RULES AND REGULATIONS

Title 52—PUBLIC UTILITIES

PENNSYLVANIA PUBLIC UTILITY COMMISSION

[52 PA. CODE CHS. 54 AND 57]

[L-00040169]

Provision of Default Service

The Pennsylvania Public Utility Commission, on May 10, 2007, adopted at final rulemaking order defining the obligation of electric distribution companies to serve retail customers at the conclusion of their respective transition periods.

Executive Summary

Section 2807(e)(2) of the Public Utility Code, 66 Pa.C.S. § 2807(e)(2) (relating to duties of electric distribution companies), requires the Commission to promulgate regulations that define the obligation of electric distribution companies to serve retail customers at the end of the restructuring transition period. Section 2807(e) mandates that all customers who do not receive generation service through the competitive retail market must be provided generation service by either their incumbent electric distribution company or a Commission approved alternative provider. Generation supply provided to these customers must be acquired at prevailing market prices, and the provider may fully recover all reasonable costs associated with this service. On December 16, 2004, the Commission issued a Notice of Proposed Rulemaking that formally commenced this rulemaking process, which included additions to and revisions of Chapters 54 and 57 (relating to electricity generation customer choice and electric service) of the Commission's regulations. The Commission sought comments from all interested parties on the issues addressed in the proposed regulations.

The Commission identifies the generation service provided to customers under Section 2807 as "default service." The regulations require electric distribution companies to act as the default service provider to all retail customers, unless an alternative provider is approved by the Commission. Default service providers must continue to comply with all existing regulations, statutes and orders pertaining to public utility service to the extent they are not modified by this subchapter.

To meet the "prevailing market price" legal standard, the default service provider must procure all generation supply through a Commission approved competitive bidding process. The regulations provide for a two phase procedure for complying with the obligation. Providers must first submit default service implementation plans for the Commission to review, which would include a proposed competitive procurement process. Upon approval of the implementation plan by the Commission, the default service provider will execute its procurement process. The prices that result from compliance with the procurement process will be deemed the "prevailing market price" for default service.

The regulations also identify the mechanisms by which the default service provider will recover its costs, the rules governing customer migration to and from default service, and provide new competitive safeguards to ensure the reliable provision of default service.

Regulatory Review

Under section 5(a) of the Regulatory Review Act (71 P. S. § 745.5(a)), on February 14, 2005, the Commission submitted a copy of the notice of proposed rulemaking, published at 35 Pa.B. 1421 (February 26, 2005), to Independent Regulatory Review Commission (IRRC) and the Chairpersons of the House Committee on Consumer Affairs and the Senate Committee on Consumer Protection and Professional Licensure for review and comment.

Under section 5(c) of the Regulatory Review Act, IRRC and the Committees were provided with copies of the comments received during the public comment period, as well as other documents when requested. In preparing the final-form rulemaking, the Department has considered all comments from IRRC, the House and Senate Committees and the public.

Under section 5.1(j.2) of the Regulatory Review Act (71 P. S. § 745.5a(j.2)), on July 18, 2007, the final-form rulemaking was deemed approved by the House and Senate Committees. Under section 5.1(e) of the Regulatory Review Act, IRRC met on July 19, 2007, and approved the final-form rulemaking.

Public Meeting held
May 10, 2007

Commissioners Present: Wendell F. Holland, Chairperson; James H. Cawley, Vice Chairperson; Kim Pizzingrilli; Terrance J. Fitzpatrick

Rulemaking Re Electric Distribution Companies' Obligation to Serve Retail Customers at the Conclusion of the Transition Period Pursuant To 66 Pa.C.S. § 2807(e)(2); Doc. No. L-00040169

Final Rulemaking Order

By the Commission:

The Electricity Generation Customer Choice and Competition Act (Competition Act), 66 Pa.C.S. §§ 2801—2812, requires the Commission to promulgate regulations defining the obligation of electric distribution companies (EDCs) to serve retail electric customers at the conclusion of the restructuring transition periods. On December 16, 2004, the Commission issued proposed regulations for public comment on this subject. On February 8, 2007, the Commission issued an advance notice of final rulemaking (ANOFR) for public comment. The Commission has completed its review of the comments to the ANOFR, and today issues a final form default service regulation. At separate dockets, we are issuing a final policy statement on default service and retail electric markets, and identifying other policies for addressing potential electric price increases.[1]

BACKGROUND

Section 2807(e)(2) of the Competition Act requires the Commission to promulgate regulations governing an EDC's obligation to serve retail customers after the conclusion of its transition period. 66 Pa.C.S. § 2807(e)(2). This duty is often referred to as the "provider of last resort" (POLR) obligation. As the Competition Act makes clear, the purpose of this obligation is to address the scope of retail electric service that must be provided to customers who either have not chosen an alternative electric generation supplier or who contracted for electric energy that was not delivered. Section 2807(e) of the Competition Act provides several directives that the Commission must follow in its promulgation of regulations on this subject:

[1] *Default Service and Retail Electric Markets*, Docket M-00072009; *Policies to Mitigate Potential Electricity Price Increases*, Docket No. M-00061957.

(2) At the end of the transition period, the commission shall promulgate regulations to define the electric distribution company's obligation to connect and deliver and acquire electricity under paragraph (3) that will exist at the end of the phase-in period.

(3) If a customer contracts for electric energy and it is not delivered or if a customer does not choose an alternative electric generation supplier, the electric distribution company or commission-approved alternative supplier shall acquire electric energy at prevailing market prices to serve that customer and shall recover fully all reasonable costs.

(4) If a customer that chooses an alternative supplier and subsequently desires to return to the local distribution company for generation service, the local distribution company shall treat that customer exactly as it would any new applicant for energy service.

66 Pa.C.S. § 2807(e)

The proposed regulations were published at 35 Pa.B. 1421 (February 26, 2005). A 60 day comment period and 60 day reply comment period followed, the latter of which concluded on June 27, 2005. The Independent Regulatory Review Commission (IRRC) filed comments to this proposed rulemaking order on July 27, 2005.

The Commission reopened the public comment period in late 2005 to address the relationship between the default service rulemaking and the Alternative Energy Portfolio Standards Act of 2004 (73 P. S. §§ 1648.1—1648.8) (AEPS Act).[2] This second public comment period concluded on April 7, 2006. IRRC stated in a letter dated May 8, 2006, that it had no additional comments, and that the due date for a final default service rulemaking had been extended to April 7, 2008.

On February 8, 2007, the Commission issued an ANOFR at this docket. The ANOFR included numerous changes to the proposed rule intended to address concerns raised by IRRC and other parties, and to reflect changes in Commission policy on a number of issues. Comments and reply comments were requested. Separately, the Commission issued a proposed policy statement on certain issued relating to default service and retail choice. *Default Service and Retail Electric Markets*, Docket No. M-00072009 (Proposed Policy Statement Order entered February 9, 2007).

Comments to the proposed rulemaking order and/or ANOFR were filed at this docket by many parties, including the Allegheny Conference on Community Development, Allegheny Power (Allegheny), BP Solar, Citizens for Pennsylvania's Future (PennFuture), Citizens Electric Company (Citizens), Clean Power Markets, Inc., Conservation Services Group, Inc. (CSG), Constellation Energy (Constellation), Consolidated Edison Solutions, David Boonin, the Pennsylvania Department of Environmental Protection (DEP), Direct Energy, LLC (Direct), Dominion Retail, Inc. (Dominion), DTE Energy Company (DTE), Duquesne Light Company (Duquesne), the Economic Growth through Competitive Energy Markets Coalition, the Energy Association of Pennsylvania (Energy Association), FirstEnergy Solutions Corporation (FirstEnergy Corporation), the FirstEnergy Operating Companies[3] (FirstEnergy Companies), the Hess Corporation (Hess), the Industrial Energy Consumers of Pennsylvania, et al.[4] (IECPA), Mesa Environmental Sciences, Inc. (Mesa), the Mid-Atlantic Power Supply Association (MAPSA), Morgan Stanley Capital Group, Inc., the National Energy Marketers Association (NEM), the Office of Consumer Advocate (OCA), the Office of Small Business Advocate (OSBA), the PA Utility Law Project, PECO Energy Company (PECO), Pike County Light & Power Company (PCLP), PPL Electric Utilities Corporation and PPL EnergyPlus, LLC (PPL), PJM Interconnection, LLC (PJM), PPM Energy (PPM), PV Now, Reliant Energy, Inc. (Reliant), Richards Energy Group, Inc., the Retail Energy Supply Association (RESA), Strategic Energy, LLC (Strategic), UGI Utilities, Inc.—Electric Division (UGI), U.S. Steel Corporation, (US Steel), US Wind Force, LLC, and the Wellsboro Electric Company (Wellsboro). All comments are available on the Commission's public internet domain.

SUMMARY OF CHANGES

The Commission has made significant changes to the proposed regulations issued on December 16, 2004. We have determined that the public interest can best be served by modeling certain portions of the default service rules on our form of regulation of natural gas supply costs. That is, there should be regular adjustments to default service rates to reflect changes in the actual, incurred costs of the default service provider (DSP). This practice of regular adjustment with the use of spot market energy supply products will ensure that rates more closely track prevailing wholesale energy prices, and that customers do not experience large changes in rates as program terms expire. When wholesale energy prices rise over a period of several years, we find that a series of small rate increases is to be preferred to one large increase at the end of a plan's term of service. Reconciliation is strongly encouraged, though not mandated, to ensure the full recovery of the DSP's reasonable costs.

DSPs should consider a portfolio of energy supply products when developing their procurement plans. A reasonable procurement strategy may include a mix of fixed-term and spot market energy purchases, the use of laddered contracts, etc. The Commission discourages the practice of procuring all needed supply for a period of service at a single point in time. Instead, we recommend that the DSP use multiple competitive procurements and spot market purchases to meet its obligations and to reduce the risk of acquiring all supply at a time of unusual price volatility. We expect that DSPs will gradually increase their reliance on shorter term contracts and spot market energy products over time.

Rate design should be simplified to provide normal incentives for energy conservation and to facilitate customer choice. This will be done through the elimination of declining blocks rates and some demand charges. These designs may be gradually phased out to mitigate the bill impact for customers. Each default service customer will be offered a single rate option, which will be displayed on a customer's monthly bill as the Price-to-Compare (PTC). The PTC is an informational tool designed to facilitate customer choice, and represents the sum of all unbundled generation and transmission charges associated with default service. Additionally, customers may have the option of selecting an alternative time based rate if the Commission separately determines that the public interest requires DSPs to offer such rates to customers.

[2] *Rulemaking Re Electric Distribution Companies' Obligation to Serve Retail Customers at the Conclusion of the Transition Period Pursuant to 66 Pa.C.S. § 2807(e)(2)*, Docket No. L-00040169 (Order entered November 18, 2005).

[3] The Pennsylvania Power Company, the Pennsylvania Electric Company, and the Metropolitan Edison Company.

[4] The Industrial Energy Consumers of Pennsylvania, the Met-Ed Industrial Users Group, the Penelec Industrial Customer Alliance, the Philadelphia Area Industrial Energy Users Group, and the PP&L Industrial Customer Alliance.

The Commission is mindful of the risks of being too prescriptive in its approach to this rulemaking. Changes in markets, technology and applicable law may result in an approach that is too narrowly tailored to serve Pennsylvania's interests. Accordingly, we do not attempt to dictate the exact manner by which every DSP will acquire electricity, adjust rates, and recover their costs. The Commission is issuing a separate statement of policy that contains guidelines for DSPs in the areas of procurement, rate design, and cost-recovery. Reserving some aspects of our regulation of default service to a statement of policy will allow the Commission, DSPs, retail customers, and other market participants to consider these policies in the context of individual default service plans, and to more effectively respond to changes in retail and wholesale markets.

DISCUSSION

The Commission has reviewed the comments filed at each stage of this proceeding. For purposes of this Final Rulemaking Order, we will focus on revisions to the proposed regulations and ANOFR, and the issues raised by IRRC in their comments of June 27, 2005.

In developing this final form rule, the Commission has attempted to craft rules that reflect stakeholder consensus to the extent that any agreement is aligned with the requirements of the Competition Act and the interest of ratepayers. We have found, as evidenced by the comments, that there is relatively little consensus on most of the key issues addressed by this rulemaking proceeding, including energy procurement, rate design and cost-recovery. This is not surprising, given the divergence in interests among those participating in this rulemaking process.

We make this observation cognizant of the fact that this rule is subject to the review of the Pennsylvania General Assembly (General Assembly) and IRRC, and that interested parties are free to support or oppose this regulation in those forums. We find that this rule achieves the objectives of the Competition Act on issues relating to default service, including the acquisition of electricity at prevailing market prices, customer choice of generation suppliers through direct access, and the full recovery of reasonable costs for EDCs. There is sometimes a tension between these and the other objectives of the Competition Act that, if not balanced appropriately, can frustrate the intent of the General Assembly. The Commission has therefore crafted a regulatory framework that does not unreasonably advance one objective to the extent that it obstructs others. Consequently, to the extent that changes to this final form rule are required as part of the regulatory review process, such revisions may not occur in isolation.

A. *Need for Regulations, Currently Effective Default Service Plans, and Pending Default Service Proceedings.*

In its first comment, IRRC questioned whether the Commission was promulgating regulations too far in advance of the expiration of rate caps. Several parties who participated in the POLR Roundtable proceeding in 2004 recommended that the Commission wait at least several more years before promulgating regulations. These parties cautioned that changes in retail and wholesale markets might render ineffective any regulations adopted too far in advance of the end of the transition period. IRRC noted that additional experience, including more study of default service models in other states, and further consideration of the requirements of the AEPS Act, might benefit the Commission in preparing regulations.

