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**PUBLIC UTILITY COMMISSION**

**Harrisburg, PA 17105-3265**

Public Meeting held February 14, 2013

Commissioners Present:

Robert F. Powelson, Chairman, Joint Statement

John F. Coleman, Jr., Vice Chairman, Joint Statement

Wayne E. Gardner

James H. Cawley, Statement

Pamela A. Witmer, Statement

Investigation of Pennsylvania’s I-2011-2237952

Retail Electricity Market:

End State of Default Service

**FINAL ORDER**

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BY THE COMMISSION:

By this Order, the Pennsylvania Public Utility Commission (Commission) issues its proposed model for default electric service in the Investigation of Pennsylvania’s Retail Electricity Market (Investigation or RMI). This default service model was developed based on input from numerous stakeholders participating in the Investigation, as well as recommendations from the Commission’s Office of Competitive Markets Oversight (OCMO). For the reasons described herein, the Commission believes that this default service model will further the development and aid in the maturation of a healthy and competitive retail electric market in Pennsylvania. Additionally, while we refer to this model as an “end state” with regard to the Investigation, we foresee the Commission’s policies with regard to the competitive retail market evolving and changing to reflect market realities and experiences.

# BACKGROUND AND HISTORY OF THE PROCEEDING

In its Order entered April 29, 2011, the Commission initiated an investigation into Pennsylvania’s retail electricity market. *See Investigation of Pennsylvania’s Retail Electricity Market*, Docket No. I-2011-2237952 (Order entered April 29, 2011) (*April 29 Order*). The *April 29 Order* tasked OCMO, with the input of stakeholders, to study how to best address and resolve issues identified by the Commission as being most relevant to improving the current retail electricity market.

Initial stakeholder input was solicited via specific questions included in the *April 29 Order*. Thirty-nine parties filed comments[[1]](#footnote-2) in response to the questions, which are available on the Commission’s website.[[2]](#footnote-3) Additionally, these topics and comments were further discussed at the June 8, 2011 *en banc* hearing, where representatives of consumer interests, electric distribution companies (EDCs), electric generation suppliers (EGSs), subject matter experts, and regulators were invited to testify.

After review of both the written comments and the comments conveyed during the *en banc* hearing, the Commission issued an Order initiating the second phase of its Investigation. *See Investigation of Pennsylvania’s Retail Electricity Market*, Docket No. I-2011-2237952 (Order entered July 28, 2011) (*July 28 Order*). In the *July 28 Order*, the Commission concluded that:

Pennsylvania’s current retail market requires changes in order to bring about the robust competitive market envisioned by the General Assembly when it passed the Electricity Generation Customer Choice and Competition Act, 66 Pa. C.S. §§ 2801, *et seq*., in 1996.

*July 28 Order* at 7.

Consequently, the Commission directed OCMO to hold technical conferences to address intermediate and long-term issues pertaining to the competitive market. The Commission also directed OCMO to present specific proposals for changes to the existing retail electricity market and default service model.

OCMO held technical conferences on the following dates: August 10, 2011; August 31, 2011; September 14, 2011; September 21, 2011; September 28, 2011; October 6, 2011; October 27, 2011; November 8, 2011; November 17, 2011; December 2, 2011; January 5, 2012; February 1, 2012; March 15, 2012; and October 17, 2012. Interested stakeholders participated in these conferences and provided OCMO with information relevant to the topics that were addressed on each date.[[3]](#footnote-4)

During the technical conferences, OCMO first initiated a discussion to identify intermediate steps that could be implemented to enhance the competitive market on a shorter-term basis. These discussions led to the development and issuance of several orders pertaining to the following topics: upcoming default service plans and an intermediate work plan.

In order to ensure that the next round of default service plans did not hinder the ability of the Commission to implement changes addressed within the Investigation, on October 14, 2011, the Commission issued a Tentative Order describing OCMO’s recommendations for the format and structure of the EDCs’ upcoming default service plans. Comments were requested on each of OCMO’s recommendations. *See Investigation of Pennsylvania’s Retail Electricity Market: Recommended Directives on Upcoming Default Service Plans*, Docket No. I-2011-2237952 (Order entered October 14, 2011) (*October 14 Order*). OCMO’s recommendations included such issues as the next default service plan time period, contract durations for upcoming default service purchases and a number of intermediate competitive enhancements that could be implemented during the next default service plan time period.

Twenty-one parties filed comments[[4]](#footnote-5) to the *October 14 Order*. After reviewing the comments, the Commission entered a Final Order, which adopted recommendations with respect to the next phase of EDC default service plans. *See Investigation of Pennsylvania’s Retail Electricity Market: Recommendations Regarding Upcoming Default Service Plans*, Docket No. I-2011-2237952 (Order entered December 16, 2011) (*December 16 Order*).

Intermediate issues were also discussed at the *en banc* hearing that the Commission held on November 10, 2011. Representatives of EDCs, EGSs and consumer interests presented a discussion on the following topics: consumer education, accelerated switching timeframes, customer referral programs, retail opt-in auction programs and default service plans beyond May 2013. Ten parties[[5]](#footnote-6) filed informal comments following the *en banc* hearing.

After considering the remarks at, and comments following, the November 10 *en banc* hearing, on December 16, 2011, the Commission entered a Tentative Order that issued for public comment the Intermediate Work Plan (IWP). *See Investigation of Pennsylvania’s Retail Electricity Market: Intermediate Work Plan*, Docket No. I-2011-2237952 (Order entered December 16, 2011) (*December 16 IWP Order*). The *December 16 IWP Order* identified issues, tasks and goals that could be resolved and implemented prior to the expiration of the EDCs’ next round of default service plans, in an effort to improve the retail electricity market. The *December 16 IWP Order* provided recommendations regarding consumer education, accelerated customer switching timeframes, customer referral programs, retail opt-in auction programs, placement of the default service Price to Compare (PTC) on customer bills and mechanisms for increased EDC and EGS coordination. Two programs, the Retail Opt-in Auction and Standard Offer Customer Referral Programs, were specifically proposed for inclusion in the EDCs’ upcoming default service plans.

Twenty-three parties filed comments[[6]](#footnote-7) and thirteen parties filed reply comments[[7]](#footnote-8) to the *December 16 IWP Order*. Following a careful consideration of the comments and reply comments that were filed, on March 2, 2012, the Commission entered a Final Order that adopted the IWP and directed that the proposals included therein be implemented prior to the expiration of the next round of the EDCs’ default service plans. *See Investigation of Pennsylvania’s Retail Electricity Market: Intermediate Work Plan*, Docket No. I-2011-2237952 (Order entered March 2, 2012) (*March 2 Order*).

Subsequent to addressing intermediate issues and the IWP, the Investigation moved to a discussion of the end state of default electric service in Pennsylvania. On March 21, 2012, the Commission held an *en banc* hearing where EDCs, EGSs and representatives of consumer interests shared their perspectives on three proposed end state default service models, which OCMO developed and distributed for discussion prior to the *en banc* hearing.[[8]](#footnote-9) In each of the three models, EGSs served in the default service role with variations proposed for the default service product. In Model A, default service would be provided on the basis of real-time/hourly PJM Interconnection, LLC. (PJM) locational marginal pricing (LMP) and an administrative adder. Prices would change monthly (or more frequently) and not be reconciled. In Model B, default service would be provided on the basis of prevailing market prices, as established through an index, auction or other acceptable method. Prices would change quarterly or semi-annually and not be reconciled. In Model C, default service would mirror the existing procurement framework. Prices would change quarterly or semi-annually and be reconcilable on a twelve-month rolling basis.

Also at the March 21 *en banc* hearing, various small and medium businesses presented their experiences with shopping for electricity. In addition, the Commission heard from a panel of speakers who discussed the development of a comprehensive statewide consumer education program and ways to fund those consumer education efforts. Twenty-one parties filed informal comments[[9]](#footnote-10) following the March 21 *en banc* hearing.

On November 8, 2012, the Commission entered a Tentative Order that issued for public comment a proposed end state model for default electric service in Pennsylvania. *See Investigation of Pennsylvania’s Retail Electricity Market: End State of Default Service*, Docket No. I-2011-2237952 (Order entered November 8, 2012) (*Tentative* *Order* or *November 8 Order*). Comments were due within thirty days of entry of the *November 8 Order*.

The following parties filed comments to the *Tentative Order*: AARP, the Pennsylvania Utility Law Project, PCADV and CLS (collectively, PULP); Citizen Power; Citizens’ and Wellsboro; COMPETE Coalition (COMPETE); ConEdison Competitive Energy Businesses (ConEd); DLC; Electric Generation Supplier Parties (EGSP); Electric Power Generation Association (EPGA); Electric Power Supply Association (EPSA); EAP; Exelon Generation Company, Constellation Energy and PECO Energy Company (collectively, PECO); FES; Industrials; FE; MAREC; Mid-Atlantic Solar Energy Association and Pennsylvania Solar Energy Industry Association (MSEIA & PASEIA); NEM; NRG; OCA; Pennsylvania Chamber of Business and Industry (PA Chamber); PCADV; PEMC; PennFuture; Pike; PJM Power Providers Group (P3); PPL; PULP; RESA; The Sierra Club (Sierra Club); Verdigris Energy, LLC (Verdigris); and WGES.[[10]](#footnote-11)

# END STATE OF DEFAULT SERVICE

Upon consideration of the entire record developed in the Investigation, including remarks presented at the *en banc* hearings, written comments (particularly those filed to the *Tentative Order*), and staff recommendations as set forth in the *Tentative Order*, the Commission has developed the following model for the end state of default electric service in the Commonwealth.

The topics addressed in this Final Order include the following: guiding principles for the end state; a definition of default service provider (DSP); definitions of the default service products to be offered to various retail electric rate classes; a timeline for the implementation of the new default service model; a discussion of applicable consumer protections; a discussion of the portability of customer assistance program (CAP) benefits for low-income customers; a discussion of the potential implementation of supplier consolidated billing (SCB); a plan for the implementation of accelerated switching; a discussion of the provision of metering services, including net metering services; a discussion of the provision of Energy Efficiency and Conservation (EE&C) programs; a discussion of logistics for existing and future long-term contracts, including those for Alternative Energy Credits (AECs); a plan for the implementation of a statewide consumer education campaign; and a discussion of regulatory costs and assessments.

## A. Guiding Principles

In developing a framework to move Pennsylvania toward a more competitive market for electricity and establish a better platform for the sustainability of the competitive market, the Commission has relied on several underlying principles. These principles include the Commonwealth’s legislative policy favoring competition over regulation; a continuation of fundamental consumer protections; structuring the default service model to more closely reflect current market conditions; and encouraging investment by EGSs that results in innovative and competitively-priced product offerings for consumers.

Since 1996, with passage of the Electricity Generation Customer Choice and Competition Act, 66 Pa. C.S. §§ 2801, *et seq*. (Competition Act), the legislative policy in the Commonwealth has called for a competitive electric generation market to replace the regulated electric generation market. In passing the Competition Act, the General Assembly declared as a matter of policy that “[c]ompetitive market forces are more effective than economic regulation in controlling the cost of generating electricity.” 66 Pa. C.S. § 2802(5). The General Assembly further recognized that the “cost of electricity is an important factor in decisions made by businesses” when “locating, expanding and retaining facilities in the Commonwealth.” 66 Pa. C.S. § 2802(6). Due to the importance of a competitive retail market in controlling electric prices, the General Assembly found that this “Commonwealth must begin the transition from regulation to greater competition in the electricity generation market to benefit all classes of customers and to protect this Commonwealth’s ability to compete in the national and international marketplace for industry and jobs.” 66 Pa. C.S. § 2802(7).

Following passage of the Competition Act, the Commission immediately embarked upon implementation, which entailed the issuance of interim guidelines, the promulgation of regulations and the review and approval of restructuring plans filed by the EDCs. Throughout the implementation process, the Commission has remained committed to the successful development of the retail electric market in Pennsylvania, always vigilant of the need to balance regulatory requirements aimed at consumer protection against policies designed to facilitate entry and participation in the market by EGSs.

In launching this Investigation in April 2011, the Commission recognized the need to assess the current status of the retail electric market and explore changes that may be needed to allow customers to more fully realize the benefits of competition. Following a review of comments and testimony offered at the June 8, 2011 *en banc* hearing, the Commission reached the “inescapable conclusion that Pennsylvania’s current retail market requires changes in order to bring about the robust competitive market envisioned by the General Assembly when it passed” the Competition Act.  *July 28 Order,* page 7.

While shopping statistics alone are not indicative of the success of a competitive market, we note that, as of February 13, 2013, nearly two-thirds of Pennsylvania’s electric customers still received electric generation supply from their EDCs.[[11]](#footnote-12) Despite a large number of EGSs in the market, many offers are only slightly below each EDC’s PTC and few innovative product offerings have emerged to date that attract residential and small commercial customers into the competitive retail market.

As discussed throughout this Final Order, EGSs face any number of challenges to operate in the current competitive environment, which hinders consumers’ ability to enjoy a fully functioning competitive market. The primary price signal provided to consumers is the EDC’s PTC. However, due to reconciliation and the mix of contracts that EDCs use to establish the PTC, EGSs must compete with a PTC that often is not correlated to wholesale energy markets and may move in directions opposite that of wholesale energy markets trends. This can inhibit consumers’ ability to make informed decisions due to the receipt of false or misleading price signals.

Other issues, like the inability of EGSs to issue consolidated bills to customers; the lengthy switching process that is linked to EDC meter read dates; and the requirements that new customers receive service from the EDC and moving customers revert back to the EDC before moving to a competitive supplier makes the relationship between the EGS and the customer tenuous at best. This dynamic can result in customer confusion and hesitancy among EGSs to invest more resources in the Commonwealth. It most certainly does not foster a robust and vibrant competitive market in Pennsylvania, as envisioned by the Legislature.

In this Final Order, the Commission is outlining fundamental long-term changes to the underlying default service structure. The Commission is confident that the various intermediate measures underway, including Standard Offer Customer Referral and Retail Opt-in Programs, will improve the overall operation of the competitive market in the near term. However, the testimony and comments filed in this Investigation have convinced us that the development and sustainability of the retail market will continue to lag behind our expectations until we effectively address the fact that the currently-structured default service product does not reflect current market conditions. The changes we seek to implement will provide default supply prices that bear a closer resemblance to market conditions. These changes will also provide a regulatory framework that encourages substantial EGS investment in Pennsylvania’s retail electric market. We believe this will move the Commonwealth towards a robust competitive market, where a large number of suppliers provide customers with a wide array of competitively-priced generation supply products and offerings from which to choose.

Act 129 of 2008, P.L. 1592, added extensive language to Section 2807 of the Public Utility Code (Code), 66 Pa. C.S. § 2807, to require the default service product to fulfill a variety of statutory requirements, moving away from a default service product that reflected “prevailing market prices.” Section 2807 (e)(3.2) mandates that the electric power procured by the DSP include a prudent mix of contracts. In addition, Section 2807 (e)(3.6) requires the filing of competitive procurement plans by DSPs, on which hearings must be held as necessary and Commission Orders entered prior to commencement of the competitive procurement process. To implement these mandates, the Commission has promulgated regulations setting forth the various requirements for these plans. The initial plans were required to span two to three years, 52 Pa. Code § 54.185 (d), and while the Commission has flexibility as to the time period the plans cover, any shorter period would likely result in too frequent litigation for the EDCs and intervening parties. Necessarily, these plans rely on forecasting energy prices and, because they span two to three years, the resulting prices contain varying levels of risk premiums. When the quarterly reconciliation process (which makes the EDCs whole despite errors in forecasts) is layered over these price projections, risk premiums and EDC reconciliation accounting practices, the result is that EGSs are competing with a PTC that, at any given time, may not be reflective of current market conditions.

Two basic problems result from this structure. First, during periods when market prices are lower than the EDC’s PTC, EGS offers are frequently driven by the PTC. In those circumstances, the EGS offers often remain close to the above-market PTC and consumers do not fully realize the benefits of the lower market prices. Under a model where the default service product more closely reflects market conditions, the market should be the primary factor driving EGS prices, which is consistent with the purposes of the Competition Act.

A second concern about the existing structure is that when market prices rise, EGSs find it difficult to compete with a PTC that may reflect both prices that are not market-responsive and the EDC’s obligation to refund over-collections (artificially decreasing the PTC). A continuation of this structure exposes the Commonwealth to the risk that, when market prices increase and PTCs are artificially depressed by EDCs that have over-collected from ratepayers, EGSs will exit the Commonwealth. While consumers may not initially be harmed because they will have access to the EDCs’ PTCs for the remainder of the term, that exit would likely signal the end of the retail electricity market in Pennsylvania. That is what occurred in 2001, and the Commission is not confident that another restart of the market would be possible.

The expiration of generation rate caps in 2009 and 2010 was a major factor breathing new life into the electric retail competitive market and, since that was a one-time event, it would be difficult to once again attract EGSs to Pennsylvania. Absent a robust competitive market for electricity, consumers’ only option would be the default service supplier. Pennsylvania would not have the current situation of many active EGSs and competitive offers or realize the potential of a variety of innovative product offerings that are available to consumers in a properly-functioning market. Without the changes proposed herein, this Commission has substantial concerns that the current retail electricity market construct will not be viewed as sustainable by EGSs. By ensuring a robust competitive electricity market, the Commission believes long-term energy costs will be reduced and EGSs will be better able to price their offerings, leading to less customer confusion, lower prices and a broader array of products available to all Pennsylvanians.

So, while the stated intention of the Act 129 statutory requirements added in 2008 was to ensure adequate and reliable service at the “least cost to consumers over time,” 66 Pa. C.S. § 2807(e)(3.4), some interpretations of these mandates have had the unintended effect of creating a default service product that bears little or no resemblance to market conditions. They have also unnecessarily hampered the Commission’s ability to develop a regulatory framework that encourages investment by EGSs and a robust competitive market. Further, it is not clear that the statutory requirements, as applied, have produced the “least cost to consumers over time” during the past few years. Spot 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.

Therefore, the Commission, through this Final Order, recommends fundamentally changing the default service product so that it more closely resembles market conditions. Through the changes proposed herein, the Commission hopes to create a structure where the market drives prices charged by EGSs, where EGSs expand their investment in Pennsylvania due to certainty and a more level playing field, and where consumers enjoy competitive prices and a wide variety of innovative product offerings. In this manner, the Commission expects Pennsylvania to achieve and sustain the robust competitive market that was envisioned in 1996 by the General Assembly.

The Commission recognizes that some of the changes proposed herein may require amendments to the existing legislation and Commission regulations. Since we believe it is critical to move forward quickly while many EGSs are actively participating in the market, we are prepared to devote the resources needed to effectuate these changes so that our changes to the default service product can go into effect on June 1, 2015.

## B. Provision of Default Service

In its *Tentative Order,* the Commission proposed to retain the EDC as the DSP and continue to permit the EDC to obtain full cost recovery. We further proposed that the EDC remain in the DSP role unless the Commission approves an alternative DSP entity pursuant to Section 2803 of the Code, 66 Pa. C.S. § 2803, and the Commission’s regulations on default service at 52 Pa. Code § 54.183. Lastly, we proposed that an alternative DSP may be selected through one of the following means: (1) an EDC may petition to be relieved of its default service obligation; (2) an EGS may petition to be assigned the default service role in a particular EDC service territory; or (3) the Commission, upon its own motion, may propose that an EDC be relieved of its default service obligation. 52 Pa. Code § 54.183(b)(1)-(3).

**1. Comments**

OCA, the Industrials, Citizens’ and Wellsboro, PECO, PPL and Citizen Power support the Commission’s proposal to retain the EDC as the DSP.

OCA asserts that the EDC is best positioned to provide default service in the most cost-effective manner. The EDC is tasked to keep electricity flowing regardless of the entity that serves as DSP. Further, OCA submits that since the EDC is tasked with maintaining its distribution system, the EDC is in an ideal position to serve as DSP to ensure all customers receive electric service regardless of electric generation supplier performance. OCA at 7.

The Industrials assert that, although the Commission’s proposal reserves the Commission’s right to select and alternative DSP, the EDCs’ proven track record of reliable default service provides support for the EDCs’ continued performance of such service to all customers, unless the EDC is unable to do so. Industrials at 9.

PPL submits that the EDC or an alternative DSP should be subject to the same regulations and, therefore, should have the right to recover the costs of administering default service on a full and current basis. PPL further submits that allowing the EDC to exit the role of DSP will help to alleviate customer confusion as to the EDC’s true role as a “delivery” business that provides the same level of service regardless of a customer’s generation supply decisions. Consequently, PPL states that it would be inappropriate to establish the EDC as the permanent provider of default service. PPL at 8.

PECO states that continuing the role of the EDC as the DSP will provide certainty of default service supply and retail market infrastructure for customers and market participants as the competitive landscape continues to evolve. Further, PECO submits that the Commission’s existing authority to approve an alternative DSP provides an adequate process for the selection of an alternative DSP should future changes be appropriate. PECO at 5.

Citizens’ and Wellsboro submit that the Competition Act and the Commission’s Regulations permit the Commission to authorize an alternative DSP. Consequently, Citizens’ and Wellsboro contend that it would be beneficial if the Commission provides clarity on how an alternative DSP would be implemented. For instance, Citizens’ and Wellsboro seek clarity on whether the implementation of an alternative DSP would, in effect, permanently relieve the EDC of the responsibility. Further, Citizens’ and Wellsboro proposes a specific option to create an “agency” backstop to serve as the DSP if an alternative DSP fails. This agency backstop could be made up of EGSs that provide backstop service at spot market rates. Citizens’ and Wellsboro at 3 and 4.

FE avers that any proceeding that determines a potential alternative DSP should occur outside of the EDC’s default service proceedings and the transition should coincide with the implementation of a new default service term. FE at 2 and 3.

WGES submits that the ideal end state is one in which the default service role is fulfilled by an EGS. As such, WGES agrees with the Commission’s recommendation to retain the authority to revisit to concept of placing an EGS in the DSP role at a future point in time. WGES at 1.

