BEFORE THE
PUBLIC UTILITY COMMISSION

Energy Efficiency and Conservation
Program and EDC Plans : Docket No. M-2008-2069887

Comments of ClearChoice Energy regarding the November 26, 2008 draft staff proposal and further questions relative to the first phase of the Act 129 of 2008 implementation plan

ClearChoice Energy commends the staff's efforts to interpret and provide guidance on the many issues raised by the implementation of Act 129 on such a short schedule. We appreciate the opportunity to file comments on the draft proposal and answer questions relative to the first phase of the Act 129 of 2008 implementation plan.

Introduction

ClearChoice Energy is a privately-owned, certified woman-owned business headquartered in western Pennsylvania, providing energy management services including conservation services under PJM's demand response programs. We are registered as a Curtailment Service Provider as a member of the PJM Interconnection and serve on the PJM Demand Response Steering Committee. We are currently working with retail electric customers including school districts and municipalities to enroll them in PJM demand response programs for the upcoming PJM planning year that begins June 1, 2009. We also work with partner companies that provide energy efficiency services, including newer technologies, to commercial, industrial and institutional customers.

ClearChoice Energy's management has twenty years of experience in deregulated energy markets, including the management of both wholesale and competitive retail power supply operations throughout North America. We have provided energy management services to commercial, industrial and institutional electric customers since 2003.

Response to Additional Questions

1. **Efficiency targets/Goals:** We have no comments on this issue.

2. **Program Design:**

   a. Statewide vs. EDC specific: Should the Commission encourage, by policy, a statewide approach to some programs that are likely to be effective across Pennsylvania? For example, should rebate programs be harmonized across the state? Should specific programs, such as Energy Audits, PJM load reduction programs, Home Performance with Energy Star, and Energy Star Homes be consistently available in all EDC service territories? If so, what programs should the EDCs implement consistently across the state?

   Yes, there should be some consistency across the state. For instance, rebates should be offered for energy audits as well as certain types of equipment, such as interval metering, energy efficient lighting, etc. Equipment rebates should be based upon the purchase and installation of equipment, and should be provided not only to a conservation service provider who demonstrates they have purchased and installed such equipment, but also directly to an end use consumer who elects to perform the work themselves, and can meet the measurement and verification requirements.

We believe there should be consistency across demand response programs. With respect to the PJM load reduction program, one of the EDC's covered under Act 129, Penn Power, is not a member of the PJM Interconnection for purposes of managing the reliability of its transmission facilities and therefore could not participate in the PJM load reduction programs. Duquesne Light is currently a member of PJM, but has received approval from FERC to leave PJM and join the Midwest ISO effective 60 days after providing firm, unconditional notice to FERC of its withdrawal date. We are proposing a program design for demand response that would complement PJM and MISO programs and provide for consistency in program design across all Act 129 EDC service territories.

b. Can Act 129 programs have negative impacts on existing cost effective energy efficiency and demand side programs by 3rd parties? If so, how can this Commission avoid damaging existing 3rd party efforts when socializing Act 129 energy efficiency and demand side programs through non-bypassable charges to all customers, while increasing customer participation in these services?

Yes, as we expressed in our En Banc hearing comments, Act 129 as well as existing EDC conservation programs can have negative impacts on energy efficiency and demand side programs by independent 3rd parties. We have experienced significant downward pressure on margins due to existing EDC demand response programs. Also, despite what appear to be promising growth opportunities in the Commonwealth for conservation service providers, the regulatory uncertainty relative to the ability of an EDC or EDC affiliate to compete with privately financed, competitive providers of conservation services has negatively impacted our ability to raise outside capital for business expansion. A decision by the Commission to allow EDCs and/or their affiliates to compete with third party conservation service providers will severely limit the state's economic development strategy and new job creation in this market sector. We propose a program design that will complement existing and new 3rd party programs and work in concert with EDC programs to incentivize reductions in electric consumption.

c. Should the Commission seek to harmonize Act 129 programs with other Federal, State, local, RTO or other group programs? If so, what specific programs should this Commission encourage EDCs to replicate, incorporate, or leverage as part of their compliance filings? How can this best be achieved?

See proposal beginning on page 9 of our comments.

3. **Total Resource Test –** We have no comment on this issue.