We believe this issue has been resolved given the passage of time since we proposed this rule. Six EDC generation rate caps have expired, and the remaining ones will end by December 31, 2010. The Commission has also had the benefit of several more years to study how neighboring jurisdictions are managing POLR service and the expiration of rate caps. The Commission now has a significantly better understanding of the impact of the AEPS Act on default service than it did in 2004. We have also learned from the experience of several Pennsylvania EDCs who have concluded their transition periods and implemented default service plans since 2004. Finally, the overwhelming majority of stakeholders would prefer to have regulations finalized as soon as possible. Accordingly, the Commission finds that it would be appropriate to conclude the default service rulemaking by mid-2007. This will provide needed regulatory certainty to those EDCs preparing their first default service programs, who collectively serve the large majority of Pennsylvania ratepayers.

The Commission has already approved interim default service plans for six EDCs that have completed their transition periods.[5] A number of parties, such as Duquesne, UGI, the Energy Association, and the OSBA, have asked that the Commission clarify the impact of final regulations on plans that are effective or now under Commission consideration.[6] It has been suggested that this issue be addressed by delaying the effective date of these regulations until January 1, 2011, when the last EDC generation rate cap has expired.

The Commission will not apply these regulations to already effective default service plans. In Pennsylvania, the retroactive application of laws is disfavored when it affects the substantive rights of parties. *Giant Eagle, Inc. v. Worker's Compensation Appeal Board*, 764 A.2d 663 (Pa. Cmwlth. 2000). Most of these interim default service plans will expire within the next 12 months, and we can find no public interest in disturbing their terms and conditions of service for so short a period of time.

Nor will the Commission require EDCs with pending default service proceedings to withdraw their filings and submit new plans. The Commission will not know if these final form regulations have obtained all necessary regulatory approvals for several months. Even assuming these regulations are approved by the end of July 2007, we question whether there would be sufficient time for EDCs to seek Commission approval of new, amended default service plans and obtain supply at reasonable prices prior to the expiration of their currently effective rates on December 31, 2007.[7]

However, the Commission will not grant a blanket waiver of these regulations at this time for plans now, or soon to be under, consideration by the Commission. Instead, the Commission recommends that EDCs with pending plans evaluate whether they wish to amend their filings. EDCs should take into consideration whether the delay of these proceedings resulting from an amendment would materially prejudice their ability to procure energy prior to the expiration of currently effective rates. If EDCs do not wish to amend their pending plans, they should request a waiver, in the pending proceeding, from any provision of the approved regulations that conflicts with their proposal. In reviewing any waiver requests, the

[5] Citizens, Duquesne, Pennsylvania Power Company, PCLP, UGI and Wellsboro.
[6] Default service proceedings are currently pending before the Commission for Duquesne, PCLP and the Pennsylvania Power Company. Citizens and Wellsboro are also expected to file plans for our consideration during 2007.
[7] Currently effective rates for Duquesne, PCLP, Citizens and Wellsboro will expire on December 31, 2007.

Commission will be guided by its stated policy objectives of mitigating the impact of potential electric price increases for retail customers.

B. *§ 54.123. Competitive safeguards*

IRRC commented that certain proposed safeguards may improperly restrain customer choice, which is protected by section 2807(e)(4) of the Competition Act. We have deleted the language IRRC identified as problematic. The Commission will instead rely on its powers to prosecute and assess civil penalties on electric generation suppliers for violations of the Code of Conduct at 52 Pa. Code § 54.122 and other relevant regulations and statutory provisions. Given our finding that rates be regularly adjusted to reflect changes in the composition of the DSP's portfolio, we find that the risk of an EGS exploiting seasonal price variation, to the detriment of the DSP, is greatly reduced.

C. *§ 54.181. Purpose*

IRRC commented that this section should be revised to reflect that parties other than EDCs may be approved to serve as a DSP. Any DSP, whether they are an EDC or not, is entitled to full recovery of reasonable costs. Accordingly, the phrase "other approved entity" has been added to the last sentence of § 54.181. The purpose of our default service regulatory framework is expanded upon in the final statement of policy on "Default Service and Retail Electric Markets."

D. *§ 54.182. Definitions*

The Commission received many comments on the proposed definitions and this section reflects some revisions. Certain terms have been deleted given changes in other parts of the regulation, and new terms have been added. IRRC provided comments on four different definitions. "Default service provider" has been modified consistent with IRRC's suggestion to comply with the *Pennsylvania Code & Bulletin Style Manual*. "Fixed rate option" and "hourly priced service" have been deleted from this section given our changes to the section on rate design and cost recovery. The definition for "competitive procurement process" has been revised, and we will respond to IRRC's comment on this issue in subsequent sections of this final order.

New definitions have been added, including PTC, maximum registered peak load, and spot market energy purchase. These definitions are required due to other changes to the regulations that will be discussed in subsequent sections of this final order.

Definitions have been further revised based on comments to the ANOFR by PPL and the Energy Association. For example, the word "lowest" has been added to the definition for "competitive bid solicitation process" to be consistent with the version that appears in the default service statement of policy. The definition for "default service" has also been clarified. Additionally, the definition for PTC has been revised to reflect that it is intended to serve as a new line item to facilitate customer choice.

E. *§ 54.183. Default service provider*

IRRC asked the Commission to explain its decision in § 54.183(a) to require the EDC to serve as the DSP unless the Commission approves an alternative. IRRC observes that section 2807(e)(1) of the Competition Act requires an EDC to assume this role while it is recovering stranded costs, but that it does not mandate that this role continue indefinitely. This description of the statutory language is correct.

However, the Commission cannot assume that there will be other parties qualified to or even interested in taking on the DSP role. There must be a DSP already in place in each territory to serve retail customers the day generation rate caps expire. Accordingly, the Commission must pick some party to be the initial DSP. The EDCs are the only parties that currently have certificates of public convenience to provide electric utility service in all of their particular territory. As the holder of a certificate, the EDC cannot refuse to serve retail electric customers within its designated service territory. The Commission cannot force another party, such as an EGS, to assume the DSP role. Therefore, the Commission has no choice but to initially designate the EDC to assume the DSP role. Section 2802(16) of the Competition Act clearly gives the Commission this authority:

> Electric distribution companies should continue to be the provider of last resort in order to ensure the availability of universal electric service in this Commonwealth unless another provider of last resort is approved by the Commission.

66 Pa.C.S. § 2802(16). This section does not include language supporting a limitation of the DSP role to the transition period. Additionally, the Commission does not interpret section 2807(e)(2) as in any way requiring the Commission to allow an EDC to exit this function. The Commission has been granted broad authority by the General Assembly to define the obligations of EDCs after the transition has expired, including whether they are to continue in the role of the DSP. Designating the EDC as the initial DSP in each service territory is a reasonable approach to take to ensure the availability of electric service to all customers. Section 54.183 of these regulations identifies a process by which the DSP can be changed from an EDC to another party, as allowed by section 2807(e)(2), when the Commission finds it to be in the public interest. The Commission's interpretation of the Competition Act is reasonable and consistent with the intent of the General Assembly.

In regards to § 54.183(b), IRRC has requested that the Commission provide more specific criteria for changing the DSP. The Commission agrees that more specific criteria are appropriate. This version includes proposed changes to address this issue. The Commission draws on sections 1103, 1301, and 1501 and 2807(e)(3) of the Public Utility Code, 66 Pa.C.S. §§ 1103, 1501, 2807(e)(3), in developing these criteria. Section 1103(a) requires that the Commission only award a certificate of public convenience when finding that utility service is necessary for the ". . . accommodation, convenience, or safety of the public." Section 1301 requires that all rates charged by a utility be "just and reasonable." Section 1501 requires that the conditions of public utility service ". . . be adequate, efficient, safe, and reasonable." Section 2807(e) finds that a DSP can only recover "reasonable" costs. Thus, if an EDC can no longer provide default service in a safe and efficient manner, and/or in a way that reflects the incurrence of reasonable costs, the Commission may make a finding that other parties should be considered for the role.

IRRC identified several concerns regarding § 54.183(c). It asked whether it would be appropriate to require an EGS or EDC to obtain a certificate of public convenience if it wished to assume the DSP role. We now conclude that a certificate is not necessary, and have eliminated that requirement. We have also identified criteria, similar to those in § 54.183(c), for selecting from among more than one qualified parties who wish to serve as the alternative DSP. Finally, we observe that to the extent that an alternative DSP is approved, this entity will be subject to assessments for the Commission's regulatory expenses. Specifically, we would require a party to agree to subject themselves to regulatory assessments as a condition of becoming an alternative DSP.

If a party does not wish to be responsible for these costs, then they should not seek to become a DSP. The Competition Act does not give any party a statutory right to become an alternative DSP. The Commission, at its discretion, may impose terms and conditions it believes to be appropriate for the reassignment.

In response to comments by Strategic to the ANOFR, we have made other revisions to § 54.183(c) to be able to fully utilize the potential of alternative DSPs. For example, it may be in the public interest to reassign some, but not all, customer classes to an alternative DSP. It may also be appropriate to utilize more than one alternative DSP if the obligation is assigned. One alternative DSP could be approved for residential and small business customers and a separate DSP for large customers.

F. *§ 54.184. Default service provider obligations*

IRRC asked that the Commission more specifically identify what regulations and statutory provisions a DSP must adhere to. We have added these references for purposes of clarity in § 54.184(b).

IRRC properly raised the issue of whether an alternative DSP would have a universal service obligation. In the event that a reassignment occurs, the incumbent EDC's universal service obligation must be addressed. The Commission finds that the Competition Act requires that consumer protections be maintained at the level they existed at the time of the Competition Act's passage. 66 Pa.C.S. § 2802(10). In § 54.184(c), the Commission now acknowledges that if an EDC is relieved of the default service obligation, consideration will need to be given to the proper allocation of universal service responsibilities between that EDC and the replacement DSP. Universal service programs must be maintained at the same level in the event of the reassignment of the DSP role.

In a recent order the Commission provided guidance on the recovery of universal service program costs. *Customer Assistance Programs: Funding Levels and Cost Recovery Mechanisms*, Docket No. M-00051923 (Final Investigatory Order entered December 18, 2006). The order provides that utilities may propose a surcharge to recover the costs of these programs from residential customers.

Even if the DSP role is reassigned, the incumbent EDC will still be providing transmission and distribution service to retail customers. Universal service programs cover the costs of transmission, distribution and generation service. The proper solution may be for the EDC to continue to administer and recover all costs for universal service programs. The EDC could then reimburse the alternative DSP for whatever services are provided by the DSP.

Some parties commented on this issue in their response to the ANOFR. For example, PPL recommended that the universal service obligation be largely shifted to the alternative DSP. However, the OCA and FirstEnergy believes that this function should remain with the incumbent EDC. In the absence of any actual experience with reassigning the full default service role, we are reluctant to issue a blanket rule at this time. A uniform standard may be developed after the Commission has adjudicated a petition to reassign the DSP role.

At the suggestion of the OCA, we have also made express the DSP's obligation to serve retail customers whose EGS has defaulted on their obligation to provide generation service. This revision is made in § 54.184(a).

G. *§ 54.185. Default service programs and terms of service*

This section has been significantly revised. Pursuant to § 54.185(a), DSPs will be filing "default service programs" instead of implementation plans, and this definition has been added to § 54.182. Responding to IRRC's question on alternative DSP filings, the Commission notes that no alternative DSPs have been approved, and no requests are pending. In the event that an alternative DSP was approved after this regulation became effective, we would expect that the alternative DSP file its program at least twelve months prior to the expiration of the generation rate cap or approved default service program in that service territory. If this is not possible due to the timing of the reassignment, a waiver of this provision could be sought, consistent with 52 Pa. Code § 5.43.

Section 54.185(b) has been amended consistent with IRRC's recommendation to identify the documentary filing regulations that must be adhered to. Therefore we are including a reference to 52 Pa. Code § 1.1, et seq. We are also directing the DSP to serve a copy of its default service program on any EGSs registered in the DSP's service territory, and to make it available on their public internet domain.

After reflecting on IRRC's and other parties comments on this issue, the Commission has revised the language of § 54.185(c) on program duration by selecting a 2 to 3 year term for the first default service program filed after the effective date of these regulations. The Commission has not been able to identify an optimal program duration based on its current knowledge of energy markets. This issue has therefore been reserved to the default service statement of policy, which recommends a standard duration of 2 years for subsequent programs. As wholesale and retail markets change over time, the Commission will provide guidance on appropriate program durations. If markets mature to the point where the Commission can identify the ideal program duration, this regulation will then be revised accordingly.

We also agree with IRRC's comment to this section about excessive reliance on energy contracts of greater than one year. We are encouraging DSPs to gradually increase their utilization of spot market purchases and short fixed term contracts, a subject which is discussed at length in this order. The final statement of policy we are issuing contains guidelines on this topic.

Section 54.185(d) of the proposed rules has been eliminated, as procurement specific requirements have been moved to the new § 54.186. The revised § 54.185(d) identifies the required elements of the default service program. The default service program will consist of three main elements: a procurement plan for acquiring electric generation supply, an implementation plan that identifies the schedules and technical requirements of these procurements, and a rate design plan. The program will also include documentation of compliance with the RTO requirements, a contingency plan in the event of supplier default, copies of all agreements and forms to be used in competitive solicitations, and schedules identifying generation contracts with existing customers.

Section 54.185(e) remains largely the same in the final form version. The Commission recognizes that retail customers may benefit from the economies of scale realized by combining the procurements of more than one service territory into a single auction process. DSPs may submit such proposals for our consideration.

The Commission is also concerned about the possibility of DSPs scheduling multiple, large procurements at the same point in time. This might negatively impact the price of bids. Guidelines on this issue are included in the default service statement of policy. We will work with relevant parties to balance the potential benefits associated with building economies of scale, with the associated increase in interest by suppliers, versus potential complications related to suppliers having to commit a large amount of their generation portfolio at a single point in time.