NRG contends that retaining the EDC in the DSP role will not result in the development of robust sustainable retail competition and will not completely unlock the full array of innovative products and services. NRG submits that only when the EDC has been removed from the DSP role will a fully functioning, robust, and sustainable competitive market be realized. Further, NRG states that having the EDC exit the DSP role will enable the EDC to focus on its core competencies and obligations for safe and reliable distribution service. Consequently, NRG avers that retaining the EDC in the DSP role should be viewed as a transitional step toward full competition, as opposed to the “end state.” NRG, therefore, urges the Commission to set a timeline for the replacement of the EDC as the DSP. NRG at 5.

PEMC expresses concerns that the Commission proposal to permit the implementation of an alternative DSP in the future could merely result in the establishment of a new de facto monopolist. PEMC contends that a single EGS acting as a DSP is not in the interests of the competitive marketplace. Consequently, PEMC offers three potential options to restructure default service in order to truly advance the competitive marketplace and benefit consumers. The first option is to eliminate utility-provided default service and transition non-shopping customers to certified EGSs through an open auction. The second option is to retain the EDC in the DSP role but require a premium be placed on the default service price to compensate EDCs for maintaining a non-core business, to reflect the value placed on default service by customers who made an effective choice to stay on default service, and to recognize that the default service price is subsidized since it does not contain all the costs of providing and receiving competitive service. The third option is to retain the EDC in the DSP role but unbundle commodity costs from distribution rates, incorporate those unbundled costs in the PTC, and eliminate utility reconciliation for commodity costs. PEMC at 5 and 6.

EGSP raises concerns similar to those expressed by PEMC. Specifically, EGSP emphasizes that the default service price must contain all costs of providing the service, noting that there are costs that would be built into the retail commodity rate if this service was provided by a retail provider in a truly competitive environment. EGSP at 4.

RESA disagrees with the Commission’s proposal. RESA avers that default service can, and should, be fulfilled by competitive EGSs rather than the EDC. In support, RESA submits that retaining the EDC in the DSP role presents structural barriers that impede market development and prevent customers from realizing the benefits of a fully workable and competitive market. RESA states that the Commission’s overall proposal in the *Tentative Order* will continue to provide the EDC, as the DSP, a competitive advantage over EGSs. Consequently, RESA submits that the Commission should remain open to implementing other reforms appropriate to achieve the goal of robust competition. Lastly, RESA contends that any legislative changes the Commission chooses to pursue should not foreclose the possibility of further market refinements, such as those advocated by RESA. RESA at 4 and 5.

**2. Resolution**

Upon review of the comments, we are persuaded to adopt our initial proposal to retain the EDC in the DSP role. The Commission believes the various revisions to the default service product that we direct within this proceeding are a reasonable step in the evolution of Pennsylvania’s retail electric market. In the future, the Commission may revisit the concept and merits of adopting an alternative DSP or DSPs. We acknowledge the arguments of those parties who state that keeping the EDC in the DSP role presents structural barriers to a robust retail market place and that the EDCs should focus on their core competencies. However, we believe that, at this time, it would be most prudent to be patient and allow the revisions proposed in this proceeding to be implemented. As we stated in our *Tentative Order*, we continue to believe that, at this time, permitting the EDCs to continue to provide default service strikes an appropriate balance that allows the retail electric market to continue its fairly steady progress of organic growth while providing the Commission with the ability to take further action in the future, if necessary. *Tentative Order* at 14.

Although we are keeping the EDCs in the default service role, we emphasize that our decision has no basis in the rationale offered by the Industrials relating to continued reliability of service. To the contrary, we view the EDCs as responsible for the reliable delivery of electric service regardless of the entity providing default generation service.

The Commission agrees with Citizens’ and Wellsboro that clarity is necessary regarding the implementation of a model in which an alternative entity, or multiple entities, provides default service to customers. To provide such clarity, we direct OCMO to convene a working group to identify issues related to the implementation of such a model. OCMO shall provide recommended solutions to the Commission no later than November 15, 2013.[[12]](#footnote-13) At a minimum, we envision that this working group will provide recommendations regarding the potential for cost recovery; the timeline in which an alternative entity would begin providing default service; whether or not multiple entities could provide default service within a single EDC’s service territory; and the potential provision of net metering benefits.

As to the comments suggesting a further unbundling of commodity costs from distribution rates to ensure that the PTCs reflect all costs of default service, the Commission agrees with this concept and has strived to address these issues as they have arisen in distribution rate cases. At this time, however, the Commission is not inclined to launch any generic investigations or promulgate regulations requiring such further unbundling as we believe these measures would be a significant undertaking and require the time and resources of many stakeholders. We would prefer to focus available resources on the changes we have identified, keeping in mind that this does not preclude the Commission from addressing the further unbundling of commodity costs and distribution rates in another proceeding in the future.

## C. Applicability of Proposed End State

In its *Tentative Order*, the Commission proposed that the changes be applicable to all jurisdictional EDCs to achieve and sustain the robust competitive market that was envisioned with the passage of the Competition Act. The Commission believed that such a market should be available statewide, regardless of the size of the EDC. Comments were sought regarding the feasibility of such a model being implemented in the service territories of smaller jurisdictional EDCs. *Tentative Order* at 14.

**1. Comments**

The Industrials, PECO, PEMC, PPL and RESA agree with the Commission’s proposal that the changes proposed in the *Tentative Order* be applicable to all jurisdictional EDCs in Pennsylvania. Industrials at 9; PECO at 6; PEMC at 6; PPL at 9; RESA at 6. PPL does note, however, that certain aspects of the model do not apply to smaller EDCs. These aspects are the provision of EE&C programs under 66 Pa. C.S. § 2806.1 and the procurement and installation of smart meters under 66 Pa. C.S. § 2807(f), specifically 66 Pa. C.S. § 2807(f)(6). Accordingly, PPL avers that the smart meter aspects of the Commission’s proposals regarding accelerated switching may be difficult for smaller EDCs to achieve. PPL at 9.

Citizens’ and Wellsboro urge the Commission to retain flexibility in the applicability of these changes, and consider the impacts of the proposed default service structure on small EDCs. Citizens’ and Wellsboro at 4. Similarly, Pike states that the general rules that apply to EDCs should not apply to them. Pike avers, that because the majority of its customers are already participating in the retail market, because it is a small company and because it is part of a different regional transmission organization (New York Independent System Operator, as opposed to PJM), it should not be viewed similarly to the other Pennsylvania EDCs. Pike believes that the Commission should exempt small EDCs and/or those EDCs with significant levels of EGS penetration from having to make some of the recommended changes from the *Tentative Order*. Pike at 5.

OCA does not support the Commission’s proposed applicability of its end state model, as it does not support the model as a whole. Additionally, OCA notes that, given the differing sizes of the EDCs, a “one size fits all” approach is unworkable. OCA at 8.

**2. Resolution**

The Commission maintains its position that the changes included within this end state model be applicable to all jurisdictional EDCs. This will provide uniformity and benefits statewide. However, our determination here does not preclude a smaller EDC from submitting, for the Commission’s review, a petition that provides evidence as to why it may not be appropriate, beneficial to customers or feasible to implement this model or specific requirements in its service territory.

The Commission would like to clarify that those obligations in the Code regarding the provision of EE&C programs, 66 Pa. C.S. § 2806.1, and the procurement and installation of smart meters under 66 Pa. C.S. § 2807(f)(6), will not be applied to smaller EDCs with this end state model, nor will such application be included in proposed legislative changes. Those obligations will remain with the larger EDCs, as outlined within the statute.

## D. Default Service Product

Given the Commission’s decision to not seek to remove EDCs from the DSP role, it becomes paramount to change the products offered by DSPs so as to enhance the ability of EGSs to compete on a level playing field. Since the EDCs will maintain the right to full cost recovery for their provision of default service, the EDC has an entirely different exposure to risk than an EGS. Under the current construct, the EDC purchases large portions of load months, and even years, in advance of delivery. This, in turn, creates the potential for a situation in which the PTC is based more on historical market conditions than that at the time of delivery. Further exacerbating this issue are the instances when the EDC’s PTC fails to reflect the actual cost of service due to inaccurate customer migration projections, certain accounting practices or inaccurate spot market price projections. These inaccuracies can lead to the inclusion of significant reconciliation costs within the PTC that have little or no relationship to the present market for energy and, therefore, can potentially further move the PTC away from market conditions at the time of delivery.

EGSs primarily operate in current market conditions. EGSs do not have any right to cost recovery and, as such, pricing corrections, as implemented through EDC reconciliation processes, do not play any role in their price offers to customers.

Consequently, the Commission’s main goal in developing a revised default service product is to create a more market-based PTC. This type of product will mitigate the potential for “boom/bust” scenarios to occur. “Boom” scenarios are those in which the EDC’s PTC is inflated when compared to market price indicators at the time. In this situation, the PTC acts as an artificial price ceiling under which EGSs set prices to attract waves of customers. As explained earlier, this boom scenario will enable EGSs to beat the EDC’s PTC, but may not provide shopping customers with prices pegged to lower market price indicators.

“Bust” situations are those in which the EDC’s PTC is substantially lower than market priced indicators. In this situation, customers will, in many cases, revert back to default service because EGSs cannot beat the PTC that the EDCs formulated with their no-risk procurement portfolio. As explained previously, such a scenario may benefit customers in the short term, but in the long term, such a scenario is likely to drive EGSs out of the market, as occurred in 2001, thereby eliminating consumers’ ability to shop for a lower price when the default service price rises. Therefore, the elimination of potential “boom/bust” cycles will create a more sustainable retail market, which, in turn, should lead to enhanced product offerings to consumers and long-term EGS investments within Pennsylvania. With this rationale, the Commission seeks to implement the default service products and procurement strategy described below.

### 1. Medium and Large Commercial and Industrial Rate Classes

In the *Tentative Order*, the Commission proposed that EDCs offer hourly LMP for medium and large commercial and industrial (C&I) accounts through quarterly auctions. For accounts in this group that do not have interval meters, the Commission proposed that EDCs charge hourly LMP by using customer load profiles. Noting that LMP pricing is already offered to large C&I customers,[[13]](#footnote-14) the Commission suggested that medium C&I customers are equally well-equipped and educated to manage their commodity costs in an hourly LMP default service environment. The Commission described this proposal as a natural progression for the retail marketplace and opined that having EDCs offer hourly LMP to these accounts will put EGSs on a level playing field for competing not only with the PTC but with each other. *Tentative Order* at 16-17.

Additionally, the Commission recognized that there is currently no uniform delineating point across the EDCs to distinguish these accounts from small C&I accounts. By way of general guidance, the Commission suggested that EDCs offer hourly LMP to accounts with demand of 100 kilowatts (kW) or greater. The Commission also proposed that EDCs be permitted to designate a delineation point between small C&I customers and medium and large C&I customers based on existing rate schedules, where it is impractical to create default service subclasses. *Tentative Order* at 16.

**a. Comments**

Several parties support the Commission’s proposal to implement an hourly-priced product for medium and large C&I customers. As explained by NRG, a default service product that more closely resembles market conditions over time is necessary to spur competition to the next level. NRG at 6. RESA describes the Commission’s goal of a more market-based PTC as a “good step forward in the transition to an optimal end state where a fully robust competitive market exists.” RESA at 6. PECO notes that virtually all of these customers are now shopping and have the ability to secure the types of products and services they desire from EGSs. PECO at 6. PPL explains that it currently provides real time default service to C&I customers whose peak load contribution is greater than 500 kW and that it has already stated its intent to expand this service to customers with demands of less than 500 kW but greater than 100 kW in its next default service plan with an implementation date of June 1, 2015. PPL at 11. The Industrials indicate that if a handful of safeguards are adequately addressed, they are not opposed to the continuation of hourly LMP pricing as the default service option for large C&I customers or the extension of that product to medium C&I customers. Industrials at 4.

As to the use of an auction process, the Industrials propose that the hourly-priced services should be provided by EDCs, not auctioned to other suppliers, claiming that this approach will result in the most cost-effective adder. The Industrials explain that dividing the small amount of large C&I customers relying on default service among multiple wholesale suppliers would not be efficient or produce a just and reasonable result. Industrials at 4 and 5.

If an auction process is used, the Industrials suggest that it should be conducted annually, rather than quarterly, to help keep the administrative costs reasonable. Industrials at 4. PPL observes that since most of the components of this product are determined by PJM markets, the administrative adder will be the only component subject to competition among suppliers. Therefore, PPL suggests that any additional savings resulting from more frequent competition may not justify the administration burden of procuring more often than annually. PPL at 13.

The Industrials also propose conditions to avoid cost shifting among medium and large C&I customers. Specifically, the Industrials contend that only customers who are new to this hourly product should pay costs associated with implementation, and separate procurements should occur to minimize interclass cost shifting. They explain that the characteristics of the “large” and “medium” C&I customers differ on issues such as creditworthiness, predictability of usage and payment history, which could translate to higher risk premiums for serving the smaller customers. The Industrials further note that allocating, collecting and reconciling any default service charges for capacity and transmission for all hourly price customers in accordance with the PJM rates and rate design for each product will avoid interclass and intraclass cost shifting. Industrials at 5.

The Industrials further maintain that a failsafe mechanism needs to be in place to address the possibility of market failure, such as a situation where no EGSs are offering products that respond to the customers’ needs. Specifically, the Industrials suggest that the Commission ensure it has sufficient flexibility under the statute to step in and revise the default service paradigm if necessary. Industrials at 7 and 8.

PECO, PPL and FE contend that the proposal to use load profiles to establish hourly prices for medium and large C&I customers without interval meters is not feasible or supported by current billing systems. PECO asserts that issues associated with reconciliation of real-time load obligations and load profiles would complicate the provision of LMP-based default service to customers in the absence of interval meters. PECO at 7. FE explains that billing these customers on the basis of load profiles would mean that no load-shedding strategy would relieve them of high LMP prices. Additionally, FE notes that it would need to program functionality into its billing system to use load profiles to price hourly LMP for medium C&I customers who do not have interval meters. FE at 4 and 5.

PPL points out that relying on load profiles would produce a bill that is calculated by multiplying a rate by an estimate of usage and is not reflective of the customer’s own usage pattern. Noting that the customers who fall into this group (i.e. customers with demands of less than 500 kW but greater than 100 kW) represent a wide variety of customers with diverse usage patterns, PPL expresses concerns about how a representative load profile would be established. DLC echoes these concerns, noting that it does not have the capability to use load shapes to determine actual hourly consumption. DLC at 4. PPL suggests that the better way to move closer to market-based prices for these customers is to expand the deployment of interval meters and smart meter capabilities. PPL at 11 and 12.

With respect to the proposed threshold of more than 100 kW of demand to distinguish medium and large C&I customers from small C&I customers, PPL and PECO concur with this delineation point. PPL at 11; PECO at 6 and 7. FE states that Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company have a delineation of 400 kW, which is the level at which interval metering is installed and the hourly LMP default service product is offered under the default service plan that goes through May 31, 2015. As to West Penn Power Company, FE explains that it has a rate schedule delineated at the 100 kW level, but its requirement for interval metering does not begin until 500 kW of demand. FE at 5. DLC notes that it does not currently have the infrastructure capable of providing hourly priced service to C&I customers below demands of 300 kW and therefore recommends that lowering the threshold for hourly priced service below that level should await the completion of smart meter deployment. DLC at 4.

RESA cautions against providing too much latitude to the EDCs to define the appropriate customer-size threshold for the hourly LMP product. Recognizing that EDCs currently have in place different tariff rate classifications and different default service procurement group classifications, RESA urges the Commission to require EDCs to expand hourly-priced default service to a larger group of medium C&I customers rather than relying on existing definitions. RESA at 7-9.

Pike seeks to be exempted from the Commission’s proposal regarding the default service product as it already provides default service at spot market prices and will continue to do so under its approved plan for the period from June 1, 2012 through May 31, 2014. Noting that this approach is wholly consistent with the Commission’s stated goal of creating EDC default service products that are more market-based, Pike also refers to difficulties it would have in conducting quarterly auctions for its supply since it would have to negotiate and enter into a contract with a merchant generator and pay an unjustified premium given the small amount of default service load to be served. Pike at 6 and 7.

**b.** **Resolution**

As was noted in our *Tentative Order* and many of the comments, hourly LMP is already offered to large C&I customers, and medium C&I customers are equally well-equipped and educated to manage their commodity costs in an hourly LMP default service environment. Therefore, in the next round of default service plans that begin on June 1, 2015, we expect that EDCs will offer only hourly LMP to medium and large C&I customers with interval meters, subject to the several conditions discussed herein. Generally, this LMP product will be offered on a quarterly basis, with auctions for the entire LMP default service load in each EDC territory held in unison with auctions for residential and small C&I customers, as described in subsequent sections of this Order. Additionally, we will direct that the quarters synchronize with the PJM energy year starting on June 1 of each calendar year and ending May 31 of the following calendar year. As with current default service plans for large C&I accounts, wholesale energy suppliers participating in the auctions will bid on an administrative adder, with the generation component of the product being established by the hourly LMP.

As to the Industrials’ proposal that hourly-priced services for large C&I customers be provided by the EDCs, the Commission prefers the model under which these services are auctioned to wholesale suppliers. Having the EDC providing these services and charging an administrative adder to large C&I customers entails a degree of involvement by the EDC that the Commission seeks to avoid with this group of customers in the robust competitive market we are seeking to promote. The Commission notes, however, that we are simply indicating that these services should be auctioned to other suppliers – not that they will necessarily be accepted. In a scenario where the auction results are not reasonable, the Commission retains the authority to reject them and direct the EDC to provide these services.

With respect to the frequency of the auctions, the Commission recognizes that the administrative adder is the only component on which the suppliers will be bidding since all other elements of the hourly product will be established by the market. Further, the Commission is cognizant of the concern raised by PPL that quarterly LMP product auctions may be hindered by potential administrative burdens. However, we do not have enough evidence within this proceeding to make a decision on which option, annual or quarterly auctions, is most prudent. Consequently, we will defer this decision until further evidence is provided within the EDCs’ default service proceedings. We will note that, whichever option is chosen, the auction or auctions are to be held in unison with the residential and small C&I auctions, as specified in subsequent sections of this Order.

Regarding the Industrials’ proposal for a failsafe mechanism in place to address the possibility of market failure, the Commission agrees. With only an hourly-priced default service option, most customers will shop to avoid the variability. As a result, if EGSs are not meeting the needs of large and medium C&I customers, we expect the Commission will have sufficient flexibility and a willingness to step in and revise the default service paradigm.

With respect to the use of load profiles to bill hourly LMP to customers who do not have interval meters, the Commission is persuaded by the parties opposing the use of this approach. While the Commission desires to expand the pool of large and medium C&I customers who receive hourly LMP services from the EDCs, the Commission understands the need to limit these services to those customers who have interval meters.

Specifically, the Commission agrees with PPL’s comments regarding the difficulty of establishing a representative load profile for such a diverse group of customers which might, as a result of shopping, change character from time-to-time. Also, the Commission concurs with FE’s observation that customers might become frustrated if they are billed at the hourly LMP on the basis of load profiles but cannot avoid high LMP prices through load-shedding measures. In addition, the Commission recognizes the challenges raised by PECO associated with reconciliation of real-time load obligations and load profiles in the absence of interval meters. Further, the Commission notes FE’s comments regarding the need to program its billing system to accommodate the use of load profiles. Finally, although we realize that an accelerated or expanded deployment of interval meters and smart meter capabilities would enable EDCs to offer hourly LMP services to a larger number of large and medium C&I customers, we are not inclined to address those deployment schedules here since they are being, or have been, addressed in other proceedings.

As to the proposed delineation point of above 100 kW of demand, the Commission acknowledges that the more compelling point of delineation is whether the customer has an interval meter, as no EDC suggested any difficulty creating a subclass for default service. Therefore, at this time, the Commission continues to support the threshold of 100 kW for purposes of determining medium and large C&I customers, but expects EDCs to offer hourly LMP products only to the customers above that demand level who have interval meters. We expect the EDCs to continue adding medium C&I customers to the hourly LMP product as interval meters are deployed. Further, the Commission directs all LMP default service customers to be grouped into one single auction class for each EDC in order to avoid creating extremely small procurement classes. Lastly, the Commission agrees with the Industrials that the default service charges for capacity and transmission should be allocated, collected and reconciled for all hourly-priced customers in accordance with PJM rates and rate design for each product, and therefore directs such.

As to the Industrials’ comments regarding the need to avoid cost shifting among medium and large C&I customers, since the Commission is neither directing the acceleration of smart meter deployment nor the application of load profile LMP billing, we believe any concerns about cross-subsidies are largely mitigated. Any potential new costs that may arise from expanding LMP billing for default service customers with smart meters and demand greater than 100 kW can be addressed in future default service proceedings.

Regarding the concerns presented by Pike, the Commission maintains its position that the changes included within this end state model should be applicable to all jurisdictional EDCs. The Commission appreciates that Pike’s current default service product for all customers is based on spot market prices, which is consistent with our overall objectives. However, the Commission does not presently know what product will be proposed and approved in Pike’s next default service plan proceeding. Therefore, it would be premature to exempt Pike, at this time. However, as noted previously, a smaller EDC is not precluded from submitting, for the Commission’s review, a petition which provides evidence as to why it may not be appropriate, beneficial to customers or feasible to implement this model or certain specifics of this model in its service territory.

### 2. Residential and Small Commercial and Industrial Rate Classes

In its *Tentative Order*, the Commission proposed that EDCs offer quarterly PTCs that are synchronized with the PJM energy year for residential and small C&I rate classes. Further, we proposed that the PTC be established by procuring 100% of each EDC’s default service load for each quarter one or two months in advance of the applicable quarter. We also proposed that the EDCs procure only full requirements products and that the EDCs continue to provide PTC estimates until the exact tariffed rate is established. *Tentative Order* at 17-18.

