Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company (collectively the "Companies") appreciate the opportunity to provide comments to this DSR Working Group Report draft outline. The Companies support the use of cost effective conservation measures, energy efficiency activities and demand side response programs particularly upon the expiration of generation rate caps. The timing of rate cap expiration as well as differences in service territories may dictate the need for individual plans. However, based upon experience gleaned from extensive programs implemented at Jersey Central Power & Light ("JCP&L") in its New Jersey service territory, the Companies support the use of a third party to implement, administer and track the results of any statewide programs approved by this Commission.

With respect to the appropriate cost recovery mechanism for electric utilities, the Companies believe it is premature to move forward with a "full-blown" revenue decoupling mechanism for several reasons. First, generation rate caps remain in place for most of the large EDCs and we believe that demand response initiatives and conservation are implemented by consumers as a way to deal with rising costs of generation service. Most would agree that generation rates are capped at rates below current market prices; this situation creates a disincentive for consumers to invest in DSR and conservation. Therefore, it is our belief that, during the remainder of the rate cap period, rapid growth in DSR and conservation by consumers will likely be limited to those specific programs approved by the Commission. Second, the current situation for electric utilities is obviously different than the experience of gas utilities. Gas utilities have seen a continued decline in growth due to rapid increase in prices of natural gas, and rapid growth in conservation by consumers; therefore, a comprehensive revenue decoupling mechanism may be a necessary incentive for gas utilities to promote energy conservation. Finally, the complexities and uncertainties associated with implementing a new ratemaking mechanism would likely outweigh the minimal likely impacts of demand response initiatives when customers are shielded from market rates. The potential regulatory benefits do not match the risks.

In light of the above, the Companies are proposing a rate decoupling plan through implementation of a rate decoupling and demand side response rider to recoup specific lost revenue on a rate schedule basis that is limited in scope to specific Commission approved energy conservation and DSM programs. Attachment A sets forth the Companies' proposal for such a tariff rider. Essentially, this proposed decoupling approach would be a scaled down version of revenue decoupling. The tariff rider would estimate direct, indirect and administrative costs to be incurred by the Company to provide DSR programs to customers. The tariff rider would also reflect the projected measure of lost distribution and CTC revenues by the Company due to reduced kilowatt sales resulting from energy savings from Commission approved programs for DSR, energy efficiency, and conservation programs administered by the Company or approved third parties on behalf of the Companies. Measurement of the energy and demand savings for each program would be based upon standards identified in the Commission's current Technical Reference Manual adjusted for the number of program participants, as appropriate, multiplied by the average distribution and CTC revenue per kWh determined by rate schedule excluding Pennsylvania gross receipts tax reflected in existing base rates. Measurement and reconciliation of the lost distribution revenues associated with each program would continue annually until addressed by a Commission order in the Company's next base rate case proceeding.

Additional comments are made throughout the draft outline. These comments are highlighted in yellow for ease of reading.

Pennsylvania Public Utility Commission

Investigation of Conservation, Energy Efficiency Activities, and Demand Side Response by Energy Utilities and Ratemaking Mechanisms to Promote Such Efforts; Docket M-00061984

DSR Working Group Report Draft Outline

## I. History and Scope of Investigation

## II. Summary of Information Collected

A. Existing Programs and Level of AMI Deployment – Tables available on PA PUC web site.

B. White Papers on Metering, Energy Efficiency, Conservation, and Demand Side Response – Available on PA PUC web site.

C. January 19, 2007 Presentations – Available on PA PUC web site.

D. December 8, 2006 Revenue Decoupling Presentations

E. Other Reports

1. Quantifying Demand Response Benefits – Brattle Group 2007 Report to PJM and MADRI.
2. ACEEE April 2004 Report
3. NYSERDA's Annual Energy $mart Reports
4. FERC's August 2006 Report on DSR; Docket AD06-02
5. PA DSR WG 2004 reports
6. Others

## III. Findings

A. A wide array of studies and sources seem to confirm that energy efficiency, demand side response, and conservation programs and technologies can be cost-effective means of controlling the cost of electricity and natural gas.

The Companies believe the term cost-effective needs to be defined. The Companies are inclined to believe that benefits would flow to all customers; therefore, programs costs should be recovered from all ratepayers. A program will pass the Cost Effective Test (CET) if the benefits of the program exceed the costs of the program. Program benefits and associated costs will typically be determined over a time period tied to 75% of the expected service life of the installed equipment.

The CET will be calculated on a present value basis (using the Companies' weighted cost of capital) by comparing the annual program benefits to the sum of the equipment, installation and operating costs.

