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## **TO THE INVESTMENT COMMUNITY:<sup>1</sup>**

As detailed in today's attached news release, Metropolitan Edison Company ("Met-Ed") and Pennsylvania Electric Company ("Penelec"), collectively the "Companies", today filed a transition rate plan ("Transition Plan"), including requests for general rate increases, with the Pennsylvania Public Utility Commission ("PUC"). This letter provides additional details about today's filing.

### **Background**

The last retail base rate cases that included combined generation, transmission and distribution service rates were based on a 1992 rate filing for Met-Ed and a 1986 rate filing for Penelec. In 1998, pursuant to the restructuring of the electric utility industry in Pennsylvania through the Electricity Generation Customer Choice and Competition Act ("Competition Act"), the Companies' rates were capped and unbundled to separate the generation rate from the transmission and distribution rates. At that time, the Companies each became an electric distribution company ("EDC") as defined by the Competition Act.

Under the Competition Act, non-regulated electric generation suppliers ("EGSs") are encouraged to furnish generation service to retail customers in Pennsylvania. Generation default service to retail customers not served by an EGS is still available from their EDCs under the provider of last resort ("POLR") provisions of the Competition Act.

The Competition Act required company-specific restructuring plans to be implemented for each electric utility consistent with the Competition Act's provisions. The Companies' plan for transitioning retail customers to market-based generation rates was established in 1998 through a PUC order approving a restructuring settlement ("1998 Plan"). Among other provisions, the 1998 Plan provided for at least 80% of the Companies' POLR customers to move to a competitive default service ("CDS") provider by mid-2003 for their generation service, but that never occurred due to circumstances beyond the Companies' control. As a result, the Companies have borne the costs and risks of providing ongoing generation service for virtually 100% of

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<sup>1</sup> Please see the forward-looking statements at the end of this letter.

their POLR load, instead of the anticipated 20%. This generation service is being provided at an extremely low capped generation rate, which is only about 50% of the current and projected competitive market rates for generation service in the Companies' service territories.

The 1998 Plan extended the Companies' T&D rate cap through year-end 2004 and extended the generation rate cap through year-end 2010, five years beyond the statutory generation rate cap imposed by the Competition Act that expired at year-end 2005. Additionally, the 1998 Plan provided for recovery of transition or stranded costs through a competitive transition charge ("CTC") and provided for the deferral and recovery of stranded costs associated with non-utility generation ("NUG") purchase power supply contracts.

A variety of unanticipated events, changed markets and market conditions, a failed CDS process, significant federally-imposed transmission cost increases, and other cost-related issues have resulted in the Companies' need to file the Transition Plan, which includes requests for general rate increases. The elements of the Transition Plan are discussed in the following sections.

### **Overview of the Transition Plan**

One of the purposes of the Companies' Transition Plan is to restore the intent of the 1998 Plan which has failed to provide for the transition of retail customers to market-based generation rates, a failure which has placed the Companies in a financial situation that is unreasonable and unsustainable. Were it not for a deeply discounted power purchase agreement that the Companies have with FirstEnergy Solutions ("FES"), an affiliated non-regulated company, the Companies would have already faced serious adverse financial consequences from supplying generation service to their retail customers at below-market rates. Additionally, the Transition Plan seeks to recover significant federally-imposed transmission cost increases, fully recover all of the PUC-approved costs related to the NUG contracts, and provide relief for other inflationary cost increases.

The comprehensive Transition Plan is a combination of rates, tariffs and accounting procedures that, taken together, are intended to provide the Companies with a reasonable opportunity to earn a fair return, measured in the aggregate, across all aspects of their utility business: generation supply, retail transmission and distribution service, and the recovery of PUC-approved transition costs.

The Transition Plan has five components:

- 1. Distribution Rates:** A distribution rate change and related accounting procedures that provide a reasonable opportunity for the Companies to earn a fair return on their utility investments.
- 2. Transmission Rates:** A transmission rate change to reflect federally-imposed transmission-related charges imposed upon the Companies by the PJM Interconnection ("PJM") and the expenses associated with managing such costs for serving their POLR loads.
- 3. CTC Rates:** Authorization to accrue a carrying charge on unrecovered NUG stranded cost balances in order to avoid the need for a current increase in Met-

Ed's CTC rate. Absent this authorization, a requested increase in Met-Ed's CTC rate to allow it to fully recover its non-NUG stranded cost balance by the end of 2010, as required under the 1998 Plan.

4. **NUG Cost Recovery Rates:** A change to either NUG accounting or to NUG cost recovery in order to provide full recovery of NUG costs, either through current rates or through a deferral including carrying charges.
5. **Generation Rates:** A gradual four-year (2007–2010) transition of customers' generation rates towards market-based generation rates, as generally contemplated by the 1998 Plan. This move to market-priced energy purchases from market suppliers will progressively reduce the current FES contract supply and subsidy over time.