**a. Comments**

PPL, ConEd, WGES, PECO and NRG generally support the Commission’s proposal to have EDCs offer a quarterly PTC based entirely on three-month, full requirements contracts procured in a single auction prior to each quarter. PPL submits that such a product will be more reflective of current market conditions than default products currently offered. PPL also states that reforming default service to offer this type of product to residential and small commercial customers is a logical step in the evolution of the marketplace. PPL at 14.

WGES states that the structure of default service is a major factor considered by EGSs when entering a retail market. WGES submits that the PTC should reflect prevailing market prices. In support, WGES contends that generation supply markets have been generally flat since the recession in 2008. Consequently, the presently-blended default service prices have given EGSs a window of opportunity to enter the market. However, WGES contends that if the generation market price trajectory moves upward, the blended default service contracts could establish a PTC that reflects previously lower prices and therefore forces EGSs to leave the market as they could not compete with the regulated default service price. Further, WGES submits that this scenario would send the wrong price signal to customers. WGES believes that this problem can be resolved by eliminating long-term contracts for default service supply, as the Commission has proposed. WGES at 2.

PPL and PECO also submit that auctions pursuant to the Commission’s proposed default service products should be coordinated statewide for all EDCs. PPL contends that, since the product and procurement timing will be standard throughout the state, the Commission should consider introducing a common supply auction similar to the Basic Generation Service auction employed in New Jersey. PPL believes this may ensure the success of procurements in each EDC’s service territory and could be a precursor to having DSPs that are not incumbent EDCs. PPL at 14.

PECO asks the Commission to establish a collaborative stakeholder process in the RMI proceeding to develop a uniform procurement process for all EDCs along with uniform supply master agreements (SMAs). PECO proposes to have the procurement process and SMAs approved by the Commission no later than June 1, 2014. In support of the coordinated procurement approach, PECO contends that the Commission’s proposal may create significant resource and timing challenges for wholesale energy suppliers to participate in each quarterly auction for each EDC. Consequently, some wholesalers may choose not to participate in certain EDC auctions. These challenges will be compounded if EDCs decide to use different procurement strategies, such as declining clock or requests for proposals (RFPs), along with different SMAs. PECO submits that using a single, coordinated uniform procurement throughout the state will manifest significant administrative savings for EDCs and wholesalers which, in turn, may be reflected in wholesalers’ bids. PECO notes that products and tranches would remain specific to each EDC. PECO at 8-10.

PECO states that the specifics of the uniform procurement and SMAs should be developed in the stakeholder group. However, PECO suggests that the Commission recommend some overarching design requirements and goals to guide the stakeholder proceeding. Specifically, PECO submits that a uniform statewide procurement process include the following features: (1) a standard certification process for each procurement year; (2) an end-of-day bid submission with notification that same evening; (3) a proportional assignment of time of use (TOU) load; (4) the exclusion of load tranches from existing block contracts that carry into the next round of default service; and (5) an established stakeholder process for continued improvement. PECO at 8-10.

RESA supports the Commission’s stated goal to create a more market-based PTC. RESA believes that default service rates must be market-responsive and must reflect all costs related to default service so that competitive retail suppliers can compete on an equal footing with the EDC’s default service. As such, RESA generally supports the Commission’s proposed residential and small C&I product structure. However, RESA submits that the PTC for upcoming quarters should be provided to EGSs as soon as possible. RESA states that providing the final PTC calculation in a reasonable amount of time in advance of its effective date is important to provide both customers and EGSs time to react to the new PTC price signal. Consequently, RESA proposes that default service procurements be held 60 days in advance of upcoming quarters in order enable EDCs to calculate the new PTC no later than 45 days in advance of its effective date. RESA at 10.

PEMC cautiously supports the Commission’s proposal, as it believes the proposal represents a marginal improvement over the current approach to procuring default service supply. However, PEMC submits that, if the PTC continues as the Commission proposes, including unbundled commodity costs or the introduction of a premium in this price is vital to give customers an apples-to-apples comparison with supply offers. PEMC at 6.

OCA and PULP submit that the Commission’s proposed residential and small C&I default service product would not improve the competitive retail market, nor would it be in the best interest of residential customers. Both parties state that the Commission’s proposal will cause customers to experience price volatility. According to these parties, this volatility will likely expose customers to seasonally high bills in the peak electric usage months of the summer. OCA and PULP contend that this exposure may compromise customers’ ability to pay their electric bills, particularly those customers who have a lower income, may be older in age, or who may be victims of domestic violence. PULP also submits that the potential for higher summer bills can potentially result in an increase in utility disconnects which, in turn, can lead to potential dangerous health conditions such as fires and carbon monoxide poisoning from the use of unsafe heating sources. OCA at 10; PULP at 11-16.

OCA and PULP also contend that budget billing may not be a viable option for customers to avoid seasonally high bills. OCA states that, under the Commission’s proposal, EDCs may face difficulty in estimating the annual generation costs of each customer when the default service supply and, consequently, the PTC is re-established every three months. In support, OCA states that there could be large true-ups needed in the budget billing process if the estimates of quarterly purchase prices in the future are inaccurate. OCA asserts that such a scenario may eliminate the usefulness of budget billing. OCA at 11.

OCA contends further that the volatility of the Commission’s proposed product structure will be a detriment to customer choice because customers will only be able to determine if EGS offers are in their best interest for a three-month period. The potential for customers to enter into a contract with an EGS that may quickly move above the renewed PTC may depress, rather than foster, customer switching. Further, OCA submits that the price volatility inherent in the PTC under the Commission’s proposal will make it more difficult for EGSs to plan their pricing and purchasing as their own customer loads may become less predictable as the PTC changes. Competitive EGS offers in the summer may be non-competitive in the shoulder or off-peak seasons. Customers may therefore switch to an EGS during the summer and revert to default service in the shoulder seasons. OCA concludes that this scenario might result in the very type of “boom/bust cycle” that the Commission is seeking to avoid. OCA at 12.

OCA further contends that the Commission’s platform that longer-term contracts somehow bear less of a resemblance to current market conditions than shorter-term contracts is incorrect. OCA believes that the EDCs’ present strategy keeps the default service price current through the wholesale market auctions and RFPs which procure contracts of various lengths which, when blended to formulate a PTC, create a less volatile market-based price. PULP echoes these sentiments. OCA at 12; PULP at 6 and 7.

OCA states that the default service product should be designed to be a stable product acquired through a mix of resources, with different contract delivery periods, from the competitive wholesale markets. In conclusion, OCA avers that limiting default service to a single, short-term product is not in the best interest of customers and will not support sustained, robust competition. OCA comments at 13-14.

Similarly, DLC submits that it is concerned that the sole use of three month procurements for residential and small C&I customers will produce unnecessary volatility in default service rates due to changes in seasonal demand and due to the potential for a dislocation in the wholesale energy market at the time of procurement. DLC avers that these forms of volatility are not the type that would lead to the “boom/bust cycles” about which the Commission is most concerned. Rather, a long-term rise in prices mixed with procurements years in advance of the delivery period is more likely to result in default service prices that are below current market prices. Therefore, DLC submits that a one-year default service rate procured no more than six months prior to the commencement of the delivery period is a better approach. DLC believes this approach provides reasonably contemporaneous pricing while avoiding concerns about volatility. DLC at 3.

DLC contends that the best inducement for shopping is long-term savings. DLC believes the volatility inherent in the Commission’s proposal will lead to customer dissatisfaction if the PTC drops significantly after a customer enrolls with an EGS for a long-term product. Therefore, DLC opines that the Commission’s proposal will not enhance shopping by residential and small C&I customers. DLC concludes that, whatever procurement period and structure is employed for residential and small C&I customers, the Commission should implement procurements of contracts at different times for each PTC period in order to dampen the effect of market dislocations at the time of a single procurement. However, DLC clarifies that it does fully support the elimination of laddering any contracts over various PTC periods in order to reduce over- and under-collections. DLC at 4.

EGSP contends that the Commission’s proposed residential and small C&I product will do nothing to lower barriers to market entry for EGSs. EGSP submits that this proposal fails to remedy the inequities of current default service and the resulting anti-competitive effect. EGSP avers that implementing an annual procurement with annual price changes will produce better results for EGSs. In support, EGSP explains that an annual procurement of fixed-price products will eliminate the odd variability of quarterly prices and reconciliation. Further, EGSP states that an annual model would provide customers with greater price stability, which would be more comparable to typical EGS offers and would match market prices more closely than the present default service model while avoiding unnecessary volatility. EGSP at 7 and 8.

EGSP opines that the Commission’s proposal will most likely lead to a scenario in which only those entities that own or control significant generation assets will be able to manage the risks of offering longer-term fixed priced products to customers. Instead, most EGSs will only be able to offer customers shorter-term prices, which may or may not compete with the PTC. EGSP believes this construct will increase the frequency of “boom/bust cycles” which, in turn, may drive customers back to default service for longer periods of time, if not permanently. EGSP at 7 and 8.

Citizen Power submits that semi-annual auctions should be used instead of quarterly auctions. In support, Citizen Power states that semi-annual auctions offer more stable prices for default service customers which, in turn, can provide more budget stability for said customers. Citizen Power also states that semi-annual auctions provide a less frequently changing PTC for customers who wish to shop. Citizen Power explains further that the disadvantage to its semi-annual auction proposal is that it provides a greater chance for the PTC to diverge from market prices. However, Citizen Power contends that large price swings in the electric market are not commonplace occurrences. Further, if a large price swing occurred, it would only affect the marketplace for a maximum of six months. Last, if the market price drops, customers will have an opportunity to receive service from an EGS at a more competitive rate. In summary, Citizen Power submits that it is unlikely that an EGS would choose not to participate in a market based on the small chance that the PTC will be below the market price for short period of time. Citizen Power at 2 and 3.

Citizens’ and Wellsboro submit that they have a single default service product for all customers and therefore oppose splitting the default service product into two categories based on customer class. Citizens’ and Wellsboro state that they are concerned that segregating customers into separate procurement groups, as proposed by the Commission, may diminish the attractiveness of the wholesale supply product to suppliers. Specifically, Citizens’ and Wellsboro state that the total combined load of all customers is just over 50 megawatts (MWs). Citizens’ and Wellsboro submit that, while it may be possible to conduct a quarterly, full requirements solicitation for a single tranche for each service territory, the Commission should consider the possibility that no suppliers will be interested in the territory and should develop a contingency plan prior to making a decision to include the companies in the new approach. Citizens’ and Wellsboro at 5 and 6.

Citizens’ and Wellsboro also contend that the Commission’s proposal for residential and small C&I customers may not address the over- and under-collection issue. The two EDCs submit that full requirements tranches are delivered on a calendar quarter basis. Since customers’ billing cycles often do not synchronize with the beginning of the month, generation bills will need to be pro-rated resulting in over- and under-collections. Citizens’ and Wellsboro ask that the Commission explore whether wholesale suppliers could take on this collection risk associated with the proposed full requirements, load-serving contracts to alleviate the burden on small EDCs. Citizens’ and Wellsboro at 6.

Lastly, Citizens’ and Wellsboro state that implementing the Commission’s proposal will require them to upgrade their information systems to facilitate additional electronic interactions with both retail and wholesale suppliers. Citizens’ and Wellsboro are also exploring the use of a third-party vendor to provide Electronic Data Interchange (EDI) services. As such, Citizens’ and Wellsboro state that the Commission should confirm that they will be entitled to full and timely recovery of costs to implement EDI, billing system changes and other activities related to implementation of customer choice from EGSs and/or in a non-bypassable generation rider. Citizens’ and Wellsboro at 7.

Pike seeks to be exempted from the Commission’s proposal regarding the default service product as it already provides default service at spot market prices and will continue to do so under its approved plan for the period from June 1, 2012 through May 31, 2014. Noting that this approach is wholly consistent with the Commission’s stated goal of creating EDC default service products that are more market-based, Pike also refers to difficulties it would have in conducting quarterly auctions for its supply since it would have to negotiate and enter into a contract with a merchant generator and pay an unjustified premium given the small amount of default service load to be served. Pike at 6 and 7.

**b. Resolution**

The Commission agrees with the numerous parties who generally support the proposed residential and small C&I product. Consistent with the positions detailed in the *Tentative Order*, along with the support presented in the comments by parties such as PPL, ConEd, PECO, WGES and NRG, we agree that the product, as proposed, will reduce the likelihood of over- and under-collections and foster a PTC that more closely tracks current market conditions.

As discussed in a subsequent section of this Order, the Commission believes a change to the existing statutory procurement standard may be required to use a 90-day default service product for residential and small C&I customers. Should legislative efforts fall short, we will consider an alternative shorter-term product that is more reflective of market conditions than the currently-offered default service products. If such legislative changes are effectuated, the Commission expects the EDCs to offer a 90-day product, as described above, to residential and small C&I customers. This product would be included in the next round of default service plans, which take effect on June 1, 2015.

Additionally, the Commission agrees with RESA’s timeline concerns. The Commission believes that establishing the exact PTC no less than 45 days prior to its effective date will be beneficial for consumers and EGSs for shopping and marketing, respectively. Consequently, we direct that the EDC auctions be held far enough in advance to permit EDCs to establish a final PTC no less than 45 days prior to the effective date of the PTC.

Further, the Commission agrees with PECO and PPL’s recommendation to collaborate all EDC auctions in order to realize efficiencies and reduce expenses. As such, we direct all EDCs to hold collaborative quarterly auctions. In order to develop the details required to collaborate quarterly auctions, and consistent with the comments provided by PECO, we direct OCMO to form a Procurement Collaboration Working Group. The end goals of this Group will be to formulate a uniform yearly certification process, a uniform supply master agreement, and a procurement methodology/timeline. We further direct the Procurement Collaboration Working Group to develop any other necessary protocols, procedures, or documents required to run an auction every quarter which procures default service load for each EDC through a single, third-party consultant. We specifically note that individual EDC load will not be aggregated, but rather separate auctions for each service territory will be held in a parallel process, which will be monitored and managed by a single third party consultant. Further, we agree with PECO’s recommended timeline for the working group process, and therefore direct that the Procurement Collaboration Working Group submit its recommendations to the Commission as soon as practicable, but no later than April 1, 2014, in order to provide the Commission time to approve or amend the recommendations by June 1, 2014. Finally, we note that the group need not reach consensus as long as the views of all parties are documented in its submittal to the Commission.

As to OCA’s concern about the effectiveness of budget billing under the proposed default service product construct, we note that this topic is addressed in the Consumer Protections section of this Order.

Concerning Citizens’ and Wellsboro interest in obtaining Commission approval for cost recovery associated with upgrades to its systems necessary to accommodate our directives, the Commission will not make any affirmative declaration of cost recovery within the scope of this proceeding. Any such cost recovery should be sought by Citizens’ and Wellsboro through a proceeding that specifically addresses the prudency and necessity for specific incurred costs.

As with the default service product for medium and large C&I customers, the changes included within this end state model will be applicable to all jurisdictional EDCs. The Commission appreciates that Pike’s current default service product for all customers is based on spot market prices, which is consistent with our overall objectives. However, the Commission does not presently know what product will be proposed and approved in Pike’s next default service plan proceeding. Therefore, it would be premature to exempt Pike, at this time. As noted previously, a smaller EDC is not precluded from submitting, for the Commission’s review, a petition which provides evidence as to why it may not be appropriate, beneficial to customers or feasible to implement this model or certain specifics of this model in its service territory.

### 3. Legislative Changes

In the *Tentative Order*, the Commission recognized that many of the proposals may require changes to existing legislation and Commission regulations. The proposed changes to the default service product are among those that the Commission intends to pursue with the General Assembly. *Tentative Order* at 18.

**a.** **Comments**

While many commenters acknowledge or agree with the need for legislation to change the default service products in the manner proposed by the Commission, RESA submits that the proposed procurement approach is consistent with the existing law. RESA maintains that the law does not require a specific rate design methodology for default service. Rather, RESA explains that the law requires the DSP to offer electric generation service pursuant to a Commission-approved default service plan that must include a “prudent mix” of resources designed to provide adequate and reliable service, provide the least cost over time and to achieve those results through competitive processes that include one or more of the following: auctions, RFPs and/or bilateral agreements. RESA notes that the Commission has determined that what constitutes a prudent mix should be interpreted in a flexible fashion to permit DSPs to design their own combination of products to meet the requirements of the statute.

In support of its view that the Commission does not need legislative changes to pursue the changes to the default service product proposed in the *Tentative Order*, RESA refers to Commission decisions addressing default service plans filed by Pike that have approved spot-market-only approaches for all customers. In addition, RESA emphasizes that the Commission has approved hourly prices for large C&I customers in several service territories. RESA at 11-13.

**b. Resolution**

Section 2807(e)(3.1) of the Code, 66 Pa. C.S. § 2807(e)(3.1), which was added to Chapter 28 of the Code by Act 129, obligates EDCs to procure electricity through competitive procurement processes that include one of the following: (i) auctions; (ii) requests for proposals; and (iii) bilateral agreements. Section 2807(e)(3.2) of the Code, 66 Pa. C.S. § 2807(e)(3.2), further provides that the purchased power must include a “prudent mix” of spot market purchases, short-term contracts and long-term purchase contracts. According to Section 2807(e)(3.3) of the Code, 66 Pa. C.S. § 2807(e)(3.3), the prudent mix of contracts shall be designed to ensure adequate and reliable service and the least cost to customers over time.

As noted by RESA, the Commission has found in Pike’s default service plan proceedings that the “prudent mix” standard may be fulfilled by only one product – a spot market product in Pike’s case – when it is the option that is most likely to produce the least cost over time and the benefits provided by the other products are not commensurate with their costs. While this finding originally occurred in 2007, prior to the passage of Act 129,[[14]](#footnote-15) the Commission has reached the same decision in 2009 and 2012.[[15]](#footnote-16) It is important to note that, before reaching those decisions, the Commission considered a variety of factors that were unique to Pike. Most recently, those factors included Pike’s extremely small customer base and the fact that 73% of customers are served by EGSs, leaving only 1300 customers on default service. Finding that the spot market approach complies with the law under those circumstances, the Commission concluded that requiring Pike to follow a procurement approach that includes hedging would produce an unreasonable result: namely, higher prices with little or no customer benefits. Similar rationales have applied to the approval of hourly LMP for large C&I customers.

While the Commission is steadfast in its view that our decisions to permit spot market approaches in specific situations are appropriate, we are concerned that a general pronouncement directing a 90-day product for residential and small business customers and an hourly LMP product for “medium” C&I customers may raise legal questions about compliance with the above-referenced provisions of the Competition Act. To avoid any legal uncertainty,[[16]](#footnote-17) the Commission would prefer to pursue legislative amendments that clearly provide the authority to approve default service plans containing products that more closely resemble current market conditions at the time of delivery. Further, as a creature of the Legislature, the Commission is well-served to ensure that the General Assembly is supportive of our overall policy direction on matters as important as the retail market for electricity. Although the Commission appears currently to have authority to establish shorter-term default service products that are more reflective of market conditions than existing products, our intention is to seek legislative changes that afford the Commission as much flexibility as possible going forward so that we can quickly adapt our policies as necessary to meet the needs of the competitive market and consumers.

## E. Transition Timeline

In the *Tentative Order*, the Commission proposed June 1, 2015, as the effective date for changes to the default service product offered by the EDCs, noting that existing and pending default service plans are scheduled to terminate on May 31, 2015. With that implementation date in mind, the Commission stated in the *Tentative Order* that we would encourage the passage of any necessary legislative changes in 2013. *Tentative Order* at 18.

Further, since the Commission expects the next phase of default service plans to be significantly more streamlined than has been the case under Section 2807(e)(3.6), 66 Pa. C.S. § 2807(e)(3.6), we proposed to issue an order containing filing guidelines as soon as practicable after the passage of legislation to set forth the components that should be included in the default service plans and any other implementation issues. To ensure that EDCs have sufficient time to implement the next round of default service plans, the Commission proposed to require them to be filed by July 1, 2014, for approval within six months. *Tentative Order* at 18.

**1. Comments**

Several parties support June 1, 2015, as the implementation date for the new default service products. FE characterizes the Commission’s proposal as a logical timeline for a seamless transition, given the expiration of default service plans on May 31, 2015. FE at 5 and 6. PPL notes that its default service plan for the period ending May 31, 2015, contains a procurement schedule under which all supply contracts will expire by that date, so that a relatively clean transition is possible on June 1, 2015. PPL at 15 and 16. PEMC calls the timeline reasonable and likely achievable. PEMC at 6.

OCA agrees that no changes to default service should be implemented before June 1, 2015. However, it urges the Commission to forego establishing a timeline for implementation until the General Assembly determines whether it will enact any changes. OCA at 14 and 15.

RESA generally supports the Commission’s timing proposal but is concerned about delays that may result from pursuing what it believes are potentially unnecessary legislative changes. Therefore, RESA urges the Commission to avoid letting the pursuit of unnecessary legislative changes slow the progress toward the June 1, 2015 goal. RESA at 11-13.

Some parties raise concerns about the Commission’s proposal to shorten the review period to six months for the next round of default service plans, noting that the Commission’s regulations provide for a nine-month review period, which is consistent with the Competition Act. OCA submits that the nine-month timeframe is reasonable and should be maintained, contending that shortening it to a six-month period would make it increasingly difficult to fully examine each EDC’s plan. OCA also suggests that a six-month timeframe may not allow sufficient lead time for plan corrections, auctions or RFPs. OCA at 14 and 15. PECO shares similar concerns, noting that six months may be insufficient time to review the first default service plan under a new legislative and regulatory framework. PECO therefore recommends that the Commission maintain the nine-month time period between filing and approval of the first round of default service plans after the changes but retain flexibility to implement a shorter review time for future plans. PECO at 12 and 13.

NRG urges the Commission to establish a timeline for post-2015 when the default service products proposed in the *Tentative Order* will be transitioned to EGSs and then subsequently eliminated at a later date after transition to EGSs. Specifically, NRG suggests that the date for this transition to EGS-provided default service should be no later than June 1, 2016. NRG at 4-7. RESA offers a similar comment, describing the Commission’s goal of a more market-based PTC as a good step forward in the transition to an optimal end state where a fully robust competitive market exists. RESA at 11-13.

