Strategic Energy

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COPY

VIA OVERNIGHT DELIVERY

James J. McNulty, Secretary
Pennsylvania Public Utility Commission
400 North Street
Harrisburg, PA 17105-3265

Re: 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 Comments of Strategic Energy, LLC

Dear Secretary McNulty:

Enclosed for filing with the Commission are the original and fifteen (15) copies of Strategic Energy LLC's Comments in the above-captioned matter. If you have any questions concerning the submittal, please direct them to the undersigned.

Very truly yours,

Julie A. Coletti
Assistant General Counsel
Strategic Energy, LLC

JAC/cab

Enclosures

cc: Brian Vayda

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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**

COMMENTS OF STRATEGIC ENERGY, LLC

Strategic Energy, LLC ("Strategic") respectfully submits these comments to the Pennsylvania Public Utility Commission's ("Commission") Proposed Rulemaking Order on Dec. 16, 2004 requesting comments on the proposed regulations for implementation of Default Service at the conclusion of the utilities' transition periods.

Introduction

Strategic appreciates the opportunity to offer comments on an issue that it believes is the key to the success or failure of electric choice in Pennsylvania. Strategic supports a bifurcated default service model that provides for variable energy pricing for large and medium business customers ("C&I") and a fixed priced service for residential and small, non-residential customers ("small customers"). However, all non-residential customers should be provided with an option to select variable pricing. This model provides safeguards to mitigate market shock for smaller, unsophisticated energy users and in the process advances an eventual transition to full market pricing for all customer classes. Rate caps fully expire in the Commonwealth after 2010, and Strategic believes, metering technology will be much more cost effective at that time, thus allowing hourly price signals to be transparent to most, if not all customer classes. Default service should be a temporary mechanism only and should not impede the development of full retail competition in the Commonwealth. The goal of any default service plan should be for all consumers eventually to be served by a competitive supplier.

As evidenced by comments advanced by Strategic in the Provider of Last Resort Roundtable Docket No. M-00041792, Strategic still embraces the concept of a retail default model. In this Proposed Rulemaking Order, the Commission stated "The Commission has the statutory authority to require such a process, pursuant to §66 Pa. C.S. 2807(e)(3), but concludes that the public interest, at this time, is best served by having the EDC act as the default service provider". Given the Commission's comments and the statutory mandate at §66 Pa. C.S. 2807(e) that a Commission approved default service provider ("DSP") may be someone other than the incumbent EDC, Strategic recommends the Commission undertake a separate NOPR sometime around January, 2007 (prior to most of Pennsylvania's larger utilities default service implementation plans) to explore a retail model in more depth.

Strategic will offer comments on the following issues: (I) competitive procurement model, (II) customer switching and new customers, (III) prevailing market price, (IV) retail service cost recovery charge, (V) uniform standards, (VI) access to customer information, (VII) Alternative Energy Portfolio Standards and (VIII) Affiliate Code of Conduct. Strategic also offers revisions to proposed regulations set forth in Annex A.

I. Competitive Procurement Model

Strategic supports a competitive procurement model where small customers would employ a Request for Proposal ("RFP"), for full requirements of energy, capacity, ancillary services and losses similar to the process Ordered by the Commission for Duquesne Light Company in offering POLR III service to large C&I customers receiving fixed price service effective January 1, 2005. Compliance Order at 70. Strategic also supports a competitive procurement model where C&I customers would employ an RFP, for full requirements of capacity, ancillary services and losses. The Commission already has a blueprint in place and efficiencies could be realized by following this recently adopted plan. Strategic believes the RFP processes should be ordered by the Commission as a uniform process throughout the Commonwealth.

The RFP should be segmented into two RFP's, one for large and medium C&I customers (initially set at >= 500 kW peak load) for full requirements hourly priced service and another for small customers for full requirements fixed-price service. The RFP design should also incorporate limiting the ability of any one entity to exceed pre-specified load caps. No one bidder may win the opportunity to supply more than 40% of the total load within a distribution territory, nor more than 50% of any customer class in the territory (with the exception, perhaps, of Pike County Power and Light, Citizens Electric of Lewisburg, Wellsboro Electric Company and UGI Utilities Inc. – Electric Division, where no more than 60% of a class may be served by a single supplier). This feature is designed to mitigate market power.

Strategic supports an RFP process because it is efficient and also because of the need to be able to divide the load among several suppliers. Single RFP processes tend to attract the needed competition among bidders, and bidders are required to employ their best bid practices at the onset, and don't get a "second bite at the apple" as is typically the case under descending clock auctions. The Commission needs to be extremely cautious on the design of the procurement model. There are essentially an unlimited number of possible designs of procurement models and the design can have a significant impact on the outcome. Strategic believes the RFP's should initially be held on a territory-by-territory basis, because of the staggered expiration of stranded costs and rate plans, but the Commission should eventually explore a single statewide RFP process with price differentials for local deliverability areas once all utilities are on equal time footing.

Other states use various approaches for bid evaluation, though all require that bid parameters be established and approved prior to the issuance of an RFP. In Maryland, for example, the Commission's rules require that an independent evaluator participate in the process to ensure that the bidding process is fair and complies with the Commission rules. In Massachusetts, the utilities which have fully divested their generation and merchant businesses run their bidding process to serve their default service loads with little Commission oversight. The one utility with a merchant affiliate in Massachusetts is required to have an independent evaluator review the procurement process. In Maine, the Commission runs the entire process and evaluates the bids. As all the utilities in Pennsylvania either own generation or have a merchant affiliate (or both), Strategic believes that the Commission should control the process, and, at the very least, an independent evaluator be appointed to oversee the process and evaluate bids. Without strong independent oversight, affiliate abuse concerns will harm the market, as evidenccd by several Federal Energy Regulatory Commission ("FERC") cases on affiliate abuses. The FERC has addressed affiliate abuses in Boston Edison Co. Re: Edgar Elec. Energy Co., stating that "it must ensure that the buyer has chosen the lowest cost supplier from among the options presented, taking into account both price and non-price terms (i.e., that it has not preferred its affiliate without justification)."[1] There have also been more recent FERC cases over the objectivity of franchised utility RFP processes, where affiliated merchant generators emerged as winners, which have triggered recent FERC affiliate transaction hearings.[2] It is critical for competition that any affiliate abuses or other anti-competitive behavior is deterred, identified, and remedied. In Iowa, utility affiliates were required to submit their bids seven days before other bidders are required to submit their bids. The Iowa Commission reasoned that by submitting their bid first, the other bidders are assured that the affiliate was not privy to their bid information. The affiliate was not given the opportunity to adjust their bid. In Connecticut, the utility affiliates were allowed to bid through the same process as other competitive entities; however, the Commission had in place a stringent set of affiliate rules to guard against potential affiliate abuses. In Colorado, the Commission process did not allow the utility or its affiliate to bid, while in other states, placing limitations as to percent an affiliate can provide has been discussed (e.g., Arizona). If affiliates are allowed to participate in default service, the Commission must ensure that all entities are bidding on an equal footing, and that all options are being evaluated uniformly, and that all potential

[1] *Boston Edison Co. Re: Edgar Elec. Energy Co., 55 F.E.R.C. P 61,382, 62,168 (1991) ("Edgar")*

[2] *See e.g., Entergy Servs., Inc., 103 F.E.R.C. P 61,256, 61,948-61,949, and Southern Power Co., . S. Power Co., 104 F.E.R.C. P. 61,041.*

bidders have equal access to all necessary information, including the same access to information that an affiliated entity has. At a minimum, Strategic believes the Commission should follow the protocol where default service affiliates will be required to submit bids a minimum of three-days in advance of the competitive RFP.

a. *Small Customer Model*

Some visionaries look forward to a world where individual consumers will have their appliances automatically programmed to respond to spot electricity prices that change every fifteen minutes. Until we see more cost effective advances in this technology, Strategic supports a fixed-price model for small customers with prices obtained through an RFP. However, Strategic still believes an eventual transition to market prices for all customers is inevitable as advances in metering technology occur and the future needs to be considered now. As evidenced by the table below, many default service plans are to take effect years into the future.