4. **Evaluation, Measurement and Verification –** There should be a standard format for collecting M&V data across all EDC programs. We believe it should mirror the applicable RTO/ISO business rules for the program selected (demand response, on-site renewable generation, or energy efficiency). PJM is scheduled to publish business rules for how M&V will be treated for energy efficiency projects by January 1, 2009.

5. **Revenue Requirement –** We have no comment on this issue.

6. **Cost Recovery Issues** – We have no comment on these issues.

7. **CSP Issues:**

   a. Does the definition of "Conservation Service Provider" (CSP) in the Act prohibit an affiliated company of an EDC from serving as a CSP to an EDC other than its affiliate?

   Yes, the plain language of the statute prohibits an EDC or EDC affiliate from providing conservation services.

   b. Are there existing barriers to CSP market development that the Commission should address in the context of Act 129? For example, what data access, meter access or other barriers should the Commission accelerate resolution of in order to enhance Act 129 goal achievement?

The following should be made available for use by CSPs in implementing Act 129 programs:

- Individual customer:
  - Name, account number, service address:
  - historical usage data (summary and interval);
  - peak load contribution;
  - rate class;
  - generation and transmission charges; and
  - losses (transmission, distribution, capacity).
- Aggregate customer information for purposes of market segmentation; and
- Meter access.

Currently, the time and cost to obtain this information are both barriers to the successful implementation of Act 129 programs. It is also a competitive issue for independent service providers because EDCs providing these services are advantaged by already having the data. This should be provided at no charge and in a timely manner to CSPs.

The Commission also needs to address the installation of interval meters, communication, telemetry and other technical infrastructure necessary for demand side resources to participate in demand response programs.

c. How should the Commission ensure that EDCs self supplied EE&C programs are more cost effective than similar services offered by CSPs? Should this Commission require EDCs to demonstrate in their implementation filing that their self supplied program is more cost effective than similar CSP provided services?

We interpret the Act as not allowing EDCs to perform conservation services as a self-supplied offering to retail customers. If the Commission determines EDCs are permitted to self-supply conservation services to retail customers, then the EDCs should be required to identify the specific services they intend to self supply, along with the costs associated with providing those services they want to include under the cost recovery mechanism in their tariff. An independent party should prepare and issue an RFP whereby competitive CSPs can bid on those same services. The independent party should also evaluate the responses. If the competitive bidding process for the same services results in an offer to provide those services for less than the amount the EDC desires to include in its tariff, then those services should be provided by independent CSPs.

The Commission and independent party must ensure an "apples to apples" comparison of services and costs as well as competitive neutrality. Any EDC assets that are derived from ratepayer funding, should be provided free of charge to the independent CSPs. For instance, if the EDC wants to use its “brand name” to advertise the conservation program, or use its customer database for purposes of market segmentation, use of those assets should be provided to the independent CSPs at no charge.

The EDC must also live by the terms of the deal when it comes to cost recovery. If the RFP for competitive contracts requires fixed price services, then it would be reasonable and prudent for the EDC’s cost recovery to also be capped at a fixed price.

Proposal for EE&C Open Market Program Design

We propose the EE&C programs be designed as "open market" programs.

A. Benefits

Our proposed open market design has the following benefits. It would:

1. mitigate the competitive issues that negatively impact independent third party energy efficiency and demand side programs;
2. increase competition among independent conservation service providers and incentivize CSPs under a pay for performance model to bring the lowest cost demand side resources to the EDCs;
3. leverage the financial incentives for demand response and energy efficiency provided by existing and future RTO/ISO programs;
4. provide for low cost implementation and administration by harmonizing Act 129 programs with existing and future RTO/ISO programs;
5. address the challenges faced by Duquesne Light and Penn Power due to the fact that significant amounts of their distribution customers' load is served by competitive electric generation suppliers;
6. be consistent with the pro competition policy for Pennsylvania's retail electric market laid out by the General Assembly in Title 66, §2802;
7. coordinate the state's retail policy with federal policy that promotes competitive markets, expands and stimulates participation in demand response programs, and provides for transparency in wholesale market transactions;

8. increase the Commission's influence in RTO/ISO stakeholder proceedings on matters relating to the participation of demand side resources in wholesale electric markets; and

9. address a deficiency in PJM's reliability pricing model design by providing for greater diversity of control over capacity market resources and consequently reduce structural market power in PJM's capacity market.