Section 54.185(f) has been moved to § 54.185(d)(4) and is largely unchanged. The term ISO, which stands for Independent System Operator, has been dropped from this section as no Pennsylvania EDC is under the operational control of an ISO. While PCLP is owned by a member of the New York Independent System Operator (NYISO), its transmission system is not under the NYISO's operational control.

Section 54.185(g) has been moved to § 54.185(d)(3). Sections 54.185(h) and (i) have been deleted. Section 54.185(j), now § 54.185(d)(7) has been revised from "long term generation contracts" to "generation contracts greater than 2 years" to respond to a comment from IRRC. Section 54.185(k), has been moved to § 54.185(d)(6) and expanded to include all forms and agreements used as part of the default service implementation plan. The inclusion of these documents has been made mandatory, consistent with the recommendation from IRRC.[8] Section 54.185(l) has been moved to § 54.185(d)(5), and left largely unchanged. Section 54.184(m), which IRRC identified some concerns with, has been deleted.

In response to comments to the ANOFR by FirstEnergy and others, the time for the filing of a default service program has been reduced from fifteen to a minimum of twelve months in advance of the expiration of the current program in § 54.185(a). However, DSPs should give consideration to filing more than twelve months ahead of time, particularly for complex or initial post-rate cap default service programs.

We also received responses to our request for comments in the ANOFR on the coordination of procurements. PPL, PECO, FirstEnergy, Allegheny and Constellation have all expressed an interest in some form of coordinated, statewide or multi-territory procurement process with uniform rules. We agree that such an approach may reduce administrative costs and facilitate wholesale supplier participation. Additionally, as recommended by Constellation, the Commission has no objection to the use of a single independent consultant to manage a multi-territory, coordinated, procurement process. However, a multi-service territory default service program must comply with the other aspects of this rule, including procurements by customer class, regular adjustments of rates, etc.

Both Citizens and Wellsboro filed comments to the ANOFR and default service statement of policy highlighting the challenges faced by smaller EDCs in managing the default service obligation. For example, these EDCs comment that they may have difficulty managing a portfolio of resources, multiple procurements, etc., even if they were to aggregate their load. They suggest that the Commission make more express its willingness to grant small DSPs waivers from appropriate provisions.

[8] The Commission has initiated a separate proceeding to develop standardized request for proposal forms and supplier master agreements at Docket M-00061960.

We agree that smaller DSPs such as Citizens, Wellsboro, PCLP and, to a lesser extent UGI, face different challenges than larger EDCs, and have fewer resources to manage their obligation. Accordingly, we are adding § 54.185(f) to the final form rule. This has two purposes. First, it puts all DSPs on notice that they should include all requests for waivers to this subchapter in their default service program filings. Second, it affirms that special consideration will be given to the waiver requests of DSPs that serve smaller numbers of customers.

Section 54.185(d)(7) has been revised in response to a comment to the ANOFR by IECPA. Schedules identifying each generation contract between the incumbent EDC and customers shall only be provided to the Commission. Individual customer information will be given confidential status.

H. *§ 54.186. Default service procurement and implementation plans*

This section has been substantially revised. We will first address IRRC's comments to both this section and § 54.185(d) regarding the requirement for competitive procurement processes. IRRC and some other commentators question the need to prescribe the manner in which electricity can be procured. IRRC observes that section 2807(e) does not expressly mandate that competitive bidding be used to procure electric generation supply for default service customers. IRRC recommends that this be modified, and that the Commission should be disinterested as to the method for procurement, so long as supply as acquired at prevailing market prices.

Initially, we must observe that we are expressly charged by the General Assembly with defining the obligation to "acquire" electricity:

> At the end of a transition period, the commission shall promulgate regulations to define the electric distribution company's obligation to connect and deliver and acquire electricity under paragraph (3) that will exist at the end of the phase-in period.

66 Pa.C.S. § 2807(e)(2). The scope of this rulemaking properly includes the acquisition of electricity. This obligation cannot be defined without addressing the method of the acquisition.

It is true that electric utilities do routinely acquire electricity through bilateral contracts that are not a result of competitive procurement processes. These bilateral contracts may very well reflect "prevailing market prices." However, the Commission concludes that the optimal method of acquiring electricity includes a direct exposure to market forces. This exposure can best occur either through a competitive procurement process or a purchase in a spot energy market managed by an RTO such as the PJM Interconnection, LLC.[9] We note it is the standard practice of the Commonwealth of Pennsylvania to use competitive bidding when procuring goods or services of significant value. 62 Pa.C.S. § 101, et seq.

[9] We remind the IRRC that most Pennsylvania EDCs have wholesale energy supplier affiliates with substantial generation assets. Permitting the routine use of bilateral contracts would allow an EDC to negotiate a contract with its affiliate, with all the potential risks and conflicts of interest this would entail. Requiring competitive procurements largely eliminates the risk that an EDC's wholesale energy affiliate would be given some preference in the procurement of default service supply. Some parties who commented to the ANOFR suggested that the Commission allow bilateral contracts with non-affiliates. As discussed in this section, the Commission is very skeptical of a DSP's ability to obtain the best price for customers with bilateral, long-term contracts.

In considering this rulemaking, IRRC should be cognizant of one of the key findings of the General Assembly included in the "Declaration of policy" section of the Competition Act:

> Competitive market forces are more effective than economic regulation in controlling the cost of generating electricity.

66 Pa.C.S. § 2802(5). In interpreting a statute, legislative intent controls. 1 Pa.C.S. § 1921. We find that the plain language of the Competition Act demonstrates a preference for the use of "competitive market forces" in controlling the cost of electricity. The regular use and Commission approval of no-bid, bilateral energy contracts would be an exercise in "economic regulation"' of the sort that the Competition Act discourages. We conclude that section 2807(e) must be read together with the General Assembly's declarations of policy in section 2802. The optimal forms of default service procurement are therefore competitive bid solicitations and spot market energy purchases. The recognition that spot market purchases are appropriate is a change from the proposed version of the rules, and consistent with IRRC's request that DSPs be given more procurement options and that the Commission allow procurements that reflect "prevailing market prices." The Commission's interpretation of the Competition Act is reasonable and reflects the intent of the General Assembly.

However, the Commission recognizes that there may be some circumstances where a short-term, bilateral contract is necessary and appropriate. For example, in the event that a wholesale energy supplier would default on a contract, the DSP would need to acquire replacement supply. We would not want to limit the DSP to acquiring electricity in only the spot market. In that situation, one or more bilateral contracts of 1-3 months may be appropriate until a permanent solution could be achieved, and may be incorporated in a DSP's contingency plan. To the extent a DSP believes an exception to the procurement standard is required regarding bilateral contracts, a petition for waiver may be filed pursuant to 52 Pa. Code § 5.43.

Section 54.186 has been significantly revised as to form and content. Section 54.186(a) provides that supply will be acquired consistent with Commission approved default service procurement and implementation plans. Section 54.186(b) identifies procurement plan standards, some of which are new to this version. This includes the requirement to use competitive procurement processes or spot market energy purchases only. This change is at least partly in response to IRRC's comment to the proposed § 54.187(b), that rates includes seasonal or monthly variation to reflect the prevailing market prices. Incorporating spot market products in a DSP's portfolio, when coupled with the regular adjustment of rates, will ensure that retail rates are responsive to changes in wholesale market prices.

Procurement plans should have the objective of obtaining the lowest, reasonable price. Given our recent experience with PCLP, we recognize that small DSPs have a greater challenge in attracting the interest of wholesale energy suppliers. Accordingly, they are directed to consider the benefits of coordinating their procurements with other DSPs. Section 54.156(b)(1), relating to affiliate participation, has been moved to § 54.156(b)(5).

Section 54.156(b)(2) has been moved to § 54.156(c)(1) in this version with few changes. In responding to IRRC's questions regarding bid evaluation criteria, we are revising this to "price-determinative bid evaluation criteria." It is our expectation that the energy suppliers who submit the lowest priced bids, providing they have met all bidder qualification criteria, will be awarded generation contracts by the DSP. Issues regarding the reliability and creditworthiness of a supplier should be addressed in bidder qualification criteria.

The original § 54.156(c) has been deleted and § 54.186(d) has been moved to new § 54.186(c)(3). Consistent with IRRC's and other parties' recommendations, third party oversight is now a mandatory part of this process. Guidelines for selecting a third party evaluator are addressed in more detail in the default service statement of policy.

The original § 54.186(f) has been deleted and its substance is addressed in the revised § 54.188. In the revised § 54.188, we address IRRC's comment on the old § 54.186(f)(2) that we reduce the time to review competitive procurement results.

We have also responded to IRRC's comment on contingency plans in § 54.186(g) (and §§ 54.187(i) and 54.188(e)). The prior versions of these sections have been deleted as duplicative or otherwise revised or moved to new sections. Contingency plans must be still included in the default service program, at the new § 54.185(d)(5). The terms and conditions of a contingency plan will be subject to Commission review as part of the examination of the default service program under the procedures at the revised § 54.188. Responding to IRRC's comment on "acquisition strategies," we find that acceptable contingency plans may incorporate spot market purchases, a competitive bid solicitation process (if time permits), or a short-term bilateral contract, as acknowledged previously in this section. Individual spot market purchases do not require prior Commission approval, consistent with the revised § 54.188. When issuing an order on a particular default service program, the Commission would clearly address the level of Commission oversight in the execution of a contingency plan.

Section 54.186(h) has been moved to § 54.186(c)(5). Additional guidelines regarding confidentiality of information are addressed in the default service statement of policy.

In response to a comment by UGI to the ANOFR, the words "to the extent applicable" have been added to § 54.186(c)(1) to acknowledge the fact that a DSP may not solely procure load following service. For example, a DSP has the discretion to use other types of contracts including on-peak, off-peak, or structured block products (e.g., 7 days a week, 24 hours a day), etc., as part of its procurement plan. In response to a comment by PPL, § 54.186(c)(1)(vii) has been revised to state that data may need to be provided according to the divisions in maximum registered peak load, as opposed to customer class. We have also adjusted the wording of this subsection, in response to a comment by FirstEnergy to the ANOFR, to ensure that "current" load information be made available to suppliers at an "appropriate time," which will likely be a time closer to the actual competitive bid process. The reference to § 54.186(b)(2)(vi) in § 54.186(c)(4) of the ANOFR, which was intended to refer to price determinative bid criteria, has been corrected to § 54.186(c)(1)(vi).

In response to comments by Strategic and other parties, we wish to clarify that § 54.186(b)(3), which allows for supply contracts that extend beyond the duration of the program term, is primarily intended to address the subject of contract laddering. The Commission recognizes that the laddering of supply products may be a valid element of a portfolio strategy, particularly in the initial period following the expiration of rate caps. For laddering to occur, it may be necessary for some portion of the supply acquisition to overlap the end of one program term, and the beginning of another.

This section should not be interpreted to mean that the Commission has no policy preference on contract lengths. We stand by § 69.1805 of the default service statement of policy, which provides that long-term contracts should primarily be used to meet the requirements of the AEPS Act, and the supply needs of residential and small business customers in the early years of the post-transition period. We do suggest in the statement of policy that full requirements or block purchase contracts of 1 to 3 years in length, which may be laddered, be part of the portfolio for residential and small business customers for the DSP's first default service program. We also suggest that the portion of the portfolio that relies on shorter term contracts (e.g., 1 year or less) and the spot market be gradually increased with time. This procurement approach is consistent with Competition Act standard that energy be acquired at prevailing market prices.

In conclusion, we are generally skeptical of the DSP's ability to beat the market over periods of time greater than one year. Incumbent EDCs have simply not provided any real record in this or other default service proceedings to show that they can anticipate changes in market prices, and take advantage of this information to obtain consistently lower prices through long-term contracts compared to short-term and spot market purchases. Wholesale market prices are very sensitive to factors completely beyond the control of DSPs, suppliers and regulators, including weather, global energy demand, and war. This is one of the key reasons we are discouraging the use of bilateral contracts in the acquisition of default service supply. We believe customers will save more money as DSPs gradually increase their utilization of short-term fixed price contracts and spot market products, and what data we do have supports this premise. For example, Direct Energy cited to a report in its reply comments that Duquesne's residential customers would have saved $75 million during the first two years of its "POLR III" plan if they had been on monthly priced service.[10] Small commercial customers would have realized savings of $28 million over the first 23 months of the POLR III plan. Id.

We are sensitive to the concerns of parties regarding price volatility, and the need for customers to become accustomed to market pricing and the regular adjustment of rates. Therefore we do support reliance on longer-term, fixed price products in the years immediately following the expiration of rate caps.

I. *§ 54.187. Default service rate design and the recovery of reasonable costs*

This section has been significantly revised. After reviewing the many comments on this issue from IRRC and other parties, the Commission concluded that its approach to rate design and cost recovery was too prescriptive. Therefore, this section has been revised to provide more flexibility to DSPs and the Commission to manage the default service obligation. Additional guidelines on rate design and cost-recovery are included in the default service statement of policy.

Many commentators believed that the proposed version of § 54.187(a) was overly complex, or simply incorrect in its design. IRRC also had many questions about this section. We agree that this is one of the more technically complex issues of this rulemaking. In the revised § 54.187(a), the Commission limits its finding to the requirement that the default service rate should represent the sum of all generation and transmission related costs.

In response to IRRC's comments on the proposed § 54.187(a)(1) and (a)(2), the Commission maintains its position that distribution rates should be examined to ensure that no generation costs remain embedded. The PTC, which is derived from default service rates at a particular point in time, shall be designed to recover all default service costs for an average member of a customer class. The revised § 54.187(d) provides that the default service rate may not include any distribution costs, and that EDC distribution rates be reduced to reflect embedded costs reallocated to the generation component of the PTC. However, we believe that this issue will require considerable study and additional policy development. Therefore we have moved much of the detail on this issue to the final statement of policy on default service, where we identify what we believe to be the appropriate cost elements for default service. We expect that each EDC will have its distribution rates addressed in a separate proceeding to finally resolve this issue. This may involve the performance of new cost of service studies for each EDC, as suggested by IRRC. The Commission may also make use of a collaborative process to develop uniform standards on embedded costs to be applied to each EDC.