	Stranded cost/ Rate plans expire[3]
Pike County Power and Light	December 31, 2005
Citizens Electric of Lewisburg	February 28, 2006

[3] *The Commission has approved interim POLR plans for a number of EDCs (Pike, Citizens, Wellsboro and UGI). The Commission has also approved POLR rates in the Duquesne territory through December 31, 2007. The Commission will continue to approve interim POLR plans for these companies until final POLR regulations become effective.*

Wellsboro Electric Company	February 28, 2006
UGI Utilities Inc. – Electric Division	December 31, 2006
Pennsylvania Power Company	December 31, 2006
Duquesne Light Company	December 31, 2007
West Penn Power Company[4]	December 31, 2008
PPL Electric Utilities, Inc.	December 31, 2009
Pennsylvania Electric Company	December 31, 2010
Metropolitan Edison Company	December 31, 2010
PECO Energy Company	December 31, 2010

For small customers, at this time, Strategic proposes a wholesale RFP for full requirements fixed price service in each service territory once all stranded costs and generation rate plans expire. Additionally, all non-residential customers should be afforded the option to select hourly priced service, prior to the commencement of the RFP. However, if a small commercial customer chooses to take hourly priced service, that customer must notify the default supplier prior to the start of the RFP and once this option is chosen, the customer should not be able to revert back to the fixed price option for a full twelve months. Strategic proposes the Commission undertake a study sometime around January 1, 2007 to determine if metering technology has advanced to the point where it is economically feasible for all customer classes. If the results of the metering study indicate that the technology has advanced, Strategic proposes the Commission mandate that all or a portion of customers under 500 kW (all customers with peak

[4] *On September 7, 2004, the Commission was asked to approve a settlement agreement that would extend West Penn Power's stranded cost recovery period through December 31, 2010. Petition of West Penn Power Company for Issuance of Further Supplement to its Previous Qualified Rate Orders Under Sections 2802 and 2812 of the Public Utility Code, Docket No. R-00039022; Joint Petition of the West Penn Power Company's Restructuring Plan and Related Proceeding; Docket No. R-00973891. The proposed settlement is pending before the Office of Administrative Law Judge for a Recommended Decision on its merits.*

load of at least 25 kW) move to default hourly pricing beginning January 1, 2009 (or upon the conclusion of stranded costs, whichever is longer), with prices determined by an RFP for capacity only. Since interval metering is required for hourly-pricing signals, and if the technology has developed, Strategic proposes the Commission use the time between the completion of the metering study and January 1, 2009 to mandate that the Electric Distribution Company ("EDC") be responsible for installation and maintenance of standardized interval metering equipment. The entire costs of installation and maintenance should be fully recovered by EDCs on the customer's bill, with terms agreed upon by the Commission, the EDC and customer. Additionally, the Commission would need to establish performance metrics for EDC compliance on installation and maintenance of standardized interval metering equipment.

If the results of the study indicate that technology has not advanced to the point where the smallest customers cannot economically benefit from price signals, Strategic proposes the Commission maintain the bifurcated model as proposed, but incrementally, each year, adjust the level of fixed-price-service downward as the benefits of demand response become more evident and metering technology more fully develops.

In the interim, until advanced metering technology is cost effective, the structure proposed by Strategic is an RFP where each supplier will bid for a specific number of "tranches" of load they wish to serve at a given fixed-price in a single-round of binding firm offers. Strategic suggests that the Commission employ a fixed "tranche" method similar to that of Maryland Standard Offer procurement. The Commission, prior to the start of each RFP will need to define each "tranche", representing a fixed MW value. Strategic suggests a 25 MW tranche for the small customer RFP. This tranche is the size of a standard wholesale block, but small enough for multiple bidders to participate. To accommodate retail access, the Maryland model includes a volumetric risk adjustment mechanism that reduces the supplier's exposure to load shifts. The volumetric adjustment works by reducing Standard Offer suppliers load obligation as load shifts away, and by pricing incremental Standard Offer at market if load returns. Strategic believes the full requirements price for fixed price service for residential customers and small commercial customers should include: the average cost of electric generation as determined by the RFP, which is multiplied by pre-determined on-peak and off-peak energy adjustment factors; the average clearing price of a coincident PJM (or MISO for Pennsylvania Power or NYISO for Pike County, if applicable) planning period forward unforced capacity credit; the actual network integrated transmission service price based on the PJM/MISO/NYISO tariff; the actual "Seams Elimination Cost Assignment" as per the PJM/MISO tariff, if applicable; the cost, as determined for each zone, of all ancillary services, including but not limited to regulation, spinning reserve, operating reserve, synchronous condensing, reactive services, reactive supply, black start, Mid-

Atlantic Area Council; applicable RTO/ISO/NYISO administration charges; applicable Transmission Owner administration chares as per the PJM/MISO/NYISO tariff, congestion; applicable line losses; a fixed retail services charge ("customer charge" as defined by the Commission) in consideration of the DSPs cost of providing certain retail services for all customers with peak load greater than or equal to 25 kW and all applicable taxes. Strategic believes the 25 kW should be chosen since 52 PA Code §54.2 has defined a "small business customer" as "a person, sole proprietorship, partnership, corporation, association or other business entity that receives electric service under a small commercial, small industrial or small business rate classification, and whose maximum registered peak load was less than 25 kW within the last 12 months". All variable and ancillary service payments to winning suppliers should be set at what the local DSP believes is a reasonable approximation of current costs. The setting of this payment should be reviewed annually by the Commission. The Commission will also need a mechanism to allow winning suppliers to pass along costs for specified changes in RTO/ISO charges. The winning bidder, and not the DSP, is the Load Serving Entity ("LSE") and the Network Transmission Customer for PJM/MISO purposes, so the winning bidder would be eligible to acquire the Auction Revenue Rights ("ARRs") and would receive any revenue associated with these ARRs. In addition to all wholesale costs, all default service offers should include any and all requirements placed on competitive suppliers, including any alternative energy portfolio standards. If marginal losses are implemented at some future date by PJM, an adjustment should be made to prices to avoid double counting of losses.