B. Conceptual Framework For an "Open Market" Program

In order to establish a framework for the program design, it's important to recognize that **what** the EDC's need to purchase in order to accomplish their goals under the Act is a commodity. It is **megawatt-hours of energy** reduced across a year, and **megawatts of demand** in certain peak hours. Each unit of this commodity is, by definition, homogeneous, and can be differentiated based only on price. So long as the EDC programs pay for performance in terms of megawatt-hours and megawatts delivered, nothing other than price matters. The amount of the conservation service provider's individual net worth, credit rating, type or amount of insurance coverage they carry, and their years of experience in the business are ALL irrelevant. The only things that matter are: 1) did the demand side resources the conservation service provider brought to the EDC perform, and 2) at what price?

An EE&C program that attempts to stimulate demand-side resource participation (whether from energy efficiency or demand response) involves transactions between three parties: an EDC, a conservation service provider, and a retail electric customer.

The EDC has a transaction with a conservation service provider to purchase the commodity. The conservation service provider sells the commodity to the EDC and purchases its supply of the commodity from retail electric customers who own demand side resources.[1] Under our proposed model, the EDC itself does not have a direct contractual relationship for the purchase of the commodity with retail electric customers who own demand side resources. EDC programs pay for the commodity based on performance of the demand side resources in the conservation service provider's portfolio (in terms of megawatt-hours delivered). EDC requirements for who may participate, competitive bids, and resulting contracts between the EDC and conservation service providers would only address the sale of the commodity between the CSP and the EDC, and would not reach into the privately negotiated supply transactions between the CSP and retail electric customers who supply the CSP from demand side resources.

Using this framework, we propose the EE&C programs have the following components:

1. Incentive payments to conservation service providers for megawatt hours obtained from demand response activities;
2. Incentive payments to conservation service providers for megawatt hours resulting from energy efficiency or on-site renewable generation projects;
3. Payments for enabling services and equipment such as energy audits, communication, metering, telemetry and other technical infrastructure solutions necessary for participation in RTO/ISO demand response and

[1] In addition to purchasing supply from the retail electric customer, the conservation service provider typically provides additional services that facilitate the commodity transaction, including information and technical assistance to enable the customer to increase energy efficiency or reduce energy consumption.

capacity market programs as well as the energy efficient equipment defined in §2806.1(M) of the Act;

4. Promotional campaign and outreach to the general public regarding the program; and

5. Coordination of a pilot program or other mechanism, in conjunction with PJM and MISO, of the technical feasibility and value to the market of smaller demand response resources providing ancillary services as required by FERC Order 719.

The Commonwealth has a great model for an "open market" program design in PJM's demand response programs. PJM's programs have not only demonstrated their success overall, but have proven successful within the service territories of six of the seven EDCs that will be developing EE&C plans. PJM's economic program provides the business rules and processes for implementing the incentive payments for demand response. PJM business rules and processes for treating energy efficiency and on-site renewable generation as capacity resources under the reliability pricing model provide the basis for making incentive payments for energy efficiency and renewable projects.[2] The timeline for developing EDC plans for the EE&C program parallels RTO/ISO implementation of FERC Order 719.[3] We believe coordinating state with federal policy

[2] A summary of the PJM staff proposal for treating energy efficiency as a capacity market resource is included on page 23 of our comments.

[3] Order 719 requires each RTO/ISO to file a proposal for reasonable standards necessary for system operators to call on demand response resources, and mechanisms to measure, verify, and ensure compliance with any such standards by April 17, 2009. The Order requires an assessment and filing on the feasibility and value of smaller demand side resources providing ancillary services by October 17, 2009.

over the next year will maximize the financial incentives and results from implementation of Act 129.

