Policies to Mitigate Electric Price Increases - Docket # M-00061957
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I submit these comments as an impartial public utility economist with extensive experience in the field, knowledge of the region and respect for the Commissioners and the staff of the PUC. These comments are not intended to advocate for any particular approach or resource, especially as the applicability of any particular solution will depend heavily on the facts at a particular time and place. These are some of the ideas that I would have in mind and want more fully developed if I were again a regulator, and ones I have been discussing them for years in various forums. I have assumed that electric choice remains the law of the land. These comments cut across the issues raised by the Commission in its Investigation Order and those raised by Commissioner Shane in his associated comments. Although it is not possible to accurately quantify the impact of any or of these proposals at this time, each could potentially reduce rates in excess of 10%.

Let me commend this Commission on seeking solutions to the looming specter of rate shock and for its willingness to explore diverse issues ranging from phase-in to new rate levels to enhanced LIURP programs to customer education. In the 80s, when rate shocks were being caused by nuclear plants coming into service significantly over budget, we knew that the attendant rate hikes could be difficult for households to manage and injurious to the economy. The same is true today.

As rate caps continue to be removed, rate shock and rate volatility will become increasing concerns of the PUC. Let's keep in mind that these caps will be coming off after being in place for a dozen years, in some cases. At an annual 4% increase, with compounding, we would have experienced a 60% increase in rates over the twelve years of rate caps. We must remember the deal was get consumers out from under the fixed costs associated with nuclear plants and replace that with market-based, fuel-price-driven prices after a period of rate caps. During the electric restructuring discussions, I suggested that there be a reconciliation mechanism that would have reduced stranded costs should the actual price of electricity be greater than used in calculating stranded costs. This was not the path taken. Here we are, almost a decade later, with the price of natural gas and oil up, and we ask, "How do we protect ourselves from the consequences of the deal that was made?"

Today, I would like to focus on just a few issues, without dismissing the importance of the many other issues that have the potential to mitigate electric price increases. These selected approaches are:

- Post-cap default service rules;
- New resource evaluation metrics in a competitive wholesale electricity market;
- Targeted asset-backed financing; and
- Post-rate cap incentive-based rates and rate design.

Default Service Rules
This Commission has a separate but related investigation regarding how default service providers are to procure the resources needed by customers who choose not to shop. My

comments in that investigation found the short and medium-term futures market for electricity to be grossly inefficient, largely because electricity cannot be stored as a way of hedging against supply crunches. This means that those who purchase electricity in the near-term future at prices established today will pay an enormous premium. The literature I reviewed regarding electricity futures in the PJM market found these risk premiums to be huge – 10 to 15% higher than the average spot market price over the course of a year. This tells consumers to take all the risks of volatility but restricts how they mitigate the risk to a single and inefficient approach.

Economic theory teaches us that the spot market over the long-term is always cheaper than the purchase of short-term hedges. (The short-term is defined as a period in which the capital equipment cannot be changed). Short-term hedges are meant to be used to set an acceptable price, not the lowest price, as there is the added cost of the hedge – an insurance premium. I understand the concern about exposing certain consumers to the price volatility of the electricity marketplace. There are other ways of protecting customers from this volatility that do not have these huge risk premiums driving up the price. I suggest that the Commission consider my comments in L-00040169 that proposes an alternative to buying short and intermediate term energy futures and instead allow default service providers to purchase their resources on the spot market with the added protection of a Volatility Protection Fund. A Volatility Protection Fund is a tool where a utility would be allow allowed to create a pot of money to smooth out costs it experienced by being in the spot market. In essence, consumers would be creating a self-insurance program rather than purchasing the over-priced insurance of a short-term price hedge.

The premium associated with a Volatility Protection Fund may be ten times than the premium required by the electric futures market. The PUC would still need to establish a regulated base price for electricity, which could vary seasonally, by time-of day or be constructed with demand and energy components. The amount placed in the Volatility Protection Fund could be set by examining at the volatility of the expected spot price to the actual price over several years. Base revenues would then be compared to actual costs with the pre-funded Volatility Protection Fund being used to reconcile any differences. When prices exceed the amount charged in rates, the utility default provider could withdraw dollars from the fund. When rates exceed prices, deposits would be made to the fund.

If the Volatility Protection Fund were established as an off-balance-sheet asset, it should be possible fund it with low-cost special purpose bonds serviced by dedicated revenues. An off-balance sheet approach may also be preferable so as not to upset the utility's capital structure while simultaneously isolating the capital costs that would be needed to be recovered to support the Volatility Protection Fund.

As stated earlier, the annual cost premium associated with futures contracts were found to be in excess of 15%. If a Volatility Protection Fund equal to 1/5 of the entire forecasted energy purchase for the year were established through a special purpose bond and the cost of capital was 7.5%, the annual premium on the spot price of electricity would only be 1.5%, before any net offsets for interest that may be earned by the Volatility Protection Fund. This is 1/10 of the forward contract insurance premium and more typical of what an unbiased and efficient future commodity price hedge costs relative to spot prices for other commodities.

