition in order to provide cost savings to consumers. RESA Exc. at 5 (citing *ARIPPA v. Pennsylvania Public Utility Commission*, 792 A.2d 636, 642, 654 n. 30; (Pa. Cmwlth. 2002); *PP&L Industrial Customer Alliance v. PUC,* 780 A. 2d 773, 776 (Pa. Cmwlth. 2001). Thus, RESA avers that in addition to ensuring that the specific requirements of Section 2807(e)(3.1) regarding procurement plan design are satisfied, the Commission is also legally required to make sure the default service plan promotes the development of a workably competitive retail generation market. RESA Exc. at 5.

RESA contends that the ALJ focused only on the product mix for C&I customers with demand at or above 100 kW to conclude that PPL's proposal is not consistent with the "prudent mix" goal of the Competition Act, and did not discuss how the goals of competition and direct access to the competitive market would be accomplished by denying hourly-priced service to C&I customers. *Id*. at 5-6. RESA also criticizes the ALJ's conclusion that a 5% decrease in the shopping rate for the Small C&I customers illustrates a preference by these customers for the current full-requirements load following contracts approach. According to RESA, the ALJ's belief that a default service plan should be designed to satisfy what she believes to be the preferences of customers based on her interpretation of shopping statistics lacks evidentiary support, and fails to achieve all the goals of the Competition Act. *Id*. at 6.

RESA opines that the evidence in this proceeding makes clear that all the requirements of the Competition Act would be satisfied by adopting PPL's proposal. Specifically, RESA maintains that hourly default service pricing is a more sustainable design that promotes the development of a robust competitive retail market, resulting in a variety of products and services for customers, and leading to least cost over time. RESA contends that hourly pricing avoids the "boom" or "bust" business cycle that can result during times when retail competition is stifled, because longer-term fixed price service fails to reflect current market conditions. RESA also contends that hourly pricing leads to more accurate price signals, thereby encouraging energy conservation and demand response. RESA Exc. at 6-7.

Finally, RESA asserts that the Commission has expressed its preference for the expansion of hourly-priced default service for C&I customers with demand at or above 100 kW on a number of occasions, including the *End State Order*, wherein the

Commission stated its expectation that EDCs would offer only hourly LMP to medium and large C&I customers with interval meters, effective June 1, 2015. *Id*. at 8-9 (citing *End State Order* at 29, 31). RESA contends that the ALJ's attempt to isolate and compare 52 Pa. Code § 69.1805(2) and the *End State Order* misses the point that the market continues to evolve, and that the Commission has made it clear that its policies would continue to evolve. RESA states that there is nothing illegal about the *End State Order*, and nothing to justify the ALJ's recommendation that it be disregarded. Rather, RESA asserts that PPL's proposal to lower the hourly demand threshold for C&I customers to 100 kW is supported by the evidence of record, and fully satisfies all the requirements of the Competition Act. RESA Exc. at 9.

c. OSBA's Replies to Exceptions

In its Reply to PPL's Exceptions, the OSBA argues that PPL's reliance on the Pike County case, in which the Commonwealth Court upheld the Commission's authority to move customers to the hourly spot market, was misplaced. The OSBA contends that the circumstances affecting Pike County are not relevant to PPL's Small C&I customers with loads between 100 and 500 kW. Specifically, the OSBA states that while Pike County procures its default service supplies on an hourly basis, it sets its prices on a quarterly basis, as opposed to the hourly basis proposed by PPL. In addition, the OSBA asserts that, at the time hourly default service pricing was implemented, Pike County was a "tiny" utility where most of its customers were shopping under a Commission-sponsored aggregation plan. OSBA R. Exc. at 4. The OSBA further asserts that stable prices were readily available from competitive suppliers, while Pike County's ability to contract for stable priced supplies from the wholesale market for its small default service load was limited. *Id*. (citing *Petition of Pike County Light & Power Company*, Docket No. P-2008-2044561 (Order entered March 23, 2009) at 14-15).

With regard to PPL's assertion that its proposal to drop the Small C&I customer size limit from 500 to 100 kW is consistent with the *End State Order*, the OSBA contends that consistency with the *End State Order* is not a basis for the Company to remove 13.7 percent of the Small C&I customer load from those customers' current choice for stable rate default service. The OSBA avers that the *End State Order* is not a legal mandate, but rather, is a statement by the Commission as to what it envisions for the future of default service. The OSBA states that the Commission itself expressed its concern regarding the legality of moving medium C&I customers, with maximum demand between 100 and 500 kW, from stable-rate default service to hourly-priced service. OSBA R. Exc. at 5-6 (citing *End State Order* at 45).

The OSBA also argues that PPL's reliance on 52 Pa. Code § 69.1805 does not support approval of its proposal or the legal authority of the *End State Order*. The OSBA contends that PPL provided no evidence that its proposal to reduce the demand limit from 500 to 100 kW for Small C&I customers will "ensure least cost" to customers," consistent with 52 Pa. Code § 69.1805. OSBA R. Exc. at 6.

In its Reply to RESA's Exceptions, the OSBA disagrees with RESA's criticism of the ALJ's legal analysis regarding PPL's proposal, and her alleged failure to recognize that the Competition Act requires a default service plan to be designed to promote competition and direct access to the competitive market. The OSBA contends that RESA ignores the fact that the 430 Small C&I customers that would be affected by PPL's proposal already have complete access to the competitive market, and that they have all decided that taking default service from PPL is superior to competitive options. The OSBA further contends that RESA ignores the fact that shopping in the Small C&I class is already robust, and therefore, the existing procurement and pricing mechanism for these customers is not imposing any unreasonable bar to competition. OSBA R. Exc. at 7-8. Thus, the OSBA asserts that "the ALJ's legal analysis missed nothing," because there is already a fully robust competitive market in PPL's service territory. *Id*. at 8.

The OSBA also dismisses RESA's argument that hourly pricing avoids the "boom" or "bust" business cycle and provides more accurate price signals, contending that such an argument is irrelevant and of no legal significance. *Id*. at 8-9. The OSBA asserts that "more accurate price signals" is RESA's way of demanding "market reflective" pricing, which is not the current legal standard for judging default service rates, as the Commission has made clear. *Id*. at 9 (citing *Final Default Service Rulemaking Order* at 39-40).