C. Overview of PJM Economic Demand Response Program

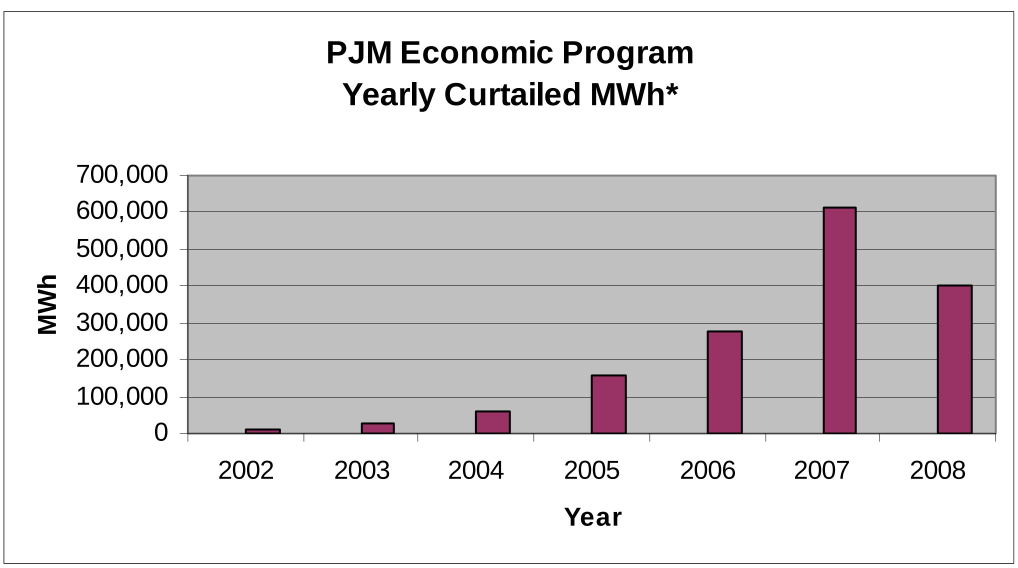
PJM's economic demand response program provides for registration of demand side resources by the Curtailment Service Provider (CSP), and acceptance of this registration by the Load Serving Entity (LSE). Within Pennsylvania, the LSE is typically also the EDC. CSPs track weather, PJM load forecasts, and PJM day-ahead and real-time market prices, and either directly control or advise demand side resources to curtail in specific hours. The CSP sets a price at which the demand side resource will sell megawatt-hours of curtailed electricity into PJM's wholesale market and communicates this price to PJM. This is referred to as a "bid." The price of this bid is typically based on the cost hurdle which the demand side resource must clear in order for its performance to be economic. If PJM accepts the bid, the demand side resource "clears" the market and is expected to perform during the hours for which its bid was accepted by PJM. PJM purchases supply from market participants at the marginal price, which is the lowest price at which PJM can fulfill one hundred percent of its supply needs for the given hour. All resources that clear the market receive that marginal price so this activity can be very profitable for low cost demand side resources. Because resources are paid based upon market prices, and market prices increase during times of peak demand, curtailments by demand side resources tend to occur in the highest price hours which generally speaking are also the highest hours of peak demand. Payments in the PJM economic program are made by PJM to the CSP based upon the measured and verified performance of the demand side resources that have curtailed, i.e. delivery of megawatt hours after each curtailment event. Measurement and verification (M&V) is based upon meter data for each account registered into the PJM program that participates in a curtailment event. The meter data used for M&V typically comes from the EDC's meter or a customer meter that has been tested for accuracy against the EDC's meter. PJM is revenue neutral and merely performs a settlement function by passing performance payments from the LSE/EDC to the CSP, which in turn provides a payment to retail electric customers that own the demand side resources within its portfolio.

PJM does not insert itself or attempt to regulate the process by which the CSP obtains its supply of megawatt hours to be delivered to PJM. Supply transactions are arranged through privately negotiated bilateral contracts between CSPs and retail electric customers.

During the period 2005 – 2007, participation in PJM's economic program grew at a rapid pace as shown in the chart on the next page. Much of this success can be attributed to an "incentive payment" that was an additional payment by the LSE during periods of high prices. Whenever PJM's market price exceeded $75 per megawatt hour, demand side resources were paid the full market price for their participation in the PJM economic program. During hours when the PJM price was below $75 per megawatt-hour, payments in the economic program were based upon the difference between the PJM market price and the account's retail rate for generation and transmission. By providing the incentive in high priced hours, PJM's program stimulated demand side performance in peak hours. Because PJM's market prices are transparent, participating CSPs receive a clear, market price signal and can calculate the cost-benefits associated with the individual demand side resources within their portfolio to determine which ones should participate and when. By sending a market price signal to the demand side resource, the retail customer can consider the cost associated with its individual performance, enabling lower cost resources to perform at lower market prices than higher cost resources. This price transparency helps to bring additional low cost supply from demand side resources into the market, and mitigate wholesale electric prices in PJM's day-ahead and real-time markets.