Small customers would be offered a one-year service term (the transition plan should coincide with PJM's/MISO's/NYISO's planning year, and in no case shall be longer than seventeen months for the initial implementation), provided by one or more winning suppliers, chosen by the RFP, with prices varying at minimum by quarter. The one-year service term and prices that are established to reflect seasonality of default service prices eliminate potential Electric Generation Supplier ("EGS") gaming opportunities. By limiting the RFP to a 12-month term, the forward price risk premiums should be lower than those included in two and three year forward products.

b. <u>Large Customer Model</u>

The proposed default service model for large and medium, non-residential customers (initially set for C&I with individual demands greater than or equal to 500 kW or for any non-residential customers that may "opt-in" to hourly priced service) is to bid for full requirements service, through an RFP, the PJM (or MISO for Penn Power, or NYISO for Pike County, if applicable) unforced capacity (UCAP) charges, for a one-year supply contract. The model for C&I customers should employ a capacity RFP that is translated to a *dollars per kW-day*. The full requirements service will include: prevailing real-time market price in the

PJM/MISO/NYISO market for energy in the respective zone; the average capacity price resulting from the RFP, the actual network integrated transmission service price based on the PJM/MISO/NYISO tariff; the actual "Seams Elimination Cost Assignment," as per the PJM/MISO tariff, if applicable; the cost, as determined for each zone, of all ancillary services, including but not limited to regulation, spinning reserve, operating reserve, synchronous condensing, reactive services, reactive supply, black start, Mid-Atlantic Area Council; any RTO/ISO administrative costs; congestion; applicable Transmission Owner administration chares as per the PJM/MISO/NYISO tariff; applicable line losses; a fixed retail services charge ("customer charge" as defined by the Commission) in consideration of the default service providers cost of providing certain retail services; an administrative charge paid to winning suppliers in consideration of bidding for and providing default service similar to New Jersey's Default Supply Service Availability Charge ("DSSAC") which is a necessary component to make an hourly priced service an attractive product to bidders, who will be bidding for the right to wait to serve eligible customers who may never take the service; any and all costs associated with compliance of alternative energy portfolio standards and all applicable taxes would be passed through by the default service supplier. The winning bidder, and not the DSP, is the Load Serving Entity ("LSE") and the Network Transmission Customer for PJM/MISO purposes, so the winning bidder would be eligible to acquire the Auction Revenue Rights ("ARRs") and would receive any revenue associated with these ARRs. The Commission will also need a mechanism to allow winning suppliers to pass along costs for specified changes in RTO/ISO charges. If marginal losses are implemented at some future date by PJM, an adjustment should be made to prices to avoid double counting of losses. This model is similar to the model used in Maryland for Standard Offer Service ("SOS") and New Jersey for Basic Generation Service ("BGS").

At a minimum, the Commission should mandate that all customers >= 500 kW peak demand (and those customers below that level that "opt-in" to hourly priced service) be required to have interval metering since it is required for hourly-pricing signals. Consistent with cost/benefit analysis, advanced meters should be deployed for all business customers before the end of each EDCs transition period. The EDC should be responsible for installation and maintenance of standardized interval metering equipment and all costs of installation and maintenance should be fully recovered by EDCs incrementally (or at the request of the customer in one lump sum) as a line item on the customer's bill.

The structure proposed by the Commission in which the price of energy for C&I customers can be fixed for a term, even say one-year, leaves little incentive for an EGS to enter or remain in the market. Under this structure, competitive suppliers purchase energy from the wholesale market in which prices are constantly fluctuating; yet they must compete against a fixed price. As a result, competitive suppliers carry the risk of purchasing the power above the fixed price and having to sell it below the fixed price, at a loss, in order to win or maintain existing customers. The best way to provide for default service is to develop a competitive market where providers have an incentive to serve customers. The key to providing default service to C&I customers is a robust wholesale market with transparent and floating prices. Continuously adjusting wholesale prices bring supply and demand into balance and also enhance demand side management programs. A default service pricing model that is based on real-time market pricing with administrative and retail adders will encourage greater competitive activity among suppliers and will be beneficial to customers, especially those with sophisticated energy needs. Offering C&I customers the opportunity to directly manage their energy purchases and consumption based on a transparent, real-time market affords them the opportunity to create and execute strategies that allows them to make real-time decisions about demand and consumption patterns. Hourly pricing structures reveal the value of programs such as demand-side management and other services, which give the customers the ability to manage peak-load and avoid peak pricing. As peak-load is decreased, or shifted to other periods, in reaction to real-time price signals, overall market efficiency will be gained, resource adequacy issues will be addressed and environmental benefits will result. With the continued development of PJM's Emergency and Economic Load Response Programs and Active Load Management, hourly-price signals foster the development of these programs.

As noted above, Strategic's proposed model has all the necessary tools in place for a properly functioning retail market. Poorly functioning retail markets mask price signals, thereby depriving consumers and EGSs of the ability to use appropriate demand-side and hedging tools to manage wholesale price volatility. In Georgia, for example, real-time price signals have translated into significant demand response. As Alan Jenkins explains in an article on the subject:

> "The real-time pricing generally is Georgia Power's projected incremental cost to serve the RTP load, which cost tends to run low in off-peak periods and high on-peak. These price signals then drive the commercial store design response.... that increases the load factor of the system as a whole and allows Georgia Power to avoid additional costs to build new generation. In any event, given the response from its commercial customers, Georgia Power's RTP program is more successful than ever. Wal-Mart Director of Project Development Jim Stanway testified that "the RTP-DA rate schedule is the only rate schedule in the country that has directly changed our building design." For example, Wal-Mart has installed gas-driven desiccant systems and natural gas-fired bakery facilities to minimize summer load and designed electric heating into Georgia stores to take advantage of the low RTP winter and other off-peak price signals. A number of other commercial witnesses likewise testified as to how real time

price signals have caused their commercial facilities to flatten their load throughout the year, not just on one peak day."[5]

In other jurisdictions, (for example, New Jersey and Maryland) that have utilized a similar method for C&I customers, have experienced significant response from competitive suppliers along with a great deal of customer switching. Switching statistics show that 84% of all eligible New Jersey "CIEP" load and 63% of eligible Maryland Type III load have switched to a third-party supplier as of February, 2005. Strategic believes an hourly-priced index for large and medium C&I customers plus administrative and retail cost recovery charges will have a similar impact in Pennsylvania. While recognizing the benefits of hedging with offering fixed price service, we are concerned that if the incumbent utilities offer fully hedged long-term fixed price options, then EGSs will undoubtedly be unsuccessful in signing up new customers, effectively stagnating the development of competitive markets. We believe that utilities should not be given regulatory tools that hinder competition. EGSs should have the right to compete on a level playing field and allowing the DSP to participate by providing options that compete with EGSs very often distorts the market. The existence of

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[5] *Real Time Pricing Alive and Well in Georgia*, www.energypulse.net, *3.17.05 Alan Jenkins, Partner McKenna, Long & Aldridge LLP*

any fixed price alternative to C&I customers will retard the development of energy competition in the Commonwealth.

II. *Customer switching and new customers*

Small customers that leave default service should, have the right to return to it and pay the prevailing price. The obligation to supply default service to returning customers should rest with the supplier that won the bid or segment containing those customers. That supplier can factor the associated volume risk into its bid price. By adopting the Maryland volumetric risk mechanism, default suppliers can sufficiently manage load shift risks, and this allows unrestricted customer movement on and off the default service. Maryland has set a "bandwidth" of 3 MW and 5 MW around load returning to and migrating from SOS. The volumetric risk adjustment in Maryland works like this, for example, the winning supplier serves all load under the contracted price up to a "base load" (the load defined at the beginning of service) plus 5 MW. If load migration to SOS is greater than 5 MW above the "base" contract load, the supplier reverts to serving only the base contract load. The utility serves all load above the base contract amount through spot Locational Marginal Price ("LMP") purchased by the utility from PJM. The retail price is the load weighted average of the supplier contract price and whatever portion is served by LMP, making it a blended, somewhat variable price. If load drops by more than 3 MW from the base amount due to migration away from SOS, the supplier's contract requirement is reduced by the load reduction. The 5 MW upward band is treated as a threshold while the 3 MW lower band is actually a downward ratchet that can happen every time load is at least 3 MW less than the current base amount. A similar bandwidth could be set up for C&I customers for increment or decrement capacity changes.

All customers will be permitted to leave and return to default service at any time, without penalty or restriction such as generation rate adjustments ("GRAs") or minimum stay provisions. Any transition period switching restrictions should not be continued into the post-transition period.