**2. Resolution**

The Commission believes that it is appropriate to establish June 1, 2015, as the implementation date for the new default service model, with the understanding that any necessary legislative changes need to be made in 2013. Not only does June 1, 2015, correspond to the expiration of the EDCs’ default service plans, we believe it is critical to implement changes designed to improve the sustainability of the market while wholesale market prices are stable. Declining to establish an implementation date by this Final Order, as suggested by OCA, would add even more uncertainty in the marketplace and potentially discourage EGSs from continuing or commencing retail activities.

While the Commission appreciates RESA’s concern about the potential for legislative changes to delay our progress toward this goal, we have expressed our views above for why we consider it prudent to pursue those amendments. Further, the Commission has indicated that we are prepared to devote the resources necessary to implement changes that we believe are essential to the proper functioning of the competitive market for electricity.

As to NRG’s suggestion that the Commission establish a timeline for post-2015 for transitioning EGSs into the default service role, we believe it is premature to do so at this time. Going forward, we plan to carefully monitor developments in the competitive market and will not hesitate to revisit the default service model in the future, if necessary.

With respect to the Commission’s proposal for a six-month timeframe for approving default service plans that go into effect on June 1, 2015, the Commission understands the concerns raised by the parties about the challenges of fully reviewing the plans, especially since they will be the first round of plans under a new legislative and regulatory framework. Therefore, the Commission will refrain at this time from establishing a review period and instead will do so when we issue an order implementing new legislation. To the extent the Commission can maintain the nine-month review period or a longer period of time than six months and still meet the June 1, 2015 implementation date, we intend to do so.

## F. Consumer Protections

The Competition Act requires that EDCs maintain, at a minimum, the levels of customer service and protections that were in existence prior to the effective date of the Act. 66 Pa. C.S. § 2807. In response to these legislative directives, the Commission promulgated regulations to ensure the continued provision of high-quality customer service, including:

* **Customer Information** (52 Pa. Code §§ 54.1 – 9). This ensures that customers have the information they need to make informed decisions while participating in the competitive market, including rules governing billing information and format, and marketing activities. This includes a rule stipulating that advertised prices must equal the price the customer is billed. Also included are detailed supplier disclosure (contract) requirements that directs a supplier to put into writing terms and conditions including pricing information, length of agreement, cancellation provisions, penalties, and any bonuses or incentives. The contract must also include a three-day right of rescission, under which the customer can cancel the contract without penalty within three days of receiving the contract.
* **Reporting Requirements for Quality of Service Benchmarks and Standards (**52 Pa. Code §§ 54.151-156).These rules allow the Commission and the public to monitor various customer service metrics to help ensure that distribution utilities continue to maintain quality service to customers. This includes call center and field personnel performance, metering, billing, dispute handling and surveys of customer satisfaction. The Commission compiles and presents this information in an annual report that is available on the Commission’s website.[[17]](#footnote-18)
* **Universal Service and Energy Conservation Reporting Requirements.** (52 Pa. Code §§ 54.71 – 78). These rules assist the monitoring of the utility collection’s performance and helps to ensure that universal service and customer assistance needs are being addressed. This includes information on the number of customers participating in universal service programs and the costs of the programs. This information is compiled and presented in an annual report that is available on the Commission’s website.[[18]](#footnote-19)
* **Standards for Changing a Customer’s Electricity Generation Supplier.** (52 Pa. Code §§ 57.171 – 179). These regulations put in place procedures suppliers and utilities are to follow to change a customer’s supplier of choice. These rules are also intended to ensure that a customer’s generation supply is not switched without the customer’s authorization. The Commission has directed staff to initiate a rulemaking to revise these regulations, with the intent of accelerating the switching process. This review will include the possibility of revising the regulations in recognition of new capabilities resulting from the implementation of advanced metering technologies. This initiative is discussed in more detail later in this Order.
* **Marketing and Sales Practices for the Retail Residential Energy Market.** (52 Pa. Code §§ 111.1 – 14). These pending regulations are intended to ensure that consumers receive the information they need from sales agents to make informed decisions about their energy choices. They are also intended to help protect public safety as it relates to door-to-door sales and marketing activities. Suppliers will be expected to obtain background checks on all door-to-door agents. In order to guard against misrepresentation or intimidation by the sales agent, the rules require that all door-to-door and telephone sales transactions are to be verified by a process separate from the sales process and agent. The rules also specify the information a sales agent should provide a potential customer to permit the customer to make informed energy choices.
* **Standards and Billing Practices for Residential Utility Service.** (52 Pa. Code §§ 56.1 – 231). Going back to the *Customer Services Order of 1997*,[[19]](#footnote-20) the Commission has required compliance with Chapter 56. Section (I)(A) of these Guidelines requires that “Electric Distribution Companies (EDC), Generation Suppliers, Brokers, Marketers and Aggregators must abide by the Standards and Billing Practices for Residential Utility Service at 52 Pa. Code, Chapter 56” and Section (L)(2) of the Guidelines requires that a supplier of last resort (DSP) “must continue to apply the Chapter 56 termination provisions for nonpayment, including negotiation of payment agreements based on a consideration of certain factors such as the ability of the ratepayer to pay.” These guidelines rest on Section 2809(e) of the Competition Act, which explicitly directs the Commission to “impose requirements necessary to ensure that the present quality of service provided by electric utilities does not deteriorate, including assuring that adequate reserve margins of electric supply are maintained and assuring that 52 Pa. Code Ch. 56 (relating to standards and billing practices for residential utility service) are maintained.” Chapter 56 standards address billing, payment, applications and credit, security deposits, termination, and dispute handling.

The default service model that was proposed in the *Tentative Order* requires no revisions to any of the consumer protections noted above, and we proposed that the protections that electric consumers have come to expect remain intact and fully in effect. We also noted that this does not preclude the Commission from considering or revising any of the above-noted regulations. However, any revision of these regulations will always be in the context of our statutory charge found in Section 2807 of the Competition Act – that the quality of the service provided does not deteriorate. Any such revision will result, at a minimum, in the maintenance of the current level of service or serve to enhance it.

**1. Comments**

The parties generally agree with the Commission’s proposal and agree that there is no need to change current consumer protection regulations to accommodate the default service model being proposed by the Commission. No party expresses a desire to extensively modify or eliminate any of the current regulations.

PPL took issue with the Commission’s linking of preserving consumer protection rules with the role of the EDC as a DSP, in part, because some of the consumer protections have nothing to do with the provision of default service. PPL at 17. However, OCA believes that the EDC’s expertise in complying with these regulations is an argument for retaining them in the DSP role. OCA at 15 and 16. PPL, along with PULP and PCADV also question the sustainability and effectiveness of Chapter 56 residential regulations governing billing, payment, termination, disputes and related matters in a Supplier Consolidated Billing (SCB) environment. These parties question the ability of the Commission to enforce the regulations in an environment where numerous suppliers may be providing SCB. PPL at 19; PCADV at 3 and 4; PULP at 19.

PCADV doubts the Commission can apply any Chapter 56 regulations to EGSs, given that the Commission has only issued guidelines in this respect; guidelines that are not enforceable as regulations. PCADV at 4. PCADV is also troubled by the Commission’s explicit reservation of its right to revise any or all consumer protection regulations. This, along with “the Commission’s failure to specify the specific legislative changes it intends to seek” causes PCADV to question the Commission’s future intentions with respect to Chapter 56. PCADV at 5.

OCA and PULP question the effectiveness of the budget billing regulations in Chapter 56 in a new default service environment. These parties believe that the price of default service obtained on a quarterly basis will be difficult to estimate in advance – thereby complicating the calculation of budget billing amounts for individual consumers. OCA at 11; PULP at 16.

**2. Resolution**

Given the widespread support among the parties, the Commission will maintain our original proposal to preserve existing consumer protection rules. No party argued or made a case for any significant revision of the current regulations. However, we do want to address the concerns and questions raised by some of the parties.

We believe PCADV’s concerns about the ability of the Commission to impose Chapter 56 standards upon suppliers are based on a misunderstanding. While the *Customer Services Order* PCADV cites is indeed a set of guidelines, this Order is not the foundation upon which the Commission’s authority regarding Chapter 56 rests. As noted above, the Commission’s authority in this regard is based on statute - Section 2809(e) of the Competition Act, 66 Pa. C.S. § 2809(e). Additionally, as part of the Commission’s supplier licensing process, suppliers must complete an affidavit acknowledging that “it has a statutory obligation to conform with 66 Pa. C.S. §§ 506, 2807(D)(2), 2809(B) *and the standards and billing practices of 52 Pa. Code Chapter 56*” (emphasis added).[[20]](#footnote-21) Given this strong foundation, the Commission is confident that it can indeed impose Chapter 56 obligations upon suppliers and has, in fact, done so and will continue to do so. As noted above, the Commission sees no need, and has no intent, to seek any legislative changes that would impact the consumer protections noted above, including Chapter 56. This includes any revision to our statutory charge found in Section 2807 of the Competition Act – that any revision to consumer protection regulations will either preserve or enhance the quality of the service provided.

As for PPL’s objection to linking consumer protections to the EDC in the role of the DSP, we want to add that while we noted in the *Tentative Order* that many of these protections, especially Chapter 56, have traditionally been the obligation of the EDC, this was not intended to preclude a supplier from performing the role as a DSP. As we noted above, the Commission clearly has the authority to impose Chapter 56 requirements upon suppliers, and this would obviously be a qualifying standard any supplier would have to agree to before even being considered as a DSP. With regard to the concerns of PPL, PULP and PCADV about Chapter 56 compliance in the context of SCB, we will address those concerns later in this Order in our discussion of SCB.

We acknowledge the concerns of OCA and PULP with the viability of budget billing in the default service environment proposed by the Commission, but believe their concerns are overstated. Quarterly default service rates are not new; they have been changing quarterly since 2010 and the utilities have been calculating budget amounts without apparent problems since then. Budget bill amounts (sometimes referred to as “equalized bills” or “average bills”) are not calculated on an annual basis. In fact, the budget billing regulations at 52 Pa. Code § 56.12(7) require that they be reviewed “at least 3 times” during the budget billing period (a budget billing period being ten, 11 or 12 months). It is expected that, during these routine quarterly reviews, the utility will adjust the budget bill amount up or down to reflect usage and rate changes in order to prevent the accumulation of large over or under-collections. Should a large under-collection accumulate, this regulation was revised in 2011 to require that any large under-collection amount be amortized over the next six to 12 months.[[21]](#footnote-22) Given these detailed requirements and protections in the budget billing regulations, the Commission is confident that consumers will continue to be able to utilize budget billing to obtain a more stable, average monthly bill, if they so prefer.

## G. Portability of Benefits for Low-Income Customers

The Competition Act requires the Commission to maintain, at a minimum, the protections, policies and services that assist customers who are low income to afford electric service. 66 Pa. C.S. § 2802(10). That Act also requires the Commission to ensure that universal service and energy conservation policies are appropriately funded and available in each electric distribution territory. 66 Pa. C.S. § 2804(9). “Universal service” is generally defined as policies, protections and services that help low-income customers maintain electric service. 66 Pa. C.S. § 2803. Universal Service programs include Customer Assistance Programs (CAP), the Low Income Usage Reduction Program (LIURP), Customer Assistance and Referral and Evaluation Programs (CARES) and various utility hardship funds.

CAP is a general term used to describe utility payment assistance and debt-forgiveness programs for payment-troubled households.[[22]](#footnote-23) CAP’s payment assistance feature is intended to provide affordable monthly bills based on a household’s size and gross income. These lower rates are applied to ongoing usage as long as the household remains current and timely in paying its monthly customer assistance payments. CAP rates may take the form of a discounted price on actual usage, on either all or a portion of the usage, or a monthly amount that is calculated upon a percentage of the household income. CAP programs are currently guided by the “Policy Statement on Customer Assistance Programs,” 52 Pa Code §§ 69.261-69.267.

At the time the Tentative Order was issued, the ability of a CAP customer to participate in the competitive market varied by EDC. Some EDCs allowed shopping without restriction while other EDCs may have had rules restricting or even prohibiting a CAP customer from shopping. In the *Tentative Order*, we proposed that all EDCs, if they have not done so already, develop plans that allow their CAP customers, on or before January 1, 2015, to shop in the competitive market without restriction. *Tentative Order* at 23.

LIURP is a statewide, utility-sponsored, residential usage reduction program mandated by Commission regulations. *See,* 52 Pa. Code §§ 58.1-58.18. The primary goal of LIURP is to assist low-income residential customers to conserve energy and, as a result, reduce energy bills. Hardship funds are programs that provide cash grants to qualifying households to assist in the payment of utility bills. They are funded through contributions made by the public and utility shareholders and employees. CARES is a social service and referral program for households encountering some form of extenuating circumstance or emergency that results in the household’s inability to pay for utility service. Qualifying households may receive counseling and/or direct referrals to community resources that can aid the family in resolving the emergency. A customer’s eligibility or participation in LIURP, hardship funds or CARES is not affected by whether or not a customer shops. As such, in the *Tentative Order*, we proposed no changes to these three programs and proposed that they should remain a function of the utility for the foreseeable future.

The Low Income Heating Energy Assistance Program (LIHEAP) is often discussed in the context of universal service, but, in fact, is not a utility-funded or administered program. LIHEAP is funded by the federal government and is administered by the Pennsylvania Department of Public Welfare (DPW). As such, in the *Tentative Order*, recognizing that our influence over this program is very limited, we only proposed that the Commission work with DPW to explore what can be done to make suppliers eligible for LIHEAP payments - making these benefits more portable.

**1. Comments**

In general, consumer representatives express concerns about the participation of CAP customers in the competitive shopping market. OCA believes that if CAP customers are going to be permitted to shop, a model must be developed that allows the customer to retain their CAP benefits without increasing the cost to the customer or to the customers who must bear the costs of the program. OCA bases their concerns on data presented in the PPL default service proceeding that indicated that, of the 47% of PPL CAP customers shopping, 73% were paying more than if they had remained with PPL. OCA also suggests that the Commission allow interested parties to participate in the development of the EDC CAP portability filings “so that solutions to these issues can be developed.” OCA at 16 and 17.

PULP believes that CAP customer participation in the competitive marketplace must be contingent on a variety of consumer protections provided on a uniform, statewide basis. These protections should include supplier prices that are always at or below the default price; cancellation without penalties at any time; exemption from security deposits; must be billed by a utility, not the supplier; specific consumer education efforts; full retention of all CAP program benefits and extended disclosure and rescission rights. PULP at 21 and 22. PULP believes these protections are needed due to the high degree of economic vulnerability and the need for rate stability and affordability for low-income households. PULP expresses concern about the potential economic harm of “unsuccessful shopping decisions or failure to maintain constant rate vigilance” to both the CAP customers and the non-CAP customers who subsidize CAP rates. PULP at 20. PULP also is concerned about the Commission’s proposal to let each EDC develop a plan suitable for its service territory. PULP believes that this indicates that the Commission has failed to seriously confront the many significant issues involved and that the delegation of this responsibility is an abuse of discretion. PULP at 21. Citizen Power likewise believes that a statewide framework regarding what consumer protections are necessary should be developed. Citizen Power at 4.

PECO, an EDC whose CAP customers cannot currently shop, notes that it will need to spend significant amounts on programming, re-training and consumer education to implement CAP customer shopping. PECO at 14. Concerning consumer protections, PECO states that, if CAP customers pay generation prices higher than PECO default prices, it will erode some of the existing protections against price volatility that these customers have enjoyed and will adversely affect the affordability of their utility service. This could result in PECO increasing CAP benefits to return the customer to affordability and that these costs would increase the cost of the CAP program. PECO recommends that the Commission carefully balance affordability and cost containment principles in reviewing CAP shopping plans to maintain public support for those programs. PECO at 15.

PPL believes it would be inconsistent to prohibit customers with the greatest economic need from shopping for alternatives to default service and that there is no evidence to suggest that CAP customers do not have the capability to make shopping decisions, just like other customers. However, PPL notes that there are complexities that must be addressed, including “ineffective” shopping by CAP customers, which could mean paying more than the default rate, or not paying the lowest available price. This “ineffective shopping” could create a burden on the rest of the residential population that supports CAP financially. PPL at 21. Also, PPL notes that current policy at 52 Pa. Code § 69.265(3)(ii) prohibits CAP participants from subscribing to “non-basic services that would cause an increase in monthly billing and would not contribute to bill reduction.” PPL questions the applicability of this policy in the context of EGS offers like gift cards, airline miles and other inducements. PPL at 21 and 22. PPL believes none of these complexities are insurmountable and are most logically addressed in the three-year universal service plans filed by each EDC. PPL also suggests that June 1, 2015, is a more appropriate effective date for any changes. PPL at 23.

FE notes that all of its Pennsylvania EDCs are already in compliance with the Commission’s proposal in that all of their CAP customers can shop without restriction or loss of benefit. FE believes that a CAP customer that shops should receive the total result of their action, regardless of the magnitude of their EGS rate in comparison to the default service rate. That is, the customer should get the benefit or detriment of the difference between the PTC and the EGS price they receive. FE 6 and 7. FE further notes that a comparison of the EGS rate to the default rate at any one point in time does not take into consideration the value a CAP customer may place on other factors, such as long-term fixed EGS rates or other value-added products and services that may be offered by the EGS. FE at 7.

In general, the EGSs believe that CAP customers should be allowed to participate in the shopping market. RESA believes that CAP customers should preserve their benefits and not be denied the benefits available from the competitive market. RESA at 14. PEMC strongly supports the Commission’s proposal, but emphasizes that care should be taken to educate and protect CAP customers in particular. PEMC at 7. NEM believes that CAP customers can receive a double benefit – the payment assistance garnered as a result of the CAP program, as well as potential energy commodity cost savings to be realized from shopping. NEM at 6. NEM adds that this double benefit is particularly significant because energy expenditures comprise a large portion of the budgets for low income consumers as compared to other households. NEM at 6 and 7. NRG opines that CAP benefits need to be fully portable to allow low income customers to exercise their right to shop for energy products that best meet their needs. NRG at 7. However, NRG encourages the Commission to require statewide uniformity in how this is accomplished in order to minimize customer confusion and to simplify the programs. NRG points to Texas as a state that successfully implemented an overhaul to its utility specific low-income customer assistance programs that now allows all customers to shop and retain their low income benefits through an easy-to-understand cents-per-kWh discount program. NRG recognizes that the significant systems improvements required to effectuate this change will require a concerted effort by all interested stakeholders. NRG at 8.

**2. Resolution**

Concerning CAP and our proposal that all EDCs, if they have not done so already, develop plans that allow their CAP customers to shop in the competitive market – we note that events have more or less taken over and have made our original proposal moot, for the most part. All of the major EDCs have reported that their CAP customers can shop, with the exception of PECO. In the case of PECO, the Commission has already provided direction in other forums – specifically PECO’s default service plan[[23]](#footnote-24) and pending CAP plan.[[24]](#footnote-25) Also, see the January 3, 2013 *Secretarial Letter* where the Commission clarifies the timeframes and sequence of the PECO CAP plan proceeding in relation to the PECO CAP shopping plan – acknowledging that what occurs in the PECO CAP plan proceeding may impact the plans to allow PECO CAP customers to shop.[[25]](#footnote-26) PECO has been directed to allow their CAP customers to shop by April 1, 2014, and has to develop and file a plan to facilitate this once their pending CAP plan is approved (it is expected that PECO will be filing a CAP shopping plan on or around May 1, 2013).

We continue to believe that one of the basic intents of the Competition Act – to “permit retail customers to obtain direct access to a competitive generation market” - was intended to include all customers. 66 Pa. C.S. § 2802(3). We agree with PPL that CAP customers have the capability to make shopping decisions and should be allowed to do so. As NEM points out, these customers can, in addition to their CAP benefit, also receive the additional benefit of possible energy costs savings. We agree with PEMC and PULP that care must be taken to educate CAP customers so that they understand how their CAP benefit interacts with shopping. EDCs should provide such information along with the information they routinely provide to CAP customers when explaining their CAP benefits.

The Commission acknowledges the concerns expressed by the parties about the complexities involved with the participation of CAP customers in the competitive market and the possible impact on these programs. However, we agree with FE that measuring and determining the benefits of shopping requires more than just comparing a supplier price to the default price at one point in time. The Commission agrees with PPL that none of these complexities or concerns is insurmountable. In response to the concerns expressed by PULP and OCA that interested parties have a chance to participate in these matters, we note, as PPL does, that the major EDCs are required to file universal service plans with the Commission every three years. That review and approval process provides any interested party an opportunity to participate in the ongoing development of universal service programs. Regarding the development of these programs in the future, we do find merit in the ideas expressed by parties, including NRG and Citizen Power, that we should explore more comprehensive statewide solutions and structures. However, we think that a major undertaking like this is outside the scope of this proceeding and is best left to a future initiative.

Concerning LIURP, hardship funds and CARES, no parties’ comments persuade us to revise our original proposal and thus we propose no changes to these three programs. They will remain a function of the utility for the foreseeable future. As for LIHEAP, as we noted in the *Tentative Order*, our influence over this program is very limited. Also, the portability of LIHEAP benefits only becomes an important issue if, at some point in the future, a supplier is moved into the DSP role. Given that we are, per this Order, keeping the EDC in the DSP role, this is not a critical matter at this time. However, if at some point it is proposed that a supplier move into the DSP role, the ability of suppliers to receive LIHEAP payments as vendors may need to be addressed.

## H. Supplier Consolidated Billing

Supplier Consolidated Billing (SCB) is a billing option where the EGS bills the customer for both its EGS’s generation charges *and* the EDC’s distribution charges. Under SCB, the customer receives only one bill, from the EGS, and no longer receives a bill from the EDC. SCB was a billing option established by some of the EDCs’ restructuring settlements in the 1990s, but was never utilized. However, some EGSs have expressed interest in resurrecting SCB, believing that it helps them establish a stronger EGS-customer relationship. SCB presents several technical and legal questions.