In response to RESA's argument that the Commission expects EDCs to offer only hourly LMP to medium and large C&I customers after June 1, 2015, as set forth in the *End State Order*, the OSBA notes the Commission's assertion that it would prefer to pursue legislative amendments that would provide the authority to approve default service plans that would include more market-based products. OSBA R. Exc. at 9-10 (citing *End State Order* at 45). The OSBA contends that no such legislative amendments have been adopted. Therefore, the OSBA concludes that, contrary to RESA's assertion that the ALJ disregarded the *End State Order* in her analysis of PPL's proposal, the ALJ simply recognized that the *End State Order* is not tantamount to a Regulation or Statute. Reply Exc. at 10 (citing R.D. 45).

4. Disposition

Upon consideration of the Parties' arguments, the record evidence, and applicable law, we will reverse the ALJ's recommendation on this issue and adopt PPL's proposal. We do not agree with the ALJ that a downward adjustment to the peak demand threshold from 500 kW to 100 kW for the Large C&I customer class is contrary to the Competition Act. We find nothing in the Competition Act that precludes us from approving a proposal that would result in some 430 additional C&I customers receiving hourly-priced default service supply. Indeed, we find the proposal to be consistent with the Competition Act's goals of promoting a competitive marketplace for electricity, and ensuring that customers receive adequate and reliable service at the least cost over time. *See*, 66 Pa. C.S. §§ 2802(7) and 2807(e)(3.4). As we stated in the *End State Order*, "[s]pot market prices tend to produce the 'least cost to consumers over time' because lower risk premiums are included in spot-market-priced contracts due to the reduced uncertainty of recovery for wholesalers of costs related to generation and transmission services." *End State Order* at 15.

In addition, in the *End State Order*, we expressed our support for the threshold of 100 kW for purposes of determining medium and large C&I customers, but stated our expectation that EDCs would "offer hourly LMP products only to the customers above that demand level who have interval meters." *End State Order* at 31. In this case, PPL indicated that all of the customers affected by its proposal to lower the demand threshold to 100 kW for the Large C&I class are equipped with demand meters. Furthermore, PPL stated that 88% of these customers are currently shopping. PPL M.B. at 14. Thus, we agree with the Company that these customers "are well-equipped and educated to manage their commodity costs in an hourly spot market default service environment." *Id*.; *See also, End State Order* at 29. As for the OSBA's concern that customers affected by PPL's proposal will be deprived of fixed-price service that may provide greater price stability, we believe that C&I customers' desire for fixed-price products can be adequately addressed though the competitive offerings of EGSs.

The ALJ appears to believe that a single, hourly-priced spot market product for the C&I customers affected by PPL's proposal does not meet the "prudent mix" standard of the Competition Act. However, we agree with PPL that the Competition Act does not require that multiple products necessarily be procured for each customer class of a default service provider, but rather, requires that a default service plan as a whole include a prudent mix of spot market purchases, short-term products, and long-term purchase contracts as necessary to ensure adequate and reliable service to customers at the least cost over time. *See*, 66 Pa. C.S. §§ 2802(e)(3.2) and 2807(e)(3.4). In addition, as PPL points out, the Commonwealth Court recently upheld the Commission's approval of a default service plan for Pike County that included only spot market purchases, finding that the Commission properly determined that a "prudent mix" of products may include only one of the sources enumerated in 66 Pa. C.S. 2807(e)(3.2) when this is the most prudent course and is likely to incur the least cost over time. *Popowsky* at 1116-1117.

The OSBA argues that the circumstances presented in the Pike County proceeding were markedly different from those in the instant proceeding, and the ALJ appears to agree, referring to the Pike County situation as a "specific exception." R.D. at 43. However, regardless of how different the specific circumstances may be, the Court found that the Commission's interpretation of 66 Pa. C.S. 2807(e)(3.2) properly allowed for the possibility that a single procurement source may constitute a "prudent mix" of sources when the evidence supports such a conclusion. Similarly, in this case, we find that PPL's proposal, which will result in the expansion of hourly-priced default service to an additional group of C&I customers, will result in least-cost service over time for these customers, and constitutes part of a prudent mix of products included in PPL's overall DSP III program, consistent with 66 Pa. C.S. 2807(e)(3.2). Moreover, this Commission has approved hourly pricing for C&I customers on a number of prior occasions. *See, e.g.*, *PPL DSP II*; *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-2013-2391368, P-2013-2391372, P-2013-2391375, P-2013-2391378 (Opinion and Order entered July 24, 2014) (*FirstEnergy DSP III Order)*; *Petition of PECO Energy Company for Approval of its Default Service Program for the period from June 1, 2015 through May 31, 2017,* Docket No. P-2014-2409362 (Opinion and Order entered December 4, 2014).

Finally, we do not agree with arguments suggesting that we are precluded from permitting EDCs to expand the availability of hourly-priced products to C&I customers with demand between 100 kW and 500 kW because of certain pronouncements we made in the *End State Order*. While we expressed a preference for legislative amendments that would provide the authority to approve default service plans containing more market-based products, we also stated our belief that "the Commission appears *currently* to have authority to establish shorter-term default service products that are more reflective of market conditions than existing products." *End State Order* at 45-46 (emphasis added). In the instant proceeding, we are not attempting to revise what the General Assembly has determined to constitute a prudent mix of products as enumerated in 66 Pa. C.S. 2807(e)(3.2). Rather, we are simply approving the proposed expansion of hourly-priced default service to an additional group of C&I customers who, as we stated above, appear to be "well-equipped and educated to manage their commodity costs in an hourly spot market default service environment," and who we believe will receive the benefits of reliable service at the least cost over time as a result, in accordance with 2807(e)(3.4).

Consistent with the above discussion, we will grant the Exceptions of PPL and RESA on this issue, and we will reverse the ALJ's recommendation and approve PPL's proposal to reduce the peak demand threshold for Large C&I customers from 500 kW to 100 kW.

B. Recovery of Non-Market-Based Charges

Under the SMA in PPL's proposed DSP III program, PPL is responsible for the following NMB costs for default service customers:

- Network Integration Transmission Services (NITS)
- Transmission Enhancement Costs

- Expansion Cost Recovery Costs
- Non-firm Point-to-Point Transmission Service Credits
- Regional Transmission Expansion Plan (RTEP)
- Generation Deactivation Charges

The wholesale supplier is responsible for all other costs. In addition, PPL's responsibility for these NMB costs relates to default service only, and the Company recovers these costs from its default service customers through its TSC. All costs incurred by retail EGSs, including NMB costs, are the responsibility of the EGS. PPL M.B. at 15; PPL St. 1-R at 42; PPL Exh. 1, Attachment B, Appendix C; PPL Exh. JMR-9-R.