The proposed section on Competitive Safeguard Regulations at 52 Pa. Code §54.123 restrains the transfer of customer accounts to default service without the consent of the DSP, except under specific circumstances. Strategic believes the specific circumstances are not inclusive enough to recognize all legitimate reasons for such transfers. Limiting the EGSs ability to switch a customer back to default service without consent, only for circumstances included on the "laundry list" makes 52 Pa. Code §54.123(a) inconsistent with 52 Pa. Code §54.123(c). The Commission, in stating in 52 Pa. Code §54.123(c) "An EGS may not initiate or encourage transfers of service to a default service provider from the EGS to exploit seasonal variations in market prices for electric generation service" assures that the EGS can only switch a customer back to default service for just causes. The Commission should not define the list as an "all inclusive" circumstance when a customer could be returned to default service, but instead should make the list "an example" of when customers may be returned to default service without the consent of the default supplier. There are other legitimate reasons for returning a customer to default service other than the ones in the "laundry list". For example, a scenario when an end use customer sells a facility to another party and that party does not want to be served by a competitive supplier and desires to be returned to default supply, which may very well be in a summer month, is not EGS "gaming". Strategic believes 52 Pa Code §54.123(a) should read "An EGS shall not transfer a retail customer from its electric generation service to the default service provider without the consent of the default service provider, in situations such as the following, as well as other situations that are not intended to exploit seasonal variations in market prices for electric generation service:"

In addition, Strategic proposes that new customers should not be automatically placed in default service. Instead, they should be asked to choose a competitive supplier from a list that should include the default provider and *all* other competitive suppliers that have indicated an interest in serving new customers. Strategic proposes 52 Pa Code §54.181 be revised as indicated in the attached Annex A.

III. Prevailing Market Price

Strategic wants to address the "prevailing market price" definition, as proposed in the default service regulations. It is defined as "(i) The price of electric generation supply for a term of service realized through a default service provider's implementation of and compliance with a Commission approved default service implementation plan and (ii) The price of electric generation supply in the RTO or ISO administered energy markets in whose control area default service is being provided, acquired pursuant to the conditions specified in §§54.186(g), 54.187(i) or 54.188(e)." This definition, as proposed in (i) above seems more like an administratively determined price if it is a price that is the result of compliance with a Commission approved plan. Even if that plan contemplates a procurement process, what if the process doesn't work? For instance, the Ohio Commission, in an attempt to test market prices, conducted a New Jersey style auction in December 2004. The resulting auction prices were deemed to be too high by the Commission and were subsequently rejected. The Ohio Commission Ordered First Energy to implement its Rate Stabilization Plan from 2006 through 2008 in lieu of auction prices. Additionally, in New Jersey, the auction process consists of a BGS-FP and BGS-CIEP auction. The BGS-FP auction seeks offers for supply of full requirements tranches for a three-year period. If the Commission mandates a term of service for default service plans for even one year, it does not adhere to part (ii) of the definition of prevailing market price "The price of electric generation supply in the RTO or ISO administered energy markets in whose control area default service is being provided". Both PJM and MISO currently have only day-ahead and real-time market prices, not annual markets. Additionally, terms of longer than one year, say three years, that allow for a blended rate are not within the legal standard and may lead to divergence from the "prevailing market price". For example, wholesale rates in years one and two may be high and low in year three, thus establishing the blended price much higher than the "prevailing market price". This distorts the price EGSs must compete against.

The proposed definition is also contrary to the Choice Act, which provides that market forces are superior to government regulation in setting retail prices. See 66 Pa. CS 2802(5). In addition, the Commonwealth has defined the term "prevailing market price" in other contexts. For example, in Pennsylvania Department of Revenue regulations "prevailing market price" is defined as "[t]he price which an item will bring if offered for sale in the open market at the time and place of the taxable use within this Commonwealth." *61 Pa. Code § 46.7* (2005). Another Department of Revenue Regulation uses a similar definition: "[t]he price which the equipment will bring if offered for sale in the open market at the time the equipment is brought into this Commonwealth." 61 Pa. Code 47.18 (2005). Commission Regulations for Telecommunications define "market price" as "Prices set at market-determined rates." *52 Pa. Code § 63.142* (2005).

These definitions show that market prices are not administratively determined. Instead, prevailing market prices are determined by market forces, they are no less than cost and they have a temporal and locational element. In sum, both the Choice Act and these definitions confirm that the proposed definition of "prevailing market price" is unworkable and should be rejected. It is not required that prevailing market price be defined in the regulations especially if it is contrary to the statute. Strategic proposes the definition of "prevailing market price" should be stricken from the regulations.

IV. Retail Service Cost Recovery Charge (Customer charge)

The retail cost recovery charge is a critical element in the establishment and maintenance of the competitive electricity market in Pennsylvania. The retail charge is not, as some suggest, introduced to force retail competition, but, absent the charge, competition will be hindered. This is also so because, absent a retail charge for default service, non-switching customers *never* see or pay the true cost of retail electric power. Pricing for default service must be set to cover the cost of the risk related to the service, *as well as the cost of the retail activities involved in providing the service.* In lieu of a full cost of service study, it will be necessary for the Commission and interested stakeholders to develop the use of a retail charge as a proxy for costs that are embedded within retail supply service and the retail charge should be designed to approximate the cost of retail supply services. For a retail market to further develop under wholesale default service conditions, the cost of all retail supply services (including, but not limited to, customer call center, customer information and record keeping, customer agreements, customer enrollment and switching capability, billing, credit and collection, revenue accounting and disbursement, managing uncollectibles, an acceptable margin and EDI capability) must be included in the default service price. Thus, an appropriate price signal is delivered to the default service customer. This price signal is essential to translate the wholesale default service offer into a retail price against which the EGS will compete. Strategic recommends, the application of the retail charge be included for all large and medium size commercial and industrial customers (>= 25 kW) on default service. Any customer taking competitive service should not pay the retail charge. In other jurisdictions, such as New Jersey, the retail charge was most recently set at 5 mils through negotiations of all interested parties. Strategic believes that a properly designed retail charge is essential to attract and retain a sufficient number of EGSs to yield vibrant retail competition among Pennsylvania's higher use customers. When a critical mass of retail competitors search the market place, end-use customers begin to receive the lowest available generation service prices. The payments under the retail charge, which is paid by all hourly customers on default supply and by those smaller customers greater than 25 kW on fixed price default supply, should be used to offset the cost of providing default service. If a full cost of service study is undertaken in the Commonwealth, the DSPs should be required to annually submit data to the Commission on what their actual costs are, and those costs should be netted from the collections. Any over-collection of retail charges will be returned to ***all*** customers, shopping and non-shopping. The over-collection should be held in an account by each DSP, and the charge adjusted occasionally if there is significant over or under collection. In lieu of a full cost of service study, in which the actual costs of DSPs are not detailed and separated from distribution rates, all monies should be held in an account by each DSP and each year, the Commission should mandate that the a portion of funds collected in prior years be refunded to ***all*** customers with the remaining monies utilized for customer education programs, potential funding for advanced metering technology, or a source for all Pennsylvania Sustainable Development Funds.