In April 2010, the Electronic Data Exchange Working Group (EDEWG) convened a working group to discuss SCB in the context of EDI requirements. In August 2010, this EDEWG-SCB working group issued a report that announced a consensus was reached on some issues, but that many issues remained unresolved and would have to be referred to OCMO and the Committee Handling Activities for Retail Growth in Electricity (CHARGE).

The issues identified during informal discussions by the above-mentioned groups included the following:

* What is the payment obligation of the EDC and EGS to each other?
* Which entity is responsible for providing regulatory inserts and information?
* Which entity addresses consumer billing disputes?
* Which entity is obligated to negotiate and track payment agreements?
* What are the eligibility standards for customers to participate in SCB?
* What occurs if an SCB customer fails to pay in full?
* What occurs if the EDC fails to submit billing information?
* What is the obligation of the EGS to handle hardship fund donations?
* Can utilities that provide and bill for both electric and gas segregate electric from gas charges if only the electric charges are SCB?

Given the complexities and controversies mentioned above, OCMO, after consulting with the Commission, decided that SCB could not be effectively addressed using an informal process such as CHARGE. It was decided, instead, to refer SCB to the Investigation. While it is apparent that the issues remain numerous and complex, none of these concerns present an insurmountable obstacle to making SCB available. In the *Tentative Order*, the Commission proposed that, by July 1, 2013, OCMO was to provide a recommendation to the Commission as to how to proceed with making SCB available as a billing option. At the same time, we emphasized that we were proposing SCB as a billing option only – joining, not replacing, the other billing options that are currently available (utility consolidated billing and dual billing).

**1. Comments**

Consumer representatives express numerous concerns, especially relating to the application and enforcement of consumer protection laws in an SCB environment. OCA believes that it is premature to require SCB, at this time, due to limited interest from EGSs and that there has been no determination of the costs of this effort and whether the benefits would justify such costs. OCA submits that the costs of SCB should be borne by EGSs. Further, if SCB is pursued, OCA insists that all consumer protections be maintained. OCA at 18.

PULP questions if it is even possible to get the multitude of licensed suppliers to comply with the provisions of Chapter 56 when it is hard to get seven EDCs, who are closely regulated by the Commission, to recognize these provisions. PULP at 19. PULP also questions the Commission spending limited resources to develop a billing option that, in PULP’s opinion, is not authorized by Section 2807(c) of the Competition Act, 66 Pa. C.S. § 2807(c). PULP does not believe that the Commission’s stated intent that SCB only be an option available to the customer reflects the realities of the retail market. A customer who is shopping, PULP adds, is not typically able to negotiate individual contract terms, such as billing options, in that most EGS contracts are take it or leave it offers. PULP at 18.

PCADV shares PULP’s concerns with the effectiveness of applying consumer protection rules to numerous EGSs, especially the protections intended for victims of domestic violence. PCADV points out that it has taken many years to educate the EDCs to ensure that victims are able to access the relief to which they are entitled and that PCADV and its member programs would be forced to spend significant resources and time to develop similar working relationships with the many EGSs. PCADV at 5.

DLC and PPL join PULP in questioning the legal foundation for SCB, pointing out that Section 2807(c) of the Competition Act does not mention it. DLC at 5; PPL at 24. PPL adds that SCB is likely to be costly and that the lack of an SCB option has not been discussed or identified as being an impediment to shopping. As such, PPL suggests that the Commission move cautiously and seek simple, cost-effective solutions. PPL at 24 and 25. DLC, Pike and Citizens’ and Wellsboro believe that duplicative EDC and EGS billing systems will result in duplicative costs ultimately being borne by customers. DLC at 4 and 5; Pike at 7-10; Citizens’ and Wellsboro at 7 and 8. FE comments that the complexity involved in the implementation of SCB is vast and questions the level of interest in it. FE notes that EGSs did not use it in the past and that, given the implementation of EDC purchase of receivable (POR) programs, which are tied to EDC consolidated billing, it would seem that from an economic perspective, EGSs would have even less interest in SCB than they did over a decade ago. FE at 8.

PECO believes that SCB can be an important billing option for both EGSs and customers and, while it presents many technical and legal questions, these can all be addressed through continuing stakeholder discussions. This would include recovery for both implementation and ongoing costs. PECO at 16. Many suppliers, likewise, support SCB and urge the Commission to proceed in that direction. WGES believes that SCB will break the customer’s inherent bias towards remaining with the EDC. WGES at 2. NEM points out that suppliers currently operating in Texas and Georgia have expertise with SCB and that its adoption here may facilitate market entry by these suppliers to operate and do business in Pennsylvania. NEM at 7. PEMC applauds the PUC for advancing this option, but believes that utility-consolidated billing should be retained for the use of EGSs, especially smaller EGSs, that may not want, or be able, to perform SCB. PEMC at 8.

NRG notes that existing EDC billing systems are designed for tariffed utility services and that they cannot accommodate the plethora of billing needs of multiple EGSs, which prevents EGSs from offering products and services aimed at helping customers. NRG believes that utility-consolidated billing precludes EGSs from billing for new and innovative services. NRG at 9. RESA supports SCB because, under the current system, the EDC reinforces its relationship with the customer every month with its EDC-branded billing. RESA adds that an effective SCB program will have to include additional tools for EGSs in managing bad debt risk, including the ability to terminate service to customers for nonpayment. RESA at 14 and 15. In addition to SCB, RESA requests that the Commission consider requiring EDCs to unbundle their billing functions. Utilities would then tariff their billing functions and require suppliers to buy billing services at cost-based rates. RESA notes that, under this approach, customer care and billing costs would be removed from distribution rates and all customers, both default and shopping, would pay the same rate for access to the regulated utility bill. RESA adds that a similar outcome could be achieved by designating a third party entity to handle the billing for those EGSs that choose to use it. RESA at 15.  
  
 **2. Resolution**

While the Commission is of the opinion that SCB might someday play a role as a billing option in the competitive market, upon review of the comments, we have to conclude that we are not prepared to move to an SCB environment at this time. We agree with many of the suppliers who point out that SCB will facilitate the offering of innovative new products and services and will also help the supplier in establishing a brand identity with the customer. However, all parties appear to be in agreement that SCB could only be implemented after extensive work and expense by many entities. We are concerned with the burden this would impose, especially given the multitude of other, more critical, changes we are mandating in the near-term. We are also concerned that the extensive work and expense could result in a feature that will not be utilized sufficiently to justify the costs at this time.

We have substantial concerns that use of an SCB process may be even more unlikely now since POR programs are available. It is unclear how many suppliers would be willing to forgo the ease and convenience of utility consolidated billing under POR, where they have no bad debt risk, to opt for an SCB model where they assume the full burden of billing, collections and bad debt. We also point out that suppliers do currently have the option of issuing a separate bill to the customer (the dual billing option) if they find utility consolidated billing not conducive to their offerings or business model.

Therefore, the Commission will revise what we proposed in the *Tentative Order* – OCMO will not be submitting a recommendation to the Commission in July 2013 as to how to proceed with SCB. Instead, we direct OCMO to explore another possibility, more along the lines of what PPL suggested, to seek “simple, cost-effective solutions.” By the end of 2013, OCMO should submit a recommendation regarding the possibilities for making the utility consolidated bill more supplier-oriented. The current utility consolidated bill looks like the utility’s bill – with supplier information often relegated to a few lines, with the supplier’s name, phone number, rate and charges. This is an especially incongruent result for many customers whose supplier generation charges actually exceed the utility’s distribution charges. We are interested in pursuing options to make the supplier’s charges and information more prominent. This could include making the supplier information more visible, incorporating the supplier’s logo, providing more space for suppliers to provide bill messages and even the opportunity to include EGS bill inserts. The expected end-result would look more like a joint EDC-EGS bill.

We acknowledge that considerable work and some expense may be required to move to this kind of format. But we expect that the effort and expense necessary for this kind of effort will be considerably less than what would be required to create SCB. We also acknowledge that this issue has not been fully vetted through any informal or formal Commission process. Therefore, we will proceed cautiously and ask OCMO to consult with utilities, suppliers and consumer representatives as they explore the feasibility of this proposal.

We believe that this approach offers several advantages over creating an SCB environment at this time. As we have noted, we fully expect that this approach will require fewer resources than would be required to implement an SCB environment. In addition, this approach does not raise the consumer protection concerns expressed by OCA, PULP, PCADV and others, since we are not changing the entity that is billing and collecting from the consumers.

While we do find merit in RESA’s comments about unbundling the EDC billing function, we decline to pursue such an effort at this time. This concept has not been fully vetted in this proceeding. Additionally, we have some of the same concerns with this that we have with SCB – this would be a significant undertaking requiring the time and resources of many stakeholders. However, this decision does not preclude the Commission from addressing the unbundling of EDC billing functions in another proceeding in the future.

We reiterate that we are not dismissing SCB. We simply find that, at this time, there are other, more pressing priorities. We are still of the opinion that SCB can play a role in the competitive energy environment and the Commission will reconsider SCB at some point in the future. When and how we proceed with SCB will depend, in part, on the results of the changes we are proposing to the utility consolidated bill, as discussed previously. We look forward to exploring the possibilities of a more supplier-oriented utility consolidated bill and invite all interested stakeholders to participate in this effort.

## I. Accelerated Switching

Presently, a change in supplier can take from 16 to 45 days. This timeframe is a result of a variety of Commission regulations and EGS and EDC procedures that were established, in large part, to guard against “slamming,” the unauthorized change of a supplier. In 1998, the Commission promulgated regulations to address the supplier switching process and to guard against slamming. These regulations are found at 52 Pa. Code § 57.171 – § 57.179 (relating to standards for changing a customer’s electricity generation supplier). Included in these regulations is a ten-day waiting period, 52 Pa Code §§ 173- 174, which provides the customer time for contacting the utility to cancel the switch in cases where the customer did not authorize the switch of supplier. This ten-day waiting period is a significant part of the 16- to 45-day switching timeframe mentioned above.

As the market has evolved since 1998, the delay in transferring a customer’s account has been noted by some consumers as a lost savings opportunity that, in turn, results in customer frustration and disappointment and a less-than-favorable opinion of the competitive retail market. Because of these concerns, OCMO explored options to shorten the timeframe for switching to an EGS.

These efforts resulted in interim guidelines that put in place temporary waivers of 52 Pa. Code §§ 57.173 – 174 to the extent necessary to shorten the current 10-day confirmation period to 5 days. *See, Final Order, Interim Guidelines Regarding Standards for Changing a Customer’s Electricity Generation Supplier*, Docket No. M‑2011-2270442 (Order entered October 24, 2012). This Final Order also directed Commission staff to initiate a rulemaking to review and revise the switching regulations at 52 Pa. Code §§ 57.171 – 179. The rulemaking will explore methods to accelerate the switching timeframes beyond simply shortening the confirmation period. This could include off-cycle switching and other processes made possible with the deployment of advanced metering. Possible interim switching procedures, to be utilized until the full deployment of advanced metering, may also be considered.

In addition to the above Guidelines and the directed rulemaking, we invited comments on other related issues that involve the switching process, including “seamless moves” and “instant connect.” A “seamless move” is the ability of a customer’s choice of supplier to move with the customer to a new address without interruption. “Instant connect” is the ability of supply service to start on “day one” of new utility service – without the customer first having to go on default service. These two processes are currently not available. The EDCs point out that their systems are not designed to allow for these enrollment options.

**1. Comments**

Concerning accelerating the switching process, PEMC, NRG, NEM, WGES, FES, and PPL support the Commission’s proposal to proceed with a rulemaking. PEMC at 8; NRG at 11; NEM at 8; WGES at 3; FES at 5; PPL at 26. However, RESA believes that a stakeholder process should be convenedto develop the shortest possible switching timeframes. RESA at 17. FES suggests that the Commission eliminate the five-day waiting period. FES at 5. OCA agrees that lengthy switching delays can result in customer frustration and supports the Commission’s efforts to improve the efficiency of customer switching. However, OCA also asks the Commission to properly protect customers from unauthorized switching while pursuing the acceleration of switching. OCA at 19.

PPL and DLC believe that off-cycle switching is linked to advanced- metering. PPL at 26; DLC at 9. WGES agrees but suggests that the rulemaking address advanced metering so that the new regulations will be in place by the time the meters are deployed. WGES at 3. FES differs in that they want the Commission to allow mid-cycle switches based on estimated meter reads while awaiting deployment of advanced metering. FES at 6. PECO mentions that recovery of costs needs to be addressed and Pike asks that any existing waivers of the rules currently in place for specific EDCs remain in effect. PECO at 17; Pike at 10 and 11.

With regard to seamless moves, RESA suggests that the Commission establish firm goals and timelines for the EDCs to submit plans to the Commission detailing how they will enable these (and instant connects) in their service territories. RESA at 18. NEM suggests that rules should explicitly recognize that contracts and supply service should move with the customer to a new location, as long as the supplier can serve the new location and the new location accommodates the same type of energy supply. NEM at 8. NRG believes that a seamless move process without interruption in EGS service is fundamental to improving the customer experience in a competitive market. NRG at 11.

In general, suppliers strongly support the “instant connects” that would allow a new utility customer to start receiving supplier service on day one. RESA believes that ensuring that customers have the ability from day one to begin service with a new supplier is an important part of leveling the playing field between the DSP and competitive suppliers. RESA at 17. Likewise, EGSP believes that the inherent advantages of DSPs, like receiving all customers first, needs to be mitigated or eliminated. EGSP would go still further and require all customers to choose an electric provider when establishing service. EGSP at 6 and 8.

NRG thinks that the ability to enroll with a supplier at the time of new service is essential to eliminating the inherent presumption that EDC’s “own” their customer from the outset. NRG at 11. NEM states that the current presumption that consumers start service as utility commodity customers is inconsistent with the retail market goals enunciated by the General Assembly and the Commission, and further, this presumption reinforces consumer apathy. NEM at 8 and 9. PEMC views “instant connects” as the next logical step for the marketplace and FES states that EDCs need to implement the technology to allow instant connections on day one of utility service. PEMC at 8; FES at 7.

No party opposes the concept of seamless moves or instant connects. Pike does note that this kind of capability would require considerable expense and that the costs should be borne by the EGSs. Pike at 11 and 12. NRG notes that PECO proposed, in their most recent DSP filing, to initiate a collaborative to develop technical requirements and cost estimates for the system changes that will be needed. NRG suggests that all EDCs do the same. NRG at 11 and 12. OCA supports seamless moves and does not object to exploring instant connects, but believes that the costs and benefits have to be considered. OCA at 19. Citizens’ and Wellsboro likewise believe that costs need to be considered. Citizens’ and Wellsboro at 8. Several EDCs noted that extensive system changes will be required to facilitate this kind of functionality and that cost recovery needs to be addressed. PPL at 26; PECO at 17; Citizens’ and Wellsboro at 8; FE at 9 and 10. FE also asks that, due to the extensive programming tasks that are involved, implementation be required no earlier than June 1, 2015. FE at 9.

**2. Resolution**

Based on the general agreement of the parties, we will proceed with our previously announced intention of initiating a rulemaking by the end of 2013 to revise the switching regulations, with the intent of accelerating the switching process. A rulemaking will provide all interested parties with the opportunity to participate and will allow the Commission to make fully informed decisions on the complex issues involved. The use of a formal rulemaking should also help clarify any cost-recovery issues. Because the resulting costs will flow as a result of a final Commission order and regulatory requirements, cost recovery for these changes should be handled the same as any costs a utility incurs as a result of a Commission mandate.

By choosing to initiate a rulemaking, we are rejecting the use of a collaborative process. We believe most of these issues have already been aired via one working group or another (including the RMI) and that there is little, if anything, to be gained by further informal discussions. Also, given that this involves a change to existing regulations, a rulemaking is the legally appropriate venue for addressing these issues.

We understand the concerns expressed by some of the parties that off-cycle switching should be contingent on advanced metering. However, we do not, at this time, want to restrict the consideration of any possible approaches raised in the rulemaking and believe it is best to leave the resolution of this issue to that forum. We do agree with WGES that the role of advanced metering should be considered in the proposed rulemaking so that updated regulations can be in place by the time advanced meters are deployed. Also, once the new regulations are promulgated, Pike, given their unique circumstances, can make a determination as to the need for a waiver at that time and file a petition with the Commission if they believe such is still needed.

While the Commission intends to initiate a rulemaking to look at the switching regulations, in doing so, we do not rule out the possibility of exploring statutory changes that would complement or assist with these efforts, especially in the context of using advanced metering. To date, most of the discussion on the use of advanced metering has centered on their use in billing and load management. However, we believe that this discussion has to be expanded to also consider their role in the supplier switching process. As such, the Commission will consider whether or not statutory changes are needed to facilitate or clarify the use of advanced meters in the switching process.

We are also of the opinion that the implementation of seamless moves and instant connects does not have to wait until after a rulemaking is completed. While we acknowledge that there are several procedural and programming (including possible EDI) changes that may be required to implement seamless moves, we are unaware of any specific regulation or statute that would bar them. To the contrary, we believe seamless moves are a natural and expected part of the competitive market that have only been hindered by the current limitations of EDC account information systems. As such, we do not believe it necessary to promulgate a new section of regulations to address this limited, discrete function. Therefore, we direct the EDCs to develop and submit plans to the Commission by the end of 2013 to implement seamless moves in their service territories by June 1, 2015. The EDCs’ plans should also address costs and proposals for the recovery of those costs. While we believe it is important for EDCs to develop these plans with input from suppliers, we do not think a special, statewide collaborative process for this purpose is necessary. Instead, we direct EDCs to utilize their existing supplier-consultation processes in developing the plans. If any party believes that, at any point, the consultation process is not working as needed, that party should contact OCMO and seek assistance and direction.

Likewise, the implementation of instant connects does not require the promulgation of new regulations. However, we do acknowledge that instant connects may be more complicated in that the supplier switching regulations may have to considered, and perhaps even waived to some limited extent. For example, what role, if any, does a confirmation letter have in an instant connect process? Due to these regulatory questions, we must make sure that the instant connect process is considered and accommodated in the supplier switching rulemaking discussed above. Regardless, we do not believe that an exploration of instant connects need await the promulgation or revision of these rules. For the reasons cited by the supplier community, we believe that the ability of a new customer to instantly connect to their selected EGS is a vital mechanism that will go far in making default service truly “default.” As the suppliers point out, requiring all customers to first go on default service before obtaining service from a competitive supplier inappropriately makes the default service the “primary” service. This too easily hands the DSP customers who may stay with default service simply out of inertia. This is unacceptable. As such, we direct the EDCs to develop and submit plans to the Commission by the end of 2013 to implement instant connects in their service territories by June 1, 2015. The EDC’s plan should also address costs and proposals for the recovery of those costs. We also direct the EDCs to utilize their existing supplier-consultation processes in developing the plans. If a party believes that the intervention of the Commission is needed at any point, that party should contact OCMO.

## J. Provision of Metering Services

### 1. General Metering Services

The Commission, in its *Tentative Order*, proposed that the EDCs retain general metering services, such as the provision of meters and performing all relevant PJM settlement tasks. The Commission stated that this would allow for the continued use of invested infrastructure and the experience of the EDCs, as well as prevent potential smart meter implementation issues. *Tentative Order* at 31-32.

**a. Comments**

Citizen Power, FE, OCA, PECO, RESA and WGES all agree with the Commission’s proposal to have EDCs retain general metering services. Citizen Power at 5; FE at 10; OCA at 4 and 20; PECO at 17; RESA at 18 and 19; WGES at 3. FE states that, in the past, competitive metering has been explored; however, no interest was expressed in offering such services. FE at 10. PECO avers that moving metering services away from the EDCs could cause issues with the implementation of smart meters. PECO at 17.

NEM and PEMC agree that the EDCs should retain general metering services with the caveat that EGSs get open, non-discriminatory, real-time access to meter data. NEM at 9; PEMC at 9. PEMC states that advanced metering infrastructure (AMI) data must be provided to EGSs to allow for the development and implementation of a variety of customer offerings. PEMC at 9.

**b. Resolution**

The Commission maintains its position that the EDCs should retain general metering services with the implementation of this default service model. This includes the provision of meters, activities associated with the reading of meter data, associating that meter data with the appropriate billing data and performing all relevant PJM settlement tasks.[[26]](#footnote-27) EDCs already have the capability and infrastructure necessary to offer these services. Additionally, we agree with PECO that moving these services away from the EDCs, at this time, may affect the implementation of smart meter technology.

However, the Commission recognizes the concerns expressed by the EGS community regarding access to meter data. We continue to encourage the EDCs to work collaboratively with the EGSs and third parties to allow for open access to customer AMI and/or smart meter data. The EDCs are still required to meet the directives for EGS and third party access to data as outlined in previous Commission Orders.[[27]](#footnote-28) We agree with PEMC that open access to data will allow EGSs to offer more dynamic and innovative products to customers and provide for increased retail electric competition.

### 2. Net Metering Services

The Commission did not address the provision of net metering services within its *Tentative Order* as the proposed model maintained the EDC in the role of DSP. However, we will address comments related to such services within this section.

**a. Comments**

While Sierra Club believes that all EGSs should be required to offer net metering, it recognizes that this may not be possible. Sierra Club at 4. Both Sierra Club and MSEIA & PASEIA express concerns regarding the provision of net metering benefits should an EGS or alternative party be designated as a DSP. Specifically, both parties request that, should an EGS or third party be approved to act as a DSP, a condition of such approval should be the requirement to offer net metering benefits, including virtual meter aggregation, as outlined at 73 P.S. § 1648.2, at 52 Pa. Code §§ 75.13 – 75.1 and in Commission Orders. Sierra Club at 4 and 5; MSEIA & PASEIA at 3 and 4.

