BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Default Service and Retail Electric Markets	:	**Docket No. L-00070183**

COMMENTS OF INDUSTRIAL ENERGY CONSUMERS OF PENNSYLVANIA, DUQUESNE INDUSTRIAL INTERVENORS, MET-ED INDUSTRIAL USERS GROUP, PENELEC INDUSTRIAL CUSTOMER ALLIANCE, PENN POWER USERS GROUP, PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP, PP&L INDUSTRIAL CUSTOMER ALLIANCE, AND WEST PENN POWER INDUSTRIAL INTERVENORS

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I. INTRODUCTION

On February 8, 2007, the Pennsylvania Public Utility Commission ("PUC" or "Commission") adopted a Proposed Policy Statement ("Policy Statement") in the above-captioned proceeding. In a companion order, the Commission adopted an Advance Notice of Final Rulemaking Order ("Rulemaking Order") that sets forth regulations defining the obligation of electric distribution companies ("EDCs") to serve electric retail customers at the conclusion of the restructuring transition periods, pursuant to Section 2807(e)(2) of the Electricity Generation Customer Choice and Competition Act ("Competition Act"). Whereas the Rulemaking Order sets forth regulations governing the "default service" framework, the Policy Statement proposes "initial guidelines" that will be applied to the first set of default service programs following the expiration of the generation rate caps and will be subject to re-evaluation prior to the submission of subsequent default service programs. See Policy Statement, p. 2. The Commission seeks public comment on the Policy Statement.

The Industrial Energy Consumers of Pennsylvania ("IECPA"), Duquesne Industrial Intervenors ("DII"), Met-Ed Industrial Users Group ("MEIUG"), Penelec Industrial Customer Alliance ("PICA"), Penn Power Users Group ("PPUG"), Philadelphia Area Industrial Energy Users Group ("PAIEUG"), PP&L Industrial Customer Alliance ("PPLICA"), and West Penn Power Industrial Intervenors ("WPPII") (hereinafter, "IECPA, et al.") respectfully submit these comments. IECPA, et al., are ad hoc groups of large commercial and industrial ("C&I") customers receiving service from almost all EDCs in Pennsylvania. Because IECPA, et al. members use substantial volumes of electricity in their manufacturing and operational processes, electric costs represent a sizeable component of overall operating costs.

According to the Commission, the Policy Statement "coupled with the default service regulations, and the order on electricity price mitigation, represents a comprehensive strategy for addressing retail rates in the context of expiring rate caps." See Policy Statement, p. 2. In light of the direct and substantial impact that the expiration of rate caps will have on the cost of operating their respective manufacturing and production facilities, IECPA, et al. submit these Comments in order to highlight areas of particular concern to large C&I customers.[1]

As detailed more fully herein, IECPA, et al. respectfully request that the Commission ensure that the final Policy Statement: (1) permits the unrestricted use of long-term contracts with affiliates to procure generation supply; (2) mandates the availability of long-term, fixed-price options for C&I customers; (3) authorizes the use of declining block rates and demand charges to encourage efficiency; (4) recognizes that a Price-to-Compare ("PTC") adjusted on a monthly (or more frequent basis) does not satisfy the business planning needs of large C&I customers; (5) clarifies the "phase-in" option proposed in Section 69.1811 to improve its usefulness and ensure that rate shock mitigation measures are available to all customer classes; and (6) clarifies that any Commission-initiated cost allocation proceedings will observe existing, approved restructuring settlements, reflect proper cost allocation principles, and result in an appropriate dollar-for-dollar reduction to distribution rates.

[1] Contemporaneous with these Comments, IECPA, et al. are filing comments in the rulemaking proceeding at Docket No. L-00040169.

II. COMMENTS

A. The POLR Framework Should Not Encumber a Default Service Provider's Use of Long-Term Contracts with Affiliates To Procure Generation Supply.

The Policy Statement encourages default service providers ("DSP") to utilize a portfolio approach in acquiring generation supply products. See Policy Statement, p. 4. As contemplated by the Policy Statement, a portfolio approach includes "the laddering of contracts," multi-period procurements, and the incorporation of spot market purchases. Id. at 4-5. As proposed, however, the portfolio approach does not envision a DSP's unrestricted use of long-term contracts. See § 69.1805. Finally, the Policy Statement also recommends customizing procurement strategies by customer class based on level of sophistication, financial resources, and opportunities to shop. See Policy Statement, pp. 5-6.