V. Uniform standards

The definition of customer classes for purposes of the provision relating to an extension of default service should not be based on existing EDC tariff definitions and a uniform standard should be adopted. In essence, customer classes need to be redefined. There is no current consistency as to how customer classes are defined across utilities. As a general matter, all rules and business practices should be uniform throughout the state and for all potential RFP suppliers as well as for competitive suppliers. This is important for both suppliers and customers. Suppliers need to be able to market their products on a statewide or regional basis and adopt procedures that are cost effective and uniform to the greatest extent possible. Customers benefit from uniformity as well because of the potential for additional suppliers who can participate in competitive programs. Furthermore any customer education programs will be more effective if the messages are similar and the ``rules of the road" easy to transmit throughout the state. Any deviation from the uniform approach should reflect only temporary deviations or exemptions due to technological constraints. Strategic recommends that customers be segmented based on their energy delivery method (*i.e.*, primary voltage, secondary voltage, etc.). Customer segments for each EDC should be established according to demand, with fine tuning based on further information regarding the current stock of meters and metering capabilities within Pennsylvania and definitions of service at primary versus secondary voltages:

Residential

Small C & I – up to 25 kW demand

Medium C & I – from 25 kW to 500 kW demand

Large C & I – greater than 500 kW demand

Strategic believes the Commission should stratify customer segments as proposed, in the event the bifurcated model (as proposed by Strategic) is adopted, in order to allow for an on-going adjustment of the level of fixed-price-service downward to reflect the then current state of metering and the value of the additional price responsive demand to the system.

VI. ***<u>Access to Customer Information</u>***

Strategic requests that the Commission resolve customer information access issues in both this and at Docket M-00041817 so that EGSs not affiliated with Pennsylvania EDCs can obtain the information they need to provide timely competitive offers. Access to customer information in an efficient, practical manner is a prerequisite for successful electric competition. Strategic supports a model employed by PECO in which customer lists are made available to all EGSs electronically and updated quarterly. The list of customers that PECO provides to all EGSs is posted on their SUCCESS website and provides a very supplier friendly means of accessing customer list information. Strategic encourages the Commission to use this as a standard for other EDCs. Strategic asserts that non-standardization of processes currently in use are insufficient, and often result in delayed and costly transmission of data. Imposing a uniform requirement throughout the Commonwealth will address the lack of enforceable requirements under which EDCs now provide customer information to EGSs.

Strategic believes all historical data for customers with interval meters should be made available to customers or an EGS in electronic format with a turn around time of three business days. Strategic understands the additional costs involved in providing such large amounts of interval data, so it is not opposed to reasonable limitations on the frequency that a customer or an EGS, acting on behalf of a customer, may submit their requests. Strategic proposes that for purposes of pricing customers, 12 months of historical interval meter data be made available to customers or an EGSs in electronic format at least once every 6 months at no charge. Strategic also believes EDCs should provide EDI hourly interval usage for customer billing purposes as well as historical usage. As more and more sophisticated energy users utilize hourly pricing in order to benefit from programs like demand response, EGS access to uniform interactive hourly data is essential to properly bill customers. Section 2804(6) of the Choice Act requires an EDC to provide access to and use of its distribution system to EGSs and their customers on a basis comparable to the access to and use of the system by the EDC itself. Strategic proposes the Commission require all EDCs to provide access to interval data for EGS customer billing on a daily basis via standard EDI protocol. This process should be automated by the EDCs system to ensure timeliness. Strategic believes that EDCs should recover their reasonable costs of compiling and providing customer information to EGSs on the customer list, historical interval data for pricing purposes and interactive interval data for billing customer's on an hourly price rate, to the extent that these activities impose incremental costs on the EDCs.

Additionally, Strategic believes the Commission should consider mandating a uniform technology so that there is state-wide consistency in access customer data. The lack of this requirement makes deregulation less effective than in other states and Pennsylvania is at risk of losing its leadership position in this regard because other states, like Texas have mandated uniform data delivery systems.

VII. Alternative Energy Portfolio Standards

Currently, each BGS supplier in New Jersey must meet the New Jersey Renewable Energy Portfolio Standards ("RPS") requirements for a percentage of its supply. The requirements may be met through direct supply of renewable energy, through alternative compliance payments, or for solar requirements, through submittal of renewable energy certificates ("RECs"). In New Jersey, the EDCs assist the winning BGS suppliers in meeting the reporting requirements and to the extent permitted by regulatory and contractual provisions, make available renewable attributes of committed supply to BGS suppliers from existing non-utility generator ("NUG") contracts. Basically, this amounts to a "freebie" of renewable attributes to BGS winning suppliers, while competitive suppliers must purchase the renewable attributes in the market place. Such an approach is clearly biased in favor of denying competitive retail providers a comparable opportunity to penetrate the Pennsylvania market. Strategic recommends that the default suppliers not be permitted to provide renewable attributes from existing NUG contracts for wholesale providers unless they offer comparable terms and conditions to competitive retail market providers for these same products. At best, these attributes could be offered in a separate bid solicitation to all successful wholesale providers and all active licensed retail market providers. Rules for a bid solicitation could be developed through a separate Commission sponsored working group. The Commission should give careful consideration when designing Pennsylvania's default supply regulations in conjunction with Act 213

("Act"). The Act states that (1) [a]fter the cost recovery period, any direct or indirect costs for the purchase by EDCs of resources to comply with this act.....shall be recovered on a full and current basis pursuant to an automatic energy adjustment clause under 66 PA.C.S. §1307 as a cost of generation supply. The Commission must not allow "freebies" of renewable attributes to winning suppliers and must let competitive forces determine the "true" cost of supply on a level playing field.

Additionally, under the recent implementation of Act, demand side management has been given consideration as an alternative energy source in Tier II. As noted above, sending real-time price signals to large users will allow these customers to fully embrace and capitalize on the intent of the Act. As more and more large users manage demand in response to real-time price signals, capital investment will be encouraged and new technologies will be brought to market.

VIII. ***Affiliate Code of Conduct***

Strategic believes the Commission should re-examine the affiliate code of conduct at 52 PA Code §54.122. The rules are somewhat broad and not specific on violations or penalties and the Commission has left a great deal of leeway in how to enforce these provisions. The Commission needs to ensure a level playing field with non-discrimination policies and where no cross-subsidization of costs occur. The Commission must also ensure that DSPs may not promote default service beyond basic information. Strategic recommends the Commission espouse competitive safeguards consistent with the "Affiliate Relations, Fair Competition and Accounting Standards and Related Reporting Requirements" adopted by the New Jersey Board of Public Utilities ("NJBPU")[6]. Another source of competitive safeguards are the Illinois Rules for Non-Discrimination in Affiliate Transactions for Electric Utilities [7]. The FERC also requires entities affiliated with a traditional electric utility to include a code of conduct governing the relationship between the applicant and their traditional electric utility affiliate.[8] This code of conduct is considered to be part of the affiliate's market-based rate schedule. The FERC Code of Conduct consists of some of the following issues: 1. All affiliate employees will operate separately from the employees of the traditional electric utility. 2. All market information shared between the traditional electric utility and affiliate will be disclosed simultaneously to the public. This includes all market information, including but not limited to, any communication concerning power or transmission business, present or future, positive or negative, concrete or potential. 3. Sales of any non-power goods or services by the traditional electric utility, including sales made through its affiliate will be at the higher of cost or

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[6] *The standards are available electronically at:* *http://www.bpu.state.nj.us/wwwroot/energy/affiltstands.pdf*

[7] *Illinois Rules for Non-Discrimination in Affiliate Transactions for Electric Utilities contained in Title 83, Chapter 1, Subchpater C, part 450 (83 Ill Admin Code 450) and the Standards of Conduct and Functional Separation for Electric Utilities Contained in Title 83, Part I, Subchapter C, Part 452 of the Illinois Revised Code (83 Ill. Admin Code 452)*

[8] *http://www.ferc.gov/industries/electric/gen-info/how-to-pm.pdf*

market price. 4. Sales of any non-power goods or services by affiliate to the traditional electric utility will not be at a price above market.