PennFuture and Sierra Club request that all EGSs be required to disclose net metering information, including a potential loss of benefits, to customers before enrollment occurs. PennFuture at 10 and 11; Sierra Club at 5. Additionally, PennFuture requests that the Commission include on its PAPowerSwitch.com website a list of EGSs offering net metering benefits. PennFuture at 11.

**b. Resolution**

The Commission recognizes the concerns of Sierra Club and MSEIA & PASEIA regarding the provision of net metering services should an alternative DSP be approved. We agree that the provision of such services must be addressed prior to the Commission’s approval of such a provider. As discussed previous within this Final Order, OCMO will convene a working group to discuss the implementation of a model in which an alternative entity, or multiple entities, provides default service. The working group shall discuss the possibility of an alternative DSP providing net metering benefits and OCMO will provide a recommendation to the Commission no later than November 15, 2013.

The Commission always encourages increased consumer education when EGSs market and enroll customers to ensure that informed decisions are being made. Additionally, we are already taking steps, such as the inclusion of a net metering designation for customers on the Eligible Customer List, to inform EGSs of those customers who are receiving net metering benefits. However, we encourage all parties in the competitive market to provide as much education as possible to customers during the switching process regarding potential changes to net metering benefits.

Regarding PennFuture’s request to include a net metering designation on the PAPowerSwitch.com website, CHARGE is already discussing potential changes to PAPowerSwitch.com, including such a designation. OCMO is currently working with the Commission’s Office of Communications to determine the feasibility of the changes received through the CHARGE forum. We encourage PennFuture to continue participating in the CHARGE discussions regarding such changes.

## K. Provision of Energy Efficiency and Conservation Programs

In its *Tentative Order*, the Commission proposed that the provision of EE&C programs be retained with the EDCs. The Commission believed this would allow EE&C measures to reach the broadest array of customers, regardless of whether or not those customers are participating in the competitive retail electric market. We also encouraged the EGSs to provide energy efficiency offerings to their customers to increase the diversity of products and services within the competitive market. *Tentative Order* at 33.

Additionally, at the Commission’s November 8, 2012 Public Meeting, Commissioner Witmer issued a Statement which presented specific questions regarding existing EGS EE&C offerings and the EGSs’ role in current EDC EE&C programs; the development of additional EE&C offerings by the EGSs; and how the EGSs could play a broader role in the current EDC-offered EE&C programs. *Investigation of Pennsylvania’s Retail Electricity Market: End State of Default Service*; *Statement of Commissioner Pamela A. Witmer*; Docket No. I-2011-2237952 (dated November 8, 2012).

**1. Comments**

Citizen Power, FES, OCA, PennFuture, Sierra Club and WGES agree with the Commission that the provision of EE&C programs should remain with the EDCs. This allows the offering of such programs to all customers, providing for economies of scale and the continued use of the same conservation service providers (CSPs) across all territories for certain measures. Citizen Power at 5; FES at 7; OCA at 4, 20 and 21; PennFuture at 2; Sierra Club at 2; WGES at 3. FES states that, even if an alternative DSP is approved, the provision of EE&C programs should remain with the EDCs to continue reaching both shopping and non-shopping customers. However, in response to Commissioner Witmer’s question regarding how EDCs and EGSs could coordinate services within the existing EE&C requirements, FES states that, while EE&C should be offered by the EDCs, TOU programs should solely be provided by EGSs. FES at 7.

NEM, NRG, PPL and RESA believe that the EGSs are well-equipped at competitively offering such programs and services and, as such, should be the sole parties offering such programs. NEM at 9 and 10; NRG at 12; PPL at 28-30; RESA at 19-21. In response to Commissioner Witmer’s question regarding changes to the end state proposal that may encourage EGSs to develop and offer EE&C services outside the scope of Act 129, NRG proposes that the EGSs and other parties be able to compete for a share of the EDCs’ EE&C funds to provide such services. NRG at 12. In response to Commissioner Witmer’s question regarding a potentially broader role to be played by EGSs in the mandated EE&C programs, NRG advocates for a transition to a fully competitive market. NRG at 12. PPL and RESA support a Commission-pursuit of legislative changes to the Competition Act to remove the EDCs’ EE&C requirements. PPL at 30; RESA at 20.

Citizen Power, FES, OCA and PennFuture agree with the Commission’s encouragement that, while the provision of EE&C programs should remain with the EDCs, EGSs should also provide such services. This allows for more diversity in the array of products and offerings to retail electric customers. Citizen Power at 5; FES at 7; OCA at 21; PennFuture at 2. In response to Commissioner Witmer’s question regarding a potentially broader role to be played by EGSs in the mandated EE&C programs, OCA states that EGSs can play a complementary role, while distinguishing themselves and their products from the EDC programs. OCA at 21.

EAP, FE and PPL opine that the Commission’s encouragement to EGSs to offer EE&C programs and services, in addition to the EDCs’ programs, reduces the EDCs’ ability to meet consumption reduction targets, as the EGS offerings reduce the potential for energy efficiency in the state. EAP at 5 and 6; FE at 10 and 11; PPL at 28-30. As such, EAP and FE request that, should the Commission continue to encourage EGS offerings of EE&C programs, the Commission should also pursue legislative changes that remove the financial penalties (as outlined in 66 Pa. C.S. § 2806.1 (f)(2)(i)) for noncompliance. EAP at 5 and 6; FE at 10 and 11.

FE, NRG and PECO request that, should the Commission maintain its encouragement to EGSs to offer EE&C measures, the EDCs be allowed to claim those savings towards their consumption reduction mandates. FE at 11; NRG at 13; PECO at 19. FE proposes that EDC-provided EE&C rebates be bundled into EGS offerings and that EGS-provided EE&C utilize, to the extent possible, the EDC-provided products and services. FE at 11. Additionally, in response to Commissioner Witmer’s question regarding how EDCs and EGSs could coordinate services within the existing EE&C requirements, PECO states that EGSs can already participate in its programs by completing rebate applications on behalf of customers and that the EDC should be able to count those savings towards its obligation. PECO at 19.

If the EDCs are to retain the provision of EE&C programs, PECO and PPL request that the Commission pursue legislative changes to remove the restriction, as outlined in the definition of a “conservation service provider” provided in 66 Pa. C.S. § 2806.1 (m), on EDC affiliates acting as CSPs. They aver that allowing affiliates to act as CSPs allows for the offering of new and innovative programs, providing a broader role for the EGSs to play within the mandated programs. PECO at 19; PPL at 30.

Commissioner Witmer solicited feedback on any EGSs currently providing, or planning to provide, EE&C services in the competitive retail market. PECO states that Exelon offers energy assessments; project financing, design and implementation; and conservation programs, like peak load management. PECO at 18. NRG asserts that Reliant Energy Northeast, LLC, currently offers TOU programs to PECO customers. NRG also states that it intends to offer more EE&C programs in Pennsylvania. NRG at 12 and 13. FES avers that, in addition to those EGSs offering TOU programs, some EGSs act as CSPs, participating in the EDC EE&C programs. FES at 8.

**2. Resolution**

The Commission maintains its position that the provision of EE&C programs be retained by the EDCs. As stated in its *Tentative Order*, the Commission believes that the EDC-provision of EE&C programs allows for widespread outreach to the majority of Pennsylvania’s retail electric customers. The EDCs’ EE&C programs also allow customers to benefit from the same, or similar, rebates and incentives. *Tentative Order* at 33. While we do not believe that EGSs could *not* offer similar programs, we believe moving the entirety of the EE&C responsibility to the competitive market, at this time, may lead to a significant loss of rebates and incentives considering the current lack of EGS-provided EE&C offerings (not including TOU rates). We believe the statewide electricity consumption reductions provided for by the EDC EE&C programs and the ability for a customer to participate in such programs regardless of whether or not they shop are beneficial to Pennsylvania ratepayers.

We maintain our encouragement to the EGSs to provide their own energy efficiency offerings in order to increase the diversity of products and services within the competitive market and to aid in the reduction of energy consumption across the state. We disagree that such encouragement will provide a largely negative effect on the EDCs’ ability to meet their consumption reduction mandates. The Act 129 Statewide Evaluator’s (SWE) Electric Energy Efficiency Potential for Pennsylvania Final Report[[28]](#footnote-29) (Market Potential Study), from which the Commission developed the EDCs’ consumption reduction mandates, outlined the opportunities, statewide, for electricity savings. The Commission is confident that, based on the results of the SWE’s Market Potential Study, the EDCs should be able to meet the mandates as prescribed, with potential savings still remaining for the competitive market to procure. Additionally, non-EDC-affiliate EGSs are welcome to become licensed CSPs within the Act 129 EE&C programs to aid the EDCs in garnering savings towards their consumption reduction targets. The Commission encourages such EGS participation within the mandated EDC EE&C programs.

The Commission will not pursue legislative changes to the definition of a CSP, as defined at 66 Pa. C.S. § 2806.1 (m), at this time. We believe it was the intent of the Legislature to prevent an EDC from providing its own ratepayers’ money to its affiliate, as well as to prevent one EDC’s ratepayer dollars from going to the EGS affiliate of another EDC. Additionally, we have not been provided with evidence that the current restriction has impeded an EDC from meeting its consumption reduction mandates.

## L. Existing Long-Term Contracts: Alternative Energy Credit, Default Service, and PURPA

The Alternative Energy Portfolio Standards Act of 2004, P.L. 1672, No. 213, (AEPS Act) became law on November 30, 2004. The AEPS Act, which took effect on February 28, 2005, established an alternative energy portfolio standard for Pennsylvania. The AEPS Act requires that an annually increasing percentage of electricity sold to retail electric customers by EDCs and EGSs be derived from alternative energy resources. The AEPS Act was codified at 73 P.S. §§ 1648.1, *et seq*.

Act 35 of 2007, P.L. 114, (Act 35) was signed into law on July 17, 2007, which took effect immediately. Act 35 amended the AEPS Act in several respects. In particular, Act 35 revised the schedule for solar photovoltaic requirements so that the requirements increase on an annual basis as opposed to increases in five year increments. 73 P.S. § 1648.3(b)(2). This legislation also made it clear that the solar photovoltaic requirement is a percentage of total retail sales, not a percentage of the Tier I requirements. *Id*. In addition, the Act 35 amendments required the Commission to consider EDCs’ and EGSs’ efforts in obtaining alternative energy credits through competitive solicitations and seeking to procure AECs or alternative energy through long‑term contracts in any *force majeure* determination. 73 P.S. § 1648.2.

While the Commission has provided some policy guidance on AEPS contracts, specifically those relating to solar AECs, we have not directed EDCs to enter into specific types of contracts for their procurement of AECs.[[29]](#footnote-30) As stated in the *Tentative Order*, the Commission proposed to hold all presently-effective AEC contracts, energy contracts that exist pursuant to previous or existing default service plans, and any contracts that exist pursuant to the Public Utility Regulatory Policies Act (PURPA) harmless from any of the changes that are effectuated in Pennsylvania’s retail markets initiated by this proceeding. Therefore, on a case-by-case basis, EDCs may propose the means by which these contracts will be addressed on the issue of cost recovery. Such means may include, but are not limited to, the inclusion of incurred costs in the PTC, the inclusion of incurred costs in a non-bypassable surcharge, or the voluntary assignment to an EGS or EGSs. We proposed that each EDC provide a proposal for the management of these energy contracts in their next round of default service filings. *Tentative Order* at 34-35.

**1. Comments**

MAREC, PennFuture, MSEIA & PASEIA, Citizen Power, OCA, RESA, and Citizens’ and Wellsboro support the Commission’s proposal to uphold all presently-effective AEC and energy contracts. MAREC at 2; PennFuture at 3; MSEIA & PASEIA at 2; Citizen Power at 5 and 6; OCA at 21 and 22; RESA at 21 and 22; Citizens’ and Wellsboro at 9. PennFuture, OCA and Citizens’ and Wellsboro also support the Commission’s recommendation to allow each EDC to provide a proposal for the management of existing long-term contracts in their next round of default service filings. PennFuture at 3; OCA at 21 and 22; Citizens’ and Wellsboro at 9.

ConEd also supports the proposal, but also seeks specific language directing that any cost recovery for such contracts be implemented in a competitively neutral fashion. ConEd at 5 and 6.

The Industrials agree with the Commission, that the appropriate venue to address cost recovery with respect to all existing long-term contracts is the default service plan proceedings. The Industrials however, go on to opine that some of these contracts may be serving only particular customer classes and traditional cost causation principles would support allocating the costs only to that class. The Industrials propose that the Commission should clarify that a “non-bypassable surcharge” can be class-specific rather than a uniform charge across all customer classes to resolve any uncertainty. Industrials at 10.

**2. Resolution**

The Commission will maintain its proposal as described in the *Tentative Order* to hold harmless all existing AEC, default service, and PURPA contracts from changes made during this proceeding. Additionally we direct the EDCs to allocate costs of contracts to rate classes for which the contracts were intended and to strive to recover contract costs in a competitively neutral manner.

## M. Future Long-Term Alternative Energy Credits Contracts

In the *Tentative Order,* the Commission requested comments on whether an EDC or an alternative DSP approved by the Commission, consistent with 66 Pa. C.S. § 2807(e)(3.1) and applicable regulations, should file a procurement plan for Tier I, Tier II, and Solar AECs with the Commission. We also requested that parties address whether it would be more appropriate to have this function fulfilled by an EDC (regardless of whether it has a default service obligation) or the entity providing default service. Comments were requested on whether these procurements should include a mix of short-term (one year or less), medium-term (one to five years), and long-term (six to ten years) contracts, or whether procurements should be EDC territory fact-specific, tailored specifically to each EDC territory’s unique circumstances, requirements and market conditions. If procurements were to be a mix of contract durations, we requested comments on whether the procurement schedules should aim to procure AECs necessary to comply with up to 50 percent of the zonal load for any given service territory and allocate those AECs on a pro-rata share basis among the EGSs operating in its zone, entirely among the default service load, or some mixture of both. *Tentative Order* at 36-37.

**1. Comments**

Sierra Club differentiates the risks associated with conventional generation resources from the risks associated with alternative energy resources. Specifically, Sierra Club submits that future variable costs are the largest risks for conventional wholesale generation resources. Conversely, Sierra Club avers that the variable costs for alternative energy resources are minimal and predictable. Sierra Club states that that the risks in developing resources such as wind and solar are largely derived from the potential for future demand to be sufficient to cover the capital cost of development. Consequently, Sierra Club submits that long term contracts for alternative energy resources will actually lower costs of development by removing this uncertainty. Sierra Club also states that long term contracts will provide alternative energy developers financing at lower interest rates which will ultimately lead to lower AEPS compliance costs. Sierra Club at 3.

Sierra Club argues further that the absence of long-term AEC contracts will make it more difficult to finance new alternative energy resource development. Future increases in AEPS requirements will, in turn, increase AEC demand and appreciate the value of AECS. However, Sierra Club opines that higher-priced AECs in the short term are unlikely to stimulate sufficient new development of alternative energy generation, as the risk of not meeting the revenue requirements still remains. Sierra Club concludes that the absence of long-term AEC contracts will either force ratepayers to pay sustained high prices for short term AECs or result in a failure of the market to meet the demands of the AEPS mandates at some point in the future. Consequently, Sierra Club advocates that the Commission adopt a policy that allows for the use of long-term contracts for Tier I AECs sufficient to stimulate and maintain a market for new development of these resources. Sierra Club at 3.

Sierra Club also requests that each EDC submit to the Commission an AEC procurement plan regardless of whether or not the EDC is the DSP. Sierra Club believes such plans will enable the Commission to determine whether each EDC has dedicated the appropriate level of resources to AEPS compliance. Sierra Club states that, since the EDCs have the most predictable customer base from year to year, that they are in a better position to enter into long term contracts. Sierra Club at 3.

Last, Sierra Club supports the concept of having EDCs procure AECs to cover 50 percent of the zonal compliance requirements for each year. Sierra Club believes that at least half of the AEC contracts to support this 50 percent portion should be of a time period that is ten years or greater and that the remaining portion should be five years or more. The other 50 percent of the AECs can be procured using any contract length deemed appropriate by the EDC or EGSs. Sierra Club states that, if an EDC’s AEC compliance requirement is reduced to less than 50 percent of the zonal load, then the procured AECs can be allocated to EGSs on a pro-rata share basis while recovering costs through a non-bypassable surcharge. This method, Sierra Club avers, eliminates any risk for the EDC to enter into long-term AEC contracts. Sierra Club at 3.

Concerning future AEC procurements, MAREC submits that the Commission is granted broad authority under Act 213, as amended, to administer the alternative energy system of payments. MAREC opines that there is no language in Act 213 that directs the Commission to implement a model where the EDCs or EGSs procure AECs jointly and/or exclusively. MAREC contends that the Act is strictly concerned with the mandatory delivery of alternative energy to the market. MAREC at 5. MAREC states that the Commission’s lack of any previously-mandated AEC longevity is not a barrier to implementing such a mandate now. Consequently, MAREC endorses the following long-term AEC procurement proposal:

* EDCs are mandated to procure 50 percent of the AECs per year required for AEPS requirements in their zones;
* Half of the procurements be for ten-year fixed price contracts and the other half for 5-year fixed-price contracts;
* EDCs retire AECS on behalf of EGSs and themselves based on a pro-rata share of EGS and EDC retail customers in a given EDC territory;
* EDCs recover costs through a non-bypassable surcharge;
* EGSs AEPS compliance obligations be reduced based on the AECs retired by the EDC on their behalf; and,
* EDCs conduct competitive, long-term AEC procurements annually until such time that the Commission determines that sufficient resources exist to meet AEPS requirements in the long-run.

MAREC at 8.

MAREC submits that it is essential that AECs send price signals sufficient to encourage development of new AEPS resources to meet the law’s requirements. MAREC details that, for this reason, renewable energy developers argue that long-term contracts provide the most efficient and best price signal. Continuing, MAREC states that the pricing of AECs is primarily associated with the recovery of long-term capital costs, which is contrary to the conventional generation market in which pricing is largely associated with variable costs. MAREC contends that relying on short-term markets for AECs will result in prices that are either too low or too high. In turn, this will create unnecessary price volatility for ratepayers and potentially discourage investment in required AEPS-qualifying capacity. MAREC at 12.

PennFuture submits that the proposed end state of default service, which relies on shorter-term default service energy procurements to facilitate retail competition, is detrimental to the development of renewable energy resources. In support, PennFuture avers that increased shopping will make EDCs reluctant to procure large portions of AECs and that EGSs are already unlikely to procure long-term AEC contracts due to high fluctuations in load. However, Penn Future contends that this issue is not isolated to Pennsylvania. Other states such as New York, New Jersey, and Rhode Island have endorsed the procurement of long-term AECs either via a central procurement model or requiring EDCs to procure a prescribed amount of AECs. PennFuture at 3 and 4.

PennFuture and MSEIA & PASEIA contend that an appropriate model for Pennsylvania would be to place a percentage of the AEPS compliance on the EDCs to be procured through a mix of long and mid-term AEC contracts. PennFuture and MSEIA & PASEIA recommend that EDCs procure 50 percent of their Tier I and solar zonal AEPS requirements, regardless of the EDC’s default service obligation, through a mix of ten-year and five-year Tier I and solar contracts. PennFuture and MSEIA & PASEIA propose that the EDCs recover the costs for these contracts through a non-bypassable rider. PennFuture at 4; MSEIA & PASEIA at 2 and 3. In support of its proposal, PennFuture submits that there is already precedent for this approach. Namely, Met-Ed, Penelec, and Penn Power currently have mechanisms in place to allow for the purchase of long-term solar AECs. PennFuture believes that its proposed model creates a mix of reasonable contract lengths. The 50 percent of AEPS compliance that remains with EGSs could be met through short-term and spot market procurements, while EDCs would enter into long-term contracts to help facilitate the build-out of renewable energy resources. PennFuture at 7-9.

PA Chamber opposes the Commission’s proposal to have EDCs enter into long-term AEC contracts. PA Chamber submits that the requirement of such contracts undermines the competitiveness of the electricity marketplace in Pennsylvania by shifting financial risks for AEPS generation facilities from developers to consumers. PA Chamber avers that the consequence will be that consumers end up paying more for electricity. Also, requiring EDCs to execute long-term AEC contracts and assigning the AECs to EGSs can end up interfering with the arrangements that customers negotiate with their retail suppliers. Last, PA Chamber avers that, according the Commission’s 2011 AEPS Report,[[30]](#footnote-31) there are sufficient alternative energy resources in PJM to meet AEPS requirements, therefore eliminating any need to mitigate financial risks. PA Chamber at 1 and 2.

Citizen Power believes that EDCs should be required to file AEC procurement plans with the Commission. Citizen Power avers that these plans should be comprised of a portfolio of medium and long-term AEC contracts that total 50 percent of the Tier I and solar AECs required for a given EDC, with half of the contracts for AECs being medium-term and half being long-term. Citizen Power submits that the AECs should be allocated to the default service load. If default load drops below 50 percent of the zonal load, the difference should be allocated to EGSs on a pro-rata basis based on EGS load. In support, Citizen Power states that the EDC, whether or not the DSP, already has experience with AEC procurement. Additionally, Citizen Power asserts that keeping the EDC in this role will avoid the potential transfer or assignment of contracts to any newly appointed DSPs. Last, Citizen Power contends that long-term contracts are preferable because they guarantee a stream of income for potential renewable generation projections. Citizen Power argues that this creates a reduction in risk for renewable generators and, in turn, avails the market to lower financing rates. Citizen Power 6 and 7.

The Industrials state that current statutory provisions neither mandate nor prohibit EDCs from entering into medium- or long-term AEC contracts. In general, the Industrials support an EDC-by-EDC resolution to this issue based on the characteristics of each EDC service territory. The Industrials aver that making a specific procurement mix a requirement may result in unintended consequences, such as customers paying AEC costs that are not consistent with current market conditions because the contract was executed five or ten year ago. Further, the Industrials maintain that the Commission’s tentative proposal could result in a scenario where the EDC or the DSP has more AECs than necessary. In such a case, the solutions suggested in the *Tentative Order* interfere with the negotiations between customers and EGSs and could result in customer paying twice for AECs. Consequently, the Industrials urge the Commission to reconsider its proposal. Industrials at 11 and 12.