The Transition Plan balances stakeholder interests and provides for a paced change in customer rates while protecting the financial integrity of the Companies. If approved by the PUC, the total rate the Companies' customers would pay for electricity with the requested increase in 2007 is expected to remain comparable with the average rates other electric utilities across the state are charging their customers today.

The following material provides additional details of the components of the Transition Plan.

### **Transition Plan Components**

1. **Distribution Rate Relief:** Met-Ed is filing for a reduction in its distribution rate while Penelec is filing for a modest increase. Both requests are based on an allowed return on common equity of 12%. The Companies are also proposing to recover certain highly variable distribution costs through rate recovery mechanisms, or tariff "riders", which will permit better tracking of such costs than if they were included in base rates. The tariff riders would use deferred cost accounting along with tracking and "true up" mechanisms so that, ultimately, customers will only pay for the costs actually incurred. The Companies believe that the use of these tariff riders will assure sufficient revenue to meet customer service needs while retaining the ability to earn a fair return.

The three cost recovery tariff riders are: (1) a rider to track and recover the cost of storm restoration, (2) a rider to track and recover universal service costs, including costs to maintain service to economically disadvantaged customers, and (3) a "government mandate" rider to track and provide for cost recovery of programs related to utility service that are required by the government.

2. **Transmission Rate Relief:** Met-Ed's T&D rate has not increased in over fourteen years and Penelec's has not increased in over twenty years. However, costs have continued to increase during the past two decades. Among these costs are substantial increases in transmission charges that the Companies must pay to PJM as the Regional Transmission Organization ("RTO") under tariffs approved by the Federal Energy Regulatory Commission ("FERC"). The following table details the increasing level of RTO costs and the growing shortfall the Companies are experiencing under their current tariff rates.

**Met-Ed and Penelec**  
**RTO Transmission Revenue and Expenses**  
(\$ millions)

|                                     | <u>2001</u> | <u>2002</u> | <u>2003</u> | <u>2004</u> | <u>2005</u> | <u>2006</u> |
|-------------------------------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Transmission Revenues               | \$ 47       | \$ 48       | \$ 47       | \$ 50       | \$ 52       | \$ 52       |
| Transmission Expenses               |             |             |             |             |             |             |
| NITS, Other <sup>1</sup>            | 95          | 99          | 92          | 121         | 133         | 140         |
| Congestion Costs (net) <sup>2</sup> | <u>6</u>    | <u>38</u>   | <u>2</u>    | <u>18</u>   | <u>62</u>   | <u>98</u>   |
| Pretax Shortfall                    | \$ (54)     | \$ (89)     | \$ (47)     | \$ (89)     | \$(143)     | \$ (186)    |

**NOTE:** 1. Includes Network Integration Transmission Service (“NITS”), ancillary services, scheduling and dispatch charges from PJM  
2. Reflects increased costs of energy assessed to PJM market participants based on LMPs due to system redispatch during hours when the PJM transmission system is operating under constrained conditions.

Consistent with the PUC’s recent decision in the PPL Electric Utilities Corporation base rate proceeding, the Companies are requesting the implementation of a transmission service charge (“TSC”) tariff rider.

The Companies are proposing a TSC as a transmission rate tracking mechanism that would function similar to the Energy Cost Rate (“ECR”) utilized prior to restructuring in the electric industry in Pennsylvania. The TSC will allow the Companies to recover their FERC-approved transmission costs billed by PJM and the expenses for managing such costs for serving retail POLR customers. The TSC will reflect the current level of transmission charges and forecasted POLR sales, and will be reconciled annually. The Companies would use deferred cost accounting, similar to the operation of the ECR.

This transmission cost recovery approach meets the standard criteria for an appropriate cost-tracking mechanism – the expense level is easily identifiable and the Companies have little discretionary control over the size or the timing of the expenditures. Similar to the distribution tariff riders, the Companies believe the TSC will assure that they have sufficient revenue to meet customer service needs while retaining the ability to earn a fair return.

In January, 2005, the Companies requested PUC permission to defer all FERC-approved PJM transmission charges that were incremental to the levels reflected in the current tariff rates. Although the request was for deferral commencing January 1, 2005, the Companies are not making any ratemaking claim for the 2005 period in the Transition Plan. However, the Companies are requesting that the actual 2006 incremental expenses be recognized through a ratemaking deferral that would be amortized over ten years.