1. PPLICA Supports the Commission's Endorsement of a Portfolio Approach.

PPLICA supports the Commission's decision to encourage a portfolio approach, rather than a statewide process, for procuring generation supply. See Policy Statement, p. 4. The service territories and customer bases of the various EDCs are very different throughout Pennsylvania. As the Commission correctly noted, a portfolio approach will permit each provider-of-last-resort ("POLR") to "craft a solution best suited to its own service territory." Id. Moreover, the use of a portfolio approach that includes laddered contracts, multi-period procurements, and class-based procurement strategies is consistent with the Competition Act's intention to permit DSPs to maintain a well-equipped "toolbox" of instruments to procure service from a variety of sources in order to offer electricity to customers at just and reasonable prices. Providing DSPs with the ability to tailor their procurement processes to fit the needs of their service areas and the particular needs of their customers will facilitate just, reasonable, and non-discriminatory default service rates throughout the Commonwealth.

2. Long-Term Bilateral Contracts with Affiliates Should Be Permitted Default Service Procurement Options.

According to Section 69.1805, long-term contracts "should only be used where necessary and required for DSP compliance with alternative energy requirements, and should be restricted to covering a relatively small portion of the default service load." See § 69.1805. The Commission fears that an "over-reliance" on long-term contracts would "mute demand response, create the potential for future default service customers to bear future above market costs, and limit operational flexibility for DSP's to manage their default service supply." See id.

According to the proposed regulations, a DSP's procurement plan "should be designed to acquire electric generation supply at prevailing market prices to meet the DSP's anticipated default service obligation at the lowest reasonable long-term cost." See Proposed POLR Regulations, § 54.186(b)(1). Notwithstanding the goal of securing default service at the "lowest reasonable long-term cost" to customers, the Commission inappropriately restricts DSPs from using long-term bilateral contracts with affiliates to procure electricity for POLR customers. See § 69.1805; see also Rulemaking Order, n.4 & pp. 14-15. This restriction is fundamentally at odds with the goal set forth in Section 54.186(b)(1) of the proposed POLR regulations.

As discussed in IECPA, et al.'s Comments on the Rulemaking Order, the Competition Act does not prohibit a DSP from entering into long-term contracts or contracts with affiliates. A long-term contract satisfies Section 2807(e)(3) as long as it reflects the prevailing market price for similar contracts of like character and duration at the time of execution. Moreover, Commission has the power to review any affiliated interest agreement under Chapter 21 of the Public Utility Code to ensure that ratepayers are not disadvantaged. See 66 Pa. C.S. §§ 2101-

2106. The Federal Energy Regulatory Commission ("FERC") also has a process to review contracts between FERC-regulated utilities and their affiliates. Because many affiliates of EDCs in Pennsylvania continue to own lower fuel cost, highly depreciated generation facilities in the PJM Interconnection, L.L.C. ("PJM") footprint, negotiating a long-term, bilateral contract based on the affiliate generator's actual costs may produce the lowest reasonable rates for customers. The Pennsylvania consumers who have paid the stranded costs associated with this generation should not be deprived of this option.

The Policy Statement and the Rulemaking Order, however, vacillate between implementing procurement strategies designed to mute the impact of market movements (such as laddering and the portfolio approach) and the clear goal of exposing customers to market forces to encourage conservation and the entry of electric generation suppliers ("EGSs"). In doing so, the PUC has inappropriately eliminated one element of a balanced portfolio approach that could benefit customers; i.e., allowing the DSP to enter into long-term bilateral contracts with affiliated generation owners. As FERC has recognized, "in markets that are competitive, a combination of long-term contracts and adequate demand response provide[s] the best way to limit exposure to price risk in spot energy markets." See Midwest Indep. Transmission Sys. Operator, Inc., 102 FERC ¶ 61,280 at P 58 (2003). To ensure that DSPs are able to obtain electricity for POLR customers at just and reasonable rates, DSPs must be permitted to include the use of long-term contracts with affiliates in their procurement toolbox.

B. A PTC Adjusted on a Monthly (or More Frequent) Basis Generally Does Not Satisfy C&I Customers' Business Planning Needs.

Section 69.1809 recognizes that "the PTC will be adjusted...as frequently as every month for large business customers". See § 69.1809; see also Proposed POLR Regulations § 54.187(j) (providing the PTC "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"). In addition, the Policy Statement provides for interim adjustments, which are defined as "changes in rates more frequently than at the normal adjustment interval," if there is a divergence greater than 5%. See Policy Statement, pp. 7-8; § 69.1809.