OCA supports the implementation of a procurement structure that fosters the successful development of alternative energy resources. OCA believes the Commission proposal for more short-term default service energy procurements will not likely achieve this result. OCA further states that the EDCs’ upcoming default service plans handle AECs in different manners and that these experiences will allow for a more fully-informed discussion of the best method for meeting AEC obligations. OCA at 22 and 23.

PPL opines that requiring EDCs or the DSP to enter into long-term AEC contracts is not necessary to help Pennsylvania meet its alternative energy goals. PPL states that such a requirement is anti-competitive and contrary to the objectives of the Investigation. PPL contends that there is no evidence to suggest that the competitive market is not working to meet the AEPS goals, but rather, that the currently-suppressed price for AECs due to excess alternative energy generation resources is demonstration that the market is sending proper price signals. Finally, PPL asserts that the development of generation through non-bypassable charges will distort the competitive market and hinder future development of generation without subsidies. PPL at 31 and 32.

FE submits that the obligation to provide AECs should continue to be placed on the load serving entity (LSE), regardless of whether the LSE is an EGS or the wholesale supplier of energy to the DSP. However, FE states that if an EDC acquires additional long-term AECs they should be provided to EGSs and DSP suppliers on a load share basis. Further, the costs should be recovered from all customers via a non-bypassable rider. FE at 11 and 12.

FE avers that, given the current over-supply of AECs, as well as the Commission’s estimates for future demand of Pennsylvania AEPS qualifying AECs, there will no longer be a need for EDCs to procure contracts on a long-term basis in order to support alternative energy development after the expiration of the upcoming default service plans, which expire on May 31, 2015. FE also states that if these circumstances should change, this issue could be revisited at that point in time. FE at 12 and 13.

Citizens’ and Wellsboro contend that requiring small EDCs to implement a portfolio approach for AEC procurements may present challenges. For instance, the total AEC requirements for small EDC territories may be too small to warrant segregation into short-, medium-, and long-term transactions. As such, Citizens’ and Wellsboro request that the Commission adopt a flexible approach that allows each EDC to determine, within their default service plan proceedings, whether such an approach is both feasible and rational for implementation. Additionally, Citizens’ and Wellsboro request that the Commission ensure that EDCs will be entitled to full cost recovery for any short-, medium-, or long-term AEC procurements. Citizens’ and Wellsboro at 9.

EAP expresses concern that the Commission’s proposal to establish rules for EDC AEC procurements may unnecessarily increase alternative energy mandates. First, EAP submits that the AEPS Act mandates the amount of AECS EDCs and EGSs must purchase but not the type of contract they must enter into. Second, EAP contends that the Commission’s proposal is inconsistent with the Commission’s Solar Policy Statement, which only encourages, but does not require, EDCs to enter into long-term solar AEC contracts. EAP states that there are sufficient AECs in the market, at present, to satisfy AEPS mandates without mandating long-term contracts. As such, EAP contends that the AEPS is working and there is no need to compel such a procurement structure. Lastly, EAP believes that such a mandate shifts risks from developers to customers, which EAP avers is contrary to the purpose of the Competition Act. Consequently, EAP believes the Commission should not compel EDCs to file procurement plans requiring a mix of contract lengths for AECs. EAP at 6 and 7.

COMPETE strongly opposes the Commission’s proposal to have the DSP enter into a mix of short-term, medium-term, and long-term AEC contracts. COMPETE submits that this requirement would increase costs by forcing customers to pay for generation development before it is needed. COMPETE compares the assured cost recovery created in this proposal to the historical regulated generation environment which led Pennsylvania to restructure its market and provide customer choice in the first place. COMPETE also states that forcing customers to pay for these contracts through a non-bypassable surcharge, when alternatives exist in the market, deprives customers of the flexibility to choose the EGS and product that best suits their needs. Further, COMPETE opines that subsidies for development through non-bypassable surcharges will distort the market and significantly impact the ability of future generation to be developed without its own additional subsidies. Consequently COMPETE urges the Commission to modify its proposal to allow customers to continue to choose for themselves how best to meet their own individual electric needs. COMPETE at 3-5.

RESA does not support the Commission’s proposal to require EDCs to procure up to 50 percent of the AECS required for all load in the EDC’s service territory. RESA states that removing the AEC procurement responsibility from EGSs effectively denies EGSs an opportunity to enact competitive strategies to procure AEPS supply more efficiently. RESA recognizes that some EDCs already procure AECs on behalf of EGSs. RESA submits that, in these territories, it may be appropriate to maintain the status quo in order to avoid disrupting existing retail contracts and EGS procurement strategies. RESA at 23. RESA further submits that the current glut of AECs in the market gives the Commission more time to assess whether the competitive market can continue to be an efficient and cost-effective way to balance the supply and demand of AEPS eligible generation. If this glut diminishes, the Commission may, in the future, determine requirements to help achieve the goals mandated in the AEPS legislation. RESA at 24 and 25.

ConEd submits that properly-implemented, long-term AEC contracts by EDCs can be an effective policy tool to promote the continued build-out of alternative energy resources. It avers that cost recovery is a critical issue to consider when formulating an effective approach. ConEd believes there are three general approaches that can be utilized for AEC procurements. First, ConEd describes a scenario where the EDC procures AECs for all load and recovers costs through a non-bypassable surcharge. This approach is already used in the Met-Ed and Penelec service territories. ConEd believes this approach helps to stimulate demand and stabilize future revenue streams for solar projects in a competitive neutral manner. However, ConEd contends that a downside arises by eliminating the EGSs ability to form strategies to compete with each other in the AEC market. ConEd at 3.

Second, ConEd describes the option where AEC requirements are placed upon wholesale, full requirements suppliers of default service load. In this case, these costs are fully bypassable by customers because the costs are embedded in the PTC. Also, EGSs retain the liability to comply with AEPS and, therefore, will include those costs within their competitive offers. This model gives EGSs the ability to gain competitive advantages through their own management of AEPS compliance mandates. However, ConEd opines that this method may create little incentive for market participants to enter into long-term AEC contracts because EGS customer bases are migratory and default service contracts, as proposed in the *Tentative Order*, will only be for three months. Consequently, ConEd submits that this method may not meet the Commission’s policy objective of promoting renewable development by encouraging long-term AEC contracts. ConEd at 3 and 4.

Third, ConEd describes an option in which an EDC would procure a specified amount of AECs through a separate procurement and use these AECs to fulfill some of its AEPS requirements. ConEd asserts that, under this approach, the PTC reflects the combination of the EDC’s cost of AEPS procurements plus the residual amount of AECs that wholesale suppliers are responsible for, which is imbedded in default service bid prices. ConEd at 4 and 5.

PECO avers that the *Tentative Order* section regarding Future Long-Term AECs is based on the mistaken belief that the DSP procurement of a portion of AEPS requirements through subsidized long-term contracts will help facilitate a successful capacity build-out of AEPS-qualified generation facilities and help to ensure that the percentage goals of AEPS are met. PECO argues that the proposal errs in in three areas: (1) risk increases consumers’ prices for AEPS compliance; (2) deter competitive investment in renewable resources; and, (3) impede the competitive retail market. PECO at 20.

PECO points to PURPA, where utilities were required to enter into long-term contracts with the express intent to incent the development of renewable energy technologies and cogeneration. PECO opines that the result of PURPA was consumers being locked into paying billions above market prices. PECO agrees with EAP that the solar AEC market is over-supplied and that solar AEC prices have sharply declined over the past two to three years. PECO states that, a few years ago, solar AECs were trading on the short-term market for over $250 and are now trading for $10. Therefore, long-term contracts entered into a few years ago are significantly over market price. PECO contends that, if the contracts were mandated on utilities, consumers would be locked into above market prices. Conversely PECO states that long-term contracts negotiated by the competitive suppliers place the risk on the shareholders. PECO at 21 and 22.

PECO declares that AECs are inherently a part of the supply of electricity and should remain with the LSE. Further supporting this point, PECO refers to the PECO and FE default service plan proceedings, where the Commission ruled that Generation Deactivation Charges were determined to be “inherently part of the supply of electricity and should remain with the EGSs.” PECO at 22.

As to long-term, subsidized AEC contracts, PECO avers that such contracts will deter competitive investment in renewable generation. PECO states that there is currently an oversupply of renewable generation and there will continue to be an oversupply through at least 2015, as evidenced by the Commission’s 2011 AEPS Annual Report. PECO further explains that the data on pages 20 and 22 of the 2011 AEPS Annual Report show that the Tier I and the solar supplies are in excess of the projected demand in 2015 and suggests an additional year of excess. Additionally, PECO submits that AECs can generally be banked in all state renewable portfolios programs in PJM, therefore pushing the oversupply out another two years. Further, PECO claims that, since the publishing of the 2011 AEPS Annual Report, installed wind capacity has increased from 5,800 to 6,300 MW and solar photovoltaic MW have almost doubled. With this information, PECO contends that the market is oversupplied until at least 2017. PECO at 23.

PECO goes on to explain that the oversupply of renewable resources was caused, in part, by state and federal subsidies, despite a lack of demand. Renewable projects are more expensive than current energy and capacity prices and, therefore, rely on the value of AECs and other renewable energy credits (RECs) for development. PECO claims that interfering in the AEC market only exacerbates the oversupply of qualifying resources keeping AEC prices artificially low and, in turn, devalues the investment made by merchant developers of existing renewable generation. PECO at 24 and 25.

PECO requests the Commission to resist the urge to “fix” a nonexistent problem and let the market work as intended. It contends that, as the oversupply of existing renewable energy resources is reduced by increasing AEPS demand, the AEC prices will respond accordingly. PECO at 25.

PECO, as well as EPGA, note the comments of the Commission at the Federal Energy Regulatory Commission (FERC) addressing the potential anti-competitive results of New Jersey and Maryland’s proposals for subsidized long-term contracts for new natural gas generation. PECO at 26. The Commission noted, in its comments, that Pennsylvania has “abandoned direct command and control regulation…in favor of a market based approach which relies on economic signal to “tell” potential investors when, where, and how to add generation capacity.” Finally, PECO cites the Commission’s summary of the ultimate harm of subsidized generation:

In the short run, there may be savings achieved by paying

subsidized prices to a subset of suppliers, and lower prices to the

rest. But in the long run, consumers will pay more, up to and

including losing the benefits of competitive markets…This is

not in the public interest.

PECO at 27.

Lastly, PECO opines that long-term, subsidized AEC contracts impede competitive retail markets. PECO maintains that many EGSs have made significant investments (including renewable energy investments) in order to competitively serve their customers. It specifically points to Exelon Generation and Constellation wind and solar generation investments. PECO opines that those investments were made with the expectation that, as LSEs, they would have ongoing AEPS obligations and an opportunity to sell renewable energy and resulting AECs in the market at competitive prices. PECO opposes any scenario that does not involve the LSE being fully responsible for competitively procuring all energy for its customers. PECO at 27.

FES is closely aligned with PECO in that they believe the procurement of long-term AEC contracts should be the responsibility of EGSs, not EDCs. FES urges the Commission not to pursue legal authority to use the EDC, or DSP, to incent new construction of generation. FES states that, presently, the DSP has the sole discretion to determine the generation source and fuel type for its long-term contracts. FES opines that removing this discretion potentially leads to a harmful scenario of entering into long-term contracts at above-market prices to encourage new construction. It believes that the Commission’s proposal is contrary to the Competition Act. FES at 10 and 11.

NRG supports the continuation of EDCs entering into long-term contracts for, and the allocation and cost recovery of, solar AECs. However, NRG generally opposes the requirement that EDCS procure long-term non-solar AEC contracts. NRG believes that EGSs are best suited to competitively procure alternative energy resources to meet their AEPS obligations and the needs of their customers. NRG contends that, if EDCs are to undertake this procedure, EGSs may face challenges in providing offers that are 100 percent renewable. NRG at 14.

EPGA generally opposes the Commission’s proposal concerning long-term AEPS contracts. EPGA believes that the Commission’s proposal will result in a distortion of the wholesale markets by arriving at a price for these contracts that is substantially different from a price that a market would achieve under conditions of perfect competition. EPGA at 4. EPGA contends that the allowance of this subsidy is discriminatory towards non-AEPS-qualified generation resources which must compete without the benefits of a Commission-sponsored financial risk mitigation plan. Additionally, EPGA argues that mitigating long-term cash flow risks for AEPS-qualified generation is contrary to the Competition Act. EPGA at 4.

EPGA contends that current and projected capacity are adequate. EPGA cites the 2011 AEPS Annual Report and PJM’s Generation Attribute Tracking System (GATS) to validate their argument. EPGA at 9 and 12.

Finally, EPGA alleges that the Commission lacks statutory authority for its proposed market interventions. EPGA cites the Commission’s responsibilities under Act 213 of 2004, enumerated 1 through 19. They go on to assert 66 Pa.C.S. § 2807(e)(3.2)(iii) states that “the default service provider shall have sole discretion to determine the source and fuel type.” EPGA at 13-16.

EPSA opposes the Commission’s proposal. In general, EPSA states that the Commission’s proposal would be anti-competitive in Pennsylvania’s retail markets and would hurt the marketplace if Pennsylvania policy was extended or expanded to other resources by policy makers in other states. Secondly, EPSA opines that there is adequate renewable generation in PJM to meet Pennsylvania’s AEPS requirements through at least the next three years. EPSA at 2-5.

P3 specifically opposes the Commission’s proposal which would help facilitate a successful build-out of AEPS-qualified generation facilities by mitigating long-term cash flow risks for relevant generation owners or financiers. P3 argues that this proposal is anti-competitive and leads to long-term contracts that are uneconomic. P3 states that there is no evidence in this record, or otherwise, that suggests the competitive market will not work to send proper price signals for energy, capacity and AECs when renewable generation is needed. P3 contends that renewable generation already has an advantage over traditional forms of generation because of the legislatively-mandated AEPS requirements. P3 at 4.

**2. Resolution**

Given the multitude of comments in opposition, the Commission, at this time, will not adopt a prescriptive AEC procurement methodology. Rather, we believe that this subject would be more appropriately addressed by the Legislature, if they so desire.

## N. Statewide Consumer Education Campaign

In its *Tentative Order*, the Commission proposed the development and implementation of a comprehensive statewide consumer education campaign (campaign) based, in part, on the input of stakeholders participating in the RMI consumer education subgroup.

The proposed campaign, estimated to cost $5 million per year, for at least three years, would have required both EGSs and EDCs to contribute to the campaign following the “Fair Share” approach offered by EGSs during the subgroup process. The campaign’s primary message would focus on educating electricity consumers about the benefits of electric shopping and using the Commission’s online shopping and comparison tool, [www.PAPowerSwitch.com](http://www.PAPowerSwitch.com). Secondary messages would educate consumers about other RMI actions. *Tentative Order* at 37-39.

1. **Comments**

Throughout this Investigation, nearly all stakeholders have consistently supported the Commission’s efforts to enhance consumer education, including the initiatives undertaken as part of the Commission’s December 15, 2011 Secretarial Letter[[31]](#footnote-32) and the *March 2 Order*. However, comments to the *Tentative Order* reflect the lack of a clear consensus among stakeholders in moving forward with the proposed campaign.

RESA comments that the proposed plan is too large in scope, and believes that much of the work done up to this point can easily be reused. RESA at 25-32. FES makes the argument that marketing and consumer education aimed at particular customer classes, or at customers in individual EDC service territories, should be left to the discretion of, and funded by, individual EGSs as part of their competitive strategies and not part of a directed statewide campaign. FES at 11-15.

The Commission’s proposed funding mechanism for the campaign, the “Fair Share” approach described in the *Tentative Order*, also did not generate a clear consensus. DLC, PPL and Verdigris support EGSs paying all or a majority of the costs associated with the campaign. DLC at 1 and 10; PPL at 32 and 33; Verdigris at 5. On the other hand, FES points out that the Commission’s 2007 Final Order (*Policies to Mitigate Potential Electricity Price Increases*, Docket No. M-00061957 (Order entered May 17, 2007)) did not propose that EGSs bear any costs for consumer education, and, furthermore, the Commission may lack statutory authority to impose these costs on EGSs. FES at 11-15.

Additionally, several EDCs recognize that EDCs may still have consumer education obligations under the new campaign and, therefore, should be able to not only continue conducting current consumer education efforts in their service territories (DLC and PPL), but also recover costs incurred for consumer education (DLC, PPL, PECO and FE). DLC at 1 and 10; PPL at 32 and 33; PECO at 28 and 29; FE at 14 and 15.

Along the same lines, FE, NEM, OCA, PEMC and RESA feel strongly that consumer education benefits all customers and, therefore, the cost of the campaign should be included in the EDC delivery rates as a non-bypassable charge. FE at 14 and 15; NEM at 10; OCA at 23-25; PEMC at 9 and 10; RESA at 25-32. RESA elaborates that, under the currently-proposed “Fair Share” approach, it is the shopping customers who are penalized by bearing a majority of the costs for the campaign. RESA at 25-32. Finally, the Industrials agree with the Commission that only residential and small C&I customers should pay for the consumer education campaign, as the campaign would be conducted primarily for their benefit. Industrials at 13.

1. **Resolution**

After reviewing the comments of the parties to the *Tentative Order*, the Commission has decided to reduce the size and scope of the campaign.

The EDCs’ existing consumer education plans, pursuant to the Commission’s *Policies to Mitigate Potential Electricity Price Increases* Final Order, Docket No. M 00061957, entered May 17, 2007, expired in 2012 and will not be renewed. The Commission directs any EDCs which may continue to have Commission-approved consumer education obligations to coordinate those obligations with the messages of this statewide campaign to ensure consistency.

The Commission will direct its Office of Communications to work with a vendor, which the Commission will select, to develop, a detailed plan for a statewide consumer education campaign for the Commission’s consideration. The campaign will be funded directly by those EDCs that currently have competitive offers in their service territories, with a total aggregate funding not to exceed $2 million. The funding allocation will be based on their total number of residential and small commercial customers, both shopping and non-shopping, and recovered from those customers through a non-bypassable surcharge.

Furthermore, the Commission strongly encourages, and fully expects, those EGSs who are active in Pennsylvania to make significant contributions of funding and other resources to this campaign, which will be a part of the maximum $2 million total for the campaign and will help to offset the costs to the EDCs and their customers. The allocation of the $2 million total aggregate funding for EDCs will not be determined or instituted until after there is a clear understanding of the level and type of participation volunteered by EGSs.

The Commission directs its Office of Communications to work with RESA, the American Coalition of Competitive Energy Suppliers (ACCES), NEM and their respective members, to secure partnerships and commitments to this campaign and to participate in campaign activities, such as consumer incentive contests.

The campaign will launch by June 2014.

The campaign’s primary message will focus on educating consumers about the benefits of electric shopping and referring customers to [www.PAPowerSwitch.com](http://www.PAPowerSwitch.com), to shop, to switch or to become informed. Additionally, the education campaign will inform consumers of "typical" contract terms and conditions. The Commission directs its Office of Communications to contact the Commonwealth's statutory advocates, PULP and the Commission’s Consumer Advisory Council to identify possible issues and concerns with EGS contracts.

The primary audience of the proposed campaign will be residential and small business customers. The initiative will include customer surveys, advertising, consumer incentive contests and other educational initiatives.

The Commission will also work proactively with the National Federation of Independent Businesses, PA Chamber, and trade and civic organizations to promote [www.PAPowerSwitch.com](http://www.PAPowerSwitch.com), this campaign and its messages.

## O. Regulatory Costs and Assessments

### 1. Annual Electric Generation Supplier Licensing Fee

In its *Tentative Order*, the Commission proposed that EGSs pay an annual licensing fee to the Commission. This annual fee would help defray Commission costs associated with the following tasks that staff undertakes with respect to EGSs: review of reports, oversight of regulatory compliance issues including consumer complaints, maintenance of and upgrades to [www.PAPowerSwitch.com](http://www.PAPowerSwitch.com) and review of EGS bonding requirements. Many of these tasks involve not only suppliers that take title to electricity, but also brokers and marketers. *Tentative Order* at 40.

We also recognized in our *Tentative Order* that the Commission is prohibited from levying assessments on EGSs[[32]](#footnote-33) and a one-time licensing fee in the amount of $350 is the sole funding that the Commission presently receives from EGSs.[[33]](#footnote-34) Given the amount of work performed, and time spent, on EGS-related issues, combined with the small sum that licensed EGSs currently pay to the Commission, we proposed an annual fee. We presented two options on how to structure the fee: (1) a fee that is based on a percentage of an EGS’ gross intrastate revenues, subject to a maximum cap;[[34]](#footnote-35) or (2) a flat annual fee of $1,000. We proposed including brokers and marketers, as well as EGSs taking title to electricity, in the obligation to pay the annual fee. We recommended that EGSs that do not take title to electricity and are not liable for gross receipts tax, such as brokers and marketers, pay a flat annual fee of $1,000. *Tentative Order* at 40-41.

**a. Comments**

The majority of stakeholders who commented on this issue agree that the Commission should impose an annual fee. Several parties, such as NEM, PECO, PPL and RESA, prefer a flat annual fee over a fee that is based on a percentage of EGS sales, provided that the amount of the fee reasonably reflects Commission costs and is capped at an amount that does not create a barrier for EGSs to enter the market. NEM at 11; PECO at 29; PPL at 34; RESA at 32-34. PULP asserts that the $1,000 flat fee is a trivial sum and suggests that the Commission increase the fee. PULP at 19.