**3. CTC Relief:** Met-Ed’s CTC rate, which recovers NUG and non-NUG stranded costs, is currently failing to recover all of the non-NUG stranded costs which the PUC has authorized to be fully recovered by year-end 2010, the end of the current transition period.<sup>2</sup> At its current rate

<sup>2</sup> Met-Ed’s deferred NUG stranded costs are to be recovered by 2020 under the 1998 Plan. Penelec’s initial non-NUG stranded costs were fully recovered by the net generating plant divestiture proceeds.

level, the CTC would have to increase sharply just before the end of the transition period unless an alternative recovery plan, as proposed by Met-Ed in the Transition Plan, is implemented.

Under the 1998 Plan, the unamortized non-NUG stranded costs accrue a carrying charge but the unamortized deferred NUG stranded costs do not. The Companies have the right to allocate the CTC revenues towards amortizing either of these unrecovered stranded cost balances and have first allocated the revenues to the deferred NUG stranded cost balance since that balance does not accrue a carrying charge. The Transition Plan requests the PUC to authorize the application of a carrying charge on any unrecovered NUG stranded cost balance in a manner parallel to the current treatment of the non-NUG stranded cost balance. If approved, Met-Ed would allocate the dominant portion of the current CTC revenues to amortizing the non-NUG balance first. This would fully recover those costs by the targeted 2010 date without requiring any current rate increase in the CTC. Of course, the deferred NUG stranded cost balance would be higher, but those costs would still be recovered by the targeted 2020 date as the NUG contracts expire at various dates prior to 2020. The benefit of this preferred approach is that there would be no requirement to increase Met-Ed's CTC rate as a part of this filing. If this approach is not acceptable to the PUC, then the Transition Plan reflects an alternative approach which increases Met-Ed's CTC rate in order to ensure that all of the non-NUG stranded costs are fully recovered by year-end 2010.

**4. NUG Cost Recovery:** The current elevated level of market power prices is preventing the Companies from fully recovering their costs of power obtained from NUGs that have PUC-approved purchase power contracts with the Companies. Under the 1998 Plan, the Companies' recovery of NUG stranded costs is based on valuing NUG energy at hourly locational marginal market prices and associated capacity costs (collectively, "LMP"). The Companies are not proposing to disturb that stranded cost provision of the 1998 Plan. However, with sustained escalation of market prices, the Companies are no longer recovering all of their NUG costs under this approach. The 1998 Plan allows the Companies to defer, as stranded costs for future collection from customers, the excess of the NUG contract cost over the LMP. But since the LMP is currently above the POLR rate, the Companies are not collecting the difference between the LMP and their POLR rate. This result is contrary to federal and state law requiring full cost recovery for the Companies' NUG power purchase costs.

The Transition Plan proposes three approaches for complete NUG power supply cost recovery. The first, and preferred, approach is to create a new regulatory asset based on a deferral of the difference between the generation rate and the LMP for energy supplied by NUGs. Under this deferral alternative, the Companies would recover the amounts deferred from 2007 through 2010, and thereafter as long as the NUG output is used to supply POLR load, including an appropriate carrying charge commencing at such time when the Companies seek and receive approval for a reduction in the CTC charges as a result of the expiration of existing NUG contracts. At such time, the difference between the prior CTC charge and the newly-reduced CTC charge is expected to be available to provide a revenue stream to the Companies to recover the accumulated deferred balance through a separate surcharge mechanism. The second alternative method is to currently recover the presently unrecovered difference between the NUG values based on LMP and the generation rate through a separate reconcilable rider-based charge. The rider would use deferred cost accounting and be reconciled on an annual basis. This alternative would require a current incremental revenue increase since the increased NUG costs

would be recovered currently instead of deferred for future recovery. In the event that the PUC rejects the deferral approach or the reconcilable rider, the Companies are requesting as a third alternative, the establishment of a fixed base rate charge sufficient to recover the 2006 test year shortfall. The first alternative – the deferral approach – is preferable because it would avoid such a current revenue increase.<sup>3</sup>

Failure to recover all of the NUG purchase power contract costs is contrary to the language in each NUG contract, contrary to the related PUC orders requiring full and current recovery of NUG contract costs, and contrary to portions of Public Utility Regulatory Policies Act of 1978 (“PURPA”) and the Pennsylvania Public Utility Code. Any of the three approaches will insure full recovery, although the Companies prefer the first approach which does not require a current increase in customers’ rates.

**5. 2007-2010 Generation Rates:** The 1998 Plan required the Companies to auction their generation plant assets for sale to the highest bidder and to credit customers with all net divestiture proceeds, thereby reducing customers’ obligations to pay for stranded costs.