In response to IRRC and other parties' comments to § 54.187(b), (c) and (d), we have removed the language mandating fixed rate options and hourly rates for certain customer classes. The associated definitions have been deleted from § 54.182. The new § 54.187(b) now provides that each customer will have a single rate option, which will be described as the PTC. The PTC will be a new, separate line item on a monthly bill that represents the sum of all transmission and generation related charges. The PTC will not replace the unbundled generation, distribution, and transmission charges that currently appear on a monthly bill. The use of a PTC will enable customers to make more informed choices regarding whether or not to seek service with an EGS. We intend that customers be educated about the use of the PTC as part of the consumer education initiatives that will be implemented pursuant to the Final Order in the price mitigation proceeding.

To provide normal incentives for conservation, and to reflect the actual cost of energy, we have revised § 54.187(c). The revised language will have the effect of eliminating "declining blocks" from rate schedules. Some EDC rate schedules currently provide that the rate charged per kWh declines once the customer uses a certain amount of electricity in a given month, such as 1000 kW. This provision would require those rate designs for default service to be eliminated.[11]

Sections 54.187(e) and (f) address the issue of cost reconciliation. Consistent with the comments of IRRC,

[10] *Intelometry Inc., Power Price Report, Pittsburgh Market (Duquesne Light) 1/1/05 through 11/30/06*, December 2006. Direct Energy also provided evidence in a separate proceeding, which they refer to in their reply comments, that the PJM monthly clearing price in the PJM zone was less than the PPL tariff price for residential customers in at least 32 out of 49 months between 2002 and 2005. Direct Energy Reply Comments, pg. 3. Direct Energy asserts that PECO's small commercial customers would have saved approximately $1.1 billion off their tariff rate between January 1, 2002, and November 30, 2005, through the use of a monthly pricing mechanism. *Intelometry Inc., Power Price Report, Philadelphia Market (PECO) 1/1/02—11/30/06*, December 2006.

[11] In its most recent POLR filing, at Docket P-00072247, Duquesne proposed to eliminate declining blocks and demand charges for all customers by 2010.

§ 54.187(e) has been revised to include a reference to the Commission's alternative energy regulations in Chapter 75. In responding to IRRC's concern about reconciliation, we note that the AEPS Act expressly provides that alternative energy costs be recovered through a Section 1307 automatic adjustment clause. See 73 P. S. § 1648.3(a)(3). Cost-recovery mechanisms for alternative energy are also being specifically addressed in a pending rulemaking at Docket L-00060180.[12] As the alternative energy portfolio standard is effectively a component of the default service obligation, these rules necessarily contain cross-references.

In response to IRRC's comment to the proposed § 54.187(a)(3) and § 54.187(d), we do not believe that these rules will hinder the ability of DSP's to meet their AEPS requirements. The AEPS Act expressly provides that:

> (4) (i) An electric distribution company or electric generation supplier shall comply with the applicable requirements of this section by purchasing sufficient alternative energy credits and submitting documentation of compliance to the program administrator.
>
> (ii) For purposes of this subsection, one alternative energy credit shall represent one megawatt hour of qualified alternative electric generation, whether self-generated, purchased along with the electric commodity or separately through a tradable instrument and otherwise meeting the requirements of commission regulations and the program administrator.

73 P. S. § 1648.3(e)(4). Accordingly, a DSP may meet its portfolio requirements solely with alternative energy credits that have been separated from the energy commodity. Therefore, the use of competitive procurements in combination with automatic adjustment clauses, or hourly priced options, poses no problems for alternative energy compliance.[13] Energy prices or rate options are irrelevant, because the DSP does not have to buy energy to satisfy the requirements of the AEPS Act.[14]

In § 54.187(f) the Commission provides that a DSP may propose cost-reconciliation of non-alternative energy costs as part of its default service program. The Commission now concludes that reconciliation of default service costs may be necessary, and in fact is more desirable, to enable the DSP to ". . . recover fully all reasonable costs" so that the PTC reflects market prices. 66 Pa.C.S. § 2807(e)(3). If the DSP wishes to utilize a cost reconciliation mechanism, the default service statement of policy provides guidelines on this subject. The original § 54.187(h), which was commented on by IRRC, and included a prohibition on reconciliation, has therefore been removed.

To respond to the concern of IRRC regarding reconciliation, we find that parity between EDCs and EGSs can be maintained through the regular adjustment of rates, the gradual increase in spot market products, and the limitation on the use of long-term contracts, and several other measures. With these elements, the default service rate will more closely track the market prices offered by EGSs. The elimination of declining blocks and the use of the PTC will also facilitate competitive choice. We are also exploring a variety of other initiatives through the default service statement of policy to facilitate retail choice. Finally, this regulation does not *mandate* the use of reconciliation. We will be monitoring DSP's use of reconciliation mechanisms going forward, and to the extent that they are abused, we will decline to approve, or otherwise modify, their use.

Section 54.187(g) requires the DSP to include demand side response and management rates in their default service program *if* the Commission has mandated that such rates be available. The Commission is studying this topic as part of a pending investigation into conservation, energy efficiency, and demand side response.[15] Consistent with IRRC's suggestion, we have included a definition of demand side response and demand side management by reference to an existing definition found in section 1648.2 of the AEPS Act, 73 P. S. § 1648.2. In response to IRRC's question regarding potential hardship for smaller DSPs in offering these programs, this is an area where a waiver may be requested.

The revised § 54.187(g) allows for the option of an hourly priced rate for residential customers, as recommended by IRRC in their comment to proposed § 54.187(b). We are aware that real time pricing pilots have recently been implemented in Illinois for residential customers in response to the expiration of rate caps, and believe that such pilots may also be appropriate in Pennsylvania. A DSP may therefore propose to include an optional, hourly priced rate for residential customers in its default service program. However, we are reluctant to mandate that hourly priced service be offered at this time to all customers. For hourly priced service to be offered, EDCs may need to make significant new investments in metering, billing and communication systems. These investments may cost a significant amount of money, and these costs would ultimately be recovered from ratepayers. The Commission needs to carefully consider the costs associated with hourly pricing before mandating that all customers have this option. This is one of a number of issues being studied in our pending investigation on DSR, energy efficiency and conservation.

Section 54.187(h), (i) and (j) represents major revisions to the rulemaking. Specifically, the Commission finds that the PTC should be adjusted on a regular basis as opposed to remaining fixed for the entire duration of a program. This is consistent with a recommendation made by IRRC, in its comment to the proposed § 54.187(b), that rates have some variability to reflect market prices. This also addresses IRRC's comment to the proposed § 54.187(g), that adjustment mechanisms be clearly set forth. The frequency of this PTC adjustment would be dependent on the customer class.[16] For residential and small business customers, rates will be adjusted at least every quarter. For large business customers, the PTC will be adjusted at least every month. DSPs have the discretion to propose more frequent adjustments in their program filings, consistent with IRRC suggestion that flexibility be allowed

[12] *Implementation of the Alternative Energy Portfolio Standards Act of 2004*, Docket L-00060180 (Proposed Rulemaking Order entered July 25, 2006).

[13] PECO filed a petition with the Commission on March 19, 2007, regarding its AEPS obligations. It proposes to hold several competitive auctions for alternative energy credits only in late 2007 and early 2008. The costs of these credits would be recovered through a Section 1307 automatic adjustment clause after PECO's generation rate cap expired. *Petition of PECO Energy Company for Approval of (1) A Process to Procure Alternative Energy Credits During the AEPS Banking Period and (2) A Section 1307 Surcharge And Tariff To Recover AEPS Costs*; Docket P-00072260. PECO would bank these credits during its rate cap period and use them satisfy its non-solar photovoltaic Tier I obligations for several reporting periods.

[14] This statutory interpretation is codified in the pending rulemaking at Docket L-00060180. The legal challenge to this interpretation filed in the context of the appeal of the Commission's ruling on Pennsylvania Power Company's POLR filing at Docket P-00052188 has been withdrawn. See Commonwealth Court Docket 1085 C.D. 2006. We note that in that case, Pennsylvania Power Company made its wholesale suppliers contractually responsible for providing it with sufficient alternative energy credits to meet its portfolio obligation under the AEPS Act for the term of that plan.

[15] *Investigation of Conservation, Energy Efficiency Activities, and Demand Side Response by Energy Utilities and Ratemaking Mechanisms to Promote Such Efforts*, Docket No. M-00061984 (Order entered October 11, 2006).

[16] Consistent with suggestions made by the IRRC and other commentators, we are giving the DSP some flexibility in determining the divisions of customers to preserve existing rate schedules.

for in this area. Accordingly, DSPs may elect to offer hourly rates to large commercial and industrial customers.

As stated earlier, this approach is similar to our regulation of natural gas supply costs. The purchased gas cost rate for most natural gas distribution companies is adjusted quarterly to reflect changes in their incurred costs of supplying customers. 52 Pa. Code § 53.64(i)(5). When wholesale market prices move higher, rates increase. When prices decline, rates are reduced. Having regular adjustments allows the utility to collect its costs immediately, avoid and manage cost under recoveries, and not incur additional costs associated with trying to recover the difference between costs and revenues all at one time. If gas customer rates were not adjusted quarterly, the annual reconciliation process could demonstrate larger divergences between costs incurred and revenues received. Overall costs would be higher, as more interest would need to be paid either by the utility or customers in reconciling costs and revenues. Pennsylvania's residential gas customers, most of whom are also customers of EDCs, are well accustomed to having their gas rate adjusted quarterly. We expect that retail electric customers can manage quarterly adjustments as well.

In both this rulemaking and the accompanying statement of policy, the Commission is encouraging DSPs to acquire a portfolio of generation supply products. Rather than simply procuring all generation at one time for the entire duration of the program, DSPs should consider a mix of fixed-term and spot market energy purchases, laddered contracts, and the use of both supply and demand resources. The Commission recognizes the risks posed by the practice of procuring all generation supply for the entire duration of a program at a single point in time.

PCLP's last default service filing is a case in point. PCLP procured all of its default service supply for 2006-2007 through an auction held in October of 2005, approximately two months after Hurricane Katrina severely disrupted wholesale energy markets and the nation's energy infrastructure. As a result of very high prices in wholesale markets, PCLP's average customer experienced a total bill increase of about 75% on January 1, 2006, which included a generation rate increase of about 129%. Because all energy was acquired at one point in time, PCLP's default service rate for the entire two year program was locked in and reflected the market price of the day of the auction. Even though wholesale energy prices retreated substantially from their late 2005 and early 2006 peaks, PCLP's high default service rate was not reduced.

This is in marked contrast to the experience of retail customers of PCLP's parent company, Orange & Rockland Utilities, Inc. (O & R), whose territory lies just across the state line in New York. For the same time period covered by PCLP's plan, Orange & Rockland was utilizing a portfolio approach, whereby it was acquiring supply through a mix of fixed-term contracts and spot market energy purchases. The costs O & R incurred to serve its default customers therefore changed over time in response to changes in wholesale market prices. O & R's retail customers are charged a "market supply charge" which changes every month. While O & R's market supply charge increased in October of 2005, it declined in subsequent months as wholesale energy prices retreated.[17] PCLP's customers did not benefit from the decline in wholesale energy prices as their rate was set in advance for a two year period.

In this rulemaking and the default service statement of policy, the Commission is encouraging DSPs to take an approach similar to O & R's. This would include the use of multiple fixed-term contracts and spot market energy purchases. Laddering of contracts should also be considered. This is a departure from some of the recent POLR filings where the entire supply was provided pursuant to one or more fixed-term contracts. A small step was taken in this direction in the recent Pennsylvania Power Company default service plan, where energy was procured for a 17 month period in two separate auctions.

In arriving at this decision, we find that there is simply too much risk associated with procuring all supply at a fixed rate for the entire duration of the program. When a price is locked in and wholesale rates move lower, customers will experience what PCLP customers have dealt with over the past few years. When wholesale energy prices increase above a fixed rate, customers may experience sharp, unplanned increases when the program expires (e.g., the experience of many customers in this region, including Maryland, when generation rate caps set during a time of lower wholesale energy prices expired).

Fixed default service rates for prolonged periods are also detrimental to the development of retail markets in Pennsylvania. For example, EGSs have simply not been able to compete with the below market rates offered by EDCs during the generation rate cap period. Customer choice is largely nonexistent outside the territory of Duquesne, the only large EDC whose generation rate cap has expired.[18] A PTC that is fixed for long periods of time, and that does not adjust to changes in wholesale energy prices, will stifle competition. We believe customers will receive the lowest rates when multiple EGSs are competing for their business, as is the case for any good or service that consumers need.

If DSP rates are fixed at below market prices for prolonged periods, EGSs will not be able to make price attractive offerings to customers. Instead, customers will be left with no readily available alternative to the DSP's rate when it eventually is adjusted to reflect the market price. The PCLP experience will be repeated again and again. If EGSs know that the PTC will be adjusted consistent with the DSP's incurred costs as wholesale markets change, they will invest more time and money in establishing a presence in Pennsylvania, and marketing their service to customers. Customers will then have greater opportunity to choose among suppliers and realize savings.