Other stakeholders, such as NRG, PEMC and WGES, recommend that the Commission impose a fee that is based on a percentage of sales. NRG at 15; PEMC at 10 and 11; WGES at 3 and 4. These stakeholders agree that the amount of the annual fee should be capped so as not to create a barrier to enter the market and that it should reflect Commission costs. If the Commission uses the fee structure based on a percentage of EGS sales, then OCA and WGES recommend that the Commission also impose a minimum annual fee, given that every EGS generates costs for the Commission and an EGS without sales in a certain year would be exempt from the annual fee. OCA at 25 and 26; WGES at 3 and 4.

PPL suggests that the annual fee be used towards consumer education purposes. PPL recognizes that allocating the fee for this purpose may necessitate legislative changes. PPL at 34.

On the other hand, some stakeholders disagree with the Commission’s imposition of an annual administrative fee on EGSs. FES argues that the Commission’s institution of an annual fee on EGSs requires a revision to the Code. FES notes that Section 317(a) of the Code, 66 Pa. C.S. § 317(a), permits the Commission to charge fees for certain services, including copying and certifying paper, testimony and records, and processing filings such as securities certificates and applications. However, Section 317(a) does not appear to permit the assessment of an annual fee upon EGSs. FES suggests that if statutory authority is obtained to impose an annual fee on EGSs, that the fee amount be established on a “reasonable costs basis,” pursuant to 66 Pa. C.S. § 317(a), and shared equally by all licensed EGSs. FES at 15 and 16.

RESA notes that EGS customers already pay Commission costs through EDC assessments and, therefore, there is no need to separately assess EGSs. RESA at 32-34.

Verdigris pleads that the Commission exempt brokers and marketers from the annual fee and states that the cost of overseeing brokers and marketers is negligible. If brokers and marketers are not exempted from the fee, then Verdigris suggests that they pay a licensing fee based on a percentage of revenues. Verdigris at 1-5.

**b. Resolution**

At the outset, the Commission agrees that legislative changes are necessary in order to impose an annual fee on EGSs, as mentioned by FES. The Commission proposes to seek to amend Section 317(a) of the Code to permit the Commission to establish, by a rulemaking, reasonable fees to be charged and collected for other services that are not currently enumerated in Section 317(a). The Commission expects to pursue this legislative change in order to lawfully collect fees from EGSs to reimburse the Commission for employee time and resources spent on supplier-related matters. At this time, the Commission does not envision using the annual EGS fee for consumer education, as suggested by PPL.

After the Code is amended, the Commission intends to require all EGSs, including brokers and marketers, to pay an annual flat fee in the amount of $1,000. The Commission believes that a flat fee structure is the easiest for the Commission to administer and suppliers to anticipate. Further, upon considering comments from the majority of stakeholders, a $1,000 annual fee does not appear to be so expensive that it would act as a barrier for new EGSs to enter the Pennsylvania market or existing licensed EGSs to remain in Pennsylvania.

The Commission disagrees with Verdigris that the cost of overseeing brokers and marketers is negligible. The Commission notes that brokers and marketers are listed on [www.PAPowerSwitch.com](http://www.PAPowerSwitch.com), a website for which the Commission must pay to update and maintain. In addition, the Commission is tasked with overseeing compliance with its regulations set forth in Chapter 54 of the Pennsylvania Code, 52 Pa. Code §§ 54.1, *et seq*., “Brokers, marketers, aggregators or any other entities, that sell to end-use customers electricity or related services utilizing the jurisdictional transmission and distribution facilities of an EDC” are required to abide by the Commission’s regulations in this chapter unless they are expressly excluded. *See* 52 Pa. Code § 54.31, relating to Definition of EGS. Thus, the Commission expends considerable staff time and resources on EGSs, including brokers and marketers, and the Commission maintains that an annual fee, payable by all EGSs, is essential to defray costs related to EGSs.

### 2. Recovery of Electric Industry Assessments through an Automatic Surcharge Mechanism

In its *Tentative Order*, the Commission proposed seeking legislative changes to permit EDCs to use an automatic surcharge mechanism, such as that which is available for the recovery of state taxes in Section 1307(g.1) of the Code, 66 Pa. C.S. § 1307(g.1), to recover electric industry assessments paid to the Commission. We noted that the Commission collects all regulatory expenses associated with the electric industry from EDCs. While EDCs may seek recovery of assessments through their distribution charges as part of a base rate case, the Commission believes that it would be more equitable to permit EDCs to recover assessments through an automatic surcharge mechanism. In this manner, EDCs would be able to fully recover assessments, which represent an unavoidable expense that is incurred by the Commission to regulate the electric industry – including EGSs – and also would be required to pass-through any reductions in assessments to consumers. *Tentative Order* at 41-42.

**a. Comments**

Several stakeholders support the Commission’s initiative to seek legislative changes that would permit EDCs to recover assessments through a surcharge mechanism. These stakeholders, DLC, FE and PECO, remark that EDCs have traditionally recovered this expense in distribution charges that are established in base rate cases. DLC at 1 and 10; FE at 15; PECO at 29 and 30. However, the annual amount of this unavoidable expense has fluctuated and use of a surcharge mechanism will result in a fairer recovery. DLC recommends that the Commission provide EDCs with the flexibility to implement the adjustment clause in either the next base rate filing or by a separate filing. DLC at 10.

Three stakeholders oppose the Commission’s proposal: Citizens’ and Wellsboro, the Industrials and OCA. Citizens’ and Wellsboro argues that the costs to regulate EGSs should be solely the expense of EGSs. Citizens’ and Wellsboro at 10. Likewise, the Industrials assert that the Commission’s assessments should be allocated to the entities that are responsible for them – the EGSs. The Industrials question why the Commission is not seeking to amend the Code to give it authority to directly assess EGSs. Industrials at 13-15.

OCA submits that Commission assessments are not large or volatile expenses that require special ratemaking treatment. Rather, assessments are a normal recurring operating expense that are appropriately included in base rates and no legal or policy justification exists to single-out this one item for surcharge treatment. OCA at 26.

The Industrials also support retaining assessments in base rates and note that EDCs can file base rate cases to reflect the level of assessments. The Industrials remark that some EDCs file base rate cases every 2 to 3 years. If the Commission chooses to implement an automatic surcharge mechanism, the Industrials recommend that the clause be designed to reflect the allocation methodology for regulatory assessments that is used in rate cases. The Industrials assert that a clause that results in a per-meter surcharge or a percentage of the customer’s distribution costs, such as the State Tax Adjustment Surcharge, would be more appropriate than a kWh surcharge. Industrials at 13-15.

Citizens’ and Wellsboro argue that the recovery of EGS assessments through an automatic surcharge mechanism penalizes customers who do not shop in the retail market. Citizens’ and Wellsboro claim that it is not reasonable to require customers who do not use EGS services to subsidize EGS regulatory costs. Citizens’ and Wellsboro at 10.

**b. Resolution**

The Commission intends to pursue legislative changes to allow EDCs the option to implement an automatic surcharge mechanism to recover electric industry assessments paid to the Commission. When the Code is revised, the Commission anticipates providing EDCs with flexibility to decide whether, and how, they would like to implement the adjustment clause, such as by including it in a base rate filing or by a separate filing. The Commission will address the appropriate allocation methodology for assessments after the Code is amended.

In response to Citizens’ and Wellsboro’s concerns that the automatic surcharge mechanism penalizes customers who do not choose an EGS, the Commission notes that electricity customers will not fare worse than the current method of EDC recovery of electric industry assessments in base rates. Rather, the surcharge mechanism will result in a fairer recovery to the EDCs, who must pay for all electric industry assessments, and will not adversely affect electricity customers.

As to the Industrials’ question asking why the Commission is not seeking an amendment of the Code to allow assessments on EGSs, the Commission believes that the better solution is to continue collecting all costs associated with regulating the electric industry from EDCs and allowing EDCs to recover those assessments through an automatic surcharge mechanism. Our reasons are explained below.

Initially, we note that it would often be difficult for Commission staff to determine proper time allocations as between EDC and EGS industry groups. For instance, although time spent on an EDC’s base rate case would clearly be allocated to the EDC industry group and time spent an EGS’s license application would be allocated to the EGS industry group, it would be challenging for staff, with any accuracy, to allocate time spent on this Final Order or on a default service plan order on either the EDC or EGS industry group. Since many of the proceedings and issues affect both EDCs and EGSs, it is more efficient to simply allocate all time spent on electric issues to the same category. Additionally, assessing only EDCs is simpler from an administrative standpoint since that process involves the issuance of assessment notices to ten companies rather than 230 companies. Further, assessing only the EDCs provides greater certainty for the source of revenues needed to fund the Commission’s budget due to their presence in Pennsylvania as the delivery companies. Finally, assessing EGSs could be viewed as anti-competitive since EDCs recover these costs through the distribution charge while EGSs would only have the commodity charge available for recovery.

# CONCLUSION

For the above-described reasons, the Commission adopts the end state model for default electric service as described herein.

**THEREFORE,**

**IT IS ORDERED:**

1. That the End State of Default Service, as set forth in this Final Order, is adopted.

2. That the Office of Competitive Markets Oversight shall convene a working group to identify issues related to the implementation of a model in which an alternative entity, or multiple entities, provides default service. Recommended solutions for these issues shall be provided to the Commission no later than November 15, 2013.

3. That the Office of Competitive Markets Oversight shall develop a Procurement Collaboration Working Group which will formulate a uniform yearly certification process, a uniform supply master agreement and a procurement methodology and timeline for the electric distribution companies’ quarterly default service auctions. This working group will also develop any other necessary protocols, procedures or documents necessary to run the quarterly auctions. The working group will provide recommendations to the Commission as soon as practicable, but not later than April 1, 2014, in order to provide the Commission time to approve or amend the recommendations by June 1, 2014.

4. That the Office of Competitive Markets Oversight shall explore options to create a more supplier-oriented utility consolidated bill and provide recommendations to the Commission by the end of 2013.

5. That the electric distribution companies shall utilize their existing supplier-consultation processes to develop and submit plans to the Commission by the end of 2013 which allow the implementation of seamless moves in their service territories by June 1, 2015.

6. That the electric distribution companies shall utilize their existing supplier-consultation processes to develop and submit plans to the Commission by the end of 2013 which allow the implementation of instant connects in their service territories by June 1, 2015.

7. That the Office of Communications shall implement the statewide consumer education campaign as set forth in this Final Order. The campaign will target residential and small business customers and will include significant contributions from electric generation suppliers, as well as electric distribution companies, in further promoting the benefits of electric shopping, directing consumers to [www.PAPowerSwitch.com](http://www.PAPowerSwitch.com) and educating consumers about changes brought about by the Retail Markets Investigation.

8. That the Office of Communications shall secure partnerships with the key stakeholders identified in this Final Order in an effort to maximize resources and ensure appropriate levels of communication and coordination on a statewide basis.

9. That this Final Order shall be served on all Electric Distribution Companies, all licensed Electric Generation Suppliers, the Bureau of Investigation and Enforcement, the Office of Administrative Law Judge, the Office of Consumer Advocate, the Office of Small Business Advocate, the Energy Association of Pennsylvania, and all other parties who filed comments or testified in Phases I and/or II of the Retail Market Investigation.

10.That a copy of this Final Order shall be filed at Docket No. I-2011-2237952 and posted on the Commission’s website at the Retail Markets Investigation web page: <http://www.puc.state.pa.us/utility_industry/electricity/retail_markets_investigation.aspx>.

11.That the Office of Competitive Markets Oversight shall electronically send a copy of this Final Order to all persons on the contact list for the Committee Handling Activities for Retail Growth in Electricity, and to all persons on its contact list for the *Investigation of Pennsylvania’s Retail Electricity Market.*

12.That the Secretary close this docket upon the entry of this Final Order.



**BY THE COMMISSION,**

Rosemary Chiavetta

Secretary

(SEAL)

ORDER ADOPTED: February 14, 2013

ORDER ENTERED: February 15, 2013

1. AARP, American Public Power Association, BlueStar Energy Services, Brighten Energy, Citizen Power, Inc. (Citizen Power), Citizens' Electric and Wellsboro Electric (Citizens’ and Wellsboro), Citizens for Pennsylvania’s Future (PennFuture), City of Philadelphia, Community Legal Services of Philadelphia (CLS), Consolidated Edison Solutions, Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc. (Constellation), Direct Energy Services, LLC (Direct Energy), Dominion Retail, Inc. and Interstate Gas Supply (Dominion Retail and IGS), Duquesne Light Company (DLC), Energy Association of PA (EAP), Exelon Generation Company and Exelon Energy Company, FE (Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company), FirstEnergy Solutions Corporation (FES), Future Times Energy Aggregation Group, Hess Corporation (Hess), Industrials (Industrial Energy Consumers of Pennsylvania, Duquesne Industrial Intervenors, Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance, Penn Power Users Group, Philadelphia Area Industrial Energy Users Group, PP&L Industrial Customers Alliance and West Penn Power Industrial Intervenors), Liberty Power, Mid-Atlantic Renewable Energy Association, National Energy Marketers Association (NEM), NRG Energy, Inc. (NRG), Office of Consumer Advocate (OCA), Office of Small Business Advocate (OSBA), Pennsylvania Coalition Against Domestic Violence (PCADV), Pennsylvania Energy Marketers Coalition (PEMC), Pennsylvania Utility Law Project , PPL Electric Utilities Corporation and PPL EnergyPlus, LLC (collectively, PPL), ResCom Energy, Retail Energy Supply Association (RESA), State Representative C. George, Stream Energy PA, Washington Gas Energy Services, Inc. (WGES), and York Solid Waste & Refuse Authority. [↑](#footnote-ref-2)
2. <http://www.puc.state.pa.us/utility_industry/electricity/retail_markets_investigation.aspx> [↑](#footnote-ref-3)
3. Recaps of these conferences are also available on the Commission’s website at: <http://www.puc.state.pa.us/utility_industry/electricity/retail_markets_investigation.aspx> [↑](#footnote-ref-4)
4. AARP and the Pennsylvania Utility Law Project, Citizen Power, Citizens’ and Wellsboro, Constellation, Direct Energy, Dominion Retail and IGS, DLC, Exelon Generation Company, Exelon Energy Company and PECO Energy Company, FE, Hess, Industrials, NEM, OCA, OSBA, PPL, PECO Energy Company (PECO), PennFuture, Pike County Light and Power Company (Pike), RESA, Solar Alliance and UGI Energy Services, Inc. (UGIES). [↑](#footnote-ref-5)
5. Direct Energy, Dominion Retail and IGS, DLC, EAP, FE, FES, Industrials, PEMC, OCA and PECO. [↑](#footnote-ref-6)
6. AARP, the Pennsylvania Utility Law Project and CLS, Citizen Power, Citizens’ and Wellsboro, Constellation, Direct Energy, Dominion Retail, DLC, Exelon Generation Company and Exelon Energy Company, FE, FES, Industrials, NEM, OCA, PCL&P, PECO, PEMC, PPL Electric Utilities Corporation, RESA, Spark Energy, L.P., UGIES, UGI Utilities, Inc. – Electric Division, Wal-Mart Stores East, LP and Sam’s East, Inc. (Wal-Mart) and WGES. [↑](#footnote-ref-7)
7. AARP, the Pennsylvania Utility Law Project and CLS, Citizens’ and Wellsboro, Direct Energy, Dominion Retail, DLC, FE, FES, Industrials, OCA, PECO, PCADV, PEMC and RESA. [↑](#footnote-ref-8)
8. The discussion document is available at <http://www.puc.state.pa.us/electric/pdf/RetailMI/RMI-SecLtr_Staff_Doc_EnBanc_Hearing030212.pdf> [↑](#footnote-ref-9)
9. AARP, the Pennsylvania Utility Law Project and CLS, Citizen Power, Citizens’ and Wellsboro, Direct Energy, Dominion Retail and IGS, DLC, EAP, Exelon Generation Company, Exelon Energy Company, Constellation NewEnergy, Inc. and PECO Energy Company, FES, FE, Industrials, Mid-Atlantic Renewable Energy Coalition (MAREC), NRG, OCA, PCADV, PennFuture, PEMC, RESA, Solar Energy Industries Association and PA Solar Energy Industries Association (SEIA and PASEIA), Wal-Mart and WGES. [↑](#footnote-ref-10)
10. The Commission received comments from EverPower Wind Holdings, Inc. on December 13, 2012. These comments will not be considered as they were filed after the final date to submit comments to the *November 8 Order*. In addition, the comments of EverPower Wind Holdings, Inc. responded to specific comments that other stakeholders submitted. It would be inequitable to consider the comments of EverPower Wind Holdings, Inc., given that they essentially constituted reply comments and no other party had an opportunity to file reply comments to the *November 8 Order*. [↑](#footnote-ref-11)
11. We note that the Code allows for either an electric distribution company or a competitive supplier to fulfill the default service role. Currently, the default service roles across all service territories are fulfilled by electric distribution companies. Because of this, we use the terms “default service provider” and “electric distribution company” interchangeably throughout this Order. We do not, however, intend for this to be a signal that we expect that the default service role will always be fulfilled by electric distribution companies. [↑](#footnote-ref-12)
12. While OCMO will address all stakeholder viewpoints when providing its recommendations to the Commission, we will not require that consensus be met. [↑](#footnote-ref-13)
13. For the purposes of this proceeding, the Commission defines large C&I customers as those with demand of 500 kW or greater. [↑](#footnote-ref-14)
14. *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan*, Docket No. P-00072245 (Opinion and Order entered August 16, 2007). [↑](#footnote-ref-15)
15. *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan*, Docket No P-2008-2044561 (Opinion and Order entered March 23, 2009); *Petition of Pike County Light & Power Company for Approval of its Default Service Implementation Plan*, Docket No. P-2011-2252042 (Opinion and Order entered February 25, 2011). [↑](#footnote-ref-16)
16. The most recent Pike decision is on appeal at the Commonwealth Court, in *Irwin A. Popowsky v. Pennsylvania Public Utility Commission*, Commonwealth Court Docket No. 1179 C.D. 2012. [↑](#footnote-ref-17)
17. These reports are available at the following link: <http://www.puc.pa.gov/filing_resources/customer_service_performance_reports.aspx>. [↑](#footnote-ref-18)
18. These reports are available at the following link: <http://www.puc.pa.gov/filing_resources/universal_service_reports.aspx>. [↑](#footnote-ref-19)
19. *See Guidelines for Maintaining Customer Services at the Same Level of Quality Pursuant to 66 Pa. C.S. § 2807(D), and Assuring Conformance with 52 Pa. Code Chapter 56 Pursuant to 66 Pa. C.S. § 2809(E) and (F),* Docket No. M-00960890F0011 (Order adopted July 10, 1997). [↑](#footnote-ref-20)
20. This affidavit is Appendix B of the supplier application package and can be viewed on the Commission’s website at: <http://www.puc.state.pa.us/general/onlineforms/pdf/EGS_Licen_App.pdf> [↑](#footnote-ref-21)
21. This 2011 revision to 52 Pa. Code § 56.12(7) is an example of the Commission revising a consumer protection regulation in the context of Section 2807 of the Competition Act in that it served, in this case, to enhance the protections consumers receive. [↑](#footnote-ref-22)
22. 52 Pa. Code § 54.72 – CAP – Customer Assistance Program – An alternative collection method that provides payment assistance to low-income, payment troubled utility customers. CAP participants agree to make regular monthly payments that may be for an amount that is less than the current bill in exchange for continued provision of electric utility services. [↑](#footnote-ref-23)
23. *Petition of PECO Energy Company for Approval of its Default Service Plan*, Docket No. P-2012-2283641 (Order entered November 21, 2012). [↑](#footnote-ref-24)
24. *PECO Energy Company Universal Service and Energy Conservation Plan for 2013-2015 Submitted in Compliance with 52 Pa. Code §§ 54.74 and 62.4*; Docket No. M-2012-2290911. [↑](#footnote-ref-25)
25. Secretarial Letter re: *Petition of PECO Energy Company for Approval of its Default Service Program*; Docket No. P-2012-2283641; *PECO Energy Company Universal Service and Energy Conservation Plan for 2013-2015 Submitted in Compliance with 52 Pa. Code §§ 54.74 and 62.4*; Docket No. M-2012-2290911, dated January 3, 2013. [↑](#footnote-ref-26)
26. The EDC-provision of metering services will not affect any metering provided to customers by PJM Curtailment Service Providers. [↑](#footnote-ref-27)
27. *See,* *Smart Meter Procurement and Installation* Implementation Order, at Docket No. M-2009-2092655 (Order entered June 24, 2009); *Smart Meter Procurement and Installation* Final Order, at Docket No. M-2009-2092655 (Order entered December 6, 2012). [↑](#footnote-ref-28)
28. The SWE’s Market Potential Study is available at the following link: <http://www.puc.state.pa.us/filing_resources/issues_laws_regulations/act_129_information.aspx>. [↑](#footnote-ref-29)
29. *See, Policy Statement in Support of Pennsylvania Solar Projects* Final Policy Statement Order, Docket No. M-2009-2140263, (Order entered September 16, 2010). [↑](#footnote-ref-30)
30. The Commission’s Alternative Energy Portfolio Standards 2011 Annual Report is available at the following link: <http://www.puc.state.pa.us/consumer_info/electricity/alternative_energy.aspx>. [↑](#footnote-ref-31)
31. *Investigation of Pennsylvania’s Retail Electricity Market; Directive to Specified Electric Distribution Companies to Produce and Mail Electric Shopping Postcards to Customers,*  Docket No. I-2011-2237952. Secretarial Letter dated December 15, 2011. [↑](#footnote-ref-32)
32. *See, Delmarva Power & Light Co. v. Commonwealth*, 870 A.2d 901, 911 (Pa. 2005). [↑](#footnote-ref-33)
33. The Commission charges a $350 application fee for an EGS license pursuant to section 317(a)(4) of the Code, 66 Pa. C.S. § 317(a)(4), and section 1.43(a) of the Commission’s regulations, 52 Pa. Code

    § 1.43(a). [↑](#footnote-ref-34)
34. We noted that EGS intrastate revenues can be obtained from reports pertaining to gross receipts that EGSs are required to file with the Commission pursuant to 52 Pa. Code § 54.39. [↑](#footnote-ref-35)