As detailed in IECPA, et al.'s Comments at Docket No. L-00040169, a default service rate that fluctuates on a monthly basis, or more frequently, is impractical, unreasonable, and, in some cases, infeasible. Many C&I customers have load profiles or production/manufacturing processes that prevent the utilization of a monthly pricing option. Moreover, not all C&I customers have the sophistication and resources to administer such an option efficiently. A rate that fluctuates on a monthly basis (or more frequently) is volatile and, as such, unpredictable. Due to its volatile and unpredictable nature, such a pricing option introduces significant uncertainty to customers' business planning and budgeting processes. As the costs of doing business in the Commonwealth continue to escalate, the pressure on Pennsylvania industry to remain competitive at home and abroad intensifies. A key component of C&I customers' respective strategies for maintaining and enhancing their competitive posture is energy cost management. The effective implementation of an energy cost management strategy, however, depends on C&I customers' ability to budget for anticipated future needs (e.g., capital investment, production, and staffing levels) and develop the means by which to fulfill those needs during their annual business planning cycles.

The usefulness of a business plan, however, depends on the underlying inputs. For energy-intensive C&I customers, a critical business plan input is anticipated energy costs. A monthly PTC, however, does not provide C&I customers with the level of certainty regarding energy costs necessary to plan for the future. A default service rate that is constantly in flux is at odds with the typical C&I customer's annual business planning cycle. As a result, a monthly PTC will only frustrate C&I customers' efforts to manage energy costs, the success of which is integral to preserving and enhancing their competitiveness in the national and international marketplace. Accordingly, a POLR plan that only offers a monthly default service rate cannot meet the business needs of Pennsylvania's large C&I customers.

To be clear, IECPA, et al. do not oppose the monthly PTC as one default service option; however, it should not be the only option. Such a rate may be a desirable option under certain circumstances. For example, a monthly fixed PTC may be a useful option for a customer that is in between long-term contracts. Under this scenario, the customer could use the monthly PTC as a bridge between competitive supply contracts in the event that it does not complete the contracting process with a new supplier in sufficient time to ensure that the new supplier begins service as of the termination date of the prior contract. A monthly pricing option may also be useful when market conditions at the time a customer is entering into the new contract are inflating competitive offers, which may become more moderate in the short-term, thereby resulting in lower rates for the customer's next competitive supply contract. Finally, depending on the design of the monthly rate, customers with operations that can withstand monthly electric price changes, or that can modify consumption in response to those changes, may view this default service option as a viable, least-cost procurement strategy. Notwithstanding the potential utility of a monthly PTC, a long-term, fixed-price option must accompany any monthly default pricing option.

C. The Competition Act Supports Approval of Long-Term, Fixed-Price Options for C&I Customers.

The Policy Statement provides that the Commission will consider fixed-price options for large customers (i.e., greater than 500 kW in maximum registered peak load) on a case-by-case basis. See § 69.1805(3). As discussed in IECPA, et al.'s Comments at Docket No. L-00040169, although IECPA, et al. appreciate the Commission's recognition of its prior arguments by including this as a permissive default service offering, to meet the goals of the Competition Act, it should be a mandatory default service offering. An overarching objective of the Competition Act is to "benefit all classes of customers and to protect this Commonwealth's ability to compete in the national and international marketplace for industry and jobs." 66 Pa. C.S. § 2802(7). As the General Assembly determined in passing the Competition Act, the "cost of electricity is an important factor in decisions made by businesses concerning locating, expanding, and retaining facilities in this Commonwealth." Id. § 2802(6). On the eve of the expiration of transitional rate caps, which will expose Pennsylvania customers to the brunt of market forces, Pennsylvania's capability to realize the objectives of the Competition Act is of paramount importance. To protect the Commonwealth's ability to retain existing and entice new business and industry, and in light of the General Assembly's recognition that a key to realizing this objective is linked to the cost of electricity, the Commission should mandate that DSPs provide a long-term, fixed-price default service option; otherwise, large C&I customers will be severely disadvantaged in their ability to compete in the national and international market place for industry and jobs. Such an outcome clearly contravenes the intent of the Competition Act.

Moreover, providing large C&I customers with a long-term, fixed-rate option is consistent with the Competition Act if the energy is acquired at prevailing market prices and the DSP recovers fully all reasonable costs. See 66 Pa. C.S. § 2807(e)(3). Multiple products exist in the wholesale market with differing duration and price stability. Each product has its own "prevailing market price" at a given time. By using the plural term "prevailing market prices" in Section 2807(e)(3), the General Assembly clearly expressed its desire for the Commission to adopt default service regulations that provide multiple products, such as a long-term fixed-rate for large C&I customers.