The calculation of program benefits will include:
1. Reduced energy costs based on projected market prices as determined by the on-peak RTO forwards market as determined by a Commission approved forecast source
2. Reduced capacity requirements based on the average on-peak RTO capacity price for summer months applied to reduced demand levels
3. Reduced ancillary charges from the RTO (the MW value will be calculated as the load reduction that occurred if customers were cycled during the time at which the Company's control area monthly peak was measured
4. The impact of emission benefits

B. Individual customers can directly benefit through participation in DSR or conservation programs and utilization of energy efficiency technologies.

C. Reduction in peak demand and strategic conservation can favorably impact wholesale energy prices, to the benefit of all retail customers. This is consistent with the Commission's objective of mitigating the effect of future price increases.

Strategic conservation should be defined as conservation initiatives that pass the CET.

D. General education about demand side response, energy efficiency and conservation will be important to heightening awareness about the existence of these programs and building acceptance for programs and technologies as they are offered. Consumer education should involve a variety of tactics, from advertising, media relations and grassroots outreach. Efforts should be measurable with annual surveys of results. Stakeholders should have regular involvement and opportunities for input. Education strategies used should be based on effective programs employed in other states when applicable. *(See comments, dated March 5, 2007, of the Companies regarding Policies to Mitigate Potential Price Increase at Docket No. M-00061957)*

The Companies believe that the findings set forth above, when limited to cost effective DSR and conservation programs and coupled with the appropriate cost recovery mechanism, should serve as the basis for a Commission policy statement in order to provide flexibility to all stakeholders. The Companies judge that developing cost effective conservation, energy efficiency and DSR programs are complex issues and while programs or technology requirements may seem appropriate in the near term, there is always a concern that the investment of time and money in new programs could be stranded shortly after implementation due to changes in the energy markets or advances in technology. Therefore, a policy statement seems to be appropriate since it can be changed more readily to provide flexibility to the Commission and all stakeholders.

Additionally, a fundamental finding related to market drivers supporting customer motivation to engage in conservation or demand management is missing. Customers shielded from market prices are minimally motivated to react to price they are not exposed to. In the absence of market-based prices, the viability of new demand response rates (e.g. RTP) that would need to compete with low flat rates is small, and costs for programs that would motivate customers to engage or participate would be high.

The findings should recognize that programs should be EDC specific. For example, some companies may have less air conditioning saturation or less concentrated loads making summer peak load management more expensive and less viable. Timing of programs will be different for different EDC's due to the timing of rate caps, approval of cost recovery riders and program plans necessary to enable programs, experience with pilot programs, existing infrastructure and other factors.

## IV. Legal Authority

A. The Commission may order gas and electric utilities to implement load management and conservation programs that it determines to be prudent and cost-effective. 66 Pa.C.S. § 1505(b). This provision is the statutory authority for the LIURP programs.

B. Commission must separately ensure that "universal service and energy conservation" programs are available in each territory. 66 Pa.C.S. §§ 2804(4), 2203(8).

C. The information gathered represents a sufficient foundation for the Commission to direct EDCs and NGDCs to file a DSR, Energy Efficiency and Conservation plan with the Commission for its approval consistent with these statutory provisions.

*The Commission, in ordering programs, should also approve a reasonable mechanism for timely recovery of costs as forth in 66 Pa. C.S.A. 2203(8) and (9).*

## V. Objectives

A. Nature of Objectives. The Commission initiated a price mitigation proceeding in 2006 at Docket M-00061957. Consistent with that, the focus should be on developing policies with quantifiable economic benefits for ratepayers. The Commission has previously identified non-quantifiable benefits in reports prepared by DSR WG in 2004. It may be assumed that some of those non-quantifiable benefits will also accrue with implementation of these programs.

The Companies believe the Commission should use the technical manual *(Final Order and Technical Manual - Docket No. M-00051865 from the public meeting of September 29, 2005)* supported by participants in the Commission's Alternative Energy Portfolio Standards proceeding. The Tier II requirements of Act 213 includes demand side management, energy efficiency and load management programs and technologies among the resources eligible for participation in Pennsylvania's alternative energy market. The standards set forth in the technical manual govern the tracking and verification of DSM/EE measures.

The wide range of energy prices experienced over time makes it difficult to determine whether programs are cost effective.

B. Many existing programs have as their objective a reduction in peak demand and/or overall energy conservation. This is quantified as a % reduction of overall or peak demand by a certain time period. Examples

1. Connecticut's energy independence law established a goal of a 10% reduction in peak demand by 2010. *Public Act 05-01, An Act Concerning Energy Independence*. According to January 19 presentation by Enernoc, Connecticut has developed DSR capacity equal to about 6% of peak load at this time.