Prior to the final divestiture arrangements agreed to under the 1998 Plan, the Companies had begun to reserve rights to some of the output from the generation assets they intended to sell. However, the 1998 Plan prohibited any further efforts to secure such rights. As the PUC specifically noted in its Order on the divestiture results, the Companies were prohibited from placing puts, calls or other options in place as a condition of the divestiture process. As a result, the Companies were not permitted to pursue any rights that could have impaired or reduced the generation assets’ fair market value and, thus, reduce the divestiture-driven credits to customers, even though such reservations would have assisted with ongoing POLR service arrangements. The 1998 Plan balanced these considerations by weighing in favor of maximizing post-divestiture credits to customers and relying on the CDS program to satisfy the Companies’ POLR obligations, recognizing that the generation rates were subject to increases, if necessary, in order to conduct a successful CDS program.

The 1998 Plan required the Companies’ POLR service obligations to be addressed through the CDS program, under which POLR service to customers “shall be provided via competitive bid”. Customers were to be assigned to a CDS provider, commencing June 1, 2000. Over a four-year period it was intended that at least 80% of the Companies’ retail customer load was to be assigned to one or more CDS providers. To the extent CDS could not be obtained for customers at the original capped generation rates under the 1998 Plan, the Companies had authorization to apply to the PUC on an expedited basis to raise the generation rate cap level. The Companies agreed to retain only 20% of the POLR load.

The CDS portion of the 1998 Plan was implemented but it failed to achieve its intended results. No bids were ever submitted to provide CDS service to any POLR customer, and the PUC eventually issued an order permitting the Companies to withdraw from the CDS program. While

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<sup>3</sup> To illustrate, assume that the generation rate is 4.1¢/kWh, LMP is 6.0¢/kWh, and the NUG contract price is 7.0¢/kWh. Currently the Companies report revenues of 4.1¢/kWh, expenses of 6.0¢/kWh, and a deferred stranded NUG cost of 1.0¢/kWh, resulting in a pretax loss of 1.9¢/kWh. Under the preferred approach, revenues are still 4.1¢/kWh and expenses are 6.0¢/kWh. A NUG Service regulatory asset deferral is recorded equal to 1.9¢/kWh, and the deferred NUG stranded cost expense remains at 1.0¢/kWh. Under either alternative method, a revenue increase of 1.9¢/kWh would eliminate the current loss and maintain the NUG stranded cost deferral of 1.0¢/kWh.

the failure of the CDS program was completely outside of the Companies' control, it left the Companies with the entire POLR load. This increased risk is a financial burden the Companies never agreed to bear at the current POLR rate levels.

The Companies filed for a generation rate increase in 2001 and received substantial recommended rate relief from the presiding administrative law judge in the proceeding. Subsequently, the Companies and most of the other case participants agreed on a settlement that avoided a generation rate increase by recognizing the Companies' actual ongoing POLR costs through ratemaking deferrals and a reallocation of CTC revenues. Although the PUC approved that settlement, it was overturned by the Pennsylvania Commonwealth Court upon appeal.

Subsequent to the 2001 FirstEnergy / GPU merger, the Companies have received substantial assistance in serving their POLR loads through a voluntary wholesale power supply agreement with FES. In recent years, the contract provides that FES will supply all of the Companies' POLR needs that are not being "self-supplied" by the Companies themselves through either the NUG contracts or through bilateral supply agreements between the Companies and non-affiliated suppliers. Under the agreement FES has been providing power to the Companies at the current capped generation rate, which is a deep discount from current market prices. For example, FES provides power to the Companies at approximately \$41.50 per MWh<sup>4</sup>, compared to current energy prices at about twice that price. The FES wholesale agreement has been shielding the Companies from the losses they would have incurred had they purchased power at the high market prices that have prevailed in recent years, while charging their customers what has turned out to be an unfairly low generation rate. Since FES faces the same high market prices, this arrangement has resulted in FES, and therefore FirstEnergy shareholders, effectively subsidizing the Companies and their POLR customers.

FES has notified the Companies that it cannot continue indefinitely to provide this subsidy to the Companies at current levels. Consequently, the supply agreement between FES and the Companies has been modified such that FES has indicated a willingness to continue to subsidize the POLR costs for the Companies, in decreasing amounts, consistent with the Transition Plan. Specifically, the supply agreement now requires the Companies to procure power supplies for their POLR customers, exclusive of the FES supplies, totaling approximately 32% of the non-committed supplies between December 1, 2006 and December 31, 2007. For these purposes, committed supplies include NUG purchase power contracts, owned generating facilities, other purchase power contracts and distributed generation. FES will consider a similar supply arrangement with the Companies after 2007 but only if the Companies procure power supplies for their POLR customers, exclusive of the FES supplies, totaling approximately 64% in 2008, 83% in 2009 and 95% in 2010 of the non-committed supplies in those respective time periods. This modified FES supply agreement is reflected in the Transition Plan and provides a stepped exit strategy over years 2007 through 2010, to gradually eliminate the current FES power supply subsidy. The unit price at which FES sells power to the Companies will not change under the modified supply agreement.