This is not to say that customers should be deprived of the opportunity to obtain a fixed price for generation service. We have concluded that the public interest will be served, in the form of lower rates over the long term, if the default service rate is regularly adjusted to reflect changes in default service costs as they occur. In this regulatory environment, EGSs will respond by entering the market in greater numbers, and if there is a significant demand for these types of rates, offer them.[19] We caution, however, that such price certainty does not come

[17] O & R's price to compare for the last few years can be viewed at http://www.oru.com/energyandsafety/energychoice/newyork/orupricetocompare.html

[18] The experience of Duquesne shows that retail markets can work. Duquesne's territory has the highest rate of customer choice in Pennsylvania. See http://www.oca.state.pa.us/Industry/Electric/elecstats/instat.htm. Its overall retail electric rates remain 15% below what they were when the Competition Act was passed in 1996. http://www.puc.state.pa.us/general/pdf/Thomas_Stmt_OSA0203_081904.pdf.

[19] In support of this assertion we refer to the OCA's residential gas customer shopping guide, dated January 5, 2007. One year, fixed price contracts for residential customers are currently available in the service territories of Columbia Gas, Dominion Peoples, and UGI Utilities, Inc.—Gas Division.

without increased costs for the customer. A retail rate that cannot be adjusted over a significant period of time in response to changes in wholesale energy markets will reflect a risk premium, whether offered by a DSP or an EGS.

Many comments were filed in response to this section of the ANOFR on the subject of declining blocks, cost-reconciliation, customer groupings and rate design. The Commission has made a number of changes to the ANOFR in response to these comments.

The Price-to-Compare

In response to comments to the ANOFR, we are clarifying the use of the PTC. This is a new line item that represents the sum of generation and transmission related charges. However, transmission and generation related charges should still be included on the monthly utility bill as separate line items. In response to a comment from Constellation regarding taxes, we wish to confirm that sales tax should not be included in the PTC.

Declining Blocks and Demand Charges

The Commission received comments both for and against the elimination of declining blocks in response to the ANOFR. Some parties, such as the OCA, warned that their abrupt elimination may lead to rate shock for certain customer classes. Others, like IECPA, Allegheny, US Steel, and PECO, believe that demand charges and/or declining blocks are an appropriate element of rate design.

In addressing these comments, we will review UGI's most recent default service plan. On April 17, 2006, UGI filed a petition with the Commission to establish default service rates for the 2007—2009 period. After the proceeding was initiated, UGI and several other interested parties initiated settlement discussions. A Joint Petition for Settlement was filed with the Commission on June 1, 2006. The signatories included UGI, the OCA, the OSBA and Constellation.

Under the terms of the settlement, UGI agreed to phase out some declining block rates and generation demand charges over a 3 year period. UGI attached the testimony of David C. Beasten, Director of Electric Power Supply and Rates, in support of the settlement. On the topic of declining blocks, Mr. Beasten testified:

> When one purchases energy in the market, one generally pays the same price for all the energy purchased. Having declining block rates for generation service thus gives a false price signal to customers.

Mr. Beasten explained that immediate elimination of these rates could result in rate shock for some customers. Accordingly, UGI proposed to phase out these rates over three years. The Commission accepted this proposal, and approved the Joint Settlement. *Petition of UGI Utilities, Inc.—Electric Division for Approval to Implement 2007-2009 Default Service Tariff Provisions on One Day's Advance Notice,* Docket No. P-00062212 (Order entered June 22, 2006).

We still agree with Mr. Beasten's testimony that declining block rates for default service gives false price signals to customers. This false price signal discourages energy conservation and complicates retail choice. Therefore, the requirement to eliminate all declining block rates will remain in the final version of this rule.

However, we do accept the argument of IECPA, Allegheny, US Steel and PECO that generation and transmission demand charges may be appropriate in some circumstances for large commercial and industrial customers. Accordingly, this rule does not include a blanket prohibition on generation and transmission demand charges. DSPs may propose demand charges that are rationally related to the costs of providing service to large commercial and industrial customers. Incumbent EDCs should not assume that the Commission will approve the demand charges currently appearing in their tariffs. We agree with the reply comments of the OSBA that the current demand charges are a legacy from the pre-restructuring era, and do not reflect the actual costs of serving these customers in today's markets. DSPs should be prepared to include strong evidence in their default service program filings that supports the design and cost basis of any proposed demand charges.

The UGI Joint Settlement is also appropriate for consideration in the context of price increase mitigation. The Commission agrees with the OCA that the immediate termination of declining block rates and generation demand charges could lead to rate shock for certain customers. Therefore, we will apply the rate change mitigation provision of the default service statement of policy to this issue. If a DSP finds that the elimination of declining blocks or demand charges would lead to an increase of 25% or more for any customer class, it should propose to gradually phase out these design elements through a series of annual adjustments. The length of this adjustment process may vary, depending on the size of the increase to be mitigated. Generally, we believe this can be done within 2—3 years.

Cost Reconciliation

We recognize that the use of a reconciliation mechanism was strongly opposed by some who responded to the ANOFR, who assert that the use of a reconciliation mechanism may harm the development of retail competition. Some, like Dominion, believe that DSPs may use reconciliation to give a false price signal to keep retail customers from shopping. The DSP could attempt this by charging a below market PTC and then recovering any under collections, with interest, during an end of the year reconciliation process.

We have given serious consideration to these comments and the potential problems identified. Consistent with the gas cost recovery model, we will provide for asymmetrical interest calculations for under and over collections.[20] Interest paid to the DSP will be at the legal rate of interest, which is 6%.[21] The interest rate paid to customers for refunds of over collections shall be 8%. This will serve as a disincentive to price manipulation behavior, and an incentive to acquire energy at prevailing market prices. The Commission will also closely monitor the use of reconciliation mechanisms by DSPs.

We remind DSPs that the discretion afforded them by this regulation is not an invitation to acquire all energy through a handful of multiyear full requirements contracts and then passively observe costs and revenues significantly diverge in response to wholesale market events, customer migration, etc. Such conduct would not be consistent with the acquisition of energy at "prevailing market prices" or the incurrence of "reasonable costs." 66 Pa.C.S. § 2807(e)(3).

Rather, we are giving DSPs the tools to proactively manage their default service obligation. A DSP may minimize the risk of under collection through the regular

[20] 66 Pa.C.S. § 1307(f)(5).
[21] 41 P. S. § 202.

adjustment of rates. Additionally, we believe the risk of seasonal gaming will be greatly reduced when the PTC is adjusted on a regular basis in response to the change in composition of the portfolio. This is why we have directed that the PTC be adjusted at least every quarter or month, depending on customer size. This approach ensures full customer choice but protects DSPs from seasonal gaming and under recovery of costs.

To the extent that a DSP is concerned that it lacks the expertise or resources to proactively manage short-term purchases, they are free to retain the services of other parties and include these costs in their rates. For example, a DSP could outsource the management of its spot and short-term energy portfolio. As stated earlier in this order, this regulation also allows DSPs to coordinate their procurements of default service supply. Smaller DSPs are strongly encouraged to consider pooling their resources in the management of the default service obligation, and may request waivers from provisions that are too burdensome.

Additionally, at the suggestion of IECPA and others, we have revised this section to clearly state that the use of a reconciliation mechanism will be subject to annual review and audit, consistent with section 1307(d) and (e) of the Public Utility Code. The review of alternative energy and non-alternative energy costs recovered through an automatic adjustment clause should be addressed in the same proceeding to reduce administrative costs to the parties. The public notice and hearing provisions of section 1307(e) will apply to these filings.

Customer Groupings and Frequency of Rate Changes

Some parties have objected to the frequency of rate changes for customers, asserting that this will produce harmful volatility in rates. We simply disagree with this analysis. We cite to the experience of the State of Maryland, which has already transitioned to market based rates, as referenced by Strategic and NEM in their comments to the ANOFR:

> The Commission concurs with the parties that rate stability is an important public policy goal generally, and particularly with respect to SOS. Recent experience suggests that longer term fixed prices do not contribute to that goal; indeed they create a false sense of complacency that costs are in fact stable, followed by the painful transition when rates are finally adjusted to reflect current costs . . . The upshot is that frequent, albeit small rate changes, are a better vehicle for insuring relative rate stability (and a more gradual reflecting of changes in current market prices) rather than longer periods of frozen rates, followed by rate shock.

Maryland Public Service Commission, Case No. 9056, *Investigation into Default Service For Type II Standard Offer Service Customers*, Order 81019, Issued August 19, 2006.

In response to those suppliers who feel that quarterly and monthly changes in rates are too infrequent, we remind them that the regulation sets the minimum frequency of change. For example, DSPs may propose more frequent changes in rates, such as hourly priced service, for their larger commercial and industrial customers.

In response to the comments of IRRC on this issue to the proposed § 54.187(c), the Commission wishes to emphasize that the regulations allow DSPs the discretion to propose alternative groupings of retail customers for good cause. For example, Duquesne may propose to continue to offer hourly priced service to all customers at or above 300 kw. DSPs may also separate residential and small business customers for procurement purposes, as recommended by the OCA.

We recognize that the number and distribution of customers across classes varies significantly from territory to territory. For example, it may be necessary to combine the customer classes of smaller DSPs to develop tranches of sufficient size for competitive auctions. Alternatively, individual tranches may be stratified into residential and business customer segments when there are insufficient customers to create separate tranches for the different customer classes. Reasonable, alternative groupings of customers may be proposed for our consideration, consistent with the suggestion of IRRC.

Single Rate Option

Some parties believe that the Commission is unduly restricting the rate options available to customers in this rulemaking. It has been suggested that section 2806(h) of the Public Utility Code, 66 Pa.C.S. § 2806(h), be used in the context of default service to provide flexible pricing options to individual customers. DSPs may include proposals for flexible rates in their default service programs. However, these programs may increase the complexity and costs of providing basic default service. Additionally, these proposals must comply with the Public Utility Code and recent precedent regarding reasonable differences in rates between customer classes. 66 Pa.C.S. § 1304; *Lloyd v. Pa. Public Utility Commission*, 904 A.2d 1010 (Pa. Cmwlth 2006).

The Commission will keep an open mind on the appropriateness of renewable energy default service products, such as PECO's "Wind Tariff."[22] However, we observe that two EGSs are currently offering "green" energy products to residential customers in PECO's service territory. Additionally, default service supply will begin to incorporate a gradually increasing renewable energy component with the expiration of the rate cap, consistent with the requirements of the AEPS Act. PECO may propose the continuation of this rate in its first default service program and submit evidence of how this service is consistent with a "provider of last resort" role in the post-transition period.

Finally, we are revising § 54.187(k) in response to a comment made by the OCA to the ANOFR. The OCA recommends that a DSP be required to first use any collateral owed by a wholesale supplier pursuant to an energy contract in the event of a default. Only after this collateral was fully exhausted could the DSP seek to recover the incremental costs of a default from customers. We agree with this recommendation and have revised § 54.187(k) to require DSPs to first seek recovery under their "contract terms with the default supplier."

J. *§ 54.188. Commission review of default programs and rates*

Section 54.188 has been revised to reflect the introduction of new terms such as default service program, etc. The review period standard has been moved from § 54.186(f)(2) to § 54.188(d) in this version. Some parties commented that the proposed review period was too long and open-ended, and may detrimentally affect the prices

[22] The Commission held that offering and marketing this tariff was permissible under the terms of the settlement agreement relating to the establishment of the Exelon Corporation and its merger with the Unicom Corporation. However, the Commission did not make a final decision on the availability or marketing of this tariff in the context of post-transition period default service. *Green Mountain Energy Company v. PECO Energy Company*, Docket R-00016938C0001 (Order entered July 18, 2003).

bid by suppliers. IRRC, in comments to the prior version of § 54.186(f)(2) recommended reducing the review period from "no less than" to "no more than" 3 business days. The Commission agrees with these comments, and believes the period can be reduced. Accordingly, the Commission is reducing its review period from "no less than 3 business days" to no more than "1 business day." The Commission provides additional guidelines on this issue in the default service statement of policy.

We have clarified § 54.188(d) to state that while the result of a solicitation may be deemed approved if not formally rejected within 1 business day, this does not represent the end of the Commission's oversight. Should information subsequently come to the attention of the Commission that the DSP failed to adhere to the approved plan, that the DSP disclosed confidential information to an affiliate, or that one or more bidders engaged in fraud, collusion, bid rigging, price fixing or other unlawful acts the Commission would investigate and seek appropriate remedies.

We agree with IRRC that procurement plans should be reviewed to ensure that their design will result in reliable supply of electric at market prices with the incurrence of reasonable costs. The default service statement of policy includes guidelines for DSPs intended to help achieve this goal.

We are declining to adopt IRRC and some other commentators' suggestion that we lengthen the default service case timeline from 6 to 9 months. The Commission has adjudicated several default service cases, including the Pennsylvania Power Company's most recent filing, within a 6 month period. We believe that with the issuance of final regulations, greater consistency among filings, and the experience that will come with each case, the Commission, DSPs, and other parties will become more efficient in the filing and review of default service programs. However, we will adjust the standard to 7 months, and these final-form regulations reflect this change. This is the same time period for which the Commission may suspend a tariff in the context of requests for general rate increase. 66 Pa.C.S. § 1308(d). Where more time is truly necessary, particularly with initial filings, the DSP can petition for a waiver or modification of the seven month standard pursuant to 52 Pa. Code § 5.43.

Section 54.188(e) provides more structure for the review and approval of the initial rates that will take effect at the beginning of a default service program. The revised regulations establish a standard that should result in customers receiving notice of new rates within a reasonable period of time, and more opportunity to consider other options, including service with an EGS.

Section 54.188(f) now addresses standards for tariff filings required by our decision to require regular adjustment of the PTC. Section 54.188(g) has been eliminated as unnecessary and duplicative. A provision for the waiver of Commission regulations is already in place in 52 Pa. Code § 5.43.

In response to comments by UGI and others to the ANOFR, we are revising § 54.188(d) to state that we will not conduct an after the fact prudency review of purchases made consistent with a Commission approved default service plan. We are also revising this section, based on a comment from FirstEnergy, to observe that the Commission approval is not required for individual spot market purchases made pursuant to a Commission approved procurement plan. The Commission will study the DSPs overall spot market acquisition strategy in its review of the default service program. However, as noted above, a DSP's disclosure of confidential information to an affiliate or fraud, collusion, bid rigging or price manipulation by suppliers would be subject to Commission investigation and appropriate remedial action.