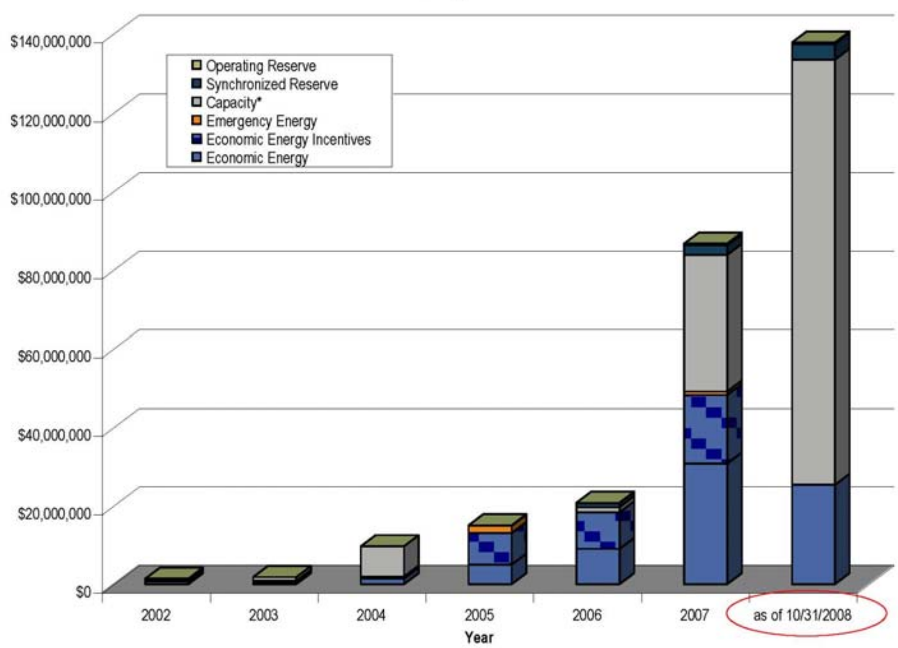
The PJM program is competitively neutral in that any demand side resource that performs within a given hour is paid based upon the same formula, smaller resources are paid the same per unit price as large resources (i.e., there is no such thing as a premium related to the size of the performing resource or conservation service provider); PJM's credit requirements are directly tied to a CSP's market activity and exposure across PJM's markets; and any CSP who brings them resources that perform can participate and receive payments.

The following chart shows the growth of PJM's economic program from its inception through October 31, 2008.



*2008 figures are for ten months. Demand side resources in the six Pennsylvania EDC service territories represent approximately 55% of the total megawatt hours curtailed in 2008. Megawatt-hour reductions within the six Pennsylvania EDC service territories in PJM's economic demand response program declined from 317,679 for the ten months ended October 31, 2007 to 218,623 for the ten months ended October 31, 2008, or 31% on a year-over-year basis. As shown on the chart below, this decline in participation in PJM's economic program is largely attributable to the loss of the incentive payment in 2008.

PJM Demand Side Response Estimated Revenue



*Capacity revenue prior RPM implementation on 6/1/07 estimated based on average daily ALM capacity credits and weighted average daily PJM capacity market clearing price.

D. Proposed Open Market Program Design & Guidelines

We propose the EDC demand response and energy efficiency programs follow the same rules as the RTO/ISO they participate in,[4] and simply provide an additional incentive payment for each resource that performs in the RTO/ISO program. Demand response resources would be paid during summer peak hours. The amount of this incentive can be at the discretion of the EDC so long as all participating resources are paid the same per unit incentive. The program can be administered with minimal additional cost by using the existing RTO/ISO program infrastructure. The EDC will simply make an additional payment to the Curtailment Service Provider just as they did in 2005 – 2007. This approach is easy, the EDC's have done it before, and it has been demonstrated to work in Pennsylvania.

The design of an open market program would have the following guidelines:

- EDC's would administer the program, but EDCs and their affiliates would not act as CSPs;
- allow for as broad participation as possible by prohibiting unnecessary barriers to market participation;[5]
- provide financial incentives that are transparent to send a market price signal to program participants so that the lowest cost resources perform;

[4] The EDC/LSE already approves the PJM registration for each account. An approval for purposes of the PJM program would automatically approve the registration in the EDC program. The same meter data used for measurement and verification under the PJM program would be used for measurement and verification under the EDC program. Settlement payments would be processed under the EDC program at the same time as settlement payments under the PJM program.