2. Austin Energy: According to February 9, 2007 presentation, they intend to satisfy 15% of expected 2020 demand with DSM resources.

3. California: 5% of system peak demand MWs enrolled in DSR economic programs by end of 2007.

The Companies recommend that if the Commission adopts a specified percent reduction of overall or peak demand by a certain time period as an objective, the specific amount be reflective of reasonable results from cost effective programs.

C. Objectives.

1. Develop policies that allow individual customers to take advantage of cost effective DSR, energy efficiency, and conservation measures. For reasons of equity, there should be programs available to residential, small business and large commercial and industrial customers.

The Companies as well as most participants in the DSR Working Group believe that customer participation must be voluntary.

2. Materially impact wholesale energy prices through cost effective DSR, conservation, and efficiency measures.

3. Educate consumers so that they can take advantage of these opportunities.

*(See comments of the Companies regarding Policies to Mitigate Potential Price Increases at Docket No. M-00061957 dated March 5, 2007)*

4. Objectives should be quantified in terms of DSR capacity reduction of peak load and overall conservation:

a. Develop DSR capacity of ___ % of peak load by 2____.
b. Strategic conservation of ___ % of kWh and mcf by 2____.

These targets should be measured against PJM's forecasted load for a given period as well as the Commission's annual Electric Power Outlook Report and other sources.

The Commission must recognize that it takes time to develop and implement new programs. Ultimately, it will take several years before benefits are realized. The Companies believe there should be different objectives for gas and electric utilities. If specific targets are set for percentage of peak load and percentage of kWh and mcf, the specific targets need to be developed based on the potential outcomes of specific cost-effective programs.

D. AMI deployment. To develop a robust DSR capacity, additional metering will be required in some service territories. However, we note that many large commercial and industrial customers already have time-of-use meters, even in territories where system wide deployments have not occurred. Approximately 78,000 residential customers in Penelec and Met-Ed's territory are served under TOU rates even though there has not been a system wide AMI deployment.

It should be noted that the programs in Met-Ed and Penelec are time-of-day programs or simple on- and off-peak pricing programs. Time-of-use programs generally have multiple tiers of pricing (e.g., low-, mid-, high- and peak prices).

DSR programs can move forward without full AMI deployment. For example, EDCs can implement time of day rates or seasonal rates without full AMI deployment. While there may be an additional cost for the meters to implement time of day rates, the Companies are certain the cost would be less than the cost of wide-ranging AMI deployment. The Companies' objective is to spend capital dollars on increased reliability rather than AMI deployment. Based upon cost estimates for full AMI deployment, the Companies would need full and immediate cost recovery to move forward with such a capital investment.

1. This presents the question of whether AMI should be deployed system wide for all customers, or just certain customer classes.

Met-Ed, Penelec and Penn Power support the use of appropriate technologies for DSR by rate class rather than wholesale AMI deployment.

2. Is it viable for PA EDCs that have not deployed AMI system-wide to enable medium and small customers who wish to be on TOU rates to be offered such a rate along with the meter to support that rate without deploying AMI technology system-wide? Would this accomplish the objective of enabling medium and small customers of most PA EDCs the opportunity to participate in DSR programs through TOU rates prior to the time when AMI technologies will be available system-wide?

Yes. However, it is important for the Commission to understand that TOU rates and seasonal rates should be developed around generation prices/costs rather than distribution prices/costs. It would be more appropriate to create new generation pricing such as seasonal rates or TOU rates upon the expiration of rate caps. Voluntary participation in market-based TOU rates may not be when default service rates are fixed.

3. If AMI deployment is appropriate, what is a reasonable time frame for this to occur within?

The Companies question whether it would be more appropriate to implement a pilot program to understand costs and benefits prior to a full scale deployment. Would it be more appropriate to implement a pilot program to understand costs and benefits prior to full scale deployment?

## VI. Implementation Issues

A. Coordinated vs. Individual Responses: Should EDCs develop and manage their own portfolios of programs? Alternatively, should programs be coordinated by third party administrator or state agency (e.g. NYSERDA approach)? This is a threshold issue that will impact how programs are designed and implemented.

The Companies support statewide programs run by a third party administrator when possible. A statewide approach has the advantages of consistent messages state support and equity across customer classes. A statewide approach has been supported in other states such as Vermont, New York and New Jersey.