The Transition Plan filing replaces the failed and unworkable retail CDS program with a wholesale Request for Proposal ("RFP") process for procuring a portion of the Companies' POLR supply requirements. The RFP process will acquire power for the Companies starting December 1, 2006 through year-end 2010. It is anticipated that the Transition Plan will also

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<sup>4</sup> The Companies' retail price is about \$46 per MWh due to gross receipt taxes and distribution system line losses.

continue to provide customers the full benefit of low-cost power supplies through the bilateral contracts the Companies have procured with unaffiliated suppliers to serve their POLR loads. This blended supply approach provides moderately stepped increases in generation rates for customers over time, rather than an inevitable large step increase to full market prices in 2011.

The Companies' POLR energy supply for 2007 through 2010 will be a blend from four sources:

- Market-priced power procured through the RFP process,
- FES-supplied power,
- NUG supply, and
- Committed supply contracts from non-affiliated third party suppliers.

The following table details this four-part supply. The 2006 FES supply reflects the estimated supply from FES for the Companies' POLR requirements net of the Companies' NUG, committed supplies, and a small amount of market power supplied in December through the RFP process.

**Met-Ed and Penelec  
POLR Energy Supply  
(thousand GWh)**

|                                 | <u>2006</u> | <u>2007</u> | <u>2008</u> | <u>2009</u> | <u>2010</u> |
|---------------------------------|-------------|-------------|-------------|-------------|-------------|
| Market Power (RFP) <sup>1</sup> | 0.3         | 2.8         | 6.1         | 11.9        | 14.2        |
| FES Supply                      | 8.0         | 6.0         | 3.3         | 2.4         | 0.8         |
| NUGs                            | 5.3         | 5.3         | 5.2         | 5.2         | 5.0         |
| Committed Supply <sup>2</sup>   | <u>16.2</u> | <u>15.9</u> | <u>15.9</u> | <u>11.5</u> | <u>11.5</u> |
| Total POLR Requirements         | 29.8        | 30.0        | 30.5        | 31.0        | 31.5        |

**NOTE:** 1. Reflects Market Power in 2006 only for December.

2. Includes Met-Ed's York Haven hydro output.

Based on the Companies' current estimate of forward energy prices in their regions, the following table details the estimated change in the generation rate over time as the various supply sources are blended into the Companies' generation tariff rate. Because of the FES supply and the favorable existing supply arrangements with non-affiliated suppliers, the proposed generation rate is expected to remain below the currently anticipated full market price.

**Met-Ed and Penelec  
Proposed Generation Rate  
(cents per kWh)**

|                          | <u>2006</u> | <u>2007</u> | <u>2008</u> | <u>2009</u> | <u>2010</u> |
|--------------------------|-------------|-------------|-------------|-------------|-------------|
| Proposed Generation Rate | 4.6         | 5.5         | 6.2         | 7.1         | 7.5         |
| Estimated Power Costs    |             |             |             |             |             |
| Retail Market Price      | 9.5         | 8.9         | 8.4         | 8.4         | 8.0         |
| FES & Existing Contracts | 4.0         | 4.0         | 4.0         | 4.1         | 4.1         |

The proposed RFP process provides a reasonable plan to protect customers from rate shock in 2011 and to flow through to them the benefits of lost-cost POLR power supplies, while also preserving the financial integrity of the Companies.

As an additional customer protection, the Transition Plan also includes a rate cap on the proposed generation rate as detailed in the following table:

**Met-Ed and Penelec  
Proposed Generation Rate Cap<sup>1</sup>  
(cents per kWh)**

|                             | <u>2007</u> | <u>2008</u> | <u>2009</u> | <u>2010</u> |
|-----------------------------|-------------|-------------|-------------|-------------|
| Met-Ed Generation Rate Cap  | 5.7         | 6.5         | 7.5         | 7.8         |
| Penelec Generation Rate Cap | 5.4         | 5.9         | 6.8         | 7.1         |

**NOTE: 1.** The generation rate cap is subject to certain exceptions such as gross receipts tax increases and committed supplier defaults, and certain conditions, such as FES being permitted to participate in the RFP process and PUC approval of the timing of the supply procurement process.

This generation rate cap represents the maximum customer generation rate level even if the cost of the RFP-supplied power would produce a blended generation rate, and cost to the Companies, in excess of the capped level.