Section 54.188(e) has been clarified at the suggestion of the OCA to require that customers be given initial notice of the filing of the default service program. This notice is modeled on the provision that applies to natural gas distribution companies utilizing section 1307(f) of the Public Utility Code.

In response to IRRC's comment on this section, we note that the proposed § 54.188(g) has been deleted. Requests for waivers must now be included in the default service program, consistent with the new § 54.185(f). The phrase "and other applicable laws" no longer appears in this context.

K. *§ 54.189. Default Service Customers and the Standards for Transferring Customer Accounts to Default Service Providers*

We agree with IRRC that limitations on choice are inappropriate and contrary to the provisions of the Competition Act. We find that by providing for regular rate adjustments that track changes in market prices, any incentives to game the system through frequent changes in suppliers is greatly reduced. References to regulatory provisions have been added for clarity.

In response to comments by the OCA and IECPA, the Commission is making several edits to this section. Customers who are taking service with an EGS do not need to "apply" for default service. These customers should have already gone through an application process with an EDC when they first signed up for electric utility service. Since the incumbent EDC is currently the DSP in all service territories, customers who are shopping are still EDC customers for purposes of distribution and transmission service. Accordingly, they do not need to apply again, and potentially be required to pay onerous security deposits, to return to the DSP from an EGS.[23]

CONCLUSION

The Commission thanks the parties for their comments and participation in this proceeding. Given the high level of public interest in this matter, we offer the following information on the next steps in this rulemaking procedure. Upon the entry of this Final Order, the Commission will prepare this rule for delivery to the General Assembly and IRRC. If the rule is approved by IRRC, it will be forwarded to the Pennsylvania Attorney General for review as to form and legality. The Pennsylvania Attorney General has 30 days to review this final-form rule. If not rejected by the Pennsylvania Attorney General, the rule will become legally effective upon publication in the *Pennsylvania Bulletin*. This process should take approximately 2 to 3 months.

Accordingly, under sections 501 and 2807(e)(2) of the Public Utility Code (66 Pa.C.S. §§ 501 and 2807(e)(2)), sections 201 and 202 of the act of July 31, 1968 (P. L. 769 No. 240) (45 P. S. §§ 1201 and 1202), and the regulations promulgated thereunder at 1 Pa. Code §§ 7.1 and 7.2 and 7.5, the Commission adopts the regulations pertaining to the obligations of EDCs to connect, deliver and acquire

[23] Several parties commented on PECO commercial customers currently receiving generation service from an EGS as a consequence of PECO's Market Share Threshold program. These customers have the right to change their generation service provider at any time. However, the Commission will not, and PECO should not, automatically reassign these customers to default service upon the expiration of the generation rate cap.

electricity at the conclusion of the transition period, as noted and set forth in Annex A; *Therefore,*

It Is Ordered That:

1. The regulations of the Commission, 52 Pa. Code Chapters 54 and 57, are amended by amending §§ 54.4—54.6, 54.31, 54.32, 54.41 and 57.178 and by adding §§ 54.123 and 54.181—54.189 to read as set forth in Annex A.

2. The Secretary shall submit this order and Annex A to the Office of Attorney General for approval as to legality.

3. The Secretary shall submit this order and Annex A to the Governor's Budget Office for review of fiscal impact.

4. The Secretary shall submit this order and Annex A for review by the designated standing committees of both houses of the General Assembly, and for review and approval by the Independent Regulatory Review Commission.

5. The Secretary shall deposit this order and Annex A with the Legislative Reference Bureau for publication in the *Pennsylvania Bulletin*.

6. The final-form rulemaking becomes effective upon publication in the *Pennsylvania Bulletin*.

7. The contact person for this final-form rulemaking is Shane M. Rooney. Alternate formats of this document are available to persons with disabilities and may be obtained by contacting Sherri Delbiondo, Regulatory Coordinator, Law Bureau, (717) 772-4597.

JAMES J. MCNULTY,
Secretary

(*Editor's Note*: This final-form rulemaking refers to the statement of policy published at 37 Pa.B. 5019 (September 15, 2007) (Fiscal Note #57-254).)

(*Editor's Note*: For the text of the order of the Independent Regulatory Review Commission, relating to this document, see 37 Pa.B. 4411 (August 4, 2007).)

Fiscal Note: Fiscal Note 57-237 remains valid for the final adoption of the subject regulations.

Annex A

TITLE 52. PUBLIC UTILITIES

PART I. PUBLIC UTILITY COMMISSION

Subpart C. FIXED SERVICE UTILITIES

CHAPTER 54. ELECTRICITY GENERATION CUSTOMER CHOICE

Subchapter A. CUSTOMER INFORMATION

§ 54.4. Bill format for residential and small business customers.

(a) EGS prices billed must reflect the marketed prices and the agreed upon prices in the disclosure statement.

(b) The following requirements apply only to the extent to which an entity has responsibility for billing customers, to the extent that the charges are applicable. The default service provider will be considered to be an EGS for the purposes of this section. Duplication of billing for the same or identical charges by both the EDC and EGS is not permitted.

(1) EDC charges must appear separately from EGS charges.

(2) Charges for basic services must appear before charges for nonbasic services, and appear distinctly separate.

(3) Customer bills must contain the following charges, if these charges are applicable, and these charges must appear in a distinct section of the bill. The designation or label of each charge as either a basic charge or nonbasic charge appears in parenthesis following the name of the charge. This label of either basic or nonbasic is not required to accompany the name of the charge on the bill.

(i) Generation charges (basic).

(A) Generation charges shall be presented in a standard pricing unit for electricity in actual dollars or cents per kWh, actual average dollars or cents per kWh, kW or other Commission-approved standard pricing unit.

(B) Generation charges shall appear first among the basic charges with one exception. EDCs may place the customer charge first among the basic charges.

(ii) Transmission charges (basic).

(iii) Distribution charges (basic).

(iv) Customer charge or basic charge (charge for basic service in § 56.15 (relating to billing information)) (basic).

(v) Advanced metering charges (basic).

(vi) Transition charges (basic).

(vii) Taxes (comply with § 56.15) (basic).

(viii) Late payment charges (basic).

(ix) Security deposit (basic).

(x) Reconnection fee (basic).

(xi) Itemization of nonbasic charges (nonbasic).

(xii) Overall billing total.

(4) The entity reading the meter for billing purposes shall provide the following electricity use data figures:

(i) The total annual electricity use for the past 12 months in kWh, including the current billing cycle. This is a single cumulative number.

(ii) The average monthly electricity use for the past 12 months in kWh, including the current billing cycle. This is a single cumulative number.

(5) The requirements of § 56.15 shall be incorporated in customer bills to the extent that they apply.

(6) Definitions for the following charges and terms are required in a customer's bill, if they appear as billing items, as contained in "Common Electric Competition Terms" and shall be in a distinctly separate section of the bill:

(i) Generation charges.

(ii) Transmission charges.

(iii) Distribution charges.

(iv) Customer charge/basic charge (charge for basic service in § 56.15).

(v) Advanced metering, if applicable.

(vi) Transition charges.

(7) "General Information" is the required title for customer contact information in a customer's bill.

(i) The name, address and telephone number for the EGS and EDC shall be included.

(ii) Both EDC and EGS information in subparagraph (i) is required on all customer bills with the billing entity's information first.

(8) When a customer chooses the option to receive a separate bill for generation supply, the EDC shall include in a customer's bill the following information where the EGS charges would normally appear:

(i) The EGS's name.

(ii) A statement that the customer's EGS is responsible for the billing of EGS charges.

(9) When a customer chooses the option to receive a single bill from the EDC, the EDC shall include in the customer's bill the name of the EGS where the EGS charges appear.

(10) For customers who have chosen electric generation services from a competitive supplier, the customer's bill shall include the following statements which may appear together in a paragraph:

(i) "Generation prices and charges are set by the electric generation supplier you have chosen."

(ii) "The Public Utility Commission regulates distribution prices and services."

(iii) "The Federal Energy Regulatory Commission regulates transmission prices and services."

(c) The billing entity shall provide samples of customer bills to the Commission for review.

§ 54.5. Disclosure statement for residential and small business customers.

(a) The agreed upon prices in the disclosure statement must reflect the marketed prices and the billed prices.

(b) The EGS shall provide the customer written disclosure of the terms of service at no charge whenever:

(1) The customer requests that an EGS initiate service.

(2) The EGS proposes to change the terms of service.

(3) Service commences from a default service provider.

(c) The contract's terms of service shall be disclosed, including the following terms and conditions, if applicable:

(1) Generation charges shall be disclosed according to the actual prices.

(2) The variable pricing statement, if applicable, must include:

(i) Conditions of variability (state on what basis prices will vary).

(ii) Limits on price variability.

(3) An itemization of basic and nonbasic charges distinctly separate and clearly labeled.

(4) The length of the agreement, which includes:

(i) The starting date.

(ii) The expiration date, if applicable.

(5) An explanation of sign-up bonuses, add-ons, limited time offers, other sales promotions and exclusions, if applicable.

(6) An explanation of prices, terms and conditions for special services, including advanced metering deployment, if applicable.

(7) The cancellation provisions, if applicable.

(8) The renewal provisions, if applicable.

(9) The name and telephone number of the default service provider.

(10) An explanation of penalties, fees or exceptions, printed in type size larger than the type size appearing in the terms of service.

(11) Customer contact information that includes the name of the EDC and EGS, and the EGS's address, telephone number, Commission license number and Internet address, if available. The EGS's information shall appear first and be prominent.

(12) A statement that directs a customer to the Commission if the customer is not satisfied after discussing the terms of service with the EGS.

(13) The name and telephone number for universal service program information.

(d) Customers shall be provided a 3-day right of rescission period following receipt of the disclosure statement.

(1) The 3-day right of rescission is 3 business days.

(2) The 3-day right of rescission begins when the customer receives the written disclosure.

(3) The customer may cancel in writing, orally or electronically, if available.

(4) Waivers of the 3-day right of rescission are not permitted.

(e) Definitions for generation charges and transmission charges, if applicable, are required and shall be defined in accordance with the "Common Electric Competition Terms." Definitions for each of the nonbasic services, if applicable, are required. The definition section of the bill must be distinctly separate.

(f) The EGS shall include in the customer's disclosure statement the following statements which may appear together in a paragraph:

(1) "Generation prices and charges are set by the electric generation supplier you have chosen."

(2) "The Public Utility Commission regulates distribution prices and services."

(3) "The Federal Energy Regulatory Commission regulates transmission prices and services."

(g) Disclosure statements must include the following customer notification:

(1) "If you have a fixed term agreement with us and it is approaching the expiration date or whenever we propose to change our terms of service in any type of agreement, you will receive written notification from us in each of our last three bills for supply charges or in corresponding separate mailings that precede either the expiration date or the effective date of the proposed changes. We will explain your options to you in these three advance notifications."

(h) If the default service provider changes, the new default service provider shall notify customers of that change, and provide customers with its name, address, telephone number and Internet address, if available.

§ 54.6. Request for information about generation supply.

(a) EGSs shall respond to reasonable requests made by consumers for information concerning generation energy sources.

(1) EGSs shall respond by informing consumers that this information is included in the annual licensing report and that this report exists at the Commission. Providers

shall explain that the report is available to them and offer to provide it, if requested.

(2) The default service provider shall file at the Commission the annual licensing report as required by the Commission's licensing regulations in this chapter and shall otherwise comply with paragraph (1).

(3) EGSs operating for less than 1 year may respond to customer inquiries about generation energy sources by furnishing the information as described in subsection (b).

(b) Verification of the anticipated generation energy source, of the identifiable resources (if and when they have been "claimed") and the fact that energy characteristics were not sold more than once, shall be conducted by an independent auditor at the end of each calendar year and contained in the annual report to the Commission, relating to information disclosure requirements in subsection (a) and the licensing regulations in this chapter.

(c) Whenever EGSs market their generation as having special characteristics, such as "produced in Pennsylvania" or "environmentally friendly" and the like, providers shall have information available to substantiate their claims.

(1) Disclosure of generation energy sources shall be identifiable, which is defined as electricity transactions which are traceable to specific generation sources by any auditable contract trail or equivalent, such as a tradable commodity system, that provides verification that the electricity source claimed has been sold only once to a retail customer. If generation energy sources are not identifiable, the provider shall disclose this fact.

(d) Electricity providers, whether they make distinguishing claims or not, shall include in their general communications with consumers that electricity is the product of a mix of generation energy sources, that is delivered over a system of wires.

(e) Electricity providers shall respond to reasonable consumer requests for energy efficiency information, by indicating that these materials are available upon request from the Commission or the EDC.

(f) The use of general, unsubstantiated and unqualified claims of environmental benefits, such as "green" and "environmentally friendly," is prohibited. The Commission supports the application of the Federal Trade Commission's (FTC) Guides for the Use of Environmental Marketing Claims (see 16 CFR 260.1—260.8 (relating to guides for the use of environmental marketing claims)), in the enforcement of this section and the following specific principles:

(1) Section 260.6(a) (relating to general principles) which states that qualifications or disclosure should be clear, prominent, and of relative type size and proximity to the claim being qualified. In addition, contrary assertions which undercut the qualifications should not appear.

(2) Section 260.6(c) which states that environmental claims should not overstate the environmental attribute or benefit, expressly or by implication.

(3) Section 260.6(d) which suggests that marketing materials which make comparative claims should clearly state the basis for the comparison, be able to be substantiated, and be accurate at the time they are made.

(4) Section 260.7(a) (relating to environmental marketing claims) which labels unqualified claims of environmental benefit as deceptive.