B. Initiating the Implementation Process: Generic Commission Orders? Or are regulations needed?

The Companies support the use of a policy statement as discussed earlier in this document.

C. Timeline: What schedule should be set for the filing and approval of programs, and their effective date.

D. Program plans/lifecycles. Three years, five years, etc. What are the respective advantages and disadvantages of shorter vs. longer plans. Is their an optimal program duration given Pennsylvania's particular situation?

The Companies believe that timelines/plans /lifecycles would need to be examined based on cost/benefit analysis, the known life of a particular technology and the expected payback or benefits to all consumers.

E. Program design.

1. Should program designs be developed solely by EDCs? Alternatively, should they be selected by the Commission or a third party administrator?

   One idea would be for the Commission to issue a RFP and then meet with the EDCs to decide what ultimately would be appropriate within the EDCs service territory. An alternative view would have the EDCs taking the lead on program design in the early stages of program(s) development in order to determine size and scope of the program(s).

2. Do we want to pre-approve a menu of DSR, energy efficiency and conservation programs that has been developed by the Commission or another party? EDCs or the third party administrator can then select from this list?

   This approach seems reasonable to the Companies.

3. Regardless of the process used, potential programs should be ranked according to the best available data as to their effectiveness. Top ranked programs should be given preference when designing plans for each service territory.

This approach sounds reasonable to the Companies.

F. Program Evaluation. Who does it? What benchmarks and tests are used? <u>Evaluation should be independent</u>. Example of standard: California cost-benefit test.

The Companies agree that the guide rails for evaluation should be standardized for all participants. Furthermore, the Companies support the idea that evaluation should be independent, but should not impact cost recovery/decoupled revenue recovery.

**VII. Funding and Cost-Recovery**

A. Section 1319 of the Public Utility Code, 66 Pa.C.S. § 1319, identifies a cost-recovery standard for programs implemented pursuant to Section 1505(b). Utility may recover all prudent and reasonable costs associated with managing, developing, operating and financing program.

If the Commission does not accept the rate decoupling DSR tariff rider as proposed by the Companies, a societal benefits charge would be another alternative for cost recovery of all program costs including lost revenues.

B. Revenue decoupling mechanisms do not appear to be expressly contrary to the provisions of the Public Utility Code. An appropriately designed revenue decoupling proposal may be in the public interest, if approved by the Commission as part of a package of DSR, energy efficiency, and conservation measures (see separate reports prepared by decoupling subgroup).

As discussed earlier, see attached rate decoupling DSR rider for cost recovery.

C. Energy Efficiency and DSR are Tier II alternative energy resources under the AEPS Act.

As discussed earlier, all stakeholders should use the technical manual approved for Act 213 DSR and energy efficiency. Title to any alternative energy credits should accrue to program sponsors.

AEPS costs can be recovered through a Section 1307 mechanism on a full and current basis. Should Section 1307 play a role in cost-recovery?

The Companies support use of a the tariff rider for cost recovery (see earlier comments).

D. EDC vs. Third party administration will drive funding issues. If a third party administrator is used, who hires them? EDCs or the Commission? The EDCs believe it would be appropriate to issue a RFP for a third party administrator and then review the list of candidates with the Commission prior to making a selection. Does the procurement code apply? Commission would have to approve overall level of budget for programs.

E. A Systems Benefit Charge may be an appropriate mechanism to fund these programs. An SBC is addressed in draft legislation that has been circulated. Advantages and disadvantages.

A non-bypassable systems benefit charge is a fair and equitable mechanism for recovering costs from customers that benefit from the funded programs. The basic rationale for an SBC is that other means of funding public benefit programs are not viable under deregulation. The attached rate decoupling DSR rider supports equity. If a statewide initiative is supported, a consistent SBC across utilities (gas and electric) would be appropriate, and mechanisms should be in place to support equity and avoid cross-subsidies between utilities.

E. Equity of funding and benefits must be considered. Funds raised from one service territory should be used for projects within that territory.

## VIII. Other recommendations

A. Amend Act 213: Amendments to Act 213 are being considered as part of the Governor's Energy Independence Strategy. As part of this review, give strong consideration to the reclassification of Demand Side Response, Energy Efficiency and Conservation as a Tier I alternative energy source.

The Companies support redefining use of DSR and energy efficiency as a Tier I resource, or as either a Tier I or Tier II resource to maximize flexibility. Note that under current rules, DSR remains non-viable as an alternative energy source credit unless energy savings are somehow associated with the strategy.

There is likely to be a surplus of Tier II alternative energy credits for the foreseeable future. Credit prices are very low compared to Tier I. DSR and energy efficiency are unlikely to benefit much from current credit values.