**Transition Plan Customer Impacts (2007)**

The following revenue and customer cost increase amounts combine all five components of the Transition Plan. The values in the “preferred” column reflect approval of the requested accounting procedures discussed in this letter. The values in the “alternative” column show the requested revenues assuming the accounting modifications are not approved, and instead, rates are required to be adjusted to provide for appropriate cost recovery:

**Transition Plans**  
**Requested Revenue Changes (2007)**  
**(\$ Millions)**

|                                 | <u>Met-Ed</u> |             | <u>Penelec</u> |             | <u>Total</u> |             |
|---------------------------------|---------------|-------------|----------------|-------------|--------------|-------------|
|                                 | <u>Pref.</u>  | <u>Alt.</u> | <u>Pref.</u>   | <u>Alt.</u> | <u>Pref.</u> | <u>Alt.</u> |
| Distribution Rates <sup>1</sup> | \$ (37)       | \$ (37)     | \$ 20          | \$ 20       | \$ (17)      | \$ (17)     |
| Transmission Rider              | 123           | 123         | 49             | 49          | 172          | 172         |
| CTC Rates <sup>2</sup>          | 0             | 11          | 0              | 0           | 0            | 11          |
| NUG Cost Recovery <sup>3</sup>  | 0             | 43          | 0              | 49          | 0            | 92          |
| Generation Rate                 | <u>131</u>    | <u>131</u>  | <u>88</u>      | <u>88</u>   | <u>219</u>   | <u>219</u>  |
| Net Revenue Change <sup>4</sup> | \$216         | \$ 269      | \$157          | \$206       | \$ 373       | \$475       |
| % Change to Current Rates       | 19%           | 24%         | 15%            | 19%         | --           | --          |

**NOTE:** 1. Includes impact of proposed tariff riders  
2. Preferred approach reflects modification in NUG and CTC accounting  
3. Preferred approach reflects modification in NUG output valuation accounting  
4. May not total due to rounding

**Financial Impacts**

In general, it is anticipated that the revenue changes in the Distribution, Transmission, and NUG Cost Recovery<sup>5</sup> categories will directly impact the Companies' earnings on an after-tax basis<sup>6</sup>. Changes to the CTC revenue levels do not generally directly impact earnings. The generation revenue increases are offset by an equal increase in energy expenses as customers are transitioned towards market-based energy prices.

FES is expected to see an earnings benefit related to the transition of energy sales from the Companies at a price of approximately \$41.50 per MWh to the sale of those MWhs at a market-based price.

**Selected Filing Data**

Some selected filing data for the Companies is attached to this letter as Exhibit 1.

**The Hearing Process**

Following today's filing, we expect the PUC to assign an administrative law judge ("ALJ") to hear our case and other parties will have the opportunity to intervene. The ALJ will schedule a

<sup>5</sup> Although the NUG Cost Recovery category shows zero revenue in the "preferred" column, the earnings impact would be the same as the "alternative" column (revenue of \$43 million for Met-Ed and \$49 million for Penelec) since the preferred approach would defer the expenses that would be covered by the revenue increase in the alternative approach.

<sup>6</sup> The revenues in the table include a 5.9% Pennsylvania gross receipts tax. The combined Pennsylvania state and federal income tax rates are 41.5%. Included in the distribution revenue requirements are increased funding amounts for the Universal Service Programs (approximately \$5 million for Met-Ed and \$9 million for Penelec). Revenues associated with these dollar amounts would have a matching incremental expense increase and would not produce an incremental earnings impact.

pre-hearing conference and set the schedule for discovery, hearings and the briefing period. At the end of that process, the ALJ will issue a recommended decision to the PUC and then the PUC will issue a final order. We expect this process to be completed in a timeframe that should result in a PUC order early in the first quarter of 2007 although no assurance can be given that this timeframe will be met. As in all of our contested regulatory proceedings, we will remain open to the possibility of a settlement by working to find common ground among the parties.

## **Summary**

In prior regulatory orders, the PUC has emphasized that Pennsylvania's electric industry restructuring process has involved, in the case of each utility, a delicate balancing of often competing interests. Individual circumstances, and inherent differences among Pennsylvania's electric utilities, call for flexibility in structuring an appropriate remedy for a particular utility to address problems that have emerged.

There is little doubt that the Companies are unique within Pennsylvania with respect to their restructuring plans. Customers received the considerable benefit of all of the net gains realized from the divestiture of the Companies' generation assets while the Companies were to receive certain benefits and protections expected to result from the 1998 Plan. Had the 1998 Plan worked as intended, at least 80% of the Companies' POLR load would be at or near market-based generation rates today. As discussed in this letter, the 1998 Plan has not worked as intended. Consequently, mid-course adjustments must be made at this time to give effect to the intent of the 1998 Plan, provide a transition to market-based generation rates, ensure full and timely recovery of CTC non-NUG stranded costs and NUG power supply costs, recover the large increase in RTO costs, and allow the Companies to earn a reasonable return in order to remain financially viable and to be able to economically finance their necessary infrastructure expansions and system improvements.

Today's filed comprehensive Transition Plan is a carefully balanced combination of rates, tariffs and accounting procedures that, when taken together, achieves the above objectives. The Transition Plan is expected to allow our customers to continue to pay below-market prices for generation through 2010, and the total rate our customers would pay for electricity with the requested increase in 2007 would remain comparable to the average rates other electric utilities across the state are charging their customers today.