PPL noted that this assignment of NMB cost responsibility is identical to that approved in its DSP II program. PPL has not proposed to change the responsibility for NMB charges in its DSP III program. PPL M.B. at 15. Moreover, PPL noted that proposals to hold PPL responsible for NMB costs relating to both default service load and shopping load were rejected by the Commission in the *PPL DSP II Order*. *Id*. at 17.

1. Positions of the Parties

a. RESA's Position

RESA and ExGen both take issue with PPL's plan to retain the current arrangement with regard to NMB cost responsibility in its DSP III program. RESA recommends that PPL be directed to assume the cost responsibility for the NMB costs on behalf of *both* the wholesale default service suppliers *and* EGSs, and to recover these costs from all customers—both default service customers and shopping customers—through a non-bypassable charge. RESA M.B. at 8-9. RESA asserted that NMB costs are unpredictable and cannot be hedged by competitive retail suppliers or wholesale default service suppliers. *Id*. at 9. Thus, RESA contended that allowing PPL to assume the cost responsibility for these costs on behalf of only wholesale default service suppliers rather than for all load unfairly shifts a competitive advantage to PPL for default service, because the wholesale default service suppliers will not be required to factor the risk of future price increases in NMB charges into the bids they submit for default service supply. PPL will simply pass through the NMB charges to its default service customers through its TSC rider without any additional amount to account for the risk of future price increases to these charges. In contrast, RESA asserted that the retail price offered by EGSs must account for the current transmission rate, as well as an amount to account for the risk of potential future increases in the NMB charges. Thus, RESA stated that shopping customers may be required to pay more if an EGS chooses to embed a risk premium into its pricing. *Id*. at 12.

RESA noted that in *PPL DSP II*, the Commission concluded that EGSs had the ability to adjust to changes in NMB costs through special contract terms with their customers, while wholesale suppliers do not. *Id*. at 13 (citing *PPL DSP II Order* at 86). However, RESA argued that this option has now been curtailed by the Commission's determination that a "fixed price" product must not change in price during the term of the agreement. *Id*. at 13 (citing *Guidelines for Use of Fixed Price Labels for Products With a Pass-Through Clause*, Docket No. M-2013-2362961 (Final Order entered November 14, 2013) (*Fixed Price Order*)). RESA contended that, in accordance with the *Fixed Price Order*, an EGS is not permitted to offer a fixed price product to mass market customers that is subsequently adjusted for increases to NMB charges, unless the EGS provides notice to its customers of its intent to alter the contractual price. If the customer does not affirmatively accept the new price, then the EGS must cancel the contract without customer penalty. RESA. M.B. at 13, 17 (citing *Fixed Price Order* at 26). However, RESA asserted that an EDC has the right of full cost recovery and default service reconciliation. Thus, RESA concluded that the only fair and equitable approach is for PPL to assume the costs of NMB charges on behalf of both wholesale default service suppliers *and* EGSs. RESA M.B. at 13.

RESA noted that in *FirstEnergy DSP III*, the Commission determined that requiring an EDC to assume the cost responsibility on behalf of all load and to recover the costs from all customers through a non-bypassable charge did not violate the Competition Act, the Code, or the Commission's Regulations. *Id*. (citing *FirstEnergy DSP III Order* at 38). However, RESA opined that when an EDC assumes the responsibility for NMB charges for default service suppliers but not for EGSs, the result is inconsistent with the Competition Act because the EDC can leverage its ability to receive full cost recovery on the NMB charges to impact the default service rate. Thus, RESA argued that PPL's approach with regard to NMB charges amounts to discriminatory and advantageous access to its facilities for wholesale default service suppliers vis-à-vis EGSs, in violation of the Competition Act. RESA M.B. at 14-15 (citing 66 Pa. C.S. §§ 2803 and 2804(6)).

RESA pointed out that while the Commission rejected a proposal that NITS costs relating to all load be recovered through a non-bypassable charge in *FirstEnergy DSP III*, it did adopt the parties' settlement in that proceeding to require such a proposal with regard to other NMB charges. *See*, *FirstEnergy DSP III Order* at 22-23, 53. Thus, RESA concluded that there is no legal bar to adopting RESA's preferred approach with regard to all NMB charges. RESA M.B. at 16. In addition, RESA contended that this case is distinguishable from *FirstEnergy DSP III* because the FirstEnergy Companies never assumed the cost responsibility for NMB charges on behalf of the wholesale default suppliers, but rather, the suppliers assumed their own cost responsibility. RESA also stated that the Commission made it clear in the *FirstEnergy DSP III Order* that it based its decision on the record in that proceeding, and not because it was constrained by the doctrine of issue preclusion to reach the same conclusion it reached in FirstEnergy's DSP II proceeding. *Id*. at 16 (citing *FirstEnergy DSP III Order* at 53). Thus, RESA argued that the Commission's rejection of proposals to shift NMB cost responsibility to

PPL for all load in the *PPL DSP II Order* does not preclude adoption of its proposal in this proceeding. RESA M.B. at 16-17.

RESA averred that any customer transition issues resulting from adopting its proposal can be adequately addressed, as they were with regard to the FirstEnergy Companies. For example, RESA contended that the proposed change in cost responsibility for NMB charges could be limited to new charges, thus eliminating concerns of double recovery of costs that are already embedded in existing EGS contracts. Alternatively, RESA stated that the change in cost responsibility could be deferred to a later date, such as June 2016, to provide a transition period during which many EGS contracts would expire and renew. The new renewal rates would then reflect removal of the cost obligations from the EGSs, which also would address concerns of double recovery. *Id*. at 18-19.

Finally, RESA stated that if the Commission does not adopt its proposal that PPL take on the cost responsibility for NMB charges with respect to all load, and recover the costs from all customers through a non-bypassable charge, then PPL should be directed to modify its SMA to require that wholesale default service suppliers assume their own cost responsibility for the default service load, just as EGSs assume the cost responsibility for shopping customers. RESA argued that, while this would not be the ideal approach because it would result in the need for wholesale suppliers to account for the risk of increases to NMB charges in their bid prices, it would at least put the wholesale suppliers on equal footing with EGSs, who also must include a risk premium in their retail prices. *Id*. at 19-20; RESA St. No. 1-SR at 12-13.

b. ExGen's Position

ExGen also proposed that PPL be responsible for all NMB charges, and that it recover these charges through its TSC from both default service customers and shopping customers. ExGen St. No. 1 at 4-5. Similar to RESA, ExGen argued that the *Fixed Price Order* limits an EGS's ability to pass through unanticipated costs, such as unhedgable NMB costs, to customers with fixed-price contracts. ExGen asserted that if EGSs must account for NMB costs themselves, they are more likely to either offer variable-priced products or include premiums in their fixed-priced offers to account for the risk of changes in the NMB costs. Thus, ExGen contended that customers will end up paying higher prices regardless of whether or not NMB costs change over the term of the fixed-priced contracts. According to ExGen, allowing NMB charges to be collected by the EDC from all distribution customers will best allow EGSs to continue to offer competitive fixed-price contracts to shopping customers. *Id*. at 5-6.