[5] Such barriers would include requirements for large transaction sizes, or minimum capital, credit or insurance requirements that are unrelated to risk exposures to ratepayers. These items can be found in utility programs in other jurisdictions and largely exist to mitigate risk to utility shareholders from penalties for failing to make their conservation goals under jurisdictional resource standards. These kinds of requirements simply add costs of capital into the CSP's cost of service while doing nothing to ensure performance comes from the lowest cost demand side resources.

- pay based on measured and verified performance of the demand side resources (i.e. megawatt-hours delivered);
- pay for the commodity on a per unit basis, i.e., per megawatt hours reduced in total as well as payments for megawatts reduced in the top 100 peak hours;
- allow for participation by small resources or conservation service providers;[6] and
- mirror the PJM/MISO business rules for program participation unless the Commission makes an exception.[7]

When EDC programs are coupled with RTO/ISO programs using business rules that are common to both programs, the amount of financial incentives available to pay demand side resources increases significantly. This is very important in convincing the retail consumer to participate, as the consumer sees demand response as a new concept and looks at the financial benefits of participation across all programs. For purposes of discussion, we estimated what the annual payments would be for a 1 megawatt demand side resource in the PJM programs for each EDC service territory that would be available to leverage the Commonwealth's Act 129 program investment under our proposed program design.

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[6] PJM's program sets the minimum size for participation at 100 kw or 1/10th of one megawatt within an EDC service territory.

[7] We believe the effect of "mirroring" the applicable RTO/ISO business rules for program participation has two benefits. First, it reduces the incremental cost associated with administering the EDC program. Second, it increases the Commission's influence in RTO/ISO stakeholder proceedings as any change in business rules in those programs will automatically affect the success or failure of the EDC's Act 129 program. RTO/ISO stakeholder decisions that reduce the likelihood of participation by demand side resources could therefore subject the EDC to penalties under Act 129. This would help to motivate EDC's with affiliated generation to promote consumer interests in RTO/ISO stakeholder proceedings involving demand response programs. The Commission could retain the right to modify EDC program rules.

E. <u>Financial Incentives Leveraged by the Proposed Open Market Program</u>

The proposed open market program design leverages financial incentives provided through existing RTO/ISO programs. The table on the next page shows the estimated payments associated with PJM's demand response programs.

Since each resource is permitted to have multiple registrations, a resource in the PECO service territory could, for instance, participate in the emergency, economic and synchronized reserve programs all in the same year. While it could not be dispatched and paid for all three programs in the same hour, it could be available as a stand-by resource to provide both emergency and synchronized reserves, allowing it to get paid for every hour, in addition to the hours it selected to participate in the economic program. Using our estimates, the performance payment for a one megawatt resource in the PECO service territory would be paid approximately $158,658 for the delivery year June 1, 2009 – May 31, 2010.

Estimated Payments Associated with PJM's Demand Response Programs per 1 MW of Reduction in Electric Consumption (All shown on an annual basis except Energy Efficiency)

EDC Service Territory/ PJM Load Zone	Emergency Program[8]	Economic Program[9]	Synchronized Reserves[10]	Regulation Reserves[11]	Day-Ahead Scheduling Reserve[12]	Energy Efficiency[13]
Duquesne Light	DY 2009-2010: $37,245 DY 2010-2011: $63,616 DY 2011-2012: Not applicable	$6,332	De minimus	$47,306	$1,236	Not applicable
Met-Ed	DY 2009-2010: $68,821 DY 2010-2011: $63,616 DY 2011-2012: $40,165	$13,168	De minimus	$47,306	$1,236	DY 2012-2013 plus 3 years $160,658
PECO	DY 2009-2010: $68,821 DY 2010-2011 $63,616 DY 2011-2012 $40,165	$13,450	$76,387	$47,306	$1,236	DY 2012-2013 plus 3 years $160,658
Penelec	DY 2009-2010: $68,821 DY 2010-2011 $63,616 DY 2011-2012 $40,165	$9,445	De minimus	$47,306	$1,236	DY 2012-2013 plus 3 years $160,658
PPL	DY 2009-2010: $68,821 DY 2010-2011 $63,616 DY 2011-2012 $40,165	$12,542	De minimus	$47,306	$1,236	DY 2012-2013 plus 3 years $160,658
West Penn	DY 2009-2010: $68,821 DY 2010-2011 $63,616 DY 2011-2012 $40,165	$10,227	De minimus	$47,306	$1,236	DY 2012-2013 plus 3 years $160,658

[8] Demand side resources registering in the emergency program agree to be a standby resource in the event of a system emergency, and are available to be called upon for mandatory curtailment one to two hours ahead of the operating hour. Estimated payments are based on capacity payments in the Interruptible Load Resource program.