Strategic proposes the following rules be adopted regarding affiliate Code of Conduct and supplement 52 PA Code § 54.122:

(1) The Commission shall establish regulations that prohibit transactions between an electric distribution company or default supplier and a related competitive business segment except for instances when the sale or purchase of goods and services by the electric distribution company or default supplier are generally made available to all market participants through an open, competitive bidding process.

(2) The selling or offering to sell surplus energy and ancillaries by an electric distribution company or default supplier to a competitive affiliate shall be required to make the products available on a non-discriminatory basis to all non-affiliated parties via a public posting, which includes but is not limited to the EDC or DSP website or other industry recognized and publicly accessible electronic or print medium.

(3) The an electric distribution company or default supplier shall not be allowed to discount or waive all or any part of any charge or fee to a competitive affiliate unless the electric distribution company or default supplier shall make such discount or waiver available on a non-discriminatory basis to all non-affiliated parties.

(4) The electric distribution company or default supplier shall not provide any assistance, aid or services to a competitive affiliate related to customer enrollment, marketing or business development; including providing leads, soliciting business on behalf of its affiliate, acquiring information on behalf the affiliate, sharing of market analysis, representing or implying that the electric distribution company or default supplier speaks on behalf of the affiliate and may receive preferential treatment.

(5) The electric distribution company or default supplier shall not discriminate nor provide preferential treatment with regards to accessing customer information, for which the electric generation supplier has received authorization.

(6) The electric distribution company or default supplier shall not promote default service nor provide its customers with any list of product or service providers, which highlights or otherwise identifies a competitive affiliate unless the list also includes the names of unaffiliated suppliers. Any meetings held by the electric distribution company or default supplier regarding energy supply should be open to the public.

(7) The electric distribution company or default supplier shall be allowed to create or establish a separate business segment solely to perform corporate services such as corporate oversight, corporate governance, support systems and personnel. However, any shared support service shall be priced at fair market value.

(8) The electric distribution company or default supplier and a competitive affiliate shall not employ the same employees or otherwise retain, with or without compensation, as employees, independent contractors or consultants. In the instance an employee is transferred from an electric distribution company or default supplier to a competitive affiliate, the employee may not return to the electric distribution company or default supplier for a period of twelve months, unless the competitive affiliate goes out of business or is acquired by a non-affiliated company during that twelve-month period.

(9) Any transfer of service produced, purchased or developed by the electric distribution company or default supplier is prohibited to a competitive affiliate unless it is priced at no less than fair market value.

(10) No later than three months after the final adoption of these standards, each electric distribution company or default supplier shall be required to file a compliance plan with the Commission demonstrating that there are adequate procedures in place for compliance.

(11) The Commission shall require an audit to be performed annually by an independent auditor chosen by the Commission and shall also establish the scope of the audit, which verifies that the electric distribution company or default supplier is in compliance with the standards.

(12) The audit shall be performed at the electric distribution company's or default supplier's expense, with full cost recovery through distribution rates.

(13) If, as a result of an audit conducted pursuant to subsection XX above or by any other means, the Commission determines that an electric distribution company or default supplier has committed violations of the Sections of these standards which are not substantial violations, the Commission is authorized to impose a penalty of up to $20,000 for each such violation upon said electric distribution company or default supplier.

(a) If, as a result of an audit conducted pursuant to subsection XX above or by any other means, the Commission determines after providing the electric distribution company or default supplier notice of a public hearing and an opportunity to be heard, that an electric distribution company or default supplier has committed violations of these standards which are substantial in nature, the Commission is authorized to take some or all of the following actions:

1. Impose a penalty of up to $20,000 for each such violation(s).

2. Order appropriate reimbursement to electric distribution company or default supplier ratepayers or electric generation suppliers, including interest.

3. For a first violation:

(a) Order a violating electric distribution company or default supplier to cease some or all competitive product and/or service offerings and form a related competitive business segment of the electric distribution company or default supplier to perform the competitive product and/or service offerings; or

(b) Order a violating electric distribution company or default supplier to cease some or all competitive product and/or service offerings through a related competitive business segment of the electric distribution company or default supplier; and

4. For a second violation:

(a) Initiate a hearing to reconsider its approval of the formation of the electric distribution company or default supplier.

IX. Conclusion

We are living in a time of rapid technology advance, and since utilities have typically been associated with cost of service rates, innovation and investment in utility type technology has not developed. Deregulation should lead to a more efficient use of the electricity network. There have been enormous strides toward having wholesale market prices reflect true marginal value of electricity and the network. LMP, Financial Transmission Rights ("FTRs") and marginal losses are just a few of the tools used to get better wholesale prices. Cost averaging, deferrals, price caps and default service fixed price options ensure that customers do not see their true cost of electricity. Even where good wholesale price signals exist, the default supplier offering a fixed price option will have no incentive to get customers to respond to price signals because they are supplying a full-requirements wholesale product to a slice of system without any connection to the end-use customer. Connecting consumers to the true cost and the supplier of their generation service will provide both an incentive to shop for electricity and an opportunity to be price responsive. The only way to accurately connect consumers to the true cost is through hourly price signals. Costs of energy production which is highly dynamic over short timeframes is now clearly tied to supply-side entities, but the price to smaller consumers in particular contains no clear link to these costs. It is clear that the mismatch between cost drivers and price signals contributes to a growing need to invest substantially more in production required for only short durations during increasingly extreme peak periods. This creates a challenge for consumers that is magnified by a lack of incentives, particularly for residential consumers, to take advantage of affordable energy saving appliances or smart metering technology. This would be less of a challenge for consumers if the electricity supply infrastructure did not limit their ability to respond to highly volatile cost drivers. Put simply, the ability of consumers to respond is limited, in part, because they have no access to proven, cost-effective technology that would allow them to do so easily and conveniently. With the recent announcement that the Spanish wind-energy company Gamesa Corporation has agreed to base its United States headquarters and east coast development offices and to open an advanced technology manufacturing facility for wind turbine generator blades in Pennsylvania, the state's reputation as a leader in the development and deployment of clean energy technology has been enhanced. Gamesa's two offices and manufacturing facility are expected to create as many as 1,000 jobs in the Commonwealth over the next five years. Similarly, with properly designed default service plans, as proposed by Strategic, Pennsylvania could also become a national leader in the development and deployment of advanced metering technology.

Strategic offers changes to proposed regulations set forth in Annex A, attached hereto. If a section is not listed, Strategic proposes no changes to that section of proposed regulations, which are found at Annex A in the Commission Order.

For the foregoing reasons, Strategic requests that the Commission order the requested modifications/proposals herein.

Respectfully submitted,

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ANNEX A

TITLE 52. PUBLIC UTILITIES

PART I. PUBLIC UTILITY COMMISSION
Subpart C. FIXED SERVICE UTILITIES
CHAPTER 54. ELECTRICITY GENERATION CUSTOMER CHOICE

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Subchapter E. COMPETITIVE SAFEGUARDS

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§ 54.122. Code of conduct.

Electric generation suppliers, default service providers, and electric distribution companies shall comply with the following requirements:

(1) An electric distribution company or a default supplier may not give an electric generation supplier, including without limitation, its affiliate or division, any preference or advantage over any other electric generation supplier in processing a request by a distribution company customer for retail generation supply service.

(2) Subject to customer privacy or confidentiality constraints, an electric distribution company or a default supplier may not give an electric generation supplier, including without limitation its affiliate or division, any preference or advantage in the dissemination or disclosure of customer information and any dissemination or

disclosure shall occur at the same time and in an equal and nondiscriminatory manner. ''Customer information'' means all information pertaining to retail electric customer identity and current and future retail electric customer usage patterns, including appliance usage patterns, service requirements or service facilities.