(5) Section 260.7(f) which addresses claims regarding source reduction, such as reduced toxicity or reductions of other environmentally negative effects.

(g) Residential and small business customers are entitled to receive at no charge and at least once a year, historical billing data from whomever reads the meter for billing purposes.

(1) The EDC is only obligated to provide information that is readily available in its billing system.

(2) The historical billing data shall be conveyed in terms of kWh, and kW, as applicable, and associated charges for the current billing period and for the year preceding the current billing period.

(3) The historical billing data will be updated with each billing cycle.

(h) Electricity providers shall notify consumers either in advertising materials, disclosure statements or bills that information on generation energy sources, energy efficiency, environmental impacts or historical billing data is available upon request.

Subchapter B. ELECTRIC GENERATION SUPPLIER LICENSING

§ 54.31. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise.

Aggregator—An entity licensed by the Commission, that purchases electric energy and takes title to electric energy as an intermediary for sale to retail customers. See section 2803 of the code (relating to definitions).

Applicant—A person or entity seeking to obtain a license to supply retail electricity or electric generation service.

Broker—An entity, licensed by the Commission, that acts as an intermediary in the sale and purchase of electric energy but does not take title to electric energy. See section 2803 of the code.

Code—The Public Utility Code (66 Pa.C.S. Part I).

Default service provider—The incumbent EDC within a certificated service territory or a Commission approved alternative supplier of electric generation.

Department—The Department of Revenue of the Commonwealth.

EDC—Electric distribution company.

EGS—Electric generation supplier

—(i) A person or corporation, including municipal corporations which choose to provide service outside their municipal limits except to the extent provided prior to the effective date of this chapter (*Editor's Note:* The reference to "this chapter" refers to the code.), brokers and 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, or that purchase, broker, arrange or market electricity or related services for sale to end-use customers utilizing the jurisdictional transmission and distribution facilities of an EDC.

(ii) The term excludes building or facility owner/operators that manage the internal distribution system serving the building or facility and that supply electric power and other related power services to occupants of the building or the facility.

(iii) The term excludes electric cooperative corporations except as provided in 15 Pa.C.S. Chapter 74 (relating to generation choice for customers of electric cooperatives). See section 2803 of the code.

Interim license—A temporary license granted to an EGS under interim standards adopted in the Commission's Final Order on Licensing Requirements for Electricity Generation Suppliers, entered February 13, 1997 at Dkt. No. M-00960890 F0004.

License—A license granted to an EGS under this subchapter.

Licensee—A person or entity which has obtained a license to provide retail electricity or electric generation service.

Market aggregator—An entity licensed by the Commission, that purchases electric energy and takes title to electric energy as an intermediary for sale to retail customers. See section 2803 of the code.

Marketer—An entity, licensed by the Commission, that acts as an intermediary in the sale and purchase of electric energy but does not take title to electric energy. See section 2803 of the code.

Marketing—The publication, dissemination or distribution of informational and advertising materials regarding the EGS's services and products to the public by print, broadcast, electronic media, direct mail or by telecommunication.

Offer to provide service—The extension of an offer to provide services or products communicated orally, or in writing to a customer.

Renewable resource—As defined in section 2803 of the code.

§ 54.32. Application process.

(a) An EGS may not engage in marketing, or may not offer to provide, or provide retail electricity or electric generation service until it is granted a license by the Commission.

(b) An application for a license shall be made on the form provided by the Commission. A copy of the application may be obtained from the Commission's Secretary. The application form will also be made available on the Commission's Internet web site. An application shall be verified by an oath or affirmation as required in § 1.36 (relating to verification). See section 2809(b) of the code (relating to requirements for electric generation suppliers).

(c) An original and eight copies of the completed application and supporting attachments shall be filed. An application for a license shall be accompanied by the application fee as established in § 1.43 (relating to schedule of fees payable to the Commission).

(d) Copies of the completed application with supporting documentation shall be served on the following: the Office of Consumer Advocate, the Office of Small Business Advocate, the Department and the Office of the Attorney General and the EDCs through whose transmission and distribution facilities the applicant intends to supply customers.

(e) Incomplete applications and those without supporting attachments, when needed, will be rejected without prejudice. The license application, with supporting attachments, shall be completed in its entirety.

(f) When an answer on the application requires the disclosure of privileged or confidential information not otherwise available to the public, the applicant may designate at each point in the application where information is disclosed that is confidential and privileged.

(1) One copy of this confidential or privileged information conspicuously marked at the top as "CONFIDENTIAL" may be submitted to the Office of the Secretary with the application. An applicant shall provide reasons for protecting this information.

(2) The request for confidentiality will be treated as a petition for protective order and will be ruled on by the Commission in conjunction with the license application.

(3) Pending disposition, the information will be used solely for the purpose of evaluating the license application, and the confidentiality of this information will be maintained consistent with regulations in this title pertaining to confidentiality.

(g) An EGS who has been granted an interim license shall apply for a license under this subchapter by updating its prior license application to include additional and updated information required by § 54.33 (relating to application form). An updated application shall be submitted by December 7, 1998.

(h) An EDC acting within its certificated service territory as a default service provider is not required to obtain a license.

§ 54.41. Transfer or abandonment of license.

(a) A license may not be transferred without prior Commission approval. See section 2809(d) of the code (relating to requirements for electric generation suppliers). Approval for transfer shall be obtained by petition to the Commission. The granting of such a petition does not eliminate the need for the transferee to complete and file with the Commission an application that demonstrates the transferee's financial and technical fitness to render service under the transferred license.

(b) A licensee may not abandon service without providing 90 days prior written notice to the Commission, the licensee's customers, the affected distribution utilities and default service providers prior to the abandonment of service. The licensee shall provide individual notice to its customers with each billing, in each of the three billing cycles preceding the effective date of the abandonment.

Subchapter E. COMPETITIVE SAFEGUARDS

§ 54.123. Transfer of customers to default service.

The following standards apply to the transfer of a retail customer's electric generation service from an EGS to a default service provider within the meaning of § 54.182 (relating to definitions):

(1) An EGS may not transfer a retail customer from its electric generation service to the default service provider without the consent of the default service provider, except in the following situations:

(i) Upon Commission approval of the abandonment, suspension or revocation of an EGS license, consistent with §§ 54.41 and 54.42 (relating to transfer or abandonment of license; and license suspension; license revocation).

(ii) Upon nonpayment by a retail customer for services rendered by the EGS.

(iii) To correct an unauthorized or inadvertent switch of a retail customer's account from default service to an alternative EGS's service, consistent with § 57.177 (relating to customer dispute procedures).

(iv) Upon the normal expiration of contracts.

(2) An EGS may initiate transfers in the situations in paragraph (1) through standard electronic data interchange protocols.

(3) The Commission may impose a penalty for every retail customer transferred to default service in violation of this section, consistent with 66 Pa.C.S. §§ 3301—3316 (relating to violations and penalties).

Subchapter G. DEFAULT SERVICE

§ 54.181. Purpose.

This subchapter implements 66 Pa.C.S. § 2807(e) (relating to duties of electric distribution companies), pertaining to an EDC's obligation to serve retail customers at the conclusion of the restructuring transition period. The provisions in this subchapter ensure that retail customers who do not choose an alternative EGS, or who contract for electric energy that is not delivered, have access to generation supply at prevailing market prices. The EDC or other approved entity shall fully recover all reasonable costs for acting as a default service provider of electric generation supply to all retail customers in its certificated distribution territory.

§ 54.182. Definitions.

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise:

Alternative energy portfolio standards—A requirement that a certain percentage of electric energy sold to retail customers in this Commonwealth by EDCs and EGSs be derived from alternative energy sources, as defined in the Alternative Energy Portfolio Standards Act (73 P. S. §§ 1648.1—1648.8).

Commission—The Pennsylvania Public Utility Commission.

Competitive bid solicitation process—A fair, transparent and nondiscriminatory process by which a default service provider awards contracts for electric generation supply to qualified suppliers who submit the lowest bids.

DSP—Default service provider—The incumbent EDC within a certificated service territory or a Commission approved alternative supplier of electric generation service.

Default service—Electric generation supply service provided pursuant to a default service program to a retail electric customer not receiving service from an EGS.

Default service implementation plan—The schedule of competitive bid solicitations and spot market energy purchases, technical requirements and related forms and agreements.

Default service procurement plan—The electric generation supply acquisition strategy a DSP will use in satisfying its default service obligations, including the manner of compliance with the alternative energy portfolio standards requirement.

Default service program—A filing submitted to the Commission by a DSP that identifies a procurement plan, an implementation plan, a rate design to recover all reasonable costs and other elements identified in § 54.185 (relating to default service programs and periods of service).

Default service rate—The rate billed to a default service customer resulting from compliance with a Commission approved default service program.

EDC—Electric distribution company—The term has the same meaning as defined in 66 Pa.C.S. § 2803 (relating to definitions).

EGS—Electric generation supplier—The term has the same meaning as defined in 66 Pa.C.S. § 2803.

FERC—The Federal Energy Regulatory Commission.

Maximum registered peak load—The highest level of demand for a particular customer, based on the PJM Interconnection, LLC, "Peak Load Contribution Standard," or its equivalent, and as may be further defined by the EDC tariff in a particular service territory.

PTC—Price-to-compare—A line item that appears on a retail customer's monthly bill for default service. The PTC is equal to the sum of all unbundled generation and transmission related charges to a default service customer for that month of service.

Prevailing market price—The price that is available in the wholesale market at particular points in time for electric generation supply.

RTO—Regional transmission organization—A FERC-approved regional transmission organization.

Retail customer or *retail electric customer*—These terms have the same meaning as defined in 66 Pa.C.S. § 2803.

Spot market energy purchase—The purchase of an electric generation supply product in a FERC-approved real time or day ahead energy market.

§ 54.183. Default service provider.

(a) The DSP shall be the incumbent EDC in each certificated service territory, except as provided for under subsection (b).

(b) The DSP may be changed by one of the following processes:

(1) An EDC may petition the Commission to be relieved of the default service obligation.

(2) An EGS may petition the Commission to be assigned the default service role for a particular EDC service territory.

(3) The Commission may propose through its own motion that an EDC be relieved of the default service obligation.

(c) The Commission may reassign the default service obligation for the entire service territory, or for specific customer classes, to one or more alternative DSPs when it finds it to be necessary for the accommodation, safety and convenience of the public. A finding would include an evaluation of the incumbent EDC's operational and financial fitness to serve retail customers, and its ability to provide default service under reasonable rates and conditions. In these circumstances, the Commission will announce, through an order, a competitive process to determine the alternative DSP.

(d) When the Commission finds that an EDC should be relieved of the default service obligation, the competitive process for the replacement of the default service provider shall be as follows:

(1) An entity that wishes to be considered for the role of the alternative DSP shall file a petition under 66 Pa.C.S. § 2807(e)(3) (relating to duties of electric distribution companies).

(2) Petitioners shall demonstrate their operational and financial fitness to serve and their ability to comply with Commission regulations, orders and applicable laws pertaining to public utility service.

(3) If no petitioner can meet this standard, the incumbent EDC shall be required to continue the provision of default service.

(4) If one or more petitioners meets the standard provided in paragraph (2), the Commission will approve the DSP best able to fulfill the obligation in a safe, cost-effective and efficient manner, consistent with 66 Pa.C.S. §§ 1103 and 1501 (relating to procedure to obtain certificates of public convenience; and character of service and facilities) and 2807(e).

(5) A petitioner approved to act as an alternative DSP shall comply with applicable provisions of the code, regulations and conditions imposed in approving the petition to act as an alternative DSP.

§ 54.184. Default service provider obligations.

(a) A DSP shall be responsible for the reliable provision of default service to retail customers who are not receiving generation services from an alternative EGS within the certificated territory of the EDC that it serves or whose alternative EGS has failed to deliver electric energy.

(b) A DSP shall comply with the code and Chapter 1 (relating to rules of administrative practice and procedure) to the extent that the obligations are not modified by this subchapter or waived under § 5.43 (relating to petitions for issuance, amendment, repeal or waiver of regulations).

(c) A DSP shall continue the universal service and energy conservation program in effect in the EDC's certificated service territory or implement, subject to Commission approval, similar programs consistent with the 66 Pa.C.S. §§ 2801—2812 (relating to Electricity Generation Customer Choice and Competition Act). The Commission will determine the allocation of these responsibilities between an EDC and an alternative DSP when an EDC is relieved of its DSP obligation.

§ 54.185. Default service programs and periods of service.

(a) A DSP shall file a default service program with the Commission's Secretary's Bureau no later than 12 months prior to the conclusion of the currently effective default service program or Commission-approved generation rate cap for that particular EDC service territory, unless the Commission authorizes another filing date. Thereafter, the DSP shall file its programs consistent with schedules identified by the Commission.

(b) Default service programs must comply with Commission regulations pertaining to documentary filings in Chapter 1 (relating to rules of administrative practice and procedure), except when modified by this subchapter. The DSP shall serve copies of the default service program on the Pennsylvania Office of Consumer Advocate, Pennsylvania Office of Small Business Advocate, the Commission's Office of Trial Staff, EGSs registered in the service territory and the RTO or other entity in whose control area the DSP is operating. Copies shall be provided upon request to other EGSs and shall be available at the DSP's public internet domain.

(c) The first default service program shall be for a period of 2 to 3 years, or for a period necessary to comply with subsection (d)(4), unless another period is authorized by the Commission. Subsequent program terms will be determined by the Commission.

(d) A default service program must include the following elements:

(1) A procurement plan identifying the DSP's electric generation supply acquisition strategy for the period of service. The procurement plan should identify the means of satisfying the minimum portfolio requirements of the Alternative Energy Portfolio Standards Act (73 P. S. §§ 1648.1—1648.8) for the period of service.

(2) An implementation plan identifying the schedules and technical requirements of competitive bid solicitations and spot market energy purchases, consistent with § 54.186 (relating to default service procurement and implementation plans).