[9] Demand side resources registering in the economic program voluntarily sell energy into either the day-ahead or real-time market. Estimated payments based on participation in the day-ahead market in the top 1 percent of hours (88 hours) of peak prices over the period July 1, 2007 – June 30, 2008, and assume retail generation and transmission rates of $.075 per kilowatt-hour.

[10] Resources in the synchronized reserves program commit to respond to a system contingency within 10 minutes. Estimates based on average synchronized reserve payments January - October, 2008.

[11] Resources in the regulation reserve program respond to signals as needed to keep the system at 60 Hz. Estimate based on clearing in regulation when the price exceeds $100/MW (~ 305 hours).

[12] Resources in the day-ahead scheduling reserve program commit to be available to respond within 30 minutes of a signal to respond in real-time. Estimate based on clearing prices June 1 – August 31, 2008.

[13] Estimate assumes acceptance of the PJM staff proposal which proposes to pay energy efficiency projects for four years and uses the 2011-2012 Base Residual Auction Resource Clearing Price.

F. Consistency with State & Federal Policy Regarding Competitive Markets

The proposed design is consistent with state policy regarding competitive markets in Title 66, §2802. It addresses the concerns raised by Duquesne Light, Penn Power and the Retail Energy Supply Association in the En Banc hearing since retail customers served by competitive suppliers are treated the same as customers who take default service from the EDC.

The proposed design is consistent with federal policy which promotes demand side participation as a competitive supply resource in wholesale markets. It coordinates the development of EDC programs for demand side resources to provide ancillary services, and provides for transparency in pricing to provide market price signals to demand side resources.

Finally, it leverages the financial resources from existing and future RTO/ISO programs. By combining financial incentives from state and RTO/ISO programs, it maximizes the incentive for retail electric consumers to participate in the combined programs, including participation as resources in PJM's capacity market.

PJM's market design for capacity under its reliability pricing model suffers from a key flaw that biases market outcomes against the electric consumer, i.e. structural market power in the capacity market. According to PJM's market monitor, "the capacity market is unlikely to ever approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership." [14] By combining financial incentives for demand side resources in state and RTO/ISO programs, and allowing competition in EDC programs from a broad number of

[14] Analysis of the 2008/2009 Third Incremental RPM Auction, PJM Market Monitoring Unit, July 3, 2008. Page 2.

independent CSPs, the Commission puts in place a state program that not only brings greater amounts of demand side resources into PJM's capacity market, but also diversifies the entities that control those resources. Conversely, if the Commission allows EDCs to limit participation to a small number of large CSPs, it will consolidate the CSP market. This market segment would also be subject to greater control, by virtue of contractual arrangements, by the EDC and their holding companies. Rather than diversifying control over resources in the PJM capacity market, the Commission would put demand side resources under the same control (through the EDC's holding company) as many of the power generation resources in PJM's capacity market.[15] We believe the Commission should grab this opportunity to diversify control and put PJM on the path to reducing structural market power in its capacity market.

[15] We respectfully remind the Commission that the Commission itself noted this problem in its April 21, 2007 comments to FERC regarding the Notice of Proposed Rulemaking on Wholesale Competition in Regions with Organized Electric Markets, Docket Nos. RM07-19-000 and AD07-000, p. 14 where it states *"In the PaPUC's experience, most if not all of the stakeholder opposition and delay in demand response integration is due to the opposition, overt or covert, of generation owners or vertically integrated electric utility monopolies that have a vested interest in keeping demand response in limited "pilot project" status for as long as possible."*

ENERGY EFFICIENCY AS A CAPACITY RESOURCE

PJM has recently published a draft of proposed tariff language relating to energy efficiency projects receiving capacity payments. PJM has to file the tariff with FERC by mid December.