ExGen also asserted that its NMB proposal is not prohibited by the Competition Act, and may, in fact, be considered more consistent with the provisions of the Competition Act in that it allows generation and other related products to be the primary focus of competitive offers from EGSs, while the EDC would be responsible for the costs of transmission and distribution services. ExGen R.B. at 8-9 (citing 66 Pa. C.S. §§ 2802(16) and 2803). ExGen also argued that there is nothing in the Commission's Regulations that require EGSs to be responsible for recovering NMB costs from their retail customers. ExGen R.B. at 11-14. In addition, ExGen agreed with RESA that there are reasonable ways of dealing with any customer transition issues that may arise if its proposal is adopted. *Id*. at 15.

c. PPL's Position

PPL contended that because RESA's and ExGen's proposals regarding NMB costs are entirely outside the proposals set forth in the Company's DSP III program, those parties bear the burden of proof with respect to their proposals. PPL asserted that RESA and ExGen have failed to meet their burden of proof, and therefore, their proposals should be rejected. PPL M.B. at 16

PPL argued that RESA's and ExGen's proposals are inconsistent with PJM rules, under which all Load Serving Entities (LSEs)[10] are charged market-based and NMB costs based on each LSE's share of the load served. Thus, PPL stated that each EGS bears the costs for the customers served by that EGS, and PPL bears the costs for its default service customers. PPL contended that it would not be appropriate to make the Company pay the NMB costs for shopping customers, for whom it does not provide generation service. *Id*. at 16-17; R.B. at 17-18.

With regard to RESA's contention that NMB costs are unpredictable and cannot be hedged, PPL stated that RESA provided only one example in which NITS charges increased in the PPL Zone between January 1, 2013, and June 1, 2013. PPL R.B. at 15 (citing RESA M.B. at 10-11). PPL noted that the Commission recently found that such a single instance is insufficient to demonstrate the alleged volatility. PPL R.B. at 15 (citing *FirstEnergy DSP III Order* at 31-32). Moreover, PPL asserted that the fact that NMB charges may be variable or difficult to hedge is irrelevant to determining the proper cost responsibility for these charges because every LSE must be held responsible for the costs relating to its share of the load. PPL M.B. at 18. In addition, PPL contended that there is no evidence that the unpredictability or unhedgability of NMB charges has changed since the Commission's decision in *PPL DSP II*. *Id.* at 19. As for the concern that EGSs must add a risk premium to their prices, PPL argued that this pricing structure is part of the reality of managing risk in a competitive industry, and that EGSs are aware of this structure when they enter the market and choose to compete under these conditions. *Id*.

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[10] PPL notes that "[u]nder the PJM rules, a LSE is defined as 'any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer that (a) serves end-users within the PJM Control Area, and (b) is granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Control Area.'" PPL M.B. at 16, n.10 (citing PPL St. No. 3-R at 13).

PPL also argued that, in its *Fixed Price Order*, "the Commission clearly explained that the 'price an EGS presents to residential or small business customers is expected to be "all inclusive" – including all of the pricing components found in the PTC for default customers (generation, transmission where applicable, gross receipts tax, etc.).'" *Id*. at 20 (quoting *Fixed Price Order* at 28). In addition, PPL noted that the *Fixed Price Order* permits EGSs to reformulate existing contracts with customers by proposing new contract terms to fully account for unanticipated changes in costs, including NMB charges. PPL M.B. at 21.

Additionally, PPL contended that if the EDC were to develop a non-bypassable clause to recover the NMB charges from all customers, every customer with every EGS would need a revised contract effective on the date on which the change took place in order to avoid customers paying both the EDC and EGS for the same transmission costs. Furthermore, PPL asserted that changing the cost responsibility for NMB charges from the EGS to PPL will deprive customers, as well as the EGS, of the bargain they negotiated in fixed-price contracts that do not allow for changes due to NMB charges. *Id*.

Finally, PPL stated that in *FirstEnergy DSP III*, the Commission considered and rejected RESA's and ExGen's arguments that the unpredictable and unhedgable nature of NMB charges, and the Commission's determinations in the *Fixed Price Order*, justified the non-bypassable nature of NMB charges. *Id*. at 21-22 (citing *FirstEnergy DSP III Order* at 31-32). PPL asserted that neither RESA nor ExGen has offered any reason or evidence to depart from the Commission's decision in that proceeding. PPL M.B. at 22.

d. PPLICA's Position

PPLICA also opposes RESA's and ExGen's proposals to require PPL to be responsible for the NMB costs relating to all customer load, and to recover those costs through a non-bypassable charge. PPLICA contended that the record evidence indicates that NMB costs are not volatile as RESA claims. PPLICA asserted that, in support of its allegations of such volatility, RESA relied upon a single instance involving a NITS rate increase of 52% in the PPL zone between January 1, 2013, and June 1, 2013, which PPLICA characterizes as an "outlier" in comparison to data showing more moderate changes in NITS charges. PPLICA M.B. at 13. In addition, PPLICA stated that NITS charges are calculated on an annual basis, with a thirty-day notice provided before the rates take effect on June 1, the first day of the PJM Planning Year. *Id*. (citing PPL St. No. 3-R at 7). Moreover, PPLICA contended that in *FirstEnergy DSP III,* the Commission found that NITS should not be recovered through a non-bypassable rider because the evidence of a single increase offered to show volatility in NITS costs was unconvincing. PPLICA M.B. at 13 (citing *FirstEnergy DSP III Order* at 31).