If programs such as demand-side response evolve to a point where volatility and the risk premiums associated with the spot market were greatly reduced or eliminated, the Volatility Protection Fund could be reduced or eliminated. The spot price or the average of the projected spot price could also be used without the need for a volatility safety net. Unfortunately, this is not the case today.

New Metrics

A competitive wholesale market for electricity can radically change the value of a resource from a public policy perspective compared to a resource's value under the old PJM shared-savings paradigm. It is critical to your search for ways to mitigate price increases to understand the direct value of these resources to all of Pennsylvania's retail customers. By knowing the true value of these resources, the Commission can set better policies to control rates.

So how is the direct dollar value to the Commonwealth's electricity customers of an additional resource determined? For simplicity, assume that Pennsylvania is an island served by a single utility using the same market rules as PJM. This means that all sales of electricity made on the hourly spot market for electricity are sold at a single market clearing price – assuming no congestion. A change in a resource – whether supply or demand - has the potential of affecting the market price for all energy being sold at that point in time. We can all remember the old paradigm when the impact would have been limited to the difference between the value of resource displaced and the new resource. This change in the valuation of resources can have a major impact on the Commission's policies to control price increases.

In our simplified single utility model, assume a new resource is introduced at below the market-clearing price. The market-clearing price will fall until a new supply/demand equilibrium is achieved. Assume the demand for electricity in a particular hour is 20,000 MW and that the market-clearing price would have been $80/MWh. Assume that a 500 MW resource can be added with an incremental cost basis of $40/MWh. In the old paradigm, the benefit to customers of this additional resource was $20,000 or less (500 MW multiplied by the cost differential of no more than $40/MWh). Under the new paradigm the question is how much will the market clearing price change. Let's assume that the new market-clearing price is $60/MWh, noting that it could be considerably more or less depending on the steepness of the supply curve at that time. The savings to customers is now $400,000 (the entire 20,000 MW multiplied by the price difference of $20/MWh) or 20 times greater than under the old paradigm.

In short, PJM's wholesale market clearing rules can have a great impact on the value of resources to customers. By looking at the correct metrics, the Commission may be interested in encouraging or enabling certain resources. For example when I use a compact florescent bulb, I get the resource savings similar to those under the old paradigm. I've reduced my consumption by a certain amount and save based upon my reduce usage multiplied by the cost I am paying for electricity. There may have been a small impact on the market that others – so called non-participants may have reaped. Under the new paradigm, I have the same gains but non-participants may have significant savings, depending upon how my actions and similar ones by others have on the market clearing prices for electricity over the course of the life of this light bulb. In situations like this, the PUC may want to have programs where non-participants subsidize the capital cost of participants in return for a share of the benefits. This same thought process can be applied to metering and communication systems or even supply-side resources that may produce enormous non-participant benefits, which might not be otherwise developed.

Focusing on resource benefits in this way also changes the perception of when resources might be most valuable. Our old intuition tells us to look at periods of high electric prices and/or high demand but the real focus should be during periods when the supply curve is steep. This is when a relatively small change in resources can cause a large change in the market-clearing price. For example, a change from $100/MWh to $98/MWh with a load of 20,000MWh produces savings of $40,000. Moving from $60/MWh to $30/MWh as we move from an oil-based resource to a coal-based resource with a demand of 12,000 MW has savings of $360,000.

The application of these metrics could lead to the development of resources that create de facto physical hedges against price volatility and make the spot market safer for all customers.

Please note that the same approach should be used when addressing LMP congestion. In these cases, however, the benefits are often restricted to small geographic regions and therefore the benefits rather than accruing to all of PJM are restricted to the electricity purchased in the congested zone.

Both PJM and the Federal government recognize these benefits (see the February 2006 report by the USDOE to the US Congress on the Benefits of Demand Response in Electricity Markets). In my discussions with PJM staff, they have indicated a willingness to help develop the models and analysis necessary for the PUC to evaluate resources using these market-based metrics. Capturing these benefits and implementing policies will take dedication not only by this Commission but other PJM states' commissions, as what happens in one state can affect customers in other PJM states. In my simplified example, I had a single utility serving Pennsylvania's isolated electric load. Although the concepts still hold, actions taken in DQE's service territory may not only help PECO customers but out-of-state customers, as well. This makes the analysis a little more challenging but just as important to do as part of this Commission's electricity price mitigation efforts.

Good information can radically change the policy directions of this Commission on DSR, LIURP, low-fuel cost supply-side resources, etc. I have provided more detailed presentations on this issue to the Commission's DSR working group as one of the participants in the subgroup that was asked to develop the methodology to quantify the direct benefits of DSR.

Targeted Asset-Backed Financing

Asset-backed financing exists when an asset is used to support a debt. A home mortgage is an example of asset-backed financing. When applied to utilities, the asset is usually an irrevocable stream of future revenues. Asset-backed financing may be particularly useful applied to mandates such as alternative energy standards.