(3) An electric distribution company, default supplier or electric generation supplier may not engage in false or deceptive advertising to customers with respect to the retail supply of electricity in this Commonwealth.

(4) Each electric distribution company or default supplier shall adopt the following dispute resolution procedures to address alleged violations of this section:

(i) Regarding any dispute between an electric distribution company, default supplier or a related supplier, or both, and an electric generation supplier (each individually referred to as a ''party'' and collectively referred to as ''parties''), alleging a violation of any of the provisions of this section, the electric generation supplier shall provide the electric distribution company, or default supplier or related supplier, or both, as applicable, a written notice of dispute which includes the names of the parties and customers, if any involved and a brief description of the matters in dispute.

(ii) Within 5 days of receipt of the notice by the electric distribution company, <u>default supplier</u> or related supplier, or both, a designated senior representative of each of the parties shall attempt to resolve the dispute on an informal basis.

(5) An electric distribution company <u>or default supplier</u> may not illegally tie the provision of any electric distribution service within the jurisdiction of the Commission to one of the following:

(i) The purchase, lease or use of any other goods or services offered by the electric distribution <u>or default supplier</u> company or its affiliates.

(6) An electric distribution company <u>or default supplier</u> may not provide any preference or advantage to any electric generation supplier in the disclosure of information about operational status and availability of the distribution system.

(7) An electric distribution company <u>or default supplier</u> shall supply all regulated services and apply tariffs to nonaffiliated electric generation suppliers in the same manner as it does for itself

and its affiliated or division electric generation supplier, and shall uniformly supply all regulated services and apply its tariff provisions in a nondiscriminatory manner.

(8) Every electric distribution company <u>or default supplier</u> and its affiliated or divisional electric generation supplier shall formally adopt and implement these provisions as company policy and shall take appropriate steps to train and instruct its employees in their content and application.

(9) If an electric distribution company <u>or default supplier</u> customer requests information about electric generation suppliers, the electric distribution company shall provide the latest list as compiled by the Commission to the customer over the telephone, or in written form or by other equal and nondiscriminatory means. In addition, an electric distribution company <u>or default supplier</u> may provide the address and telephone number of an electric generation supplier if specifically requested by the customer by name. To enable electric distribution companies <u>or default suppliers</u> to fulfill this obligation, the Commission will maintain a written list of licensed electric generation suppliers. The Commission will regularly update this list and provide the updates to electric distribution companies as soon as reasonably practicable. The

Commission will compile the list in a manner that is fair to all electric generation suppliers and that is not designed to provide any particular electric generation supplier with a competitive advantage.

(10) An electric distribution company, default supplier or its affiliate or division may not state or imply that any delivery services provided to an affiliate or division or customer of either are inherently superior, solely on the basis of their affiliation with the electric distribution company or default supplier, to those provided to any other electric generation supplier or customer or that the electric distribution company's or default supplier's delivery services are enhanced should supply services be procured from its affiliate or division. When an electric distribution company's or default supplier' s affiliated or divisional supplier markets or communicates to the public using the electric distribution company's name or logo, it shall include a disclaimer stating that the affiliated or divisional supplier is not the same company as the electric distribution company or default supplier, that the prices of the affiliated or divisional supplier are not regulated by the Commission and that a customer is not required to buy electricity or other products from the affiliated or divisional supplier to receive the same quality service from the electric distribution company or default

supplier. When an affiliated or divisional supplier advertises or communicates through radio, television or other electronic medium to the public using the electric distribution company's name or logo, the affiliated or divisional supplier shall include at the conclusion of any communication a disclaimer that includes all of the disclaimers listed in this paragraph.

(11) An electric distribution company or default supplier which is related as an affiliate or division of an electric generation supplier or transmission supplier (meaning any public utility that owns, operates, or controls facilities used for the transmission of electric energy) which serves any portion of this Commonwealth; and any electric generation supplier which is related as an affiliate or division of any electric distribution company, default supplier or transmission supplier which serves any portion of this Commonwealth, shall insure that its employees function independently of other related companies.

(12) The Commission shall establish regulations that prohibit transactions between an electric distribution company or default supplier and a related competitive business segment except for instances when the sale or purchase of goods and services by the electric distribution company or default supplier are generally made available to all market participants through an open, competitive bidding process.

(13) The selling or offering to sell surplus energy and ancillaries by an electric distribution company or default supplier to a competitive affiliate shall be required to make the products available on a non-discriminatory basis to all non-affiliated parties via a public posting which includes but is not limited to the EDC or DSP website or other industry recognized and publicly accessible electronic or print medium.

(14) The an electric distribution company or default supplier shall not be allowed to discount or waive all or any part of any charge or fee to a competitive affiliate unless the electric distribution company or default supplier shall make such discount or waiver available on a non-discriminatory basis to all non-affiliated parties.

(15) The electric distribution company or default supplier shall not provide any assistance, aid or services to a competitive affiliate related to customer enrollment, marketing or business development; including providing leads, soliciting business on behalf of its affiliate, acquiring information on behalf the affiliate, sharing of market analysis, representing or implying that the electric distribution company or default supplier speaks on behalf of the affiliate and may receive preferential treatment.

(16) The electric distribution company or default supplier shall not discriminate nor provide preferential treatment with regards to accessing customer information, for which the electric generation supplier has received authorization.

(17) The electric distribution company or default supplier shall not promote default service nor provide its customers with any list of product or service providers, which highlights or otherwise identifies a competitive affiliate unless the list also includes the names of unaffiliated suppliers. Any

meetings held by the electric distribution company or default supplier regarding energy supply should be open to the public.

(18) The electric distribution company or default supplier shall be allowed to create or establish a separate business segment solely to perform corporate services such as corporate oversight, corporate governance, support systems and personnel. However, any shared support service shall be priced at fair market value.

(19) The electric distribution company or default supplier and a competitive affiliate shall not employ the same employees or otherwise retain, with or without compensation, as employees, independent contractors or consultants. In the instance an employee is transferred from an electric distribution company or default supplier to a competitive affiliate, the employee may not return to the electric distribution company or default supplier for a period of twelve months, unless the competitive affiliate goes out of business or is acquired by a non-affiliated company during that twelve-month period.

(20) Any transfer of service produced, purchased or developed by the electric distribution company or default supplier is prohibited to a competitive affiliate unless it is priced at no less than fair market value.

(21) No later than three months after the final adoption of these standards, each electric distribution company or default supplier shall be required to file a compliance plan with the Commission demonstrating that there are adequate procedures in place for compliance.

(22) The Commission shall require an audit to be performed annually by an independent auditor chosen by the Commission and shall also establish the scope of the audit, which verifies that the electric distribution company or default supplier is in compliance with the standards.

(23) The audit shall be performed at the electric distribution company's or default supplier's expense, with full cost recovery through distribution rates.

(24) If, as a result of an audit conducted pursuant to subsection 23 above or by any other means, the Commission determines that an electric distribution company or default supplier has committed violations of the Sections of these standards which are not substantial violations, the Commission is authorized to impose a penalty of up to $20,000 for each such violation upon said electric distribution company or default supplier.

(a) If, as a result of an audit conducted pursuant to subsection 23 above or by any other means, the Commission determines after providing the electric distribution company or default supplier notice of a public hearing and an opportunity to be heard, that an electric distribution company or default supplier has committed violations of these standards which are substantial in nature, the Commission is authorized to take some or all of the following actions:

1. Impose a penalty of up to $20,000 for each such violation(s).

2. Order appropriate reimbursement to electric distribution company or default supplier ratepayers or electric generation suppliers, including interest.