Here are the basics:

- Projects are eligible to bid into PJM's capacity auction in May 2009 for payments in the June 1, 2012 - May 31, 2013 planning year.
- Eligible projects are those that reduce electric consumption based on the average load reduction for the hours-ending 3 pm to 6 pm (hours 2, 3, 4, and 5) for June 1 - August 31, 2012. Measured hours are weekdays only and exclude holidays.
- The reduction is based on whether the project existed in summer 2007. If someone did an energy efficiency project that went in after September 1, 2007, it would seem to qualify.
- The project must be in excess of what is required in building codes and appliance standards, and must reduce consumption year-round.
- Projects will get payments for 4 years so long as the year for which you apply for credit is not beyond the expected life of the equipment.
- Annual measurement and verification is required along with lots of details about the project. (PJM is to develop M&V requirements by January 1, 2009.)
- In order for the project to participate in the next auction which is scheduled in May 2009, project sponsors must submit details to PJM not later than March 15th.
- Project sponsors can bid in projects that are planned or not completed, as well as pre-existing projects, but they must post credit for the ones that are not yet completed.

<u>Comments on Attachment B – Draft Implementation Order</u>

Our comments on the staff's Draft Order focus on the Commission's criteria for reviewing and approving the CSP bidding process outlined in Section G on pp 18 - 20.

1. <u>Requirement to acquire bids from "disadvantaged businesses"</u>

We appreciate the Commission's encouragement that EDCs acquire bids from "disadvantaged businesses." We urge the Commission to strengthen this provision to specifically require bids from disadvantaged businesses for all RFPs issued and provide a justification to the Commission if no contracts are awarded to disadvantaged businesses. We are concerned that EDC requirements may otherwise automatically exclude the majority of disadvantaged businesses. A disadvantaged business tends to be "disadvantaged" because of a lack of capital when compared to publicly traded entities or privately funded entities that have been in business for long periods of time. Comments from the Electric Association of Pennsylvania regarding the Registry of Conservation Service Providers suggest its member companies which include the seven EDCs that must develop EE&C plans, have a preference for dealing with larger, well established companies as they reference the need for annual reports, extensive bonding and insurance requirements, past experience, etc.

2. <u>Pay for performance contracts</u>

We urge the Commission to set forth a clear definition of what it means by "pay-for-performance" contracts with CSPs. In a number of jurisdictions, such as California, it is common for utilities to award contracts to curtailment service providers for demand response. These contracts set a fixed payment for a guaranteed number of megawatts for the CSP to deliver to the utility. The utilities prefer to deal with CSPs that will guarantee a large number of megawatts which may range from 50 MW to 200 MW. The guarantees require strong capitalization or collateralization that is beyond what many smaller CSPs can provide. The CSPs responding to utility RFPs commit to the sale of the MW prior to actually having supply arrangements in place with retail customers. This practice is not only imprudent as it requires the CSP to take on unnecessary risk in the form of an unhedged short position in the commodity, but it also adds an unnecessary cost of capital into the transaction, results in contracts that act as a barrier to other CSPs in the market, and greatly diminishes the likelihood that the lowest cost demand side resources will be utilized. The contracts often keep the price terms confidential so that there is no transparency in market prices or signal to demand side resources for performance.

A short example illustrates what can happen. For sake of discussion, assume there are two CSPs in the market. One CSP which we'll call CSP A is a small CSP and has very low cost resources in its portfolio. Another CSP, CSP B is a large CSP with higher cost resources in its portfolio. CSP B is a publicly traded and well funded CSP, able to post collateral behind its guarantee to bring megawatts to the utility. The utility will pick CSP B over CSP A even though CSP A has lower cost resources in its portfolio. In return, CSP B will have a financial incentive available to pay retail customers for the supply of megawatts. When CSP A's contract expires with its retail customer, CSP B will be able to provide a greater financial incentive to the retail customer by virtue of the fact that CSP A has been deemed "unqualified" to contract with the utility. CSP A will eventually be forced out of the market under this construct.

This type of performance requirement frustrates the intent of a demand response program which is meant to send market pricing signals to demand side resources to ensure that the most cost effective resources perform.

This type of “pay for performance” guarantee does not mitigate risk to utility ratepayers. By adding in a capital cost, it actually makes the program less cost effective. The “pay for performance” guarantee in this example is to mitigate risk to utility *shareholders* from penalties for failing to meet jurisdictional resource standards.

We encourage the Commission to define “pay for performance” in contracts to mean conditioning payments on the performance of the demand side resources in the CSP’s portfolio to actually deliver the megawatts or megawatt-hours to the EDC. This definition of “pay for performance” would not require a contractual guarantee, upfront collateralization, or commitment by CSPs to deliver a minimum amount of megawatts or megawatt-hours into the EDC contract.

We thank the Commission for their time and attention to these issues and respectfully request the Commission to consider our comments.

Respectfully submitted,

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