With regard to RESA's contention that, unlike EGSs, PPL can pass through NITS charges without reflecting a risk premium in its price for generation supply, PPLICA asserted that an EGS can negotiate a pass-through clause with its customers, as has been done by many Large C&I customers. PPLICA M.B. at 15. Moreover, PPLICA argued that the *Fixed Price Order* does not prevent EGSs from doing this, as RESA contended, but simply prohibits EGSs from including variable-price components and regulatory-out clauses in fixed-price contracts. *Id*. at 14 (citing *Fixed Price Order* at 21-23). PPLICA also argued that Large C&I customers are often willing to pay a risk premium in fixed-price contracts with EGSs for various reasons, including avoiding market volatility and establishing firm budgets, an option that a non-bypassable rider would remove. PPLICA M.B. at 15, 18-19. PPLICA further argued that having PPL collect NMB costs from all customers would effectively re-bundle transmission and distribution, in violation of the Competition Act. *Id*. at 15-16 (citing 66 Pa. C.S. §§ 2802(13) and 2804(3).

PPLICA also contended that there would be significant transitional issues if RESA's and ExGen's proposals were adopted. Specifically, PPLICA expressed concern regarding the effect of these proposals on existing fixed-price contracts that Large C&I customers have with EGSs, which may already include recovery of transmission-related charges. PPLICA argued that it would be difficult to determine how to adjust those contracts to properly remove the transmission and transmission-related costs that PPL would recover through a non-bypassable charge in order to avoid double recovery of those costs. *Id*. at 19-21. PPLICA contended that RESA's proposed solutions to such concerns are inadequate because they fail to address all potential problems that may arise. *Id*. at 21-22; R.B. at 12-14. In addition, PPLICA asserted that the record contains no details with regard to the methodology that would be used to collect the NMB costs from all customers, or with regard to how such costs would be allocated among the rate classes, and how customers would be impacted by these changes. PPLICA M.B. at 22-23.

Finally, PPLICA stated that, should the Commission approved a non-bypassable rider for the collection of any transmission or transmission-related costs, it should also approve a carve-out for Large C&I customers. PPLICA asserted that Large C&I customers in PPL's service territory have successfully utilized the existing market structure, with 98.6% of these customers taking competitive supply from EGSs. Thus, PPLICA argued that "there is no need to make changes creating unnecessary restrictions on available competitive products (*i.e.* eliminating fixed price arrangements for transmission and transmission-related costs) and imposing transitional risks to Large C&I customers in PPL's service territory." *Id*. at 23, n.13.

e. Noble Americas' Position

Noble Americas supports PPL's DSP III as filed, which continues to require LSEs, such as EGSs, to maintain responsibility for the PJM charges assigned to them, and opposes RESA's and ExGen's proposal that PPL recover these charges from all customers through a non-bypassable rider. Noble Americas contended that NMB costs are manageable and predictable, and that an EGS's ability to manage such costs is an acceptable responsibility and inherent risk of competing in the retail market. Noble Americas M.B. at 3. Noble Americas also argued that adopting a non-bypassable rider would have an adverse effect on the shopping decisions of customers, and would limit a customer's ability to negotiate contracts relative to a variety of competitive retail products. *Id*. at 4.

Noble Americas also expressed concern regarding possible double recovery of NMB costs, and the effect on existing contracts between customers and EGSs. *Id*. at 4-5. In addition, Noble Americas asserted that "any attempt to divide customers up by volume with respect to the treatment of NITS would be very problematic in terms of settlements with PJM, which does not recognize any artificial division of load." *Id*. at 5. However, Nobel Americas submitted that, should the Commission adopt the approach proposed by RESA and ExGen, the entire load should be moved to a non-bypassable charge for Independent System Operator settlement purposes, and the proposal should not become effective without three years advance notice to avoid affecting current retail contracts. *Id*.

2. ALJ's Recommendation

Initially, the ALJ found that RESA and ExGen bear the burden of proof with regard to this issue. The ALJ stated that, while PPL has the ultimate burden of proof in this proceeding, and the initial burden of going forward with evidence showing that its proposals are lawful and reasonable, the proposal at issue here was not raised by the Company, and therefore, the burden of proof lies with those parties who raised it. R.D. at 46.

The ALJ then noted that PPL proposed no change in its approach regarding NMB costs from that approved by the Commission in *PPL DSP II*. *Id*. at 47 (citing *PPL DSP II Order* at 85). The ALJ further noted that in *FirstEnergy DSP III*, the Commission affirmed its prior decision, set forth in *FirstEnergy DSP II*, that NITS costs should not be collected through the FirstEnergy Companies' non-bypassable rider. R.D. at 47-48 (citing *FirstEnergy DSP III Order* at 31-32). The ALJ asserted that "the Commission has repeatedly and consistently decided that the NMB costs should be assigned to those served by the load which is accompanied by those costs." R.D. at 48. Thus, the ALJ concluded that RESA's and ExGen's proposals to aggregate the NMB costs and spread them evenly among all customers is not consistent with prior Commission decisions on this issue. *Id*.

The ALJ agreed with PPL that EGSs are the LSEs for shopping customers, and stated that it is unclear whether PJM rules would permit a third party to assume the LSEs' obligations to pay NMB charges. In addition, the ALJ stated that the record contains no details regarding the implementation of RESA's and ExGen's proposals, which makes it impossible to evaluate the extent to which the proposals may shift costs. *Id*. at 49.

The ALJ also agreed with PPLICA's concern that the imposition of a non-bypassable rider to recover NMB costs would re-bundle transmission and distribution costs in violation of the Competition Act. *Id*. at 50. The ALJ stated that this concern is consistent with the Commission's position in Duquesne Light Company's prior default service plan proceeding, in which the Commission determined that RESA's proposal that a non-bypassable charge be established to recover certain transmission-related charges would be a step backward because it would result in the re-bundling of transmission costs with distribution costs. *Id*. at 50-51 (citing *Petition of Duquesne Light Company for Approval of Default Service Program and Procurement Plan for the Period of June 1, 2013 Through May 31, 2015,* Docket No. P-2012-2301664 (Opinion and Order entered January 25, 2013) (*Duquesne Light DSP VI Order*) at 222. The ALJ also found that, from the point of view of a large industrial or commercial energy user, there is a concern that the imposition of a non-bypassable rider to recover NMB costs would create significant contractual and double collection concerns, which would have to be addressed before such a rider could be implemented. R.D. at 51.

The ALJ concluded that the record in this case contains no persuasive evidence to support a modification to the present method used by PPL for the collection of transmission and transmission-related costs. Therefore, the ALJ recommended that RESA's and ExGen's proposals to require PPL to recover NMB charges through a non-bypassable rider be denied. *Id*.