The Competition Act also recognizes EDCs' ability to develop and implement rates that will specifically address customers' needs. Under Section 2806(h), the Commission has the authority to "approve flexible pricing and flexible rates, including negotiated contract-based tariffs designed to meet the specific needs of a utility customer and to address competitive alternatives." See 66 Pa. C.S. § 2806(h). As discussed in IECPA et al.'s Comments on the Proposed POLR Regulations, large C&I customers need long-term price certainty in order to manage energy costs. The lack of a long-term, fixed-price option will undermine C&I customers' cost management efforts and, consequently, place them at competitive disadvantage vis-à-vis industry rivals located in lower-cost jurisdictions. In light of the Competition Act's intent to permit negotiated tariffs in order to meet the needs of a specific utility customer, requiring DSPs to offer a long-term, fixed-price option is consistent with the Competition Act.

The Competition Act requires that electric service should be available to all customers on reasonable terms and conditions. See 66 Pa. C.S. § 2802(9). As discussed in IECPA, et al.'s rulemaking comments, a PTC that is "adjusted on a monthly basis, or more frequently" for large customers is not reasonable, because it subjects such customers to arbitrary price increases, which can detrimentally affect load usage. Moreover, frequent adjustments, which are largely driven by unpredictable locational marginal prices ("LMP") resulting from a flawed wholesale market design that is highly sensitive to steep and volatile natural gas prices, may also result in higher than expected prices. Because large customers utilize significant amounts of electricity, this can result in significant budget expenditures. This level of price volatility undermines a company's business planning procedures. If large customers are unable to specifically determine and plan for budgetary expenses, their ability to manage energy costs and, thus, optimize production/manufacturing processes will likely be compromised. Thus, a POLR pricing strategy that undermines large customers' ability to do business in the Commonwealth is directly inconsistent with the Competition Act, which recognizes that electric service is "essential...to orderly economic development." 66 Pa. C.S. § 2802(9).

The intent of the Competition Act is to provide a DSP that is a competitive alternative to the marketplace. See 66 Pa. C.S. § 2806(h). If POLR regulations do not require DSPs to offer a long-term, fixed-price option for large customers, such customers would be forced into the competitive market in order to obtain fixed-price options and, consequently, the DSP will not be a competitive alternative. Under this scenario, EGSs will have the opportunity to raise their fixed prices significantly above what the market would otherwise bear merely because EGSs would control the universe of fixed-price options and, consequently, could exercise considerable leverage vis-à-vis customers seeking such options. As a result, large customers would be subject to unjust and unreasonable rates from EGSs as a direct result of the lack of a fixed-price option for POLR rates.

Artificially boosting shopping levels by such means is not consistent with true competition or success under the Competition Act. Mandating that DSPs offer a long-term, fixed-price option for large C&I customers will ensure that DSPs represent a competitive alternative in the post-restructuring marketplace. Moreover, such a long-term, fixed-price option can act as a benchmark that will discipline the prices that EGSs can demand in the market. Accordingly, the DSP must be required to offer at least one long-term, fixed-priced option for large C&I customers.

Finally, under the Public Utility Code and Commission regulations, different classes of customers can be treated differently only as long as the disparate treatment is not unduly discriminatory. See 66 Pa. C.S. § 1304. Requiring large customers on default service to receive a default service rate that is "adjusted on a monthly basis, or more frequently" would discriminate against this customer class by subjecting only these customers to price volatility, arbitrary price increases, and artificial market prices.[2] Although some customers may opt for a monthly PTC, many large C&I customers have inadequate resources to cope with this type of pricing methodology and engage in manufacturing/production processes that are not compatible with a monthly PTC. Accordingly, all customers must be offered at least one long-term, fixed-price POLR rate; no customer should be forced to pay rates that fluctuate on a monthly basis or even more frequently.

D. The Commission Should Authorize the Use of Declining Block Rates and Demand Charges To Encourage Efficiency.

In an attempt to remove "any disincentives to energy conservation" from rate design, the Policy Statement abolishes the use of declining block rates and demand charges. See § 69.1810. Implicit in the Commission's rationale for these revisions is the presumption that declining block rates and demand charges impede conservation and prevent customers from seeing accurate price signals. As discussed in IECPA, et al.'s rulemaking comments, this presumption is erroneous. The use of declining block rates and demand charges promotes efficiency, a goal that is not mutually exclusive with conservation. Moreover, these tools also ensure that customers receive accurate price signals, in light of the fact that the actual costs incurred by a load-serving entity ("LSE") to serve its customers include both energy and demand components.