(3) A rate design plan recovering all reasonable costs of default service, including a schedule of rates, rules and conditions of default service in the form of proposed revisions to its tariff.

(4) Documentation that the program is consistent with the legal and technical requirements pertaining to the generation, sale and transmission of electricity of the RTO or other entity in whose control area the DSP is providing service. The default service procurement plan's period of service must align with the planning period of that RTO or other entity.

(5) Contingency plans to ensure the reliable provision of default service when a wholesale generation supplier fails to meet its contractual obligations.

(6) Copies of agreements or forms to be used in the procurement of electric generation supply for default service customers. This includes all documents used as part of the implementation plan, including supplier master agreements, request for proposal documents, credit documents and confidentiality agreements. When applicable, the default service provider shall use standardized forms and agreements that have been approved by the Commission.

(7) A schedule identifying generation contracts of greater than 2 years in effect between a DSP, when it is the incumbent EDC, and retail customers in that service territory. The schedule should identify the load size and end date of the contracts. The schedule shall only be provided to the Commission and will be treated as confidential.

(e) The Commission may, following notice and opportunity to be heard, direct that some or all DSPs file joint default service programs to acquire electric generation supply for all of their default service customers. In the absence of such a directive, some or all DSPs may jointly file default service programs or coordinate the scheduling of competitive bid solicitations to acquire electric generation for all of their default service customers. A multiservice territory procurement and implementation plan must comply with § 54.186.

(f) DSPs shall include requests for waivers from the provisions of this subchapter in their default service program filings. For DSPs with less than 50,000 retail customers, the Commission will grant waivers to the extent necessary to reduce the regulatory, financial or technical burden on the DSP or to the extent otherwise in the public interest.

§ 54.186. Default service procurement and implementation plans.

(a) A DSP shall acquire electric generation supply at prevailing market prices for default service customers in a manner consistent with procurement and implementation plans approved by the Commission.

(b) A DSP's procurement plan must adhere to the following standards:

(1) The procurement plan shall be designed to acquire electric generation supply at prevailing market prices to meet the DSP's anticipated default service obligation at reasonable costs.

(2) DSPs with loads of 50 mW or less shall evaluate the cost and benefits of joining with other DSPs or affiliates in contracting for electric supply.

(3) Procurement plans may include solicitations and contracts whose duration extends beyond the program period.

(4) Electric generation supply shall be acquired by competitive bid solicitation processes, spot market energy purchases or a combination of both.

(5) The DSP's supplier affiliate may participate in a competitive bid solicitation process used as part of the procurement plan subject to the following conditions:

(i) The DSP shall propose and implement protocols to ensure that its supplier affiliate does not receive an advantage in the solicitation and evaluation of competitive bids, or other aspect of the implementation plan.

(ii) The competitive bid solicitation process shall comply with the codes of conduct promulgated by the Commission in § 54.122 (relating to code of conduct).

(c) A DSP's implementation plan must adhere to the following standards:

(1) A competitive bid solicitation process used as part of the default service implementation plan must provide, to the extent applicable and at the appropriate time, the following information to suppliers:

(i) A bidding schedule.

(ii) A definition and description of the power supply products on which potential suppliers shall bid.

(iii) Bid price formats.

(iv) A time period during which the power will need to be supplied for each power supply product.

(v) Bid submission instructions and format.

(vi) Price-determinative bid evaluation criteria.

(vii) Current load data for rate schedules or maximum registered peak load groupings, including the following:

(A) Hourly usage data.

(B) Number of retail customers.

(C) Capacity peak load contribution figures.

(D) Historical monthly retention figures.

(E) Estimated loss factors.

(F) Customer size distribution.

(2) The default service implementation plan must include fair and nondiscriminatory bidder qualification requirements, including financial and operational qualifications, or other reasonable assurances of a supplier of electric generation services' ability to perform.

(3) A competitive bid solicitation process used as part of the implementation plan will be subject to monitoring by the Commission or an independent third party evaluator selected by the DSP in consultation with the Commission. A third party evaluator shall operate at the direction of the Commission. Commission staff and a third party evaluator involved in monitoring the procurement process shall have full access to all information pertaining to the competitive procurement process, either remotely or where the process is administered. A third party evaluator retained for purposes of monitoring the competitive procurement process shall be subject to confidentiality agreements identified in § 54.185(d)(6) (relating to default service programs and periods of service).

(4) The DSP or third party evaluator shall review and select winning bids procured through a competitive bid solicitation process in a nondiscriminatory manner based on the price determinative bid evaluation criteria set forth consistent with paragraph (1)(vi).

(5) The bids submitted by a supplier in response to a competitive bid solicitation process shall be treated as confidential pursuant to the confidentiality agreement approved by the Commission under § 54.185(d)(6). The DSP, the Commission and a third party involved in the administration, review or monitoring of the bid solicitation process shall be subject to this confidentiality provision.

(d) The DSP may petition for modifications to the approved procurement and implementation plans when material changes in wholesale energy markets occur to ensure the acquisition of sufficient supply at prevailing market prices. The DSP shall monitor changes in wholesale energy markets to ensure that its procurement plan continues to reflect the incurrence of reasonable costs, consistent with 66 Pa.C.S. § 2807(e)(3) (relating to duties of electric distribution companies).

§ 54.187. Default service rate design and the recovery of reasonable costs.

(a) The costs incurred for providing default service shall be recovered through a default service rate schedule. The rate schedule shall be designed to recover fully all reasonable costs incurred by the DSP during the period default service is provided to customers, based on the average cost to acquire supply for each customer class.

(b) Except for rates available consistent with subsection (f), a default service customer shall be offered a single rate option, which shall be identified as the PTC and displayed as a separate line item on a customer's monthly bill.

(c) The rates charged for default service may not decline with the increase in kilowatt hours of electricity used by a default service customer in a billing period.

(d) The PTC shall be designed to recover all default service costs, including generation, transmission and other default service cost elements, incurred in serving the average member of a customer class. An EDC's default service costs may not be recovered through the distribution rate. Costs currently recovered through the distribution rate, which are reallocated to the default service rate, may not be recovered through the distribution rate. The distribution rate shall be reduced to reflect costs reallocated to the default service rate.

(e) A DSP shall use an automatic energy adjustment clause, consistent with 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments) and Chapter 75 (relating to alternate energy portfolio standards), to recover all reasonable costs incurred through compliance with the Alternative Energy Portfolio Standards Act (73 P. S. §§ 1648.1—1648.8). The use of an automatic adjustment clause shall be subject to audit and annual review, consistent with 66 Pa.C.S. § 1307(d) and (e), regarding fuel cost adjustment audits and automatic adjustment reports and proceedings.

(f) A DSP may use an automatic energy adjustment clause to recover reasonable nonalternative energy default service costs. The use of an automatic adjustment clause shall be subject to audit and annual review, consistent with 66 Pa.C.S. § 1307(d) and (e). A DSP may collect interest from retail customers on the recoveries of under collection of default service costs at the legal rate of interest. Refunds to customers for over recoveries shall be made with interest, at the legal rate of interest plus 2%.

(g) The default service rate schedule must include rates that correspond to demand side response and demand side management programs, as defined in section 2 of the Alternative Energy Portfolio Standards Act (73 P. S. § 1648.2), when the Commission mandates these rates pursuant to its authority under 66 Pa.C.S. Chapter 1 (relating to general provisions).

(h) Default service rates shall be adjusted on a quarterly basis, or more frequently, for all customer classes with a maximum registered peak load up to 25 kW, to ensure the recovery of costs reasonably incurred in acquiring electricity at prevailing market prices and to reflect the seasonal cost of electricity. DSPs may propose alternative divisions of customers by maximum registered peak load to preserve existing customer classes.

(i) Default service rates shall be adjusted on a quarterly basis, or more frequently, for all customer classes with a maximum registered peak load of 25 kW to 500 kW, to ensure the recovery of costs reasonably incurred in acquiring electricity at prevailing market prices and to reflect the seasonal cost of electricity. DSPs may propose alternative divisions of customers by maximum registered peak load to preserve existing customer classes.

(j) Default service rates shall be adjusted on a monthly basis, or more frequently, for all customer classes with a registered peak load of equal to or greater than 500 kW to ensure the recovery of costs reasonably incurred in acquiring electricity at prevailing market prices and to reflect the seasonal cost of electricity. DSPs may propose alternative divisions of customers by registered peak load to preserve existing customer classes.

(k) When a supplier fails to deliver electric generation supply to a DSP, the DSP shall be responsible for acquiring replacement electric generation supply consistent with its Commission-approved contingency plan. When necessary to procure electric generation supply before the implementation of a contingency plan, a DSP shall acquire supply at prevailing market prices and fully recover all reasonable costs associated with this activity that are not otherwise recovered through its contract terms with the default supplier. The DSP shall follow acquisition strategies that reflect the incurrence of reasonable costs, consistent with 66 Pa.C.S. § 2807(e)(3) (relating to duties of electric distribution companies), when selecting from the various options available in these energy markets.

§ 54.188. Commission review of default service programs and rates.

(a) A default service program will initially be referred to the Office of Administrative Law Judge for further proceedings as may be required.

(b) The Commission will issue an order within 7 months of a program's filing with the Commission on whether the default service program demonstrates compliance with this subchapter and 66 Pa.C.S. §§ 2801—2812 (relating to the Electricity Generation Customer Choice and Competition Act).

(c) Upon entry of the Commission's final order, a DSP shall acquire generation supply for the period of service in a manner consistent with the terms of the approved procurement and implementation plans and consistent with the standards identified in § 54.186 (relating to default service procurement and implementation plans).

(d) Upon receiving written notice, the Commission will have 1 business day, to approve or disapprove the results of a competitive bid solicitation process used by a DSP as part of its procurement plan. When the Commission does not act within 1 business day the results of the process will be deemed approved. The Commission will not certify or otherwise approve or disapprove a DSP's spot market energy purchases made pursuant to a Commission-approved procurement plan. The Commission will monitor the DSP's adherence to the terms of the approved default service program and 66 Pa.C.S. §§ 2801—2812 (relating to the Electricity Generation Customer Choice and Competition Act). The Commission may initiate an investigation regarding implementation of the DSP's default service program and, at the conclusion of the investigation, order remedies as may be lawful and appropriate. the Commission will not deny the DSP the recovery of its reasonable costs for purchases made pursuant to an approved competitive procurement process unless the DSP concealed or misled the Commission regarding its adherence to the program, or otherwise violated the provisions of this subchapter or the code.

(e) A DSP shall adhere to the following procedures in obtaining approval of default service rates and providing notice to default service customers:

(1) A DSP shall provide all customers notice of the filing of a default service program in a similar manner as found in § 53.68 (relating to notice requirements).

(2) A DSP shall provide all customers notice of the initial default service rates and terms and conditions of service 60 days before their effective date, or 30 days after bidding has concluded, whichever is sooner, unless another time period is approved by the Commission. The DSP shall provide written notice to the named parties identified in § 54.185(b) (relating to default service programs and periods of service) containing an explanation of the methodology used to calculate the price for electric service.

(3) After the initial steps of a default service procurement and implementation plan are completed, the DSP shall file with the Commission tariff supplements designed to reflect, for each customer class, the rates to be charged for default service. The tariff supplements shall be accompanied by supporting documentation adequate to demonstrate adherence to the procurement plan approved by the Commission, the procurement plan results and the translation of those results into customer rates.

(4) A customer or party identified in § 54.185(b) may file exceptions to the initial default service tariffs within

20 days of the date the tariffs are filed with the Commission. The exceptions shall be limited to whether the DSP properly implemented the procurement plan approved by the Commission and accurately calculated the rates. The Commission will resolve filed exceptions by order. The Commission may allow the default rates to become effective pending the resolution of those exceptions.

(f) A DSP shall submit tariff supplements on a quarterly or more frequent basis, consistent with § 54.187(h) and (i) (pertaining to default service rate design and recovery of reasonable costs), to revise default service rates to ensure the recovery of costs reasonably incurred in acquiring electricity at prevailing market prices. The DSP shall provide written notice to the named parties identified in § 54.185(b) of the proposed rates at the time of the tariff filings. The tariff supplements shall be posted to the DSP's public internet domain at the time they are filed with the Commission. A customer or the parties identified in § 54.185(b) may file exceptions to the default service tariffs within 20 days of the date the tariffs are filed with the Commission. The exceptions shall be limited to whether the DSP has properly implemented the procurement plan approved by the Commission and accurately calculated the rates. The DSP shall post the revised PTC for each customer class within 1 business day of its effective date to its public internet domain to enable customers to make an informed decision about electric generation supply options.

§ 54.189. Default service customers.

(a) At the conclusion of an EDC's Commission approved generation rate cap, retail customers who are not receiving generation service from an EGS shall be assigned to the Commission-approved DSP in that service territory.

(b) A DSP shall accept applications for default service from new retail customers when the customers comply with Commission regulations pertaining to applications for service, including those in Chapter 56 (relating to standards and billing practices for residential utility service) and accept all retail customers assigned to its default service who switch from an EGS.

(c) A DSP shall treat a customer who leaves an EGS as it would a new applicant for default service.

(d) A default service customer may choose to receive its generation service from an EGS at any time, if the customer complies with all Commission regulations pertaining to changing generation service providers in Chapter 57 (relating to electric service).

(e) A DSP may not charge a fee to a retail customer for changing its generation service provider in a manner consistent with Commission regulations.

CHAPTER 57. ELECTRIC SERVICE

Subchapter M. STANDARDS FOR CHANGING A CUSTOMER'S ELECTRICITY GENERATION SUPPLIER

§ 57.178. Default service provider.

This subchapter does not apply when the customer's service is discontinued by the EGS and subsequently provided by the default service provider because no other EGS is willing to provide service to the customer.

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