3. Exceptions and Replies

a. RESA's Exceptions

In its Exceptions, RESA asserts that the ALJ erred in recommending rejection of its proposal that PPL be required to recover the NMB costs from all distribution customers through a non-bypassable surcharge. RESA opines that the record fully supports rejecting the ALJ's recommendation. RESA Exc. at 9.

RESA reiterates its position that the amount paid by all customers through a non-bypassable charge would be only the actual costs of the NMB charges, because there would be no need to factor in a risk premium to account for the unpredictability and unhedgability of NMB charges. RESA asserts that when the EDC assumes the cost of

NMB charges for all load, no customers will need to pay anything beyond the actual costs of these charges, because the EDC is permitted to recover all reasonable costs incurred to provide default service on a full and current basis pursuant to a reconcilable adjustment clause. However, RESA contends that under PPL's current and preferred approach, EGSs are required to determine how to factor risk premiums into their retail pricing, while wholesale suppliers have no need to include risk premiums in their default service supply bids. Furthermore, RESA argues that if an EGS does not include a risk premium in the retail price it charges its customers, it may be required to absorb the costs of NMB charges that it was not able to account for in the price. RESA asserts that its proposal would resolve this inequity and ensure that all customers pay only the actual costs of the NMB charges. *Id*. at 10-12.

RESA states that the Commission has already concluded that there is no legal bar to requiring PPL to assume the cost responsibility for NMB charges. *Id*. at 12 (citing *FirstEnergy DSP III Order*). In contrast, RESA contends that allowing PPL to continue assuming cost responsibility for wholesale suppliers but not for EGSs is contrary to the Competition Act, which requires that EDCs allow EGSs to utilize the electric transmission and distribution system on a non-discriminatory basis, at rates, terms and conditions of service that are comparable to the utilities' own use of the system. RESA Exc. at 12 (citing 66 Pa. C.S. §§ 2803 and 2804(6)). According to RESA, if an EDC assumes NMB cost responsibility for wholesale default service suppliers but not for EGSs, then only the wholesale suppliers receive the benefit of the EDCs right to full cost recovery of NMB charges, which amounts to discriminatory access in violation of the Competition Act. RESA Exc. at 13.

RESA argues that the only way to satisfy the non-discriminatory access requirements of the Competition Act and to ensure that all customers pay the actual costs of NMB charges is to require the EDC to assume the cost responsibility for these charges on behalf of both the wholesale default service suppliers and the EGSs. *Id*. In the alternative, RESA recommends that the Commission adopt an approach similar to that approved in *FirstEnergy DSP III*. Specifically, RESA recommends that wholesale default service suppliers be required to assume cost responsibility for NITS, and PPL should be directed to assume cost responsibility for Transmission Enhancement Costs, Expansion Cost Recovery Costs, Non-firm Point-to-Point Transmission Service Credits, Regional Transmission Expansion Plan, and Generation Deactivation Charges. *Id*. at 14-15.

b. PPL's Reply to RESA's Exceptions

In its Reply to RESA's Exceptions, PPL asserts that the ALJ properly determined that RESA bears the burden of proof on this issue, and failed to meet that burden. PPL R. Exc. at 2. PPL agrees that because RESA's proposal to shift cost responsibility for NMB charges is entirely outside the proposals set forth in its DSP III program, and because the Commission rejected such a proposal in the Company's DSP II proceeding, RESA has the burden to provide credible evidence sufficient to demonstrate a change in circumstances from DSP II to DSP III that would justify a departure from the approach previously approved by the Commission. PPL R. Exc. at 3-4 (citing *FirstEnergy DSP III Order* at 31-32).

With regard to RESA's assertion of the unpredictability of NMB charges, PPL contends that there is no evidence in this proceeding that these charges are any more unpredictable or unhedgable than they were in the DSP II proceeding. PPL further argues that there is no basis in law, fact or policy to support the position that EGSs should bear the costs to serve its own customers only when those costs can be hedged. Moreover, PPL avers that EGSs have the ability to pass through unanticipated NMB charges to their customers, and that the *Fixed Price Order* does not foreclose this ability as RESA contends. PPL R. Exc. at 4-5.

With respect to RESA's contention that its proposal is consistent with the Commission's decision in the *FirstEnergy DSP III*, PPL asserts that the Commission's decision to allow the FirstEnergy Companies to assume cost responsibility for some, but not all, NMB charges was the result of a settlement in that proceeding. Moreover, PPL argues that the *FirstEnergy DSP III Order* "unequivocally rejected the very same arguments raised by RESA in this proceeding." *Id*. at 5 (citing PPL M.B. at 20; PPL R.B. at 19-20). In addition, PPL contends that RESA failed to provide any details regarding how its proposal would be implemented in this proceeding, including the methodology for recovering NMB costs through the proposed non-bypassable rider. PPL argues that without such information, it is not possible to determine to what extent the proposal might shift costs between shopping and non-shopping customers. PPL R. Exc. at 5-6.

PPL also dismisses RESA's argument that the Company's different treatment of NMB charges between EGSs and wholesale default suppliers is discriminatory, in violation of the Competition Act. PPL argues that EGSs and wholesale suppliers are not similarly situated, because EGSs provide retail competitive supply to end-use shopping customers, while wholesale suppliers do not serve end-use customers, but provide wholesale electric supply to EDCs that serve as the default supply provider to non-shopping customers. Thus, PPL contends that the circumstances under which these entities provide electric generation supply, and the contracts, risks, premiums, terms and conditions involved in these differing transactions, are not at all similar. Therefore, PPL states that different treatment of these different entities cannot be seen as discriminatory, as RESA suggests. *Id*. at 7-8.

PPL further contends that Sections 2803 and 2804(6) of the Code, which RESA cites in support of its unlawful discrimination argument, have nothing to do with NMB charges. PPL argues that these sections are not about access to the Company's default service cost recovery mechanism, but about equal and open access to its transmission and distribution systems. PPL avers that there is nothing on the record in this proceeding to suggest that EGSs do not have equal and open access to PPL's transmission and distribution systems. *Id*. at 8.

PPL also argues that, under PJM rules, all LSEs are charged market-based and NMB costs base on each LSE's share of the load served, and that each LSE is obligate to pay those costs. PPL asserts that it is undisputed that EGSs are the LSEs for shopping customers and PPL is the LSE for default service customers, and therefore, the EGS must bear the costs for the shopping load it serves, and PPL must bear the costs for the default service load it serves. In addition, PPL contends that the Commission previously concluded in *PPL DSP II* that NMB costs should be recovered from customers by the entity that serves the customers. *Id*. at 9 (citing *PPL DSP II Order* at 85).