[2] The Commission proposes quarterly adjustments for smaller customers. See Proposed POLR Regulations, §§ 54.187(h)&(i).

The PJM wholesale market structure includes charges that are assessed on demand (i.e., MW or kW) and energy (i.e., MWh or kWh) bases. Capacity and transmission[3] are assessed on a demand basis, while energy and most ancillary services are assessed on an energy basis. To provide customers with proper signals regarding the need to minimize their peak demand during PJM peak periods, retail rates must reflect both an energy and a demand component.

For example, assume that the owner of a hypothetical large office building determined that it could use 5% fewer kWh of electricity by cycling its air conditioning unit on and off during peak days and that the building's demand increased by 50% each time the air conditioner cycled back on. This dramatic demand increase would not occur if the air conditioner were operating on a constant basis to produce the same internal temperature. Under this scenario, the building owner's conservation strategy may not further the PUC's efficiency goals. If the retail rate design were to include a demand charge that reflected the demand impact of the cycling, then the building owner would have an incentive to efficiently use electricity and avoid drastic demand spikes. If the retail rate design reflects only an energy charge, then the appropriate price signal is not conveyed to the customer.

Similarly, using a demand charge and declining block structure encourages large C&I customers to operate manufacturing facilities at a higher load factor (i.e., more efficiently) to result in lower realized per kWh costs. In other words, as a customer's efficiency (i.e., load factor) increases, the cost of serving that customer decreases. A pricing structure that fails to recognize this efficiency benefit will result in unjust and unreasonable rates. Thus, declining block rates and demand charges must not be eliminated, as these rate design components best reflect the cost differences and efficiencies attributable to high-load factor customers.

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[3] IECPA, et al. explain in Section II.F why transmission should not be included in the PTC.

If rates are set based on cost of service, customers will receive proper and efficient price signals that will guide their consumption. Such rates do not either discourage or encourage conservation, but rather encourage efficient and economic use of energy. While it is true that, all else being equal, higher kWh rates will result in lower consumption (and thus "conservation"), it does not follow that this is an optimal outcome. If off-peak energy, for example, is lower cost than on-peak energy, efficiency is not promoted by raising the off-peak rate, simply to discourage usage. If rates are based on cost, including cost-based fixed charges where justified, customers will face prices that are consistent with the costs of providing each component of electric service and, consequently, make rational consumption decisions. Thus, if declining block rates or demand charges are cost justified, then such rate designs are appropriate and do not represent an impediment to conservation. The Commission should authorize demand charges and declining block rate structures for default service.

E. The "Phase-In" Option Under Section 69.1811 Must Be Modified To Improve its Usefulness as a Mitigation Option and Available to All Customer Classes.

In the event that a DSP's total retail rate increases by more than 25% following the expiration of the generation rate cap, a DSP may offer residential and small business customers the "opportunity to pre-pay or defer some portion of the rate increase for as long as three years," pursuant to Section 69.1811. See § 69.1811. DSPs would be able to fully recover the reasonable carrying costs associated with a rate increase deferral program, including associated administrative costs. See id. Thus, a customer who elects this option "will ultimately pay more for their electricity." See Policy Statement, p. 9.

As proposed, the "phase-in" proposal will be unattractive to customers as a mitigation mechanism. The availability of the mitigation mechanism is triggered if upon expiration of a rate cap customers realize more than a 25% increase. The objective of the mitigation measure is to provide a means for customers to cope with the rate shock associated with a +25% increase. While allowing customers with the option to pre-pay or defer payment over the course of three years may provide some relief, this option is rendered unviable and unattractive by the fact that customers who elect this option "will ultimately pay more for their electricity." See Policy Statement, p. 9. In order words, electing this "mitigation" option will only exacerbate the any rate shock attributable to the expiration of a rate cap. Such an outcome would defeat the purpose of the proposal.

To be clear, IECPA, et al. support the Commission's efforts to develop proposals that will mitigate any rate increases that are attributable to the expiration of rate caps; however, it may be more appropriate to develop modifications to the "phase-in" proposal as well as additional mitigation proposals in the context of Docket No. M-00061957. Finally, to comply with Section 1304 of the Public Utility Code, rate mitigation proposals should be available to all customer classes, not just residential and small business customers. See 66 Pa. C.S. § 1304 (prohibiting unduly discriminatory differences in customer classes' rates).