3. For a first violation:

(a) order a violating electric distribution company or default supplier to cease some or all competitive product and/or service offerings and form a related competitive business segment of the electric distribution company or default supplier to perform the competitive product and/or service offerings; or

(b) order a violating electric distribution company or default supplier to cease some or all competitive product and/or service offerings through a

related competitive business segment of the electric distribution company or default supplier; and

4. For a second violation:

(a) Initiate a hearing to reconsider its approval of the formation of the electric distribution company or default supplier.

§54.123. Transfer of customers to default service.

The following standards shall 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:

(a) An EGS shall not transfer a retail customer from its electric generation service to the default service provider without the consent of the default service provider, in situations such as the following, as well as other situations that are not intended to exploit seasonal variations in market prices for electric generation service:

(1) 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).

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

(3) To correct an unauthorized or inadvertent switch of a retail customer's account from default service to an alternative EGS's service.

(4) Upon the normal expiration of contracts that are not structured in a way to exploit seasonal variations in market prices for electric generation service.

(b) An EGS may initiate transfers in the above situations through standard electronic data interchange protocols.

(c) An EGS may not initiate or encourage transfers of service to a default service provider from the EGS to exploit seasonal variations in market prices for electric generation service.

(d) The Commission may impose a penalty for every retail customer transferred to default service in violation of §54.123, consistent with 66 Pa. C.S. §§3301-3316 (relating to violations and penalties).

Subchapter G. DEFAULT SERVICE

§54.181. Purpose.

New customers should not be automatically placed in default service. Instead, they should be asked to choose a competitive supplier from a list that should include the default provider and *all* other competitive suppliers that have indicated an interest in serving new customers.

§54.182. Definitions.

~~*Prevailing market price*—~~

~~(i) The price of electric generation supply for a term of service realized through a default service provider's implementation of~~ a ~~and compliance with a Commission approved default service implementation plan.~~

~~(ii) The price of electric generation supply in the RTO or ISO administered energy markets in whose control area default service is being provided, acquired pursuant to the conditions specified in §§54.186(g), 54.187(i) or 54.188(e).~~

<u>§54.185. Default service implementation plans and terms of service.</u>

(c) A default service implementation plan ~~shall~~ ~~propose a minimum~~ term of service ~~of at least~~ <u>shall be for</u> twelve months, <u>but not longer than seventeen months to coincide with PJM's/MISO's/NYISO's planning period</u> ~~or multiple twelve month periods, or for a period~~ necessary to comply with §54.185(f).

<u>§54.186. Default service supply procurement.</u>

(1) A default service provider's supplier affiliate may participate in any competitive procurement process. The default service provider shall propose and implement protocols to ensure that its supplier affiliate does not receive an advantage in either the solicitation and evaluation of competitive bids, or any other aspect of the competitive procurement process. The process shall comply with the codes of conduct promulgated by the Commission at §54.122 (relating to code of conduct). <u>Default service affiliates are required to submit bids a minimum of three-days in advance of the competitive bid.</u>

(c) A default service provider ~~may~~ <u>shall</u> employ a third-party to design and implement the competitive procurement process.

(d) The competitive procurement process ~~may~~ <u>shall</u> be subject to direct oversight by the Commission or an independent third party. Any third party shall report to the Commission. Commission staff and any third party involved in oversight of the procurement process shall have full access to all information pertaining to the competitive procurement process, and may monitor the process either remotely or where the process is administered. Any third party retained for purposes of monitoring the competitive procurement process shall be subject to confidentiality agreements identified in §54.185(k).

(e) The ~~default service provider~~ independent third party shall evaluate and select winning bids in a non-discriminatory manner based on bid evaluation criteria set forth consistent with §54.186(b)(2)(vi).

§54.187. Default service rates and the recovery of reasonable costs.

(c) A default service implementation plan shall include a fixed rte option for non-residential default service customers whose load test indicates a registered peak demand of 500 or less kilowatts. However all non-residential default service customers whose load test indicates a registered peak demand of 500 or less kilowatts has the option to select an hourly rate

(d) The default service provider shall include an hourly rate in its implementation plan for all default service customers whose load test indicates a registered peak demand of greater than 500 kilowatts~~. The default service provider may propose a fixed rate for these customers in its default service implementation plan.~~

(j) At a minimum, all customers whose load test indicates a registered peak demand of greater than 500 kilowatts are required to have interval metering since it is required for hourly-pricing signals. The EDC is responsible for installation and maintenance of standardized interval metering equipment and all costs of installation and maintenance are to be fully recovered by EDCs on the customer's bill through an agreed upon arrangement with the Commission, the EDC and the Customer. The Commission will establish performance metrics for EDC compliance on installation and maintenance of standardized interval metering equipment

§54.610. Electric Generation Supplier Access to historical Customer Information.

All EDCs are required to provide licensed EGSs with access to ***minimum*** information on all retail distribution customers via a customer list (for those that do not opt out of the list) and through the standardized EDI data sets. All EDC's to update the customer lists quarterly. All EDC's are required to provide twelve months of historical customer interval meter data be made available to customers and EGS's in electronic format at least once every 6 months at no charge.

(a) To the extent a customer wishes to be on the customer list, but opts not to provide their usage information, the EDC is required to provide the following minimum customer information:

(i) Account Number
(ii) Billing Route
(iii) Customer Name
(iv) Service Address
(v) Service City
(vi) Service State Zip
(vii) Billing Address
(viii) Billing City
(ix) Billing State Zip
(x) Contact Name (applicable to large industrial and commercial customers only, where "large" is defined as any customer with greater than 25 kW billing demand in any of the most recent 12 months on a rolling basis)
(xi) Contact Address (applicable to large industrial and commercial Customers only as defined above)
(xii) Contact City, State, Zip (applicable to large industrial and commercial Customers only as defined above)
(xiii) Rate Class

(b) For those customers that have not opted to restrict access to their usage information, the EDC is required to provide the following **minimum** information:

(i) Account Number
(ii) Billing Route
(iii) Customer Name
(iv) Service Address
(v) Service City
(vi) Service State Zip
(vii) Billing Address
(viii) Billing City
(ix) Billing State Zip
(x) Contact Name (applicable to large industrial and commercial Customers only, where "large" is any customer with greater than 25 kW billing demand in any of the most recent 12 months on a rolling basis)
(xi)Contact Address (applicable to large industrial and commercial Customers only as defined above)
(xii) Contact City, State, Zip (applicable to large commercial Customers only as defined above)
(xiii) Rate Class
(xiv) Rate Code
(xv) Strata or Profile
(xvi) Total kWh
(xvii) Registered Peak Demand
(xviii) Load Factor
(xix) Peak load obligation as determined by the EDC for purpose of determining customer's ICAP/UCAP obligation
(xx) 12 Individual Months of billed) demand (kW)
(xxi) 12 Individual Months of (TOU if used in billing)Usage (kWh)
(xxii) Meter number(s)
(xxiii) Transmission peak load obligation
(xxiv) Sales Tax exemption (%)

(c) The reasonable costs of compiling and providing customer information to EGSs on the customer list should be recoverable through distribution rates.

§54.611. Electric Generation Supplier Access to real-time Customer Information.

(a) All EDCs shall provide via an automated EDI process, on a daily basis, hourly (or sub-hourly, where applicable) interval usage for EGS billing to EGS customers.

(b) The reasonable costs of compiling and providing such customer information to EGSs shall be recoverable through distribution rates.