Finally, PPL opposes RESA's alternative proposal that the Commission adopt an approach similar to that approved in *FirstEnergy DSP III* with regard to NMB charges, in which the EDC would assume cost responsibility for some, but not all, NMB charges. PPL points out that the Commission's decision in that proceeding was the result of a settlement, and argues that the FirstEnergy Companies' agreement to adopt that approach does not mean it is acceptable for all other EDCs. PPL R. Exc. at 10. PPL further notes that the settlement petition in that proceeding clearly indicated that it was not binding on any party, and asserts that it is certainly not binding on PPL, which was not a party to that settlement. Moreover, PPL contends that RESA's proposal is not consistent with the *FirstEnergy DSP III Order*, which, according to PPL, rejected RESA's argument that the unpredictable and unhedgable nature of NMB charges, as well as the *Fixed Price Order*, justified the non-bypassable collection of NMB charges. *Id*. at 11. In addition, PPL avers that adopting the proposal approved in *FirstEnergy DSP III* would require new contracts with wholesale suppliers, as well as a modified SMA. PPL contends that this would be problematic because current DSP II contracts extend the various terms into the DSP III period. PPL asserts that RESA failed to provide any details regarding how its alternative proposal would be implemented, including what changes would need be made to the SMA. *Id*. at 11-12.

c. PPLICA's Reply to RESA's Exceptions

In its Reply to RESA's Exceptions, PPLICA states that, contrary to RESA's assertion, the ALJ provided a well-reasoned analysis of the record and applicable law. PPLICA R. Exc. at 2. PPLICA submits that the ALJ agreed with evidence provided by PPL, PPLICA, and Noble Americas that disproved RESA's claim of unmanageable volatility in the NMB charges, and that RESA's claims with regard to the volatility of NITS charges in particular were unfounded. *Id*. at 3 (citing R.D. at 47). PPLICA also contends that the ALJ cited to extensive record evidence indicating that any EGS concerned with volatility of MNB charges has the authority to recover such charges on a pass-through basis. PPLICA R. Exc. at 4 (citing R.D. at 11). In addition, PPLICA disputes RESA's assertion that the *Fixed Price Order* has any effect on the EGS's ability to apply pass-through arrangements. PPLICA R. Exc. at 4.

PPLICA also asserted that the ALJ correctly recognized that the risk premiums charged by EGSs to account for NMB charges are part of a valued fixed-price service, and that customers—particularly Large C&I customers—may be willing to pay the risk premium in exchange for greater rate stability. PPLICA R. Exc. at 5 (citing R.D. at 50). PPLICA contended that under RESA's proposal, customers would lose this option, thus limiting the competitive retail options currently available to customers. PPLICA R. Exc. at 5. In addition, PPLICA asserts that RESA has failed to address transitional issues that would result from the adoption of its proposal, such as the significant risk of double recovery of NMB charges, the need for EGSs to revise all of their contracts with their shopping customers, and the details of cost allocation and rate design relating to the implementation of the proposed non-bypassable charge. *Id*. at 5-6.

PPLICA further asserts that the ALJ appropriately rejected RESA's claim that PPL's current practice of recovering NMB charges on a load-following basis violates the equal-access provisions of the Competition Act, and found that this practice is supported by PJM rules assigning responsibility for NMB charges to each LSE. PPLICA argues that wholesale default service suppliers are not LSEs, and therefore, the Competition Act does not require parity between wholesale suppliers and EGSs, but simply requires that PPL offer use of its system to EGSs on terms that are comparable to the Company's own use of the system. According to PPLICA, because PPL and the EGSs remain responsible for NMB charges incurred on behalf of their respective customers, PPL has satisfied the equal-access provision with regard to these charges. *Id*. at 6-7.

Finally, PPLICA noted that the Commission has previously rejected RESA's proposal to force EDCs to involuntarily implement non-bypassable riders to recover NMB charges on multiple occasions. *Id*. at 7 (citing *PPL DSP II Order* at 85; *FirstEnergy DSP II Order* at 83; *Duquesne Light DSP VI Order* at 222; and *Petition of PECO Energy Company For Approval of its Default Service Program II*, Docket No. P-2012-2283641 (Opinion and Order entered October 12, 2012) at 60.

4. Disposition

Upon consideration of the Parties' arguments, the record evidence, and applicable law, we will adopt the ALJ's recommendation on this issue and reject the proposals of RESA and ExGen to require PPL to recover NMB transmission-related costs from all distribution customers through a non-bypassable charge. As the ALJ pointed out, PPL's current approach of incurring and recovering NMB costs relating to default service load only, while EGSs assume responsibility for the NMB costs relating to the shopping load they serve, was approved by this Commission in *PPL DSP II*. In that proceeding, we rejected a similar proposal to that proffered by RESA in the instant proceeding to require PPL to assume responsibility for NMB costs relating to both default service load and shopping load, and to recover those costs through a non-bypassable charge. *See, PPL DSP II Order* at 85. We find nothing on the record to indicate that there has been any significant change in circumstances surrounding PPL's current approach with regard to these NMB costs since our prior approval of it in *PPL DSP II.*

Consistent with our discussion in *PPL DSP II*, we are concerned that the imposition of a non-bypassable charge would interrupt existing contracts between EGSs and their customers, which already account for NMB costs, and may lead to the possibility of double-recovery of those costs. While RESA maintains that such transition issues can be resolved, we find the record evidence to be insufficient to allow us to evaluate possible solutions to these issues. Moreover, we agree with PPLICA that including NMB costs relating to shopping load in a non-bypassable charge would eliminate the option for shopping customers to choose the stability of fixed-price contracts with EGSs that include NMB costs, or to negotiate the terms of such contracts in relation to these costs.

RESA points to *FirstEnergy DSP III*, in which we approved a plan that allows the FirstEnergy Companies to recover some, but not all NMB costs through a non-bypassable charge. RESA requests that we adopt a similar approach here, should we reject RESA's primary recommendation that *all* NMB costs be recovered through the non-bypassable charge. However, we note that the plan adopted in *FirstEnergy DSP III* was developed and presented as part of a settlement, in which the parties to the settlement agreed to the inclusion of certain NMB charges in the FirstEnergy Companies' existing Default Service Supply Rider. *See*, *FirstEnergy DSP III* at 13-14. No such agreement was reached in this proceeding.