If you have any questions concerning information in this update, please call Kurt Turosky, Director of Investor Relations, at (330) 384-5500, or me at (973) 401-8519.

Very truly yours,

Terrance G. Howson  
Vice President – Investor Relations

**Exhibit 1**

**Metropolitan Edison Company  
Selected Normalized Filing Data**

**Ratemaking Test Year:** Calendar Year 2006

**Retail Sales:** 13,961 GWh

**Ratebase:** \$1,291 million

**Requested Return on Common Equity:** 12%

**Capital Structure and Cost of Capital:**

|                | <u>Capital<br/>Ratios</u> | <u>Cost<br/>Rate</u> | <u>Weighted<br/>Cost</u> |
|----------------|---------------------------|----------------------|--------------------------|
| Long-Term Debt | 51%                       | 6.09%                | 3.11%                    |
| Common Equity  | <u>49</u>                 | 12.00%               | <u>5.88</u>              |
| Total          | 100%                      |                      | 8.99% <sup>1</sup>       |

**NOTE: 1.** The weighted cost rate of return is applicable to the \$1,000 million of distribution rate base. No change has been requested regarding the 10.4% pretax carrying charge applicable to the \$291 million of non-NUG stranded cost rate base.

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**Pennsylvania Electric Company  
Selected Normalized Filing Data**

**Ratemaking Test Year:** Calendar Year 2006

**Retail Sales:** 14,208 GWh

**Ratebase:** \$1,095 million

**Requested Return on Common Equity:** 12%

**Capital Structure and Cost of Capital:**

|                | <u>Capital<br/>Ratios</u> | <u>Cost<br/>Rate</u> | <u>Weighted<br/>Cost</u> |
|----------------|---------------------------|----------------------|--------------------------|
| Long-Term Debt | 51%                       | 6.56%                | 3.35%                    |
| Common Equity  | <u>49</u>                 | 12.00%               | <u>5.88</u>              |
| Total          | 100%                      |                      | 9.23%                    |

## Forward-Looking Statements

This investor letter includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Actual results may differ materially due to the speed and nature of increased competition and deregulation in the electric utility industry, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices, replacement power costs being higher than anticipated or inadequately hedged, the continued ability of our regulated utilities to collect transition and other charges or to recover increased transmission costs, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), and the legal and regulatory changes resulting from the implementation of the Energy Policy Act of 2005 (including, but not limited to, the repeal of the Public Utility Holding Company Act of 1935), the uncertainty of the timing and amounts of the capital expenditures (including that such amounts could be higher than anticipated) or levels of emission reductions related to the Consent Decree resolving the New Source Review litigation, adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits, fines or other enforcement actions and remedies) of governmental investigations and oversight, including by the Securities and Exchange Commission, the United States Attorney's Office, the Nuclear Regulatory Commission and the various state public utility commissions as disclosed in our Securities and Exchange Commission filings, generally, and with respect to the Davis-Besse Nuclear Power Station outage and heightened scrutiny at the Perry Nuclear Power Plant in particular, the timing and outcome of various proceedings before the Pennsylvania Public Utility Commission, including the transition rate plan filings for Met-Ed and Penelec, the continuing availability and operation of generating units, the ability of our generating units to continue to operate at, or near full capacity, our inability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives), the anticipated benefits from our voluntary pension plan contributions, our ability to improve electric commodity margins and to experience growth in the distribution business, our ability to access the public securities and other capital markets and the cost of such capital, the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the August 14, 2003 regional power outage, circumstances which may lead management to seek, or the Board of Directors to grant, in each case in its sole discretion, authority for the implementation of a share repurchase program in the future, the risks and other factors discussed from time to time in our Securities and Exchange Commission filings, and other similar factors. We expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.

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**PENELEC AND MET-ED FILE  
TRANSITION RATE PLAN WITH PENNSYLVANIA PUC  
Would Increase Penelec Base Rates for First Time in 20 Years;  
Met-Ed's First Increase in Nearly 15 Years**

READING, PA – Metropolitan Edison Company (Met-Ed) and Pennsylvania Electric Company (Penelec), subsidiaries of FirstEnergy Corp. (NYSE: FE), today filed with the Pennsylvania Public Utility Commission (PUC) a comprehensive transition rate plan – the first request to increase base rates since 1986 for Penelec and 1992 for Met-Ed. The filing addresses transmission, distribution and power supply issues while ensuring that customers continue to pay below-market prices for generation through 2010.

If approved, Met-Ed and Penelec customer rates for electricity in 2007 would remain in line with the average rates electric utilities across the state are charging today.