One form of asset-backed financing that can help keep rates in check is ring fencing - a way of isolating a particular set of a utility's costs, make them bankruptcy remote and thus significantly reducing the associated cost of capital. This has been done in Pennsylvania when PPL Resources ring-fenced its T&D assets. There are two major factors contributing to the savings. The first is reducing the risk associated with the utility's bonds by backing them with a dedicated, irrevocable stream of revenues; and the second is shifting the utility's capital structures from about 40 to 50% equity to as close to 100% debt as practical. This type of a refinancing can cut the utility's cost of capital in about half. For example a utility with a BBB bond rating a 50/50 capital structure may be able to cut its cost of capital on its T&D plant from 12% to 6%, accounting for the tax impacts. This might produce as much as a 1/3 cut in the associated revenue requirement for transmission and distribution services.

Applying asset-backed financing to long-term contracts for electricity may reduce the capital costs associated with these projects and may help mitigate electric price increases. Unlike with short-term hedges, the utility can use the associated physical resources combined with low-cost capital to help control the price electricity. If supported by the Commission and endorsed by the legislature, it may be possible for utilities to enter into long-term commitments where utility revenues guarantee the investment. This requires the utility to take a long-position in the energy market on behalf of default customers. This may allow more resources to be developed and/or those that would have been developed sold more cheaply through bilateral contracts.

Typically, merchant generation is associated with a cost of capital of about 23% (including taxes), assuming a 33/67 debt-to-equity ratio and 7.5% cost of debt and an 18% return on equity. Asset-backed financing can reduce this to 6% as discussed below and/or to 10% if a 20% equity share is retained by the developer at a 15% return on equity. In either case, this type of project financing may shift some of the risk to the customer but can greatly reduce the expected cost of electricity. Default service providers can target an acceptable price, especially for particular resources - the true use of future positions as hedges.

Post Cap Incentive-Based Rates and Rate Design

A decade or more will have passed without much if any attention to ratemaking incentives and rate design. The removal of price caps and the associated legislative restrictions on inter- and intra-class revenue responsibility shifts provides the Commission with the first time in a decade to revisit these issues.

Incentive-Based Rates (IBR) are rates that are designed to provide utilities and consumers with the proper incentives to do what is in the public interest. Wherever possible, they should be driven by positive incentives rather than negative ones. Incentive-based rates can work with particular reward for a particular action or more broadly with a general bonus (e.g., a higher return on equity) for achieving more general goals. It has been my experience that more generalized incentives require more attention as they can sometimes cause countervailing behavior. Sometimes, an IBR is just removing an existing disincentive, as was the case with the water utility Distribution System Infrastructure Charge (DSIC) that I helped designed. The DSIC is an example of an IBR where the utility earns additional revenues and income by doing exactly what the Commission wants. A similar methodology could be applied to encourage greater cost-effective LIURP spending, new metering technology, etc.

Incentive-based rates through rate design can also be used to encourage customers to behave in ways that the PUC wants to encourage. For generations, there has been a schism between the utility and its customers when it comes to conservation. Consumers like the idea of using less electricity and reducing their bills, while the utility sees not just lost revenue but lost income. As rate caps come off, the Commission might usefully consider an idea where the non-commodity portion of the bill would be set as a fixed fee for certain classes of customers. From a pure economics perspective, why should two similar customers in close proximity pay different amounts for the right to use any amount of power at any time and be billed after the fact? (Note that the Commission may want to visit this 'one-size fits all' service quality paradigm under which electric utility services are generally sold.) The infrastructure required to meet the potential demand of each customer is the same. This type of a pricing makes the utility indifferent about sales and makes it a potential willing partner in developing conservation strategies that could create large savings for customers.

But don't stop the thought process there. What if you created a zero-sum incentive for customers where those in a class who used more than a typical amount of electricity paid a penalty and those who used less got a reward? This approach is a major paradigm shift, but one worth further exploration in the post-rate cap world.

Recap

It is not possible to definitively ascertain the value of any of these individual four actions without detailed discussion and analysis. A superficial analysis, however, suggests that each may be capable of reducing post-cap rates by 10-15%. It would not be reasonable to expect that these savings would be additive, as some produce savings from the same effect (e.g., adding cost-effective resources). Each of these items may have inter- and intra-class impacts that should be carefully considered.

It is also not reasonable to assume that a day of hearings is all that will be needed to address the challenges of post-cap retail rates in a competitive wholesale marketplace. Some of the driving forces, such as wholesale pricing, may be out of the PUC's direct control. Addressing these challenges will take an ongoing effort. The Commission can get started on default service rules, resource evaluation metrics and the targeted application of asset-backed financing and the conceptual development of potential incentive-based ratemaking measures.

Again this Commission should be commended for being willing to grapple with these issues before even the potential of rate shock has negative impacts on Pennsylvania. I thank you for this opportunity and hope to be able to contribute further to this important effort you have initiated.