B. Default Service: Allow DSR/EE to bid as part of the default service provider's portfolio. Demand side resources are mentioned in the default service policy statement.

This idea seems to be a viable option that the Companies would support but it would definitely need further exploration prior to moving forward with such an initiative.

C. Require EDCs to render full cooperation to customers who wish to participate in RTO DSR programs, such as PJM's economic program.

D. Require EDCs to render full cooperation to curtailment service providers in accessing retail customer information.

RIDER _______
RATE DECOUPLING AND DEMAND SIDE RESPONSE RIDER

A Demand Side Response Charge ("DSRC") shall be applied to each kilowatt-hour delivered during a billing month to all Customers served under this Tariff, determined to the nearest one-thousandth of a cent per kilowatt-hour. The DSRC shall be calculated separately for each Rate Schedule under this Tariff. The DSRC by Rate Schedule shall be non-bypassable for all Delivery Service Customers and Full Service Customers.

The DSRC shall be calculated in accordance with the formula set forth below:

$$DSRC = [(DSR_{RSC}/DSR_{RSSales}) – (E/DSR_{RSSales})] \text{ X } [1/(1-T)]$$

Where:

DSRC = The charge in mills per kilowatt-hour to be applied to each kilowatt-hour delivered to retail Customers served under this Tariff.

$DSR_{RSC}$ = DSR + RDA

DSR = Demand Side Response Program Costs for the Specific Rate Schedule, which are the estimated direct, indirect and administrative costs to be incurred by the Company to provide Demand Side Response Programs to Customers for the DSRC Computational Year. Such costs may consist of, but not be limited to, rebates; grants; payments to third parties for program implementation; direct marketing costs; hardware; and software costs; administration; measurement and evaluation of programs; customer education; market research; costs associated with developing, implementing, and obtaining regulatory approval; and costs of research and development activities.

RDA = The Revenue Decoupling Adjustment reflecting the projected measure of lost distribution revenues by the Company due to reduced kilowatt sales resulting from energy savings from PaPUC-approved programs for demand-side management, energy efficiency, and load management programs administered by the Company or approved third parties on behalf of the Company. Measurement of the energy and demand savings for each program will be calculated on an individual program basis based upon standards identified in the PaPUC's current Technical Reference Manual, as appropriate, using the number of participants for each program multiplied by the average distribution energy and demand rates by Rate Schedule excluding Pennsylvania gross receipts tax reflected in existing base rates. Measurement of the lost distribution revenues associated with

Rider _______ (continued)

each program will continue until addressed by a PaPUC order in the Company's next base rate case proceeding.

$DSR_{RSSales}$ = The Company's projected DSR kilowatt-hour sales to Full Service Customers and Delivery Service Customers for the specific Rate Schedule for the twelve-month billing period that the DSRC will be in effect.

E = The over or under-collection of Demand Side Response Program costs and Revenue Decoupling Adjustment by specific Rate Schedule that result from the billing of the DSRC during the DSRC Reconciliation Year (an over-collection is denoted by a positive E and an under-collection by a negative E), including applicable interest. Interest shall be computed monthly as provided for in 41 P.S. § 202, the legal statutory interest rate, from the month the over or under-collection occurs to the month that the over-collection is refunded to or the under-collection is recovered from Customers.

T = The Pennsylvania gross receipts rate in effect during the billing month expressed in decimal form as reflected in the Company's base rates.

All capitalized terms not otherwise defined in this Rider shall have the definitions specified in Section 2 of this Tariff. For purposes of this Rider, the following additional definitions shall apply:

1. DSRC Computational Year - the 12 month period from January 1 through December 31 of each calendar year.

2. DSRC Reconciliation Year - the period from November 1 through October 31 immediately preceding the USC Computational Year.

The DSRC shall be filed with the Commission by December 1 of each year. The DSRC shall become effective the following January 1, unless otherwise ordered by the Commission, and shall remain in effect for a period of one year, unless revised on an interim basis subject to the approval of the Commission. The Company will review the DSRC quarterly and upon determination that the DSRC rates, if left unchanged, would result in material over or under-collection of all Universal Service Program Costs incurred or expected to be incurred during the current 12-month period ending December 31 for a specific Rate Schedule, may request the Commission for interim revisions to the DSRC to become effective thirty (30) days from the date of filing, unless otherwise ordered by the Commission.

The Company shall file a report of collections under the DSRC within forty-five (45) days following the conclusion of each Computational Year quarter.

The DSRC shall be subject to review and audit by the Commission.