“We’ve been able to hold the line on electricity prices for a long time,” said Douglas S. Elliott, president of Pennsylvania Operations for FirstEnergy. “Unfortunately, the costs we incur to serve customers have continued to rise over the years – by hundreds of millions of dollars annually for such items as higher market prices for power, transmission services from the PJM Interconnection, taxes and other expenses we must pay to meet our customers’ needs.

“Inflation has increased by nearly 40 percent since Met-Ed’s last rate increase and nearly 80 percent since Penelec’s last increase. And, many other energy costs, such as natural gas, fuel oil and gasoline, have more than doubled,” said Elliott. “If approved, this request would bring our revenues more in line with our costs while minimizing, to the extent possible, the impact on our customers.”

Penelec has requested an overall increase of \$157 million, or 15 percent, for 2007 if its preferred approach of using certain deferrals and accounting treatments in its filing is approved. If an alternative approach is approved, the increase could be up to \$206 million, or 19 percent. Penelec also has proposed changes in its generation rates for 2008, 2009 and 2010 that could increase revenues by up to \$135 million a year.

If Penelec's preferred approach is approved for 2007, the total bill for a residential customer using 500 kilowatt-hours (KWH) a month would increase 13.5 percent, or \$6.42 on a current bill of \$47.62. The total bill for a commercial customer using 15,000 KWH per month would increase 12.1 percent, or \$153 on a current bill of \$1,265. Rates for an industrial customer using 500,000 KWH per month would increase 12.5 percent, or \$3,764 on a current bill of \$29,994.

Met-Ed has requested an overall increase of \$216 million, or 19 percent, for 2007 if its preferred approach of using certain deferrals and accounting treatments in its filing is approved. If an alternative approach is approved, the increase could be up to \$269 million, or 24 percent. Met-Ed also has proposed changes in its generation rates for the years 2008, 2009 and 2010 that could increase revenues by up to \$165 million each year.

If Met-Ed's preferred approach is approved for 2007, the total bill for a residential customer using 500 KWH per month would increase 17.6 percent, or \$8.83 on a current bill of \$50.10. The total bill for a commercial customer using 15,000 KWH per month would increase 19.3 percent, or \$261 on a current bill of \$1,349. Rates for an industrial customer using 500,000 KWH per month would increase 16.4 percent, or \$5,179 on a current bill of \$31,660.

If approved by the PUC, the new rates could be effective as early as June 10, 2006.

Under Pennsylvania's Electric Competition Law, capped electricity rates have ended. While the companies' 1998 Restructuring Agreement contains price caps for generation, it calls for Met-Ed and Penelec to only serve 20 percent of their customers'

generation needs. However, the companies continue to serve virtually all customers at capped rates, which are well below market prices. The agreement specifically allows the companies to seek an increase in generation rates if efforts to move 80 percent of customers' load to alternative suppliers are unsuccessful. Also under the agreement, all net proceeds from the sale of Met-Ed and Penelec power plants – a benefit worth \$775 million – went to customers.

The proposed transition plan is designed to bring rates more in line with the cost of providing the key components of electric service – distribution, generation and transmission.

For Met-Ed, distribution rates would decrease by \$37 million annually, a reduction that reflects \$22.5 million in annual merger-related savings. For Penelec, distribution rates would increase by \$20 million annually – less than half of what the increase would have been without the benefit of \$22.3 million in annual merger-related savings. The proposed distribution rate also includes an automatic adjustment for universal service programs, storm damage expenses and government mandates.

The transmission portion of the case, which represents nearly half of the overall requested increase, reflects the pass-through of federally mandated charges for transmission services from the PJM Interconnection, the regional power pool. The charges the companies expect to pay in 2006 will exceed what they collect from customers by an estimated \$186 million.

With respect to the generation portion of the bill, the plan includes a four-year transition toward market-based generation rates. During this time, customers would continue paying below-market prices for power.

Met-Ed and Penelec have been receiving power from FirstEnergy's competitive generation subsidiary at a cost that, in recent years, has averaged more than \$300 million annually below market prices. Because of the increasing costs of producing power, including rising fuel and environmental protection expenses, this supply cannot continue to

be offered at the current level. Under the transition plan, the market-priced portion of generation supply that Met-Ed and Penelec procure for customers would gradually increase through 2010.

The transition plan also proposes to defer for future recovery costs related to power that the companies are required to purchase from non-utility generators under federal law, and for which there is no current recovery. The amount of these costs – above what the companies currently collect from customers – is expected to total approximately \$92 million in 2006. However, the deferral would begin with costs incurred after new rates become effective.

Met-Ed serves 526,000 customers within 3,300 square miles of eastern and southeastern Pennsylvania. Penelec serves 588,000 customers within 17,600 square miles of northern and central Pennsylvania. For additional information on the plan, customers may call the company at 1-866-283-8081.

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