F. The Commission's Conduct of Cost Allocation Proceedings Must Be Consistent with Existing, Approved Restructuring Settlements and Sound Principles of Cost Allocation.

The Policy Statement expresses concerns that some generation costs may have been improperly embedded in EDC distribution rates. See Policy Statement, p. 6. Accordingly, Section 69.1808(b) provides:

> EDC rates should be scrutinized for any generation related costs that remain embedded in distribution rates. This review should occur no later than the next distribution rate case for each EDC filed after the effective date of this policy statement. The Commission may initiate a cost allocation case for each EDC on its own motion if such a case is not initiated by December 31, 2007.

> Changes to rates resulting from such examination would take effect after the expiration of Commission approved rate caps.

See § 69.1808(b). IECPA, et al. commend the Commission's commitment to ensuring that generation costs are properly allocated and reserving the right to initiate a cost allocation proceeding to examine distribution rates if an EDC does not address this issue in a timely manner. As the Commission is well aware, however, a number of PUC-approved restructuring settlement agreements exist that restrict certain EDCs' ability to file distribution rate cases through 2010. Accordingly, the Commission should clarify that it will exercise its discretion to initial a cost allocation proceeding in a manner that is consistent with these existing restructuring settlement agreements.

The Policy Statement further specifies the various categories of cost elements that should be included in the PTC as follows:

> (a) The PTC should be designed to recover all generation, transmission related and other related costs of default service. These cost elements include, but are not limited to:
>
> > (1) Wholesale energy, capacity, ancillary, congestion, applicable RTO or ISO administrative and transmission costs.
> > (2) Supply management costs, including supply bidding, contracting, hedging, risk management costs, any scheduling and forecasting services provided exclusively for default service by the EDC, and applicable administrative and general expenses related to these activities
> > (3) Administrative costs, including billing, collection, education, regulatory, litigation, tariff filings, working capital, information system and associated administrative and general expenses related to default service.
> > (4) Applicable taxes, excluding sales tax.
> > (5) All costs for alternative energy portfolio standard compliance.

§ 69.1808(a). IECPA, et al. have several concerns regarding this list and the allocation process.

First, as detailed in IECPA, et al.'s Comments on the Proposed POLR Regulations, transmission and ancillary services must be unbundled and separately stated under Section 2804(3) of the Public Utility Code. See 66 Pa. C.S. § 2804(3). In addition, consistent with applicable precedent, these items must be allocated to rate schedules on a cost of service basis to reflect the demand or energy nature of the underlying costs. See Lloyd v. Pa. Pub. Util. Comm'n, 904 A.2.d 1010 (Pa. Commw. Ct. 2006); see also 66 Pa. C.S. § 2804(6). Any services that have been unbundled as part of the restructuring proceedings, distribution base rate proceedings, or default service proceedings adjudicated since the adoption of the Competition Act should not be rebundled into the PTC.

Second, all congestion should be included in the wholesale energy prices and bids from the suppliers. Although congestion can be included in the PTC (due to its inclusion in the bid price), it should not be a pass-through item or subject to reconciliation. All congestion risk must be borne by the wholesale suppliers to the DSP.

Third, the allocation of any costs recovered through the PTC or any default supply service rate must reflect proper cost-based principles. Specific allocators have historically been used in cost of service studies to allocate cost categories such as billing, collection, uncollectibles, etc., among customer classes. These interclass allocations must be continued. In addition, the Commission must carefully examine the appropriate allocation of the costs assigned to each rate schedule between distribution service and default supply service based on sound cost allocation principles.

Fourth, in "scrutinizing" the allocation of generation and distribution costs, the Commission's objective is to ensure that default service costs are not recovered through distribution rates and that distribution costs are not recovered twice as a result of any reallocation that occurs. See Rulemaking Order, p. 17. As detailed in IECPA, et al.'s Comments in the rulemaking proceeding, the Commission should further clarify Section 54.187(d) by adding language indicating that distribution rates must be reduced on a dollar-for-dollar basis to reflect any costs reallocated to the default service rate. This clarification is necessary to realize the Commission's objectives.

III. CONCLUSION

WHEREFORE, Industrial Energy Consumers of Pennsylvania, Duquesne Industrial Intervenors, Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance, Penn Power Users Group, Philadelphia Area Industrial Energy Users Group, PP&L Industrial Customer Alliance, and West Penn Power Industrial Intervenors respectfully request that the Pennsylvania Public Utility Commission consider and adopt, as appropriate, the foregoing Comments.

Respectfully submitted,

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