In addition, we do not agree with RESA's contention that PPL's recovery of NMB costs only for default service load amounts to discriminatory access to the Company's distribution and transmission facilities in violation of the Competition Act. Section 2804(6) of the Code provides as follows:

> Consistent with the provision of section 2806, the commission shall require that a public utility that owns or operates jurisdictional transmission and distribution facilities shall provide transmission and distribution service to all retail electric customers in their service territory and to electric cooperative corporations and electric generation suppliers, affiliated or nonaffiliated, on rates, terms of access and conditions that are comparable to the utility's own use of its system.

Under the current approach, both PPL and the EGSs—as LSEs—are responsible for paying NMB charges to PJM relating to the respective loads they serve. While the methods used to recover these charges from customers differ between PPL and the EGSs, there is no evidence of record to indicate that the "rates, terms of access and conditions" under which the EGSs incur these charges are not comparable to those under which PPL incurs them.

Finally, we do not agree with RESA's contention that the *Fixed Price Order* now limits an EGS's ability to account for changes in NMB costs in the prices it charges customers. The *Fixed Price Order* prohibits a "fixed price" product from changing in price during the term of the agreement, but permits an EGS "the option of including in disclosure statements a provision that allows the EGS to, in the event of an unanticipated cost, reformulate the contract by proposing new contract terms to the customer, as long as the customer affirmatively consents." *Fixed Price Order* at 32. Similar to our finding in *FirstEnergy III* with regard to the inclusion of NITS in a non-bypassable charge, we find the *Fixed Price Order* does not amount to "changed circumstances” that would cause us to reconsider our prior decision on the issue of NMB costs in *PPL DSP II*. *See*, *FirstEnergy III Order* at 31.

Consistent with the above discussion, we will deny RESA’s Exceptions on this issue, and we will adopt the ALJ’s recommendation to reject the proposals of RESA and ExGen that PPL be directed to assume responsibility for NMB transmission-related costs on behalf of both wholesale default service suppliers and EGSs, and to recover those costs from both default service and shopping customers through a non-bypassable charge.

VI. Conclusion

Based on the foregoing discussion, we shall: (1) grant the Exceptions of PPL, consistent with this Opinion and Order; (2) grant, in part, and deny, in part, the Exceptions of RESA, consistent with this Opinion and Order; (3), adopt, in part, and modify, in part, the ALJ’s Recommended Decision, consistent with this Opinion and Order; (4) approve the Partial Settlement without modification; (5) adopt PPL’s proposal to reduce the peak demand threshold for Large C&I customers from 500 kW to 100 kW; (6) reject the proposals of RESA and ExGen that PPL be directed to assume responsibility for NMB transmission-related costs on behalf of both wholesale default service suppliers and EGSs, and to recover those costs from both default service and shopping customers through a non-bypassable charge; and (7) approve PPL’s Petition for approval of its DSP III program, consistent with the Partial Settlement and our disposition of the litigated issues as discussed above; **THEREFORE,**

IT IS ORDERED:

1. That the Exceptions filed by PPL Electric Utilities Corporation on November 19, 2014, to the Recommended Decision of Administrative Law Judge Susan D. Colwell are granted, consistent with this Opinion and Order.

2. That the Exceptions filed by the Retail Energy Supply Association on November 19, 2014, to the Recommended Decision of Administrative Law Judge Susan D. Colwell are granted, in part, and denied, in part, consistent with this Opinion and Order.

3. That the Recommended Decision of Administrative Law Judge Susan D. Colwell, issued on October 30, 2014, is adopted, in part, and modified, in part, consistent with this Opinion and Order.

4. That the Joint Petition for Approval of Partial Settlement filed in this proceeding is approved without modification.

5. That the proposal of PPL Electric Utilities Corporation to change the customer size demarcation between the Small Commercial & Industrial customer class and the Large Commercial & Industrial customer class from a peak demand level of 500 kW to a peak demand level of 100 kW is approved, consistent with this Opinion and Order.

6. That the proposal of the Retail Energy Supply Association that PPL Electric Utilities Corporation be directed to assume responsibility for non-market-based transmission-related costs on behalf of both wholesale default service suppliers and electric generation suppliers, and to recover those costs from both default service and

shopping customers through a non-bypassable charge, is rejected, consistent with this Opinion and Order.

7. That the Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period June 1, 2015, Through May 31, 2017, is granted, consistent with the terms and conditions of the Joint Petition for Approval of Partial Settlement filed in this proceeding, and consistent with the disposition of the litigated issues as discussed in this Opinion and Order.

8. That PPL Electric Utilities Corporation's DSP III program as approved herein contains all of the elements of a default service plan required by the Public Utility Code, the Commission's Default Service Regulations (52 Pa. Code §§ 54.181 – 54.189), and the Commission's Policy Statement on Default Service (52 Pa. Code §§ 69.1801-69.1817), including procurement, implementation, contingency plans, a rate design plan, and copies of the agreements and forms to be used in procurement of default service supply.

9. That PPL Electric Utilities Corporation's DSP III program as approved herein is in compliance with 66 Pa. C.S. § 2807(e)(3.7) in that: (1) it includes prudent steps necessary to negotiate favorable generation supply contracts; (2) it includes prudent steps necessary to obtain least cost generation supply contracts; and (3) neither the default service provider nor its affiliated interests have withheld from the market any generation supply in a manner that violates Federal law.

10. That the *pro forma* Supply Master Agreement included as Attachment B to the Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period June 1, 2015, Through May 31, 2017, and modified by the Joint Petition for Approval of Partial Settlement filed

in this proceeding, is approved as an affiliated interest agreement pursuant to 66 Pa. C.S. § 2102.

11. That the Third-Party Standard Offer Referral Program Services Contract extension between PPL Electric Utilities Corporation and PPL Solutions is approved as an affiliated interest agreement pursuant to 66 Pa. C.S. § 2102.

12. That the *pro forma* tariff provisions included as Attachment D to the Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period June 1, 2015, Through May 31, 2017, and modified by the Joint Petition for Approval of Partial Settlement filed in this proceeding, shall become effective as of June 1, 2015.

13. That any directive, requirement, disposition, or the like contained in the body of this Opinion and Order, which is not the subject of an individual Ordering Paragraph, shall have the full force and effect as if fully contained in this part.

14. That the investigation at Docket No. P-2014-2417907 be terminated and the record be marked closed.

BY THE COMMISSION,

Rosemary Chiavetta
Secretary

(SEAL)

ORDER ADOPTED: January 15, 2015

ORDER ENTERED: January 15, 2015